The Impact of Fuel Costs on Electric Power Prices

by

Kenneth Rose[1]

June 2007

[1]Kenneth Rose is an independent consultant and a Senior Fellow with the Institute of Public Utilities (IPU) at Michigan State University. This paper was conducted by Dr. Rose under contract with the American Public Power Association (APPA). The views expressed here in this paper are those of the author and do not necessarily reflect the views or opinions of APPA and IPU. Helpful comments were received from Elise Caplan, John Kelly, and Diane Moody of APPA. Any remaining errors are of his own creation.

Executive Summary

The dramatic increases in electricity prices, both in the wholesale spot markets and at the retail level in a number of states, have been attributed by some to be directly and primarily due to fuel cost increases, particularly natural gas prices. Prices determined in the mid-Atlantic state auctions to serve retail customers rose from 2005 to 2006 by about 67 percent. These results and similar increases for customers in various distribution companies are often attributed to the higher natural gas prices that resulted from the 2005 hurricanes.

While natural gas prices have certainly played a role, looking at the data shows that simply attributing electricity price increases to only the cost of fuels used to generate electricity is overly simplistic at best. Other important factors that determine electricity prices are the level of customer load and the seasonal variation of load, and supplier risks and other non-energy costs. In addition, it is likely that other unaccounted for factors may also help explain electricity price changes.

On the wholesale side, while natural gas is often cited as the reason for the electricity price increases, natural gas accounted for only 5.5 percent of the generation in PJM during 2006. Coal and nuclear sources accounted for over 91 percent of the generation.

An explanation for natural gas' disproportionate impact on wholesale power prices is that it is often the marginal fuel (meaning it is the fuel used to run the plants that submit the highest accepted offer and thus set the spot market electricity price at a given time). That is, during peak hours relatively more expensive units are used to meet demand and, often, these units use natural gas. Again, however, the data show a more complex picture. There is considerable variation in the number of hours each day that natural gas is on the margin, from zero to nearly 18 hours. While there are days when relatively higher prices (for example, where the price is over $100/MWh) are associated with a relatively higher number of hours that natural gas is on the margin, these two do not always coincide. The highest daily prices are not always associated with the highest number of hours and a relatively high number of hours are not always associated with a relatively higher daily price.

One reason for the lack of complete correlation between the hours that natural gas is on the margin and electricity price levels may be that different types of natural gas-fired generation technologies with different costs and bid prices may be selected for dispatch. Gas combined-cycle, for example, may be dispatched at a lower price than combustion turbines. This cannot be examined more fully since PJM data do not identify the generation technology, only the fuel used.

While natural gas may be on the margin often and for several hours during peak times, it is not the fuel that is on the margin most often during the year in PJM – coal is on the margin for more hours than natural gas. Coal was the marginal fuel 69 percent of the total hours in 2006, while natural gas was for 24.8 percent of the hours.

For northern Illinois (the ComEd zone of PJM), this disproportionate impact of natural gas was more obvious, since coal and nuclear plants generate more than 95 percent of the electricity in the state and only 3.67 percent is generated by natural gas-fired units. Yet the wholesale price in the ComEd zone moves in tandem with the overall PJM price (but at a lower level). Even in New England, where electricity and natural gas prices track each other more closely, this same disproportionate impact of natural gas occurs. Just over 37 percent of the electricity in New England was generated by plants that used natural gas. However, more than half the generation comes from other sources, including over 40 percent from coal and nuclear sources.

On the retail side, suppliers have identified certain costs and risks to providing full requirements service to retail customers in addition to the cost of the energy These may include capacity; ancillary services; transmission and RTO service charges; congestion charges; risk management costs; risks from fluctuating fuel prices; the risk that load will change; the risk that customers will migrate between suppliers; the risk of regulatory or legislative changes; counterparty risks, and administrative, marketing, and legal costs to serve retail customers.

However, since many of these factors cannot be specifically quantified, it is not clear if they fully explain the gap between wholesale prices and retail prices determined by state auctions or bidding programs. They also do not explain why these retail prices have not decreased along with natural gas prices since early 2006.

The analysis presented in this paper points to several questions that could be addressed by future work. The ability to address these and other related questions adequately depends on the availability, quality and access to data – an increasingly difficult problem in recent years.

Additional questions include:

- While customer load may explain the direction of a price change, does it fully explain the magnitude of the change?

- What other factors, including strategic actions by suppliers, may explain both the direction and level of price changes in wholesale markets?

- To what extent does market design and structure contribute or exacerbate sudden price changes or spikes? What policy changes could ameliorate such impacts?

- Are retail electricity prices reflecting wholesale energy prices consistently?

- Do the non-energy costs and risks to suppliers explain any inconsistency?

The Impact of Fuel Costs on Electric Power Prices

by

Kenneth Rose

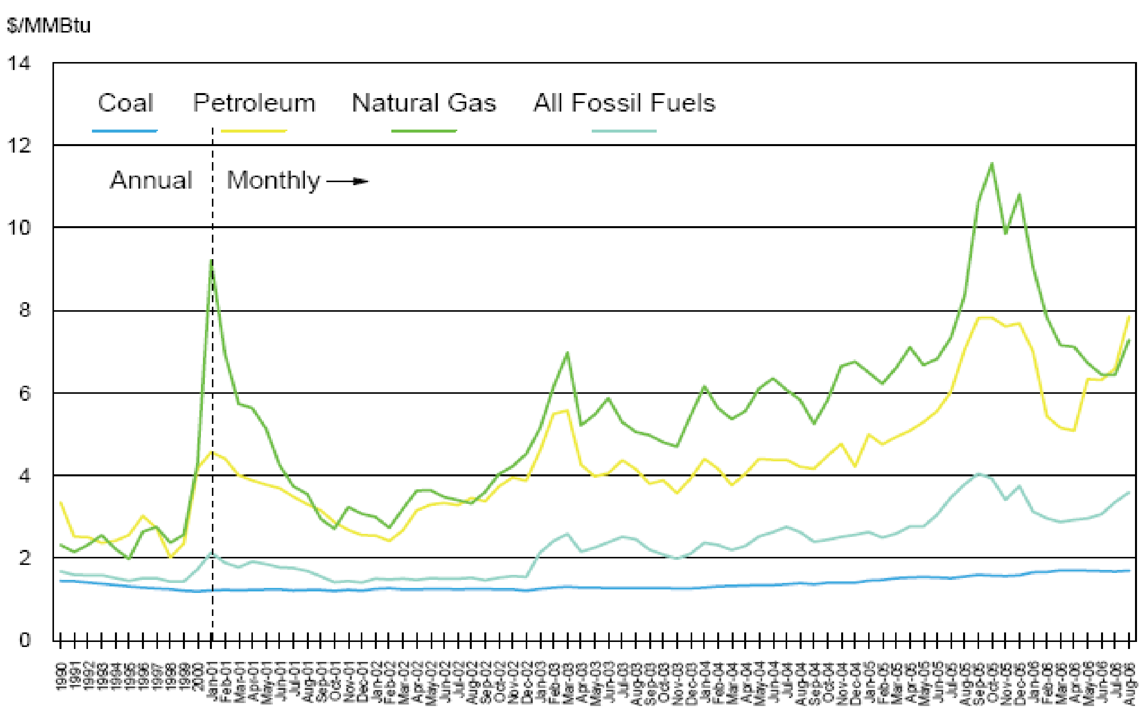
Introduction

The recent dramatic increases in electricity prices, both in the wholesale spot markets and at the retail level in a number of states, including Connecticut, Delaware, and Maryland, have been attributed by some to be directly and primarily due to fuel cost increases, particularly natural gas prices that spiked in the wake of the major 2005 hurricanes. This paper examines the question of whether the recent increases in electricity prices can be entirely or mostly attributed to fuel costs or whether other factors may also have played an important role. It is critical at this time to assess the impact of the fuel cost increases on electricity prices while a general reassessment of electricity industry restructuring is under way.

Trends in the Cost of Fuels Used to Generate Electricity

As shown in Figure 1, after a price spike during the winter of 2000-2001, the cost of petroleum and natural gas for electricity generation fell through early 2002. However, beginning in early 2002, there has been a steady increase in both the nominal and real cost of these fuels that peaked in late 2005 and early 2006. From October 2001 to January 2005, natural gas costs increased 141 percent (118 percent in inflation-adjusted 2007 dollars). By the spring of 2006, after a spike in the cost of natural gas in late 2005, natural gas costs had returned to about the same level as early 2005.

Figure 1. Cost of fossil fuels for electric generation

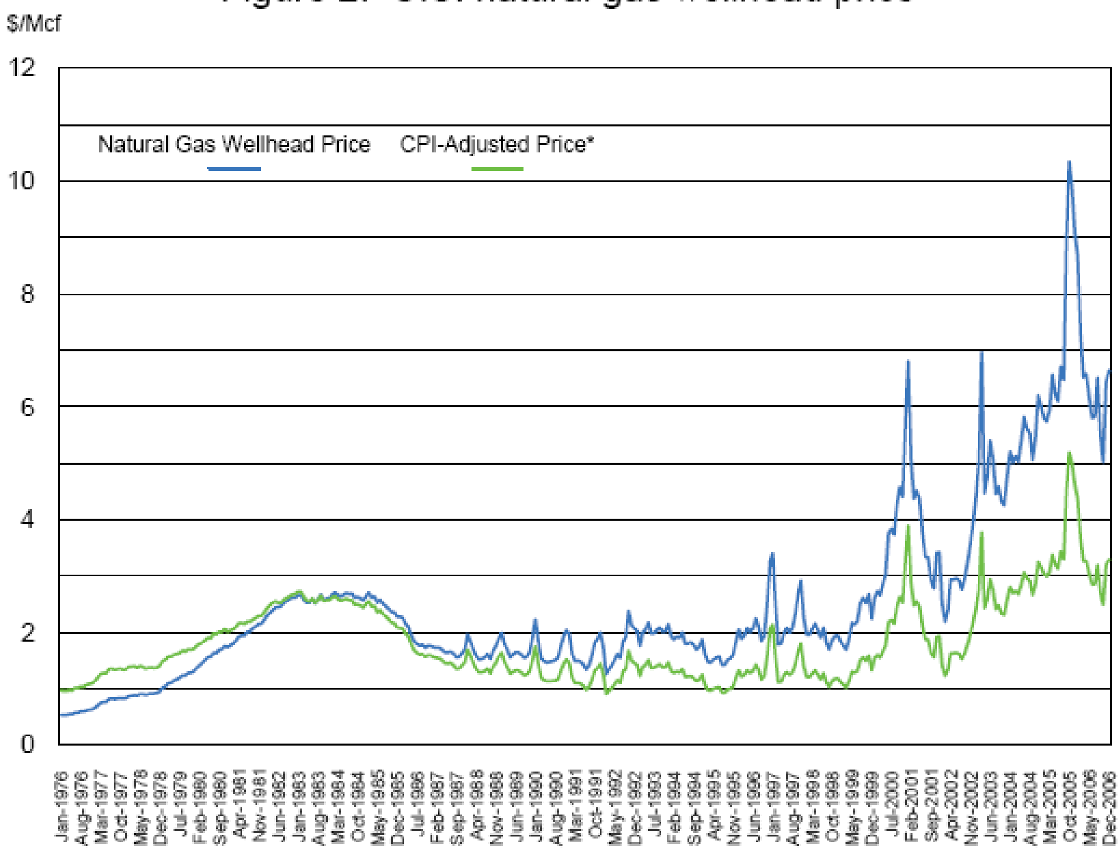


Data Source: DOE/EIA

Coal costs for electric generation have also increased, but at a slower pace than natural gas. Coal costs increased 22 percent from 2001 to January 2005 (10 percent in inflation-adjusted 2007 dollars) and increased another 16 percent between January 2005 and 2006 (a 13 percent increase in real terms).

The underlying cause for the increase in natural gas costs and the rise in the overall cost of fossil fuels used for electric generation is, of course, the wholesale price for natural gas. Figure 2 graphs the long-term trend in natural gas wellhead prices from 1976 through 2006. Prices remained at or below $2 per thousand cubic feet (Mcf) from the mid-1980s to the mid-1990s. Since the mid-1990s, prices have increased substantially and have been very volatile. For example, the price increased from about $2 in April 1999 to nearly $7 in January 2001, and then dropped back to just over two dollars in February 2002. The most recent peak occurred in October 2005, in the aftermath of Hurricanes Katrina and Rita, when the national average wellhead price increased to above $10/Mcf and remained above $8/Mcf through January 2006. The price decreased steadily to just above $5 in October 2006 and then rebounded through the end of the year.

Figure 2. U.S. natural gas wellhead price

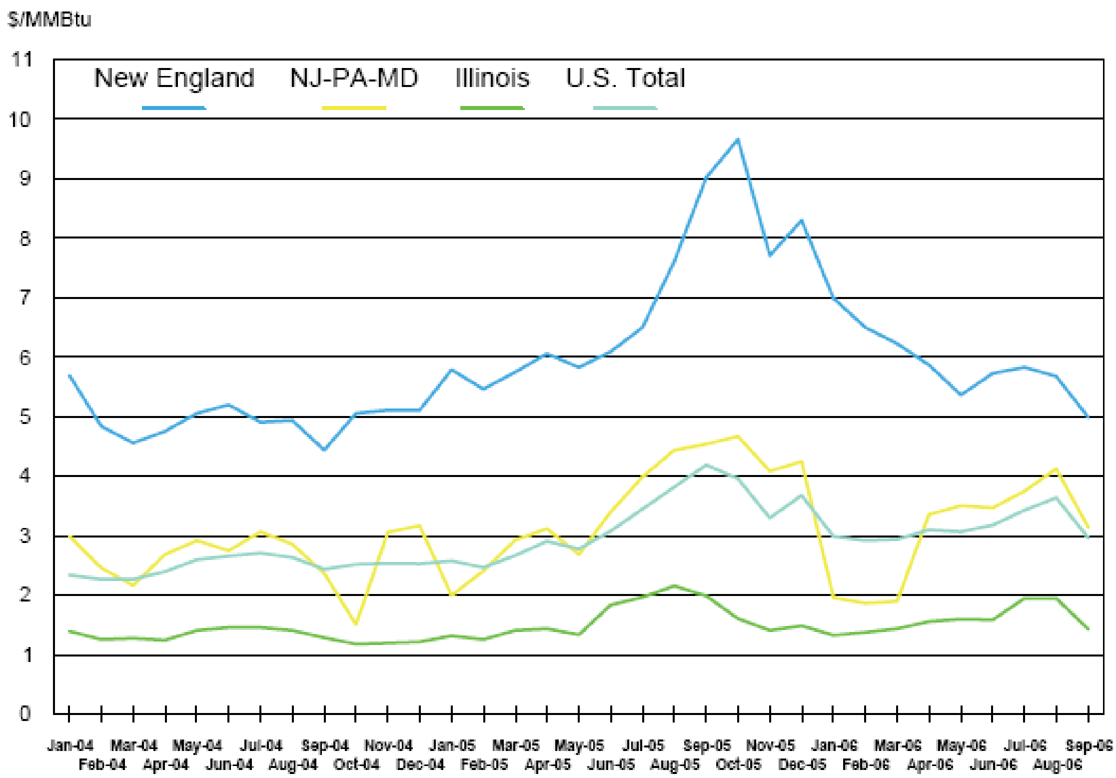


Data Source: DOE/EIA

*Adjusted using the U.S. Department of Labor, Bureau of Labor Statistics, Consumer Price Index-All Urban Consumers, All items, 1982-84=100.

There is a considerable amount of regional variation in the price and in the amount of natural gas used to generate electricity. Figure 3 graphs the fossil fuel cost for electric generation for three regions that are the focus of the analysis in this paper (mid-Atlantic, New England and northern Illinois) and the overall United States from January 2004 through September 2006. New England, with a relatively high proportion of the region's generation using natural gas, was consistently above the other regions and the national average. The mid-Atlantic states of New Jersey, Pennsylvania, and Maryland had a weighted-average generation cost similar to the national average.[2] Illinois, which generates electricity mostly from coal and nuclear energy, was consistently well below the national average. The generation fuel source for each region will be discussed in more detail below.

Figure 3. Weighted average cost of fossil fuel for electric generation

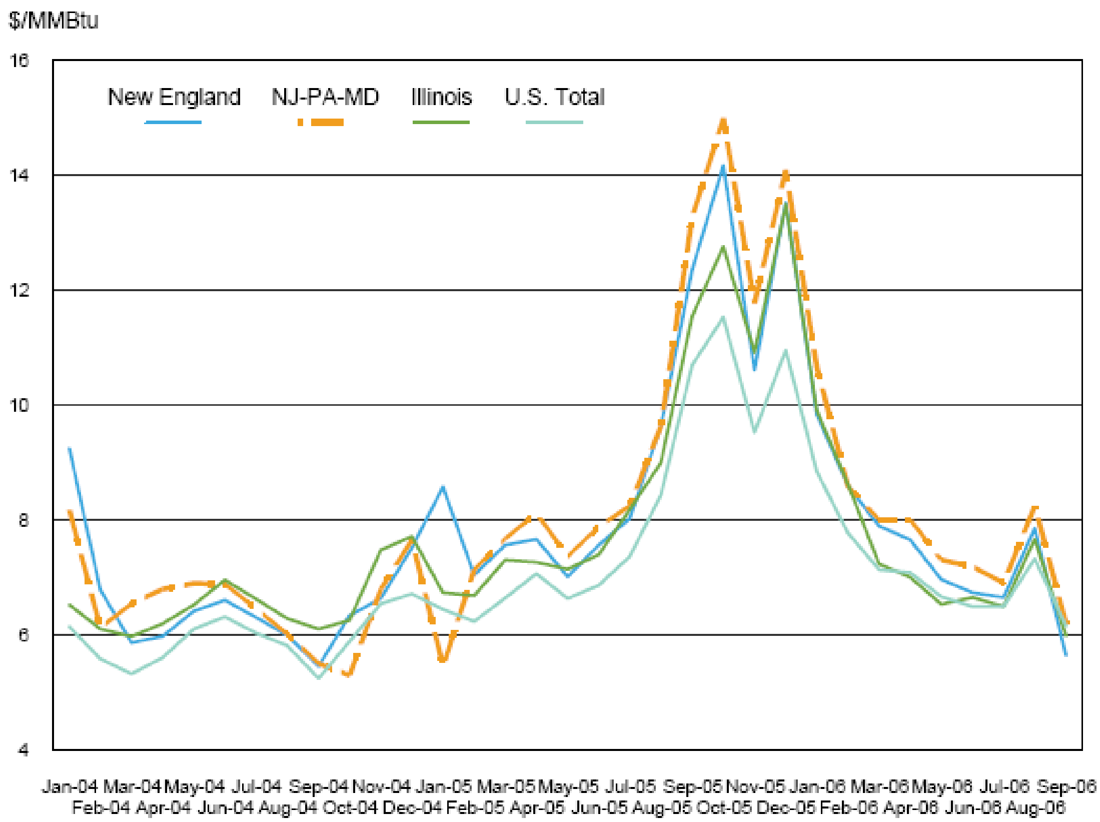


Data Source: DOE/EIA

[2] Fossil fuel costs were weighted by fuel consumption.

Figure 4 shows just natural gas costs for the electricity generation sector in the same three regions and the national average for 2004 through September 2006. The regional natural gas costs track each other much more closely that the cost of fossil fuels. The three regional costs were often higher than the national costs for this time period, with the mid-Atlantic states typically the highest.

Figure 4. Electricity Generation Sector Natural Gas Costs



Data Source: DOE/EIA

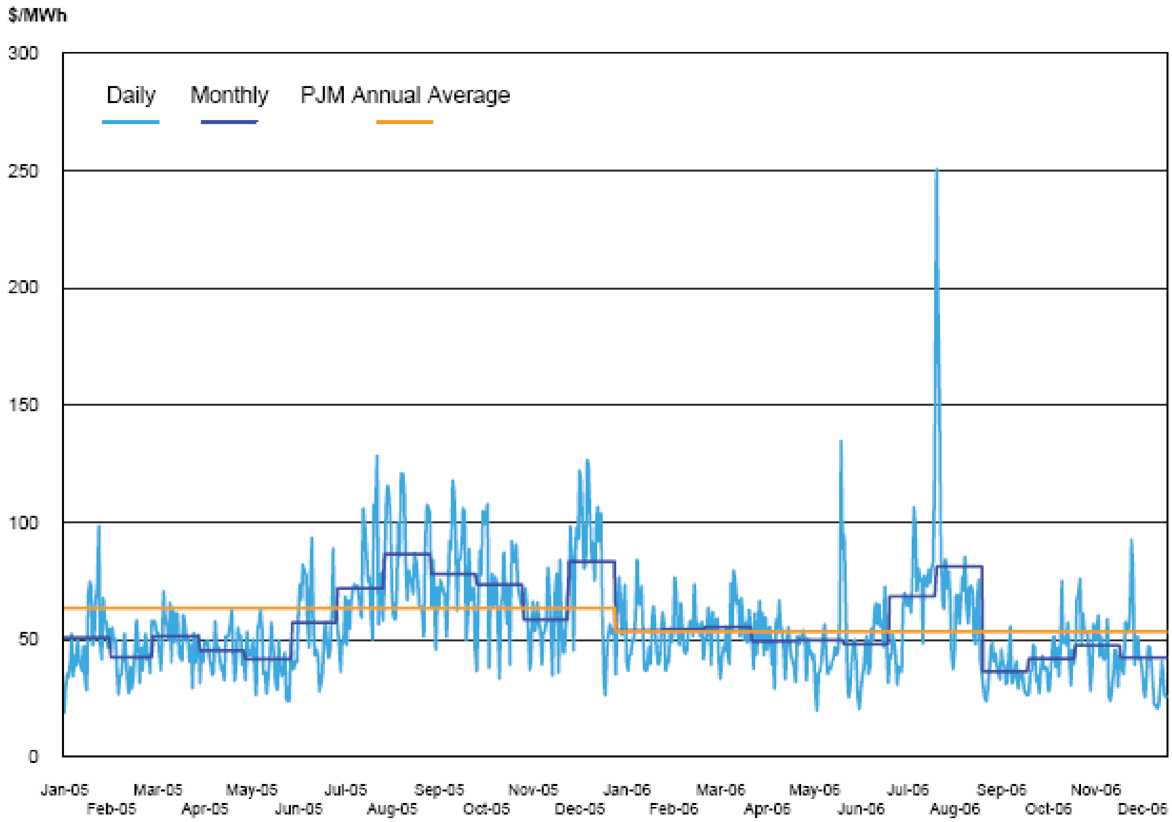
In summary, there are several trends in the fuel costs to note before a discussion of electricity prices.

- petroleum and natural gas prices increased steadily from 2002 through 2005;
- natural gas costs have increased more than other fossil fuels and generally have been more volatile;
- natural gas prices have decreased since early 2006;
- regional weighted average fossil fuel costs vary considerably, due to differences in the mix of electricity generation technologies; and
- regional costs for natural gas, while not identical, typically move in the same direction and are similar in amounts.

Regional Fuel Cost and Wholesale Electricity Prices: PJM

For a closer look at the connection between fuel costs and electricity prices, the entire PJM RTO and the northern Illinois area of PJM are examined. Figure 5 plots the daily, monthly, and annual PJM RTO-wide load-weighted real-time locational marginal prices (LMP) for 2005 and 2006. For both years, the peak monthly prices occurred in August, although December 2005 was only $3 lower than the August 2005 monthly average. The highest daily average price of both years was $250 on August 1, 2006 – which occurred during a series of hot days in the region. From July 31 through August 3 the average daily price exceeded $120 each day. The 2005 and 2006 annual load-weighted averages were $63 and $53 per MWh, respectively.

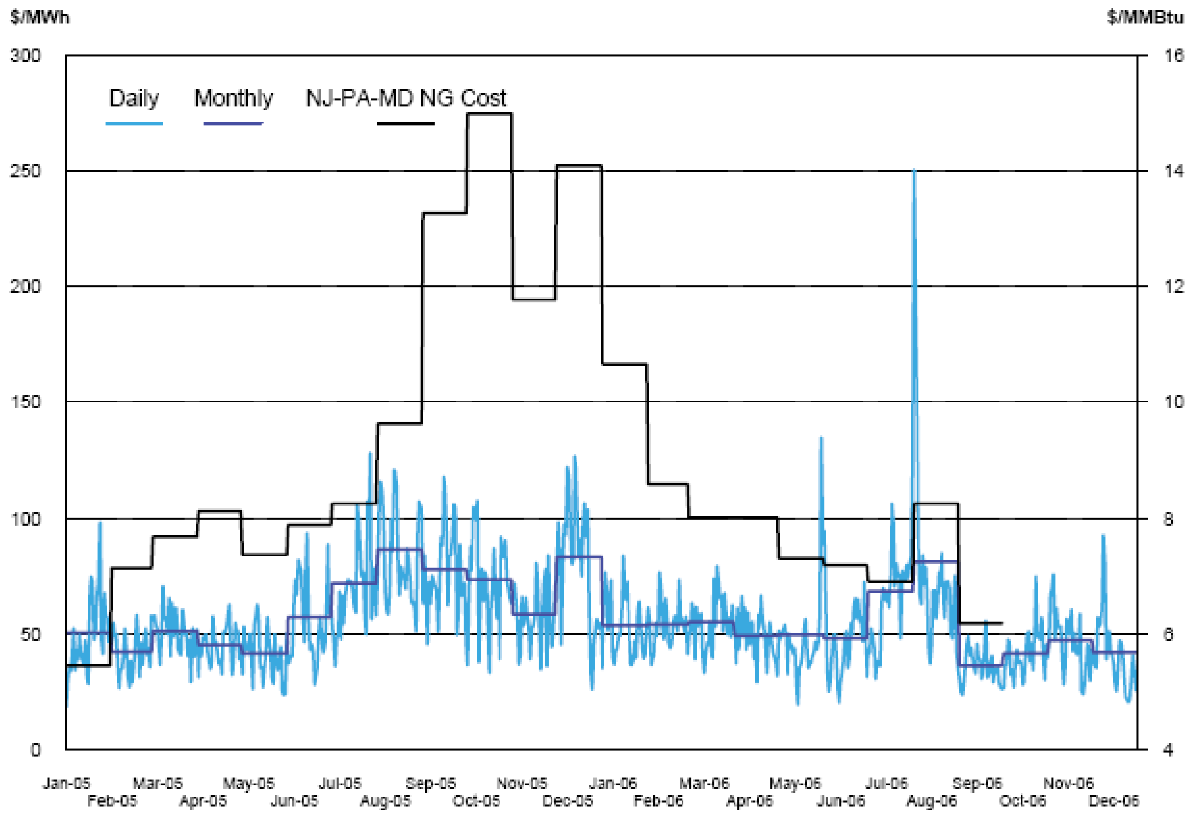
Figure 5. Daily, monthly, and annual PJM prices, 2005 and 2006



Data Source: PJM

To examine the extent to which there is a connection between these prices and the price of natural gas, the daily and monthly electricity prices of Figure 5 are shown in Figure 6 with the monthly average natural gas cost for New Jersey, Pennsylvania, and Maryland (as measured on the right axis in dollars per MMBtu). The impact on natural gas costs from Hurricane Katrina can clearly be seen in the increase in the monthly averages from September 2005 through January 2006. Average monthly cost then dropped in February 2006 back to about the same levels seen in the first seven months of 2005.

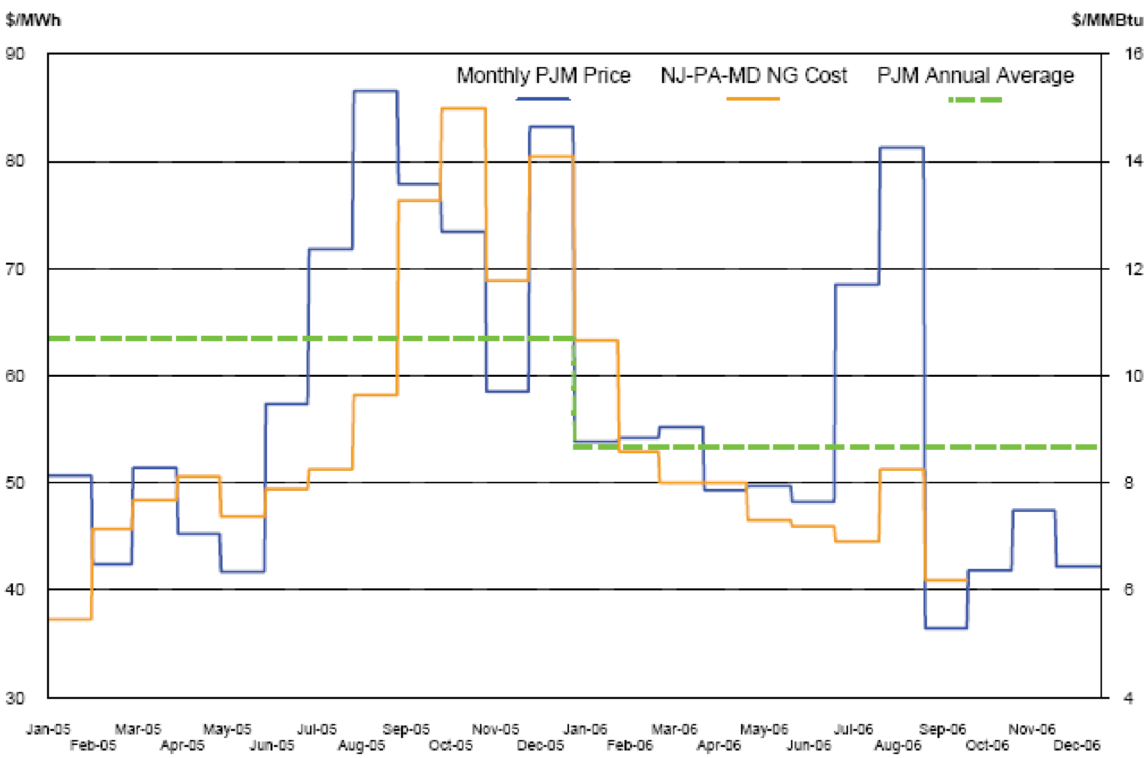
Figure 6. Daily and monthly PJM prices and monthly natural gas cost



Data Sources: PJM and EIA

For a clearer comparison of electricity prices and natural gas costs, Figure 7 shows just the monthly and annual averages. (Note that the electricity prices are on a different scale than that used in Figure 6.) It appears from this graph, that the general directions of these averages are similar. However, there are important exceptions. First, electricity prices during the summer of 2005 (June through August) began to increase sharply in June before the natural gas cost increases, which began sharply in September and peaked (for this entire two-year period) in October 2005. Moreover, while natural gas costs were reaching their peak, electricity prices *fell* from September through November 2005. Electricity price averages and natural gas cost increased again together during December 2005, then both decreased through June 2006. Again during the summer, electricity prices increased during July and August 2006, including some daily price spikes, while the natural gas cost remained at levels seen in the first half of 2005. The months during this two-year period when the electricity price and natural gas cost moved in opposite directions, that is, during both summers and in the fall of 2005, can be attributed to changes in the customer load for the PJM RTO. While electricity price and natural gas costs often moved together, the exceptions suggest that customer load is also important.

Figure 7. Monthly weighted average PJM and natural gas cost



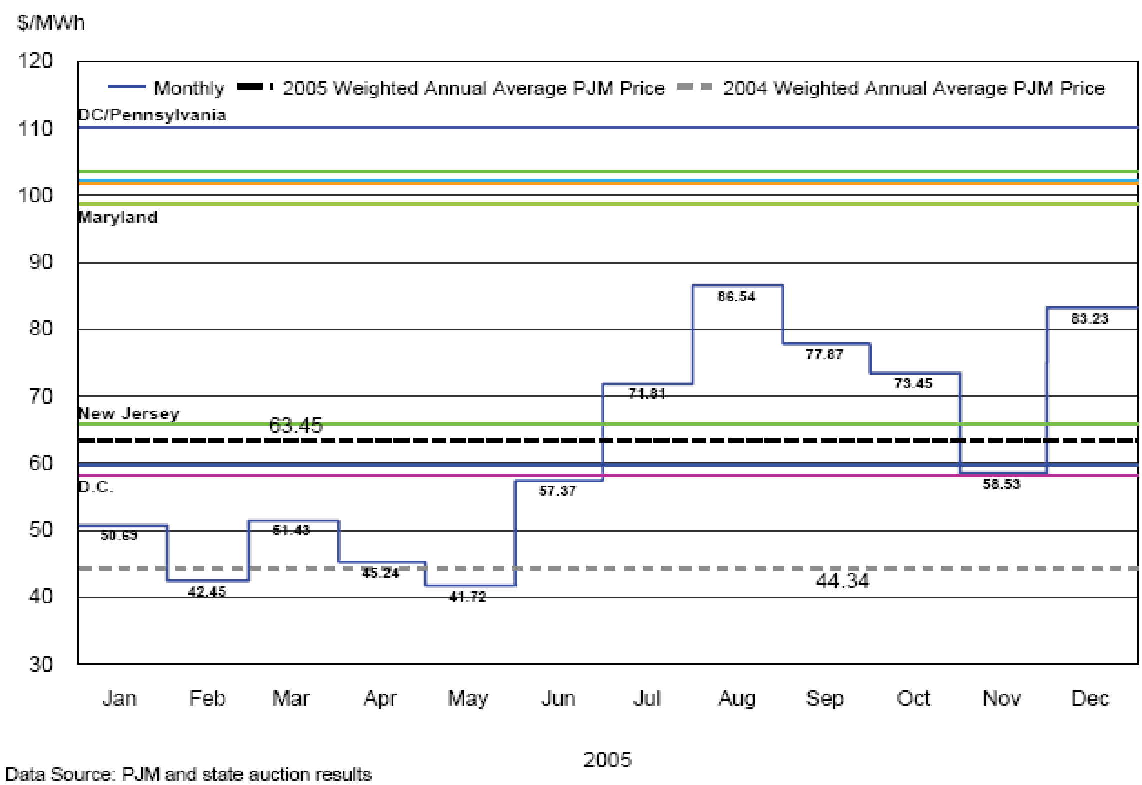
Data Sources: PJM and EIA

The Impact on Retail Prices in the PJM Region

Natural gas costs can affect retail electricity prices through two steps; first is the extent to which natural gas influences wholesale spot market prices, and second, the relationship between the wholesale and retail prices paid by customers of electric utilities. Several states in the mid-Atlantic area have conducted auctions or bidding programs to secure power for retail customers that do not purchase power from an alternative supplier.[3] For 2005, the District of Columbia, Maryland, and New Jersey each conducted an auction or solicited bids for power supply. The generation price range for residential customers, as determined by those auctions, is shown in Figure 8 by the horizontal lines bounded by D.C. at the bottom and New Jersey at the top (between \$58/MWh and \$65/MWh, the other colored line in the range is the Maryland result). In 2006, Delaware, Pennsylvania,[4] and Virginia also conducted auctions or bids.[5] The 2006 price results are shown by the horizontal lines bounded by Maryland at the bottom (\$98/MWh) and D.C. and Pennsylvania at the top (\$110/MWh), again just for residential customers (with Delaware, New Jersey, and Virginia in the mid-range).

Figure 8 shows there was a substantial increase in the price determined in these auctions to serve retail customers in these states – a percentage increase of about 67 percent. These results in particular were often attributed to the higher natural gas prices that resulted from the 2005 hurricanes.

Figure 8. Auction and bidding results and PJM market prices



Data Source: PJM and state auction results

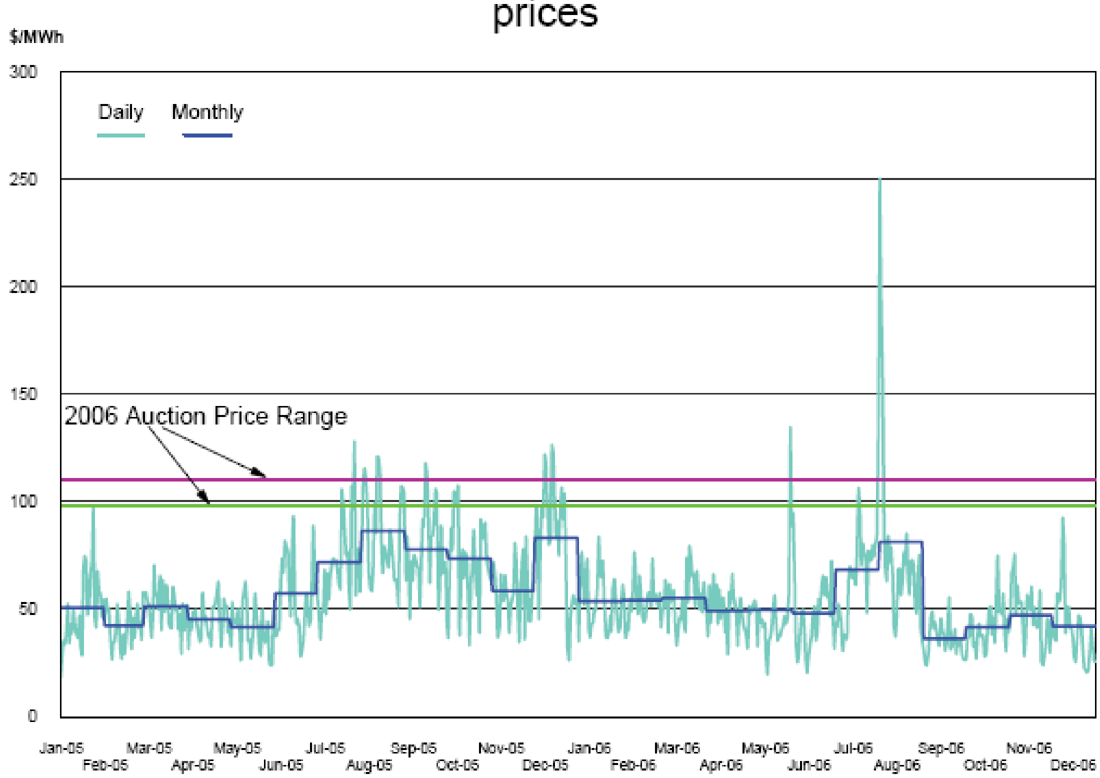
[3] These auction and bidding programs for procuring power supply for retail customers are discussed in more detail in Kenneth Rose and Karl Meeusen, "2006 Performance Review of Electric Power Markets," August 27, 2006. This and past reports are available at: http://ipu.msu.edu/research/ .

[4] The Pennsylvania utility the auction was held for, Pike County Light and Power, is in the New York ISO but is included here with other mid-Atlantic state auction and bidding results.

[5] D.C., Maryland, and New Jersey conducted auctions for both years shown in the figure.

Figure 9 shows the 2006 auction/bidding results with the PJM daily prices and monthly weighted averages for 2005 and 2006. The 2006 auction/bidding results exceeded every monthly weighed average price in PJM for both years – exceeding the highest monthly average by $12/MWh to $23/MWh and also well above the annual weighted averages for both years.

Figure 9. Daily and monthly PJM prices and 2006 auction prices



Data Source: PJM and state auction results

A number of costs and risks have been identified to account for this difference between the wholesale energy price and the retail price determined by an auction or bidding procedure, or by direct supply from suppliers to retail customers. A supplier that provides “full requirements” service to retail customers will have to provide energy and, when required for providers that serve retail customers or when not provided by the distribution company, capacity, ancillary services, and transmission and RTO service charges. Retail suppliers would also have to pay congestion charges or purchase financial transmission rights (FTRs) and incur other risk management costs. These additional costs are added to the energy cost and are passed on to retail customers through the prices offered by retail suppliers.[6]

[6] Suppliers with their own generation can “self-supply” energy and some of these other costs, but since they can sell these products or services to other suppliers, the retail price to consumers will reflect this “market” value.

Also identified are a number of risks faced by retail suppliers that include the risk that fuel prices and electricity prices will change (or incur hedging costs to offset and manage that risk), load will change (increase or decrease) due to weather or economic conditions, customer migration between suppliers, regulatory or legislative changes, and counterparty risks that could affect the payment for power supplied from the utility or distribution company. Finally, there are administrative, marketing, and legal costs to qualify and participate in an auction or bidding program or serve retail customers directly.

The value of these costs and risks will vary by location and length of commitment and, unfortunately in many cases, cannot be specifically quantified. As a result, evaluating retail prices relative to wholesale energy prices would require identification or estimation of these costs and risks on a case-by-case basis. Such an analysis is beyond the scope of this paper. However, while these costs and risk affect the retail price (and are ultimately borne by retail customers), it is not clear if they fully explain the gap between wholesale prices and retail prices determined by state auctions or bidding programs or why these retail prices have not decreased along with natural gas and wholesale prices since early 2006.

Natural Gas as the Marginal Fuel in PJM

These trends shown so far demonstrate that natural gas price changes do not always precisely match the movement of electricity prices. Even where natural gas does appear to influence electricity prices, to what degree does the generation capacity configuration, rather than changes in fuel costs, explain the price changes? As Table 1 shows, natural gas accounted for only 5.5 percent of the generation in PJM during 2006. Coal and nuclear sources accounted for over 91 percent of the generation.

Table 1. PJM generation by energy source, 2006

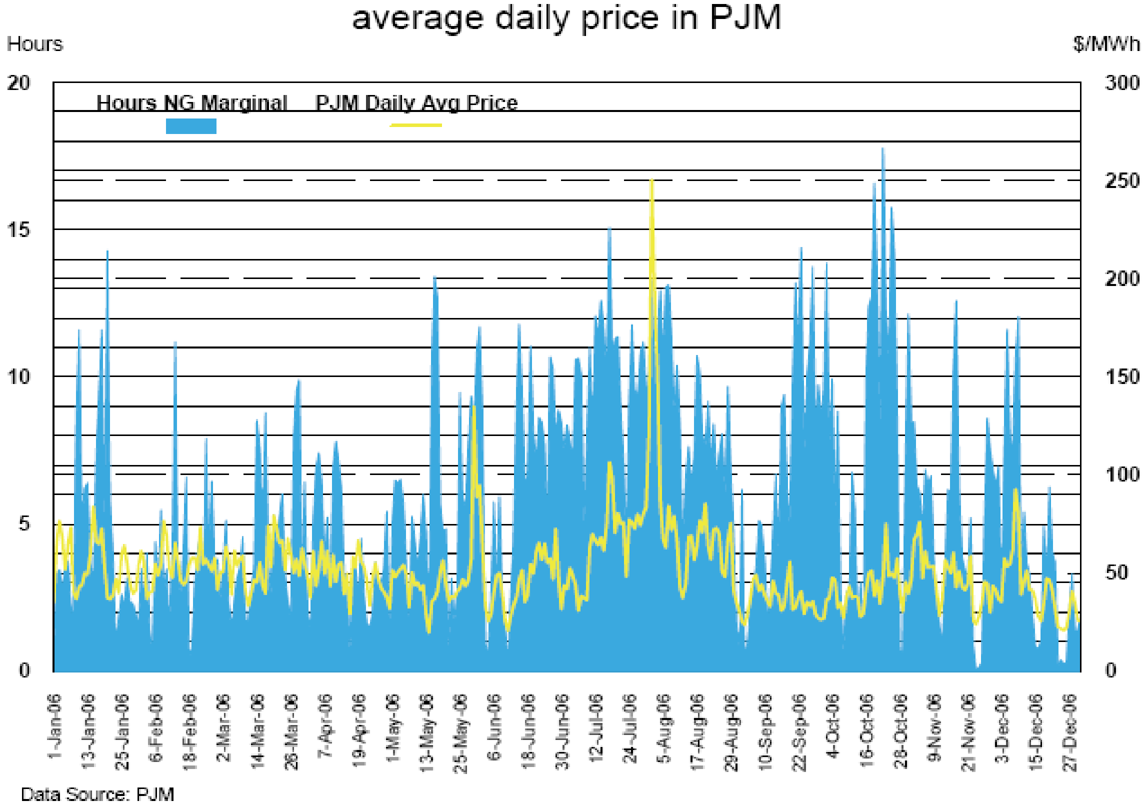
Energy Source	Percent
Coal	56.8
Nuclear	34.6
Natural Gas	5.5
Hydroelectric	2.0
Solid Waste	0.7
Oil	0.3
Wind	0.1
Total	100.0

Data Source: PJM

The typical explanation for this disproportionate impact of natural gas on wholesale power prices is that natural gas is often the marginal fuel. In PJM and other regional transmission organizations, the price for all units selected for dispatch is set by the highest offer price from a dispatched unit. The price-setting plant is known as the marginal unit. During peak hours relatively more expensive units are used to meet demand and often these units use natural gas. As a result, the wholesale price can climb quickly and to hundreds of dollars per MWh when these units are dispatched, as seen in the daily price in several of the previous figures.

PJM data were examined to determine how often natural gas units were on the margin and when. Figure 10 shows the total hours each day that natural gas units were on the margin. Also shown in the figure is the daily price for the PJM RTO. There is considerable variation in the number of hours each day that natural gas is on the margin, from zero to nearly 18 hours. Also, there are days when relatively higher prices (for example, where the price is over $100/MWh) are associated with a relatively higher number of hours that natural gas is on the margin.[7] However, the highest daily prices are not always associated with the highest number of hours (note the late July/early August price spike) and a relatively high number of hours (in October, for example) are not always associated with a relatively higher daily price.

Figure 10. Hours natural gas is the marginal fuel and weighted average daily price in PJM



Data Source: PJM

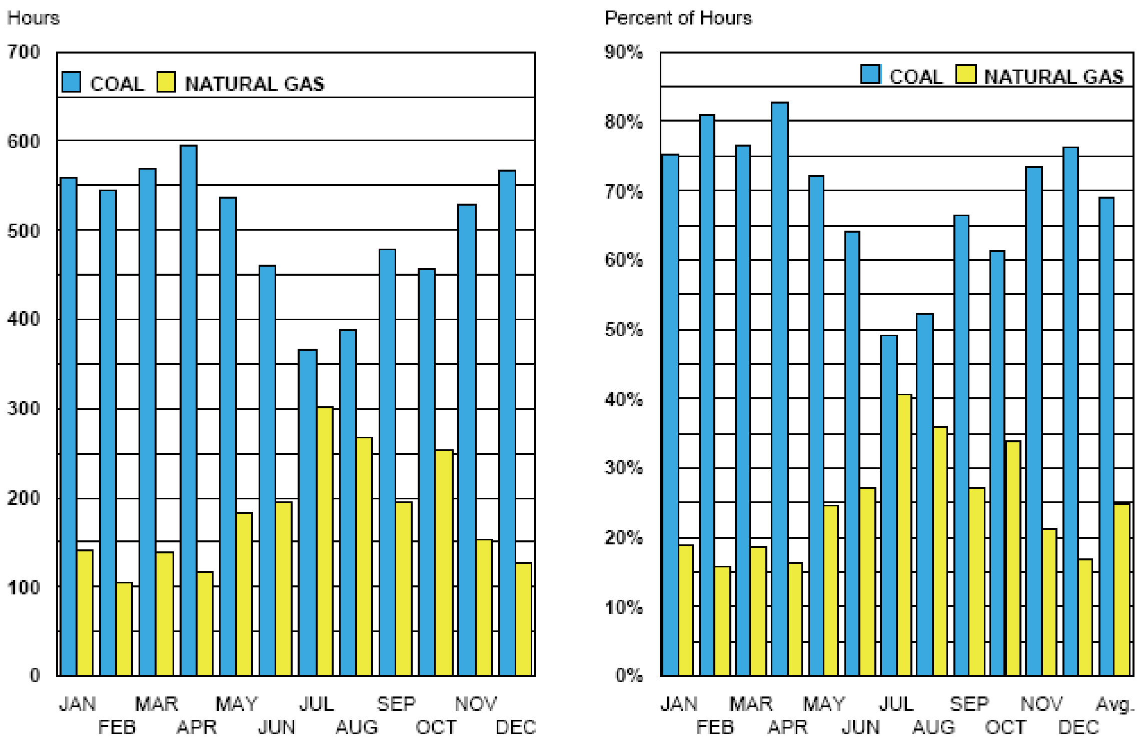
The reason for the lack of complete correlation between the hours that natural gas is on the margin and the price level may be that different types of natural gas-fired generation technologies may be selected for dispatch, each of which has different costs and bid prices. Gas combined-cycle units, for example, may be dispatched at a lower

[7] Not addressed in this paper is whether suppliers can or do deliberately withhold capacity to have higher-priced units on the margin—a strategy that results in a higher price for the units selected for dispatch.

price than combustion turbines. This cannot be examined since PJM data do not identify the generation technology, only the fuel used.

In terms of the number of hours in a day, natural gas was the marginal fuel more than 10 hours for 61 days in 2006 and less than 10 hours for 304 days. While natural gas may be on the margin often and for several hours during peak times, it is not the fuel that is most often on the margin during the year in PJM – coal is on the margin for more hours. The panel on the left of Figure 11 shows the total number of hours in each month of 2006 that coal and natural gas were the marginal fuel. The right side shows the percent of hours for each month and the annual average (the last two bars).

Figure 11. Marginal fuel in PJM during 2006

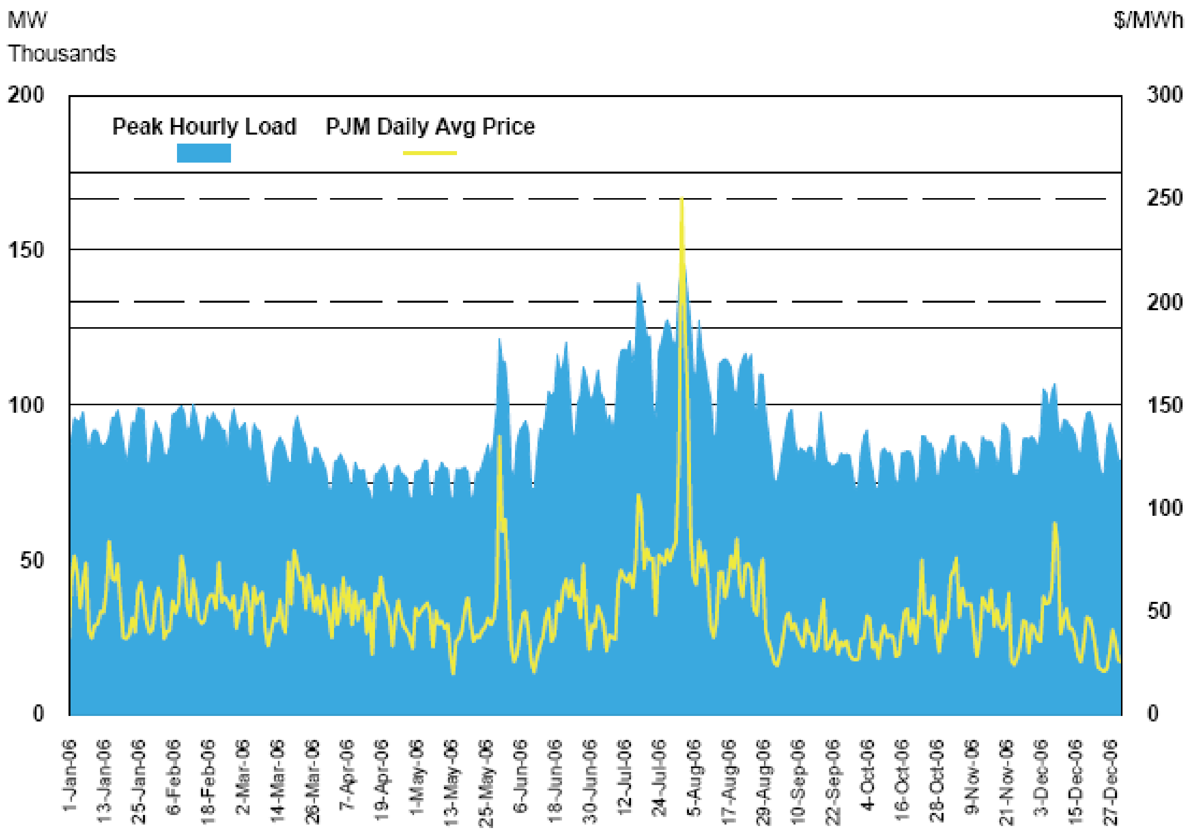


Data Source: derived from PJM data

For total hours during the year, coal was the marginal fuel 69 percent of the hours, while natural gas was for 24.8 percent, and a mix of several different energy sources was used for the remaining 6.2 percent. Again, as with percent of generation, natural gas appears to have a disproportionate impact on the price of electricity. However, an examination of electricity price and natural gas cost suggests that customer load may also be a significant factor influencing electricity prices. This is examined more carefully in the remainder of the section.

Figure 12 plots the peak hourly load for each day in 2006 and again the daily PJM price. There appears to be a closer match, albeit not perfect, between the peak hourly load and the electricity price than between natural gas hours on the margin and price. In this case, the exceptions appear to be when similar peak load amounts do not result in the same daily price.

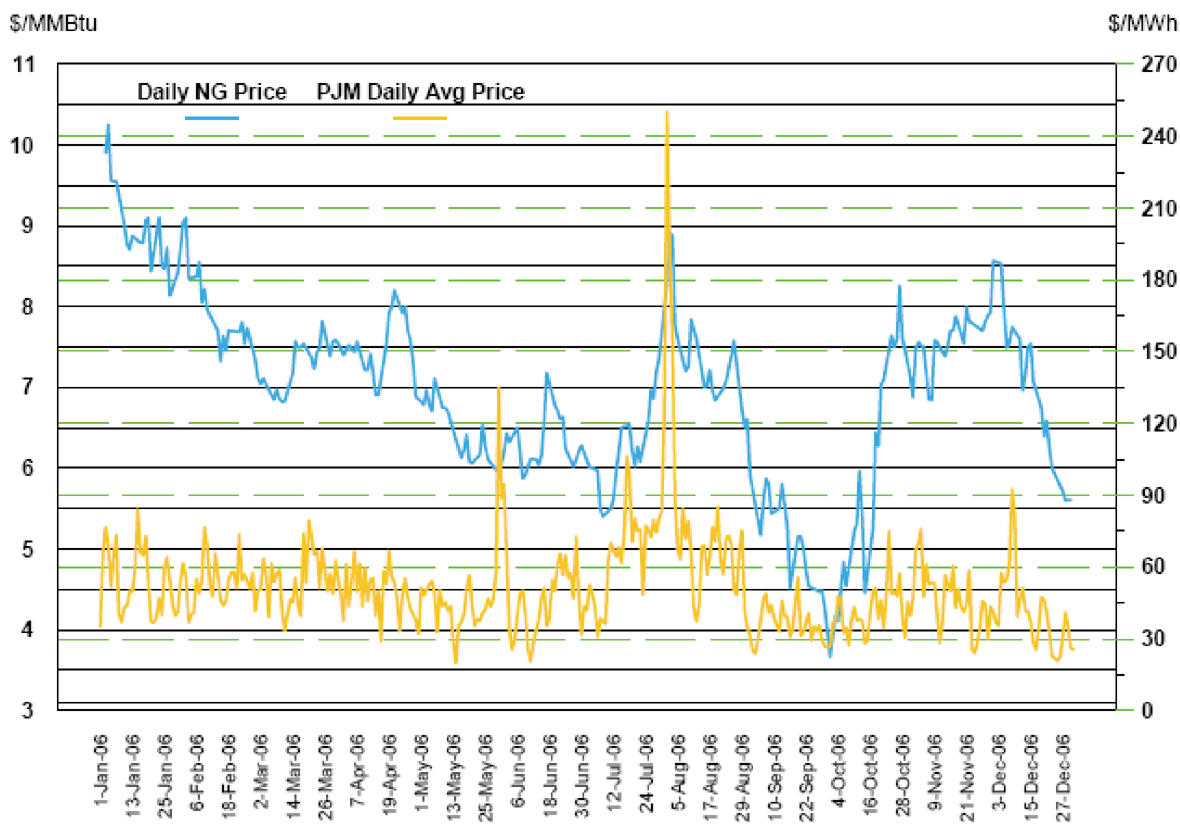
Figure 12. Peak hourly load and weighted average daily price in PJM



Data Source: PJM

Finally, Figure 13 plots the *daily* price of natural gas with the daily price of electricity in PJM. This is similar to Figures 6 and 7, but with the daily natural gas price and just 2006. What is striking about this graph is that while the daily natural gas price is drifting downward through the first half of the year, from over $10/MMBtu to about $6/MMBtu, the electricity price fluctuated mostly within the range of about $30 to $75 per MWh, with a price spike in late May and early June. Natural gas and electricity prices then both increase during the hot period of the summer and decrease together into the early fall. When the natural gas price then quickly increases in the fall, electricity prices again fluctuate in a similar price range as earlier in the year. It is difficult to draw any firm conclusions from this, other than that the prices do not move in unison, as some may suggest, and that other unaccounted for factors may help explain the electricity price variations more completely.

Figure 13. Natural gas price and weighted average daily price in PJM



Data Source: PJM and IntercontinentalExchange, Inc.

An issue not explored here is whether the demand for electricity is influencing the price for natural gas – the opposite relationship that is the focus of this paper. The electricity price spike that occurred on August 1 and the high demand for power around that date coincided with a spike in the natural gas price. It is not inconceivable that, at least during some times of the year, there is a simultaneous relationship between electricity demand and the price for natural gas.

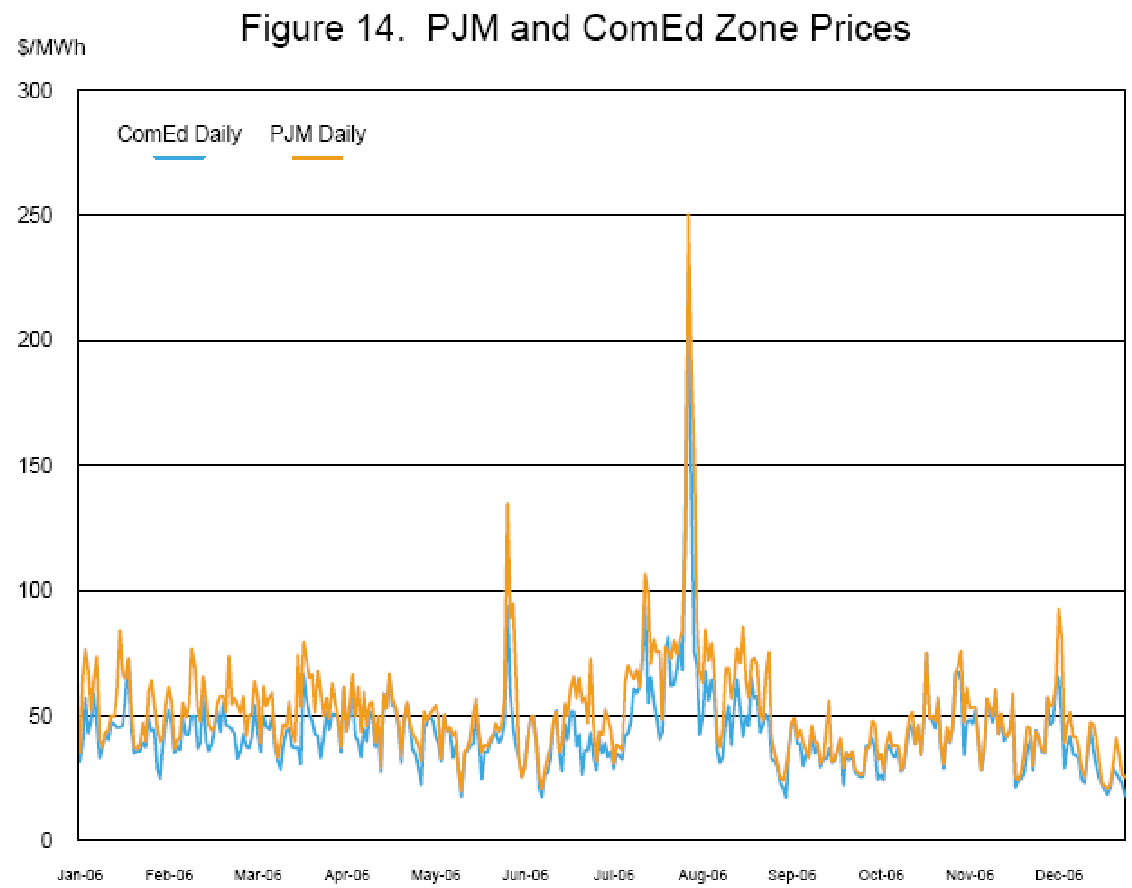
To test these relationships further, several regressions were run with electricity price as the dependent variable and different combinations of independent variables, including the number of hours natural gas was on the margin, peak hourly load for the day, and the price of natural gas. The model that provided the best fit with the data was when peak hourly load and the daily natural gas price variables were used. Both variables were significant at the 95 percent level (the t-statistics were 19.1 and 6.4, respectively) and the R-square was 0.54 (that is, roughly half the variation in electricity price is "explained" by the two independent variables, peak hourly load and the daily natural gas price).

The variable for number of hours natural gas is on the margin was dropped because it was correlated highly with hourly peak load and because the hourly peak load variable provided a better fit. This result overall is consistent with the earlier observations that there are correlations between the electricity price and the price of natural gas, but this is not entirely the complete picture. (The regression using natural gas price as the only independent variable was a particularly poor fit to the data, with an R-square of 0.09.) Clearly, load plays an important role, but it is likely that other factors not accounted for here are also significant.

The Impact on Retail Prices in the PJM Region: Northern Illinois Area

The current scope of the PJM RTO covers all or parts of 13 states and Washington, D.C., covering a wide geographic area from the mid-Atlantic states through northern Illinois. To focus this analysis, the northern Illinois or Commonwealth Edison (ComEd) zone of PJM is also examined.

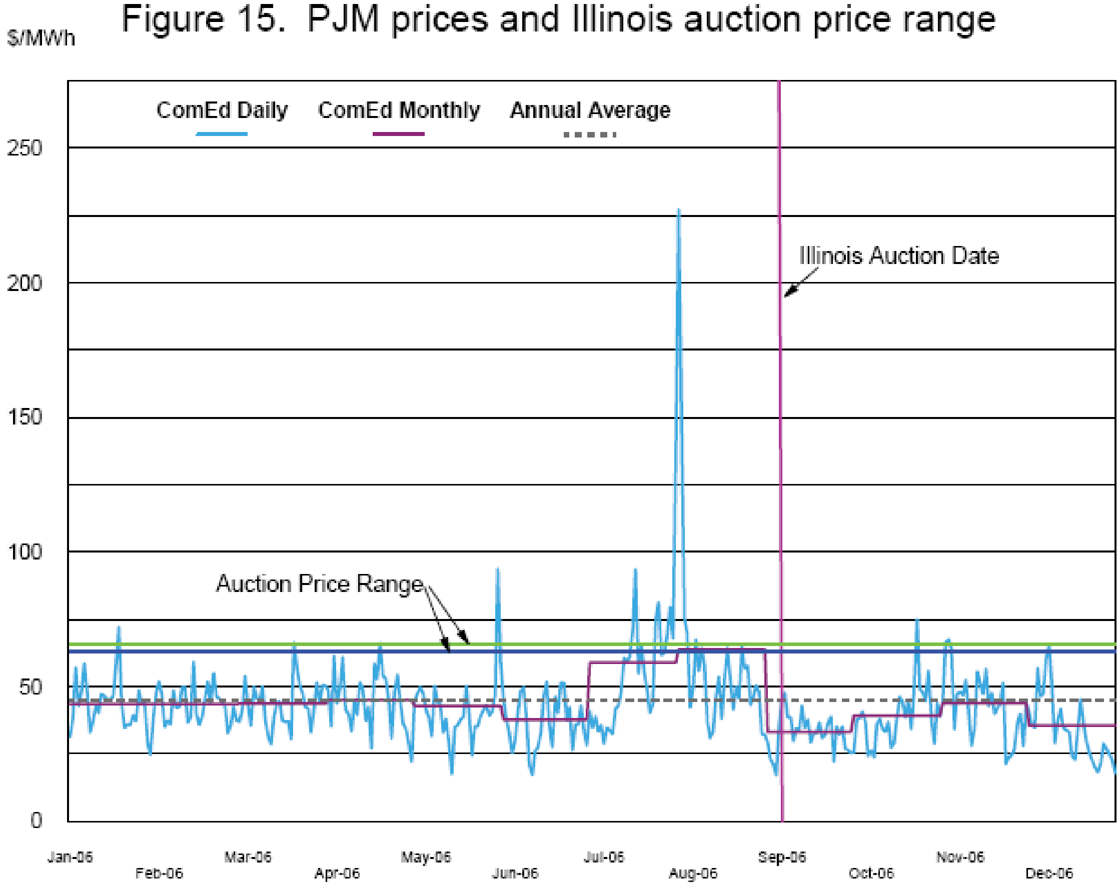
Figure 14 graphs the PJM and ComEd daily real-time prices for 2006. ComEd prices are consistently lower than the PJM prices and the prices generally move in tandem with each other.



Data Source: PJM

Figure 15 graphs the ComEd daily and monthly prices with the annual average for the ComEd zone. Also included in this figure is the price range resulting from the selection of suppliers in the Illinois auction to serve the state's investor-owned utility retail load. The vertical line marks the date the auction was held in early September 2006. As with the mid-Atlantic auction results when compared with the PJM price, the Illinois auction results are well above the load weighted average annual price of $45/MWh, or 40.6 percent to 46.6 percent above the PJM annual average price (the auction price range was $63.33/MWh to $66.05/MWh). Each monthly PJM average is below the auction price range except August, which was only about 50 cents/MWh higher than the lowest auction price. Only 26 days had a weighted average price that exceeded the lowest auction prices, or 93 percent of the daily price averages were below the auction price range. On 62 days the daily price was less than half the auction price range during 2006.

Figure 15. PJM prices and Illinois auction price range

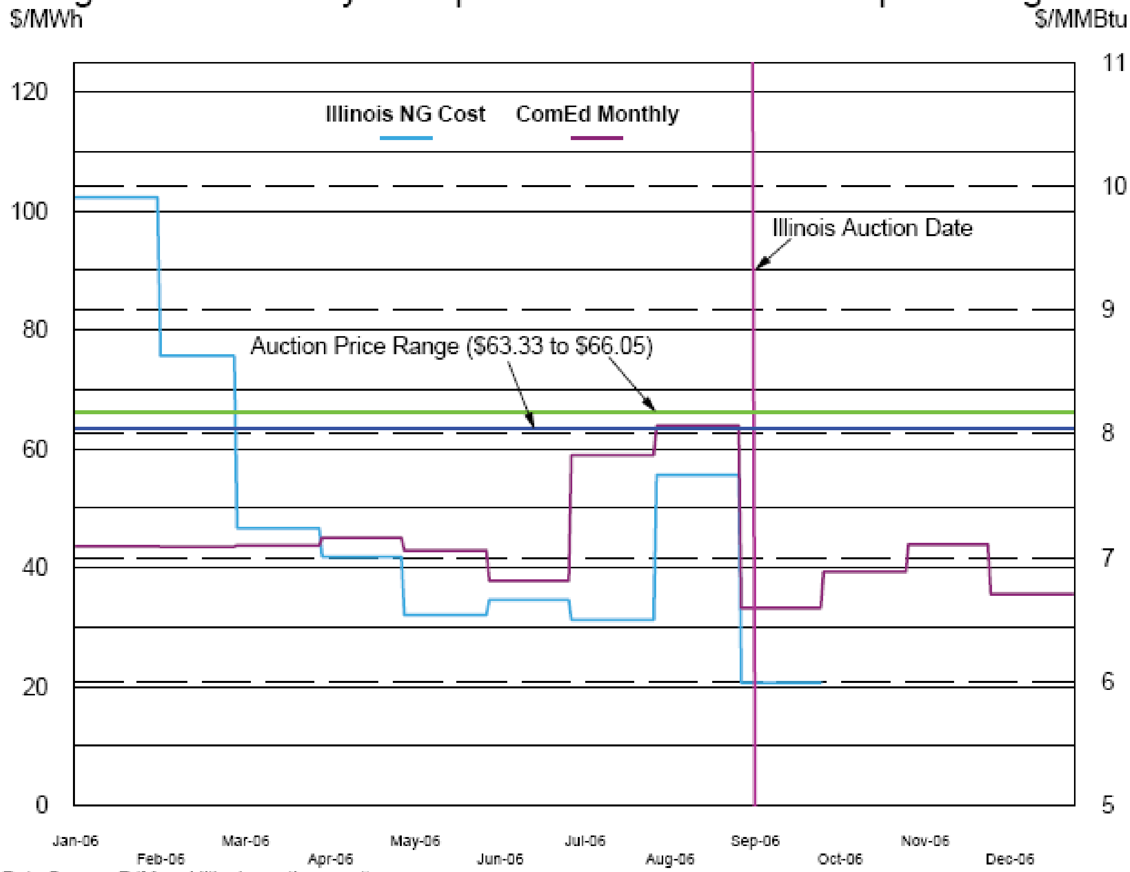


Data Source: PJM and Illinois auction results

Figure 16 is similar to Figure 15, but with the Illinois monthly natural gas cost added to the graph. Again, a pattern similar to that in the mid-Atlantic states emerges. Natural gas costs decrease considerably during the first half of the year, but the electricity prices remain at about the same level. Electricity prices increase in July, but natural gas costs remain at about the same level as prior months. Natural gas cost and electricity price then move higher in August and decrease together in September.

A similar analysis on the marginal units cannot be done for the ComEd zone since PJM does not identify the region in its data on the marginal fuel used.

Figure 16. Monthly PJM prices and Illinois auction price range



Data Source: PJM and Illinois auction results

Table 2 shows the generation energy sources for Illinois. Over 95 percent of electricity in Illinois is generated by coal and nuclear sources and only 3.67 percent is generated from natural gas-fired units.

Table 2. Illinois generation by energy source, 2005

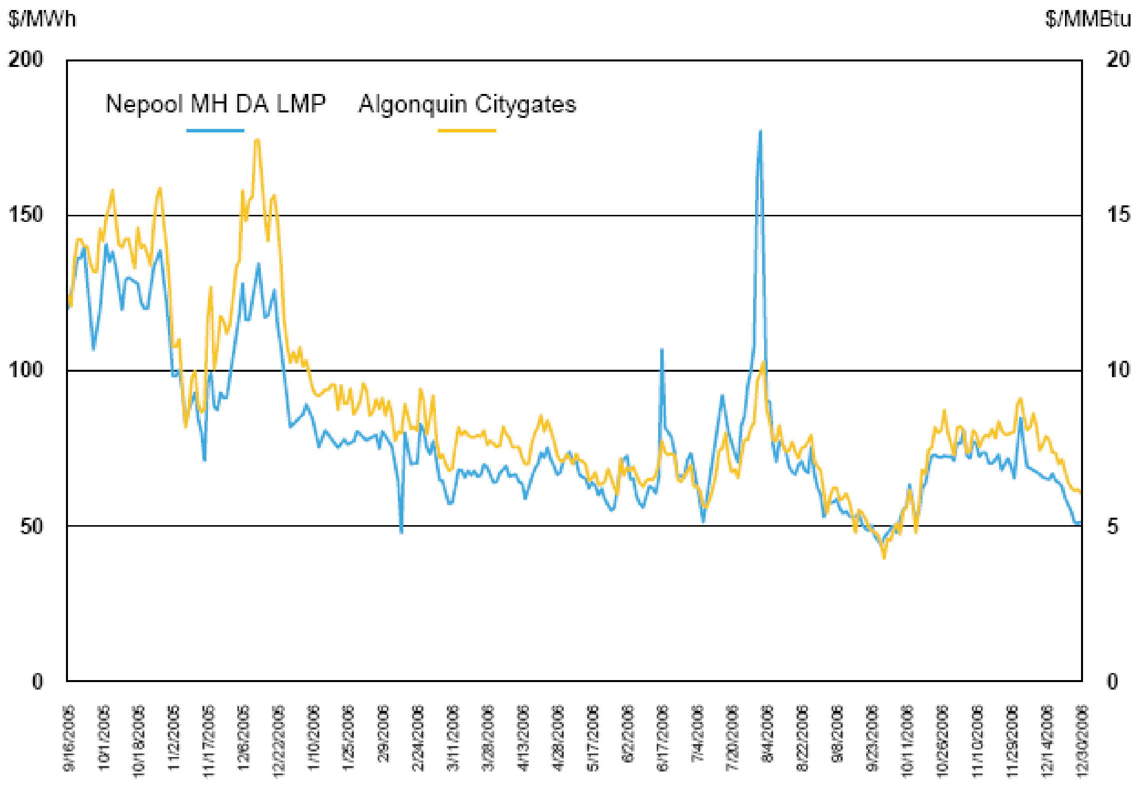
Energy Source	Generation (MWh)	Percent
Coal	92,264,272	47.53%
Hydroelectric Conventional	129,037	0.07%
Natural Gas	7,116,309	3.67%
Nuclear	93,263,001	48.04%
Other	0	0.00%
Other Gases	198,788	0.10%
Other Renewables	822,715	0.42%
Petroleum	326,024	0.17%
Total	194,120,146	100.00%

Data Source: DOE/EIA

Regional Fuel Cost and Electricity Prices: New England

Figure 17 plots New England wholesale electricity prices and natural gas prices from September 2005 through December 2006.[8] Electricity and natural gas prices track each other closely throughout the period. These prices may track each other more closely than in PJM because a much higher proportion of the generation in the region uses natural gas and petroleum (as shown in Figure 1, petroleum prices have followed a pattern similar to natural gas prices, but generally at a lower level).

Figure 17. New England electricity and natural gas prices



Data Source: IntercontinentalExchange, Inc.

[8] This figure uses IntercontinentalExchange, Inc. data for New England electricity and natural gas prices.

As shown in Table 3, just over 37 percent of the electricity was generated from units that used natural gas and close to 10 percent from units running on petroleum in 2005. However, more than half the generation comes from other sources, including over 40 percent from coal and nuclear sources.

Table 3. New England generation by energy source, 2005

Energy Source	Generation (MWh)	Percent
Coal	20,425,384	15.08%
Hydroelectric Conventional	7,892,800	5.83%
Natural Gas	50,316,428	37.16%
Nuclear	34,564,611	25.53%
Other	10,356	0.01%
Other Gases	1,620	0.00%
Other Renewables	9,356,355	6.91%
Petroleum	13,310,249	9.83%
Pumped Storage	-463,296	-0.34%
Total	135,414,507	100.00%

Data Source: DOE/EIA

Conclusion

The evidence shows that while fuel prices have certainly played a role in escalating electricity prices, the story is more complex than simply attributing the increases to the cost of fuels used to generate power. Rather than moving in lockstep, electricity prices and fuel costs can sometimes even move in opposite directions, as seen with PJM prices. Overall, customer load and its seasonal variation may explain the variation in electricity prices better than fuel costs or natural gas prices alone. It is also likely that other unaccounted for factors may help explain electricity price changes.

While natural gas prices are often cited as the reason for electricity price increases at the wholesale level, natural gas accounted for only 5.5 percent of the generation in PJM during 2006. Coal and nuclear sources accounted for over 91 percent of the generation. An explanation for natural gas' disproportionate impact on wholesale power prices is that it is often the marginal fuel. However, this does not always fully explain variations in electricity prices. Natural gas-burning units are not the units that are most often on the margin during the year in PJM – coal units are on the margin for more hours. Coal was the marginal fuel 69 percent of the year, while natural gas was for 24.8 percent of the year.

On the retail side, natural gas is also often cited as the culprit for recent price increases for retail customers, but suppliers of full requirements retail service add to the wholesale price additional costs and risks not directly related to the costs of energy. These may include capacity; ancillary services; transmission and RTO service charges; congestion charges; risk management costs; risks from fluctuating fuel prices; the risk that load will change; the risk that customers will migrate between suppliers; the risk of regulatory or legislative changes; counterparty risks, and administrative, marketing, and legal costs to serve retail customers.

However, it is not clear if these costs and risks, which are often unquantifiable with reasonable precision, fully explain the gap between wholesale prices and retail prices.

Additional Questions and Data Availability and Access

The analysis presented in this paper points to several questions that could be addressed by future work. Additional questions include:

- While customer load may explain the direction of a price change, does it fully explain the magnitude of the change?

- What other factors, including strategic actions by suppliers, may explain both the direction and level of price changes in wholesale markets?

- To what extent does market design and structure contribute or exacerbate sudden price changes or spikes? What policy changes could ameliorate such impacts?

- Are retail electricity prices reflecting wholesale energy prices consistently?

- Do the non-energy costs and risks to suppliers explain any inconsistency?

The ability to address adequately these and other related questions depends on data availability, quality, and access. A further investigation for this paper on fuel costs relative to overall electricity generation costs at the state or company level was prevented because data were not readily available. FERC Form 1 collects cost information from regulated utilities, but this information is not available for unregulated generators. These companies now own a significant percentage of generation in RTO regions. Prior to restructuring, regulated utilities owned generating assets and reported their operating costs on Form 1. Now, many of these utilities are receiving power from the same generating assets, but are purchasing it from unregulated affiliates or independent generating companies that are not required to file this information with FERC. In addition, the Form 1 information that is collected does not appear to be checked for quality, as some submissions include incomplete data. Unfortunately, this loss of data makes it extremely difficult to conduct important analyses of electricity markets and restructuring policy issues at this critical time in the industry's history.