RATES AND RELIABILITY:
INSIGHTS INTO THE NEW YORK ELECTRICITY MARKET

A Thesis

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ABSTRACT

The lowering of rates for consumers and the continuing reliability of service were two of the major goals that the New York Public Service Commission (PSC) sought to achieve when it restructured the New York electricity industry in the late 1990s. This thesis seeks to gain insights into just how successful industry deregulation has been in achieving these goals. To investigate the lowering of rates for consumers, this thesis examines the evolution of the "average cost per ultimate consumer kWh." Upon finding that costs have not fallen since deregulation, we subsequently decompose them into three components: (i) capacity markets and other add-ons, (ii) wholesale prices, and (iii) distribution costs. We then attempt to identify possible causes behind the evolution of each of the three components. The analysis is focused on three major New York electricity distribution companies: New York State Electric & Gas Corporation (NYSEG); Niagara Mohawk (NiMo); and Consolidated Edison Company of New York (ConEd). Our analysis suggests that incentive regulation has not had a substantial impact on reducing distribution costs; that the Installed Capacity market (ICAP) is creating a large premium over wholesale costs in the New York City Area; and that rising fuel costs have been a major factor in the increase in the wholesale price of electricity. To investigate the effect deregulation has had on the reliability of the system, we examine the integration of the New York Electricity Market by estimating the pair-wise relationships between day-ahead zonal price data. As reliability and competition are maximized when the pool market is integrated, the insights that this thesis provides into when and how the New York electricity market segments offer useful information for policy makers. The analysis indicates that the overall market is becoming more segmented over time, and that the main locations of the segmentation are between zones C and G, and G and J.

BIOGRAPHICAL SKETCH

Steen Videbaek graduated in 1998 with a Bachelor’s degree in Commerce from the University of Canterbury, gaining honors the following year. In 2001 he enrolled at Victoria University of Wellington (VUW) and began writing his Masters thesis under the supervision of Professor Graeme A. Guthrie and Professor Lewis T. Evans. Over the next two of years he researched various issues pertinent to the New Zealand Electricity Market, including high frequency stochastic modeling of the wholesale spot price and spatial market segmentation of the network. He worked concurrently as a research assistant at the New Zealand Institute for the Study of Competition and Regulation (NZISCR) and as a teaching assistant for various finance and economics courses at VUW. In 2004 he graduated with distinction with a Master of Arts in Economics.

In 2005 he traveled to Ithaca, New York to attend Cornell University, where he studied towards a Master of Science in Applied Economics and Management, under the supervision of Professor Timothy D. Mount and Professor Richard E. Schuler. He also worked concurrently as a research assistant at the Power Systems Engineering Research Center (PSERC).

To Mum, Dad, Mor Mor and Far Mor.

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The views expressed in this thesis and any remaining errors are mine alone.

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INTRODUCTION

1.1 Background

In the mid 1990s New York State, motivated by some of the highest electricity prices in the United States, began its march towards industry restructuring--- a journey that the New York Public Service Commission (PSC) believed would result in the lowering of rates for consumers[1] and continuing reliability of service.[2] More than a decade later, a number of authors have questioned just how successful industry restructuring has been in achieving these goals. For example, Apt (2005) calculates the annual rate of industrial price change in New York State and finds that prices have risen 4.3% since restructuring, compared to a 1% decrease in the 8 years prior. The New York State price history from his study for residential, industrial and commercial consumers is presented in Figure 1.1. The results pertaining to the annual rate of change in price for New York residential consumers have been similarly disappointing --- as witnessed by the upward trending middle line in Figure 1.1. Apt (2005) also compares the price changes in states that have deregulated, with the counterfactual, states that have not, and concludes "*there is no correlation between restructuring or regulation and improvement in the annual rate of price change.*" (p. 3)[3]

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[1] From page 28 of Opinion 96-12 State of New York Public Service Commission (1996): "*Lowering Rates for Consumers: Market forces overall are expected to produce, over time, rates that will be lower than they would be under a regulated environment. As we move toward competition, our expectation is that rates overall will be reduced.*"

[2] From page 28 of Opinion 96-12 State of New York Public Service Commission (1996): "*Continuing Reliability of Service: In order to protect all consumers, any new system involving competition in the generation sector must have reliability of the bulk power system as a top priority, including an independent system operator (ISO) that must have the authority and means to continue to provide this reliability.*"

[3] While such studies provide a useful overview of the impact of deregulation on prices, they are dependent on having an accurate counterfactual --- a challenging task due to the idiosyncrasies that are present across states.

Similarly, the 2003 Northeast blackout, in which approximately 50 million people lost power and caused estimated outage-related financial losses of between 4 and 6 billion USD,[4] provides stark, albeit anecdotal, evidence on reliability. Additional evidence on the state of reliability is provided by the falling reserve margins in New York State (see Figure 1.2) According to the 2005 New York Independent System Operator's (NYISO) forecast, the New York Control Area will fall below the 18% summer reserve margin which is needed to meet the North American Electric Reliability Corporation (NERC) reliability margin of 18% (fail less than 1 day in 10 years) in 2008. Furthermore, in 2007 NYISO approved a second 'Reliability Needs Assessment' (RNA).[5] It concluded that "*…generation and transmission resources on New York's bulk electricity grid are expected to be adequate though 2010. Power deficiencies, primarily in the state's southeast region, could occur by 2011 and become acute by 2016 if expected demand isn't addressed by then*." The RNA report's specific concern about the southeast region is complemented by a recent empirical study by Mount and Ju (2006) who showed using principal component analysis that over the last few years the highly populated New York City Area has become more segmented from the rest of New York State Market. As we will explain later, the degree of segmentation present in a pool market is thought to be inversely related to both reliability and the level of competition that is present in the market.

[4] U.S.-Canada Power System Outage Task Force, "Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations." April 2004. http://www.ferc.gov/

[5] "The NYISO Issues Second Reliability Needs Assessment", News Release, New York Independent System Operator, March 19, 2007.

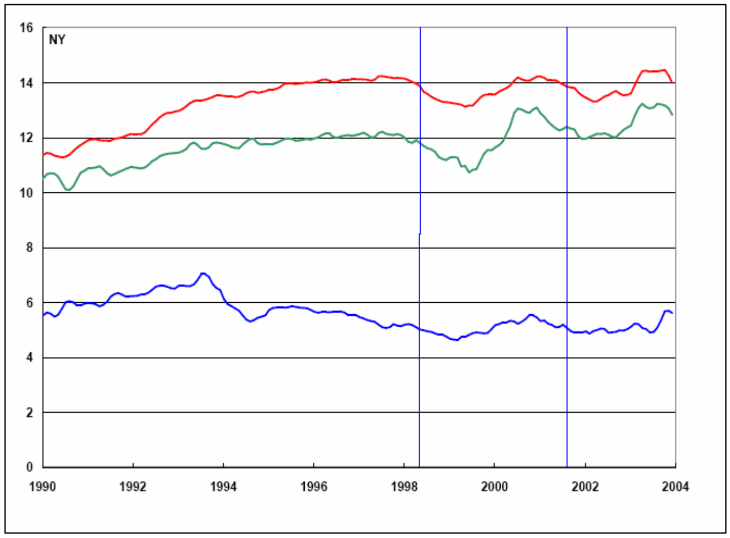

Figure 1.1: New York State Prices (with seasonal adjustments) in U.S. cents/kWh

Key: Residential (top line), Commercial (middle line), Industrial (bottom line).

Source: Apt (2005)

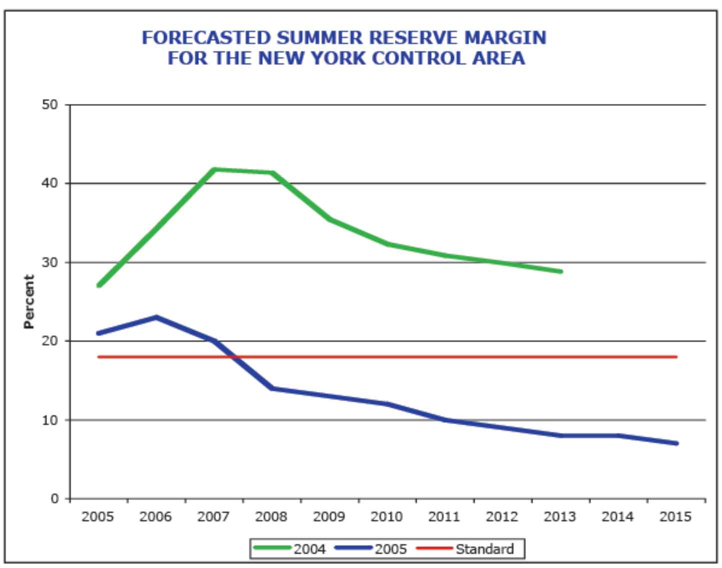

Figure 1.2: Forecasted Summer Reserve Margin for the New York Control Area

Key: Reserve Margin is the amount of Installed Capacity above the Forecasted Peak Load (%). NYISO standard --- A reserve margin of 18% is needed to meet NERC reliability (Fail <1 day in 10 years). Source: NYISO PowerTrends

1.2 Overview

This thesis seeks to gain insights into the progress New York State has made towards the PSC's aforementioned goals for industry restructuring. It is structured as follows:

First in Chapter 2 we provide a general history of the New York electricity market in order to set the scene for what is to follow. We pay special attention to explaining the motivation behind industry deregulation and the circumstances which lead to the creation of stranded assets. The divestiture of generation capacity by regulated incumbents is documented. This chapter also explores the implementation of the wholesale market price cap, which aims to mitigate price spikes caused by market power, and the Installed Capacity market (ICAP), which aims to stimulate generation investment. The ICAP market operates in parallel with New York's wholesale electricity spot and day-ahead markets and will play an important part in the subsequent analysis.

In Chapter 3 we focus on the progress toward lowering rates for consumers. While many studies examine the competitiveness of the wholesale spot market, it is important to realize that the absence of market power in the wholesale market does not guarantee the achievement of low retail prices for consumers. The formation of the price ultimately paid by consumers is reliant on the interplay between three sectors -- generation, transmission and distribution, and retail -- and supplementary markets, like the Installed Capacity market (ICAP). Thus to gain a more complete picture of the progress toward the lowering of rates faced by consumers we analyze the behavior of the "average cost to consumers per kWh" (a proxy for retail prices) for three major New York electricity distribution companies [New York State Electric & Gas Corporation (NYSEG); Niagara Mohawk (NiMo); and Consolidated Edison Company of New York (ConEd)] over the period 1985 – 2005. In particular, we decompose "average cost to consumers per kWh" into three components: (i) wholesale, (ii) capacity markets and other add-ons, and (iii) distribution costs. We then attempt to identify possible causes behind the evolution of each of the three components.

The second part of our analysis is presented in Chapter 4. In this chapter we focus on whether the PSC's second major goal, to maintain the reliability of service, has been achieved. To do this we examine the segmentation of the New York State Electricity market from 2001 to 2005 using pair-wise correlation analysis --- an empirical approach that measures market integration using the classical economic definition of a market.[6] Our interest in the segmentation of the market is twofold. Firstly, it provides insight into the reliability of the system over time. When a market is often segmented, the system operator has fewer generators to dispatch and thus the region is more vulnerable to outages due to the greater probability that supply will not be sufficient to meet load. The aforementioned 2003 Northeast blackout is a dramatic example of a transmission based outage.[7] Secondly, the degree of segmentation in the market also provides insights into the competitiveness of the wholesale market --- which is relevant to PSC's goal of lowering rates for consumers. Given the number of firms in a pool market, competition is maximized if there are no transmission constraints[8] or other phenomena that segment the market. This ensures that every firm competes with

[6] The classical economic definition of a market was advocated by Marshall (1961) when he stated that "the more nearly perfect a market is, the stronger is the tendency for the same price to be paid for the same thing at the same time in all parts of the market: but of course if the market is large, allowance must be made for the expense of delivering the goods to different purchasers." See Section 4.1 for a more detailed discussion of correlation analysis.

[7] Other examples of transmission based blackouts include: 23 September 2003 when over 4 million homes and businesses in Denmark and Sweden lost power for four hours; 28 August 2003 when an estimated 400,000 people were without power in London; and 28 September 2003 when 57 million people were affected by a blackout in Italy.

[8] Transmission constraints occur when a line between parts of the network cannot transmit any more electricity.

every other firm, which lessens the chances that market power can be exercised. Conversely, if the market becomes segmented, decreased competition may result due to the diminished market contestability and the consequent increase in concentration of ownership and control. The analysis in Chapter 4 is specifically concentrated on the pair-wise relationships between Zone J (New York City), A (West), C (Central) and G (Hudson Valley), over off peak trading period 6 (5:00-6:00 a.m.) and peak trading period 18 (5:00-6:00 p.m.). We are particularly interested in identifying the geographical dispersion of segmentation and gaining insights into whether the New York electricity market, with its alleged "third-world electricity grid," [9] is becoming less integrated over time.

Box 1.1: Description of the Selected New York Distribution Companies
SOURCE: Collected from the 2004 10-K annual report filings publicly available on SECInfo.com

New York State Electric & Gas Corporation (NYSEG) --- Subsidiary of Energy East
"NYSEG's principal business consists of its regulated electricity transmission and distribution operations and its regulated natural gas transportation, storage and distribution operations in upstate New York. NYSEG also generates electricity primarily from its several hydroelectric stations. NYSEG serves approximately 854,000 electricity and 254,000 natural gas customers in its service territory of approximately 20,000 square miles. The service territory, 99% of which is located outside the corporate limits of cities, is in the central, eastern and western parts of the State of New York and has a population of approximately 2.5 million. The larger cities in which NYSEG serves both electricity and natural gas customers are Binghamton, Elmira, Auburn, Geneva, Ithaca and Lockport. Approximately 78% of NYSEG's operating revenues for 2004 and 2003 and 82% for 2002 were derived from electricity sales, with the balance each year derived from natural gas sales. No customer accounts for more than 5% of either electric or natural gas revenues."

Continued on next page…

[9] The statement "A superpower with a third-world electricity grid" was made in response to the New York Blackout by Bill Richardson, the New Mexico governor and former head of the Department of Energy, 2003.

Box 1.1 (cont.): Description of the Selected New York Distribution Companies

Niagara Mohawk Power Corporation (now "National Grid")

"Niagara Mohawk Power Corporation (the Company) was organized in 1937 under the laws of New York State and is engaged principally in the regulated energy delivery business in New York State. The Company provides electric service to approximately 1,600,000 electric customers in the areas of eastern, central, northern and western New York and sells, distributes, and transports natural gas to approximately 562,000 gas customers in areas of central, northern and eastern New York. On January 31, 2002, Niagara Mohawk Holdings, Inc. (Holdings), the parent company of Niagara Mohawk Power Corporation became a wholly owned subsidiary of National Grid USA (National Grid). National Grid is a wholly owned subsidiary of National Grid Transco plc (NGT)….Although the Company has exited the generation business, the Company must still arrange for electric supply through a transition period and as provider of last resort, in that the Company will provide electricity and gas to its customers who are unable or unwilling to obtain an alternative supplier (which accounts for approximately 93% of the Company's customers). The Company purchases energy from various suppliers under long-term Purchase Power Agreements (PPAs) and purchases any additional power needs on the open market through the New York Independent System Operator (NYISO)…. As of March 31, 2004, the Company had approximately 52,000 pole miles of transmission and distribution lines for electric delivery."

Consolidated Edison Company of New York

"Con Edison of New York, incorporated in New York State in 1884, is a subsidiary of Con Edison and has no significant subsidiaries of its own. Con Edison of New York provides electric service in all of New York City (except part of Queens) and most of Westchester County, an approximately 660 square mile service area with a population of more than nine million…. Con Edison of New York's principal business segments are its regulated electric, gas and steam businesses. In 2004, electric, gas and steam operating revenues were 77 percent, 16 percent and 7 percent, respectively, of its operating revenues. Electric operating revenues were $6 billion in 2004 or 77 percent of Con Edison of New York's operating revenues. The percentages were 78 and 80 percent, respectively, in the two preceding years. In 2004, 55 percent of the electricity delivered by Con Edison of New York in its service areas was sold by the company to its full-service customers, 45 percent was sold by other suppliers, including Con Edison Solutions, an unregulated subsidiary of Con Edison, to the company's customers under its electric retail access program and the balance was delivered to the state and municipal customers of the New York Power Authority (NYPA) and the economic development customers of municipal electric agencies. (p.10-11)… Con Edison of New York is primarily a 'wires and pipes' energy delivery company that: has sold most of its electric generating capacity; provides its customers the opportunity to buy electricity and gas from other suppliers; purchases most of the electricity and all of the gas it sells to its full-service customers (the cost of which is recovered pursuant to provisions approved by the PSC); and provides energy delivery services to customers pursuant to rate provisions approved by the PSC." (p.14)

CHAPTER 2

HISTORY OF ELECTRICITY DEREGULATION IN NEW YORK STATE

2.1 The Path to Deregulation

Prior to deregulation, the New York State electricity industry was highly vertically integrated --- consisting of seven major utility companies: *Consolidated Edison Company of New York; Central Hudson Gas & Electric; Long Island Lighting Company; New York State Electric and Gas Corporation; Niagara Mohawk Power Corporation; Orange and Rockland Utilities;* and *Rochester Gas and Electric Corporation*.[10] Each utility was responsible for the supply of electricity within its service territory, with the mutually exclusivity of these territories ensuring that each utility was a monopoly supplier.[11] Because of this, utilities were heavily regulated to counteract their monopoly urge to overprice and under-produce. 'Rate of return regulation' was the New York Public Utility Commission's preferred regulatory approach until the mid 1990s. Under this regulatory regime the price the regulated utility can charge consumers is set by the regulatory authority, the State of New York Public Service Commission (PSC). Note that 'rate of return regulation' is sometimes confused with 'price cap regulation'. While both stipulate the prices a regulated firm may charge for its products, rate of return regulation does this by setting the price of each product individually, whereas under price cap regulation a cap is set for a basket of goods --- thus allowing more price flexibility. Rate of return regulation's somewhat

[10] While the utilities owned generation, power was also purchased from non-utility generators and other regulated utilities.

[11] Note that dual franchise areas did exist, but they were extremely rare. See Pechman (1993) for a discussion on the configuration of the New York Investor Owner Utilities service territories.

misleading name comes from the procedure to find the stipulated prices. Prices are set in order to ensure the firm can earn a fair rate of return on its agreed upon rate base.[12]

The mid 1990s saw rising disquiet over persistently high electricity prices. Industrial lobby groups argued that the high electricity prices were damaging the competitiveness of New York-based businesses, leading to an exodus of firms, and consequently job losses. Many blamed the high prices on the regulated utilities' inflated rate bases, due to stranded assets[13] incurred by utilities building what in hindsight turned out to be uneconomic generation facilities and entering into high priced long-term contracts with independent suppliers in the 1970s and 80s.[14] The primary initiator of asset stranding was the greatly inflated price of oil in the 1970s and 80s --- a result of the 1973 and 1979 oil crises.[15] During these periods the real world price per barrel of oil increased from $3 in 1972 to $32 USD in 1980.[16] Furthermore some experts predicted future prices to top $80 USD in the United States. These high prices and wildly inflated price expectations would have a profound effect on the New York State electricity market for decades to come. Firstly, at the firm level, the high price of oil and fears over its supply meant that in the 1970s and 1980s many existing utilities sought to diversify their electricity generation portfolios away

[12] See Guthrie (2006) for a more detailed discussion of the differences between 'rate of return' and 'price cap' regulation.

[13] Asset stranding occurs when investments have become uneconomic before the end of their physical lives.

[14] In 1997 the Public Service Commission estimated the cost of buying out these over priced, state ordered contracts to be $10.6 billion (Perez-Pena, 1997b).

[15] The 1970's had heralded a turbulent era in world energy markets. First in 1973, the first oil crisis began when members of Organization of Arab Petroleum Exporting Countries (OAPEC) began an embargo on oil exports to the United States, who had continued to support Israel during the Yom Kippur War, and the Organization of Petroleum Exporting Countries (OPEC) cartel used its market power to further increase prices. Then in 1979, the second oil crisis occurred when the US favored Shah of Iran, Mohammad Reza Pahlavi, was overthrown in the Islamic Revolution of Iran. He was replaced by Shi`i Muslim cleric, Ayatollah Khomeini.

[16] Source: Energy Information Administration, Annual Energy Review 1997, DOE/EIA-0384(97). (Washington, DC, July 1998), Table 5.19. http://www.eia.doe.gov/emeu/cabs/AOMC/7079.html

from oil. An obvious candidate was nuclear power, which at current and projected electricity prices had become economically viable. Secondly at the federal level, the 1978 Public Utility Regulatory Policies Act (PURPA) was passed by the United States Congress. The legislation, enacted to reduce the United States' dependence on foreign oil in an attempt to insulate the United States economy from the predicted high oil prices, forced existing utilities to buy from new 'non utility' generators that were not oil dependent.[17] Interestingly, PURPA was not enforced by federal agencies. Rather it was up to individual states to implement it, which New York State emphatically did, requiring utilities to sign long term contracts with non utility generators and enacting regulations that exceeded the obligations under PURPA (Joskow, 2000). The high prices expectations of the late 70s and early 80s did not materialize, as oversupply saw the price of oil steadily decreased to under $20 by 1985. This left many utilities holding long term contacts (20-30 years) that required them to purchase electricity at prices far above cost, and owning inefficient generation that were not longer economically viable. The situation was also made worse by large cost overruns on many of the nuclear generation projects.[18]

For major industrial users, deregulation, with its considerable success in the long distance telecommunications and airline industries, offered hope of a fresh start free of these stranded assets and inefficient generation. In 1993, the PSC began to publicly investigate the deregulation of the New York State electricity industry.[19] This heralded the start of a highly consultative process, with input solicited from both the

[17] This also could be seen as the electricity industries' first foray into competition.
[18] Section 2.2 provides a detailed description of the stranded costs of the three utilities we examine.
[19] Case 94-E-0952 (previously titled 93-M-0229 "Proceeding on Motion of the Commission to Address Competitive Opportunities Available to Customers of Electric and Gas Service and Develop Criteria for Utility Responses")

public[20] and major interest groups.[21] Industry lobbyists also had some unlikely allies, with various environmental groups also favoring deregulation, believing it would lead to an increase in consumers 'green power' choices.[22] In late 1994, industry deregulation received another boost, with the election of pro-deregulation candidate Mr. George E. Pataki as Governor of New York. Pataki had campaigned on a platform of lowering electricity prices and halting job losses.[23] The next three years would see a flurry of activity directed towards the deregulation of the industry. On June 7th 1995, the New York Public Service Commission issued Opinion No. 95-7 on Case 94-E-0952, which outlined the principles to "form the basis for the development of a framework for movement toward a more competitive electric marketplace." The following year on May 20th 1996 the PSC issued Opinion No. 96-122 on Case 94-E-0952,[24] which outlined the six major goals for deregulation. These included: 1) lowering rates for consumers; 2) increasing customer choice; 3) continuing reliability of service; 4) continuing programs that are in the public interest; 5) allaying concerns about market power; and 6) continuing customer protections and the obligation to serve.[25]

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[20] Public input was solicited via the Public Involvement Program, Public Statement Hearings, as well as a website and an 800 phone line.

[21] Major Interest Groups included: industrial and large commercial consumers; residential and small commercial consumers; investor-owned utilities; labor unions; publicly-owned utilities; competitors (independent power producers and energy service companies); environmentalists; department of public service staff, and other public agencies.

[22] Most consumers in New York State are now able to purchase electricity produced using environmentally-friendly electricity generation through various green energy service companies. Such green energy service companies include: Agway Energy Services, Community Energy, Inc., ConEdison Solutions, EarthKind Energy, Inc., Energetix, Inc., EnviroGen, and NYSEG Solutions, Inc. More information can be found on: http://www.askpsc.com/askpsc/page/?PageAction=renderPageById&PageId=a8022193f892947a1d26b67506005183

[23] Pataki narrowly defeated three-term incumbent Democratic Governor Mario Cuomo.

[24] For more information see: http://www.dsireusa.org/documents/Incentives/NY11R.pdf

[25] See Box 2.1.for a more detailed description of each goal.

To achieve these goals the PSC envisaged having, where possible, competitive generation and retail markets, together with regulated transmission and distribution networks.[26] This industry structure is consistent with standard microeconomic theory, which tells us that an industry which is a natural monopoly[27] should be provided by one firm, hence taking advantage of the economics of scale, and that this firm should be subject to regulation, in order to prevent the abuse of market power;[28] in industries that are not natural monopolies, the superior incentives which competitive forces can provide to increase efficiency are often preferred, leading to the promotion of competition through divestiture and/or industry entry. The complication for New York State was that the incumbent monopoly utility companies[29] were a vertically integrated mixture of a natural monopoly (local distribution networks) and non-natural monopoly production and service (generation and retail). Thus to achieve the PSC-preferred industry structure, the incumbent utilities needed to be persuaded to divest their generation assets, and focus their business primarily on their local distribution networks (i.e. effectively become distribution companies). Such a divestiture, combined with the creation of a competitive wholesale market operated by an independent system operator, [30] would help facilitate a competitive generation sector. The distribution companies would then be regulated using modern incentive regulation, and retail competition would be encouraged through requirements that the

[26] Appendix C of Case 94-E-0952 provides an overview of the recommended industry structure.
[27] A natural monopoly is "an industry in which one firm can achieve economies of scale over the entire range of market supply" (Schiller, 2002 --- Glossary).
[28] An unregulated natural monopolist raises price above, and produces less than, those which would be observed in a competitive market --- thus creating a deadweight loss to society.
[29] Consolidated Edison Company of New York; Central Hudson Gas & Electric; Long Island Lighting Company; New York State Electric and Gas Corporation; Niagara Mohawk Power Corporation; Orange and Rockland Utilities; and Rochester Gas and Electric Corporation.
[30] The New York Independent System Operator NYISO was formed on the 1st December 1999. It is a 'not-for-profit' corporation regulated by the Federal Energy Regulatory Commission (FERC).

incumbent distribution companies allow new entrant retail firms, or energy service companies (ESCO's), access to their local distribution infrastructure.[31]

Box 2.1 New York Public Service Commission's Goals for Deregulation
SOURCE: OPINION NO. 96-12 CASES 94-E-0952 p. 29-30.

1. Lowering Rates for Consumers: Market forces overall are expected to produce, over time, rates that will be lower than they would be under a regulated environment. As we move toward competition, our expectation is that rates overall will be reduced.
2. Increasing Customer Choice: Increased customer choice among types of services and prices to be paid should mean allowing customers throughout the State the opportunity to choose among a number of suppliers (such as generators and energy service companies (ESCOs)) of electricity and other services. Customers will also be able to choose to lower their levels of electric service in return for economic benefits.
3. Continuing Reliability of Service: In order to protect all consumers, any new system involving competition in the generation sector must have reliability of the bulk power system as a top priority, including an independent system operator (ISO) that must have the authority and means to continue to provide this reliability. An example of this is interruptible electric service, that could be tailor-made to an individual customer's desires.
4. Continuing Programs that are in the Public Interest: We have the responsibility to ensure that electric service is provided safely, cleanly, and efficiently. This responsibility may entail continuing specific measures to preserve certain programs such as energy efficiency, research and development, environmental protections, and low-income beyond what competitive markets provide.
5. Allaying Concerns About Market Power: No competitor or group of competitors should be able to exercise undue market power over other competitors either because of market power at another stage of production (vertical market power) or because of dominance at the same stage of production (horizontal market power). The clearest way to preclude vertical market power is to have divestiture of (1) generation, (2) transmission and distribution, and (3) energy services. Horizontal market power can be avoided by ensuring that a sufficient number of independent competitors participate in the market.
6. Continuing Customer Protections and the Obligation to Serve: Statutory requirements make clear that our mandate is to ensure that all New Yorkers have access to safe and reliable service at just and reasonable rates. Each customer must be able to count on at least one supplier who will continue to provide service at reasonable rates in the event that (a) the customer chooses to make no change from its current situation, (b) a new supplier fails to meet its obligations, or (c) competitive alternatives are not yet available in the area.

[31] This unbundling of networks allows ESCO's to compete at the retail level with the incumbent distribution company without the burden of unnecessarily duplicating the incumbent's network.

In order to facilitate the transition to PSC's preferred industry structure, Opinion No. 96-122 on Case 94-E-0952 ordered Consolidated Edison Company of New York and New York State Electric & Gas Corporation (as well as Orange and Rockland Utilities; Rochester Gas and Electric; and Central Hudson Gas & Electric Corporation) to file proposed plans for rate/restructuring no later than October 1, 1996.[32] A description of what utility companies were asked to provide in these restructuring plans is presented in Box 2.2.

Box 2.2: Description of What the Filings Ordered by the PSC Should Address at a Minimum
SOURCE: Opinion No. 96-122 (p. 82 and 83)

1. The structure of the utility both in the short and long term, the schedule and cost to attain that structure, a description of how that structure complies with our vision and, in cases where divestiture of generation is not proposed, effective mechanisms that adequately address resulting market power concerns;
2. A schedule for the introduction of retail access to all of the utility's customers, and a set of unbundled tariffs that is consistent with the retail access program;
3. A rate plan to be effective for a significant portion of the transition that incorporates our goal of moving to a competitive market, including mechanisms to reduce rates and address strandable costs;
4. Identification of the public policy programs, whose funding is not recoverable in a competitive market, that need special rate treatment and competitively neutral mechanisms to recover such costs;
5. An examination of the load pockets unique to the utility, identification of potential market power problems, and proposals to mitigate market power; and
6. A plan for the provision of energy services, including addressing the continued provision of customer protections consistent with an emerging competitive market.

[32] Niagara Mohawk was dealt with in other proceedings and had already submitted its 'Power Choice' plan.

2.2 Deregulation by Negotiation

Over the next year the PSC negotiated individually with each of the major utility companies in order to deregulate the industry. The non-legislative approach to deregulation adopted by the PSC was a departure from the typical state legislation path used by the likes of California, and was pursued due to the partisan nature of politics in Albany at the time. Pataki, a Republican, would have needed legislation passed in each house of the New York State Legislature (Assembly and Senate) before he could sign it into law. At the time the Assembly was under Democratic control, meaning that any legislation would have likely needed major alterations in order to pass --- something Pataki was not willing to do. A summary of the PSC restructuring orders for Consolidated Edison, NYSEG and Niagara Mohawk can be found in Box 2.3.

While the non-legislative approach avoided the 'watered down' legislation criticisms that were leveled at California, it did have a major drawback. With the PSC unsure of its legal footing during the negotiation process, the utilities gained negotiating power.[33] Consequently, the PSC's early aggressive stance softened in order to avoid an uncertain, and possibly lengthy, litigated outcome."[34] While the subsequent settlements with the utilities ensured deregulation of the industry was possible, they received criticism regarding the distribution of rate cuts and the treatment of stranded assets. For example, the original settlement, for Consolidated Edison gave industrial users a 25% rate cut compared to only 3.3% for consumers.[35] This lead to criticism that the negotiated rate cuts heavily favored industrial customers and that residential

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[33] "*The commission was never sure it has the legal authority to order such changes -- the utilities threatened to tie the state up with litigation for years if it tried*" (Perez-Pena, 1999, p.37).

[34] "*We [State of New York Public Service Commission] stated our "strong interest in expeditiously negotiated resolutions of the individual utility filings" and expressed our preference for a negotiated resolution over a litigated outcome.*" [OPINION NO. 98-6 p.3].

[35] The original settlement was signed on March 12, 1997.

and commercial consumers were effectively subsidizing job creation in the state.[36] The following quote from the Consolidated 1997 Rate Case hearing is indicative of the views of many commercial and residential consumers: "*The most common concerns expressed included: the proposed rate decreases for residential and small business customers are too low, with some consumers advocating across-the-board rate reductions*…"[37] The reasoning behind the PSC division of rate cuts was given in OPINION NO. 98-6 p.22 where it was argued that *"the rate plan is intended to promote jobs and economic development by reducing rates for large industrial and commercial customers to a level approaching the national average."* They also argued that had they "*apportioned the revenue reduction equally among all classes, customers other than large industrial and commercial customers would have realized a minimal gain, while the laudatory goal of promoting job growth and economic development would have been lost.*" (p.40) On June 20th, 1997 Administrative Law Judge Judith Lee, while praising the settlement as "*an extraordinary step toward resolution of complicated and contentious issues recommendation*", recommended that "*it would be preferable, even in light of the policy goals encouraging economic development, for the gap between reductions for industrial customers and residential customers to be smaller than it is under the Settlement, resulting in a more gradual correction in rate disparity."*[38] She also recommended that continued discussions between the parties should take place. A revised settlement, which was adopted in

[36] Sheldon Silver, the Speaker of the New York Assembly, tried unsuccessfully to shift control of the deregulation process back to the New York State Legislature. According to Perez-Pena (1997a) Mr. Silver argued "*that the Public Service Commission, left to act on its own, will not pass along enough savings to ordinary consumers*." He also was in favor of utilities absorbing a greater share of the stranded costs (Perez-Pena, 1997a).
[37] Consolidated Edison Rate Case 1997: Consumer Input.
[38] CASE 96-E-0897 http://www.dps.state.ny.us/conedsettle.htm

November 3, 1997, saw promised savings for commercial, general service customers, residential and small business increased to 10 percent by the end of fifth year. [39,40]

Box 2.3: Summary of PSC Restructuring Orders for Consolidated Edison, NYSEG and Niagara Mohawk

SOURCE: This information is reproduced from Public Utilities Fortnightly Magazine "PSC Restructuring Orders", Bruce W. Radford, May 15, 1998. http://www.pur.com/pubs/2962.cfm

CONSOLIDATED EDISON OF NEW YORK, INC. RETAIL CHOICE: Begins June 1, 1998, for 500 MW of load; up to 1,000 MW by April 1, 1999; additional 1,000 MW by April 1, 2000; full implementation by Dec. 31, 2001, or when state achieves full operation of independent system operator, whichever comes first. SAVINGS: Immediate 25-percent rate cut for large industrial customers with monthly demand above 1,500 kW; 10-percent for commercial and general service customers (+1,500 kW) over 5 years; 10-percent for residential and small business by end of fifth year. Prior rate increases waived. Total savings between $1 billion and $1.5 billion over 5 years. DIVESTITURE: Company to sell at least 50 percent of in-city generating capacity; process was to begin by mid-April for 30 percent within 90 days. (Sell-off plan OK'd, Jan. 14, 1998, Case 96-E-0897, 183 PUR4th 159.) RETURN ON EQUITY: Approves 10.9 percent, with sharing of excess earnings triggered at 12.9 percent. OTHER: Plan expands company's Business Incentive Rate, making 65 MW available at reduced rates to encourage businesses to locate in ConEd's service territory. See, Case 96-E-0897, Opinion No. 97-16, Nov. 3, 1997 (N.Y.P.S.C.).

NEW YORK STATE ELECTRIC & GAS CORP. RETAIL CHOICE: Begins Aug. 1, 1999 for all customers. SAVINGS: Large industrials get 5-percent annual rate cuts over 5 years. Rates frozen for residential and small commercial classes for 4 years, with 5-percent cut in fifth year. Overall customer savings put at $725 million ($522 million from foregone rate increases). Generation backout credit equals 3.23 cents per kWh through July 31, 2000; 3.47 cents until July 31, 2001; then 3.71 cents through end of settlement. DIVESTITURE: Company must sell its coal-fired generating plants by multi-round auction process by Aug. 1, 1999. Proceeds above book value will mitigate nuclear stranded costs; company may retain 20 percent of gain from renegotiation and/or termination of above-market purchased power contracts. RETURN ON EQUITY: Earnings above 9 percent return on equity trigger sharing with ratepayers. Cap imposed at 12 percent (all excess earnings go to customers). OTHER: Includes about $40 million in funding for system benefits charge for energy efficiency and public policy programs. See, Case 96-E-0891, Opinion No. 98-6, March 5, 1998 (N.Y.P.S.C.).

Continued on next page….

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[39] "NY Atty Genl praises revised ConEd rate settlement" *Reuters News*, 5 September 1997.

[40] See http://archive.pulp.tc/O_O97-16.pdf

Box 2.3 continued: Summary of PSC Restructuring Orders for Consolidated Edison, NYSEG and Niagara Mohawk

NIAGARA MOHAWK POWER CORP. RETAIL CHOICE: Begins in 1998 for large industrial and commercial customers; available for all by Jan. 1, 2000. SAVINGS: Immediate 25-percent cut for the very largest industrial and commercial customers. By 2000, all industrials to save about 13 percent, versus 3.2 percent for residential and small commercial classes (many of whom may see no decrease, and perhaps an increase). PSC defers final decision on proposed customer charges for residential and small commercial classes that would produce net rate increase in some cases. Order admits that generation backout rate is "low" (reflects fuel costs and wholesale prices in New York Power Pool) but rejects Enron proposal for higher rate of 3.95 cents per kWh, reflecting property taxes and higher NYPP reserve margin (18 percent, up from 14 percent). DIVESTITURE: Company may retain 15 percent of any gain above net book value as incentive for sale of non-nuclear generation. Nuclear generation would remain with the regulated T&D company. RETURN ON EQUITY: Company assumes $2 billion in stranded costs by accepting "very low" equity return over 5 years. OTHER: Approves "floating" competitive transition charge to fund $3.6-billion debt needed to execute settlement with 16 independent power producers to restructure uneconomic purchased power contracts. Exit fees and backup service charges for on-site generators designed to make CTC nonbypassable. Provides third-party administrator for system benefits charge. Set up $10 million fund for employee retraining/outplacement/severance. See, Case 94-E-0098, Opinion No. 98-8, March 20, 1998 (N.Y.P.S.C.).

The treatment of stranded assets was also a contentious issue. As previously discussed, one of the major drivers behind the push towards deregulation was that it would provide a fresh start, free of stranded assets. With the PSC favoring a non-legislative approach to deregulation, stranded assets became an important negotiation point for incumbent utilities. The major question which needed to be answered was: "who should assume financial responsibility for these bad investments --- the shareholders of the utility or the utility's customers?" Attorney general Eliot Spitzer forwarded one popular argument when he commented on the infamous Nine Mile Nuclear generation facility in 2001. He stated that "*Customers should not have to pay Nine Mile stranded costs. Customers did not choose to make an uneconomic investment in these plants. Shareholders, on the other hand, voluntarily purchased the* *selling utilities' stock. When doing so, they assumed the risk that not all of management's decisions would be correct…. The very fact that the plants' market value as determined through a competitive auction is less than the utilities' cost conclusively proves that the utilities spent more for the plants than they are worth. The utilities' shareholders should bear the burden of that fact.*"[41] The counter argument to this was that, as previously discussed, New York State required utilities to sign long term contracts with non utility generators and enacted regulations that exceeded the obligations under PURPA (Joskow, 2000). Also, incumbent utilities invested in these generation projects in a regulatory environment in which prudently incurred investment would be included in their rate-base. In Cases 94-E-0952 et al., supra, Opinion No. 96-12, the PSC decided that strandable investment would be eligible for rate recovery if they are deemed to have been prudently incurred.[42]

Of the three utilities we examine, Niagara Mohawk was the most affected by stranded assets and costs. There were two main reasons for this. Firstly, Niagara Mohawk commissioned 'Nine Mile Point', a nuclear power plant located by Oswego, New York. Nine Mile Point consists of two units with rated capacities of 621 MW and 1,135 MW, that went online in 1974 and 1987, respectively.[43] Both projects were plagued by cost overruns and in 2001 Spitzer claimed that "*costs at Nine Mile 2 have been so high that, ever since it came into service, customers have paid substantially more for Nine Mile 2's output than they would have if that plant's owners had simply*

[41] Comments Of Eliot Spitzer Attorney General of the State of New York, Case No. 01-E-0011 September 25, 2001. http://www.oag.state.ny.us/telecommunications/filings/ninemile.html

[42] Prudent is defined as "*The company's conduct should be judged by asking whether the conduct was reasonable at the time, under all the circumstances, considering that the company had to solve its problems prospectively rather than in reliance on hindsight. In effect, our responsibility is to determine how reasonable people would have performed the tasks that confronted the company.*" Cases 94-E-0952 et al., supra, Opinion No. 96-12.

[43] See http://www.eia.doe.gov/cneaf/nuclear/page/at_a_glance/reactors/nine_mile.html

bought the same amount of electricity elsewhere."[44] In May 2001, Niagara Mohawk, which owned all of Nine Mile One and 41% of Nine Mile Two,[45] reported that "*it had $1.277 billion in Nine Mile One and Two costs on its books, and that after applying the proceeds from the sale of its interests and absorbing $123 million of the loss as here, it would have $686 million in stranded costs*"[46] The second main reason behind Niagara Mohawk's high stranded costs was the combination of its obligation under PURPA to buy electricity from independent generators who wanted to supply and the opening of the Empire State Pipeline in 1993. This natural gas pipeline, which runs from Buffalo, near the Canadian border, to Syracuse, in the Mohawk Valley, substantially lowered the barriers to entry that new independent entrants faced by allowing easy access to Canadian sourced natural gas.[47] This resulted in Niagara Mohawk having the largest number of IPPs in its service territory and consequently entered into a larger number of long-term contacts, compared to other New York utilities. In 1997 Niagara Mohawk commented that *"by far, the single largest factor contributing to the company's higher electric prices was increased payments to independent power producers (IPPs) pursuant to power purchase agreements (PPAs) containing prices exceeding the market value of electricity. In 1995, for example, Niagara Mohawk's total payments to IPPs exceeded $1 billion. These payments were expected to increase over the next 20 years at a rate faster than the forecast rate of inflation."*[48] In 2002, Niagara Mohawk reported that their total regulatory assets amounted to approximately $5.1 billion. Under Niagara Mohawk's 1997 Merger Rate

[44] "Sale of plants would create debt Niagara Mohawk wants to pass $1.2 billion to ratepayers. Spitzer balks." By Chris Iven, April 21, 2001 (http://archive.pulp.tc/Saleof_plants42301.pdf)
[45] In 2001 the other owners of Nine Mile 2 were: NewYork State Electric & Gas (18%); Rochester Gas & Electric (14%); Central Hudson Gas & Electric (9%); and the Long Island Power Authority (18%).
[46] From Eliot Spitzer, Attorney General of the State Of New York State of New York, comments on the Public Service Commission Case 01-E-0011
http://www.oag.state.ny.us/telecommunications/filings/ninemile.html
[47] The Empire State Pipeline is a subsidiary of National Fuel Gas Company. It is 157 miles long and has a design capacity of 525 million cubic feet per day.
[48] State Of New York Public Service Commission Case 94-E-0098 (p. 2)

Plan "*a regulatory asset was established that included the unamortized costs of the MRA [Master Restructuring Agreement], the cost of any additional independent power producer (IPP) contract buyouts, and the deferred loss on the sale of the generation assets. The MRA represents the cost to terminate, restate, or amend IPP Party contracts. Beginning January 31, 2002, the Merger Rate Plan stranded costs regulatory asset is being amortized over ten years, with larger amounts being amortized in the latter years. Niagara Mohawks rates under the Merger Rate Plan have been designed to permit recovery of, and a return on, the Merger Rate Plan stranded costs.*" [49]

NYSEG was also affected by Nine Mile Two nuclear facility, albeit to a lesser extent. In 2000 they sold their 18% stake to Constellation Energy for $123.2 million, a $332.8 million dollar loss on its $446 million book value. In total, NYSEG's stranded costs and assets amounted to $645.5 million.[50] NYSEG was able to use the after-tax proceeds from its $1.3 billion sale of its coal-fired generation facilities to offset all of the stranded costs from its nuclear generation assets.[51] The remaining stranded costs, which related to NYSEG's PPAs, are being recovered though the Transition Charge. Each month NYSEG calculates the above or below-market cost of its purchased power contracts by comparing the market price of electricity with the contracted price of the purchased power agreements. The difference is then either collected or refunded to customers through the Transition Charge.[52]

[49] Niagara Mohawks Form 10-K 2003 --- Note C Rate and Regulatory Issues and Contingencies.
[50] See http://www.oag.state.ny.us/telecommunications/filings/ninemilesale.html
[51] See http://findarticles.com/p/articles/mi_qa3718/is_199906/ai_n8859256
[52] This pricing mechanism is more fully explained in NYSEG's PSC 120 tariff which can be found at http://www.nyseg.com/nysegweb/webcontent.nsf/Lookup/120v60/$file/120v60.pdf.

Originally it was thought that Consolidated Edison would have large amounts of stranded costs. In 1997 the company estimated with forward-looking statements that "on a present value basis, its electric strandable costs could be between $4.7 billion and $6.2 billion, including an estimated $650 million relating to its fossil-fueled plants; $1.1 billion relating to its nuclear generating operations (including decommissioning costs); and $3 billion to $4.5 billion relating to capacity charges under Con Edison's contracts with NUGs."[53] However, Consolidated Edison's actual stranded costs were materially lower than this due to the higher than expected proceeds from New York City generation facilities.[54] As of December 31, 2000, Consolidated Edison reported that its net regulatory assets amounted to approximately $1.2 billion.[55] In 1997, Consolidated Edison and the PSC agreed on a revised settlement that allowed Consolidated Edison to recover substantially all of its stranded costs.

2.3 Divestiture of Generation Assets

For their part utilities agreed to open up their retail markets to competition and to divest a proportion of their generation facilities. This was done either explicitly or implicitly by providing incentives. As a result, the years following the restructuring plans saw a flurry of major transactions as incumbent utilities sort to divest their generation assets. For example, consider Consolidated Edison who agreed in 1997 to "*sell at least 50 percent of in-city generating capacity*". In 1999, they sold the 842 megawatt Arthur Kill Generating Station in Staten Island (consisting of three oil- and natural gas-burning generating units); the 614 megawatt Astoria gas turbine facility in Queens to NRG Energy Inc for $505 million; and the 2,168 megawatts of generation

[53] Consolidated Edison Co of New York Inc · 8-K · 3/13/97. See http://www.secinfo.com/dn2v.8d.htm
[54] These gains were partially offset by the sale of Indian Point Nuclear plant well below book value.
[55] See Consolidated Edison Form 10-K, 2001.

in Queens (Ravenswood Generating Station together with an additional gas turbine site) to Keyspan Energy (KSE) for $597 million.[56] In 2001, they subsequently completed the sale of Indian Point 1 and 2 nuclear units, and three natural gas-fired turbines to Entergy for $502 million.[57] Similarly, the consortium of Niagara Mohawk, NYSEG, Rochester Gas and Electric, and Central Hudson Gas & Electric sold their 82% stake in Nine Mile Two for $762 million.[58,59] A complete listing of generation divestitures by New York State Utilities for the period 1997-2002 is given in Table 2.1.

Table 2.1: Generation Divestitures by New York State Utilities for the Period 1997-2002[60]

Utility	Year	Generation Facility	Type	Location (Zone)	Capacity (mW)	Buyer	Price (millions)	Book Value (millions)*	Multiple of Book Value
Consolidated Edsion	1/28/1999	Arthur Kill Generating Station	Oil/Gas - Combustion Turbine and Steam Turbine	Staten Island (J)	842	NRG Energy Inc (subsidiary of			
		Astoria (Gas Turbine)	Oil/Gas - Combustion Turbine	Queens (J)	614	Northern States Power Co.)	$505	$201	2.5
	1/28/1999	Ravenswood Generating Station	Oil/Gas - Combustion Turbine	Queens (J)	1,753	Keyspan Energy			
		Ravenswood Gas Turbines	Oil/Gas - Steam Turbine	Queens (J)	415		$597	$319	1.9
	3/3/1999	Astoria Generating Station in Astoria	Oil/Gas - Steam Turbine (3)	Queens (J)	1,090	Orion Power Holdings			
		Gowanus and Narrows Gas Turbines	Oil/Gas - Combustion Turbine (48)	Brooklyn (J)	765		$550	$332	1.7
	11/9/2000	Indian Point Units 1 & 2	PWR Nuclear (Steam)	Buchanan (H)	970	Entergy	$502	$569	0.9
		Peaking Capacity	Oil - Combustion Turbine	(H)	150		$100		
NYSEG	7/31/1998	Kintigh	Coal - Steam Turbine	Somerset (A)	675	AES Corporation			
		Milliken (Cayuga)	Coal - Steam Turbine	Lansing(C)	306				
		Goudey	Coal - Steam Turbine	Westover (C)	126				
		Greenidge	Coal - Steam Turbine	Torrey (C)	161				
		Hickling	Coal - Steam Turbine	Corning C)	85				
		Jennison	Coal - Steam Turbine	Bainbridge (C)	71		$950	$881	1.1
		Homer City	Coal	Homer City, PA	1,424	Edison Mission Energy	$900	$279	3.2
Niagara Mohawk Power Corp.	12/3/1998	Hydroelectric facilities	Hydro	Upstate NY	661	Orion	$425	$269	1.6
	4/1/1999	Oswego (88%)	Oil - Combustion and Steam Turbine	Oswego (C)	1,700	NRG	$80	$406	0.2
	12/23/1998	Huntley	Coal - Steam Turbine	Tonawanda (A)	760	NRG			
		Dunkirk	Coal - Steam Turbine	Dunkirk (A)	600	NRG	$355	$379	0.9
	10/6/1999	Albany	Oil/Gas - Steam Turbine	Albany (F)	400	PSEG	$47.5		
	12/12/2000	Nine Mile Point 1	BWR Nuclear (Steam)	Oswego (C)	609	Constellation Energy			
NiMo,NYSEG,RG&E,CHG&E	12/12/2000	Nine Mile Point 2 (82%)	BWR Nuclear (Steam)	Oswego (C)	1550		$762	$2,467	0.3

*Note: Book Values are from pre closing data

SOURCE: Electric Power Supply Association (2002) and "Wholesale Market Issues: Utility Divestiture Process in New York" Gallagher (2006)

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[56] "Con Ed To Sell Two New York City Power Plants For $1.1 Billion" *Dow Jones Business News*, 29 January 1999.

[57] This sale included a Purchase Power Agreement (PPA) in which "*Con Edison will purchase 100% of IP2's output for 3.5 years on a unit contingent basis at a price ranging from $36-$46/MWh*" http://www.shareholder.com/entergy/releaseDetail.cfm?ReleaseID=27954

[58] See http://archive.pulp.tc/html/nine_mile_nukes_have_new_owner.html

[59] The Long Island Power Authority decided to keep their 18% share.

[60] According to the American Public Power Association's "Compilation of Investor-Owned Utility Transactions – Plant Acquisitions" there have been no additional major divestitures by the three utilities we follow through 2006. http://www.appanet.org/aboutpublic/index.cfm?ItemNumber=2737&sn.ItemNumber=2039

When we compare the sale prices of the divestitures with the book value of these assets on the utilities' balance sheets we see that steam and combustion turbines powered by oil and gas (e.g. Arthur Kill, Ravenswood and Astoria) sold at a premium, while nuclear generation (e.g. Indian Point and Nine Mile Point) sold at a discount.[61]

2.3.1 Regulatory Uncertainty Surrounding Divestures

The regulatory uncertainty surrounding the design of mitigation rules in the newly created market made the valuation of the soon to be divested generation assets a challenging prospect for potential buyers. In standard Net Present Value (NPV) analysis the after-tax cash flows generated by the investment are estimated and then discounted back to present day dollars terms using the appropriate risk-adjusted interest rate. In a deregulated setting the after tax cash flows are very much dependent on the structure of the newly restructured industry, and in particular the strength of market mitigation procedures --- which are inherently uncertain. For example, the New York State market-based trading began in 1999 with a FERC-approved price cap of $10,000 per MWH. Then on July 26, 2000, FERC ordered the NYISO replace this cap with a $1000 per MWH cap on bids. Subsequent analysis in Section 3.2.2 shows the large effect a change in the cap can have on the profits of peaking units, which are reliant on price spikes to recover their fixed costs. This and other imposed and proposed price controls[62] have led Independent Power Producers to allude to the

[61] The Oswego plant sold at a discount because in the five years prior its output had only averaged 5% of its total capacity (averaging 85 MW a year) because of the oversupply of electricity in the region and the expensive cost of running oil-fired units. See "NiMo cuts third power plant deal with NRG Energy", *Megawatt Daily*, 4(63), 5 April 1999.

[62] According to the Independent Power Producers of New York, Inc. the following additional price controls were either been proposed or imposed between January 2000 and November 2002: "*$2.52 bid cap on 10-minute non-synchronized reserve bids; Temporary Extraordinary Procedures Authority; Automatic Mitigation Procedure; Retroactive Price Adjustment Proposal; Generator of In-City Mitigation in the Day-Ahead market to all unites in N.Y.C.; Creation of In-City Mitigation in the Real-Time Market for all units in N.Y.C.*" "Charting a Course for the Future: New York's Electricity Markets Today & Tomorrow", Independent Power Producers of New York, Inc. White Paper, www.ippny.org, November, 2002, p.9.

possibility that they have been the victims of a 'classic bait and switch.' In a 2002 whitepaper the Independent Power Producers of New York argued that "*…those entities that bid for the divested NYC assets made calculations of what a reasonable bid should be based on the rules designed by the PSC for the operation and limited mitigation of the competitive marketplace it designed. Based on that market design, the auction yielded billions of dollars for the divested assets. Unfortunately, the PSC and the NYISO have repeatedly and dramatically revised the playing field following the commencement of the competitive market…*"[63]

Consolidated Edison's inconsistent ex-ante and ex-post divestiture stance on market mitigation procedures provides an interesting example of an alleged 'bait and switch'. Some have questioned whether the move was a strategic attempt to increase the proceeds from the sale of its generation assets by proposing generous price caps and then post-divesture, lobby for the tightening of mitigation procedures to help ensure lower power purchase and capacity market payments. For example, in 1998, prior to the sale of its inner city generation assets, Consolidated Edison proposed that the new owners, or divested generation owners (DGOs), be subject to a $105/kW-year cap in the Installed Capacity auction. This revenue cap was subsequently approved by FERC. In December 2006, the New York ISO filed a petition to FERC based on Consolidated Edison and the New York State Department proposal for more stringent mitigation measures in the ICAP market, including a reference price of $82/kW-year on offers from DGO's.[64] The filing was a result of the failure of the capacity auction

[63] See "Charting a Course for the Future: New York's Electricity Markets Today & Tomorrow", Independent Power Producers of New York, Inc. White Paper, www.ippny.org, November (2002), p.9.
[64] From 118 FERC ¶ 61,182 United States of America Federal Energy Regulatory Commission "*Under the proposal, if a DGO's offer is more than three percent above the proposed $82/kW-year reference level, and has the effect of raising the total market cost of capacity by three percent or more above the cost that would have resulted from an offer set at the $82/kW-year reference price, then the New York ISO will substitute the reference price. The proposal does not remove the current revenue cap of*

to clear below the $105/kW-year cap despite 1,000MW of new capacity being added in 2006.[65] In 2007 FERC rejected the New York ISO's filing citing "analytical shortcomings" and noting the "the proposal is hardly supported by rigorous analysis"[66] --- a point acknowledged by the NYISO board prior to the hearing. Consolidated Edison has also been a major proponent for increased mitigation procedures in New York Real Time and Day Ahead markets both pre-and post-divesture. In June 1998, Consolidated Edison proposed that special market power mitigation measures (MPMM) were necessary for New York City as "*when certain operating conditions exist, local reliability rules and transmission constraints intrinsic to New York City may create localized market power concerns.*" FERC concurred, approving special market power mitigation measures in New York City in September, 1998.[67] In March 2001, Consolidated Edison filed a proposal to FERC which sought to strengthen the market power mitigation measures for inner city generators. The proposal had the support of the New York Public Service Commission but not the NYISO. This lead to a heated exchange between the three parties, with the NYPSC criticising the NYISO of ineffective mitigation of market power and the NYISO criticising the NYPSC for initiating the problem by approving Consolidated Edison's divestiture plan that lead to highly concentrated inner city generation ownership.[68,69] Indeed it is probable that Consolidated Edison may have received higher sale prices by selling its generation assets in large bundles, however it is also foreseeable ex-ante that ex-post Consolidated Edison would have the incentive to lobby for increased

$105/kW-year that applies to DGOs. If the market clearing price were set by a non-DGO at a level above $105, DGOs would have to rebate their revenues above $105." (p.3)

[65] "NYISO is reviewing changes to capacity market pricing" Platts.com News Feature (2006)

[66] 118 FERC ¶ 61,182 United States of America Federal Energy Regulatory Commission

[67] 84 FERC ¶ 61,287 (1998).

[68] "New York ISO Criticizes Con Edison and New York PSC in FERC Proceeding" Public Utility Law Project, 28 June, 2001. http://archive.pulp.tc/html/nyiso_criticizes.html

[69] The NYISO also criticized Consolidated Edison for not signing long term contracts with their divested generation owners --- something both Niagara Mohawk and NYSEG did.

mitigation. In any event, FERC rejected the proposal in May 2001 asking Consolidated Edison to work with NYISO within the NYISO Stakeholder process to formulate a feasible mitigation proposal”[70]

2.4 Important Aspects of the Restructured Industry

In this section we briefly examine some of the important institutional changes which occurred due to industry restructuring. These involve the switch from rate of return to incentive regulation; the introduction of a wholesale spot market price cap; the Installed Capacity Market (ICAP); and retail competition.

2.4.1 Rate of Return Regulation to Incentive Regulation

Industry restructuring also changed the way the former vertically integrated utilities were regulated. Previously these utilities were regulated using ‘rate of return regulation.’ As described in section 2.1, rate of return regulation stipulates the prices a regulated firm may charge for each of its products individually. These prices are calculated on a ‘cost-plus’ basis i.e. the price is set equal to actual costs of production plus a determined rate of return on capital. It has been argued that the ‘cost-plus’ nature of rate of return regulation leads to so-called ‘gold plating’ inefficiencies i.e. firms over-invest in order to increase their rate base.

The restructuring of late 1990s saw the PSC begin using incentive regulation (also know as performance-based regulation) due to its superior cost minimization incentives. The electric rate plans (NYSEG and Consolidated Edison Company of New York) and the merger rate plan (Niagara Mohawk) are all examples of earnings

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[70] 95 FERC at 61,719

sharing regulation --- a form of incentive regulation.[71] In such schemes, the firm is allowed to keep all profits below a certain level. If the firm earns over a specified higher level, it must return all the incremental profits to consumers. Between these two thresholds the firm and consumers share the incremental profits. (See Box 2.4 for excerpts from each distribution company's rate plan.) The main advantage of earnings sharing regulation over traditional rate of return regulation is the stronger incentives for increasing efficiency. For example, if a firm was subject to rate of return regulation, its prices would tend to be adjusted downwards if it reduced its costs, albeit with a lag, so that all of the savings are passed onto customers. If the lag was quite short, the firm would have little incentive to reduce costs. With earnings sharing regulation the firm is guaranteed to keep a substantial proportion of its savings for the length of the contract --- ten years for the Niagara Mohawk merger pate plan.

Box 2.4: Excerpts from the Rate Plans of Consolidated Edison, NYSEG and Niagara Mohawk.

Niagara Mohawk Power Corporation Merger Rate Plan:
"The Company's delivery rates are governed by a ten-year rate plan that began on February 1, 2002. Under the plan, after reflecting the Company's share of savings related to the acquisition, it may earn a threshold return on equity for the electricity distribution business of 10.6%, up to 11.75% without any sharing with customers (12.0% if certain customer outreach, education, competition-related and low income incentive targets are met). Half of any amounts in excess of 12%, up to 14%, 25% of any earnings in excess of that up to 16% and 10% beyond that are retained by the Company. This effectively offers the Company the potential to achieve a return on equity in excess of the regulatory allowed return of 10.6%. The return on equity is calculated cumulatively from inception to December 31, 2005 and annually thereafter for the prior two calendar years."

Continued on next page…

[71] Such profit-sharing schemes are also commonly applied to US telecommunications firms. For more on this type of regulation see Sappington et al (2001).

Box 2.4 continued: Excerpts from the Rate Plans of Consolidated Edison, NYSEG and Niagara Mohawk.

NYSEG Electric Rate Plan:
"The PSC February 2002 Order also requires equal sharing of earnings between NYSEG customers and shareholders of ROEs in excess of 15.5% for 2002, and equal sharing of the greater of ROEs in excess of 12.5% on electric delivery, or 15.5% on the total electric business (including supply) for each of the years 2003 through 2006."

Consolidated Edison Company:
"Under the 2000 Electric Rate Agreement, as approved by the PSC and as modified in December 2001, 35 percent of any earnings in each of the rate years ending March 2002 through 2005 above a specified rate of return on electric common equity are to be retained for shareholders and the balance will be applied for customer benefit as determined by the PSC. There was no sharing of earnings for the rate year ended March 2002. In 2002 and 2003, Con Edison of New York established an electric shared earnings reserve of $49 million for the rate year ending March 2003. In 2004 an electric shared earnings reserve of less than $1 million for the rate year ending March 2004 was established. An electric shared earnings reserve has not been established for the rate year ending March 2005 based on results through the end of calendar year 2004. The earnings threshold for rate years ending March 2003 through March 2005 of 11.75 percent can be increased up to 50 basis points. The threshold will increase by 25 basis points if certain demand reductions and supply increases exceed targeted projections and by an additional 25 basis points if certain customer service and reliability standards are achieved."

2.4.2 Price Cap and the Installed Capacity Market

The implementation, and subsequent level, of price caps in deregulated electricity markets is another contentious issue. Those who oppose them argue that they mute market price signals and endanger reliability by deterring investment in generation, especially in peaking units that rely on such spikes to cover their fixed costs. The Australian market, with its relatively high 10,000 AUD per MWH cap, is often heralded as a market that encourages investment by allowing large price spikes and yet has few market power issues. Conversely, proponents of price caps see them as a way of insulating consumers from the damaging effects of the exercise of market power can have on a market. They argue that they are a necessary mitigating strategy to counteract market design problems, load pockets and the lack of demand side response. The California Energy Crisis of 2000/2001 is a dramatic example of what can happen when a deregulated electricity market is affected by the exercise of market power. To control the problem FERC introduced a number of declining price caps, including a $250 per MWH price cap on August 7, 2000; and a $150 per MWh soft price cap on January 1, 2001.[72,73]

The NYISO currently caps bids into its real-time and day-ahead ahead energy markets at $1000 per MWH. Market based trading actually began in November 18, 1999 with a FERC-approved price cap of $10,000 per MWH. However high prices in New York City, despite a cooler than usual summer; a $6000 price spike in the neighboring New England market[74]; delays in New York State's Article X process for licensing and sitting new generating capacity; the lack of proven demand-side response mechanisms;[75] and various transitional problems with the new market (including software problems) saw the NYSIO submit a request to FERC on June 30, 2000 for a temporary bid cap of $1,300 per MWH.[76] On July 26, 2000, FERC ordered NYISO's to set a bid cap of $1,000 per MWH --- identical to those ordered in ISO New England and PJM, so as not to undermine the neighboring markets. Interestingly, the PSC had

[72] See http://www.ferc.gov/industries/electric/indus-act/wec/chron/chronology.pdf

[73] The implementation of the soft price cap (essentially a uniform price auction below the cap and a pay as bid auction above the cap) was less than successful. Mount and Lee (2003) state "The *soft-cap auction failed dismally as a regulatory strategy for ensuring that prices in the spot market were just and reasonable.*"(p.2)

[74] "*The contract that set the $6,000/MWh clearing price was an external contract for the purchase of energy and was bundled with an ICAP contract. In anticipation of initiating OP4, ISO-New England reviewed the forecasted prices posted on the NYISO's web site, which showed advisory prices as high as $3,387/MWh….The $3,387/MWh price was revised by NYISO a week later to $331/MWh, and it was determined that the forecasted clearing price in New York was the result of flaws in the NYISO market.*" (p.1-55), Staff Report to the Federal Energy Regulatory Commission on the Bulk Power Markets In the United States, November 1, 2000. ftp://www.nerc.com/pub/sys/all_updl/mc/cms/cms-0401a.pdf

[75]See http://mis.nyiso.com/public/postings/ECA%20Extending%20Bid%20Caps%20ECA20010430.pdf

[76] NYSEG had petitioned the NYISO in April and May 2000 to investigate transitional problems of the NYISO administered energy markets. See http://www.secinfo.com/dVUa2.5j.htm

recommended that the NYISO seek FERC approval for a $150 per MWH "soft" price cap with the $1,000 per MWH "hard" price cap. However the NYISO strongly opposed the soft price cap, with NYISO President William Museler stating in a letter that such a cap would have the effect of "*reducing the incentive to invest in generating resources in New York.*"[77] Museler also predicted that *"$150 would effectively become a price floor, not a cap, since generators would no longer have a strong incentive to offer power at prices close to their marginal costs."*[78] While the soft price cap was never implemented in New York, Museler's prediction was to come true in California, where a soft price cap was tried in the Californian Market in 2001 with disastrous results.[79,80] The $1000 per MWH was to expire in October 2001, however in response to a NYISO request FERC grated an extension "*until the Northeast RTO is operational and operating pursuant to market rules as established in the final rule to be issued in FERC's RTO market design and market structure rulemaking.*" The move was greeted with support from PSC, but condemnation from the Electric Power Supply Association who deemed it counterproductive for attracting new investment in generation.[81] In July 2002, FERC proposed Standard Market Design rules that set forth a nationwide $1,000 per MWH wholesale price cap. The existing New York bid cap is therefore expected to continue for the immediate future.

One of the main concerns with the move to deregulation was the effect the separation of Load Service Entities (LSEs) and Transmission Owners (TOs) from generation[82]

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[77] "New York ISO says $150 `Soft' Price Cap would Deter New Plants, Raise Prices" *Northeast Power Report,* 15 January 2001.
[78] Ibid. Quote from article not President William Museler
[79] Department of Public Service Pricing Team, State of New York, Interim Pricing Report on New York State's Independent System Operator, (Dec. 14, 2000), http://www.dps.state.ny.us
[80] See footnote 73.
[81] "NYISO Bid Cap Plea Attracts Support from PSC, Brickbats from Others" *Inside F.E.R.C.*,9 April 2001.
[82] See Section 2.3 for a description of how incumbent utilities divested their generation assets.

would have on the ability to maintain reliability. In the past, reliability was guaranteed through LSEs being required to have a reserve margin of 18% --- a relatively easy task as they were able to build generation facilities. Ensuring the reliability standard is met in the deregulated system is a more challenging proposition as LSEs while still being responsible for maintaining reliability are separated from the generation investment decisions.[83] The implementation of the previously discussed $1000 per MWH wholesale bid cap also created further apprehension about securing the necessary investment in generation. As mentioned previously, the Australian Market favored allowing price spikes up to $10,000 AUD per MWH to induce new investment. In New York, the lower $1000 per MHW bid cap lead to the so-called "missing money problem". That is, if the price in the wholesale market is at Long Run Marginal Cost then the generators that are often at the margin (like peaking units) will find it difficult to cover their fixed costs. The Installed Capacity (ICAP) Market was expected to alleviate both the missing money problem, by supplementing generators incomes by the annual fixed costs of a peaking unit, and maintaining reliability, by providing a link between reliability standards and generators investing decisions.

The NYISO ICAP Market works by linking LSE, who need to procure enough generation capacity to satisfy reliability standards, and generators who have capacity to supply. The NYISO sets a downward sloping demand curve for purchasing capacity one month ahead. The actual price that LSE's must purchase capacity for is dependent on the amount of capacity offered into the ICAP market. The more that is

[83] For a more detailed discussion of the New York ICAP market see Mount (2007) and King (2005).

offered in the lower the price per KWH.[84] Suppliers bid their capacity into the market, and in doing so agree to be available to generate. There are three different NYISO ICAP regions, each with its own demand curve. The ICAP market clears one month ahead.

The original form of the NYISO ICAP Market used a vertical demand curve, meaning the ICAP prices were highly volatile[85] --- an undesirable property for a market signal that was meant to induce investment. Both the PSC and NYISO agreed and on March 21, 2003 the NYISO filed a proposal to implementing a downward sloping demand curve in the ICAP market. In this filing the NYISO argued that "*[f]inancing of new facilities has essentially dried up, and investors do not see a reasonably reliable stream of revenues to justify investment in New York generating facilities.*"[86] However, not all parties agreed with the implantation of a downward sloping demand curve, which according to the independent market monitor would increase annual capacity revenues to generators by $154 million. For example, the Electricity Consumers Resource Councils argued that "*the demand curve looks more like a subsidy to current generators as opposed to an incentive for future generators.*"[87] Despite detractors the NYISO's plan was subsequently approved by FERC in late May 2003. In its decision FERC stated "*that the proposal will encourage greater investment in generation capacity and thus improve reliability, by reducing the volatility of ICAP revenues.*"[88]

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[84]Note that the NYISO currently has a $105/kW-year bid cap for installed capacity in the New York City zone --- three times the annual cost of installing a new gas turbine See http://www.ferc.gov/industries/electric/indus-act/rto/handbook/NYISO/5-markets-operated.doc.

[85] For example, if capacity was scarce, the ICAP price was very high, but conversely excess supply often drove the price to zero.

[86] "Merchant suppliers back NYISO's new ICAP plan", *Megawatt Daily*, Vol. 8, No. 71, 2003.

[87] "Sharp Battle Lines Form on NYISO Plan to Revise ICAP Market Design", *Inside F.E.R.C,* 21 April 2003.

[88] "FERC okays NYISO `demand curve' plan, says it will stimulate new plant construction" *Northeast Power Report,* 2 June 2003.

The performance of the NYISO's ICAP Market has been widely criticized. Mount (2007) states that "*the current performance of this market has been disappointing. First, it has not overcome the problem of construction delays, in spite of payments of more than $1 billion a year to incumbent firms in New York City. Second, the largest firms have been able to increase the market price of capacity and their earnings by exploiting market power in New York City.*"[89] Similarly Mount (2006) states that: "*Even though generators will be paid over $400 million from the capacity auctions this summer (plus payments to an additional one third of the generating capacity through existing bilateral contracts), there is no guarantee that these payments will lead to improvements in the reliability of supply or reduce the likelihood of blackouts in the future." (p. 1)* Mount (2006a) also notes that the New England Independent System Operators proposal for their Forward Capacity Market (FCM) "*addresses many of the problems with the LICAP market design adopted in New York State.*" Key proposed differences include: the ability to purchase generation three years in advance (allowing new entrants time to build generation facilities); and a low price cap of installed capacity (to attract new investment); and high prices in the spot market reduce capacity payments (capacity payments are only make whole payments).[90]

Despite the criticisms, the NYISO have maintained faith that their ICAP Market will provide the necessary generation investment. In their 2007 Reliability Needs Assessment (RNA) they state: "*If these mechanisms work as intended and continue to require resources at the same levels as have existed in the past, they should result in the addition of new resources to meet most or all of the New York City and Long*

[89] See http://appanet.org/newsletters/ppmagazinedetail.cfm?ItemNumber=19300&sn.ItemNumber=0
[90] See Cramton (2006)

Island needs identified in this RNA." However such faith in the ICAP market may be unwise. It is important to note that the major contributors that enabled adequacy until 2010 were not due to new private investment in generation, but the deferred retirement of the New York Power Authority's Charles A. Poletti generating unit in Astoria, Queens, from 2008 until 2009; the New York Power Authority $400 Million Expansion at the Charles Poletti Power Station; and the repowering of the 400 MW Astoria Power Project.

2.4.3 Retail competition

Lastly we look at the introduction of retail competition into New York State. New entry gives consumers the choice to continue purchasing their power from either the regulated incumbent supplier or the new ESCO's.[91] The encouragement of competition through entry at the retail level was further strengthened in New York State by the PSC offering a 'shopping credit' or 'price to compare' to consumers who choose to switch to an ESCO. Such shopping credits use the following logic: If a consumer chooses to purchase their power from an ESCO, the ESCO assumes responsibility for purchasing the power required by the customer, and the incumbent supplier is effectively only responsible for the transmission and distribution. Thus in their neutral form, such shopping credits are simply an attempt to remove the incumbent supplier's cost of generation from the bills of customers who choose to purchase their power from an ESCO. The ESCO then charges the customer for power it supplies, thus effectively unbundling the price into transmission and distribution (incumbent) and purchased power (ESCO). It is important to note that the shopping credit need not be neutral. Indeed, if the shopping credit is set above the wholesale

[91] The New York State Public Service Commission has set up a website (www. http://www.energyguide.com/finder/NYFinder.asp) to help consumers compare prices/plans from different suppliers.

generation costs the shopping credit essentially becomes a government provided subsidy to encourage customers to switch from the incumbent to an ESCO. So-called "creamy shopping credits" have attracted criticism from some authors, notably Paul Joskow (2000) who argues that "*these shopping credits effectively increase the regulated price that consumers who do not choose an ESP [ESCO] must pay to levels above the wholesale commodity cost of electricity and provide an opportunity for ESPs [ESCOs] to attract customers by offering discounts…*" Joskow also warns, such "*general subsidies are likely only to stimulate a lot of customer churn, wasteful advertising and promotional expenditures, and inequitable distributions of stranded cost responsibility, without mitigating wholesale market performance problems*."[92]

In New York the shopping credits offered to consumers averaged approximately 4 cents per KWh, which look to be higher than the wholesale load-weighted average annual zonal prices observed during the first few years of the market for NYSEG and Niagara Mohawk (see figure 3.3), but certainly fall short of being described as 'creamy'.[93] Indeed, in 1999, Howard Fromer, the then director of government affairs of the now defunct Enron Corporation, complained that "*I can't believe that any outside marketer is making money in the New York market*"[94]

In any case, retail competition is unlikely to be the panacea in helping to prevent high electricity prices. As Stoft (2004) notes, "*the net result seems to be that retail competition offers no benefits in reducing wholesale market power. As it will not bring down the costs of generation, it seems to hold little promise of improving*

[92] See Joskow (2000), p. 3 and 55.

[93] It is interesting that the supplemental "shopping credit" was originally planned to last for two years --- which according to Competition Plus Energy (2000) was "*the period electricity marketers have suggested is required to 'jump start' the retail competitive market.*"

[94] See Perez-Pena (1999) p.37, column 2.

wholesale performance. The slim hope that price competition will save more on billing costs than it spends on marketing is a flimsy basis for such a large experiment." (p.29) In this thesis we therefore focus on the wholesale, and transmission and distribution sectors.

CHAPTER 3

THE LOWERING OF RATES FOR CONSUMERS

3.1 Introduction

It was stated in Section 1.1 that the New York Public Service Commission (PSC) believed that industry restructuring would result in the lowering of rates faced by consumers.[95] As the wholesale price of power makes up a large part of the total cost of electricity, a large amount of literature in this area is dedicated to assessing the competitiveness of the wholesale market.[96] While such studies are undoubtedly useful, it is important to realize that they tell only part of the story. A competitive wholesale market is a necessary but not sufficient condition for the achievement of low retail prices for consumers. The formation of the price ultimately paid by consumers is reliant on the interplay between three sectors: generation, transmission and distribution, and retail. Of these sectors, generation and retail are both open to competition, while transmission and distribution's natural monopoly characteristics mean that incentive regulation is in place. Thus, even in the 'deregulated market' the price customers pay for their electricity is still very much reliant on regulatory policy.

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[95] From page 28 of Opinion 96-12 State of New York Public Service Commission (1996): "*Lowering Rates for Consumers: Market forces overall are expected to produce, over time, rates that will be lower than they would be under a regulated environment. As we move toward competition, our expectation is that rates overall will be reduced.*"

[96] Most approaches seek to detect whether generators are unilaterally exercising market power. For example, Borenstein et al (2002) and Joskow and Kahn (2002) use a technique called 'Direct Analysis', which compares actual prices that are observed in the wholesale market with the marginal cost of production of the marginal generator in a hypothetical perfectly competitive market. Similarly, Wolak (1998) and Joskow and Kahn (2002), use another technique called 'Strategic Offering Analysis', which can be though of as direct analysis applied at the firm level (e.g. they examine whether or not individual generators are offering electricity at prices which exceed estimated marginal cost or, equivalently, whether they do not offer in all the electricity which they could profitably generate). Unfortunately, while direct and strategic offering analyses are theoretically useful approaches, the sheer complexities of electricity markets and the limited availability of data make estimating the marginal cost of generation difficult. This therefore casts doubt whether any evidence of the unilateral exercise of market power afforded by these models is due to actual non-competitive behavior or because of errors in the model. For a more detailed discussion see Videbaek (2004).

For example, it matters little if the wholesale market is perfectly competitive if regulation is failing to provide the incumbent natural monopoly distribution company the correct incentives to minimize transmission and distribution costs.[97] The price paid by end consumers is also dependent on the competitiveness of other supplementary markets, like the capacity market, whose costs are not included in the wholesale price. Indeed, the exercise of market power by generators in a market such as the capacity market has the ability to stifle even a perfectly competitive wholesale and retail market with optimal transmission and distribution regulation --- a point lost on many market monitors who tend to acutely focus on the competitiveness of the wholesale market (i.e. imposing price caps), while turning a blind eye to the monitoring of supplementary markets.

This chapter seeks to gain a more complete picture of the progress toward the lowering of rates faced by consumers by analyzing the behavior of these costs (via "total costs to consumers per kWh" --- a proxy for retail prices) over time for three major New York electricity distribution companies: New York State Electric & Gas Corporation (NYSEG); Niagara Mohawk (NiMo) [now called National Grid]; and Consolidated Edison Company of New York (ConEd).[98] The analysis is broken into four main sections. First we look to see if the "average cost to consumers per kWh" for each utility has decreased since deregulation. Upon finding they have not, we decompose the "average cost to consumers per kWh" into three important components: (i) the premium of power purchase costs over the wholesale price due to supplementary markets like the Installed Capacity market (ICAP), (ii) the wholesale

[97] This thesis will focus on the wholesale, distribution and capacity markets, and not on the retail market. This is because the effectiveness of retail competition to lower consumer prices has been questioned by many authors. See section 2.4.3 for a further discussion of this topic.
[98] See Box 1.1 for a description of each company.

price, and (iii) the cost of distributing the power to customers. We then try to identify how each of the three components has contributed to changes in the total costs to consumers per kWh since industry restructuring.

The three companies we analyze were chosen as their geographic and financial diversity enables us to investigate the effect that deregulation has had on the prices paid by consumers in different locations in New York State. For example, New York State Electric and Gas represents an upstate company that is financially sound in a market with relatively low spot prices for electricity. Niagara Mohawk represents a company in a similar market that has serious financial problems due to accumulated debt (i.e. "stranded assets"). Consolidated Edison is located in New York City --- a market that has relatively high spot prices and the additional financial burden of making substantial payments to generators in a capacity market.

3.2 Average Cost of Electricity

We begin the analysis by highlighting trends in the "average cost per ultimate consumer kWh" of our selected distribution/utility firms over the period 1986 – 2005 (see Figure 3.1). When analyzing this measure it is important to first understand the methodology used to calculate it. The average cost per ultimate consumer kWh is calculated by dividing the total costs (which is the sum of: fuel and purchased power; wages and benefits; other expenses; depreciation and amortization expenses; income taxes – operating; other taxes operating; and capital costs)[99] by total kilowatt-hour sales. Note that the methodology used by the New York State Public Service Commission to calculate the average cost per ultimate consumer kWh dictates that the

[99] Data Field and Sales and Customer Data --- New York State Public Service Commission 5 Year Book.

total kilowatt-hour sales should only include electricity supplied to full service customers and not electricity supplied to retail access customers (customers who pay for delivery service from the utility and for supply from an Energy Service Company (ESCO)). The inclusion of retail access customers would understate the average cost per ultimate consumer kWh as ‘fuel and purchased power costs’ are averaged for kWh the utility did not supply. This is important as in 2004 and 2005 sales to retail access customers, totaling 14,143 million kWh in 2004, and 16,848 kWh million in 2005,[100] were incorrectly included in Consolidated Edison’s total kilowatt-hour sales. This mistake was a result of changes in the FERC Form 1, which Consolidated Edison mistakenly carried over to the Public Service Commission’s “Financial Statements of the Major Investor-Owned [Privately Owned] Utilities in New York State”. To make the 2004 and 2005 statistics comparable with the previous years’ methodology, we have removed the kWh sold to retail access customers, as collected from Consolidated Edison’s 2005 annual report, from the incorrectly reported total kilowatt-hour sales, as reported in the New York State Public Service Commission 5 Year Book. The correction reduces the total kilowatt-hour sales from 440,134,660 kWh to 298,704,660 kWh in 2004; and from 461,916,960 to 293,436,960 kWh in 2005.[101] The correction thereby shows Consolidated Edison’s ‘cost per ultimate customer kWh’ to be increasing over the last two years (with a particularly large increase in 2005), as opposed to the sharp decrease that was incorrectly reported in the New York Public Service Commission’s statements (see Table 3.1).

[100] Consolidated Edison Annual Report “Strength” (2005), p.43.
[101] These figures are consistent with the kWh sales to ‘total full service customers’ as reported in the 2005 Consolidated Edison Annual Report “Strength” (2005), p.43.

Table 3.1: Reported and Corrected 'Cost per Ultimate Customer kWh' for Consolidated Edison in 2004 and 2005

	Reported		Corrected	
	2004	2005	2004	2005
Fuel and Purchased Power	7.11	7.10	10.48	12.09
Wages and Benefits	1.15	1.13	1.69	1.93
Other Expenses	1.02	1.18	1.64	2.00
Depreciation and Amortization Expenses	0.87	0.79	1.28	1.34
Income Taxes-Operating	0.34	0.45	0.51	0.76
Othe Taxes-Operating	1.87	1.80	2.76	3.07
Capital Costs	1.64	1.57	2.42	2.67
Total	14.01	14.01	20.64	23.86

Figure 3.1 shows that since industry restructuring in the late 1990s, the "average cost per ultimate consumer kWh" in nominal terms has increased for Consolidated Edison and Niagara Mohawk and remained approximately constant for NYSEG. These trends in costs contradict the PSC assertion that industry restructuring would result in the lowering of rates faced by consumers. To better understand why costs increased we decompose the "average cost per ultimate consumer kWh" into three important components: (i) the premium of power purchase costs over the wholesale price due to supplementary markets like the Installed Capacity market (ICAP), (ii) the wholesale price, and (iii) the cost of distributing the power to customers.

3.2.1 Premium of Power Purchase Costs

It is evident from Figure 3.1 that overall changes in average costs are mostly due to changes in the 'fuel and purchased power' component of costs. All three distribution/utility firms we monitor have seen their average 'fuel and purchased power' costs increase since 1997. For Consolidated Edison and Niagara Mohawk the trend has been increasing since deregulation, whereas NYSEG costs have seen a slight decreasing trend since 2002. In this section we investigate whether the increases in

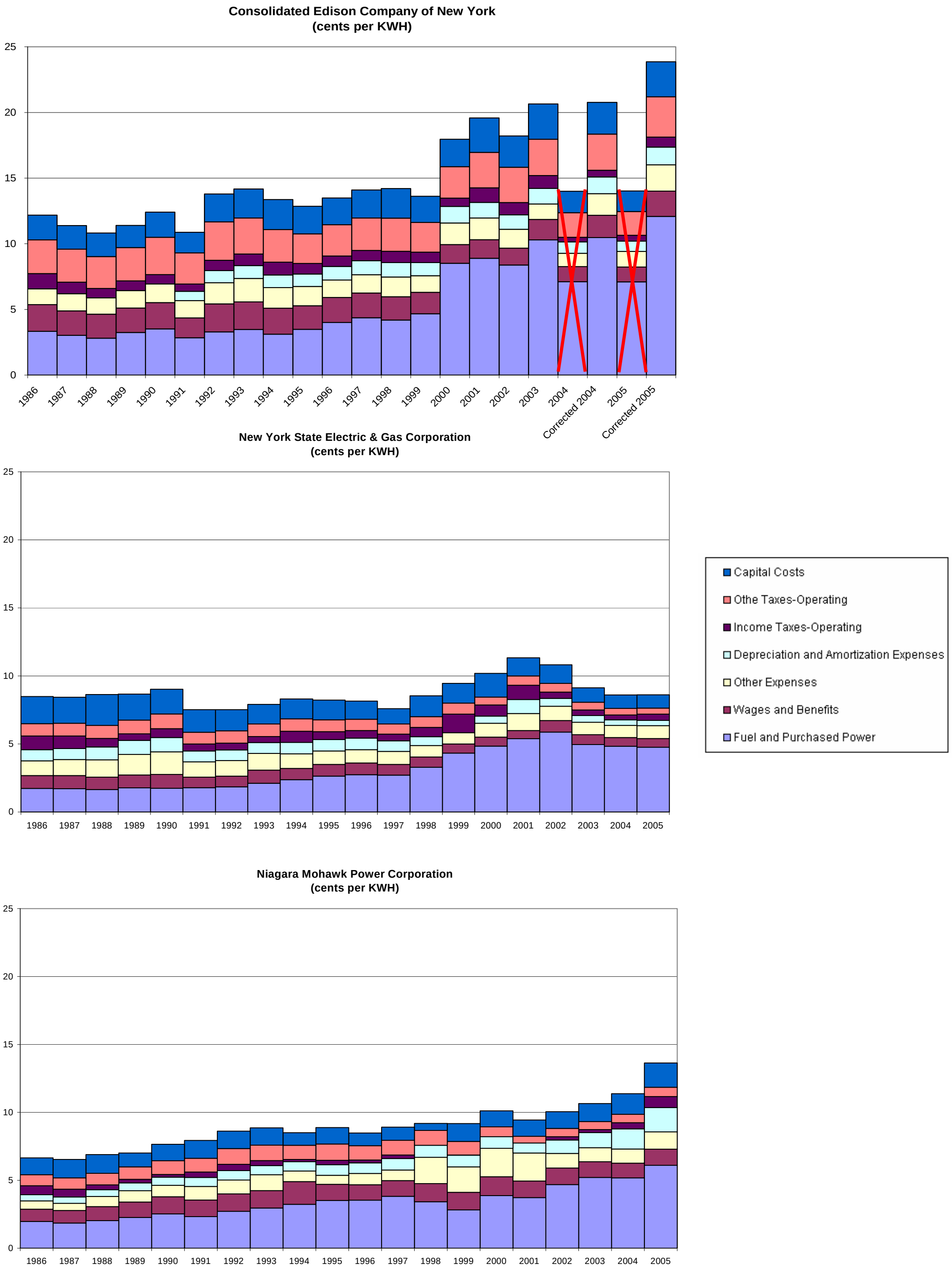

Figure 3.1: Average Cost per Ultimate Consumer KWH for 1986-2005 for Consolidated Edison (top) NYSEG (middle) and Niagara Mohawk (bottom)

‘fuel and purchased power’ are mirrored by increases in the wholesale day-ahead prices. We do this to determine if increases in ‘fuel and purchased power costs’ are due to increases in the wholesale price of electricity (which would warrant future investigation into the competitiveness of the wholesale market), or due to a bottleneck between wholesale and distribution.

To do this we compare the average ‘fuel and purchased power’ per ultimate consumer kWh with the day-ahead load weighted average price[102] from the zones that these distribution companies operate in. The service territories are defined as follows:

- Consolidated Edison Company of New York *“provides electric service in all of New York City (except part of Queens) and most of Westchester County, an approximately 660 square mile service area with a population of more than nine million.”* This corresponds to New York Control Area Zones J (N.Y.C.) I (DUNWOD) and H (MILWD). We choose to focus on Zone J (N.Y.C.).
- New York State Electric & Gas Corporation. “*The service territory…is in the central, eastern and western parts of the State of New York and has a population of approximately 2.5 million. The larger cities in which NYSEG serves both electricity and natural gas customers are Binghamton, Elmira, Auburn, Geneva, Ithaca and Lockport.”* This corresponds to New York Control Area Zones C (Central) E (Mohawk Valley), D (North) and A (West). There are also small service areas in F (Capital) and G (Hudson). We choose to focus on Zone C (Central).
- Niagara Mohawk Power Corporation: *“The Company provides electric service to approximately 1,600,000 electric customers in the areas of eastern, central,*

[102] Note that load weighting may not match the load profile the distributions companies consumers.

northern and western New York. (from Niagara Mohawk Power Corporation 10-K filing) This corresponds to New York Control Area Zones A (West), E (Mohawk Valley) and F (Capital). Due to the divergence of service areas we choose to include Zones A (West), E (Mohawk Valley) and F (Capital).

See Figure 3.2 for Control Area Load Zones and maps of all three distribution firms' service territories.

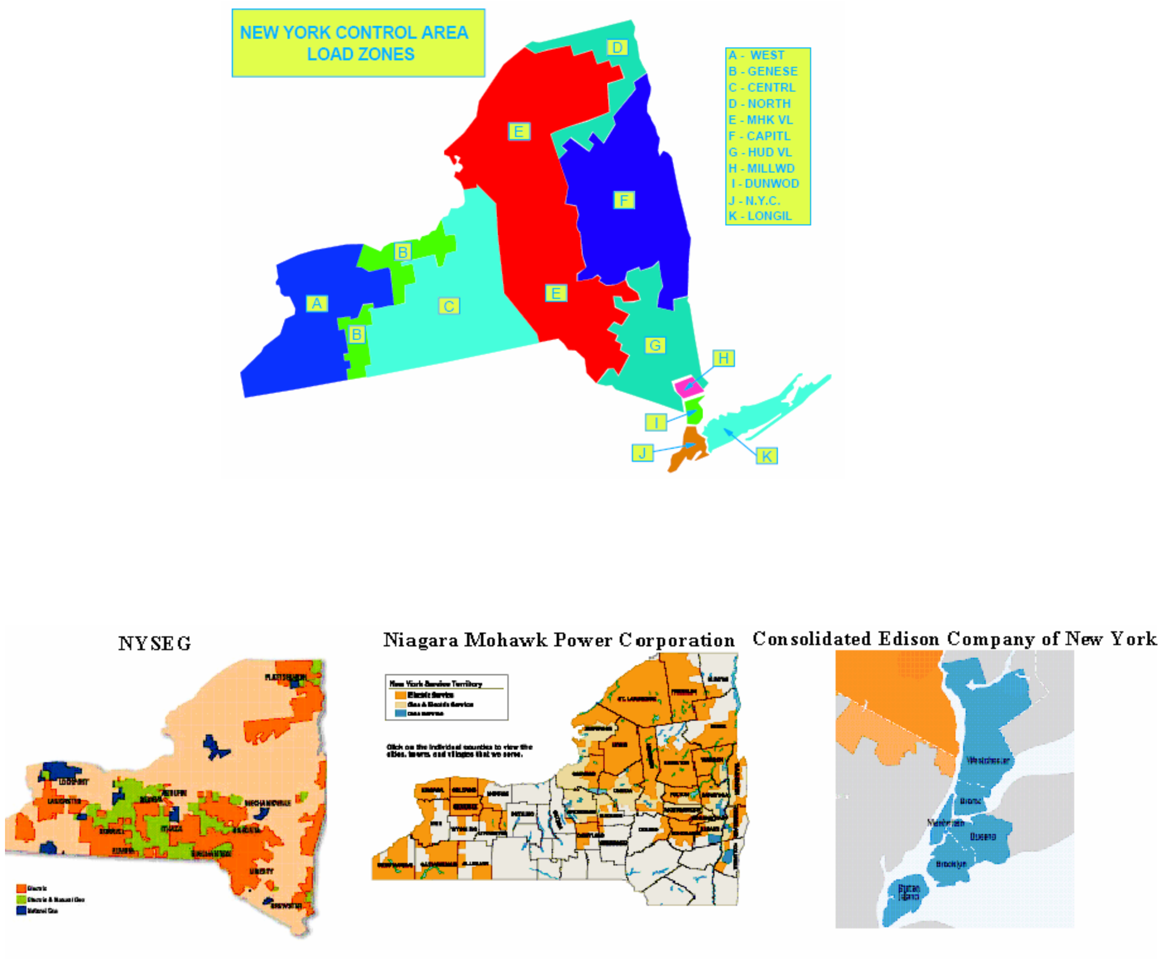

Figure 3.2: New York Control Area Load Zones (Source: www.nyiso.com) and Maps of All Three Distribution Firm's Service Territories

Figure 3.3 compares the ‘total cost to customers per kWh’ and ‘fuel and purchased power costs per kWh’ for each distribution company with the day-ahead load weighted average wholesale price for the zone which best matches each companies’ service territory for the period 2000-2004.[103] From Figure 3.3 we can see that the costs of purchased power from the deregulated market for the two upstate companies, NYSEG and Niagara Mohawk, are now below the average wholesale price of electricity in the spot market. The reason behind this is that both NYEG and Niagara Mohawk signed long term contacts with their divested generation owners (DGO). For example, in 2001 the merger between Niagara Mohawk and National Grid saw 90% of the electricity supplied to residential and small commercial customers hedged though 2008.[104]

In contrast, the cost of purchased power for Consolidated Edison is still substantially higher than the average spot price in Zone J (New York City).[105] This is despite Consolidated Edison relying heavily on spot market purchases[106] over long term bilateral contracts --- a move consistent with NYPSC recommendations, but criticized ex-post by the NYISO. The most plausible reason of the persistent premium of power purchase costs over the wholesale price for Consolidated Edison is the large Installed Capacity Market (ICAP) payments incurred from operating in New York City. While the capacity payments of individual companies are not available, as they are deemed to be commercially sensitive, we are able to get an idea of the magnitude of the

[103] Note that the difference between the ‘total cost to consumers per kWh’ and the ‘day ahead weighted average wholesale price’ is the ‘total price wedge’.
[104] Electric Energy Market Competition Task Force and the Federal Energy Regulatory Commission, Comments of the Public Utility Law Project of New York on Task Force Report to Congress, Docket No. AD05-17-000, p. 37.
[105] It is interesting that the load weighted spot price in zone C is lower than the fuel and purchased power costs of NYSEG. This could be because of the use of fixed price contracts.
[106] It has been reported that Consolidated Edison purchases 50% its electricity from the spot market. Ibid.

payments from the "Average All-In Price 2002-2005" graph (reproduced here as Figure 3.4) from the 2005 NYISO State of the Market Report. This figure shows that the capacity payments (bottom bar) for the NYC region are considerably higher than upstate regions. Indeed, the capacity payment of around \$1.50-\$2.00 per KWh seems to approximate the size of the wedge between the weighted average wholesale spot price in Zone J and the 'fuel and purchased power cost' of Consolidated Edison. This serves to reinforce that the price paid by end consumers is dependent on not only the competitiveness of the wholesale market but also the price levels in supplementary markets, like the capacity market, whose costs are not included in the wholesale price. Thus it would be a mistake to acutely focus attention only on the competitiveness of the wholesale market, and turn a blind eye to the monitoring of the capacity market. Indeed, there are growing concerns about the lack of competition in the ICAP Market is costing consumers' substantial amounts of money, while achieving little from a reliability point of view. Mount (2006) states "*By setting a price cap on the incumbent merchant generators, the regulators have set an arbitrary limit on how much manipulation is allowed in the capacity market.*" (p.7) He also points out that "*Even though generators will be paid over \$400 million from the capacity auctions this summer (plus payments to an additional one third of the generating capacity through existing bilateral contracts), there is no guarantee that these payments will lead to improvements in the reliability of supply or reduce the likelihood of blackouts in the future.*" (p. 1)

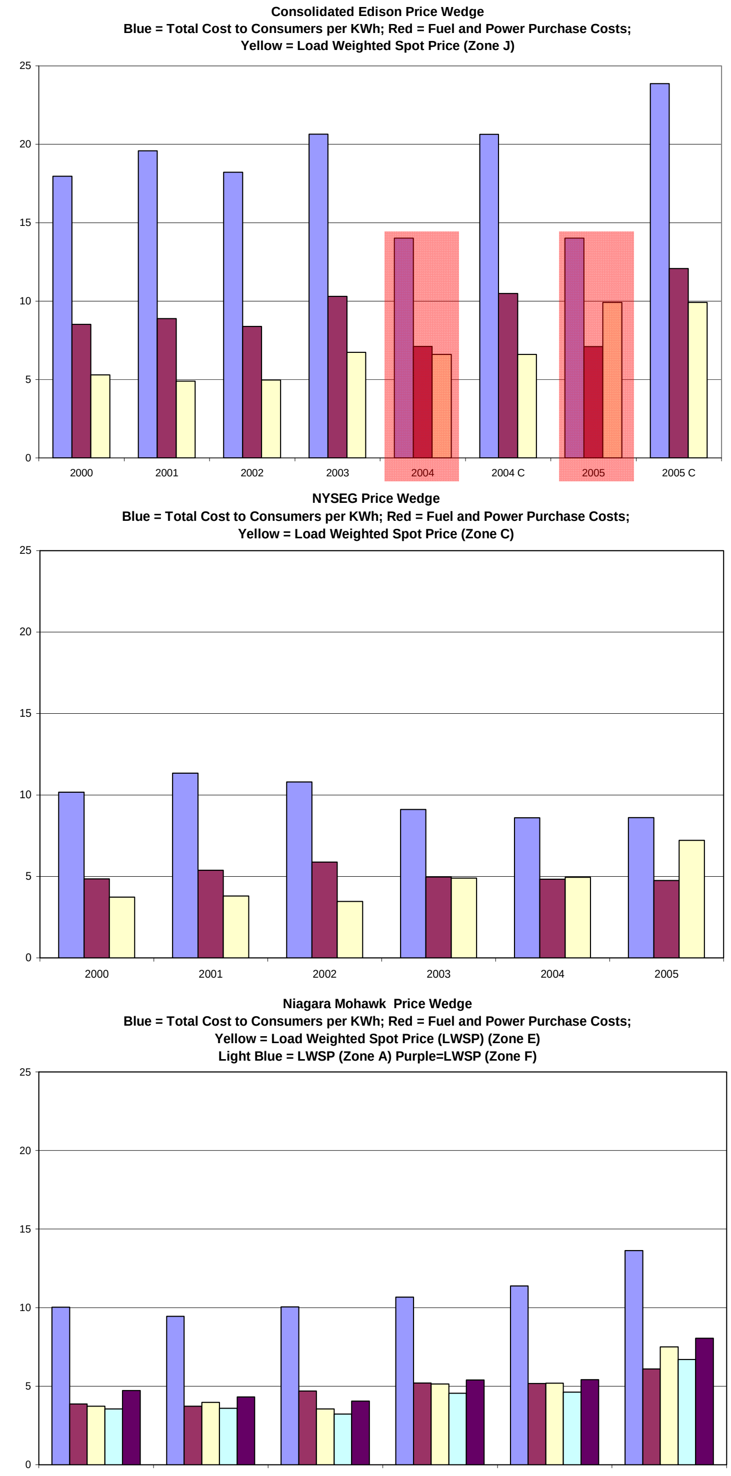

Figure 3.3: Total Cost (cents/KWh) to Consumers; Fuel and Power Purchase Costs; and Load Weighted Sport Price for Consolidated Edison (top) NYSEG (middle) and Niagara Mohawk (bottom) Note: shaded are uncorrected.

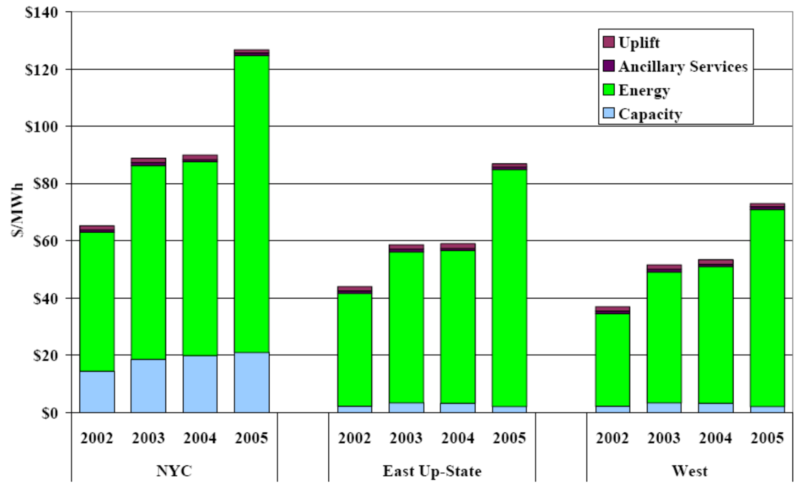

Figure 3.4: Average All-In Price 2002-2005

SOURCE: Figure 7 (p.9) 2005 NYISO State of the Market Report

3.2.2 Wholesale market

From Figure 3.3 we can also see that the weighted average wholesale price has been increasing in nominal terms for Consolidated Edison's Zone J, and Niagara Mohawk's Zones E, A and F and in NYSEG's Zone C. This indicates the rising wholesale prices are contributing to the increases in 'total costs to customers per kWh'. In this section we explore the evolution of the profitability of various types of generators in order to gain insights into who has benefited most from the newly deregulated wholesale market. To do this we estimate the post-deregulation gross profit per year per MW of capacity for a selection of hypothetical divested generators for 2000, 2001, 2003 and 2005.[107] For the analysis we use exogenous capacity factors at fixed levels relating to the type of generation (base load, peaking etc.). This is done to help isolate the effects the changing shape of the price duration curves and changes in fuel prices have had on the earnings of different generation technologies. In the analysis, the capacity factors

[107] Gross profit for the individual generation units has to be estimated as the generation companies' annual reports do not report either regional or plant specific profit information.

are converted into the total number of hours the generator was running during the year. This figure, together with the assumption that the plant ran during hours with the highest wholesale spot prices, enables us to estimate the average price received per each generation hour using the 'Price Duration Curves'[108] (see Figure 3.5) corresponding to the zone the generator was located in. The marginal cost of generating is then estimated using the assumed heat rate of the plant together with average market fuel costs for each year (from the Energy Information Administration).[109] Subtracting the estimated marginal cost of electricity from the average price allows us to calculate a gross profit per MW of capacity figure for each of the plants.[110] Note that for all of the analysis, the coal and gas fuel costs are exogenous; nuclear generation marginal cost is exogenous and fixed at $20/MWH[111]; and the heat rates of the coal and gas generation are exogenous and fixed at a rate consistent with the particular generation technology (i.e. there are no efficiency gains in response to changes in fuel prices). The hypothetical generators were chosen to provide a mix of peaking and non-peaking, generation technologies, and locations and are based on actual/planned generator units. They are:

1. **Gas Peaking Unit located in Zone J with a Heat Rate[112] of 13,000 Btu/kWh.** This approximates the Arthur Kill Generating Station: an 842-MW peaking plant located in Staten Island (Zone J). It consists of three generation units: and two fuel oil and gas fired steam turbines and one small 'black

[108] A price duration curve orders prices in descending order of magnitude.
[109] We assume that the generators do not have fixed price contracts for fuel.
[110] Note that this is marginal cost and does not include capital costs.
[111] "Alternatives to the Indian Point Energy Center for Meeting New York Electric Power Needs", National Research Council. (2006) p. 45
[112] Heat rate is defined as "is a measure of generating station thermal efficiency--generally expressed in Btu per net kilowatt-hour. It is computed by dividing the total Btu content of fuel burned for electricity generation by the resulting net kilowatt-hour generation." www.coffmanelectric.com/

start'[113] kerosene-fired gas turbine. It is owned by NRG Energy Inc. This plant is assumed to generate for 400 Hours per year.

2. **Nuclear Base Load Unit located in Zone H.** This approximates Indian Point Units 2: Indian Point 2 is a 971-MW PWR nuclear base-load plant located in Buchanan (Zone H). It is owned by Entergy Nuclear. This plant is assumed to generate for 8000 Hours per year.

3. **Coal Base Load Unit located in Zone C with a Heat Rate of 11,000 Btu/kWh.** This is similar to Milliken/Cayuga: A 306-MW coal fired steam turbine base-load plant located in Lansing (Zone C). It is owned by AES Corporation. This plant is assumed to generate for 8000 Hours per year.

4. **Nuclear Base Load Unit located in Zone C.** This is similar to Nine Mile Point 1 & 2: Two BWR nuclear base load plants located in Oswego (Zone C). Nine Mile Point 1 and 2 have capacities of 609 MW and 1550 MW, respectively. They are owned by Constellation Energy. This plant is assumed to generate for 8000 Hours per year.

5. Combined Cycle Unit located in Zone J with a Heat Rate of 9,000 Btu/kWh. This plant is based on the planned 500MW Poletti Combined Cycle Power Plant which is to be located in Astoria (Zone J). It is being commissioned by the New York Power Authority (NYPA).[114] This plant is assumed to generate for 7000 Hours per year.

[113] Black start is defined as "*an ancillary service which enables the grid to recover from a total shutdown. Power station auxiliary equipment must be supplied with power before the main generators can be started, power stations that provide black start capability are fitted with stand-by generators which can self-start and so energize the grid.*"
www.med.govt.nz/ers/electric/wind-energy/final/final-12.html

[114] For more information see http://www.dmjmharris.com/MarketsAndServices/40/10/index.jsp.

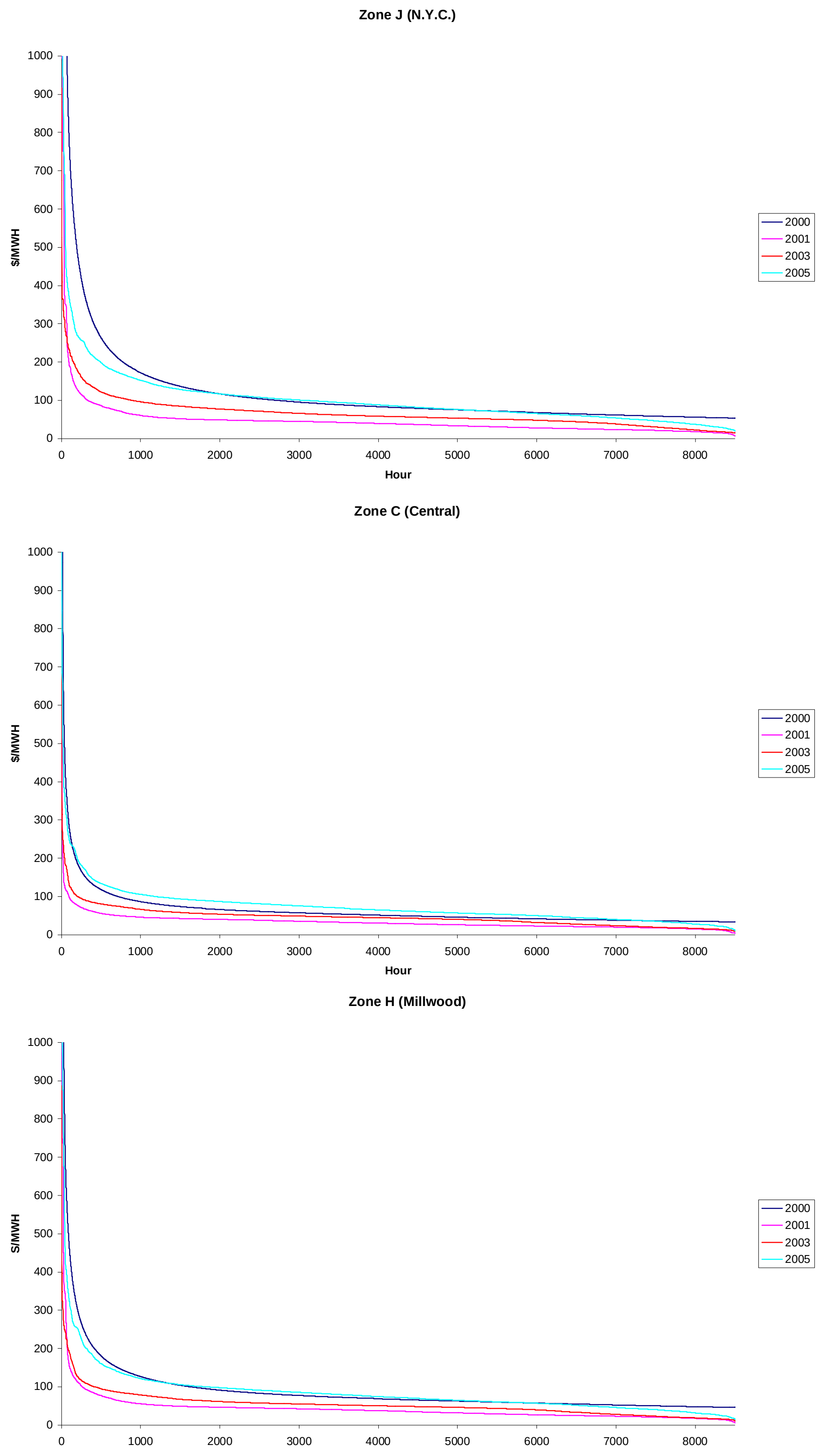

Figure 3.5: Real Time Spot Price Duration Curves for New York City (J), Central (C) and Millwood (H) for 2000, 2001, 2003 and 2005.

Before we begin the analysis it is important to note an important change in the market rules for the New York State Electricity market. As discussed previously in Section 2.4.2, market based trading actually began in November 18, 1999 with a FERC-approved price cap of $10,000 per MWH.[115] However high prices in New York City, despite a cooler than usual summer; a $6000 price spike in the neighboring New England market; delays in New York State's Article X process for licensing and sitting new generating capacity; the lack of proven demand-side response mechanisms; and various transitional problems with the new market (including software problems) saw NYISO submit a request to FERC on June 30, 2000 for a temporary bid cap of $1,300 per MWH. On July 26, 2000, FERC ordered NYISO to set a bid cap of $1,000 per MWH --- a cap that remains to this day.

Figure 3.6 and Table 3.2[116] presents the gross profit per MW of capacity for the hypothetical generators using the fixed exogenous capacity factors and heat rates noted above.[117,118] From the graphs and table we can see that gross profits fell for all

[115] Note that because of the $10,000 per MWH price cap the 2000 price duration curves in Figure 3.5 have prices above $1000/MWH i.e. they do not cross the y axis.

[116] For the analysis it is assumed that: Natural Gas: 1 CF (Cubic Feet) = 1,000 BTUs; Coal: 12,000 Btu/lb: and 1 short ton = 2 000 pounds.

[117] Note that our analysis only considers gross profit of the hypothetical generators i.e. it excludes capital costs. As different generation technologies are likely to have different capital costs (i.e. the capital costs of a nuclear base load unit would be far greater than the capital costs of a gas fired peaking unit) we do not compare the level of gross profits between generators directly.

[118] Note the above analysis assumes fixed exogenous capacity factors rather than endogenous capacity factors. We concede that the use of endogenous capacity factors would have been a more realistic assumption (e.g. we would expect that as fuel costs increase the capacity factor of the plant will decrease all else equal) and that as a result the gross profits may be underestimated. One argument for using exogenous and fixed capacity factors is that there is likely to be a strong correlation between the marginal costs of a generator using the same fuel as the marginal generator and the market price. To examine the robustness of the results we repeated the analysis assuming that, as is consistent with a competitive market, a generator will generate whenever the market price exceeds its marginal cost of production. For each generator we calculated a hypothetical capacity factor each year by counting the number of hours in which our marginal cost estimate from above was less than the price. We found that the results were broadly consistent with those discussed in the previous section.

of the generators we examine when the $1,000 per MWH bid cap was introduced. The reduction in gross profits was due to large decreases in average prices faced by all generators regardless of capacity factor. While a portion of this decrease in average prices can be explained by the bid cap removing price spikes, the decrease is too large (especially for base load units) to have been caused solely by such a price control mechanism. It is more likely that the reduction in wholesale prices were due to external factors like those highlighted in the 2001 Annual Report on the New York Electricity Markets by the Independent Market Advisor to the New York ISO. They conclude that lower overall energy prices were caused by "sharp declines in fuel costs over the year and the return of transmission and generation facilities that had been out of service during 2000."[119] Most affected by the introduction of the bid cap was the gas peaking unit located in Zone J. Because of their low capacity factors the gross profits of peaking units are very reliant upon the small number of price spikes.[120] As these price spikes were removed by the bid cap the average price faced by peaking units was dramatically suppressed, a result which was compounded by the effect of the external factors noted above. The average price received by the peaking unit again decreased in 2003, despite increases in gas prices, before increasing in 2005 --- although they are still far below 2000 levels. During 2003 and 2005 the gas peaking unit was also hit by sharply increasing gas costs which increased their marginal costs. As a result the peaking unit gross profits still remain substantially below 2000 levels. The hypothetical nuclear generation units also suffered due to the introduction of the bid cap, as they no longer received the high revenues resulting from the price spikes. However, because of their large capacity factors the effect on the average price received by such generators, and ultimately gross profits, was negligible. The main

[119] See Patton and Wander (2001), p. i.
[120] See Section 2.4.2 for a discussion on 'Missing Money' relating to the introduction of Price Caps.

driver behind the impressive recovery in the gross profits of the nuclear base load units in 2003 and 2005 was the large increases in gas prices (see Table 3.3). Higher fuel costs increased market prices by raising the marginal costs of the marginal generator --- which in New York is primarily gas-powered.[121] Nuclear base load units therefore benefited greatly from the situation as the combination of high prices and large capacity factors increased revenues, while their marginal costs remained constant as they were insulated from the rising gas and coal prices. Lastly we examine the hypothetical coal base load unit and combined cycle base load unit. As with nuclear, both benefited from increasing average wholesale electricity prices in 2003 and 2005. However unlike nuclear, such gains were offset by a large increase in fuel costs. Thus neither the coal base load unit nor the combined cycle gas base load unit have recovered to 2000 gross profit levels.

It is interesting to note that the nuclear base load generators that have faired the best since deregulation were divested at a discount (e.g. Indian Point and Nine Mile Point), while the oil and gas combustion turbines (e.g. Arthur Kill, Ravenswood and Astoria) that had been sold at a premium have performed poorly.[122] From this point of view it is easy to see how consumers may feel aggrieved. The low sale price of nuclear powered plants created stranded costs that were ultimately borne by consumers. From the above analysis, these plants now appear extremely profitable, with consumers paying the higher prices due to higher gas prices --- but the high gross profits may still not be enough to cover capital costs. It is important to note that if gas prices had fallen over this period, the marginal cost of generation (and hence the electricity price) would have fallen and nuclear generation would have become less profitable.

[121] From Table 3.2 the marginal cost of both gas powered generations doubled between 2000 and 2005.
[122] See Section 2.3 for a discussion on the divestiture of generation assets.

Therefore one needs to careful not to make ex-post assessments of divestures decisions made in the face of price uncertainty.

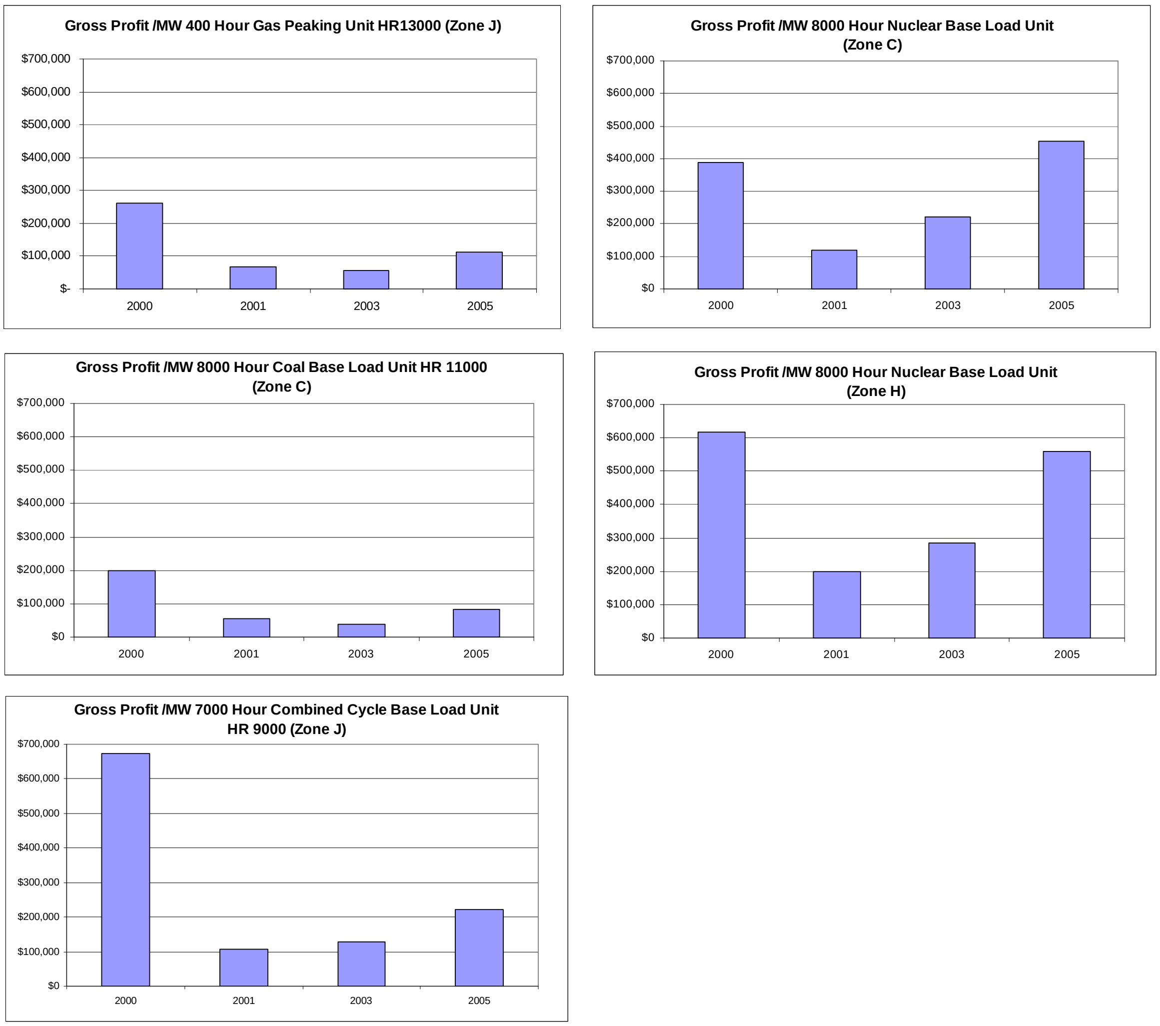

Figure 3.6: Gross Profit per MW for Various Generators Using Fixed Capacity Factors and Heat Rates

Table 3.2: Average Price ($/MWH), Marginal Cost and Gross Profit for Hypothetical Generation Plants in 2000, 2001, 2003 and 2005.

	2000	2001	2003	2005
400 hour peaking Unit HR 13000 (Zone J)				
Average Price	$715.71	$211.40	$205.10	$374.03
Marginal Cost	$60.84	$53.56	$80.86	$120.12
Margin	$654.87	$170.20	$142.90	$281.63
# of hours	400	400	400	400
Gross Profit	$261,948	$68,078	$57,162	$112,653
8000 Hour Nuclear Base Load (Zone C)				
Average Price	$68.52	$34.81	$47.69	$76.55
Marginal Cost	$20.00	$20.00	$20.00	$20.00
Margin	$48.52	$14.81	$27.69	$56.55
# of hours	8,000	8,000	8,000	8,000
Gross Profit	$388,160	$118,480	$221,520	$452,400
8000 Hour Coal Plant HR 11000 (Zone C)				
Average Price	$68.52	$34.81	$47.69	$76.55
Marginal Cost	$21.33	$20.21	$21.08	$29.97
Margin	$47.19	$14.60	$26.61	$46.58
# of hours	8,000	8,000	8,000	8,000
Gross Profit	$377,498	$116,764	$212,909	$372,662
8000 Hour Nuclear Plant (Zone H)				
Average Price	$97.23	$44.75	$55.70	$89.72
Marginal Cost	$20.00	$20.00	$20.00	$20.00
Margin	$77.23	$24.75	$35.70	$69.72
# of hours	8,000	8,000	8,000	8,000
Gross Profit	$617,840	$198,000	$285,600	$557,760
7000 Hour Combined Cycle HR 9000 (Zone J)				
Average Price	$138.22	$52.30	$74.12	$114.67
Marginal Cost	$42.12	$37.08	$55.98	$83.16
Margin	$96.10	$15.22	$18.14	$31.51
# of hours	7,000	7,000	7,000	7,000
Gross Profit	$672,734	$106,516	$127,003	$220,553

Table 3.3: Annual Average New York Gas and Coal Prices

	2000	2001	2003	2005
New York Natural Gas Prices ($/1000 Cubic Feet) --- Electric Power Price *	4.68	4.12	6.22	9.24
Average Price of Coal Delivered to ($/ per Short Ton) --- NY Electric Utilities	39.11	37.06	38.64	54.94

SOURCE:
Gas --- http://tonto.eia.doe.gov/dnav/ng/ng_pri_sum_a_EPG0_PEU_DMcf_a.htm
Coal --- Annual Coal Report 2000, 2001, 2003 and 2005, EIA Office of Coal, Nuclear, Electric and Alternative Fuels.

3.2.3 Non 'fuel and purchased power' costs

Figure 3.7 displays the average cost of distributing power to customers per kWh(i.e "average cost per ultimate consumer kWh" excluding fuel and purchased power costs). It is interesting to note that these costs have not really decreased in nominal terms for Consolidated Edison or Niagara Mohawk since 1997. NYSEG is the exception with a decreasing trend in distribution costs. Yet the lower distribution costs are offset by higher ‘fuel and purchased power costs’ --- possibly caused by the divestiture of generation assets in 1998 (i.e. capital costs have become purchase costs). We would hope that the move from rate of return regulation to incentive regulation would provide the correct incentives for distribution companies to become more efficient in their operations, thereby potentially resulting in a decreasing trend in distribution costs --- yet this does not appear to have happened.

To explore the possible explanations for why incentive regulation has not been able to reduce the distribution costs of the utilities we monitor, we need to first better understand what incentive regulation can achieve and where the increases in distribution costs are coming from. Earning sharing incentive regulation attempts to motivate firms to increase net cash flows by allowing them to keep a substantial proportion of cost savings for the length of the contract. Therefore it is most likely to be effective in the reduction of genuine cash flow items like operating and maintenance costs (e.g. ‘wages and benefits’ and ‘other costs’), as opposed to non-cash expense regulator-imposed items like depreciation and amortization. Taxes while being a cash item can also be assumed to be exogenous and not affected by incentive regulation.[123] Capital costs may also be unresponsive to incentive regulation due to the difficulties firms may have changing their physical capital.

Firstly, when we examine Consolidated Edison we see that increases in costs since 1997 have come from increases in ‘other taxes’, ‘other expenses’, ‘capital costs’, and

[123] According to the 2003 Consolidated Edison 10K report, “*[t]he New York State tax laws applicable to utility companies were changed effective January 1, 2000. Certain revenue-based taxes were repealed or reduced and replaced by a net income-based tax. In June 2001, the PSC authorized each utility to use deferral accounting to record the difference between taxes being collected and the actual tax expense under the new tax law until that expense is incorporated in base rates. For Con Edison of New York, effective October 1, 2004, state income tax is being recovered for its gas and steam businesses through base rates*.”

in the last year ‘wages’. While incentive regulation can not be expected to affect taxes (exogenous) and to a certain extent ‘capital costs’, ‘other expenses’ and ‘wages’ are both cash items that could be expected to be lowered with incentive regulation. Thus incentive regulation’s failure to decrease the level of these costs is somewhat disappointing. Looking at the distribution cost breakdown of Niagara Mohawk, we see that there have been increases in ‘amortization of utility’ since 2002, and ‘operating income taxes’. However, since 1998, ‘other expenses’ have decreased --- a somewhat encouraging sign for incentive regulation. Finally we consider NYSEG, whose total distribution costs have been decreasing. The decrease in costs is mainly from a reduction in ‘depreciation and amortization expenses’, ‘operating taxes’ and a small decrease in ‘capital costs’. This is in contrast to ‘other expenses’ and wages that have been static. The large increase in 2001 was caused by an increase in the ‘amortization of utility plant acquisition adjustment’. So while the situation at NYSEG is positive it is probably not due to incentive regulation.

3.3 Conclusion

This chapter sought to paint a more complete picture of the progress toward the lowering of rates faced by consumers by analyzing the behavior of these costs (via “total costs to consumers per kWh” --- a proxy for retail prices) over time for three major New York electricity distribution companies. We found that overall total costs to consumers have risen since 1997 for all of the three companies we monitor. Of these, Consolidated Edison’s increases in cost can be traced to increases in the wholesale price of electricity; the sustained premium of ‘fuel and distribution costs’ over wholesale costs, likely due to the ICAP market; and the failure of incentive regulation to reduce distribution costs (in particular ‘wages’ and ‘other expenses’).

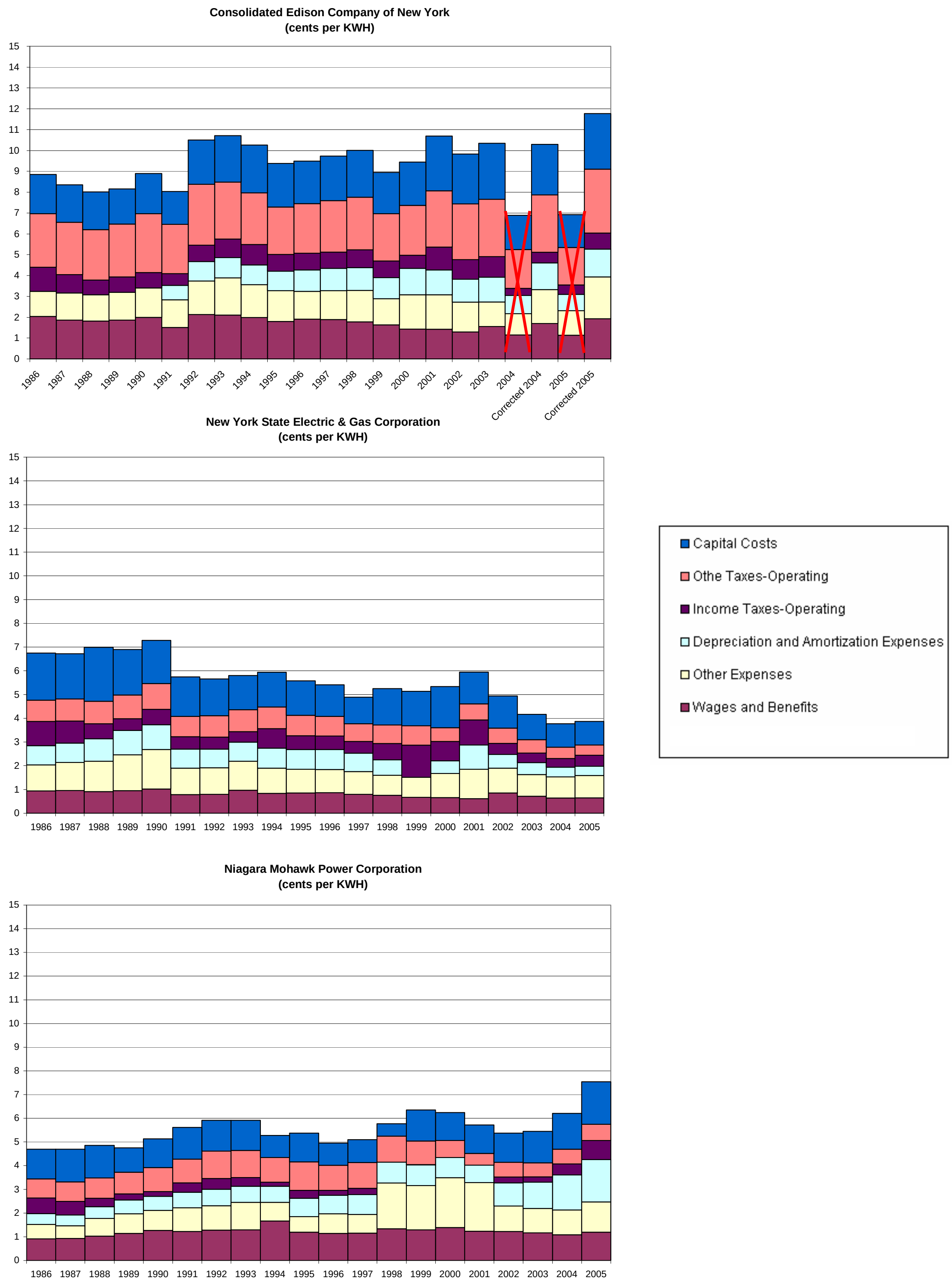

Figure 3.7: Average 'Distribution Costs' per Ultimate Consumer KWH for Consolidated Edison (top) NYSEG (middle) and Niagara Mohawk (bottom)

Niagara Mohawk's increase in costs can also be traced back to the increase in wholesale prices, although unlike Consolidated Edition there is no premium over wholesale prices. While Niagara Mohawk distribution costs have increased, this was mostly due to the increase in non-cash and exogenous expenses. Cash expenses have actually decreased --- signaling incentive regulation might be having some positive, albeit small, effect. NYSEG, whose costs increased and then decreased to lie slightly above 1997 levels, was also affected by rising wholesale prices. However this increase has been offset by a substantial reduction in distribution costs --- although it is difficult to see how incentive regulation could be responsible for this. Thus the overall evidence is that incentive regulation has not helped lower the costs of transmission and distribution companies. We also found that an important factor in the increase in the wholesale price of electricity was rising fuel costs.

CHAPTER 4

MARKET SEGMENTATION: CORRELATION ANALYSIS

4.1 Introduction

In this chapter we focus on whether the New York Public Service Commission's (PSC) second major goal for industry restructuring, maintaining the reliability of service,[124] has been achieved. One way to assess the reliability of the system is to look at the number and severity of blackouts. For example, on August 14th, 2003, New York State, together with other major regions in north-eastern United States and eastern Canada, witnessed the largest blackout in the history of the United States. The blackout affected approximately 50 million people, with outage-related financial losses were estimated at $6 billion USD. However, while such an event provides stark anecdotal evidence on reliability, the number of realized blackouts is far too coarse a measure to objectively assess the impact of reform on reliability, especially over the short period since deregulation.[125] Another approach that can be used to measure the state of reliability is to examine reserve margins. This engineering-based approach measures the extra supply capacity that is available to respond to unexpected events.[126] The NYISO stipulates that a reserve margin of 18% is needed to satisfy the proposed North American Electric Reliability Corporation (NERC) of failure in less

[124] From page 28 of Opinion 96-12 State of New York Public Service Commission (1996): "*Continuing Reliability of Service: In order to protect all consumers, any new system involving competition in the generation sector must have reliability of the bulk power system as a top priority, including an independent system operator (ISO) that must have the authority and means to continue to provide this reliability.*"

[125] This is because blackouts are large events that occur very infrequently, even when reliability is compromised. For example, an unreliable network might be one that has a major blackout once every 5 years on average. However with only 5 years of data, it is quite possible that we might not observe any outages in an unreliable network over this period. Similarly, we might actually observe one atypical blackout in what is essentially a reliable network. Therefore, actual blackouts provide motivation to look at reliability but cannot be used to assess reliability directly over such a short timeframe.

[126] The reserve margin is calculated as the amount of Installed Capacity above the Forecasted PEAK Load (%).

than 1 day in 10 years. As mentioned in Chapter 1, according to the 2005 New York Independent System Operator's (NYISO) forecast, the New York Control Area will fall below the required 18% summer reserve margin in 2008.

In this chapter we choose to apply an economic-based approach to system reliability. The approach attempts to measure the degree of market integration using the pair-wise relationships between day-ahead zonal spot price data. It is interesting to note that the aforementioned 2003 Northeast blackout was caused by transmission problems not generation adequacy.[127] This event highlights the importance that market integration plays in ensuring the reliability of supply. For example, if a network is often segmented, the system operator has fewer available generators to dispatch and thus the region is more vulnerable to outages — due to the greater chance that generation will not be sufficient to meet load. Conversely, if a market is integrated, it is more likely that power can be sourced from various locations and transmitted into the affected area — thereby decreasing the chance of blackouts. It is important to note that even a segmented market may have sufficient generation capacity located in load pockets to satisfy demand; conversely even a fully integrated market can have reliability issues due to insufficient generation capacity. Nonetheless, an integrated market is always more conducive to reliability, as a constrained solution cannot dominate the associated unconstrained one.

Determining the degree of market segmentation is also pertinent to evaluating the process towards the PSC's goal of lowering rates for consumers. Given the number of

[127] Other examples of transmission based blackouts include: 23 September 2003 when over 4 million homes and businesses in Denmark and Sweden lost power for four hours; 28 August 2003 when an estimated 400,000 people were without power in London; and 28 September 2003 when 57 million people were affected by a blackout in Italy.

firms in a pool market, competition is maximized if there are no transmission constraints[128] or other phenomena that segment the market. This ensures that every firm competes with every other firm, which lessens the chances that market power can be exercised. Conversely, if the market becomes segmented, decreased competition may result from the diminished market contestability and the consequent increase in concentration of ownership and control.[129] This is made particularly important due to the difficulty that existing empirical approaches (Wolfram, 1999; Borenstein et al., 2002; Joskow and Kahn, 2002; and Wolfram, 1998) have in detecting abuses of market power.[130]

By design, the price at every zone would be equal in a pool market with no transmission constraints or losses. However, the existence of these phenomena will cause prices at different nodes to vary. The classical economic definition of a market is particularly relevant for determining market integration. The definition advocated by Marshall (1961) is that

> *"the more nearly perfect a market is, the stronger is the tendency for the same price to be paid for the same thing at the same time in all parts of the market: but of course if the market is large,*

[128] Transmission constraints occur when a line between parts of the network cannot transmit any more electricity.

[129] It is important to note that even a segmented market may have sufficient competition amongst generators to achieve competitive outcomes; conversely even a fully integrated market can have market power issues. Nonetheless, an integrated market is always more conducive to competition, as a constrained solution cannot be more competitive than the associated unconstrained one.

[130] Such approaches rely on obtaining an accurate estimate of the marginal cost of producing electricity by the marginal generator. This is often difficult due to the inability to extract private cost information from generators. Additionally in times of fuel scarcity, the true marginal cost of producing electricity should include an option value, reflecting that the decision to generate today can affect a firm's ability to generate tomorrow. This option value is often very difficult to calculate, requiring a dynamic model and real option analysis.

allowance must be made for the expense of delivering the goods to different purchasers."

Stigler and Sherwin (1985) provide a relatively simple empirical method to delineate economic markets with the use of correlation analysis. They state "*. . . parts of a market will be more closely integrated the closer the movements of their prices*" (p.558). Thus if the market were integrated one would expect the prices to be strongly positively correlated. A separate market would have lower correlations.

A number of authors including Woo et al. (1997) and Bailey (1998a, 1998b) have subsequently used correlation-based analysis to delineate the economic markets that are present in electricity markets.[131] Both studies use statistical tests to examine the pair-wise relationships between prices within the western United States. For example, Woo et al. (1997) use the co-integration of daily electricity price series as being suggestive of market integration.[132] Once price co-integration had been inferred they test whether the relationship (the slope coefficient when the price in one zone is regressed on the price at another zone) between the prices is equal to one. If that test is not rejected, the intercept term from that regression should be equal to the actual transportation costs in order for competition and integration to be present. Bailey (1998a,b) takes a slightly different approach. In order to better understand the causes of market segmentation,[133] she uses statistical analysis to see if certain variables (like peak and non-peak periods, seasons, transmission line ratings, and hydroelectric

[131] There exists a large body of literature on market integration for many products including petroleum (Slade, 1986), oil (Gullen, 1999) and natural gas (Doane and Spulber, 1994).
[132] Doane and Spulber (1994) is another example of paper to use co-integration as a means of delineating markets --- this time in the market for natural gas.
[133] Woo et. al. (1997) also look for evidence of Granger Causality between the price series.

flows) cause lower correlations between locations.[134] She also has a slightly different view of how to interpret the slope coefficient and intercept term when the price in one zone is regressed on the price at another zone. She believes that if the market is integrated, the slope coefficient is less than 1 by an amount equal to the transmission losses; the negative of the intercept are transmission charges. If the two zones are not integrated, there should be no relationship between the two prices. i.e., the slope coefficient should be zero. We prefer this interpretation to Woo (1997). It is important to note that there exists no definitive threshold for how close to one the slope coefficient should be to imply that markets are integrated or segmented, only that the market is more integrated when the slope coefficient is closer to one.

This chapter applies an approach similar to Bailey (1998a, 1998b) and Woo et al. (1997) to data from the New York electricity market, in order to gain a better understanding of the evolution of the integration of the market over time. Many characteristics make the New York Electricity Market an excellent setting in which to conduct a study of market integration. Firstly, as described above, the 2003 blackout has raised considerable concerns about the state of the transmission network in New York State --- which in turn has lead to calls for increased infrastructure investment. Secondly, there exists considerable geographical separation between the large hydroelectric generation in the North (Niagara and Canada) and the high consuming cosmopolitan region in the South (New York City). This distribution of load and generation means that market segmentation is of particular concern, both in terms of competition and reliability. Additionally, we are fortunate that the New York

[134] She finds that high hydroelectric flows, transmission line outages and high demand are likely to cause lower correlations and hence a 'narrower' market. Having looked at correlations, she then analyzes price differences across locations and finds that transmission line congestion causes prices to diverge. Section 4 of this paper follows in the footsteps of these last two papers.

Electricity Market has been operating since 1999, thus providing this study with five full years of data.

4.2 Data

This chapter draws on the day ahead price at four (A, C, G, and J) of the eleven New York Control Area Load Internal Zones (A-K) from 1 January 2000 to 31 Decemeber 2004. In order to keep the analysis manageable we concentrate our analysis only on the pair-wise relationships between Zone A (West), C (Central), G (Hudson Valley), and J (New York City).[135] See Figure 4.1 for locations of the zones. These zones were chosen as the New York City Zone is a major load centre, the West Zone is where the large Niagara Falls hydroelectric plants are located; the Hudson Valley Zone is close to the New York Zone and the Central Zone is close to the West Zone. There exists considerable geographical separation between the New York Zone and the West Zone. Of particular interest is whether the New York electricity market, with its so called "third-world electricity grid,"[136] is becoming less integrated over time.

In the interests of brevity, this thesis will also only focus on trading periods 6 (5:00-6:00 a.m.) and 18 (5:00-6:00 p.m.). These periods were chosen to represent off peak and peak times, which is consistent with Bailey's (1998a,b) methodology.[137]

[135] Analyzing all possible 210 combinations of the zones illustrates just how cumbersome pair-wise analysis can be. (Note: this is calculated including all permutations, as AB is not the same as BA.)
[136] The statement "A superpower with a third-world electricity grid" was made in response to the New York Blackout by Bill Richardson, New Mexico governor and former head of the Department of Energy, 2003.
[137] Woo et al. (1997) used daily volume-weighted average price data.

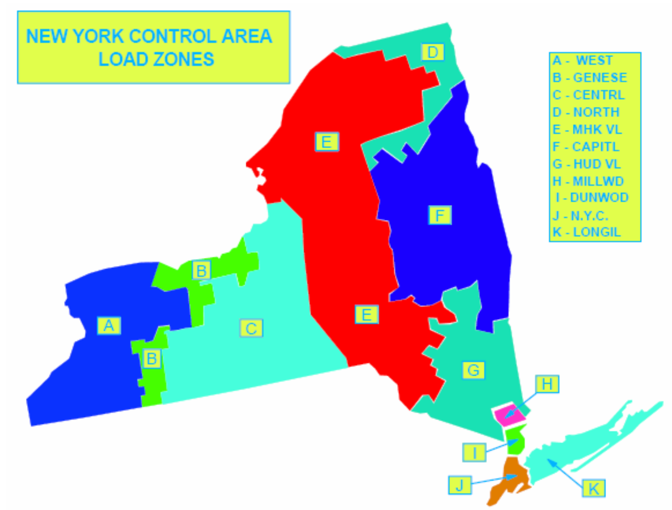

Figure 4.1: New York Control Area Load Zones

SOURCE: www.nyiso.com

From the raw time series data for each node we extract 24 separate series of prices, each one corresponding to a different trading period, with trading period zero beginning at midnight, period one beginning at 1 a.m., and so on. Each series has one observation a day for each trading period for approximately six years. As stated above we concentrate our analysis on periods 6 and 18 and Zones A, C, G, J --- i.e. A6, C6, G6, J6, A18, C18, G18, J18. We will perform our market integration analysis on each full year separately.

Table 4.1 presents the summary statistics from the four selected zones for 2000, 2001, 2002, 2003, and 2004. As to be expected the average price and volatility during period 18 (5:00pm-6:00pm), the high load period, are higher than the average price and volatility in period 6 (5:00am-6:00am), the low load period. Such time varying mean and volatility is very common in electricity markets as price and volatility closely follow demand due to the non storability of electricity. For example, in the early hours of the morning demand is very low allowing low cost base generation to be used. As demand increases throughout the day more expensive generation must be used. Demand then falls in the evening as people go to sleep. (Figure 4.2 displays graphically the mean and standard deviation throughout the day for Zone J (New York City) for the period 01/01/2000 to 8/31/2005.) The average price of electricity becomes larger the further the zone is located away from the large low cost hydroelectric generation in A. This is to be expected as transmission losses, which represent the loss of energy (as heat) while electricity is being transported, increase with distance.[138] It is also interesting to note that since 2002 the average price of electricity has increased each year in period 18 and 6 for all of the selected zones.

Table 4.1: Summary Statistics of the Period 18 (5:00pm-6:00pm) and 6 (5:00am-6:00am) Zonal Prices in the New York Electricity Market --- 2000, 2001, 2002, 2003, and 2004 (1 January – 31 December)

	2000		20001		2002		2003		2004	
	Mean	Std.Dev.	Mean	Std.Dev.	Mean	Std.Dev.	Mean	Std.Dev.	Mean	Std.Dev.
a18	45.11	22.18	43.55	28.85	39.62	17.18	55.15	17.83	56.28	14.47
c18	47.12	23.56	46.27	29.19	42.39	18.61	59.46	18.83	60.25	14.82
g18	60.76	53.60	55.35	35.49	50.99	19.66	66.33	20.03	66.46	16.13
j18	66.18	56.68	60.24	36.27	60.35	23.83	81.69	25.91	82.02	25.81
a6	24.81	10.53	25.63	6.91	23.23	6.75	33.33	12.69	34.51	9.76
c6	25.77	11.23	26.50	7.55	24.41	7.52	34.97	13.02	36.33	9.65
g6	28.62	12.14	28.84	8.30	27.19	7.96	37.86	13.74	38.93	9.94
j6	30.25	12.23	30.03	8.39	31.95	10.36	42.59	15.02	42.08	10.81

[138] There are of course generators within zones, which will have an effect on this relationship.

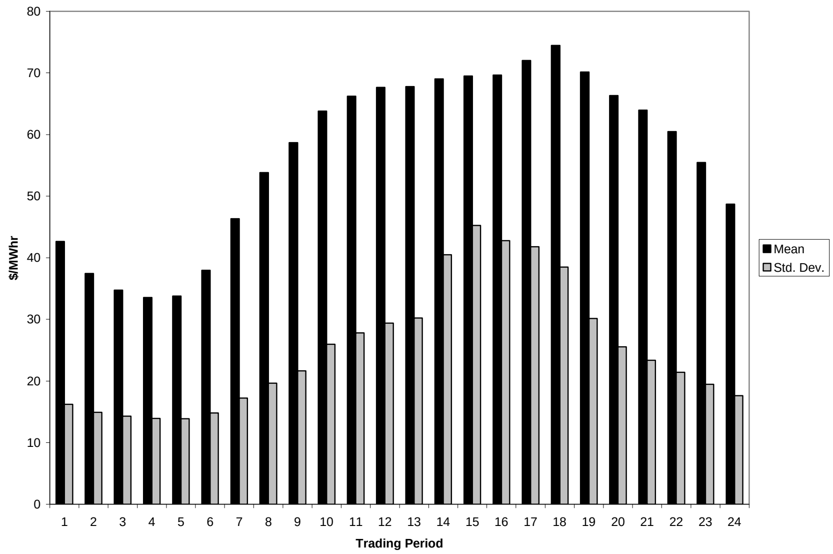

Figure 4.2: Mean and Standard Deviation of the Day Ahead Price at the NYC Zone (J) for the period 01/01/2000 to 8/31/2005

4.3 Pair-wise Analysis

In this section we will analyze the pair-wise relationship between the daily price time-series at different zones using an approach advocated by Bailey (1998a, 1998b), Woo et al. (1997) and Videbeck (2004).[139]

4.3.1 Testing the individual time series for non stationarity.

We need to test to see if individual raw zonal price time series are non-stationary (i.e. have a unit root) for a number of reasons. First, running an ordinary least squares (OLS) regression using strictly non-stationary data can result in misleading R^2's and t statistics (Kennedy, 2003).[140] Secondly, testing if two stationary processes are co-integrated[141] is redundant --- two stationary processes will not drift apart without limit

[139] As we will see later, the co-integration approach used by Woo et. al. (1997) is not suitable for analyzing our data.
[140] Stock (1987) found that if Yt and Xt are co-integrated then OLS estimates of alpha (intercept) and beta (slope coefficient) will be consistent.
[141] Price co-integration requires that prices do not drift apart without limit.

by definition. Woo et al. (1997) make this econometric error. They test to see whether the raw individual daily price series are stationary and find using ADF test statistics that they are. They then look to see if the pair-wise combinations of the stationary time series are co-integrated and find, not surprisingly, that "the ADF statistics reject the hypothesis of no price integration for all six market pairs". They then erroneously conclude that this finding is important as "*both De Vany and Walls (1993) and Doane and Spulber (1994), assert that rejecting the no price co-integration hypothesis suggests market integration.*" Yet co-integration is a technique only used to test if a certain linear combination of two non-stationary time series variables is itself stationary.

Before we examine the data we will first make an important note, for clarity, on how we label the different types of stationarity/non-stationarity in this paper. They are:

1. Strictly stationary --- the time series does not have a unit root and has a constant mean and variance.
2. Trend stationary --- it is not a strictly stationary process as it has a non-constant mean and variance, but this trend is deterministic and the series does not have a unit root.[142] To make the process strictly stationary we must remove the deterministic trend.
3. Strictly non-stationary --- has a unit root and thus has a non constant mean and variance. Such a process can sometimes be made stationary by differencing.

We would expect prices in electricity markets to exhibit trend stationarity --- it is well documented that electricity price time series have deterministic time trends including

[142] A time series process is trend stationary if after trends were removed it would be stationary.

seasonality, day of week, and even time of day effects.[143] This is because, as was mentioned earlier, the price of electricity is closely related to load, and different seasons and days of the week have different load patterns. For example, in summer there is an increased use of energy intensive air conditioning that increases load, which in turn requires increased use of high priced peaking units/old generators, and hence results in higher prices.[144]

It is also hard to imagine in theory that electricity prices would have a unit root --- and hence be non stationary (in the strict sense). Two examples illustrate the intuition behind this. First, if the price process was non-stationary a shock today would affect the distribution of prices in the future (in essence moving the entire distribution of prices to the right) --- this seems unreasonable in electricity markets as there is no underlying reason why a price spike (or even periods of high prices) would continue to affect prices far into the future. Secondly, the competitive process limits the spot price from rising without limit --- if the spot price for electricity gets too high, new generators will enter the market, increasing supply and thus limiting the spot price.

To see if our individual price series are strictly stationary, trend stationary, or non-stationary (have a unit root), we will use three techniques:

1. Visual inspection of the individual time series – a somewhat ad hoc approach;
2. Visual inspection of correlograms of the individual series; and
3. An Augmented Dickey-Fuller test for a unit root --- a more formal means of testing if a series is non stationary.

[143] For example, the mean and variance today (in summer) will probably not equal the mean and variance that is observed in December (winter).

[144] It is interesting to note that in some countries, such as New Zealand, this pattern is reversed. This is because most households use electricity in winter to heat their homes, while using air-conditioning is not overly popular.

Figure 4.3 displays plots of the day-ahead price at various zones during period 6 and period 18. A simple visual inspection of these plots suggests the prices are not strictly stationary as it does not appear the process has a constant mean and variance. Indeed, there is preliminary evidence of a slight upward trend together with seasonal "wave like" patterns. Day of the week effects, which are difficult to detect in the time series plots (due to the amount of data displayed) are identifiable in the correlograms --- presented in Figure 4.4. We can see that the correlation between the price today and prices tomorrow, the next day, and so on, follows a pattern of general decline which is interrupted around every 7th lag where the correlation rebounds.[145] The correlograms also show that the correlation on the first lag looks substantially less than one and this declines for longer lags. This suggests that the process does not have a unit root --- if it did the correlation on the first lag would be close to one and would remain approximately constant.

While both the time-series graphs and correlograms provide evidence for daily electricity prices being trend stationary, they do not rule out the presence of a unit root. We now turn to a more formal means of testing for non stationarity --- the Augmented Dickey-Fuller test for a unit root.[146]

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[145] To see if there is a day of week effect we regress price on the seven daily dummies and 11 monthly dummies and then ran an F test that the coefficients of the daily dummies were all equal. We reject Ho at the 1% level for period 6 & 18 prices in all four zones.
[146] The random walk version of the model is y_t=gamma*y_{t-1}+episilon$_t$, then the Dickey-Fuller tests the null hypothesis that the absolute value of gamma=1. This simple model can be adjusted so as to include drift and trends.

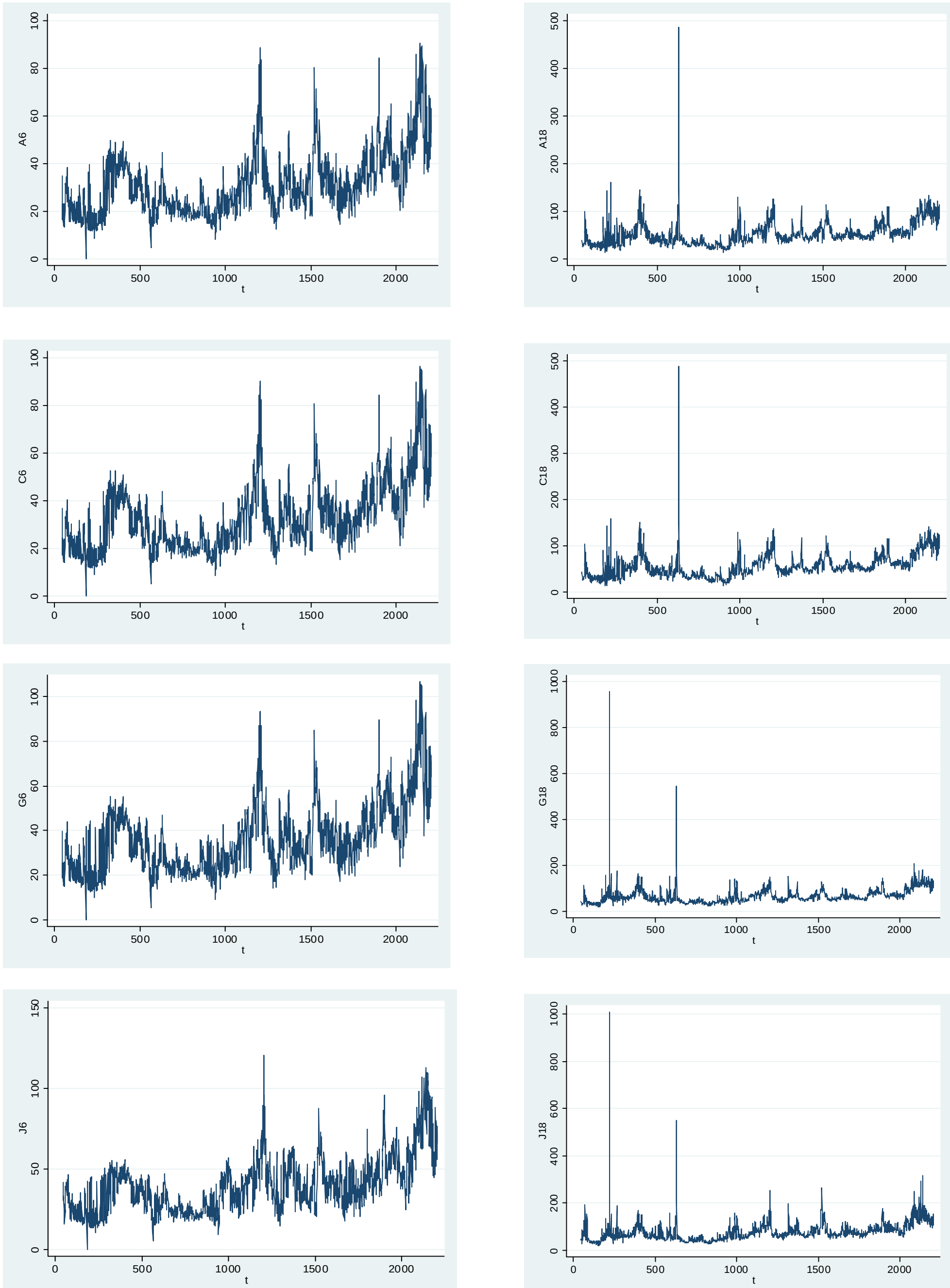

Figure 4.3: Plots of the Day-Ahead Price at Various Zones During Period 6 (5:00am-6:00am) and Period 18(5:00pm-6:00pm for 01/01/2000 to 8/31/2005

Notes: Period 6 is left, Period 18 is right. Zones from top to bottom are A, C, G, and J. All prices are in $/MWh

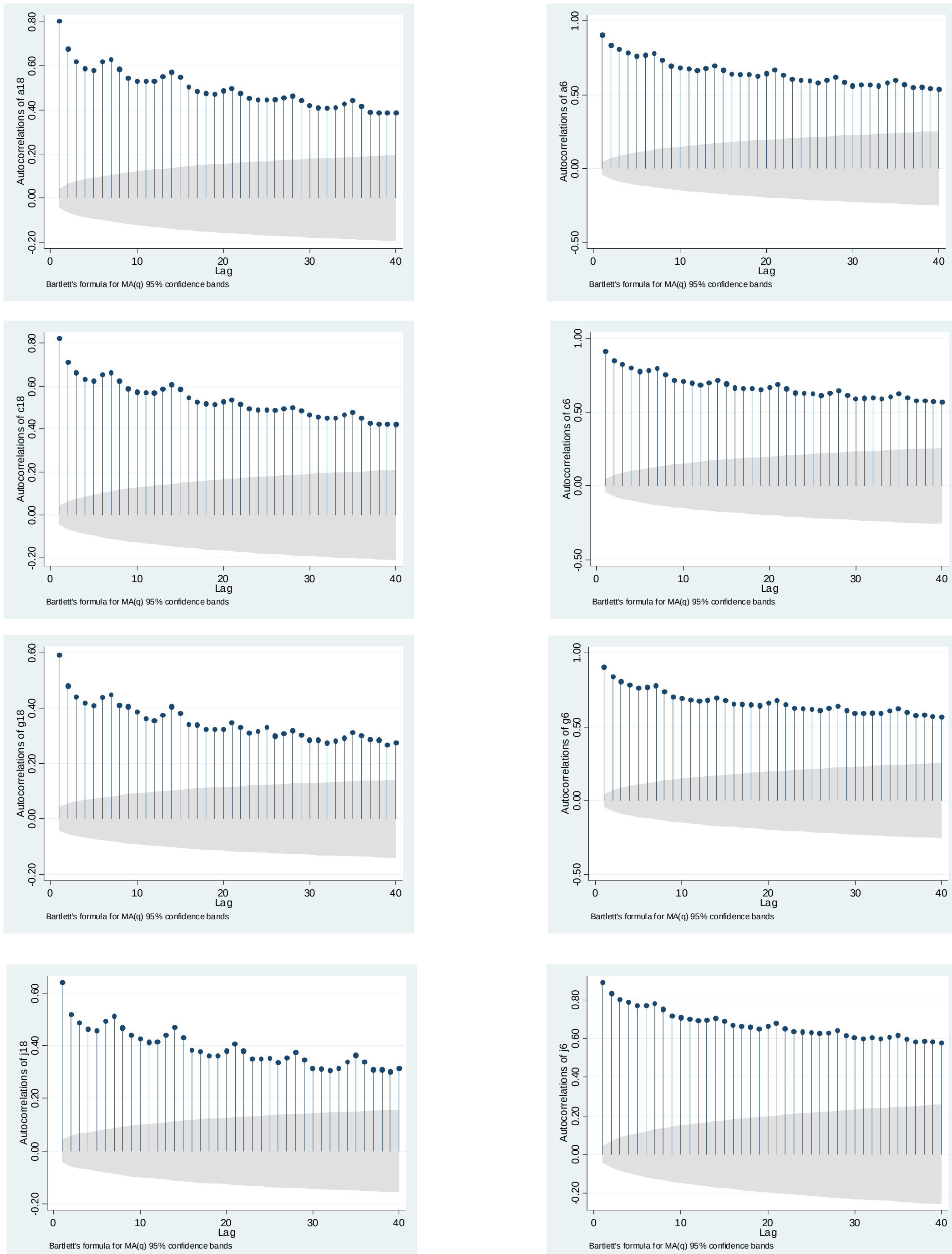

Figure 4.4: Correlograms of the Day-Ahead Price at Various Zones During Period 6 (5:00am-6:00am) and Period 18 (5:00pm-6:00pm) for 01/01/2000 to 8/31/2005.

Notes: Period 6 is left, Period 18 is right. Zones from top to bottom are A, C, G, and J

Table 4.2 presents the test results of the Augmented Dickey-Fuller test in levels with 14 lags.[147] We can see that all of the zonal test statistics lie outside of the 1% critical value of -3.43, and therefore we reject the null hypothesis that the series has a unit root in favor of the alternative that the variable was generated by a stationary process. However including more lagged differences can lead to conflicting evidence on whether the series is stationary. For example, including 40 lagged differences, thus picking up some of the seasonal trends, results in a failure to reject the null hypothesis at all zones at the 5% level. It is important to note that STATA allows the addition of a linear tread in its Interpolated Dickey-Fuller Test. If this trend is included then all zones are significant at the 10% level with 40 lagged differences (note that the critical values change with the inclusion of the time trend).

Table 4.2: Test Statistics Z(t) of the Interpolated Dickey-Fuller Test with 14 and 30 lags --- 1 January 2000 to 31 November 2005

Zone/Period	Test Statistic with 14 Lags	Test Statistic with 40 Lags	Test Statistic with 40 Lags with trend
a18	-3.780***	-2.517	-3.392*
c18	-3.505***	-2.387	-3.299*
g18	-4.632***	-2.730*	-3.339*
j18	-4.366***	-2.853*	-3.761**
a6	-3.794***	-2.391	-3.337*
c6	-3.591***	-2.240	-3.219*
g6	-3.598***	-2.226	-3.164*
j6	-3.450***	-2.038	-3.250*

Critical Values

	1%	5%	10%
without trend	-3.43	-2.86	-2.57
with trend	-3.96	-3.41	-3.12

* Significant at the 10% level
** Significant at the 5% level
*** Significant at the 1% level

[147] This lag structure was selected in order to include day of the week effects. Even with the day of week trend still in the data, we find that the process is stationary.

This leads to the question of what the optimal lag length should be when estimating Dickey- Fuller statistics. As Gordon (1995) points out, "*if too few lags are included, the size of the test changes in an unknown manner and if too many lags are included, the power of the test is reduced.*" To help address this we apply the common approach of using the Schwartz (SBC) and Akaike Information Criterion (AIC) to discover the optimal lag length in the Augmented Dickey-Fuller test (Greene, 2000 p. 644). Such criterion are used to evaluate the tradeoff between the fit of the model and the complexity of the model (number of independent variables). We will focus on the Schwarz Bayesian Criterion as "*its heavier penalty for degrees of freedom lost, will learn towards a simpler model*" (Greene, 2000 p.306). To find the optimal number of lags we run a number of autoregressive models, with from 1 lag to 80 lags, and look to see which model minimizes the SBC and AIC.[148]

Table 4.3 displays the summarized results of the optimal number of lags using both AIC and SBC as section criteria. Not surprisingly the SBC selects a model with a lower number of lags than the AIC. If we rerun all the Augmented Dickey-Fuller tests in levels with the optimal number of lags (SBC), with a trend, we reject the null hypothesis for all of our periods,[149] and conclude that the variable was generated by a stationary process, without a unit root. Combining the Dickey-Fuller Test results with our preliminary analysis would suggest that our daily day-ahead time series are trend stationary. If this is the case it does not make sense to follow Woo (1997) and see whether the pair-wise combinations are co-integrated.

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[148] As AIC and SBC measure losses we will wish to minimize their value. We estimated these models in STATA using the VARSOC command (Vector Auto-Regression with optimal lag selection) with one dependent variable, which is the equivalent to an autoregressive model.

[149] Without the time trend, we reject the null for A18, C18, G18 and J18 at the 1% level and A6, C6, G6, and J6 at the 5% level.

Table 4.3: Optimal Number of Lags determined by AIC and SBC

--- 1 January 2000 to 31 November 2005

	Optimal Number of Lags	
	AIC	SBC
a18	16	14
c18	16	14
g18	14	7
j18	14	7
a6	78	22
c6	78	22
g6	65	22
j6	45	22

4.4 OLS Estimation

It was mentioned in the introduction that if a market is integrated, prices should move together across the market – if prices diverged, profit opportunities would arise as traders sell electricity at high-priced zones and buy electricity at low-priced zones. However, the existence of transportation costs will allow some natural price deviations between zones to occur. In this section we examine the pair-wise relationships between zones using an OLS regression.[150] If the market were integrated one would expect the prices to be strongly positively correlated. A segmented market would have lower correlations. Woo et al. (1997) and Videbaek (2004) both use the following basic model to help infer if a market is integrated.

$$p_{i,t}^{A} = \alpha_i + \lambda_i^H p_{i,t}^{B} + \varepsilon_{i,t}, \qquad \text{(E1)}$$

where $p^A_{i,t}$ are the prices at node A in period i on day t, $p^B_{i,t}$ are the prices at node B in period i on day t, and λ^H_i is a measure of correlation between the prices. If the market is integrated; the slope coefficient (λ^H_i) is less than 1 by an amount equal to the transmission losses; the negative of the intercept reflects transmission charges. If the two zones are not integrated, there should be no relationship between the two prices.

[150] As our raw price series is trend stationary we are able to use OLS to estimate the pair-wise relationship between prices at different nodes.

i.e., the slope coefficient should be zero.[151] Videbeck (2004) also provides an economically-meaningful interpretation for $\lambda^{H}{}_{i}$. He shows that $\lambda^{H}{}_{i}$ can be interpreted as the estimate of the proportion of electricity that the generator located at A should sell at a fixed price at node B to achieve the minimum variance portfolio in period i. Values of $\lambda^{H}{}_{i}$ that are close to one indicate that transmission price risk is relatively low, as the generator is willing to accept transmission price risk. Such a result would indicate that the market is reasonably integrated. Similarly, the further away $\lambda^{H}{}_{i}$ is from one, the lower the level of market integration.[152]

We use a modified version of equation (E1) in this paper. Firstly, the seasonal patterns (monthly and daily) that are present in the data could introduce spurious correlations. We therefore include various daily and monthly dummies in the model so as to eliminate much of the seasonality. As we are particularly interested in seeing if the market is becoming more segmented over time we therefore propose the following model:

$$p_{i,t}^{A} = \lambda_{i}^{H} P_{i,t}^{B} + \sum_{j=1}^{7} \gamma_{i,j}^{z} d_{j,t} + \sum_{k=1}^{11} \delta_{i,k}^{z} m_{k,t} + \nu_{i,t}^{z}, \qquad \nu \sim N(0, \psi_{n,i}^{2}), \tag{E2}$$

where $p^{A}_{i,t}$ and $p^{B}_{i,t}$ are the prices in Zone A and Zone B, respectively, in trading period i on day t, $d_{j,t}$ is a dummy variable that takes the value 1 on day i and 0 otherwise (Thursday is day 1, Friday is day 2, and so on), $m_{k,t}$ is a dummy variable that takes the value 1 in month k and 0 otherwise (January is month 3, February is month 4, and so on). 11 monthly dummies are used (the dummy for month 12 – October is omitted so as not to cause perfect multicollinearity).

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[151] See Bailey (1998a) for more on this interpretation of the slope coefficient and intercept.

[152] There exists no definitive threshold for how close to one $\lambda^{H}{}_{i}$ should be to imply that markets are integrated or segmented, only that the market is more integrated when $\lambda^{H}{}_{i}$ is closer to one.

Equation (E2) is estimated for each year separately (i.e. 2000, 2001, 2002, 2003, and 2004) --- due to the partial data in 1999 and 2005 we restricted our sample to the first five full years in which the market has been operating. We are particularly interested in seeing whether the coefficient λ_i^H is decreasing overtime as this would indicate increased segmentation of the market. Note that our results will probably be sensitive to the roles of markets e.g. 'A' and 'B' as dependent and independent variables will probably provide different results if we reverse their roles in the regression. Yet as electricity usually flows in the direction of Zone A to Zone J, this chapter (in the interests of brevity) will only present results for A→J, A→C, C→G, and G→J. The examination of the trend in the coefficient λ_i^H between Zones A→J provides insights into the overall integration of the market over time between these distant zones. We also examine the trend in the coefficient λ_i^H for the piecemeal pair-wise combinations A→C, C→G, and G→J, in order to identify where network segmentation occurs.

Before the results of the regressions are presented, we first test to see if the any of the important underlying assumptions for OLS are violated. In particular we test for heteroscedasticity (using graphical inspection and White test), autocorrelation (using graphical inspection and the Durbin-Watson d-statistic) and multicollinearity (using pair-wise correlations between the independent variables).

4.4.1 Testing for Heteroscedasticity

In this section we apply the Breusch-Pagan / Cook-Weisberg test and White test of homoskedasticity for formal testing of heteroskedasticity.[153] Table 4.5 displays the results of the tests and shows that we reject Ho: homoskedasticity in favor of Ha:

[153] In order to run this test we needed to have a constant. We therefore removed dummy d7 and included a constant.

unrestricted heteroskedasticity at the 1% significance level in all but seven of the tests. Table 4.6 displays the results of the Breusch-Pagan test, which rejects the Ho: Constant variance at the 1% significance level for all but three of the tests. Our regression estimates may therefore be inefficient if we do not correct for the underlying Heteroskedasticity. [154] Note that Bailey (1998b) also finds heteroskedasticity in her data and corrects for this using the Whites (1980) Consistent Estimate of the Covariance Matrix allowing for heteroskedasticity. We follow the same approach (which in STATA is implemented using the robust command).

Table 4.5: Table of White Test for Ho: Homoskedasticity Against Ha: Unrestricted Heteroskedasticity --- 2000, 2001, 2002, 2003, and 2004

	2000		2001		2002		2003		2004	
	chi2(102)	Prob > chi	chi2(102)	Prob > chi	chi2(102)	Prob > chi	chi2(102)	Prob > chi	chi2(102)	Prob > chi
A18 J18	235.58	0.0000	317.52	0.0000	225.40	0.0000	163.77	0.0001	143.30	0.0044
A18 C18	109.76	0.2820	149.51	0.0015	117.62	0.1382	114.84	0.1814	170.07	0.0000
C18 G18	270.20	0.0000	271.06	0.0000	278.05	0.0000	298.75	0.0000	204.55	0.0000
G18 J18	299.19	0.0000	283.00	0.0000	245.74	0.0000	222.50	0.0000	188.34	0.0000
A6 J6	231.65	0.0000	152.29	0.0009	184.74	0.0000	167.41	0.0000	259.92	0.0000
A6 C6	117.98	0.1332	182.17	0.0000	112.01	0.2342	163.23	0.0001	151.39	0.0011
C6 G6	247.90	0.0000	100.27	0.5300	205.31	0.0000	152.26	0.0000	106.51	0.3602
G6 J6	158.89	0.0003	154.16	0.0007	159.58	0.0002	176.34	0.0000	254.43	0.0000

Table 4.6: Breusch-Pagan / Cook-Weisberg Test for Heteroskedasticity Where Ho: Constant Variance --- 2000, 2001, 2002, 2003, and 2004

	2000		2001		2002		2003		2004	
	chi2(1)	Prob>chi	chi2(1)	Prob>chi	chi2(1)	Prob>chi	chi2(1)	Prob>chi	chi2(1)	Prob>chi
A18 J18	102.32	0.0000	1476.26	0.0000	312.40	0.0000	117.33	0.0000	77.32	0.0000
A18 C18	245.47	0.0000	47.10	0.0000	261.35	0.0000	143.22	0.0000	56.08	0.0000
C18 G18	155.38	0.0000	1760.52	0.0000	345.83	0.0000	167.36	0.0000	27.68	0.0000
G18 J18	359.21	0.0000	119.27	0.0000	443.29	0.0000	273.59	0.0000	58.66	0.0000
A6 J6	33.51	0.0000	27.33	0.0000	56.00	0.0000	93.79	0.0000	114.69	0.0000
A6 C6	132.95	0.0000	44.61	0.0000	474.28	0.0000	98.04	0.0000	58.97	0.0000
C6 G6	50.53	0.0000	113.64	0.0000	4.07	0.0435	22.46	0.0000	3.42	0.0645
G6 J6	1.84	0.1749	14.02	0.0002	53.30	0.0000	95.49	0.0000	107.45	0.0000

[154] Note that the OLS estimates are still unbiased and consistent in the presence of heteroskedasticity.

4.4.2 Testing for Autocorrelation

Table 4.7 presents the Durbin-Watson d-statistic, a formal test of autocorrelation. The lower and upper critical values for (19,360) are 1.72299 and 1.93257, respectively.[155] In all but one of the tests,[156] the Durbin-Watson d-statistic is less than the lower critical value, meaning we reject Ho: no autocorrelation in the residuals in favour of Ha: positive autocorrelation in the residuals.[157] Our regression estimates may therefore be inefficient if we do not correct for the underlying autocorrelation.[158] We therefore adjust for autocorrelation using the Prais Winston transformation.[159]

Table 4.7: Durbin Watson D-Statistic for Various Zone Combinations

--- 2000, 2001, 2002, 2003, and 2004

	2000		2001		2002		2003		2004	
		DW d Statistic		DW d Statistic		DW d Statistic		DW d Statistic		DW d Statistic
A18 J18	(19 , 366)	1.3855	(19 , 365)	1.5350	(19 , 365)	1.0978	(19 , 365)	1.2500	(19 , 366)	1.1744
A18 C18	(19 , 366)	1.8405	(19 , 365)	1.2240	(19 , 365)	1.3810	(19 , 365)	1.7160	(19 , 366)	1.3772
C18 G18	(19 , 366)	1.3665	(19 , 365)	1.6253	(19 , 365)	0.8405	(19 , 365)	1.1593	(19 , 366)	1.4824
G18 J18	(19 , 366)	1.5038	(19 , 365)	1.3143	(19 , 365)	1.2568	(19 , 365)	1.6239	(19 , 366)	1.2251
A6 J6	(19 , 366)	1.5725	(19 , 365)	1.4215	(19 , 365)	1.2410	(19 , 365)	1.2983	(19 , 366)	1.3027
A6 C6	(19 , 366)	1.1809	(19 , 365)	0.8884	(19 , 365)	1.5240	(19 , 365)	0.9500	(19 , 366)	1.3619
C6 G6	(19 , 366)	1.6972	(19 , 365)	1.3149	(19 , 365)	1.1954	(19 , 365)	1.6451	(19 , 366)	1.7077
G6 J6	(19 , 366)	1.5442	(19 , 365)	1.5099	(19 , 365)	1.3660	(19 , 365)	1.3048	(19 , 366)	1.4081

4.4.3 Testing for Multicolinearity

Multicolinearity arises when several independent variables move together in systematic ways and can lead to large standard errors for the least squares estimator.[160]

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[155] See http://www.stanford.edu/~clint/bench/dw05c.htm

[156] The Durbin Watson d-statistic for A18→C18 in 2000 is between lower and upper critical values meaning that the test is inconclusive.

[157] These results were supported by examination of the correlogram of the residuals.

[158] Note that the OLS estimates are still unbiased and consistent in the presence of autocorrelation.

[159] For an explanation of the Prais and Winsten estimator see Greene (2003) p. 272.

[160] Note that in the presence of multicolinearity, the OLS estimator is still the Best Linear Unbiased Estimator (BLUE). Multicolinearity can lead to large variance of the estimates of the collinear variables and the monthly dummies.

Table 4.8 presents the mean Variance Inflation Factor for each regression.[161] The mean VIF's for all regressions are well within the tolerance ranges from 0.0 to 10, signalling no problems with multicolinearity.[162]

Table 4.8: Mean Variance Inflation Factor

--- 2000, 2001, 2002, 2003, and 2004

	2000	2001	2002	2003	2004
A18 J18	1.77	1.81	1.92	1.87	1.90
A18 C18	1.90	1.80	1.92	1.93	2.10
C18 G18	1.77	1.80	1.83	1.92	2.03
G18 J18	1.77	1.81	1.92	1.87	1.90
A6 J6	1.99	1.96	1.97	1.88	1.84
A6 C6	2.13	1.96	1.97	1.89	1.88
C6 G6	2.03	1.97	1.90	1.89	1.86
G6 J6	1.99	1.96	1.97	1.88	1.84

4.5 Discussion and Conclusion

Equation (E2) was estimated with the White (1980) Consistent Estimate of the Covariance Matrix (for heteroscedasticity) and the Prais Winston transformation (for autocorrelation). Table 4.9 presents the slope coefficient (λ_i^H) from the Generalized Least Squares regressions.[163] The closer the slope coefficient is to one, the more integrated the market is.

From Table 4.9 we can see the correlations in period 18 between prices in Zones A and J have been decreasing since 2001. This indicates that the overall market is

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[161] In order to run this test we needed to have a constant. We therefore removed dummy d7 and included a constant.

[162] "The VIF ranges from 1.0 to infinity. VIFs greater than 10.0 are generally seen as indicative of severe multicolinearity. Tolerance ranges from 0.0 to 1.0, with 1.0 being the absence of multicolinearity." STATA

[163] All of the λ_i^H's were significant at the 99% level.

becoming more segmented over time.[164] By looking at the intermediate pair-wise correlations we are able to gain insights into where the segmentation is occurring. For example, prices in Zone A and Zone C are highly correlated indicating that they are in the same market. Conversely, the low correlations between prices in Zones C and G in 2000 and 2002, and Zones G and J from 2002 onwards, indicate that segmentation is occurring either within or between these zones during those years.[165] Furthermore the correlation between Zones G and J has been getting consistently worse over the last three years, which suggests that New York City is becoming more isolated from the rest of the New York market. This is particularly worrying as this segmentation from the rest of the market combined with the falling New York Control Area reserve margins discussed in Chapter 1, and the inability of the ICAP market to encourage investment in generation infrastructure, could have serious impacts on reliability in New York City. The financial ramifications of outages in New York City are exceedingly high as it one of the worlds leading financial centres and home to over eight million people.

The results are only slightly more encouraging in period 6, our low demand period. The correlations between prices in Zones A and J are more stable, decreasing in 2002 but increasing in 2003 and 2004. We can see that the correlations between prices in Zones A and C in period 6 have been very high, indicating that these zones have remained in the same market. Once again we witness low correlations between prices in Zones C and G in 2002 and between G to J since 2002 --- suggesting this is where the market is breaking up. While the location of this segmentation is hardly

[164] An F-test on a pooled regression which included all five years data confirms that the slope coefficients (λ_i^H) for the individual years are not equal for all the regressions except A18 to C18, which failed to reject the null hypothesis. See Table 4.10.
[165] Transmission losses alone would not be this high.

surprising, with a number of well known constraints separating Zones G and J, the level of the segmentation during what is a low demand period is of concern. We would have expected to see the market more highly integrated during period 6 as the network is not transporting a large amount of electricity during this time.

Table 4.9: Coefficient λ_i^H from the Robust GLS Regressions (Prais Winston) for Equation E2 (95% Confidence Intervals give in Brackets)

	2000	2001	2002	2003	2004
A18 to J18	0.123	0.753	0.351	0.283	0.268
	(0.082 , 0.164)	(0.532 , 0.974)	(0.270 , 0.433)	(0.208 , 0.358)	(0.191 , 0.345)
A18 to C18	0.973	0.995	0.955	0.971	1.010
	(0.949 , 0.996)	(0.990 , 1.001)	(0.923 , 0.987)	(0.934 , 1.008)	(0.960 , 1.060)
C18 to G18	0.145	0.794	0.582	0.721	0.776
	(0.080 , 0.210)	(0.614 , 0.973)	(0.459 , 0.706)	(0.583 , 0.858)	(0.697 , 0.854)
G18 to J18	0.908	0.931	0.624	0.404	0.314
	(0.837 , 0.979)	(0.844 , 1.019)	(0.502 , 0.746)	(0.264 , 0.543)	(0.243 , 0.385)
A6 to J6	0.651	0.653	0.258	0.356	0.451
	(0.556 , 0.745)	(0.574 , 0.731)	(0.174 , 0.343)	(0.258 , 0.454)	(0.329 , 0.573)
A6 to C6	0.969	0.933	0.936	0.979	0.973
	(0.960 , 0.978)	(0.915 , 0.950)	(0.913 , 0.960)	(0.959 , 1.000)	(0.939 , 1.007)
C6 to G6	0.714	0.913	0.647	0.917	0.912
	(0.610 , 0.818)	(0.872 , 0.913)	(0.537 , 0.758)	(0.886 , 0.949)	(0.883 , 0.941)
G6 to J6	0.941	0.801	0.510	0.333	0.496
	(0.912 , 0.969)	(0.708 , 0.894)	(0.397 , 0.622)	(0.214 , 0.452)	(0.345 , 0.646)

Table 4.10: Pairwise F-tests on Slope Coefficients

	F(4, 2109)
A18 to J18	11.590
	Prob > F = 0.0000
A18 to C18	2.290
	Prob > F = 0.0573
C18 to G18	34.540
	Prob > F = 0.0000
G18 to J18	64.570
	Prob > F = 0.0000
A6 to J6	11.610
	Prob > F = 0.0000
A6 to C6	4.240
	Prob > F = 0.0020
C6 to G6	7.300
	Prob > F = 0.0000
G6 to J6	51.570
	Prob > F = 0.0000

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