2008

STATE OF THE MARKETS REPORT

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Federal
Energy
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Commission

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FEDERAL ENERGY REGULATORY COMMISSION

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2008 State of the Markets Report

OFFICE OF ENFORCEMENT

Division of Energy Market Oversight

August 2009

Executive Summary and Overview

Summary of Market Outcomes

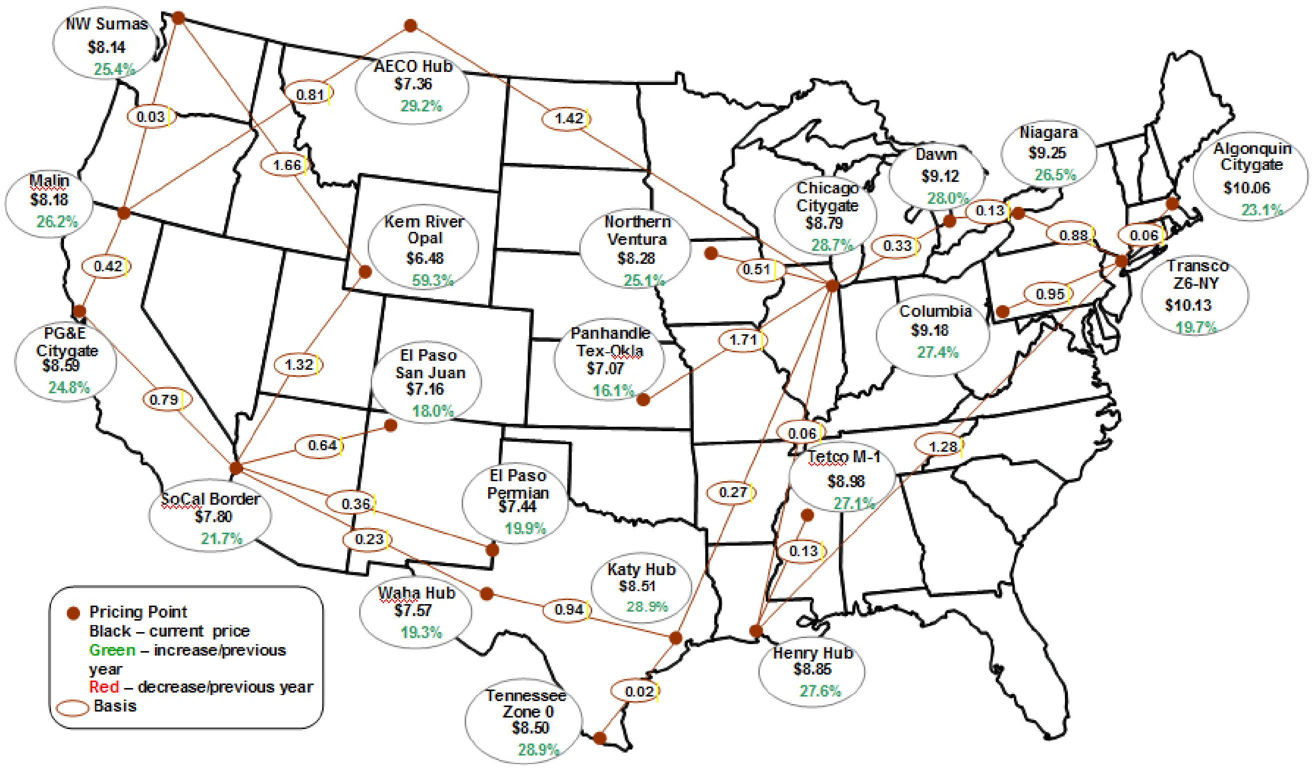
Wholesale natural gas and electricity prices rose dramatically in the first half of 2008, and then fell dramatically through the end of the year. On average, electricity and natural gas prices in 2008 were substantially greater than prices in 2007 in virtually every region of the United States.

Summary of Market Outcomes

Regional differences in spot price changes were largely the result of infrastructure issues. For instance, average electricity prices at the Minnesota Hub were almost 7 percent *lower* than in 2007, due largely to beneficial hydro imports from Manitoba and increased wind generation in western MISO. In many hours in 2008, constraints prevented this lower-cost power from moving south and east from the Minnesota Hub. Gas price changes were affected by new pipeline infrastructure. Spot gas prices at Cheyenne Hub in the Rockies were 54 percent higher in 2008 relative to 2007 due to the inauguration of the Rockies Express Pipeline (REX) that allowed Rockies gas, frequently bottled up in 2007, to flow to higher-priced midwestern markets. This had a cascading effect on surrounding regions that is discussed below.

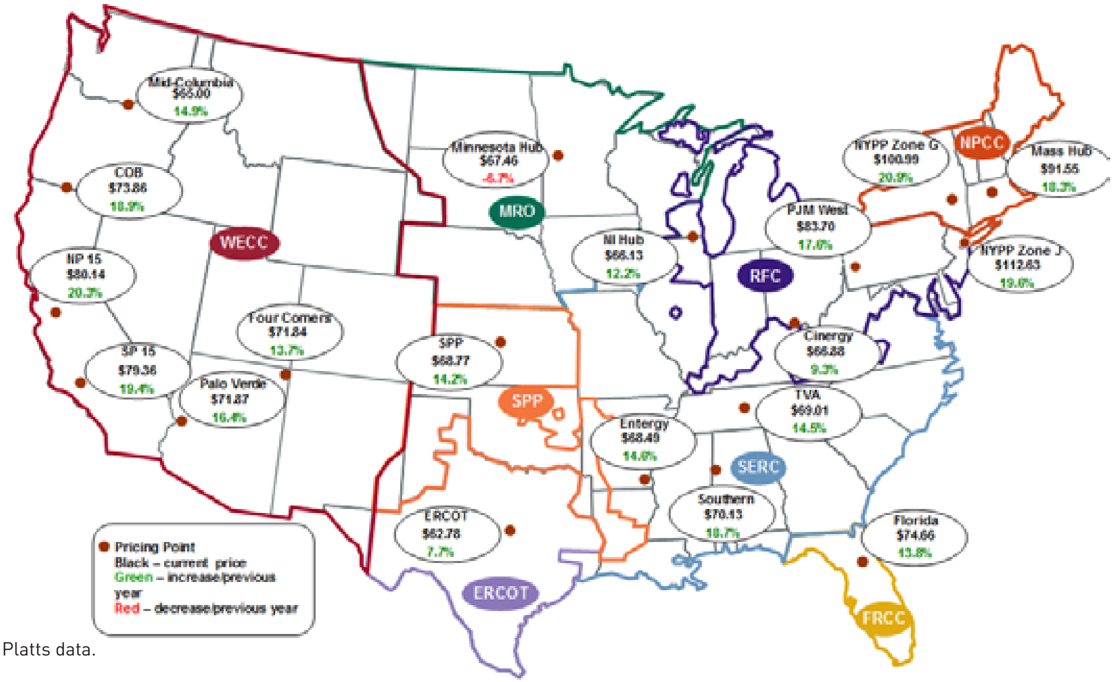
However, focusing on average prices masks the substantial swing in prices experienced during the course of the year. Electricity prices for major eastern trading hubs started the year in the range of \$60/MWh to \$80/MWh, rose to between \$100/MWh to \$160/MWh by mid-July, and ended the year

Figure ES-1 2008 Average Natural Gas Spot Prices



Source: Derived from Platts data, February 6, 2009.

Figure ES-2 2008 Average On-Peak Electricity Spot Prices

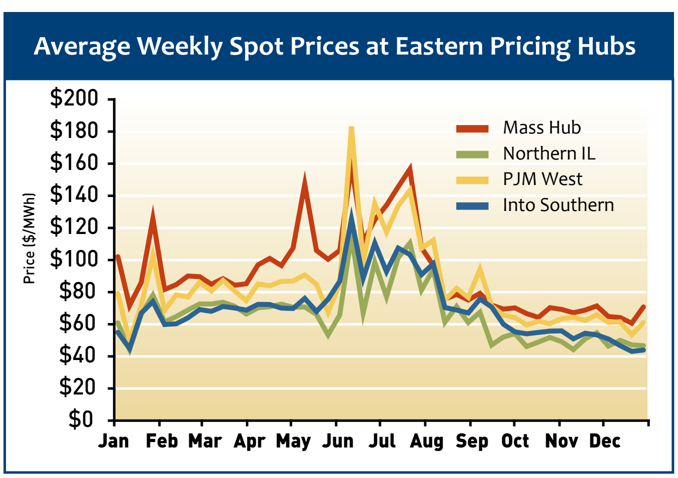


Source: Derived from Platts data.

in the range of $40/MWh to $70/MWh (see Figure ES-3). There was a similar pattern in the western United States, with the exception of the Mid-Columbia price point, where late and robust hydro generation suppressed summer prices (see Figure ES-4).

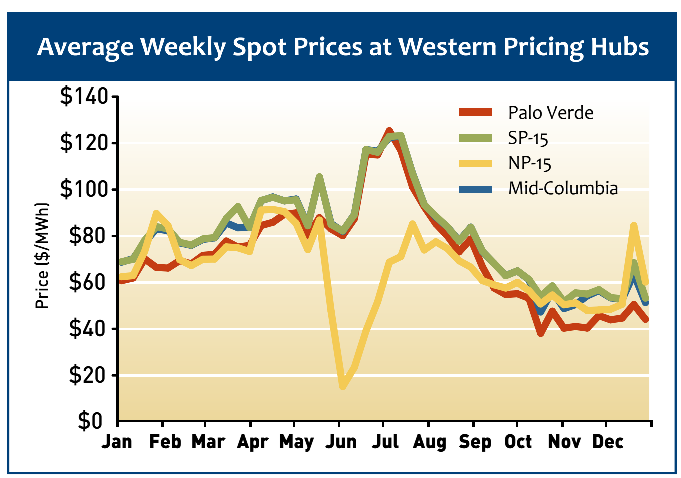
This dramatic swing in electricity prices was driven by equally dramatic swings in fuel prices, principally natural gas, coal and oil. Spot natural gas prices at Henry Hub started 2008 at $7.83/MMBtu, reached $13.32/MMBtu on July 3 and ended the year at $5.71/MMBtu

Figure ES-3



Source: Derived from Platts data.

Figure ES-4



Source: Derived from Platts data.

(see Figure ES-5). Similarly, Central Appalachia coal futures prices rose dramatically from around $55/ton to a high of almost $140/ton during the first seven months of the year, and then fell back to about $62/ton (see Figure ES-6).

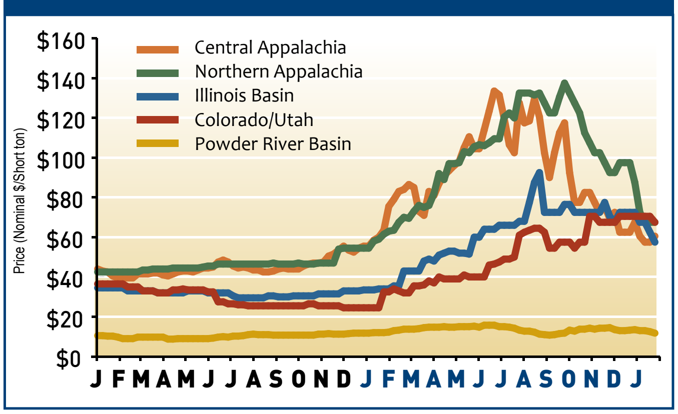
Figure ES-5

Henry Hub Daily Spot Prices in 2008

Source: Derived from IntercontinentalExchange data.

Figure ES-6

2007-2008 Regional Coal Spot Prices



Source: Derived from Bloomberg data.

The remainder of this section will discuss the factors that shaped the electricity and natural gas markets during 2008, focusing on key themes that emerged over the course of the year. These themes include:

- Physical fundamentals alone can not explain natural gas prices experienced during the year.
- Unconventional gas supplies and new infrastructure have fundamentally altered the nature of natural gas markets.
- The financial crisis that started during the second half of the year altered the role of financial energy products and financial players in energy markets and increased the cost of capital, while simultaneously reducing the access to capital.
- Most electric market outcomes were driven by external market forces – specifically, fuel and commodity prices and the financial crisis.
- Alternative energy options, including energy efficiency, demand response and wind generation, have emerged as key components of electricity markets.
- The Commission took steps to enhance release and reassignment of natural gas transportation and electric transmission capacity.

Physical Fundamentals Alone Cannot Explain Unprecedented Summer Natural Gas Prices

During the summer of 2008, natural gas prices reached high levels never before experienced during the summer in the United States. A review of the physical fundamentals during the first half of 2008 suggests that supply and demand factors alone can not explain why Henry Hub prices reached $13.32/MMBtu on July 3 and then tumbled to below $6/MMBtu by the end of the year. We discuss various physical and financial fundamentals in greater detail in Section 2 of this report. The following is a brief overview of our findings.

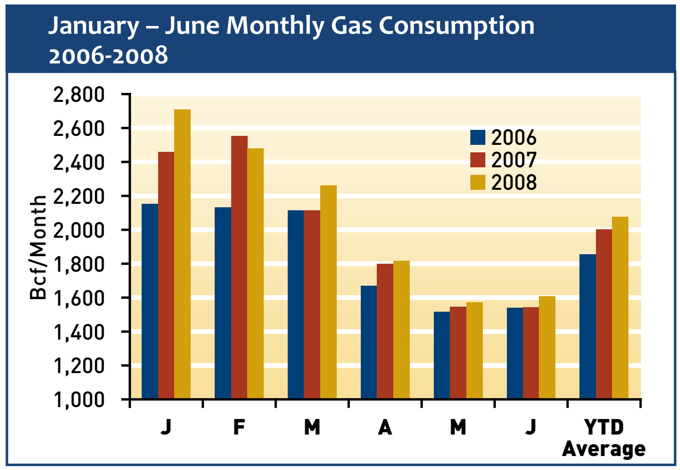
Supply

There were no major disruptions to cumulative supply during the first half of 2008 that would explain the increase in prices. Total gas supply, composed of domestic production and net imports, both from Canada and in the form of liquefied natural gas (LNG), is estimated to have increased between 1.3 percent and 3 percent during the first half of 2008 relative to 2007.[1] The increase in cumulative supplies was spurred largely by dramatically higher domestic production that offset a decline in pipeline imports. Relative to 2007, domestic supply is estimated to have been up between 5.8 percent and 10.1 percent for the first six months of 2008.[2]

Demand

Cumulative gas use through June 2008 is estimated to have increased between 2 percent and 3.6 percent relative to 2007.[3] While the growth in consumption during the first half of 2008 could have contributed to upward pressure on natural gas prices, demand alone does not seem to explain the overall level of natural gas prices. This is especially true because the growth in demand was concentrated in two months (January and March, see Figure ES-7), while spot prices continued to rise in April and May.

Figure ES-7



Source: Derived from EIA data.

U.S. Gas Balance

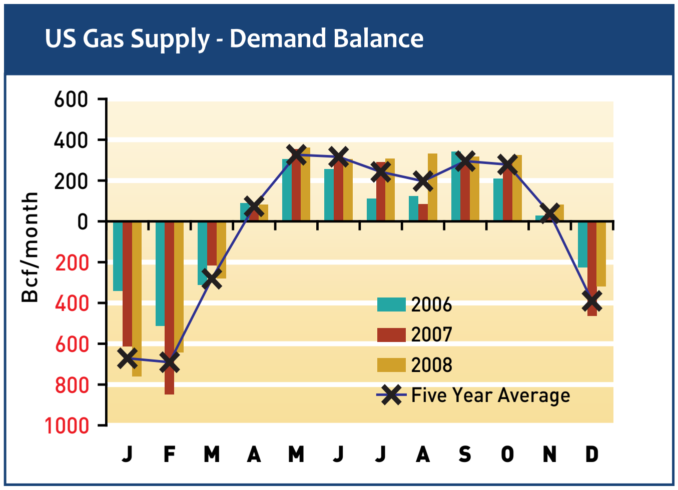
The overall state of the U.S. gas market can be summed up through the balance of supply and demand, which was not significantly more bullish than the five-year average balance, except in January (see Figure ES-8, next page). During January 2008, cold weather drove high gas demand, resulting in a supply deficit (domestic consumption less domestic supply) of 761 Bcf compared to a supply deficit of 613 Bcf in January 2007 and a five-year average supply deficit of 671 Bcf. However, after January the balance was inline with the five-year average. Importantly, there was not an exceptional surplus of gas supply in July 2008 when prices started to plunge. August does show a significant supply surplus due to the low summer demand from power generators; however, the market balance was only mildly different from the five-year average and the previous two years.

1 Bentek Energy LLC is at the lower end of supply growth estimates, while Cambridge Energy Research Associates (CERA) and the Energy Information Administration (EIA) are at the higher end. Bentek estimates from Energy Market Fundamentals - Supply/Demand Balance (Excel Report), EIA estimates from Natural Gas Navigator, http://tonto.eia.doe.gov/dnav/ng/ng_sum_lsum_dcu_nus_m.htm. CERA estimates from North American Natural Gas Market Outlook Data Tables, U.S. Lower-48 Gas Supply & Demand Balance, http://www.cera.com/aspx/cda/client/report/report.aspx?KID=8&CID=10292

2 EIA reported that gas production grew at 10.1 percent rate during the first six months of 2008, while Bentek estimated less robust growth of 5.8 percent for the first half of 2008 and CERA estimated 9 percent production growth for the first half of 2008. Bentek estimates from Energy Market Fundamentals - Supply/Demand Balance (Excel Report), EIA estimates from Natural Gas Navigator, http://tonto.eia.doe.gov/dnav/ng/ng_sum_lsum_dcu_nus_m.htm. CERA estimates from North American Natural Gas Market Outlook Data Tables, U.S. Lower-48 Gas Supply & Demand Balance, http://www.cera.com/aspx/cda/client/report/report.aspx?KID=8&CID=10292.

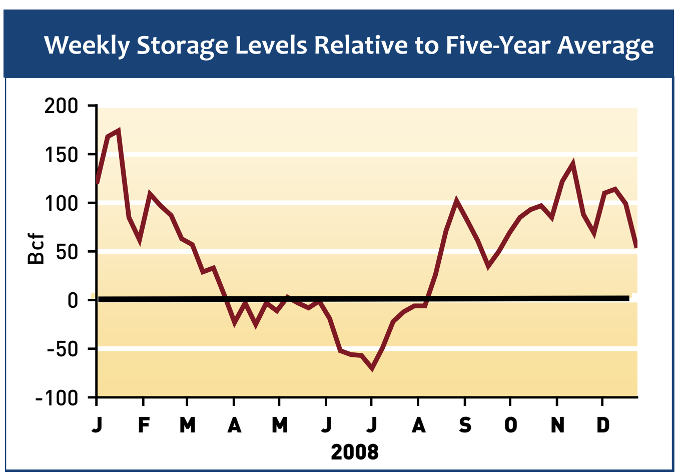
3 Bentek is at the lower end of consumption growth estimates, CERA estimates 3 percent growth, and EIA estimates the highest growth.

Figure ES-8



Source: Derived from EIA data.

Figure ES-9



Source: Derived from EIA data.

Storage Inventories

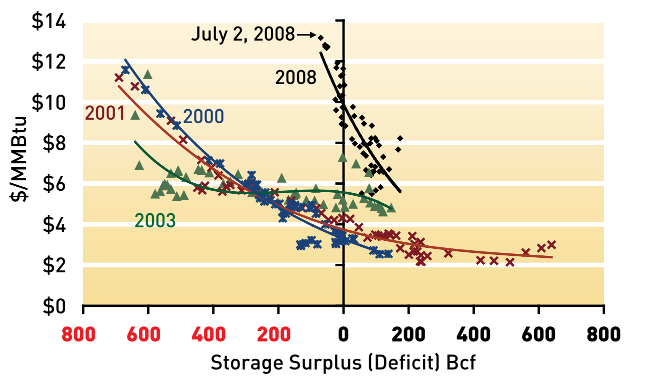
Storage levels are often cited as one of the most significant indicators of price direction and are another way to examine the supply/demand balance. By the middle of January 2008, storage levels were about 175 Bcf above the five-year average. However, storage levels fell to just 109 Bcf above the five-year average by the start of February due to extremely cold weather. As the winter progressed, storage levels continued to fall relative to the five-year average, reaching the five-year average by the end of March (see Figure ES-9). This decline in storage can certainly explain some of the increase in prices during the first three months of 2008, especially to the extent that storage levels influenced market perceptions.

Storage levels remained at the five-year average through the end of May and then dropped to levels in early July that the market had not experienced since 2004. Because the relatively low storage levels during the price run-up occurred in the spring and early summer, when those injecting gas have the maximum flexibility in their storage choices, the steep price increase likely *caused* the low inventories. In addition, storage remained relatively low throughout July and mid-August, though storage was climbing back to the five-year average as natural gas prices fell dramatically. This suggests that any adverse market perception related to low storage levels dissipated quickly.

While 2008 storage was at or above the five-year average most of the year, 2008 prices were far above other periods of similarly moderate storage levels. Specifically, higher summer storage deficits occurred in the summers of 2000 and 2003, without a similar impact on summer gas prices (see Figure ES-10 on next page).

Figure ES-10

Relationship Between Henry Hub Weekly Storage Deficit and Prices, 2008



Source: Derived EIA Weekly Storage Report and ICE data

The rise in natural gas prices coincided with a global increase in many commodity prices. This increase occurred as large pools of capital flowed into various financial instruments that essentially turned commodities like natural gas into investment vehicles.[4] Ultimately, we believe that financial fundamentals, along with the modest tightening in the supply and demand balance during the first part of 2008, explain the pattern of natural gas prices during the year.

Natural Gas Market Dynamics

By the end of 2008, natural gas prices were testing the bottom of the $6/MMBtu to $8/MMBtu range that characterized normal natural gas prices since 2005. By March 2009, natural gas prices breached the $4/MMBtu that characterized the bottom of the normal range from 2003 to 2005. The physical factors that drove prices in the fourth quarter of 2008 and first quarter of 2009 have the potential to fundamentally change the natural gas markets over the next few years. Going forward, a key consideration is whether natural gas production will be able to get into balance with consumption in a manner that will not lead to an exaggerated boom-and-bust cycle.

Production

Natural gas production growth has been concentrated in what has been traditionally referred to as unconventional gas fields. These fields include tight sands, coalbed methane and shale formations. Currently known unconventional gas resources are concentrated generally in four areas of the United States; the Rocky Mountains (coalbed methane and tight sands), the south-central and Gulf Coast region (tight sands and shale), the Appalachian region from Kentucky to New York (coalbed methane, tight sands and shale) and northern Michigan (shale). The EIA estimates that unconventional gas totaled 61 percent of Lower-48 onshore production (11 Tcf) in 2008.[5]

Unconventional gas plays have become economic due to innovations in horizontal drilling and fracturing technology.[6] Despite the horizontal drilling and fracturing advances, drilling for unconventional natural gas is still relatively expensive. Unfortunately, there is limited information available on breakeven prices needed to support gas development, and the available estimates are disparate.[7] On the low end, breakeven prices range from $3.30/MMBtu to

4 See testimony of Michael W. Masters before the House Committee on Energy and Commerce, Subcommittee on Oversight and Investigations, United States House of Representatives, June 23, 2008 ("Index speculators have poured billions of dollars into the commodities futures markets, speculating that commodity prices will increase. … assets allocated to commodity index trading strategies have risen from $13 billion at the end of 2003 to $260 billion as of March 2008")

5 Energy Information Administration (EIA), 2009 Annual Energy Outlook.

6 Fracturing refers to the process of using a water, sand and chemical composition to break open geological formations that are holding natural gas.

7 Break even prices represent the price level at which producers can cover the variable cost of operation and earn an adequate internal rate of return (around 10 percent).

$5/MMBtu.[8] On the high end, breakeven price estimates for most producing basins are in the range from $5/MMBtu to $7/MMBtu range.[9]

Given the plausible range of breakeven prices, spot prices at the end of May 2009 are just about $1.50/MMBtu below the price needed to sustain drilling activity in most unconventional basins. Therefore, any reduction in drilling is likely due to attempts to bring supply and demand into balance. In fact, drilling activity has fallen dramatically. The horizontal rig count (horizontal drilling is used extensively to produce shale gas) on June 12, 2009, was 381, down 166 (30 percent) from a year ago while the total number of rotary rigs seeking natural gas was 685, down 921 (57 percent) from the September 2008 high of 1,606 rigs. That said, forward prices for winter 2009-10 and beyond are just below the level sufficient to warrant continued drilling.[10] From a practical standpoint, a prolonged period of reduced drilling activity will make it difficult to retain trained rig crews. As rig crew workers move on to take other jobs, it will be difficult to hire and train new crews when producers want to increase drilling activity.

Infrastructure

A key issue is whether the natural gas market will be able to move available low cost supply to consumption centers. Natural gas infrastructure burgeoned in 2008. There were significant additions in both interstate and intrastate infrastructure. Specifically, EIA estimates that new interstate and intrastate gas infrastructure projects added an unprecedented 43.9 billion cubic feet per day (Bcfd) of pipeline capacity in 2008, almost three times the capacity additions from previous years.[11] Also noteworthy is the magnitude of the pipeline projects, with 15 projects designed to transport more than 1 Bcfd each.[12]

Many of the new pipelines served to better integrate robust unconventional natural gas production into the national pipeline grid. As a result, some of the most significant pipeline capacity additions altered traditional flow patterns and transformed physical transportation price relationships. These changes were especially noteworthy in the western, northeastern and Gulf regions. Increased gas flows from the Rockies Express Pipeline (REX) and new shale supplies put downward pressure on Midcontinent prices, which were, at times, the lowest cost markets in the United States in 2008. The separation of prices in Northern and Southern California grew by 30 cents, a 64 percent increase from 2007, as Permian gas displaced by REX depressed Southern California prices.

Liquefied Natural Gas

During 2008, the United States received relatively little LNG as prices in the rest of the LNG-importing world were higher than U.S. prices. However, world LNG prices have fallen substantially since the end of 2008, to the point that Northeast prices for natural gas were on par with the rest of the world by the end of March 2009 (see Figure ES-11 on next page).

Additional LNG supplies are coming online and Asian and European demand has fallen off. A total of 1.5 Tcf of liquefaction capacity should be added to global supply by the end of 2009, an increase of approximately 20 percent.

8 Bentek Energy LLC, *Bentek Market Alert: Catch the Wave, Part 3,* March 3, 2009.

9 Merrill Lynch Commodities Inc., "Fundamental Shifts for Natural Gas Market," National Association of Regulatory Utility Commissioners Winter Meeting, February 2009.

10 According to Bloomberg, forward prices for winter 2009-10 averaged $4.44/MMBtu at Transco Zone 6 as of June 15.

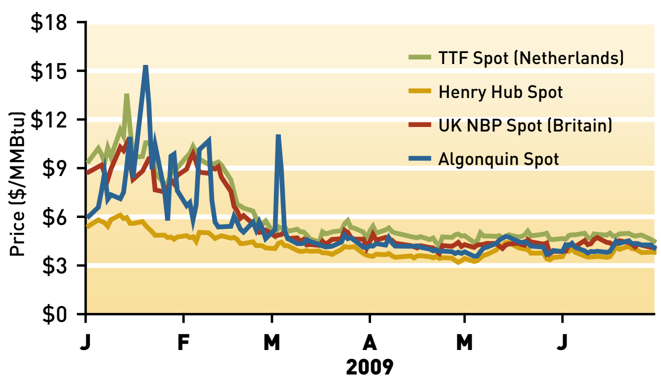
11 Energy Information Administration, Natural Gas Year-in-Review 2008 http://www.eia.doe.gov/pub/oil_gas/natural_gas/feature_articles/2009/ngyir2008/ngyir2008.html#pipeline

12 Ibid.

Asia accounted for 5.7 Tcf (70 percent) of global LNG imports in 2008, and Asian imports could fall by as much as 0.8 Tcf in 2009 due to the economic recession. This, coupled with increasing supply, could free up cargoes to flow to the United States and Europe.

Figure ES-11

Atlantic Basin European and United States Spot Natural Gas Prices



Source: Derived from Bloomberg and IntercontinentalExchange data.

While international export capabilities are increasing, the United States has an enhanced ability to receive LNG. The commissioning of three new U.S. import terminals (Freeport, Sabine Pass and Northeast Gateway) in 2008 increased import capacity to 9.3 Bcfd from 3.9 Bcfd. As a result, the United States had approximately 40 percent of global regasification capacity and was capable of importing 35 percent of the world's LNG supply. A large inflow of LNG would put substantial downward pressure on natural gas prices, especially if demand does not rebound or production does not slow.

Financial market turmoil started to affect energy markets as early as July

As tumultuous as natural gas prices were during the first half of 2008, the capital markets were similarly tumultuous during the second half of 2008. As financial institutions experienced growing distress, the energy markets were affected in two ways. First, trading of financial energy products fell and financial institutions took a smaller role as energy market participants. Second, energy market participants experienced reduced access to and a higher cost of capital, resulting in reductions in capital expenditure budgets.

Financial Products and Financial Institutions as Energy Market Participants

Prominence of Financial Energy Products

During 2008, financial products continued to play an important role in energy markets. The volume of financial natural gas trading dwarfs physical natural gas trading. For instance, the use of financial basis swaps[13] traded on both Nymex and the IntercontinentalExchange (ICE) is an order of magnitude larger than physical basis volume. Similarly, Nymex and ICE futures trading, which is for a term of one month, is several orders of magnitude greater than monthly physical deals.

This phenomenon continued in 2008, as detailed in Table ES-1 on the next page.

13 Basis swaps are instruments that call for the buyer to pay the seller a fixed price, and then the seller pays the buyer the difference between the spot price for natural gas at two different locations. For instance, on Nov. 1, 2008, a Transco Zone 6 New York basis swap for the month of December cost $2.56/MMBtu. The buyer of the basis swap paid this amount to the seller, and the seller then paid the buyer the difference between the Transco Zone 6 New York daily spot price and the Henry Hub spot natural gas price, which averaged $1.86/MMBtu in December 2008.

Table ES-1

Product	Volume Traded (Tcf) 2007	2008	Percent Change
ICE Bilateral Physical Trading			
Daily Fixed-Price	5.67	6.49	14.6 percent
Daily Index	1.54	1.93	25.7 percent
Monthly Fixed-Price	1.74	2.39	37.0 percent
Physical Basis	1.03	1.14	11.1 percent
Monthly Index	1.61	1.89	17.3 percent
Term & Other	0.53	0.27	-50.4 percent
Nymex			
Nymex Futures	367.68	494.61	34.5 percent
Nymex Swaps	14.33	13.06	-8.8 percent
Nymex Basis swaps	21.32	18.05	-15.4 percent
ICE Financial			
Swing Swaps	4.30	4.61	7.2 percent
Index Swaps	1.01	1.59	57.9 percent
Basis Swaps	20.93	33.63	60.7 percent
Futures Look Alikes	304.24	401.11	31.8 percent

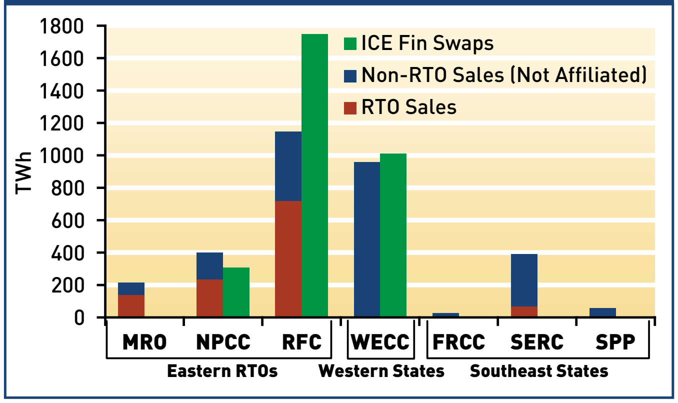
Source: Derived from Nymex and IntercontinentalExchange data

Similarly, in the electricity markets, financial contracts continue to play an increasingly prominent role. Starting with the third quarter of 2006, financial trading on ICE has increased relative to the previous year every quarter until the fourth quarter of 2008. At the same time, physical sales of electricity, as reported in the Electric Quarterly Report, have fallen every quarter relative to the previous year since 4Q04, with the exception of 1Q08.

Financial contracts are especially important in the organized electricity markets, where financial contracts on ICE have exceeded physical sales reported in EQR that were not made to the ISO or RTO.

Figure ES-12

Majority of Sales in Eastern RTO areas to the RTO



Source: Derived from Electric Quarterly Report and IntercontinentalExchange data.

Change in Financial Volumes

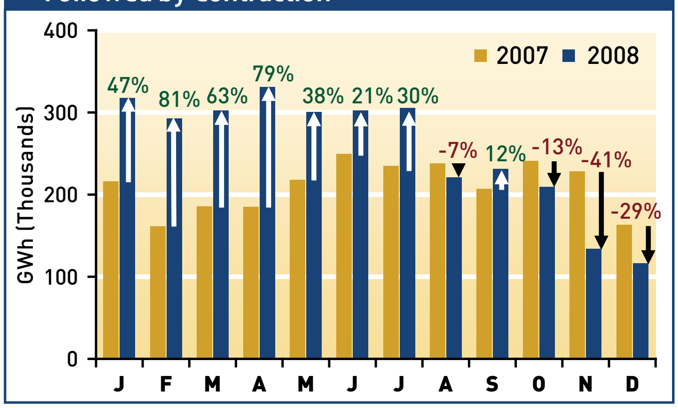
The volume of financial energy trading in natural gas and electricity markets decreased in the latter part of 2008, likely as a result of the financial market turmoil. The clearest trend was in electricity.

The volume of financial electricity products trading on ICE started to drop in August 2008 relative to the previous year after dramatic increases from January through July (see Figure ES-13, next page). This pattern held in most of the largest-volume trading hubs. At the two largest trading hubs, PJM West and SP-15, 4Q08 trading was down substantially relative to 4Q07. Trading volume in 4Q08 was flat relative to 4Q07 at several other hubs, such as Mid-Columbia and Cinergy, though trading at these hubs during the first part of 2008 was up substantially relative to 2007.

In the latter half of 2008, FTR auction activity (as measured in gigawatts traded in monthly auctions) declined compared to the previous year (see Figure ES-14, next page). Financial transmission rights (FTRs) are purely financial contracts used to hedge the cost of congestion in regional transmission organization (RTO) markets. As financial contracts, they have become popular trading vehicles for financial institutions. However, the long-term nature of the contracts means that collateral requirements associated with FTR positions can be substantial.

Figure ES-13

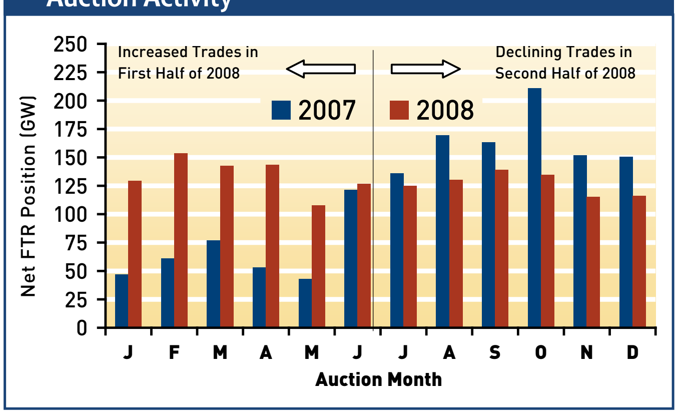
Strong ICE Financial Power Gains Followed by Contraction



Source: Derived from IntercontinentalExchange data.

Figure ES-14

Monthly Financial Transmission Rights Auction Activity

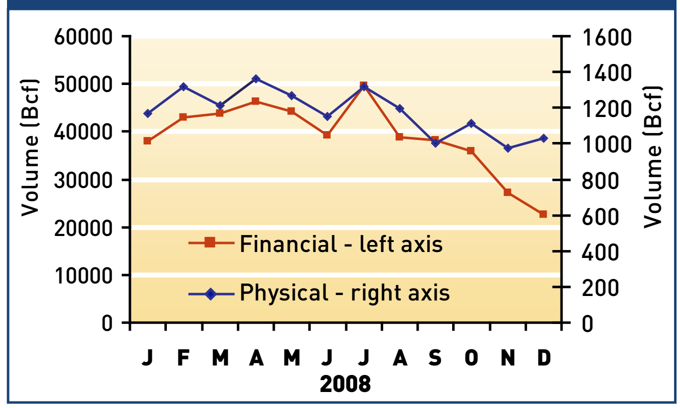


Source: Derived from Ventyx Velocity Suite data.
(1) Data reflects monthly auctions in 2007 & 2008 in PJM, MISO, ISO-NE and NYISO.
(2) Net FTR position for an auction month is calculated as the total FTR quantities bought in that month less FTRs sold.

Financial natural gas trading on ICE also declined in the last two months of 2008 (see Figure ES-15), though the volume of financial trading continued to be an order of magnitude larger than physical trading. For the first 10 months, the volume of trading across all natural gas products traded on ICE was roughly 34 times larger than physical trading. By December, that ratio fell to about 22:1.

Figure ES-15

Monthly Trade Volumes for Natural Gas

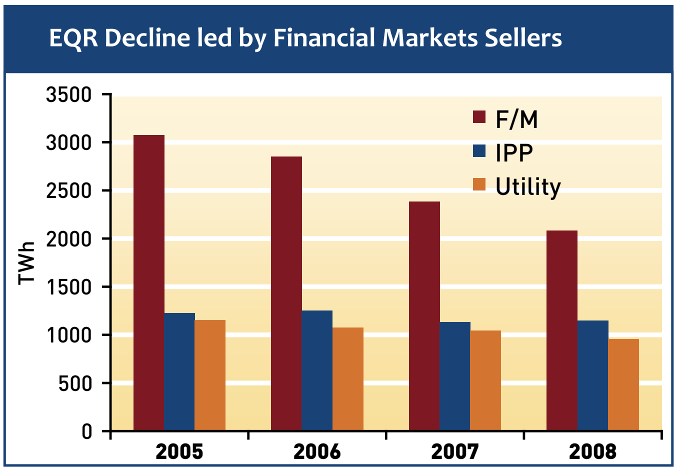


Source: Derived from IntercontinentalExchange data.

Role of Financial Entities

The reduction in financial product volumes suggests that financial institutions played a progressively smaller role as 2008 came to an end. We have categorized physical electricity sellers into three broad categories – utility, independent power producer and financial-marketer – based on the company that files the EQR. Based on this determination, we can see that much of the drop in physical market activity is the result of fewer sales by the financial-marketers category (see Figure ES-16, next page). The reduction in physical activity by financial institutions and energy marketers is particularly evident in the ReliabilityFirst, New England and California NERC subregions. ReliabilityFirst is home to PJM and parts of MISO, while New England is home to ISO-NE. All of these RTOs operate centralized day-ahead and real-time markets. California is home to the California ISO, which operates a centralized real-time market.

Figure ES-16



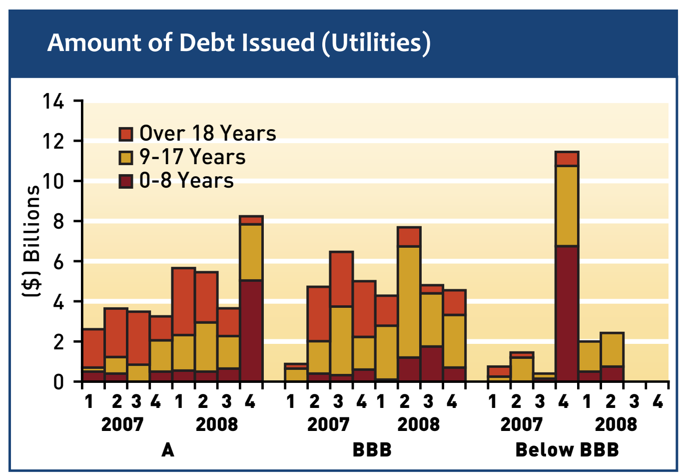
Source: Derived from from Electric Quarterly Report data.

Cost and Access to Capital and Capital Expenditures

Access to and Cost of Capital

By the fall of 2008, the depth of the financial crisis was coming into a clearer view. The financial crisis affected energy market participants in several ways. First, the financial crisis limited the availability of credit. According to Southern Companies' Chief Financial Officer Paul Bowers' statement at the Commission's January 2009 credit conference, "some companies with lower credit ratings have not been able to access commercial paper and other short-term credit markets." [14] Mr. Bowers also noted that "the availability and cost of credit from banks have been even more severely impacted due to their financial troubles. This is important since many lower rated utilities rely more on banks than the capital markets, especially for short-term financing."[15] Similarly, Arizona Public Service (APS) indicated in an Oct. 9, 2008 letter to the Arizona Commerce Commission that it also had experienced difficulty accessing the commercial paper market, stating that "over the past 15 months, APS has continuously experienced difficulty in accessing commercial paper with the market now being completely closed to APS, even though it is currently rated as an investment grade borrower (though near junk levels)."[16] Utility borrowing was down in the third quarter of 2008 across all rating classifications. In the fourth quarter of 2008, A-rated utilities increased borrowing levels, but for shorter durations (see Figure ES-17).

Figure ES-17



Source: Derived from Bloomberg data.

For those utilities that have been able to access the credit markets, the cost of credit has increased. According to Bowers, " in mid-2008 the credit spread over Treasuries for

14 Statement of Paul Bowers, Docket No. AD09-2-000, Jan. 13, 2009, page 4.

15 Ibid.

16 Arizona Public Service letter to the Arizona Commerce Commission in Docket No. E-01345A-08-0172, Oct. 9, 2009.

the average BBB+ utility was around 50 basis points higher than for the average A utility, but this rose to around 100 basis points near the end of the year. The effect has been even more pronounced for BBB- and BBB utilities."[17]

Reduction in Capital Expenditures

As a predictable result of the reduced access to capital and increased cost of capital, several energy market participants have indicated the intent to reduce capital expenditures in 2009. A survey of 357 oil and gas companies conducted by Barclays Capital Resources published in late December 2008 revealed that 74 percent of the companies said their exploration and production (E&P) spending would be equal to or less than their total cash flow in 2009. Barclays analysts also reported that U.S. E&P spending would drop by 26 percent to $79 billion, ending a four-year upturn.[18] Independent and smaller producers were affected the most while expenditures by the majors and super majors were generally flat to 2008. Some of the planned reductions were almost certainly related to the fall in natural gas prices and the desire to rebalance supply and demand. Nonetheless, some of these announcements were also likely related to reduced access to capital and the increased cost of capital.

On the electric side, a February 2009 report by the Edison Electric Institute indicated that capital expenditure budgets have been reduced by about 10 percent for 2009 and 2010.[19]

17 Testimony of Paul Bowers, Docket No. AD09-2-000, Jan. 13, 2009, page 4.

18 Respondents to the survey indicated that natural gas prices were the leading driver of 2009 E&P budget decisions. Similar surveys by Tudor Pickering Holt & Co., and Tristone Capital indicated that E&P spending in 2009 would decrease 40 percent and 30 percent, respectively.

19 "The Financial Crisis and Its Impact on the Electric Utility Industry," Julie Cannell, Edison Electric Institute, February 2009. Note, a June 2009 update suggests that capital expenditures by electric utilities will be flat in 2009 and 2010. This update is available at http://www.eei.org/whatwedo/dataanalysis/indusfinananalysis/pages/qtrlyfinancialupdates.aspx

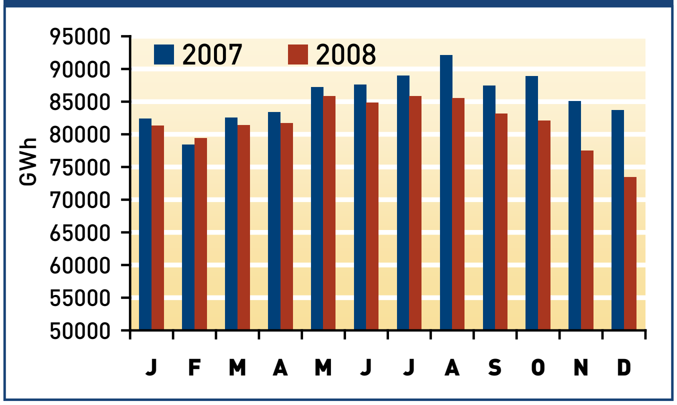
Oversight staff's survey of canceled and postponed generation projects indicates that the total capacity of canceled and postponed projects through mid-June 2009 is larger than the capacity of projects canceled and postponed in all of 2008. The main reason for the difference was a 50 percent increase in cancellations and postponements of coal, natural gas and nuclear generation through mid-June 2009 when compared to all of 2008. Hydroelectric and wind facility capacity, however, was canceled or postponed at a slower pace through mid-June 2009, with the amount of capacity canceled in 2009 year-to-date 50 percent lower than the total 2008 value. In 2008, the combined capacity of coal, natural gas and nuclear generation represented just over 50 percent of the total cancellations and postponements; through mid-June 2009 they represent 75 percent of cancellations. Wind and hydroelectric represented roughly 32 percent of the cancellations and postponements in 2008, but by mid-June 2009 represent only 17 percent of the cancellations and postponements.

Economic Activity and Energy Consumption

According to the National Bureau of Economic Research, the United States economy has been in a recession since December 2007. However, the effect of the recession on consumption of electricity and natural gas has been limited to sales to the industrial sector. This is understandable as residential and, to a lesser extent, commercial use is driven by weather. Overall, electricity sales to ultimate customers, as reported to the Energy Information Administration, were down about one-quarter of one percent, with sales to residential customers down less than 0.2 percent and sales to commercial customers up 1.9 percent. Sales to industrial customers were down 3 percent, the largest drop since 2001, with the substantial decreases starting in June (see Figure ES-18). Similarly, overall consumption of natural gas changed little from 2007, up 0.8 percent. Industrial sector demand for natural gas did not start to fall until November 2008, when it dropped 4.3 percent relative to 2007 (see Figure ES-19).

Figure ES-18

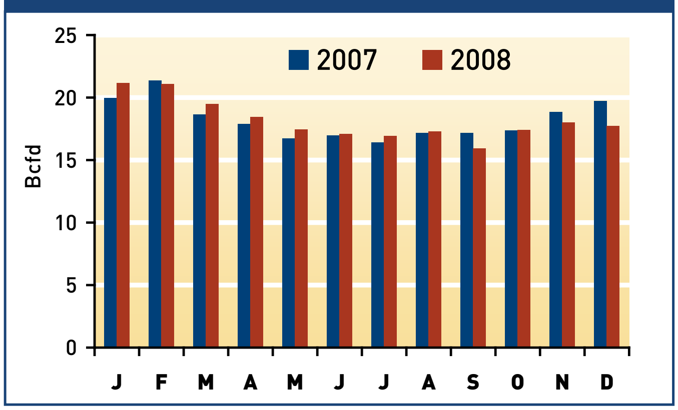
Monthly Industrial Electricity Consumption



Source: Derived from EIA data.

Figure ES-19

Monthly Industrial Natural Gas Consumption



Source: Derived from EIA data.

Electricity Market Outcomes Driven Largely by External Market Forces

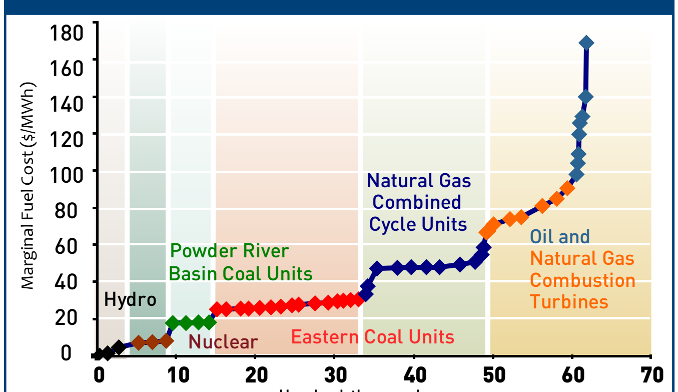
Electricity market outcomes – including spot prices, the dispatch order of generating units, the value of FTRs relative to realized day-ahead congestion costs and the construction of new electric generators – were driven largely by market forces outside the electricity market. With the exception of the maturation of alternative energy, the electricity market was like a boat on the ocean – driven up and down by external forces.

Price Outcomes and Dispatch Order

As discussed above, electricity spot prices were driven largely by the underlying fuel costs, with typical reactions to extreme weather events like the late spring runoff in the Pacific Northwest. The dispatch order for generating units, particularly in the Southeast and Mid-Atlantic, also experienced changes driven by changes in fuel prices. A supply curve based on generating unit fuel costs for units in the Southeast (SERC) during October 2007 is displayed in Figure ES-20.

Figure ES-20

Representative Regional Supply Stack, October 2007



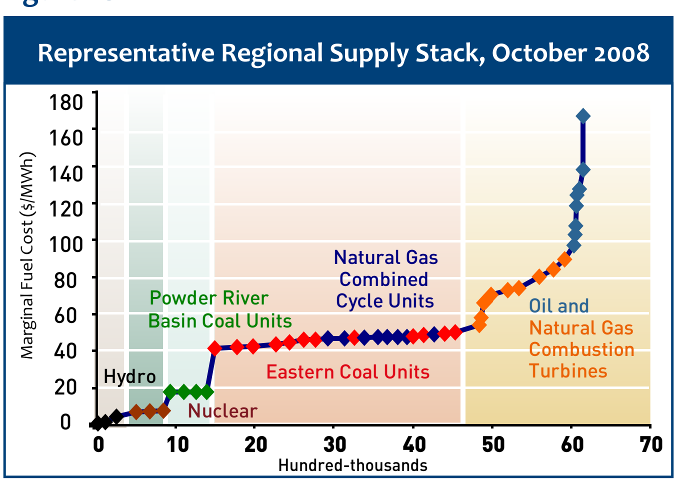
Source: Derived from Energy Velocity data.

Historically, natural gas combined cycle plants (dark blue) are more expensive than units burning eastern coal (red).

After natural gas hit record midsummer highs in 2008, the price moderated rapidly during the second half of the year. On the other hand, central Appalachian coal prices, which peaked at $134/ton in early July, descended more slowly, remaining above $117/ton into the second week in October (spot gas at the Henry Hub was below $7/MMBtu at this point).

As a result of these fuel price dynamics, gas and eastern coal-fired units switched positions in the supply stack. This caused the realignment of the supply curve in the Southeast, which looks much like Figure ES-21. We note, however, that coal-fired generation cannot be viewed independently of the coal source. The unique characteristics (mining technologies, geography and transportation, heat and emissions contents) of eastern coal such as Central and Northern Appalachian relative to Powder River Basin (PRB) and other western coals caused Appalachian coal to rise rapidly in price in recent years, whereas PRB coal has stayed in a relatively tight and cheap price band in comparison. This has created a bifurcated coal stack in which PRB coal units (green) have remained lower than eastern-coal units (red), which have split higher due to increases in Appalachian coal.

Figure ES-21



Source: Derived from Energy Velocity data.

Table ES-2 below shows the degree to which the change in relative cost of eastern coal and natural gas-fired generation changed the actual energy generated (as a percentage of total thermal generation) in the Southeast NERC subregion.[20]

Table ES-2

	Coal Gen (GWh)	Percent Thermal Gen	Natural Gas Gen (GWh)	Percent Thermal Gen	Total Thermal Gen (GWh)
10/07	13,812	67.2	3,378	16.4	20,568
11/07	12,792	68.7	2,213	11.9	18,613
12/07	13,879	68.3	2,382	11.7	20,305
10/08	11,255	61.5	3,850	21.1	18,291
11/08	11,262	63.0	3,409	19.1	17,880
12/08	12,832	66.3	2,429	12.6	19,360

Source: EPA CEMS data (via Energy Velocity).

Overall, natural gas unit generation in the Southeast increased both in absolute generation and share of total when compared to a year earlier. On the other hand, coal generation during the fourth quarter of 2008 decreased in both absolute and percentage terms when compared to one year earlier. Again, one must distinguish by source when discussing coal. Specifically, from October 2007 to October 2008, coal units burning Appalachian or a mix of eastern coals saw total generation decline between 16 percent and 19 percent, while those units burning PRB coal saw generation decline by only 3.4 percent.

20 The Southeast NERC subregion includes most of Georgia and Alabama (except for the extreme northern edges) and the western Florida panhandle and southern Mississippi.

FTR Valuations

Similarly, commodity prices also drove much of the value of FTRs over the course of the year. PJM, NYISO and ISO-NE prevailing flow FTRs were collectively overvalued (i.e., the auction price was more than the realized day-ahead congestion cost) during the first half of the year, while they were undervalued during the second half of 2008 (see Table ES-3).[21] In all of these three markets, realized spot natural gas prices during the second half of 2008 were lower, by varying degrees, compared to the natural gas futures prices that market participants saw at the time of the auction. For example, in 2008, market participants in PJM saw an average monthly natural gas price of $11.77/MMBtu for the July-December period when they were bidding in the FTR auction in May. However, spot Henry Hub natural gas prices averaged $7.71/MMBtu, or 34 percent lower, in the July-December period. As a result, price differentials across the region were compressed. In addition, the convergence of operating costs for eastern coal-fired generation and natural gas-fired combined cycle plants likely reduced some of the typical west-to-east flow.

Table ES-3
FTR Performance as a Hedge in All FTR Markets in 6-Month Valuations

	Prevailing Flow FTRs		Counterflow FTRs		All FTRs	
Market	Jan-Jun	Jul-Dec	Jan-Jun	Jul-Dec	Jan-Jun	Jul-Dec
PJM	389.8	-460.4	-55.7	117.0	334.1	-343.4
MISO	20.1	-29.4	47.1	47.4	67.2	18.0
ISO-NE	18.6	-35.0	-1.7	6.1	16.9	-28.9
NYISO	232.3	-2.2	-44.6	8.5	187.7	6.2
Total	660.8	-527.0	-54.8	178.9	606.0	-348.1

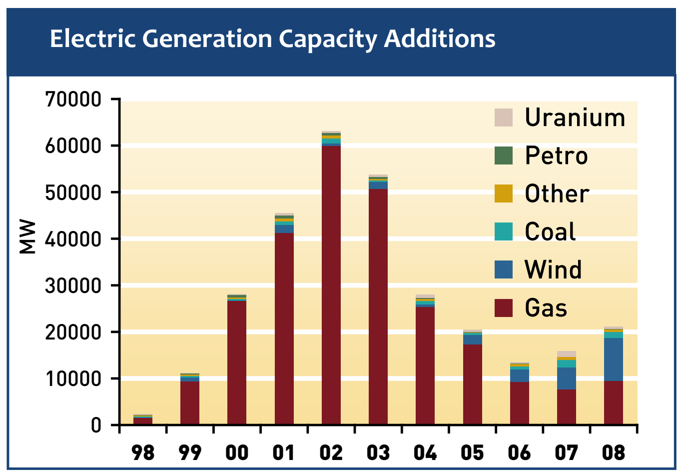
Source: Derived from Ventyx Velocity Suite.
Note: Monthly valuation is calculated as the difference between the auction clearing price and the actual day-ahead congestion price multiplied by the contract amount (in megawatts) for each cleared FTR path. The chart reflects all active FTRs applicable to both long- and short-term auctions in calendar year 2008.

21 For the purpose of this analysis, a prevailing flow FTR is any FTR for which the buyer paid to acquire the stream of congestion payments. A counterflow FTR is any FTR for which the buyer was paid to take on the responsibility for the stream of congestion payments.

Generation Additions and Cost of New Generation

Longer-term electricity market outcomes were also influenced largely by outside forces. Nationwide, during 2008, electric generating capacity was added at roughly the rate experienced since 2005, which is substantially below the rate of additions from 2001 through 2003 (see Figure ES-22). The moderate additions in new capacity were due in part to the fact that many regions of the country enjoy healthy reserve margins.

Figure ES-22



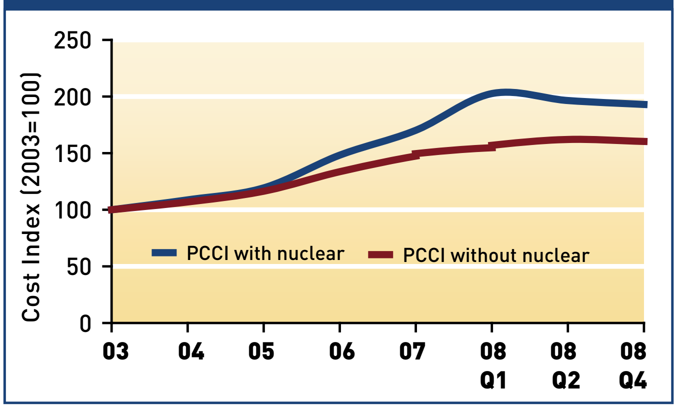
Source: Derived from Energy Velocity data.

In addition, the moderate growth in new capacity is also due to the fact that increases in construction input costs and fuel prices led to increases in the cost of new generation during the year.[22] The cost of constructing a new power plant increased almost 10 percent during the first three quarters of 2008, driven by increased costs for specialized labor as well as key inputs such as steel and cement. While underlying input costs dropped substantially in the fourth quarter, the measure of construction costs maintained by Cambridge

22 FERC staff report, "Increasing Cost in Electric Markets," June 19, 2008, http://www.ferc.gov/legal/staff-reports/06-19-08-cost-electric.pdf

Energy Research Associates (CERA) held steady (see Figure ES-23). CERA attributes the absence of downward pressure on construction costs to the backlog of orders held by equipment manufacturers and construction companies.[23] Commission staff conversations with market participants validates CERA's conclusion. In addition, during the last quarter of the year financing costs increased substantially and access to capital dried up, as discussed earlier.

Figure ES-23



Source: Derived from Cambridge Energy Research Associates (CERA) data.

23 CERA reported in the 2009 Spring CERA Executive Roundtable: CCAF-P Market and Index Forecasts (March 19, 2009) Slide 27 entitled "IHS CERA PCCI: With and Without Nuclear Update" that the (PCCI) for North America for first quarter 2009 dropped 3 percent over the previous six months, the PCCI excluding nuclear fell 6 percent over the previous six months. CERA attributed the drop in the PCCI to a decrease raw material cost, noting that equipment prices (especially highly engineered equipment) had not fallen as much as raw material costs.

Emergence of Alternative Energy

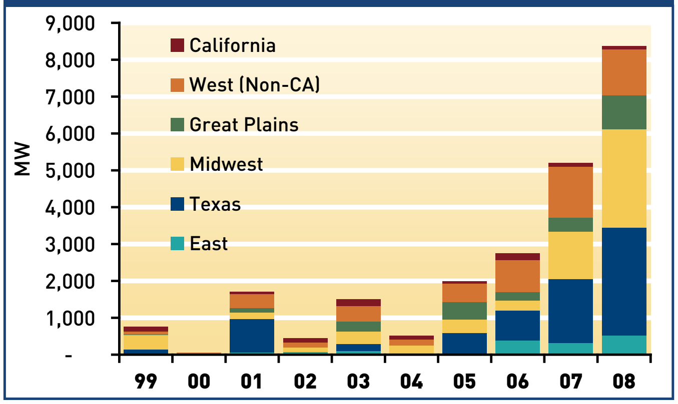
While generation additions were modest (at least relative to the boom from 2001 through 2003), energy efficiency and demand-response programs emerged as a viable option for addressing future load growth. Specifically, ISO-NE cleared 838 MW of new demand-response resources and 798 MW of new energy-efficiency resources in its two forward 2008 capacity auctions. Similarly, PJM cleared 29 MW of new demand response in its first forward auction in 2008 and 662 MW of new demand response in its second auction.

Wind Generation

The generation capacity that was added in 2008 was dominated by wind and gas-fired units. Wind capacity additions in 2008 were just over 42 percent of new generation capacity – just behind gas-fired generation. Wind capacity additions were driven in part by state renewable portfolio standards and by the renewal of the federal production tax credit. Overall, 8,376 MW of wind capacity came online in 2008, with over half of that total coming from Texas and Iowa, and more than 75 percent coming from just seven states (see Figure ES-24, next page). The top seven states have high wind potential, a renewable portfolio standard (RPS), or both. Six of these seven are members of an organized market (see Table ES-4, next page).

Figure ES-24

Regional Wind Capacity Growth, 1999 - 2008



Source: Derived from Energy Velocity, Generation data.

During 2008, the Commission took a number of actions to improve the backlog in many interconnection queues due to wind's rapid capacity growth. The Commission issued interconnection queue reform orders for the Midwest ISO (2008),[24] California ISO (2008),[25] ISO-New England (2009)[26] and the Bonneville Power Administration (BPA) (2008).[27] Southwest Power Pool's (SPP) proposed tariff reforms in 2009 are pending.[28]

24 Midwest ISO, 124 FERC ¶ 61,183 (2008).

25 California ISO, 124 FERC ¶ 61,292 (2008).

26 ISO – New England, 126 FERC ¶ 61,080 (2009).

27 Bonneville Power Authority, 123 FERC ¶ 61,264 (2008). BPA files Open Access Transmission Tariffs (OATT) and amendments to meet the Commission standards for reciprocity approval.

28 Southwest Power Pool Inc., Docket No ER09-1254 (submitted June 1, 2009).

Table ES-4 Top States by Wind Capacity Additions, 2008

Rank	State	MW wind New	Cumulative	% U.S.	2008 RPS?	2008 ISO/RTO?	Wind Potential Top 10	Wind Potential Rank	Cum Rank 2008
1	Texas	2,670	7,116	28%	yes	ERCOT/SPP	yes	2	1
2	Iowa	1,492	2,790	11%	yes	MISO	yes	10	2
3	Minnesota	481	1,752	7%	yes	MISO	yes	9	4
4	Kansas	451	815	3%	goal	SPP	yes	3	10
5	New York	407	832	3%	yes	NYISO		15	9
6	Wyoming	388	676	3%	no		yes	7	13
7	North Dakota	369	714	3%	goal	MISO - partial	yes	1	11
8	Wisconsin	342	395	2%	yes	MISO		18	15
9	West Virginia	264	330	1%	no	PJM		32	17
10	Ilinois	216	915	4%	yes	MISO/PJM		16	8
11	Washington	212	1,375	5%	yes			24	5
12	Oregon	185	1,067	4%	yes			16	7
13	Indiana	131	131	1%	no	MISO/PJM		44	21
14	Michigan	126	129	1%	yes	MISO		14	22
15	Montana	125	272	1%	yes		yes	5	18
16	Missouri	106	163	1%	yes	MISO/SPP		20	20
17	South Dakota	89	187	1%	goal	MISO - partial	yes	4	19
18	California	78	2,517	10%	yes	CAISO		17	3
19	Pennsylvania	67	361	1%	yes	PJM		22	16
20	New Hampshire	24	25	0%	yes	ISO-NE		35	28

Source: Commission staff analysis of data in Energy Velocity, AWEA project database, DSIRE-USA, Pacific NW Lab

Midwest ISO (MISO) reforms include increased fees for queue entry, increased commitments to stay in the queue and prioritization of more mature projects. In addition, MISO instituted three levels of deposits that scale up with the size of the proposed projects. CAISO reforms include adopting a clustering approach to process interconnection requests for projects in the same area, paring down the number of studies needed, and increasing and accelerating the financial commitments required for an entity to participate in the interconnection process. The Commission approved BPA's proposed network open season similar to that used by gas pipelines to address its queue and to determine the transmission additions necessary to accommodate committed generation projects.

The Commission also approved NYISO's proposal to implement a centralized forecast program for energy output from interconnected wind plants. A specialized third-party forecasting company collects data every 10 minutes, which the forecasting company submits every 15 minutes to the ISO. As a result, NYISO now integrates wind output into its real-time security-constrained dispatch.[29]

Effects of Credit Crisis and Economic Downturn on Wind Generation

Renewable projects usually have high construction costs and low operating costs. Historically, developers partnered with tax equity investors – large investment banks or insurance companies – that used specialized financing structures to capitalize on federal tax credits or accelerated depreciation.

The credit and financial crises that began in summer of 2008 profoundly affected renewable project financing. Active equity partners from the financial services sector shrank from as many as 18 in early 2008 to as few as 4.[30] As investors and developers lost money and had less taxable income, tax-based incentives were less attractive or ineffective.[31] While wind projects set all-time installed capacity records in 2008, the financing for most projects completed in 2008 was set before the economic turndown.

The effect of the financial crisis on new wind capacity became more apparent in early 2009. Some ISOs and RTOs reported slowdowns in interconnection requests, although noting it was difficult to determine how much was due to queue reform and how much was economy-related.[32] Edison International, the seventh largest owner of wind generation, deferred all wind turbine deliveries and associated payments save one in the first quarter of 2009.[33] Solar companies and wind turbine component manufacturers laid off some workers.[34]

Ancillary Services and Demand Response

The Commission took a number of actions during 2008 to enhance the ability of demand-response resources to provide ancillary services. Most notably, it issued Order No. 719 in October 2008.[35] Among other things, Order No. 719 directed each RTO or ISO to accept bids for ancillary services from technically capable demand-response resources in a manner comparable to other resources.

29 New York Independent System Operator, 123 FERC ¶ 61,267 (2008)

30 Chadbourne & Parke, tax and project finance specialist, quoted in the New York Times, Feb. 4, 2009.

31 National Renewable Energy Laboratory (NREL), PTC, ITC, or Cash Grant?, March 2009, page 1, and Stanford Group, Wind Outlook, Dec. 8, 2008, page 13.

32 ERCOT announced multiple monthly drops in interconnection requests. (SNL Energy, June 10, 2009.

33 Edison International, 10-Q Securities and Exchange Commission filing, May 8, 2009. Edison International owns wind generation through its Edison Mission Energy subsidiary.

34 "Dark Days for Green Energy," The New York Times, Feb. 4, 2009.

35 Wholesale Competition in Regions with Organized Electric Markets, Order No. 719, 73 Fed. Reg. 64,100 (Oct. 28, 2008), FERC Stats. & Regs. ¶ 31,281 (2008).

The Commission separately issued orders for market rule changes in several markets. For instance, the Commission issued an order this year in which it conditionally accepted NYISO-filed tariff revisions that allow demand-side resources to offer operating reserves and regulation service on terms comparable to generators.[36] In MISO, the Commission-approved ancillary services market (ASM) that began on Jan. 6, 2008, includes demand-response resources. MISO permits nondispatchable demand-response resources to provide energy and contingency reserves in the day-ahead and real-time markets and permits dispatchable resources to provide the same services as well as regulation service.[37]

In its 2008 State of the Markets Report, PJM's market monitor Monitoring Analytics noted that "throughout 2008, the MW contribution of demand-side response resources to the synchronized reserve market remained significant and resulted in lower overall synchronized reserve prices."[38] Monitoring Analytics went on to say that during 2008, demand-side resources accounted for all cleared tier 2 synchronized reserves in 27 percent of hours when a synchronized reserve market was cleared.[39] In the hours when all supply was from demand-side response resources, the unweighted average price was $2.58/MW. By comparison, the unweighted average synchronized reserve price for all cleared hours was $8.49/MW.

36 New York ISO, 123 FERC ¶ 61,203 (2008).

37 Midwest ISO, 122 FERC ¶ 61,172 (2008).

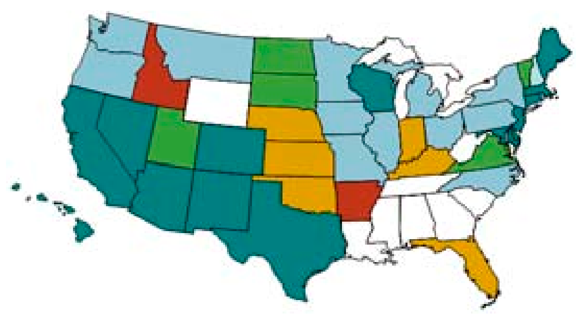
38 Monitoring Analytics, LLC, 2008 State of the Markets Report, March 11, 2009, page 300.

39 Tier 2 resources include units that are backed down to provide synchronized reserve capability, condensing units synchronized to the system and available to increase output, and demand response resources that can reduce their electricity consumption within ten minutes.

Renewable Portfolio Standards

State renewable portfolio standards have been an important driver behind new wind generating capacity. A renewable energy portfolio standard (RPS) requires a load-serving entity (LSE) to procure either a fixed percent of energy sales (MWh) or installed capacity (MW) from renewable resources. The requirement usually increases incrementally from a base year to an ultimate target. Overall, 29 states, including the District of Columbia, have a renewable mandate, while an additional 6 have renewable goals without financial penalties.

Figure ES-25
States with Renewable Portfolio Standards in 2008



RPS
Strengthened/ amended RPS
Voluntary standards or goals
Proposed RPS or studying RPS
Other renewable energy goal

Source: Derived from EEI, EIA, LBNL, PUCs, State legislative tracking services, DSIREUSA, Pew Center and the Union of Concerned Scientists.

A number of states took action during 2008 to start or expand the state's renewable portfolio standard:

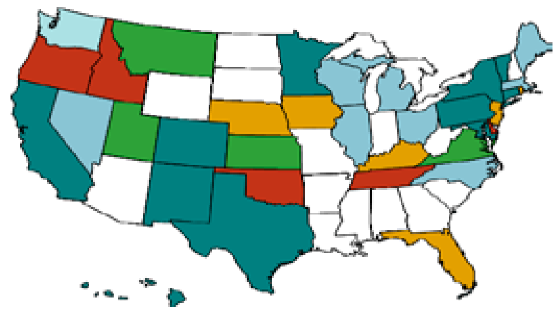
- Three states passed a new RPS (Ohio, Michigan and Missouri).[40]

40 Ohio enacted a hybrid RPS-EERS that includes 12.5 percent of retail sales (MWh) from renewable energy by 2025, with a solar set-aside (0.5 percent). Energy reduction standards are separate. Michigan's RPS replaces a goal for one utility only; it is a 10 percent capacity requirement by 2015. Missouri's RPS is for 15 percent of retail sales by 2021.

- Three jurisdictions accelerated the time to achieve an established RPS or increased the capacity or energy target in an existing RPS (Washington, D.C., Maryland and Massachusetts).[41]
- Three states with an existing RPS set goals beyond their mandates (Maine, California, Hawaii), and one with a renewable goal increased it (Vermont).[42]
- Four states adopted a voluntary RPS or renewable goal (South Dakota, Utah, Kansas and Florida).[43]

In addition to a renewable portfolio standard, some states also have an energy efficiency resource standard (EERS) (see Figure ES-26). An EERS is designed to reduce or flatten electric load growth through energy efficiency (EE) measures. Goals may specify reductions in energy (MWh), demand (MW) or both. At least 18 states include energy efficiency as part of a renewable standard or goal. During 2008, 14 states passed significant energy efficiency legislation or regulations.[44]

Figure ES-26
States with Energy Efficiency Resource Standards, 2008



EE only as part of an RPS law, rule, or goal
EERS by regulation or law (stand-alone)
Voluntary standards (in or out of RPS)
Energy efficiency goal proposed / being studied
Other energy efficiency or demand-side rule or goal

Sources: Derived from ACEEE, EPA, Regulatory Assistance Project, Union of Concerned Scientists, State regulatory and legislative sites; State Efficiency Agency reports; trade press

Transparency Efforts Bear Fruit

The Commission has taken several actions in the past few years to enhance the use of natural gas and electric transmission capacity by reforming the rules by which existing transportation service can be released or reassigned. These actions include removing the price cap on released transportation service and requiring electric transmission service customers to report reassignments of transmission service.

Order No. 712, which became effective July 30, 2008, removed the rate ceiling on short-term capacity releases on interstate natural gas pipelines.[45] The order also modified the capacity release rules to facilitate the use of asset management

41 Washington, D.C., increased its RPS from 11 percent by 2022 to 20 percent by 2020, with solar set-aside (0.4 percent); Maryland increased from 9.5 percent in 2022, with 2 percent solar, to 20 percent by 2022 with (same) solar set-aside (2 percent); and Massachusetts increased its RPS from 4 percent by 2009 with 1 percent subsequent annual increases to 15 percent by 2020.

42 Maine enacted an installed wind goal of 3,000 MW by 2020 (April). California issued an executive order setting a 33 percent by 2020 goal beyond the 20 percent by 2010 mandate (November). Hawaii's Clean Energy Initiative, agreed to by the governor and utilities, set a goal of 40 percent by 2030 of energy from renewables beyond its 20 percent by 2020 goal (January). Vermont increased its goal to 25 percent by 2025; its goal had been that incremental load growth from 2007 to 2012 should come from renewables (March).

43 South Dakota and Utah enacted goals without noncompliance penalties. A memorandum of understanding between the governor of Kansas and Kansas utilities created its goal. Florida's goal, via executive order, is for utilities to produce 20 percent from renewable energy.

44 District of Columbia, Florida, Hawaii, Iowa, Massachusetts, Maryland, Michigan, New Jersey, New Mexico, New York, Pennsylvania, Ohio, Oklahoma, Utah and Vermont.

45 Promotion of a More Efficient Capacity Release Market, Order No. 712, 73 Fed. Reg. 37,058 (June 30, 2008), FERC Stats. & Regs. ¶ 31,271 (2008).

agreements (AMAs), removing certain prohibitions on tying arrangements and bidding.

Commission staff has developed a set of initial observations of the first six months of the Commission's revised capacity release rules. Because of the seasonal nature of the natural gas market, capacity releases during this period were compared to those of previous years during the same six-month time frame. The period covers, primarily, the winter and the months leading up to it. Shorter-term decisions about whether to release capacity for a day or a month are a function of weather conditions, and are therefore as dependent on immediate circumstances as on pricing conditions. LDCs, for example, would be less likely to release capacity in the face of uncertain winter weather. Longer-term decisions to release capacity for a year or more tend to occur at or near the beginning of the gas year in April as a function of long-term planning within the natural gas cycle.

The early experience from the capacity release reforms suggests that there has been relatively little change in capacity release activity. This is partially because the period of study includes the winter and the months leading up to it when shippers are less likely to release capacity in the face of uncertain winter weather.

On the electric side, market participants that had reserved transmission service have been allowed to reassign that service above the tariff rate since Order No. 890 went into effect during the second quarter of 2007.[46] Order No. 890 also requires that electric transmission providers report in their quarterly EQR filings reassignment of TSRs for service reserved under the transmission providers open access transmission tariff. The requirement is designed to promote transparency in transmission markets, similar to the requirement that natural gas pipeline companies post capacity releases on their pipelines.

46 Market participants that have reserved transmission service have been allowed to reassign that service reservation since Order No. 888 initiated the Commission's current electric transmission service regime.

There has historically been relatively little reassignment of electric transmission service. Since the second quarter of 2007, the quantity of transmission service that has been reassigned has increased steadily. This increase in reassignments occurred across almost all dimensions. That is, the number of transmission providers reporting reassignments has increased; the number of TSRs reassigned for each particular duration (e.g, hour, daily, monthly, yearly) has increased; and the capacity (in MWh of service) reassigned has increased. Capacity reassignments occurred throughout the non-RTO markets, with no particular region standing out. The majority of completed TSR reassignments were for less than a day, though on a MWh-basis yearly and monthly reassignments comprise the vast majority of reassignments.

We are unable to fully address the pricing of TSR reassignments because many entities reassigning TSRs failed to report a price

Organization of this Report

The remainder of the report will discuss a number of specific topics in depth. These topics include:

- the physical and financial fundamentals that drove natural gas prices during the year;
- the effect of unconventional gas supplies and liquefied natural gas on future natural gas market dynamics;
- physical and financial electricity trading;
- the cost of new electric generating capacity and the role of demand response and energy efficiency in addressing capacity needs;
- the growth in new natural gas infrastructure and the resulting change in regional gas flows and prices;
- electric capacity auction outcomes; and
- early outcomes from Commission reforms to enhance release and reassignment of natural gas transportation and electric transmission capacity.

Section 1 Natural Gas Markets in 2008

Perhaps the most significant event in U.S. natural gas markets in 2008 was the large swing in prices. Spot prices began 2008 at $7.16/MMBtu, peaked at $13.31/MMBtu on July 3 and then collapsed precipitously, ending the year at $5.71/MMBtu.

While physical fundamentals can explain why natural gas prices rose during the first half of the year, none of the physical fundamentals were extreme enough to explain the high level that natural gas prices reached.

Introduction

Our review of physical fundamentals during the first half of 2008 suggests that supply and demand factors alone cannot explain the 86 percent spike in natural gas prices. Nonetheless, a number of discrete events, which we describe in detail below and summarize in Figure 1, put upward pressure on prices and contributed to the perception of market tightness during the first half of 2008. In the second half of 2008, a number of discrete events put downward pressure on prices and combined to dispel the perception that the natural market was tight.

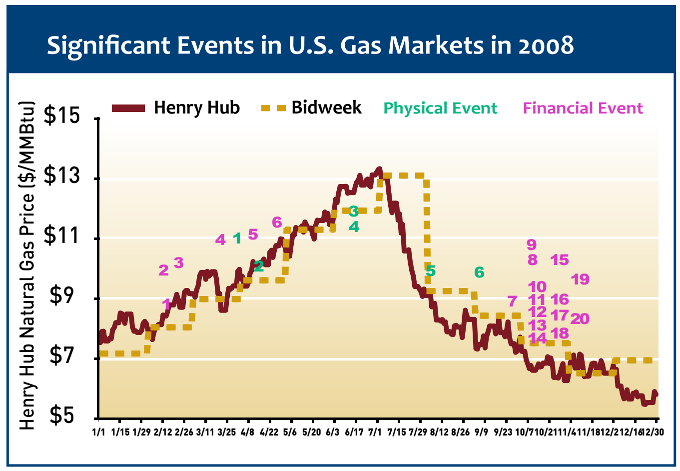
All of the discrete events identified in Figure 1 ultimately have to have acted through the balance of supply and demand. The overall balance of supply and demand through June 2008 was not significantly more bullish than the five-year average balance, except in January. Importantly, though the August surplus was large, there was not an exceptional surplus of gas supply in July when prices started to fall dramatically. Therefore, with the exception of January and August, the overall supply and demand balance was unexceptional.

A review of natural gas markets in 2008 is not complete without an analysis of financial market fundamentals, including the unprecedented increase in financial gas product open interest in 2008 and technical trading strategies that can, in the extreme, induce commodity bubble-like markets outcomes.

The past few years have seen a large influx of passive investments, primarily from institutional investors, into commodities in general. Beginning in the second half of 2007, the fall in equity values and rising commodity prices helped push investors into commodities in search of higher returns.[1] A year later, the financial crisis and subsequent failure of several large trading firms reduced liquidity and likely contributed to the deflation of the gas price.

1 The need to offset declining equity returns through commodity investments is discussed in "Absolute returns in commodity (natural resource) futures investments," Hilary Till and Jodie Gunzberg, Chapter 3, Hedge Fund Investment Management (Elsevier 2006)

Figure 1



Source: Derived from IntercontinentalExchange data.

	2008	Physical Events
1	04-01	Storage falls to a 5-year average
2	04-08	Independence Hub shut down removes 900 MMcfd through June 3rd
3	06-01	Warm temperatures spark high power demand and storage is below 5 year
4	06-01	NOAA forecasts 18 named storms, 10 hurricanes, and 6 intense hurricanes
5	07-30	Independence Hub shuts down through August 7th
6	08-29	Gulf production shut in due to Gustave and Ike

Source: Derived from ICE

	2008	Financial Events
1	02-05	Buying and selling CDOs grind to a halt
2	02-14	UBS confirms sub-prime loss of 18.4 B
3	02-21	Credit Suisse announce a $1.2 B loss for 4Q07
4	03-16	Bear Sterns collapse leads to purchase by JP Morgan
5	04-02	UBS writes down $19 B in losses
6	04-24	Credit Suisse announce a $2.1 B loss for 1Q08

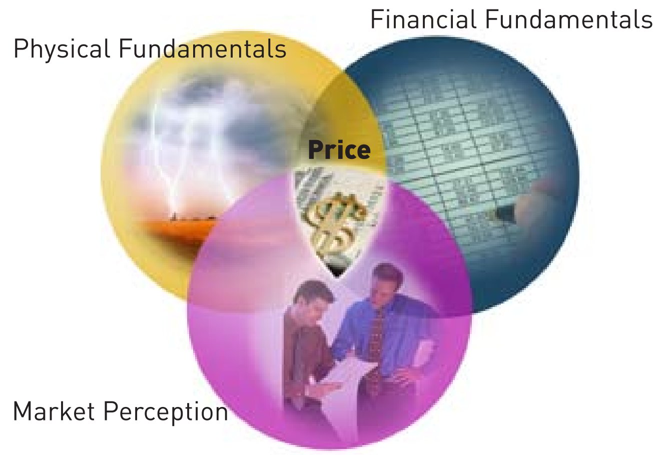
... Table continued on next page

7	09-07	Government seizes Fannie Mae and Freddie Mac
8	09-15	Lehman brothers bankruptcy
9	09-15	Merril Lynch sold to Bank of America
10	09-16	Barclays purchases Lehman
11	09-16	AIG Bailout
12	09-16	Goldman Sachs reports a 70% drop in profits
13	09-16	Japan's Nikkei Index closes 570 points
14	09-16	Constellation stock falls 25%
15	09-18	Central banks aroun the world pump $180 B in the system
16	09-29	Dow Jones falls 777 points, the most ever
17	09-29	Bailout package rejected
18	09-29	Constellation stock falls 40%
19	10-01	U.S. economic bailout passed by the federal government
20	10-13	British government unveils $37 B banking bailout

Source: Derived from ICE

Figure 2

Natural gas prices influenced by physical and financial fundamentals and market perception



In addition to the role of passive money in commodities, we believe that some of the increase in natural gas prices was the result of market perceptions and technical trading strategies. These technical trading strategies include the tendency of commodity traders to trade in a manner that is consistent with the prevailing price movement. Thus, some technical traders buy as the price is moving up and sell as the price is moving down.

Oversight staff believes that the physical and financial markets did not act in isolation during 2008, but rather influenced one another and were influenced by the expectations and perceptions of market participants (Figure 2). This interaction between physical and financial markets likely occurs most of the time. However, during 2008 the end result of this interaction resulted in prices that were substantially out of balance with the underlying physical fundamentals.

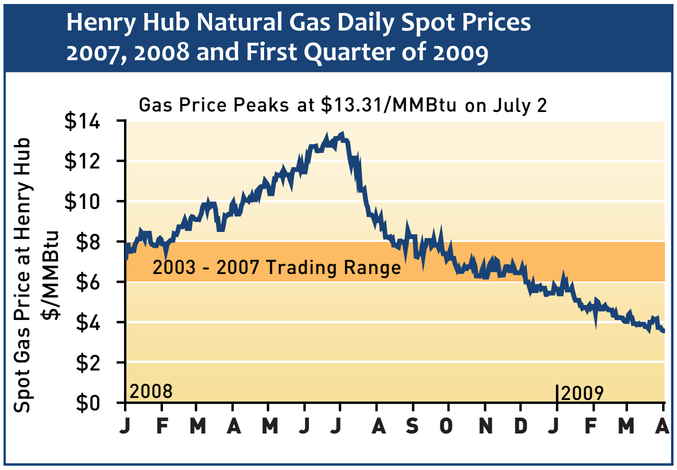
In the remainder of this chapter, we will review in detail the physical and financial fundamentals during 2008.

Physical Fundamentals

Prices

Between 2003 and 2007, spot natural gas prices at the Henry Hub settled into a $6 to $8/MMBtu trading range from which prices deviated only for readily identifiable events, such as the 1-Tcf loss of Gulf Coast production due to hurricanes Katrina and Rita in 2005, or a spike in gas demand due to winter weather. During 2008, spot natural gas prices rose far outside their normal range, peaking at $13.31/MMBtu on July 3. Prices subsequently collapsed back to the $6-to-$8/MMBtu range through the summer and continued to fall below this trading range into 2009 (see Figure 3 on next page).

Figure 3



Source: Derived from IntercontinentalExchange data.

U.S. Supply-Demand Balance

The overall balance of gas supply and demand provides a summary of prevailing fundamentals in the U.S. gas market. The difference between demand and supply is made up by either withdrawals from or injections into gas storage. Overall, the supply-demand balance in 2008 was unexceptional and not particularly strained.

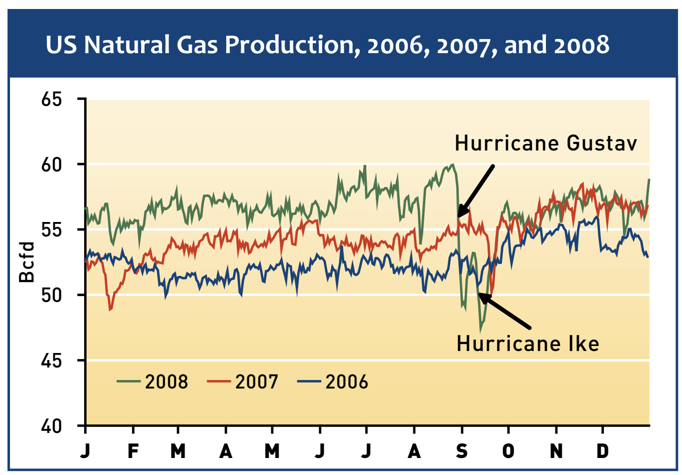
We will summarize key developments in supply and demand individually, and then discuss the overall supply-demand balance.

Supply

Notwithstanding several discrete events, there were no major disruptions to supply during the first half of 2008 that would explain the large increase in prices observed. Total gas supply, composed of domestic production and net imports [both from Canada and in the form of liquefied natural gas (LNG)], is estimated to have been up between 1.3 percent and 3 percent during the first half of 2008 relative to 2007.[2] For the entire year, gas supply is estimated to have been between 0.8 percent and 3.2 percent higher than 2007.[3] The growth in domestic supply was driven by tremendous growth in domestic production, which was partially offset by lower imports, both from Canada and LNG.

EIA reports that gas production grew at a rate of 10.1 percent during the first six months of 2008 and at 7.7 percent for the year. Bentek reports less robust growth of 5.8 percent for the first half of 2008 and 3.6 percent for the year, while CERA reports 9 percent production growth for the first half of 2008 and 7 percent for the year (Figure 4). Growth occurred despite the loss of approximately 900 MMcfd of production through the new Independence Hub, which shut down for repairs between April 8 and June 2, 2008, for a total loss of 46 Bcf.

Figure 4



Source: Derived from Bentek data.

Although the hurricane season was the most active in 64 years with a total of 16 named storms, all the storms occurred after prices had begun falling from their July peak. Prices continued

2 Bentek is at the lower end of supply growth estimates, while CERA and EIA are at the higher end.

3 Bentek estimates 2008 supply growth of 0.85 percent, CERA estimates 2 percent and EIA estimates 3.2 percent.

to fall as the season unfolded, even in the wake of hurricanes Gustav and Ike, which resulted in a loss of almost 7 Bcfd of production in September 2008 – and, according to the Minerals Management Service (MMS), with more than 404 Bcf of production lost as of February 2009. In 2005, hurricanes Katrina and Rita shut in almost 8 Bcfd of production and wellhead prices more than doubled. By comparison, in 2008 the hurricanes had little impact on prices, which declined by more than $2/MMBtu during September and October. Price declines in the face of lost Gulf Coast production indicate the degree to which the surplus in productive capacity loomed over the market in the latter half of 2008.

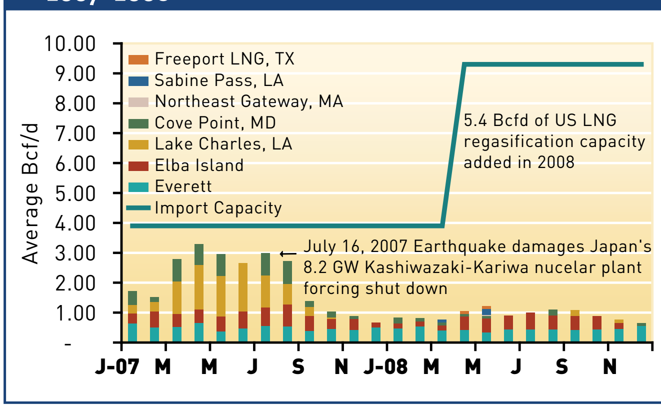
Responding to high prices, the gas rig count climbed through 2007 and the first half of 2008, from 1,425 operating rigs on December 29, 2006, to over 1,600 operating rigs in the final week of August. The rig count fell precipitously as gas prices plunged, ending the year at 1,267 operating rigs.

Offsetting the increase in gas production, net pipeline imports fell by more than 1 Bcfd (12 percent) during 2008 to approximately 7.3 Bcfd. Bentek Energy data show that pipeline-gas imports from Canada into the Midwest were down 12.5 percent on the year at 3.1 Bcfd. Imports of Canadian gas into the West were down 3.9 percent, at 2.6 Bcfd, and imports into the Northeast were down 5.3 percent, at 2.5 Bcfd. At the same time, exports to Mexico surged 15.6 percent in 2008, averaging 900 MMcfd, almost 1.5 percent of total U.S. daily consumption.

The increase in domestic gas production was also partially offset by lower imports of LNG. Average daily LNG imports fell to less than 1 Bcfd in 2008 from 2 Bcfd in 2007. The peak decline was actually much larger, since average monthly LNG sendout (the flow of regasified LNG from the terminal into the pipeline system) peaked at 3.2 Bcfd in April 2007 compared to 1.3 Bcfd in July 2008. Diversion of LNG cargoes from the United States to other ports in the world began in September 2007, when a severe earthquake shut down Japan's 8,200-MW Kashiwazaki-Kariwa nuclear power plant and Japan began bidding away spot LNG cargoes to run gas-fired generation. Diversion of cargoes to Asia intensified in 2008 as oil prices rose to more than $140/bbl. This caused oil-linked LNG spot prices in Asia to rise to over $20/MMBtu, almost twice as high as U.S. gas prices. Delays and disruptions to supply in countries as diverse as Nigeria, Norway and Algeria removed supply from the global market. Spain, the second largest importer of LNG, boosted LNG imports to make up for poor hydroelectric conditions. While most LNG terminals (including Cove Point, Md., Lake Charles, La., and the new terminals) experienced sporadic sendout as a result of these market conditions, two terminals – those at Elba Island, Ga., and Everett, Mass. – maintained sendout levels relatively well because each had long-term contracts with suppliers.

Figure 5

Monthly US LNG Imports and Import Capacity, 2007 -2008

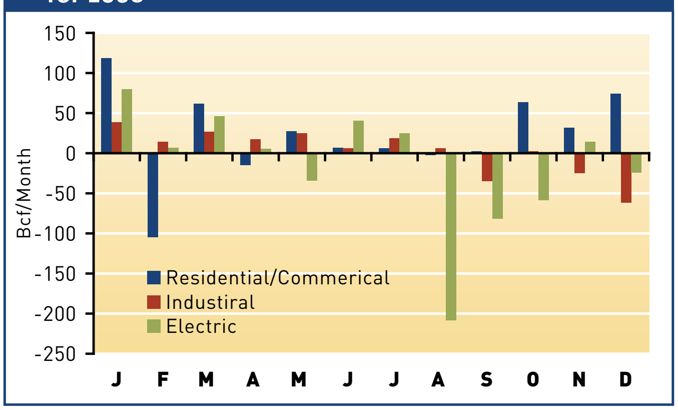


Source: Derived from Waterborne LNG data.

Demand

Notwithstanding several discrete events, demand growth during the first half of 2008 cannot explain the degree of increase in prices. Driven by cold weather in January and associated high residential and commercial gas demand, gas use through June 2008 increased between 2 percent and 3.6 percent relative to 2007.[4] This demand was easily met by a combination of production, imports and withdrawals from storage. In the second half of the year, growth in gas use was cut by low summer demand for power generation and the deepening economic recession, resulting in overall 2008 growth of less than 1 percent, with some estimates suggesting a modest decline.[5] Annual growth in gas consumption in 2008 was much lower than the 6.4 percent growth recorded in 2007.

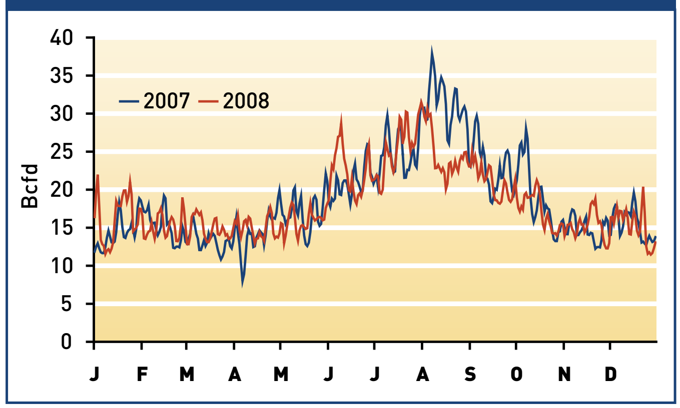
Figure 6



Source: Derived from EIA data.

Weather is one of the key drivers of natural gas consumption. Other than June, which was warmer than normal, national weather was cooler than normal through most of the spring, summer and fall. A very cold January and the cold fall contributed to residential and commercial gas consumption growth of 3 percent in 2008 (see Figure 6). According to the National Weather Service's population-weighted temperatures, cooling degree days in August 2008 were 20 percent less than in August 2007. Due to the unseasonably mild August, power plants consumed 22 percent (nearly 7 Bcfd) less gas than in August 2007 (see Figure 7). From a regional perspective, moderate increases in gas use for power generation in the West and Gulf regions were offset by even larger declines in the Northeast, Southeast and, especially, the Midwest.

Figure 7



Source: Derived from Bentek Energy data.

U.S. industrial output grew 1.4 percent during the first quarter of 2008 compared to the first quarter of 2007. With the onset of recession, U.S. industrial output fell 0.4 percent in the second quarter, 3.2 percent in the third quarter and 6.7 percent in the fourth quarter. Mirroring the decline in industrial output, U.S. industrial gas use grew at a robust 4.4 percent during the first quarter of 2008, slipping to 3.1 percent growth in the second quarter. The deepening recession resulted in declines of 0.6 percent and 4.1 percent, respectively, during the third and fourth quarters, with industrial gas use showing only 0.5 percent growth for the year.

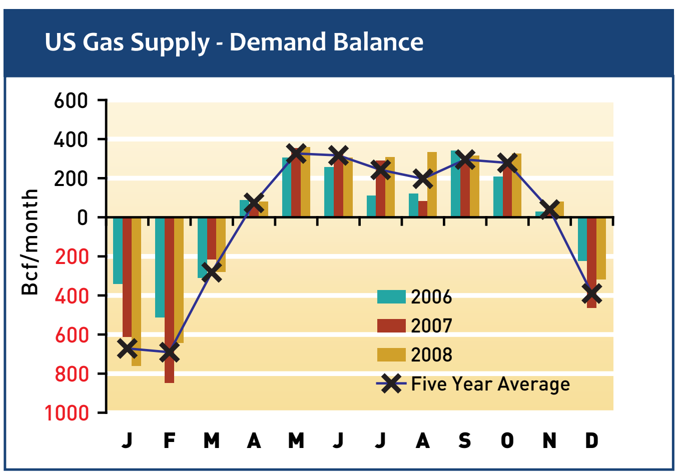
Supply-Demand Balance

4 Bentek is at the lower end of consumption growth estimates, CERA estimates 3 percent growth, and EIA estimates the highest growth

5 For 2008 Bentek estimates an annual decline in consumption of 0.4 percent, EIA estimates no growth, and CERA estimates growth of less than 1 percent.

Supply and demand do not work in isolation. Rather, the overall balance of supply and demand dictates the relative tightness of the natural gas market. Figure 8 illustrates the supply-demand balance for 2006, 2007 and 2008. Other than January 2008, the balance was in line with than the five-year average. Importantly, there was not an exceptional surplus of gas supply in July 2008 when prices started to plunge, although the August surplus was significantly greater than the five-year average because of low summer demand from power generators.

Figure 8

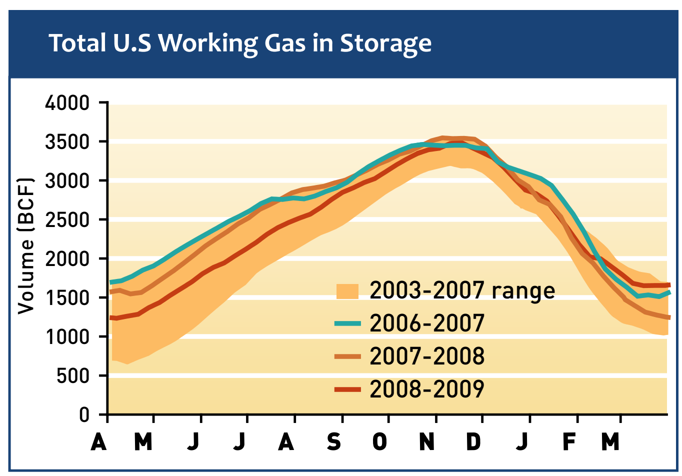


Source: Derived from EIA data.

Storage Remained Close to Five-Year Average for Most of 2008

Gas in storage remained close to the middle of the five-year range for most of 2008. Figure 9 shows that at the beginning of 2008, inventories were well below the January 2007 levels, but near the middle of the five-year range. However, January 2008 was the coldest January in four years, resulting in a record drawdown in storage. As a result, U.S. gas inventories fell significantly behind those in 2006 and 2007, but managed to remain in the middle of the five-year range and above the five-year average. As the winter progressed, storage levels continued to fall relative to the five-year average, reaching the five-year average by the end of March. Between March and June, gas storage was roughly at the five-year average, briefly dipping below during June due to high temperatures and a surge in demand from gas-fired power generation. Oversight staff notes that much of the period of relatively low storage levels occurred in the spring and early summer of 2008, when those injecting gas had the maximum flexibility in their storage choices. As a result, the steep price increase likely caused the low inventories experienced in the first half of 2008.

Figure 9



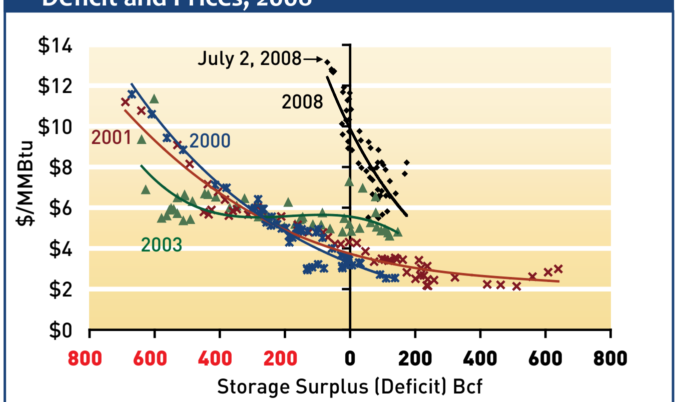
Source: Derived from EIA data.

Inventories began to surpass their five-year average in August at the same time that prices began to fall. As production grew and demand moderated due to the deepening economic recession, storage began to move up to the higher end of the five-year range. By the end of first-quarter 2009, storage had almost recovered to the upper end of the five-year range. Of particular note, storage levels in January 2009 were almost identical to storage levels in January 2008, though prices moved in the opposite direction in 2008 and 2009.

The degree of price pressure from storage is illustrated by Figure 10, which shows the difference between weekly storage and the moving five-year average versus the gas price at the Henry Hub in 2008 $/MMBtu. The years 2000, 2001 and 2003 are illustrated because they indicate historical periods with substantial deficits and high prices. During 2008, storage was at or above the five-year average most of the year. The deficit peaked at only 70 Bcf in early July, compared to deficits 10 times that in previous years. Even so, prices increased to more than $13/MMBtu by July 2008. Higher summer deficits occurred in the summers of 2000 and 2003 without a similar impact on summer gas prices.

Figure 10

Relationship Between Henry Hub Weekly Storage Deficit and Prices, 2008



Source: Derived EIA Weekly Storage Report and ICE data

Financial Fundamentals

Connection Between Physical and Financial Natural Gas Prices

Financial natural gas prices provide a basis for the formation of physical natural gas prices. Prior to growth in the use of natural gas futures, swaps and other derivatives, market participants established short-term natural gas price expectations by assessing physical supply and demand conditions. With the growth of trade in natural gas financial derivatives since the early 1990s, financial markets have played a growing role in the price discovery process. For example, trading on the Globex electronic exchange takes place around the clock, and physical traders will often look at recent prices to help determine their bid-ask values at the beginning of the trading day (8 a.m. on the IntercontinentalExchange [ICE] and 9 a.m. on the New York Mercantile Exchange [Nymex]). This is similar to the way stock traders look at European and Asian stock markets and at stock futures to ascertain U.S. stock price direction at the beginning of each trading day.

The prices of futures, swaps and other financial instruments are now used by physical markets to form price indexes. Likewise, financial markets attempt to determine prices by looking at data on fundamentals that often are not confirmed until well after the fact. This lack of real-time transparency can lead to misperceptions that lead to skewed price signals and prices that can over- or undershoot underlying values based on the physical fundamentals. An example of this occurred in 2008, when many market observers missed the extraordinary growth in unconventional gas production.

Key Financial Fundamentals

The two key financial fundamental drivers of natural gas prices in 2008 were the large influx of passive investments into commodities and technical trading strategies based on trading around the prevailing market momentum.

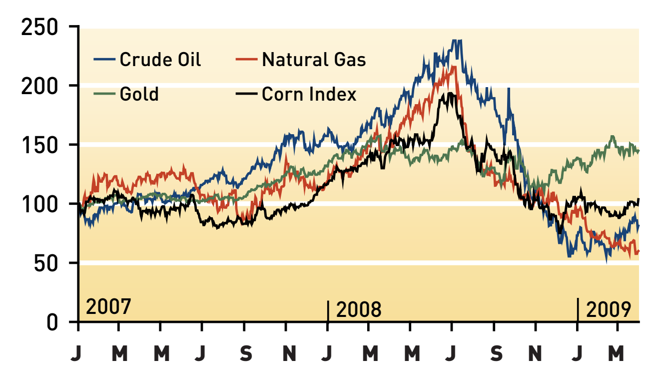
The past few years have seen a large influx of passive investments, primarily from institutional investors, into commodities in general and natural gas in particular through vehicles such as exchange-traded funds (ETFs).[6] In May 2008, Michael Masters, portfolio manager for Masters Capital Management LLC, reported in his testimony before the House Committee on Energy and Commerce that assets allocated to commodity index trading strategies rose from $13 billion at the end of 2003 to $260 billion by March 2008 and that this increase helped drive commodity prices higher. He also reported that natural gas purchases by passive investors in commodity index funds increased from 331 Bcf equivalent at the beginning of 2003 to more than 2,263 Bcf equivalent by the first quarter of 2008, an increase of 1,932 Bcf equivalent.[7]

Passive investment in commodities is not manipulation, nor is it necessarily bad for market outcomes. Passive investors and active speculators can enhance price signals to producers and consumers that energy markets are tight by bidding up prices, in effect magnifying the impact on prices of underlying fundamentals. Such a phenomenon likely contributed to the rapid rise in gas prices and other commodities during the first half of 2008 and the subsequent collapse of commodity prices during the second half of the year.

Figure 11 shows that commodity prices started trending up in unison in late 2007 and peaked in early July 2008. From Jan. 1, 2007, until July 6, 2008, prices of crude oil, natural gas and corn grew 237 percent, 215 percent and 191 percent, respectively, while gold increased by 150 percent. Prices subsequently fell back to Jan. 1, 2007, levels by November 2008 and, by March 31, 2009, commodity prices had fallen to as low as 55 percent below their Jan. 1, 2007, values.

Figure 11

Cross Commodity Price Index (January 1, 2007 = 100)



Source: Derived from Bloomberg Exchange data

In addition to the role of passive money in commodities, we believe that some of the increase in prices was the result of market perceptions and technical trading strategies. These technical trading strategies include the tendency of commodity traders to trade in a manner that is consistent with the prevailing price movement. Thus, some technical traders buy as the price is moving up and sell as the price is moving down. For instance, trader commentary on July 2, the day the natural gas price peaked, expressed this sentiment as

> "the old worn out cliche says it the best; the trend is your friend. The market is still trending higher and will continue to do so until somebody finally says they are going to stop buying it. In futures, we are advising people that they have to hold their nose and continue to buy and sell this thing because we don't know how high it is going to go."[8]

6 The ETF market has grown to over 600 ETFs since their inception in 1993.

7 As a comparison, U.S. gas consumption was 23,157 Bcf in 2008, so passive investment in natural gas via commodity index was almost 10 percent of total consumption.

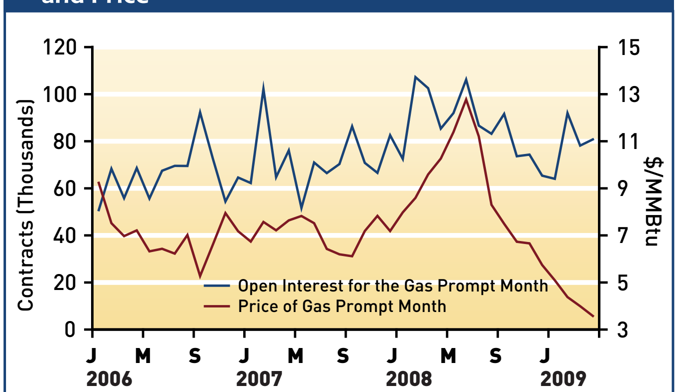
8 *"Broker: 'Trend Is Your Friend' As Futures Edge Above $13.50"*, NGI's Daily Gas Price Index, page 2, July 2, 2008

Similarly, a contemporaneous commentary by a Barclays analyst describes this phenomenon as "momentum trading," stating that "(t)he same trends responsible for increasing bearish sentiment in the financial markets have in many cases opened the door to profits for momentum-based futures traders."[9]

These strategies result in the accumulation of long positions as prices increase and the accumulation of short positions as prices fall. Figure 12 shows that average monthly open interest in the natural gas prompt month climbed 109 percent to 106,000 contracts in summer 2008 from 50,759 contracts in 2006. At the same time, average monthly natural gas prompt prices climbed 38 percent to $12.78/MMBtu in June 2008 from $9.23/MMBtu in 2006. As prompt month gas prices fell to $5.74/MMBtu at the end of the year, open interest fell 25 percent.

Figure 12

Natural Gas Prompt Month Open Interest and Price



Source: Derived from Nymex data

9 http://www.barclayhedge.com/blog/2008_07_01_archive.html

Conclusion

While physical market fundamentals, particularly relatively low gas in storage, explain part of the rise for both futures and spot gas prices, there's no physical explanation for prices in the $13 range. However, the rise in gas prices did coincide with a global increase in many commodity prices, which occurred as large pools of capital flowed into various financial instruments, turning commodities such as natural gas into investment vehicles. Oversight staff believes that it was the upward pressure of financial fundamentals on top of a modest tightening in the supply-and-demand balance for gas in first-half 2008 that explains the path of natural gas prices during the year.

Section 2 Unconventional Natural Gas Supply

The extent to which unconventional natural gas sources are economically recoverable became much more apparent during 2008, fundamentally changing the natural gas markets. In the near-term, a key consideration is whether natural gas production will be able to balance with flagging consumption in a manner that will not lead to an exaggerated boom-bust cycle.

Robust unconventional domestic gas supplies (and increased liquefied natural gas [LNG] imports) creates an environment in which natural gas will no longer be considered a scarce resource, particularly at prices above $5-$6/MMBtu.

The Expanding Natural Gas Resource Base

Recently, the long-term outlook for natural gas supplies in the United States changed dramatically. It was previously assumed that U.S. productive capacity would continue to drop (to 50.1 Bcfd in 2006 from 53.6 Bcfd in 2001) in the face of steep declines in production in the Gulf of Mexico and Lower-48 states. However, recent estimates conclude that 2008 full-year U.S. dry gas production rose 4 Bcfd (7.7 percent) to 56.2 Bcfd from 2007, despite more than 404 Bcf of lost production in the Gulf due to well shut-ins caused by hurricanes Gustav and Ike in 2008.[1] Strong growth in unconventional gas production in East Texas and the Rocky Mountain region, supplemented by new deepwater production in the Gulf of Mexico (e.g., Independence Hub, Atlantis and Thunderhorse) have prompted the reversal of the trend.

More generally, recent technological progress has made unconventional gas economic to develop in sufficient quantities so that unconventional gas plays are now transforming the nation's gas supply picture.[2] Overall, EIA estimates U.S. gas reserves, which consists of gas available from known reservoirs capable of being produced with reasonable certainty under existing economic and operating conditions, were 238 Tcf at the end of 2007, 13 percent more than at year-end 2006 and the highest level in the 31 years

1 Energy Information Administration, Natural Gas Navigator, Dry Gas Production, http://tonto.eia.doe.gov/dnav/ng/ng_prod_sum_dcu_NUS_a.htm.

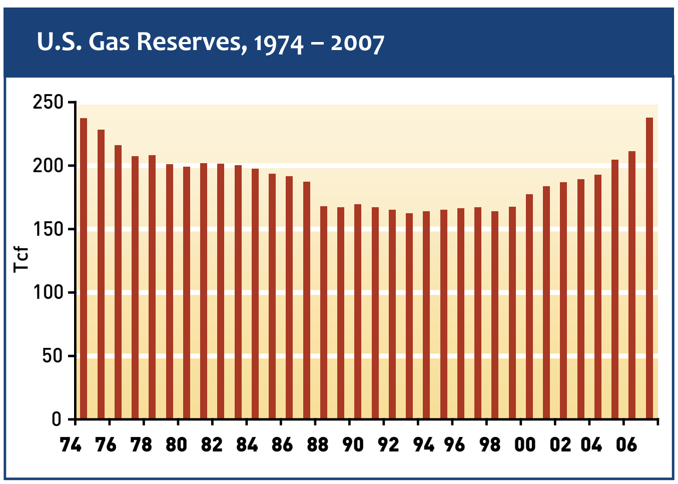
2 A *play* is a set of known or postulated natural gas accumulations sharing similar geologic, geographic and temporal properties, such as source rock, migration pathway, trapping mechanism and hydrocarbon type.

The Geography of Shale Resources

Source: Energy Information Administration, based on data from various published studies. Updated May 29, 2009.

that EIA has published annual reserves data (see Figure 13). EIA attributed the growth principally to the rapid development of unconventional gas resources, including shale, coalbed methane and tight, low-permeability formations. Shale proved reserves, in particular, increased 50 percent in 2007 and now account for about 9 percent of the U.S. total.[3] In 2007, 46 Tcf of reserves were added, twice the level of production, and 2008 could be another banner year.

Figure 13

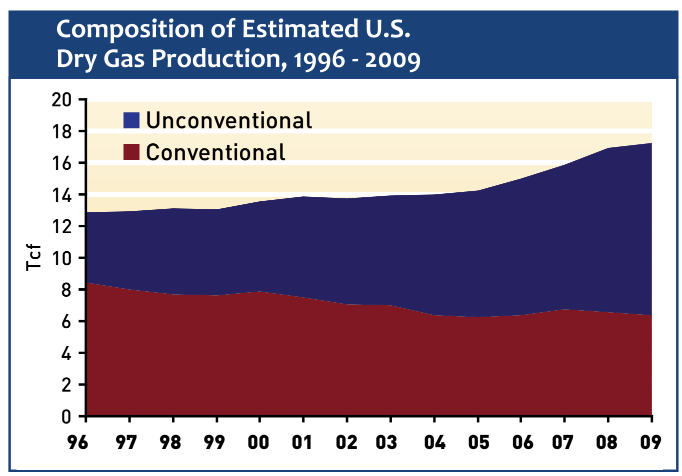


Source: Derived from EIA data.

The supply boom appears sustainable. Technically recoverable gas, a broader estimate than natural gas reserves (which it includes), now exceeds 2,200 Tcf.[4] The Potential Gas Committee (PGC), housed at the Colorado School of Mines, just reported a year-end 2008 estimate of the total available future supply of 2,074 Tcf, an unprecedented biennial increase of 35 percent from its year-end 2006 estimate of 1,532 Tcf and the highest resource estimate in PGC's 44-year history. The 2,074-Tcf supply includes 1,836 Tcf of technically recoverable resources plus the Energy Information Administration's (EIA) assessment of 238 Tcf of proved natural gas reserves. Proved reserves include gas that can reasonably be expected to be recovered in future years from known reservoirs under existing economic and operating conditions. The volumes of both proved reserves and technically recoverable gas have risen with vast increases in unconventional supplies such as shale gas.

The EIA estimates that unconventional gas (shale gas, coalbed methane and tight-sands gas) accounted for 61 percent of Lower-48 onshore production (11 Tcf) in 2008.[5] Cambridge Energy Research Associates (CERA) estimates that unconventional gas production will constitute 66 percent of U.S. productive capacity by 2018.[6] While shale gas plays garner the headlines as the source of incremental supplies going forward, tight-sands gas makes up the bulk of unconventional gas production, about 40% according to the EIA. This growth of unconventional supplies means that natural gas is no longer scarce (see Figure 14).

Figure 14



Source: Derived EIA 2009 Annual Energy Outlook data.

3 U.S. Crude Oil, Natural Gas and Natural Gas Liquids Reserves 2007 Annual Report, Energy Information Administration, February 2009.

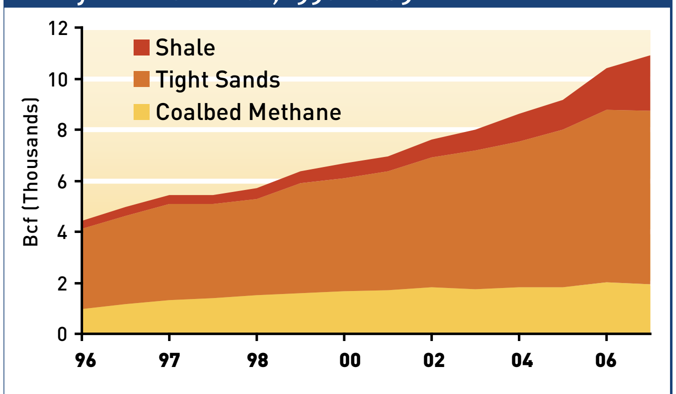
4 North American Natural Gas Supply Assessment, Navigant Consulting, July 4, 2008.

5 Energy Information Administration (EIA), 2009 Annual Energy Outlook.

6 A World of Potential-The Unconventional Revolution of Natural Gas, CERA, September 2008.

Figure 15

Estimated Annual Unconventional Dry Gas Production, 1996 - 2009

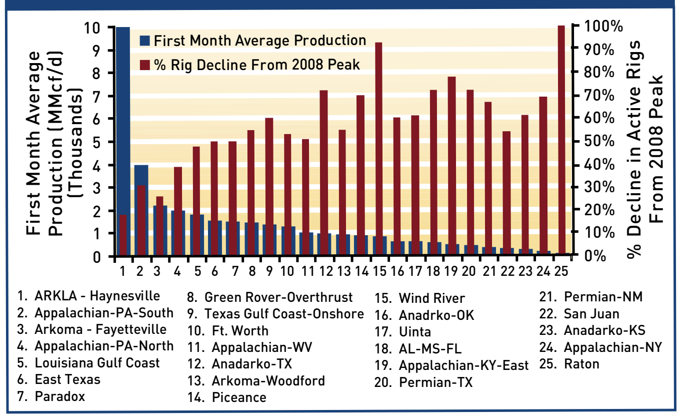


Source: Derived from EIA 2009 Annual Energy Outlook data.

One surprising market phenomenon is the sustained natural gas production in the face of an economic downturn, falling commodity prices and crumbling rotary and horizontal rig counts since September 2008. Production can be maintained due to the nature of unconventional gas wells; favorable economics in unconventional plays, the high initial production rates typical of such wells and the sheer numbers of unconventional wells drilled to exploit each play. In addition, some producers continue to drill wells in more promising unconventional plays like the Haynesville (in east Texas and west Louisiana) and Fayetteville (in Arkansas) shales, but are not completing the normal multistage fracturing process.[7] These producers continue to drill to satisfy lease requirements but cap the well, waiting for higher commodity prices before beginning production.

Figure 16

Unconventional Gas Yields



Source: Derived from Bentek Energy LLC data.

Figure 16 depicts the percentage decline in rig activity from the peak week in 2008 (red bars) and first month average production by supply basin (blue bars).[8] On examination, two issues become apparent. First, many of the new shale plays exhibit outstanding productivity. Producers are reporting initial production rates from 5 MMcfd to 20 MMcfd, much higher than initial production rates from normal conventional wells (1 MMcfd to 3 MMcfd). Second, rig activity in the more productive plays (read superior economics) is declining the least. The data illustrate anecdotal evidence that many producers have reduced drilling activity (especially in the

7 Horizontal drilling (a technical innovation begun in the 1930s) and multistage hydraulic fracturing (begun in the 1950s) are used to maximize production while minimizing both cost and surface disturbance. In this process, a vertical well is drilled several thousand feet down to a shale gas deposit. Then the drill bit is turned 90 degrees to follow the shale horizontally. This lateral wellbore may run 1,000 feet to 6,000 feet (Department of Energy; Deutsche Bank), with fracturing (or frac) stages every 500-700 feet started by puncturing the wellbore, allowing pressurized fracturing fluid (water, chemicals and proppant) to enter the shale and crack it open. As DOE's National Energy Technology Laboratory (NETL) noted in a shale gas primer, "Stages are fractured sequentially beginning with the section at the farthest end of the wellbore, moving uphole as each stage of the treatment is completed until the entire lateral well" has been tapped. There can be eight or more of these stages, which can be completed by a producing company on a schedule to economically maximize its output. This whole process minimizes cost and surface disturbance. "Complete development of a 1-square mile section could require 16 vertical wells each located on a separate well pad," NETL said. "Alternatively, six to eight horizontal wells (potentially more), drilling from only one well pad [using only one rig], could access the same reservoir volume, or even more." Thus, multiwell drilling from one pad and multistage fracturing from each horizontal wellbore can vastly increase natural gas production compared with traditional vertical drilling.

8 Rig activity is through April 17, 2009.

Rockies) and reallocated capital to those plays with high initial production rates even as they reduce overall capital expenditures.[9]

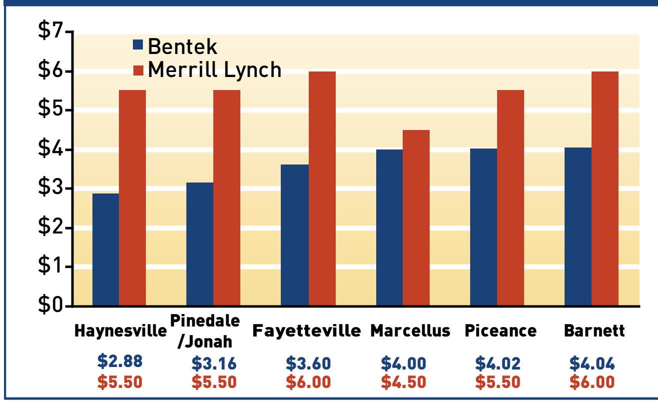
Costs

These unconventional gas plays have become economic (compared to years past) due to innovations in horizontal drilling and fracturing technology. Unfortunately, there is limited information available on the prices needed to cover operating and capital costs, including a reasonable return on investment, and the available estimates are disparate. On the low-end, Bentek Energy LLC recently compiled well-cost data from company reports and presentations to derive breakeven prices for some of the major plays in the range of $3/MMBtu to $5/MMBtu. On the high-end, breakeven price estimates for most producing basins are in the range of $5/MMBtu to $7/MMBtu. Figure 17 illustrates the range in estimates of breakeven prices for many of the major unconventional gas plays in the United States.[10]

Several factors suggest that unconventional production is possible even at current low spot prices.[11] First, although spot prices were below $4/MMBtu at the end of April 2009, forward prices at the Henry Hub were averaging almost $5.50/MMBtu for the November 2009 through March 2010 winter strip. Thus, based on forward prices, most unconventional plays are economic. Second, field services costs and steel costs are falling (down more than 50 percent from last year's highs), as are rig day rates (down about 25 percent), thereby allowing the low-cost plays to remain competitive.

Figure 17

Estimated Breakeven Costs



Source: Derived from Bentek Energy LLC, and Fundamental Shifts for Natural Gas Market, National Association of Regulatory Utility Commissioners Winter Meeting, Merrill Lynch Commodities Inc., February 2009 data.

The long-term viability of unconventional gas appears to be sound, as unconventional plays tend to hold large, long-lived reserves. The production profile generally exhibits high initial production rates, a rapid decline over the first year,[12] followed by a long, low-level production life - in some cases in the vicinity of 20-30 years at very steady flow rates. In addition, though it commonly costs at least $2 million to $3 million to drill a horizontal shale well,[13] they are less risky than conventional wells. Specifically,

9 For example, Bentek Energy said that Questar and EnCana have publicly announced they are quitting operations in some plays in the Rockies and reallocating capital to the Gulf region shale plays; Chesapeake is reducing capital expenditures in the Barnett Shale to concentrate on its Haynesville Shale leases : "Bentek Market Alert: Catch the Wave, Part 3," March 3, 2009.

10 The costs include lease operating expenses, royalty rates, gathering and transportation, severance taxes and finding and development costs, and an assumed internal rate of return of 10 percent.

11 In a recent presentation at the NARUC 2009 Winter Meeting held on Feb. 17, 2009, Tom Price, senior vice president for corporate development at Chesapeake Energy Corp., presented data showing that much of the shale industry would have virtually risk-free finding and development costs of between $1-$3/MMBtu for decades to come .

12 In Tarrant County, Texas, in the Barnett Shale, a vintage 2007 well lost 59 percent of peak production in 12 months. "Natural Gas Weekly Kaleidoscope," Barclays Capital, page 3, Dec. 9, 2008.

13 "Shale Gas Outside of North America-High Potential but Difficult to Realize," CERA, page 4, April 2009. CERA speaking to the cost to drill shale gas wells in North America. Further, CERA stated costs could range as high as $6 million per well.

gas in shale occurs in widespread, continuous layers where virtually any well drilled into the shale will produce gas and much of it in commercial volumes; once a productive area is identified, additional wells can be targeted at the same depth in the formation to maximize production. The producer then concentrates on the correct process, well spacing, fracturing fluid and fracturing technique for the play. Though it took a few years to mature, the spectacular development in the Barnett Shale is a prime example of a successful unconventional drilling program.

Issues Affecting Development

Land use and environmental issues must be addressed to assure effective unconventional gas production. The primary concern to date appears to be related to water use issues. Unconventional gas plays need large amounts of water to fracture the formations. In addition, extraction of coalbed methane produces large volumes of water during the coal formation dewatering process before natural gas can be produced. These are important issues to all stakeholders and could pose significant challenges to further unconventional gas development.

Section 3 Cost of New Generation in 2008

Despite the fact that prices of raw materials needed to build a new power plant plummeted in the latter part of 2008, the cost of building a power plant did not materially fall.

Introduction

As the summer of 2008 approached, Commission staff became concerned that electricity prices for the remainder of the summer and possibly far into the future were increasing rapidly. [1] The outlook for electricity prices increasing into the future was due to both dramatically increasing fuel prices and the growing cost to build new generation. Starting in July, the price of natural gas, oil, steel and copper, along with a slew of other commodities, fell steadily. This drop in commodity prices seemingly reduced the upward pressure on electricity prices. However, despite the fact that the price of many raw materials fell, the price of finished equipment, such as turbines, reactors and boilers, did not follow suit.

In addition, the credit and financial crisis began soon after the crash in commodity prices had commenced. The financial crisis simultaneously raised the cost of capital to fund investment in new generation and reduced the access to capital. Thus, just as one source of pressure (physical construction costs) on long-term electricity prices was seemingly reduced, another source of pressure (financing costs) was growing. Together, this left the total cost of building power generation by the end of 2008 close to where it was in June.

Thus, while forward prices for electricity had fallen by about 50 percent from June to December, primarily due to the fall in fuel prices, the cost of constructing new generation had not materially changed. This leaves open the possibility that future increases in fuel prices could lead to concerns similar to those that arose in June 2008. At the very least, persistent high cost for new generation can lead to uncertainty, and result in delayed additions to the generation fleet.

Companies may be delaying expenditures of any kind that are not pressing due to the increased cost of debt. In addition, investors that expect the cost of new generation to fall further may defer investment in new power generation as they wait for costs to fall further. These types of expectations can have a self-fulfilling nature as market participants defer investment in new generation, which reduces demand for the inputs used in building new generation (i.e., raw materials, major equipment, labor and financing), and thus creates downward pressure on the costs to build new generation.

This uncertainty regarding the cost to build new generating capacity highlights the potential role for demand-side resources to fill the void. This is especially true for demand-side resources with costs that are well below the current estimates of the levelized cost of new thermal generation.

The remainder of this section will review

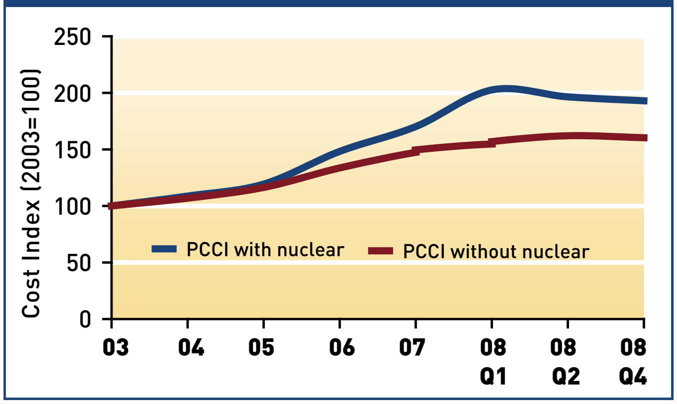
- the dynamics of the physical cost to build new generation;
- the changes in the cost and availability of credit; and
- the potential for demand-side resources to fill the void.

1 FERC, Divison of Energy Market Oversight. "Increasing Costs in the Electric Market." Federal Energy Regulatory Commission, June 19, 2008. http://www.ferc.gov/legal/staff-reports/06-19-08-cost-electric.pdf.

Physical Construction Costs in 2008

Figure 18

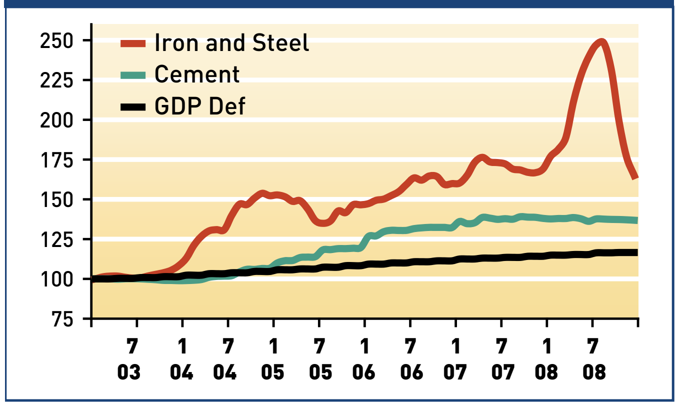
IHS/CERA Power Capital Costs Index



Source: Derived from Cambridge Energy Research Associates (CERA) data.

Figure 19

Primary Raw Materials



Source: Derived from Bureau of Labor statistics website data. Base year adjusted to 2003.

Cambridge Energy Research Associates (CERA) produces the Power Capital Costs Index (PCCI) that tracks the costs of materials, major equipment and construction labor needed to build new power plants.[2] The PCCI nearly doubled from 2003 to mid-2008. Much of this cost increase resulted from elevated costs of raw materials and scarcity in specialized equipment and labor for this type of construction. However, there have been two systemic changes in the economy since mid-2008. First, commodity prices fell substantially, and second, the credit crisis led to reduced access to and high cost of capital. According to the PCCI, the cost of constructing nonnuclear power plants first declined in the fourth quarter of 2008, while the cost of constructing all power plants, including nuclear power generation, first decreased in the third quarter.[3] It is important to note that the PCCI does not include costs associated with financing.

While the nonnuclear PCCI fell only about 1 percent from the third quarter to the fourth quarter of 2008, steel prices fell precipitously - by over 34 percent - from August 2008 to December 2008. Even though steel prices fell dramatically from where they were in August 2008, as of December 2008, they were still 65 percent higher than January 2003 prices.[4] Correspondingly, the non-nuclear PCCI was 60 percent higher than in January 2003. Copper was yet another commodity that experienced a price spike in mid-2008. Copper prices quintupled in nominal value between 2003 and mid-2008, but by the end of 2008, prices had fallen back down and, compared to 2003, had merely doubled.[5] Wages have not

2 Cambridge Energy Research Associates, *Capital Costs Analysis Forum – Power: North America: Impacts of the Financial Turmoil*, March 6, 2009.

3 On March 19, 2009, CERA reported a drop of 3 percent in the cost of constructing all new power plants from the last quarter of 2008 until the first quarter of 2009, and a drop of 6 percent in the cost of constructing non-nuclear power plants. CERA attributes this further decline to the persistence of lower steel, copper and petroleum prices, even as equipment prices remain sticky. This was reported at the 2009 Spring CERA Executive Roundtable in *CCAF-P Market and Index Forecasts* (March 19, 2009) Slide 27 entitled *"IHS CERA PCCI: With and Without Nuclear Update".*

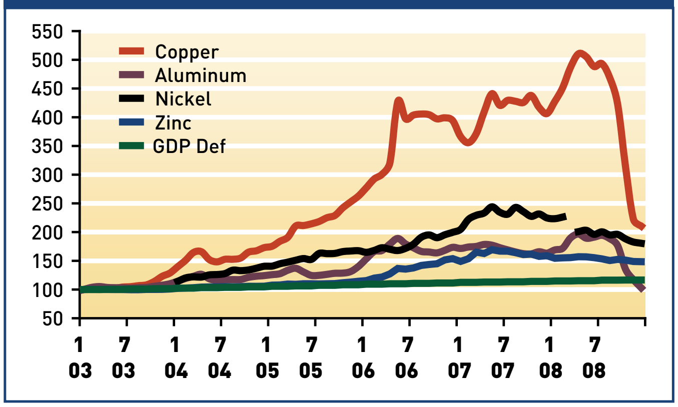
4 U.S. Bureau of Labor Statistics. *Iron and Steel: WPU101.* ONLINE. 2009, http://www.bls.gov/data/.

5 U.S. Bureau of Labor Statistics. *Copper: WPU102301.* ONLINE. 2009, http://www.bls.gov/data/.

noticeably dropped since the June 2008 presentation.[6] One reason for this may be that the recession resulted in more layoffs than wage reductions.

Figure 20

Secondary Raw Materials



Source: Derived from Bureau of Labor statistics website data. Base year adjusted to 2003.

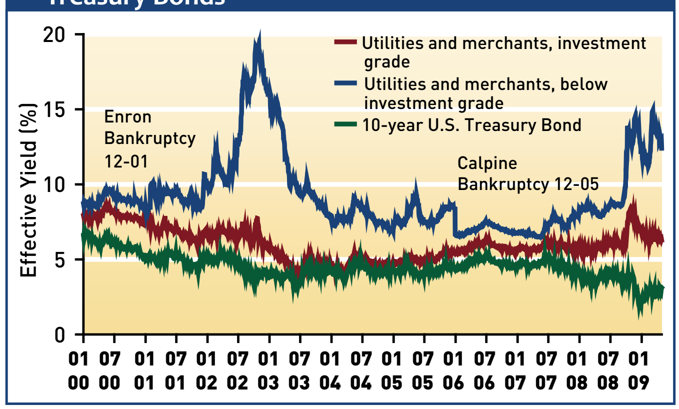
While the price of raw materials fell in the second half of 2008, the prices of finished equipment, such as turbines, reactors and boilers, did not significantly decline. There are several reasons that the lower prices of raw materials did not result in noticeably lower prices for finished equipment. First, there was a significant backlog of orders, and because manufacturers of these finished products were working through those backlogs, they were not seeking to book new business and lock in potentially disadvantageous prices.[7] Second, it is possible that manufacturers made concessions, such as promotional discounts, that would camouflage declining prices.

Credit Crisis

For years, the majority of electric utilities have moved from having an A credit rating to having a BBB credit rating.[8] This trend continued in 2008. At the beginning of the credit crisis, when credit essentially froze, yields skyrocketed. While yields did come down by over a hundred basis points in late 2008, they remained elevated above their pre-crisis level. Specifically, even though nominal yields declined in December, the credit spread (the difference between corporate bonds and a 10-year treasury bond) peaked in December reaching close to 5 percent for investment grade utilities and 11.9 percent for noninvestment grade.

Figure 21

Yields of Utilities, Merchants, and Ten Year Treasury Bonds



Source: Derived from Derived from Merrill Lynch Index U.S. Corporates, Gas and Electric Utilities and Bloomberg data.

6 U.S. Bureau of Labor Statistics. *Avg. Hourly Earnings of Utility Workers: CES4422000008 and Avg. Hourly Earnings of Construction Workers: CES2000000008.* ONLINE. 2009. Available: http://www.bls.gov/data/.

7 Cambridge Energy Research Associates, *Capital Costs Analysis Forum – Power: North America: Impacts of the Financial Turmoil,* March 6, 2009, pages 1, 5-7. Verified by staff conversations with various market participants.

8 Edison Electric Institute, *The Financial Crisis and Its Impact On the Electric Utility Industry,* February 2009, pages 10-11

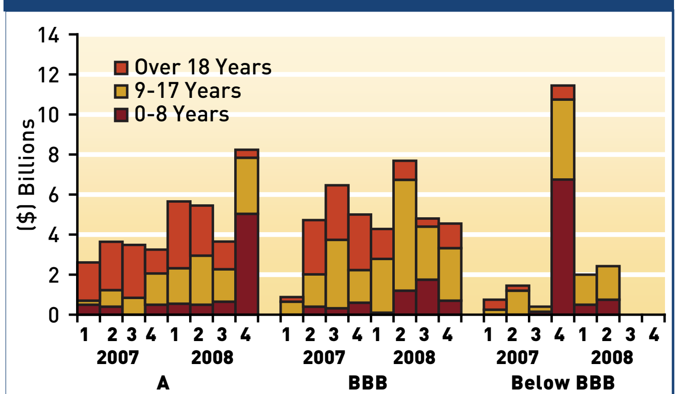
Bank of America/Merrill Lynch, *Wall Street Turmoil: Outlook for 2009 and Implications for Utilities and Regulators,* February 17, 2009, Slide14. Presented at the 2009 NARUC Winter Committee Meetings in Washington, D.C.

Potentially due to the increase in yield required to issue debt, the tenor of debt in the energy sector moved toward shorter term rather than longer term. Figure 22 illustrates that borrowing was down in the 3Q08 across all rating classifications. In the 4Q08, borrowing for A-rated utilities increased, but for shorter tenors. In addition, utilities with lower ratings had reduced access to debt markets. According to Paul Bowers, Southern Co.'s chief financial office,

> "Some companies with lower credit ratings have not been able to access commercial paper or other short-term credit markets, further exacerbating the impact of the credit crunch. In addition to this increased cost of debt, the availability and cost of credit from banks has been even more severely impacted, due to their financial troubles. This is important, since many lower-rated utilities rely on banks, rather than capital markets, especially for short-term debt financing."[9]

Figure 22

Amount of Debt Issued (Utilities)



Source: Derived from Bloomberg data.

9 Testimony of Paul Bowers, Docket No. AD09-2-000, January 13, 2009, page 4.

Energy Efficiency

As power plant investments are delayed and costs for building new generation remain elevated, demand-side resources have become an increasingly integral role in managing reserve margins. Most analysts agree that the first round of energy efficiency is the least-cost solution. The urgency to adopt this least-cost solution is compounded because the longer energy efficiency is delayed, the lower its potential benefits and higher its potential costs. Building energy efficiency into a product initially is much cheaper than later retrofitting or replacing the good with a more energy efficient good down the road.[10]

There are differing estimates of the potential costs and benefits of energy efficiency. Assuming energy efficiency is not delayed or obstructed, McKinsey & Company estimated that energy efficiency has the potential to offset up to 85 percent of the incremental increase of load by 2030 (see Figure 23 on next page), which translates into about 1,292 TWh. McKinsey's estimates include the assumption that barriers to incorporating energy efficiency are overcome.[11] A more conservative estimate by Electric Power Research Institute (EPRI) estimated the reduction of load due to energy efficiency to be between 398 and 544 TWh, 8.2 percent of projected consumption by 2030.[12] EPRI also estimated that the levelized cost for energy efficiency measures to meet these potential reductions by 2030 is 3.22¢ per kWh.[13] California Energy Commission staff stated that levelized costs for the

10 McKinsey & Company, *Reducing U.S. Greenhouse Gas Emissions: How Much at What Costs?*, December 2007, pages 69-70.

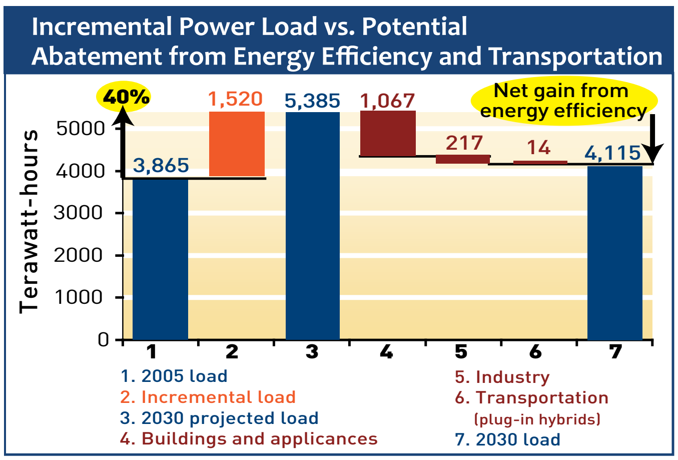
11 Ibid., pages XV, 28-30, 69-70.

12 *Assessment of Potential from Energy Efficiency and Demand Response Programs in the U.S.: (2010-2030).* EPRI, Palo Alto, CA: 2009. 1016987, January 2009, pages XX.

13 Ibid., pages 6-2.

energy efficiency programs in all sectors reached a low of a little over 1.1¢ per kWh in 2004.[14] Thus the cost of achieving the level of energy efficiency estimated by EPRI is low when compared to the cost of a new typical combined cycle gas turbine, which has levelized costs in the range from 7.3 to 10¢ per kWh.[15]

Figure 23



Source: Derived from EIA Energy Outlook (2007) "Reference case;" McKinsey analysis data.

Conclusion

As the summer of 2008 approached, Commission staff became concerned that electricity prices for the remainder of the summer and possibly far into the future were increasing rapidly.[16]

In addition, as the cost of key building inputs fell, uncertainty permeated credit markets, freezing borrowing and lending. As the credit markets started to open, yields skyrocketed for those that were able to obtain credit. As investors defer building power plants until the costs of doing so falls, demand-side resources can become a more integral part of the resource adequacy equation.

14 California Energy Commission Staff Paper, *Funding and Savings for Energy Efficiency Programs For Program Years 2000 Through 2004,* August 2005, page 14.

15 Lazard Ltd, *Levelized Cost of Energy Analysis - Version 2.0,* Presented at the 2008 NARUC Summer Committee Meetings in Portland Ore., June 2008, http://www.narucmeetings.org/Presentations/2008 percent20EMP percent20Levelized percent20Cost percent20of percent20Energy percent20- percent20Master percent20June percent202008 percent20(2).pdf.

16 FERC, Division of Energy Market Oversight. "Increasing Costs in the Electric Market." *Federal Energy Regulatory Commission.*, June 19, 2008. http://www.ferc.gov/legal/staff-reports/06-19-08-cost-electric.pdf

Section 4 Physical and Financial Bilateral Electricity Trading

During 2008, financial products played a growing role in electricity markets. This prominence occurred as the volume of physical electricity trading continued a multiyear decline, led by reduced activity from financial institutions and energy marketers.

Bilateral Trading 2008 Highlights

In addition to these overarching trends, there were important regional differences in electricity trading, to the point that one can argue that there were three distinct wholesale markets in the United States. In the Northeast and Upper Midwest, physical trading took place primarily through centralized electricity markets run by regional transmission organizations (RTOs). Financial electricity trading ranged from moderate to robust in these markets. In the Southeast, there was little to no financial electricity trading, and physical trading was conducted bilaterally. In the West, the only RTO market was California ISO's real-time market, so most physical trading was conducted bilaterally. However, in contrast to the Southeast, there was a substantial amount of financial electricity trading in the West.

While the volume of financial power traded increased in 2008 as a whole, there were starkly different trading patterns before and after the financial crisis. Financial electricity volumes grew substantially relative to 2007 during the first seven months of 2008. Financial electricity volumes fell in August relative to 2007; by October, uncertainties in financial markets contributed to decreased financial power trading, as the last three months in 2008 all traded below 2007 levels. The volume of longer-term financial electricity products fell significantly during the fourth quarter, likely because credit tightening made it more difficult to meet credit requirements necessary for longer term deals.

Bilateral Trading Mechanics and Reporting

Physical buyers and sellers can transact in a number of ways. Buyers and sellers use bilateral phone calls or instant messages, voice-broker services and electronic platforms, among other means, to find counterparties. Regardless of the manner by which buyers and sellers transact business, Commission-jurisdictional sellers must report sales transactions to the Commission through the Electric Quarterly Report (EQR). Sales by public power entities and federal power agencies such as Bonneville Power Administration are not reported to the Commission.

Financial buyers and sellers can also transact in a number of ways, including using voice brokers and electronic platforms such as the IntercontinentalExchange (ICE). Financial power transacted on ICE is typically traded as a financial swap, meaning that a buyer pays a fixed price for power and receives not power, but a floating price determined by a specific index. This index is commonly derived from physical electricity market outcomes, e.g., RTO market results (day-ahead or real-time LMP averages) or next-day physical delivery prices reported to index developers.

Buyers and sellers of financial electricity products are not required to report transaction-level data or aggregate holdings to the Commission, though Commission staff can obtain information about open interest in the financial contracts traded on ICE. As a result, we can report on trends in the types and quantity of financial products traded, but we are unable to address trading trends by individual market participants or participant class.[1]

1 While financial electricity trading occurs off the ICE trading platform and EQR volumes do not include physical sales by entities that are not jurisdictional to FERC, we nonetheless believe comparisons based on ICE and EQR volumes provide important insights into underlying patterns.

Continued Wholesale Power Declines

The volume of physical electricity sales reported in the EQR has declined consistently over the past four years. Specifically, physical wholesale power volumes have fallen every quarter, relative to the previous year, since 4Q04, excluding 1Q08. In 2008, EQR reported volumes declined 9 percent from 2007 levels, after having fallen 13 percent in 2007 and 6 percent in 2006. This decline occurred across the United States, but relatively more in California, New England and ReliablilityFirst NERC subregions (see Table 1). Changes in sales volumes in those NERC subregions that did show growth (Florida Reliability Coordinating Council, Gateway and Rocky Mountain Power Area) can be attributed to individual company behavior changes and do not appear to represent systemic increases in activity.[2]

2 In FRCC, Southern Company reported 1.55 TWh in electricity sales during 2007 through EQR and 13.11 TWh in 2008. In Gateway, Ameren reported 100.95 TWh in 2007 and 188.54 TWh in 2008. In RMPA, Black Hills Corp reported 1.38 TWh in 2007 and 2.77 TWh in 2008 while Calpine Corp. reported 1.36 TWh in 2007 and 4.52 TWh in 2008.

Exit of Financial Institutions, Marketers Drives EQR Volumes Down

Focusing on the types of entities selling power can provide clues into understanding why physical wholesale power volumes are decreasing. After classifying entities that report wholesale power sales to EQR into three different classifications (financial/marketer (F/M), independent power producer (IPP) and utility),[3] one can clearly see that reduced activity by financial/marketing companies has driven the decline in EQR-reported sales (see Figure 1, next page). Specifically, decreases in wholesale power sales by financial/marketing companies has accounted for 78% of total EQR-reported sales declines since 2005, when the decline in EQR-reported sales started.

3 Business sector classifications from Ventyx. Financial/marketer (F/M) indicates physical electricity player with no generation assets, independent power producer (IPP) is a nonutility generator and utility is a utility generator. Business sector classifications are applied to the reported seller, not the holding company level.

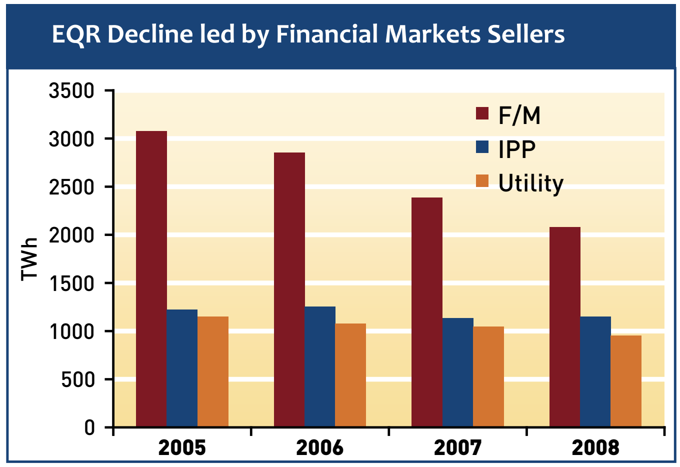
Table 1 EQR Reported Sales by NERC Sub Region in TWh (2008 vs. 2007)

	NERC Sub Region	2008	2007	Δ (TWh)	% Growth
Eastern RTOs	Midwest Reliability Organization	222	233	-11	-5%
	New England	351	468	-116	-25%
	New York	177	183	-6	-3%
	ReliabilityFirst	1578	1727	-148	-9%
Southeast States	Central (TVA)	15	18	-3	-17%
	Delta (Entergy)	92	121	-30	-24%
	Florida Reliability Coordinating Council	30	16	13	84%
	Gateway	223	138	86	62%
	Southeastern (Southern)	125	123	3	2%
	Southwest Power Pool	69	69	0	0%
	Virginia Carolinas Reliability Agreement	34	32	2	6%
Western States	Arizona / New Mexico / Southern Nevada	194	214	-20	-9%
	California	520	692	-172	-25%
	Northwest Powerpool	321	325	-4	-1%
	Rocky Mountain Power Area	22	16	6	39%

Source: Derived from Electric Quarterly Report data.

The reduction in physical sales by financial/marketer companies has been particularly noticeable in the ReliabilityFirst, New England and California NERC subregions (see Table 2). These are areas with either well-established centralized wholesale electricity markets (ReliabilityFirst, New England) or robust financial electricity markets (ReliabilityFirst, California). Therefore, it appears that traders that do not own physical generation are gravitating away from physical sales and to financial electricity trading. In parts of the Southeast, notably the Southeastern (Southern) NERC subregion, financial/marketer companies increased power wholesales in 2008 by over 60 percent since 2005; this was driven largely by Constellation's increased activity in the Southeast.

Figure 24



Source: Derived from from Electric Quarterly Report data.

Table 2
Physical Electricy Sales by Financial Institutions and Energy Marketers by NERC Subregion in TWh (2008 vs. 2005)

	NERC Subregion	2008	2005	Δ (TWh)	% Growth
Eastern RTOs	Midwest Reliability Organization	90	118	-28	-24%
	New England	196	423	-227	-54%
	New York	79	55	24	44%
	ReliabilityFirst	590	1,283	-693	-54%
Southeast States	Central (TVA)	9	5	4	67%
	Delta (Entergy)	40	37	3	9%
	Florida Reliability Coordinating Council	4	3	0	7%
	Gateway	35	33	1	4%
	Southeastern (Southern)	73	45	28	62%
	Southwest Power Pool	10	16	-5	-34%
	Virginia Carolinas Reliability Agreement	17	8	9	116%
Western States	Arizona / New Mexico / Southern Nevada	135	131	4	3%
	California	404	682	-278	-41%
	Northwest Powerpool	221	198	23	12%
	Rocky Mountain Power Area	2	1	1	195%

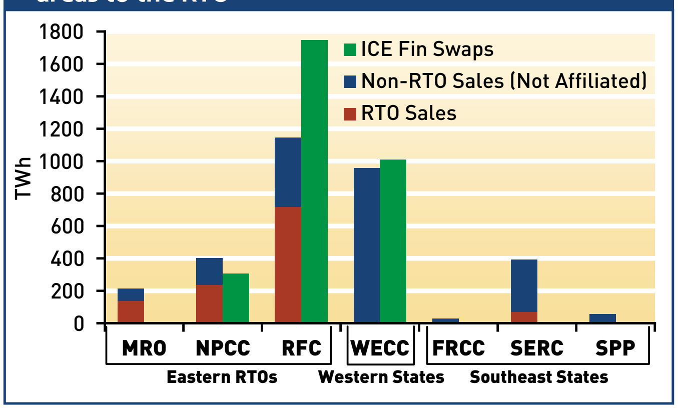
Source: Derived from Electric Quarterly Report data

Regional Characteristics of Wholesale Power Trading

A review of physical and financial trading suggests that there are three distinct wholesale markets in the United States (see Figure 25). In the Northeast and Upper Midwest, physical trading takes place primarily through centralized electricity markets run by regional transmission organizations (RTOs) with Day-2 markets.[4] Financial electricity trading ranges from moderate to robust in these markets. In the Southeast, there is little to no financial electricity trading, and physical trading is conducted bilaterally. In the West, the only RTO market was California ISO's real-time market, so most physical trading was conducted bilaterally. However, in contrast to the Southeast, there was a substantial amount of financial electricity trading in the West.

Figure 25

Majority of Sales in Eastern RTO areas to the RTO



Source: Derived from Electric Quarterly Report and IntercontinentalExchange data.

4 "Day-2 markets" refers to those RTOs with both day-ahead and real-time electricity markets. In 2008, this included ISO-NE, MISO, NYISO and PJM. In 2008, neither CAISO nor SPP administered a day-ahead energy market.

Eastern RTOs

In the region that comprises the eastern RTOs, the majority of EQR-reported wholesale power sales are into the RTO markets. Figure 25 shows this relationship well, as ReliabilityFirst (RFC), Northeast Power Coordination Council (NPCC) and Midwest Reliability Organization (MRO) NERC regions form a close geographic proxy to eastern RTOs. About 60 percent of sales (excluding sales to affiliates) were made into the RTO markets. Sales to affiliated entities are often characterized by generation arms of a company handing electricity to retail arms to serve load or marketing arms for resale; as a result we discount sales to affiliates to some degree.[5]

No category of entity dominates physical trading in the eastern RTOs (see Figure 25). In RFC, financial marketers, IPPs and utilities each made about a third of the physical sales reported to EQR. In MRO, on the other hand, IPPs played a small role in the physical market, having made around 16 percent of all sales reported to EQR, while utilities made 46 percent of physical sales. In contrast, utilities made relatively few sales in NPCC, with less than 13 percent of the physical sales volume. Financial marketers were the largest seller group in NPCC, with 61 percent of the sales.

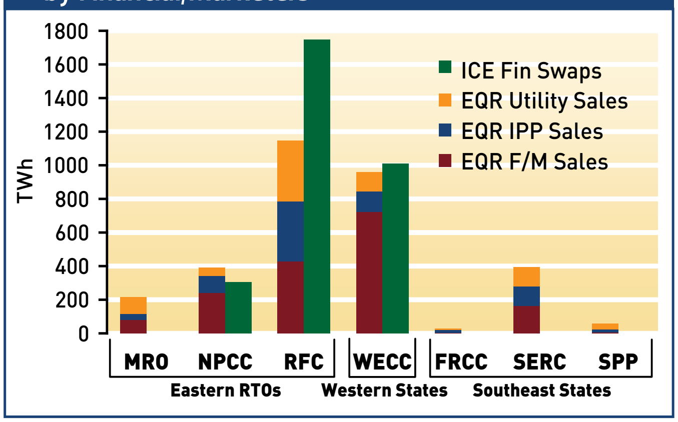
The variation across regions was driven in part by the degree to which the states in the region restructured and have retail choice. For instance, all of the states in NPCC except for

5 Mirant's wholesale power activities in PJM provide a good example of an affiliated sale. Specifically, in 3Q08, Mirant's generation assets in PJM produced a reported 4.29 TWh of electricity sales in the EQR. That entire 4.29 TWh was then sold to Mirant's marketing arm, Mirant Energy Trading LLC, which sold the same amount of energy to PJM. If one added up Mirant's entire 3Q08 sales in PJM, the total would be 8.58 TWh. This number is twice the amount of electricity generated by Mirant in PJM during 3Q08, indicating the necessity to discount sales to affiliated entities in this case. CEMS data confirms that Mirant sold its entire output at Chalk Point, Morgantown, Potamac River and Dickerson into wholesale markets.

Vermont have restructured and offer retail choice.[6] On the other hand, none of the states in MRO have restructured. RFC is a mixed bag, with Delaware, Illinois, Michigan, Maryland, New Jersey, Ohio and Pennsylvania restructured and Indiana, Kentucky and West Virginia still traditionally organized.

Figure 26

WECC Power Sales Dominated by Financial/Marketers



Source: Derived from Electric Quarterly Report and IntercontinentalExchange data.

There is some variation in the level of financial electricity trading across the eastern RTOs. In RFC, the volume of financial electricity traded on ICE surpassed the level of physical sales of electricity. In NPCC (roughly NYISO and ISO-NE), financial electricity volumes were about 76 percent of the volume of physical trading. In MRO, there was little financial trading. These differences are partially attributable to the maturity of the RTO markets in each region, with the Midwest ISO (located in MRO) being the youngest Day-2 RTO market.

Western States

Physical sales in western states (here represented by the Western Electricity Coordination Council (WECC) NERC region) were almost entirely bilateral sales, with a small amount sold into the California ISO's real-time market. The volume of financial sales on ICE was roughly as large as physical sales. ICE lists financial electricity products at a number of locations in the West, including SP-15, Mid-Columbia, Palo Verde and NP-15, along with a number of other smaller-volume locations.

Physical sales in WECC were dominated by financial/marketing companies. During 2008, 72 percent of total wholesale power was sold by financial/marketing companies, well above other regions (see Figure 26). This pattern remains consistent across all NERC subregions in WECC[7], except in Rocky Mountain Power Area (RMPA), which accounted for less than 2 percent of WECC sales in 2008. Trading in the western states differs from the rest of the country as financial players are very active in the physical markets, despite the fact that there is a robust financial electricity market. One possible explanation is that financial players and energy marketers are providing the trade coordination role provided by eastern RTOs. That said, physical sales reported through EQR in the three largest western pricing hubs (SP-15, Mid-Columbia and Palo Verde) continued a multiyear decline, as discussed above. These pricing zones are also the largest financial electricity markets in the West. Some smaller pricing hubs with relatively little financial trading activity, (NP-15, California-Oregon border and Mead) had modestly higher physical volumes in 2008.

Barclays's electricity sales and purchases during 3Q08 provide a good example of financial institution/marketer activities. Barclays was the third-largest electricity wholesaler even

6 Energy Information Administration, Electric Restructuring by State, http://www.eia.doe.gov/cneaf/electricity/page/restructuring/restructure_elect.html

7 California (CA), Arizona/New Mexico/Southern Nevada (AZNMSNV) and Northwest Powerpool (NWPP)

though it owns no electricity generation assets.[8] Notably, the top five companies Barclays purchased electricity from and sold electricity to were all also financial/marketer companies.[9] Specifically, 71 percent of Barclays electricity purchases were from five financial/marketer companies;[10] while 69 percent of Barclay PLC's energy sales were to five financial marketer companies.[11]

Southeast States

Virtually all the physical sales in the Southeast were consummated bilaterally. The NERC regions Florida Reliability Coordinating Council (FRCC), Southeastern Electric Reliability Council (SERC) and Southwest Power Pool (SPP) provide an approximate geographical proxy for this area. Sales reported in the EQR during 2008 were dominated by IPPs and traditional utility sellers, with some important differences within the region (see Figure 26). In both FRCC and SPP, financial/marketer sales accounted for less than 15 percent of total wholesale power transactions in 2008.

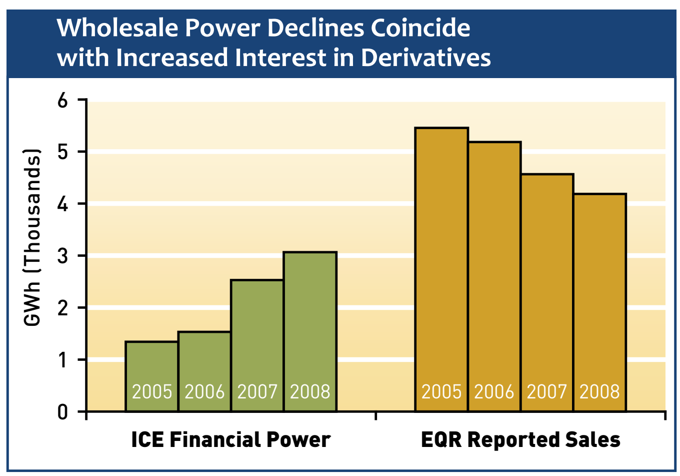
In contrast, sales by financial/marketer sellers in SERC accounted for 35 percent of total sales. In addition, financial institutions and marketers had an even larger presence in some areas within SERC. For instance, the financial/marketer presence in the Southeast (SOCO) was particularly high (over 57 percent of total sales). The large presence of financial/marketer in SOCO was driven by Constellation Energy Commodities Group's activities, which was the largest financial/marketer seller in SOCO with 41 percent of total financial/marketer sales. While Constellation does not own generation in SOCO, it does have several multiyear tolling agreements with generating units in the region.

Interest in financial power products in the Southeast is weak, as ICE does not currently provide a financial-swap product in FRCC, SERC or SPP.

Growing Prominence of Financial Electricity Products

Financial power volumes traded on ICE have grown each year since at least 2005, while physical power volumes traded as reported in EQR have declined each year since 2005 (Figure 27).

Figure 27



Source: Derived from from Electric Quarterly Report and IntercontinentalExchange data.

During 2008, financial power volumes traded on ICE grew 21 percent, surpassing 3,050 TWh. Yearly trading volume records were set at nearly every trading hub, including PJM West, Mid-Columbia, NP-15, SP-15, NYISO Zone G, Nepool and Palo Verde. Increases at western hubs alone accounted

8 Neither Barclays PLC nor any of its subsidiaries owns electricity generation assets ,according to Bloomberg data.

9 All figures based only on transactions reported to EQR.

10 Morgan Stanley (33 percent), RBS (23 percent), Goldman Sachs (7 percent), Citigroup (6 percent) and JP Morgan Chase (includes BearEnergy) (3 percent)

11 Morgan Stanley (37 percent), RBS (17 percent), Goldman Sachs (6 percent), Royal Dutch Shell (includes Coral Power LLC) (5 percent) and Citigroup (4 percent)

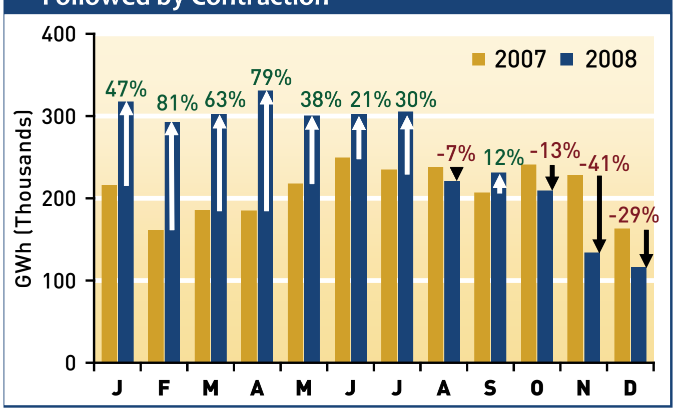
for more than 75 percent of the growth in financial power on ICE. This growth was most noticeable at SP-15 and Mid-Columbia, the second- and third-most actively traded hubs on ICE.

While financial power traded on ICE increased 21 percent in 2008, it is misleading to look at 2008 in aggregate. Instead, it is important to separate increases through July from later financial crisis-related decreases.

The Rise

Financial power began the year with spectacular gains in volume relative to 2007. Volumes during the first seven months were 48 percent higher than the same months in 2007 (see Figure 28). Volumes in February and April alone were 80 percent higher than 2007 levels. This rate of growth sets the standard against which to measure the remainder of the year.

Figure 28



Source: Derived from IntercontinentalExchange data.

The Fall

Significant downturns in financial trading volume first appeared at the most actively traded hub, PJM West (52 percent of total financial power on ICE) in August. Rebounds in September trading, the same month Lehman Brothers filed for bankruptcy and Bank of America agreed to acquire Merrell Lynch, could stem from companies unwinding or closing financial power positions. In addition, the 12-percent increase in volume must be compared to much higher growth rates in the first seven months. By October, uncertainties in financial markets contributed to decreased financial power trading, as the last three months in 2008 all traded below 2007 levels. Several hubs did well during the economic malaise; 4Q08 volumes at NP-15 and Palo Verde were substantially higher than 4Q07 levels. In the end, however, ICE financial power trading during 4Q08 was the lowest fourth quarter traded on ICE since 2005.

Notably, the volume of physical wholesale power trading did not appear to respond to credit tightening as was seen in financial power markets. Specifically, the 2008 decrease in third- and fourth-quarter physical sales on a year-to-year basis were not substantially different that the 2007 year-to-year declines in those same months.[12]

12 Physical volumes during 3Q08 declined by 13 percent relative to 3Q07, while 3Q07 declined by 16 percent relative to 3Q06. Similarly, 4Q08 volumes declined 16 percent relative to 4Q07, while 4Q07 declined 11 percent relative to 4Q06.

Changes in the Term Structure for Financial and Physical Power

Financial Products

Financial power trading on ICE is used mostly for term transactions (see Figure 29). In 2008, 88 percent of total volumes were term (65 percent monthly, 15 percent quarterly, 8 percent calendar year) while only 12 percent were spot (less than one month).

Changes in trade length were particularly apparent during 4Q08 as credit tightening may have made it more difficult to meet credit requirements necessary for longer term deals. For instance, although total volume traded during 4Q08 decreased 27 percent relative to 4Q07, spot deals increased 2 percent (see Table 3). During the same time, monthly and calendar year deals decreased faster than total financial power declines, while quarterly volumes declined at a slower rate. Calendar year trading, especially at PJM West and SP-15, dried up during 4Q08, when volumes fell by 69 percent and 52 percent, respectively, compared to 4Q07, despite total financial power volumes falling by smaller amounts at both hubs, 54 percent and 10 percent, respectively.

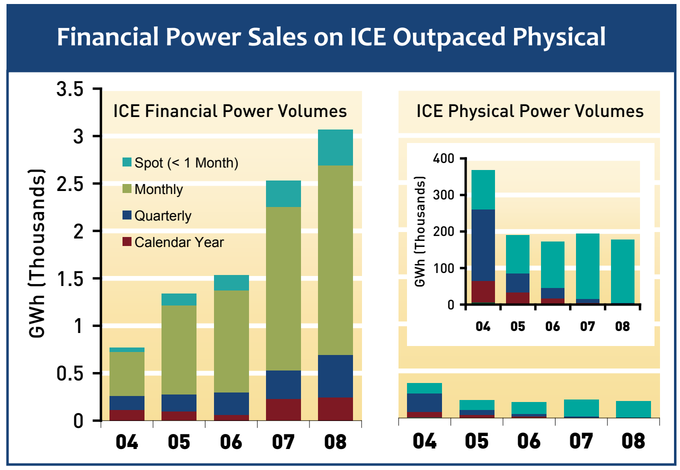
Table 3

Financial Electricity Trading on ICE in the 4th Quarter by Term (2008 vs. 2007)

	2008Q4	2007Q4	Δ (TWh)	% Growth
Calendar Year Terms	38	84	-46	-55%
Quarterly Terms	70	74	-4	-6%
Montly Terms	275	399	-124	-31%
Spot (<1 month)	77	76	1	2%
Total	**460**	**633**	**-173**	**-27%**

Source: Derived from IntercontinentalExchange data.

Figure 29



Source: Derived from IntercontinentalExchange data.

Physical Products

The volume of physical long-term (a year or more) sales transactions rose significantly between 2007 and 2008. Long-term sales volumes accounted for 43 percent of all EQR sales in 2008, up from 33 percent in 2007. Regionally, SPP, the Southeast and ERCOT had the highest percentages of long-term sales transaction in 2008. With the exception of ERCOT, these are areas where there are no RTO markets. The Northeast and the West had the lowest percentage of long-term sales. These are areas that have relatively robust financial electricity markets.

Table 4 EQR Transaction Volumes

	2007					2008				
	Short Term		Long Term		Total	Short Term		Long Term		Total
	GWh	%	GWh	%		GWh	%	GWh	%	
Northeast	534,706	78%	149,126	22%	683,833	407,519	73%	148,102	27%	555,622
Mid-Atlantic/ Midwest	1,301,306	61%	846,210	39%	2,147,516	1,108,131	52%	1,018,065	48%	2,126,196
Southeast	153,929	53%	134,254	47%	288,183	137,039	44%	175,995	56%	313,034
ERCOT	123,953	67%	61,876	33%	185,829	105,824	51%	103,726	49%	209,550
SPP	31,243	47%	35,151	53%	66,394	32,061	41%	45,216	59%	77,277
West	910,494	75%	308,859	25%	1,219,353	722,273	65%	381,724	35%	1,103,997
Total	3,055,630	67%	1,535,477	33%	4,591,107	2,512,847	57%	1,872,828	43%	4,385,675

Power sales transactions with durations of one year or greater are long-term.
Transactions with shorter durations are short-term.

Source: Derived from Electric Quarterly Report data.

Section 5 RTO/ISO Capacity Markets

During 2008, energy efficiency and demand-response resources played an important role in several RTO capacity markets.

Introduction

In 2008, Commission-approved capacity markets operated in three RTO/ISOs. These include ISO-NE's forward capacity market (FCM), PJM's reliability pricing model (RPM) and NYISO's installed capacity market (ICAP). In general, the goal of each capacity market is to provide a means for load-serving entities (LSE) to procure capacity needed to meet forecast load, or resource adequacy, requirements and to allow generators to recover a portion of their fixed costs.[1] The ISO-NE's FCM and PJM's RPM employ forward commitment auctions for capacity. That is, supplies awarded in the auction represent commitments to provide capacity three years in the future. The auctions are intended to create a smoother, more stable price signal to suppliers considering investment decisions. The NYISO's ICAP auctions provide semiannual seasonal strip auctions. In NYISO, suppliers are not assured of the amount of payments for providing capacity in forward years, as in PJM and ISO-NE.

Capacity Markets in Action in 2008

The three RTO/ISOs conducted six capability or delivery-year auctions in 2008.[2] There were two base auctions each in ISO-NE, PJM and NYISO, not including the various incremental or reconfiguration auctions that cover shorter periods.

ISO-NE and PJM held their first auctions with a three-year forward commitment in 2008.[3] In NYISO's ICAP market, capability auctions were held for summer 2008 and winter 2008-09 (monthly and spot capacity auctions were also held).

Overall, the auctions attracted new investment. In ISO-NE and PJM, a combined total of approximately 8,900 MW of new generation and demand response was committed for the forward delivery periods of 2010-11 and 2011-12. This compares to 2008 overall generation capacity figures of 31,100 MW in ISO-NE and 164,895 MW in PJM. In 2008, NYISO saw an increase of 1,075 MW of new generation, net of retirements, relative to approximately 38,900 MW of overall generation capacity in the market. Total capacity offered and purchased in New York exceeded the state's minimum resource adequacy requirements in 2008.

As discussed below, prices for the forward capacity markets of ISO-NE and PJM were generally in the $40 to $60/kW-year range for the capability or delivery year auctions conducted in 2008. Prices in NYISO's 2008 auctions ranged from $78/kW-year ($6.50/kW-month) for New York City in the summer period to $21/kW-year ($1.77/kW-month) for the non-New York City and non-Long Island area (also referred to as rest-of-state) in the winter period. Capacity prices declined going from the first capability or delivery year auction to the second, for each of the three markets.

1 The demand for each market is based on the following, listed by market. In ISO-NE FCM, an installed capacity requirement (ICR) is calculated based on load forecast, unit availability and intertie benefits. In PJM, RPM uses a downward-sloping demand curve based on target reserve margins. In NYISO, a downward-sloping demand curve is based on the installed reserve margins for New York – Rest of State, Locational Minimum ICRs for NYC and Long Island.

2 The capacity auctions cover periods up to one year. In ISO-NE, a capability year under the FCM is from June 1 through May 31, three years forward. Under PJM's base residual auctions, capacity commitments are for a delivery year from June 1 through May 31, three years forward. In NYISO, capability periods are six-month periods established as a summer capability period, May 1 through Oct. 31, and a winter capability period from November 1 of each year through April 30 of the following year. Each market also conducts shorter-duration auctions – e.g., reconfiguration, monthly or spot auctions – in which market participants can purchase capacity for incremental load growth or supply deficiencies. Discussion in this report focuses mainly on capability and delivery-year auction results.

3 ISO-NE conducted the first FCM auction in February 2008, which secured resource commitments for the 2010-11 timeframe, and the second FCM auction in December 2008, securing 2011-12 resource commitments. PJM held its 2010-11 RPM auction in January 2008 and its 2011-12 RPM auction in May 2008.

Table 5: Comparison of Capacity Markets in RTO/ISOs

Capacity Market	ISO-NE – Forward Capacity Market	PJM – Reliability Pricing Model	NYISO – Capacity Market
Delivery year for base auction	Forward procurement: Resources are committed 3 years into the future	Forward procurement: Resources are committed 3 years into the future	Six-month strips: Resources are committed for the coming season, winter and summer
Price determination	Descending clock auction	Price determined in auction by intersection of supply offers with a calculated demand curve _1/	Price determined in auction by intersection of supply offers with a calculated demand curve _2/
Demand basis (i.e., demand based on…)	An Installed Capacity Requirement (ICR) is calculated based on forecast and other parameters _3/	Downward sloping demand curve based on net cost of new entry and target reserve margins	Downward sloping demand curve, installed reserve margins for state; locational minimum ICR for NYC, Long Island _4/
Self-supply option or must-bid?	LSEs may self-supply	LSEs are able to self-supply or mandatory participation by load except for FRR option	LSEs self-supply, or utilize ICAP auctions and/or bilateral arrangements _5/
Must-offer?	Must-offer requirement for capacity	Must-offer requirement for capacity	Must-offer requirement for capacity for NYC only
Locational requirements and pricing	Yes _7/	Yes _6/	Yes _8/
Market power mitigation	Review of bids priced above and below specified thresholds _9/	Offer caps based on marginal cost of capacity	Offer caps for certain capacity in NYC spot market auctions _10/ Penalties for failure to offer certain capacity in NYC _11/ Audits for proposals to delist _12/ Offer Floor for NYC Spot Market Auctions _13/
Demand Resources (DR) and other nongeneration resources	DR and energy efficiency projects may participate in the auction	Capacity may be provided from demand response resources and new transmission projects	DR may participate in all NYISO ICAP auctions
Auction frequency	Annual Reconfiguration auctions performed annually, seasonally and monthly _14/	Annual Incremental auctions may be held prior to the delivery year	Capability period auction (covers a six-month period) monthly auction, spot market auction

_1/ PJM's demand curves, referred to as variable resource requirement (VRR) curves, are administratively determined.
_2/ Three ICAP demand curves are used in the ICAP spot market auction: one each to determine the locational component of LSE UCAP obligations for Long Island and for New York City, and the third to determine the total LSE UCAP obligations for all LSEs.
_3/ ISO-NE's installed capacity requirement (ICR) is based on three components (load forecast, unit availability and tie benefits) and is the amount of resources needed to meet the planning reliability requirements defined for the New England Control Area such that the probability of disconnecting noninterruptible customers (a loss of load expectation) is no more than once every 10(ISO-NE Market Rule 1 § III.12).
_4/ Once ICAP is determined, the NYISO converts the requirements into unforced capacity (UCAP).
_5/ Participation in NYISO auctions is restricted to NYISO customers – i.e., entities that have signed NYISO service agreements for market services and control area services.
_6/ Locational requirements are defined by transmission constraints.
_7/ Capacity zones are determined before the FCA based on an identification of transmission limits that may bind in the FCA.
_8/ Three ICAP demand curves are used in the ICAP spot market auction: one each to determine the locational component of LSE UCAP obligations for Long Island and for New York City, and the third to determine the total LSE UCAP obligations for all LSEs.
_9/ See ISO-NE Market Rule I, §§ III.13.1.1 through III.13.1.3, and III.13.1.7.
_10/ Offer caps in New York City are based on reference levels or avoided costs. Mitigated UCAP must be offered in each ICAP spot market auction, unless it has been exported to an external control area or sold to meet installed capacity requirements outside New York City in a transaction that does not constitute physical withholding.
_11/ Exports of mitigated UCAP are considered to have been physically withheld from the New York City market if: (1) the net revenues from the sale of the exported UCAP in New York City would have been greater by 5% or more than the net UCAP revenues from the export sale; and (2) the exporting market participant could have made all or a portion of the exported UCAP available to be offered in New York City by buying out of its external capacity obligation through participation in an external reconfiguration market.
_12/ Any proposal or decision by a market participant to retire or otherwise remove a supplier from the mitigated UCAP market, or to de-rate the amount of installed capacity available from such supplier, may be subject to audit and review by the NYISO, if the ISO determines that such action could reasonably be expected to affect market-clearing prices in one or more ICAP spot market auctions for New York City, to determine whether the proposal or decision has a legitimate economic justification or is based on an effort to physically withhold installed capacity in order to affect prices.
_13/ Unless exempt, offers to supply UCAP in an ICAP spot market auction from a New York City installed capacity supplier or demand response resource must equal or exceed an applicable offer floor. A New York City installed capacity supplier that is not a demand response supplier is exempt from an offer floor if it was an existing facility on or before March 7, 2008. All other exemptions are based on certain calculations tied to the relationship of the net cost of new entry to projected auction prices.
_14/ Reconfiguration auctions, conducted after the primary auction, enable trading of obligations and adjustments to capacity purchases. See ISO-NE Market Rule 1, § III.13.4.

ISO-NE and PJM increased the role of demand resources, which competed alongside traditional generating resources to meet future load growth. ISO-NE cleared 1,188 MW of new demand-response and energy-efficiency resources in its first forward 2008 capacity auction and 448 MW of new demand response and energy-efficiency resources in its second auction. PJM cleared 29 MW of new demand-response in its first forward auction and 662 MW of new demand-response in its second auction.

The following sections describe the capacity markets in ISO-NE, PJM and NYISO, along with the fundamental factors influencing the markets in 2008. Table 5 on the previous page shows a comparison of the key features of the three capacity markets.

ISO-NE's Forward Capacity Market

In ISO-NE's annual forward capacity auctions (FCA), both generator and demand resources offer capacity three years in advance of the period for which capacity will be supplied. Resources whose capacity clears the FCA acquire capacity supply obligations.[4] ISO-NE held the first two FCAs in 2008 for the 2010-11 and 2011-12 delivery years.[5] The first full year of capacity market commitments begin June 1, 2010. Capacity is paid a flat rate for a transition period (Dec. 1, 2006, through May 31, 2010) prior to ISO-NE's full, three-year forward FCA auction mechanism.[6] The FCA process includes the modeling of certain constraints to determine if load zones will be import- or export-constrained. LSEs that designate self-supply resources must offer those resources into the FCA and will have the same rights and obligations as other capacity resources accepted in the FCA.

Use of New Demand Response and Energy Efficiency to Meet Load Forecast

Capacity projections manifest in ISO-NE's FCM auction results showed that market participants were willing to commit new capacity resources despite prices at or near minimum levels included in the market rules. FCM prices cleared at the market's floor price in both auctions held in 2008, as described below.

A total of 34,353 MW of existing and new resources cleared the auction for the 2010-11 delivery year. New resources totaled 1,814 MW, which included 626 MW of new generation capacity and 1,188 MW of new demand resources. A total of 37,442 MW of existing and new resources cleared the auction for the 2011-12 delivery year. New resources totaled 3,134 MW, which included 1,157 MW of new generation capacity, 1,529 MW of new imports and 448 MW of new demand resources.

With offered capacity quantities greater than the ISO-NE's installed capacity requirement (ICR), ISO-NE saw downward pressure on prices. ISO-NE's FCM clearing price reached the administratively determined floor price of $54/kW-year in the 2010-11 auction. ISO-NE's FCM auction also cleared at the (lower) floor price of $43/kW-year for 2011-12. Offers

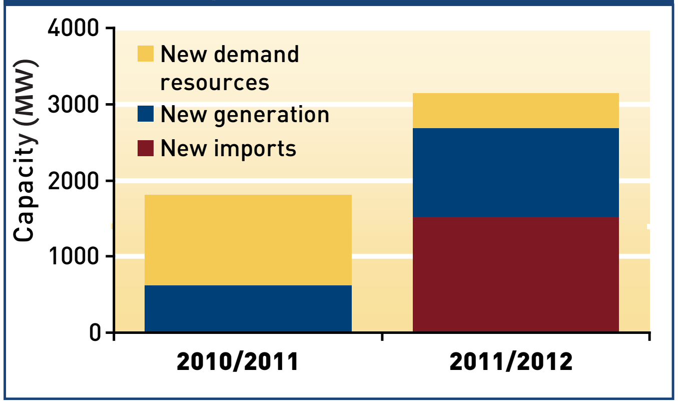
4 The Commission approved a settlement agreement in 2006 which provided a framework for drafting ISO-NE's FCM rules. Devon Power LLC, 115 FERC ¶ 61,340 (2006), order on reh'g, 117 FERC ¶ 61,333 (2006). The Commission approved the FCM rules in 2007. ISO New England Inc., 119 FERC ¶ 61,045 (2007), order on reh'g, 120 FERC ¶ 61,087 (2007) and ISO New England Inc., 119 FERC ¶ 61,239 (2007). Prior to the delivery year, parties can adjust their capacity supply obligations, and ISO-NE can increase or decrease the amount of capacity it anticipates needing, in periodic reconfiguration auctions.

5 Beginning in 1998, ISO-NE operated a bid-based market for installed capacity. See Devon Power LLC, 115 FERC ¶ 61,340 (2006) at page 5.

6 Devon Power LLC, 115 FERC ¶ 61,340 (2006), page 30. The level of payments during the transition period were as follows: Dec. 1, 2006 – May 31, 2007, was $3.05/kW-month; June 1, 2007 – May 31, 2008, was $3.05/kW-month; June 1, 2008 – May 31, 2009, was $3.75/kW-month; and June 1, 2009 – May 31, 2010, was $4.10/kW-month.

Figure 30

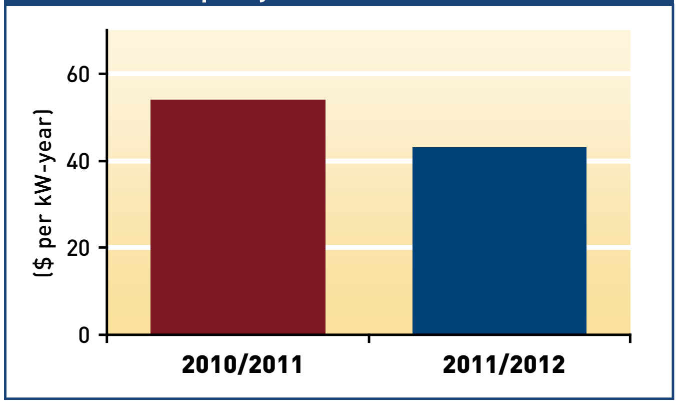
ISO-NE Quantity of New Resources Cleared in Forward Capacity Auctions Held in 2008



Source: Derived from ISO-NE data.

Figure 31

ISO-NE Clearing Price For Resources Cleared in Forward Capacity Auctions Held in 2008



Source: Derived from ISO-NE data.

for new generation, increased demand response and new energy efficiency bolstered supplies for the 2011-12 delivery year. Bilateral contracting provided another avenue for capacity to receive revenues. For example, in Connecticut, 678 MW of new generation was committed as a result of state requirements for utility procurements.[7]

For both auctions, ISO-NE modeled two import- or export-constrained capacity zones in the FCA, Maine and Rest of Pool.[8] There was no distinct capacity clearing price in the Maine capacity zone. Therefore, the auctions resulted in a single capacity zone encompassing the entire region without price splits or separations by zone.

PJM's Reliability Pricing Model

Annual RPM capacity market auctions, referred to as base residual auctions (BRA), are based on a three-year forward obligation to provide capacity. Supply offers are cleared against a downward-sloping demand curve, called the variable resource requirement (VRR) curve.[9] The VRR curve establishes the amount of capacity that PJM requires its LSEs to purchase and, in conjunction with the capacity offers, the price for that capacity. LSEs that are able to fully supply their own capacity needs can choose not to participate in the RPM auctions, and instead choose a long-term fixed resource requirement option.[10]

7 On June 25, the Connecticut Department of Public Utility Control (DPUC) issued a final order selecting three natural gas peaking generation projects totaling 678 MW to be constructed in the state (Docket No. 08-01-01, initiated in accordance with House Bill 7432, enacted in 2007). State law required electric distribution companies to submit plans to the DPUC in 2008 to build peaking generation units. In a Dec. 4, 2007, decision related to the new law, the department identified a need for 500-700 MW of new peaking generation. The DPUC determined that the selected units are to be subject to annual rate cases (cost-of-service regulation). As required by the law, the DPUC is to set the initial prices for the facilities as they are put in service, and will review the cost-of-service of the selected units in annual rate cases and update the project's ROE at least every four years (Connecticut DPUC selects peaking generation projects, SNL Energy, June 26, 2008).

8 The Rest of Pool Capacity Zone included Massachusetts, Connecticut, Rhode Island, New Hampshire and Vermont.

9 The VRR curve is based on the target level of reserves and the cost of new entry minus an offset for energy and ancillary services revenues. See PJM tariff, Attachment DD § 5.10.

10 The FRR alternative permits LSEs to opt out of RPM auctions and instead meet a fixed capacity obligation through their own generation or contracts sufficient to meet PJM's reserve margin.

PJM held two BRAs in 2008: in January for the 2010-11 delivery year and in May for the 2011-12 delivery year. The auction for the 2011-12 delivery year was the first to procure capacity under a full three-year forward commitment. Since 2007, PJM has conducted a series of transitional auctions to cover the capacity market from 2007 through May 2010.[11] PJM evaluates capacity requirements for subregions within PJM, or locational deliverability areas (LDAs), in which capacity imports are limited by transmission constraints. Capacity auction prices will be higher in these areas when LDA transmission constraints are forecast to bind in the delivery year.

Increase in Supply Commitments and Lower Forecast Load Due to the Exclusion of Duquesne Load

PJM's RPM auctions for 2010-11 and 2011-12 saw increases in both new generation and demand resources. In the first of the year's two RPM auctions, a total of 132,191 MW of existing and new resources cleared the auction for 2010-11. Capacity commitments increased by 1,503 MW net of forecasted capacity derates for the delivery period. There was a 1,776-MW increase in generation capacity, which is expected to decrease by 302 MW for generation deratings. There was also a commitment for 29 MW in new demand-resource capacity.

A total of 132,222 MW of existing and new resources cleared the auction for 2011-12. PJM received an increase of 3,973 MW of capacity, net of forecasted capacity derates, for the delivery period. Commitments for generating capacity increased by 3,576 MW (including new generation resources and capacity upgrades to existing generation capacity resources), which was offset by a forecasted 265-MW decrease in generation capacity. There was also a commitment for a 662-MW increase in new demand-resource capacity. This increase in capacity commitment represents about two times the new capacity growth compared to the 2010-11 delivery year, and is the largest increase in capacity since the implementation of RPM.

Growth in supply and a drop in demand placed downward pressure on PJM's auction clearing prices. Delivery year auction prices dropped from $64/kW-year in 2010-11 to $40/kW-year in 2011-12. Notably, PJM assumed no demand growth due to the exclusion of 3,000 MW of Duquesne load for the 2011-12 delivery period.[12]

The 2011-12 auction resulted in a uniform clearing price throughout PJM because there were no forecasted transmission constraints in the LDAs. The 2010-11 auction cleared with a uniform clearing price of $64/kW-year, with the exception of the DPL-South region of EMAAC (in Delmarva Power & Light's service territory), which cleared at $68/kW-year.

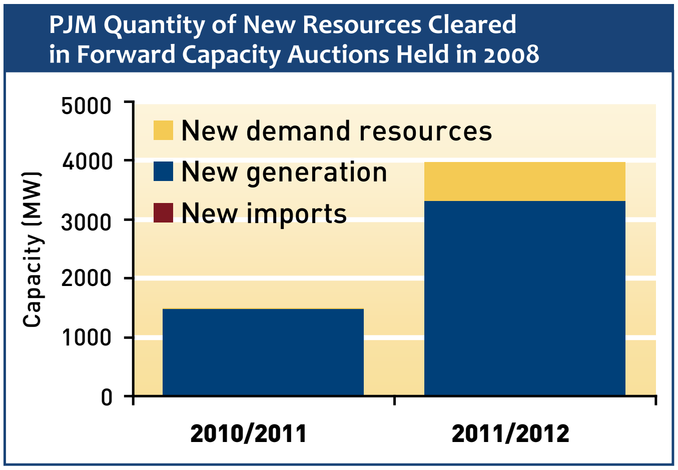
NYISO's Installed Capacity Market

In NYISO's capacity market, LSEs procure capacity through ICAP auctions, self-supply and bilateral arrangements based on their forecasted peak load plus a margin. In operation since 2000, the NYISO conducts auctions for three different service durations: the capability period auction (covering a six-month period), the monthly auction and the spot

11 The first four BRAs, covering delivery years 2007-08, 2008-09, 2009-10 and 2010-11, are the transition period auctions because they were not conducted a full three years before the delivery year. Prior PJM reliability pricing model (RPM) auctions, held from April 2007 to January 2008, were held over a shortened period – that is, capacity commitments for delivery years 2007 to 2011 were auctioned over the span of nine months.

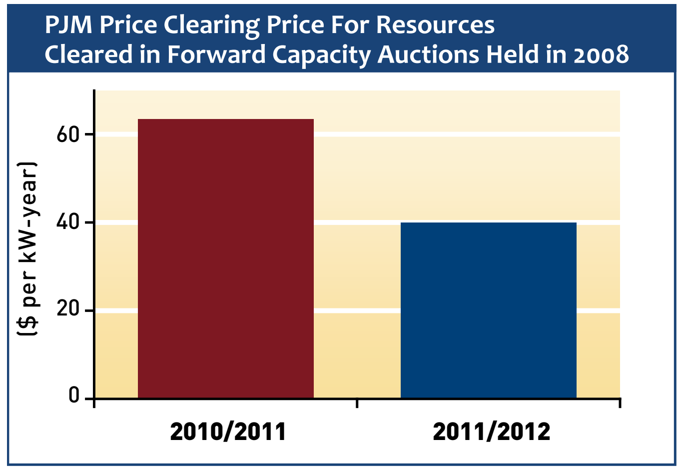
12 Based on Duquesne's notification that it expected to withdraw from PJM prior to the 2011-12 delivery year, Duquesne's load was excluded from the auction. However, most of the generation resources in the Duquesne zone offered their capacity into the 2011- auction, resulting in a larger surplus of capacity than would otherwise have occurred.

Figure 32



Source: Derived from PJM data.

Figure 33



Source: Derived from PJM data.

market auction.[13] NYISO held 2 capability period auctions, 12 monthly auctions and 12 ICAP spot market auctions in 2008.

For the capability period auctions, NYISO calculates an unforced capacity (UCAP) amount to determine the capacity that each LSE is required to procure. Because UCAP factors in the recent level of generator forced outages to ICAP amounts, UCAP identifies a smaller level of capacity available to serve load requirements.[14]

NYISO ICAP Market Prices Fell in 2008 Following New Mitigation Measures and Adjusted Load Capacity Requirements

The amount of capacity offered and purchased in NYISO exceeded the state's minimum capacity requirements during 2008. During the 2008 summer capability period, the minimum capacity requirement for New York was 36,633 MW, while the total amount of capacity sold averaged 39,729 MW.[15] Additionally, beginning in May 2008, New York lowered its installed reserve margin requirement to 15 percent (down from 16.5 percent),[16] which yielded lower

13 New York has capacity requirements for three zones: New York City, Long Island and New York – Rest of State. The resource requirements do not change in the monthly auctions and ICAP spot market auctions relative to the capability period auction. The shorter monthly auctions are designed to account for incremental changes in LSE's load forecasts. The Commission first approved an installed capacity market for the NYISO in 2000. New York Independent System Operator, 90 FERC ¶ 61,319 (2000).

14 NYISO calculates UCAP by multiplying the ICAP amount by the quantity one (1) minus the average effective forced outage rate on demand (EFORd) value for the six most recent 12-month rolling average EFORds of New York resources. For each capability period, NYISO calculates a UCAP amount for each resource qualified to supply capacity. See NYISO tariff, Attachment J, § 1.0.

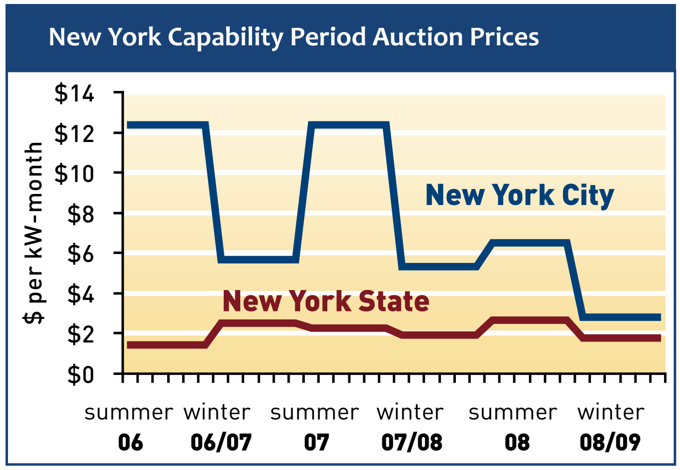
15 New York Independent System Operator, Inc., 2008 Reliability Needs Assessment.

16 The Installed Reserve Margin requirement covered the period from May 2008 through April 2009. The Installed Reserve Margin is used by NYISO to develop its capacity market demand curves. The demand curves, in turn, are used in NYISO's ICAP market auctions to determine each LSE's installed capacity requirement and price. New York Control Area Installed Capacity Requirements for the Period May 2008 through April 2009, Technical Study Report, December 14, 2007, New York State Reliability Council, LLC. *New York Independent Operator, Inc.,* 122 FERC 61,186 (2008).

minimum capacity requirements. This put downward pressure on capacity prices.

Overall, capacity prices decreased in New York in 2008 compared to 2007. This was particularly the case in New York City, where capacity prices for the summer 2008 capability period (April through September) fell to roughly half of the summer 2007 prices, from $12.37/kW-month to $6.50/kW-month. In March 2008, the Commission approved new market power mitigation measures in the city.[17] Following these measures, additional capacity was sold in the market, which contributed to the substantial decrease in capacity prices. On Long Island, bilateral contracting largely determined capacity costs seen by load prices, i.e., virtually all of the existing capacity on Long Island has been secured by contract. In addition, the local capacity requirement in Long Island decreased to 94 percent from 99 percent to account for the benefits of the Neptune HVDC line between eastern PJM and Long Island.[18] This led to a reduction in the clearing prices in both the summer and winter capability periods.[19] While capacity prices in non-New York City areas remained roughly $2/kW-month (Figure 34), capacity sales in the New York City local capacity zone affect the prices in non-New York City areas because capacity sales in the local capacity zone of New York City also satisfies the overall New York state capacity requirements.

Figure 34



Source: Derived from NY-ISO data.

Note: Prices are shown in UCAP values. 2008 State of the Market Report, NYISO Electricity Markets, Potomac Economics, May 2009.

17 New York Independent System Operator, Inc., 122 FERC ¶ 61,211 (2008), order on reh'g, 124 FERC ¶ 61,301 (2008). New mitigation measures were approved by FERC in March 2008 and became effective in May 2008. Further, the NYISO established new ICAP demand curve parameters that account for the effects over time of surplus capacity on capacity revenues *New York Independent Operator, Inc.,* 122 FERC 61,064 (2008), order on reh'g, 125 FERC ¶ 61,299 (2008).

18 The Neptune HVDC line began commercial service in June 2007. *Long Island Power Authority,* http://www.lipower.org/newscenter/pr/2007/062807_neptune.html.

19 2008 State of the Market Report, NYISO Electricity Markets, Potomac Economics, May 2009.

Section 6

Natural Gas Capacity Release and Electricity Transmission Reassignment

The Commission has recently reformed the natural gas transportation capacity release rules under Order No. 712 (18 CFR Part 284) and the electric transmission service reassignments rules under Order No. 890 (18 CFR Parts 35 and 37) in an effort to increase use of the transmission infrastructure and to promote greater transparency in wholesale markets.

Introduction

This chapter summarizes the early results of these reforms based on capacity release and capacity reassignment data during 2008. The early experience from the capacity release reforms suggests that there has been relatively little change in capacity release activity. This is partially because the period of study includes the winter and the months leading up to it when shippers are less likely to release capacity in the face of uncertain winter weather. The early experience with electric transmission service reassignments suggests slightly more change. There has historically been relatively little reassignment of electric transmission service. Since the reassignment reforms took effect, the quantity of transmission service that has been reassigned has increased steadily. This increase in reassignments is true across almost all dimensions (time, duration of reassignment, number of transmission providers reporting reassignments).

Summary of Pipeline Capacity Release Postings

On June 19, 2008, the Commission issued Order No. 712, which became effective on July 30, 2008. Order No. 712 removed the rate ceiling on short-term capacity releases on interstate natural gas pipelines.[1] The order also modified the capacity release rules to facilitate the use of asset management agreements (AMAs), removing certain prohibitions on tying arrangements and bidding.

This review provides some initial observations of the first six months of the Commission's revised capacity release rules—from Aug. 1, 2008, through Jan. 31, 2009. Because of the seasonal nature of the natural gas market, capacity releases during this period were compared to those of previous years during the same six-month time frame. The period covers, primarily, the winter and the months leading up to it. Shorter-term decisions about whether to release capacity for a day or a month are a function of weather conditions, and are therefore as dependent on immediate circumstances as on pricing conditions. LDCs, for example, would be less likely to release capacity in the face of uncertain winter weather. Longer-term decisions to release capacity for a year or more tend to occur at or near the beginning of the gas year in April and are driven by long-term planning within the natural gas cycle.

For the time period selected, above-cap, premium releases were compared to releases at or near the cap to identify distinctions between the two. Specifically, we discuss the volume of releases, the term of releases and the geographic dispersion of releases. Next we characterize the nature of the entities involved in capacity releases, focusing on the extent to which local distribution companies (LDCs) released capacity. Finally, we address the change in activity under AMAs as a result of the changes in Order No. 712.

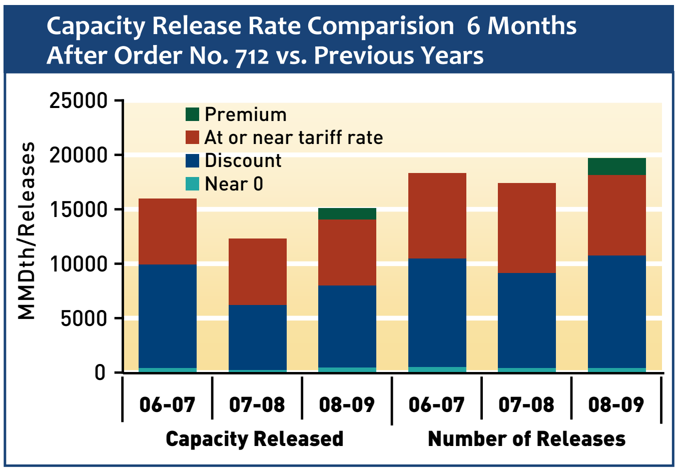
Volume

Removal of the price cap for released pipeline capacity has not substantially altered the capacity release market. Slightly more capacity was released in the first six months after Order No. 712 became effective than during the same period in 2007-08, but less than the prior year (see Figure 35). This pattern is consistent with the winter weather conditions in those years, with 2007-08 being the most severe, thereby accommodating fewer releases. The biggest difference in the releases among the years was in below-the-cap releases. In 2006-07, 57 percent more discount releases occurred and 28

1 *Promotion of a More Efficient Capacity Release Market*, Order No. 712, 73 Fed. Reg. 37,058 (June 30, 2008), FERC Stats. & Regs. ¶ 31,271 (2008).

percent more discount capacity was released than in 2007-08. In 2007-08, maximum-priced releases were about equal to discount releases, both in number and capacity released. In 2008-09, while there were fewer at-the-cap releases than discount releases, the addition of premium-priced releases to the at-the-cap releases nearly evens the count.

Figure 35



Source: Derived from Energy Velocity data.

Term

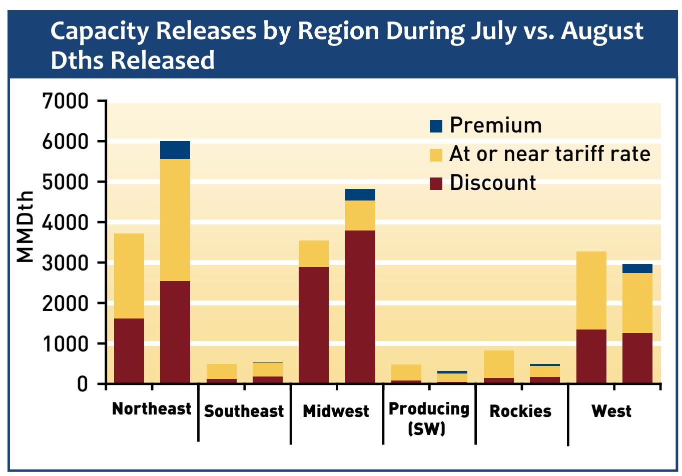
The term of the capacity releases changed little between 2007-08 and 2008-09, even with the availability of premium-priced releases. Two-thirds of the capacity releases in both years were for terms of one month. In 2007-08, a higher percentage of the number of releases occurred for terms less than a month (15 percent in 2007-08 versus 8 percent in 2008-09), but the volume of capacity released for these shorter periods amounted to little of the capacity released in either year (less than 1 percent). In the part of the capacity release market still capped at the tariff rate after Order No. 712 (over one year), there were roughly the same number of long-term and permanent releases in both years.

Looking solely at the releases above the cap in 2008-09, 59 percent of the premium-priced capacity released was for one year, the longest duration allowed under Order No. 712. By comparison, 58 percent of the capacity released at the tariff rate was for a period longer than one year.

Geographic Concentration

Geographically, most of the capacity released occurred on pipelines serving the Northeast and Midwest. About half of the capacity released on Northeast pipelines was at the tariff rate cap, and another 6 percent was above the cap. In contrast, 77 percent of capacity released on Midwest pipelines was discounted (see figures 36 and 37). Although there were fewer total releases in the Midwest than in the Northeast, half the releases above the cap in 2008 were on pipelines serving the Midwest. The number of below-cap releases on Northeast and Midwest pipelines stayed roughly the same across 2007-08 and 2008-09.

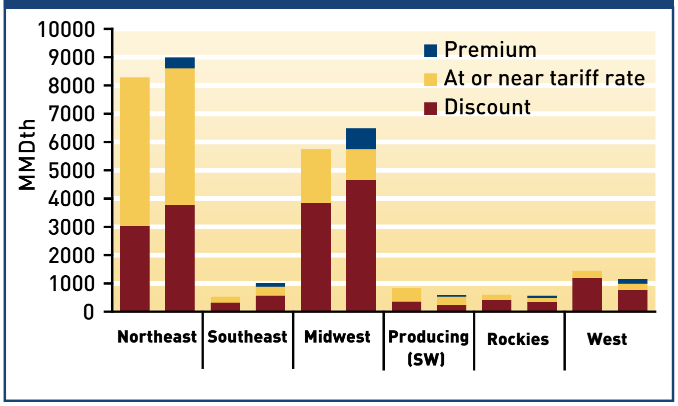
Figure 36



Source: Derived from Energy Velocity data.

Figure 37

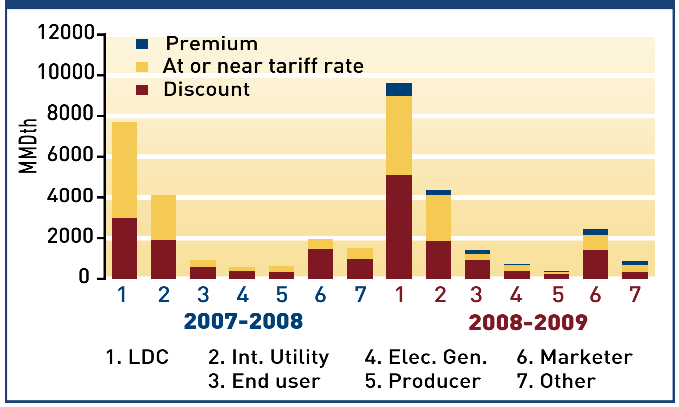
Capacity Released by Region July vs. August Number of Releases



Source: Derived from Energy Velocity data.

Figure 38

Capacity Releases by Releaser Type



Source: Derived from Energy Velocity data.

Releasing Shippers

In both 2007-08 and 2008-09, LDCs participated in more capacity releases than other types of market participants: 44 percent of the releases in 2007-08 and 49 percent in 2008-09 (see figure 37). Even though Order No. 712 eliminated the price cap late in the gas year after the current year's plans had been fixed, LDCs were responsible for 40 percent of the above-the-cap releases in the first six months after the order. Releases by integrated utilities that may have been part of the gas LDC function accounted for another 15 percent of the post-order above-the-cap releases. The total number of releases by LDCs and integrated utilities fell by about 300 (5 percent), but the amount of capacity they released increased by 25 percent. This may indicate that the decline occurred in shorter-term releases, which would be most affected by the severity of the winter. Companies identifiable as marketers accounted for a little over 10 percent of the releases in both years but almost 20 percent of the premium releases after Order No. 712.

In Order No. 712, the Commission created exemptions to the capacity release rules to accommodate the development of asset management agreements (AMA). In an attempt to capture AMA activity, we compared customer/agent information in the index of customers to releaser/bidder information in the capacity release database.[2]

Instances where the bidder is identified as a pipeline customer's agent constitute a small share of the capacity release market, but that share did double during the six months after Order No. 712 to almost 3 percent of the releases and nearly 5 percent of the capacity released in 2008-09. The largest growth occurred in long-term released capacity, which tripled between the two periods. Initial research from the Office of Enforcement's audit staff indicated that AMAs tend to be executed near the beginning of the gas year, on April 1. This would mean that data still coming in will provide a more robust picture of Order No. 712's effect on the AMA market.

2 In pipelines' index of customers, the pipeline defines an agent for a customer as "the name of any agent or asset manager managing a shipper's transportation service " (18 CFR Sec 284.13(c)(2)(viii)). This relationship is consistent with the relationship necessary to affect an asset management agreement where the customer prearranges a capacity release with its agent/manager bidding for the capacity.

Summary of EQR Capacity Reassignment Filings

Market participants that had reserved transmission service have been allowed to reassign that service above the tariff rate since Order No. 890 went into effect during the second quarter of 2007.[3] In addition to allowing transmission service reservation (TSR) reassignments, Order No. 890 also requires that electric transmission providers report in their quarterly EQR filings reassignment of TSRs for service reserved under the transmission provider's open access transmission tariff. The requirement is designed to promote transparency in transmission markets, similar to the requirement that natural gas pipeline companies post capacity releases on their pipelines.

There has historically been relatively little reassignment of electric transmission service. Since second-quarter 2007, the quantity of transmission service that has been reassigned has increased steadily. This increase in reassignments is true across almost all dimensions. That is, the number of transmission providers reporting reassignments has increased; the number of TSRs reassigned for each particular duration (e.g., hour, daily, monthly, yearly) has increased; and the capacity (in MWhs of service) reassigned has increased. TSR reassignments occurred throughout the non-RTO markets, with no particular region standing out. The majority of completed TSR reassignments were for less than a day, though on a MWh-basis, yearly and monthly reassignments make up the vast majority of reassignments. We are unable to fully address the pricing of TSR reassignments because any entities reassigning TSRs failed to report a price other than zero.

3 *Preventing Undue Descrimination and Preference in Transmission Service*, Order No. 890, FERC Stats. & Regs. ¶ 31,241, *order on reh'g*, Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 (2007), *order on reh'g*, Order No. 890-B, 123 FERC. ¶ 61,299 (2008) *order on reh'g*, Order No. 890-C, 126 FERC ¶ 61,228 (2009). Market participants that have reserved transmission service have been allowed to reassign that service reservation since Order No. 888 initiated the Commission's current electric transmission service regime.

Capacity Reassignment Sales

The reporting of capacity reassignments began in 2Q07, and has subsequently increased both in the number of providers reporting and in the volumes reported. The data reported herein include all quarterly EQR submissions made through fourth-quarter 2008.

During the 7 quarters analyzed, 19 market participants transacted 1,554 capacity reassignments under contract and 169 without contracts, for a total of 1,723 transactions.[4] Twenty-two of the 1,723 reported transactions involved sales between affiliates. These are shown by provider and by quarter in Table 6.

Table 6
Reassignments by Transmission Provider by Quarter

	2Q 07	3Q 07	4Q 07	1Q 08	2Q 08	3Q 08	4Q 08	Total
BPA	-	-	-	-	-	-	715	715
Cross-Sound Cable	103	15	16	23	36	27	20	240
Mid_Continent PP	-30	33	33	33	33	33	195	
NW Energy	-	-	8	12	14	63	70	167
Southern Co.	-	22	17	13	48	20		120
Entergy	-	34	-	-	-	6	6	46
PacifiCorp	1	1	1	1	2	13	24	43
MISO	2	3	6	9	11	4	6	41
TEC	-	-	-	-	-	-	40	40
APS	-	-	-	-	6	12	12	30
NUSCO (as Agent)*	-	-	-	6	6	6	10	28
PSNM	-	-	-	-	4	7	7	18
Idaho Power	-	-	-	-	-	7	7	14
SPP	-	-	-	2	2	2	4	10
NU Services Co.	2	2	2	-	-	-	-	6
MidAmerican	-	-	1	1	1	1	1	5
NVP	-	-	-	-	-	1	2	3
Puget Sound	-	-	-	-	-	-	1	1
EPE	-	-	-	-	-	1	-	1
	108	**107**	**84**	**100**	**163**	**203**	**958**	**1,723**

*NUSCO reported as the joint agent for WMECO and HWP in these transactions.
Source: Derived from EQR data.

4 Contracted transactions tie to an existing reassignment agreement on file with the Commission, whereas uncontracted transactions do not.

The total number of reported TSR reassignments was roughly steady through 1Q08, but increased significantly in the remainder of 2008. The number of reassignments reported by specific transmission providers has varied greatly from one quarter to the next. For example, in the fourth quarter of 2008, an unusually large number of transactions was reported by Bonneville Power Administration (BPA), most of which involved reassignments by two counterparties.[5] As BPA's reassignments represent approximately 75 percent of the total reported for that quarter, their appearance masks the fact that the remaining 243 assignments represent a 225 percent increase in transactions reported since the second quarter of 2007.

In contrast to the number of TSRs reassigned, the capacity of the TSRs reassigned (in MW) has increased through 2007 and remained fairly steady until 4Q08, when BPA's reassignments were reported. As shown in Table 7, the amount of capacity reassigned increased from 3,576 MW in 2Q07 to 8,821 MW in 4Q08, amounting to 39,430 MW across the seven quarters studied. BPA's sales added a sizable portion (about 22 percent) of the 4Q total, making them the ninth largest supplier despite contributing sale reassignments in only one quarter.

5 Those two counterparties were Shell and Powerex Corp.

Table 7

Capacity Reassigned by Transmission Provider by Quarter (in MW)

	2Q 07	3Q 07	4Q 07	1Q 08	2Q 08	3Q 08	4Q 08	Totals
Mid_Continent PP		1,448	1,698	1,698	1,698	1,698	1,698	9,936
Cross-Sound Cable	1,540	596	885	950	800	775	540	6,086
Southern Co.		1,393	300	587	1,222	712	100	4,314
NUSCO (as Agent)				665	665	665	1,115	3,110
NW Energy			274	501	617	549	762	2,703
SPP				500	500	500	1,000	2,500
MISO	102	153	306	558	660	303	405	2,487
NU Services Co.	665	665	665					1,995
BPA							1,913	1,913
Entergy	1,254	50				199	199	1,702
NVP						297	297	594
PacifiCorp	15	15	15	15	30	196	206	492
MidAmerican			87	87	87	87	87	435
PSNM					94	161	161	416
APS					80	100	100	280
Idaho Power						129	129	258
EPE						100		100
Puget Sound							82	82
TEC							27	27
Totals:	**3,576**	**4,320**	**4,230**	**5,561**	**6,453**	**6,471**	**8,821**	**39,430**

Source: Derived from EQR data.

The vast majority of reassigned capacity occurred on a small number of systems. Overall, more than half (51.5 percent) of all capacity reassigned occurred on three systems and 93 percent of the total capacity reassigned was on 10 systems.

Duration of Transmission Capacity Reassignment Transactions

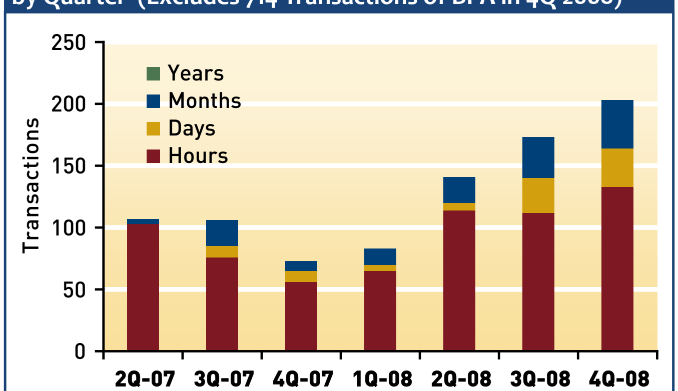
The majority of TSRs reassigned were for an hour. However, as shown in Table 8, the trend shows that the number of transactions made for all durations (hourly, daily, monthly and annually) has increased with time. The large number of transactions reported by BPA in the fourth quarter of 2008 (714) skewed the number of hourly reassignments reported for that period. Figure 39 provides a graphical presentation of the duration of TSR reassignments, with BPA reassignments excluded.

Table 8
Number of Reassigned Transmission Capacity Transactions Grouped by Duration

	Hours	Days	Months	Years	Total
2Q-07	103	0	4	1	108
3Q-07	76	9	21	1	107
4Q-07	56	9	8	11	84
1Q-08	65	5	13	17	100
2Q-08	114	6	21	22	163
3Q-08	112	28	33	30	203
4Q-08	847	31	39	41	958
Total	1,373	88	139	123	1,723

Figure 39

Duration of Transmission Capacity Reassignment Transactions by Quarter (Excludes 714 Transactions of BPA in 4Q 2008)



Source: Derived from EQR data.

Table 9 presents the volume of the capacity reassigned by quarter, exclusive of BPA reassignments. Although the number of hourly reassignments predominates in all transactions, the volumes of the longer-term transactions are significantly larger, as would be expected. In total, more than 186 TWh was reassigned.

Table 9
Reassigned Transmission Capacity (GWh)

Quarter	Hours	Days	Months	Years	Total
2Q-07	21	0	5,904	52	5,977
3Q-07	77	30	6,360	131	6,599
4Q-07	52	25	6,092	12,828	18,996
1Q-08	54	20	4,944	25,596	30,614
2Q-08	86	37	5,642	26,697	32,461
3Q-08	100	84	6,888	29,482	36,555
4Q-08	124	88	10,892	43,730	54,834
Total	514	284	46,722	138,517	186,036

Source: Derived from EQR data.

Geographic Dispersion of Transmission Capacity Reassignment Transactions

Nineteen transmission providers and 27 buyers have participated in the market to date. The capacity has been reassigned from 25 sourcing control areas to 28 sinking control regions. The transactions are grouped by sourcing region in Table 10 and by sinking region in Table 11 (both on next page). Large influence of BPA transactions is again present, reflected in the large percentage of transactions in the Northwest.

Table 10
Regional Distribution of Capacity Reassignment Transactions by Source

Region	Sources	Transactions	% of Total
Midwest	4	236	14%
Northeast	4	311	18%
Northwest	5	888	52%
Southeast	9	208	12%
West	3	80	5%
Total	**25**	**1723**	**100%**

Source: Derived from EQR data.

Table 11
Regional Distribution of Capacity Reassignment Transactions by Sink

Region	Sinks	Transactions	% of Total
Midwest	6	200	12%
Northeast	4	283	16%
Northwest	6	936	54%
Southeast	6	173	10%
Southwest	3	66	4%
West	5	65	4%
Total	30	1723	100%

Source: Derived from EQR data.

Price of Transmission Capacity Reassignments Relative to Tariff Rates

We are unable to fully address the pricing of TSR reassignments because many entities reassigning TSRs failed to report a price other than zero.[6] Specifically, 447 reassignments reported a price of zero across the seven quarters, with 14 others failing to report a tariff maximum rate. Of the remaining 1,262 reassignments, 859 (68 percent) occurred below the maximum rate, 158 (13 percent) occurred at the maximum and 245 (19 percent) transacted above the tariff, as permitted by Order No. 890. We note that 42 percent of the reassignments above the tariff rate occurred in the second quarter of 2007. These data are shown in Table 12. The 714 transactions reported by BPA in the fourth quarter of 2008 again skews the visual analysis of transactions reported, contributing 713 transactions to the "< 50%" category.

Table 12
Transmission Capacity Reassignments Rate Charged Relative to Maximum (by Quarter)

	NR	0%	<50%*	50%-100%	100%-200%	200%	>200%	Total
2Q-07	-	4	1	-	-	89	14	108
3Q-07	-	57	1	-	34	6	9	107
4Q-07	-	58	1	-	9	13	3	84
1Q-08	1	61	1	-	13	9	15	100
2Q-08	3	98	2	1	22	29	8	163
3Q-08	5	70	15	49	36	23	5	203
4Q-08*	4	99	26	49	44	21	1	244
Total*	**13**	**447**	**47**	**99**	**158**	**190**	**55**	**1,009**

Source: Derived from EQR data.

* Total excludes 714 transactions reported by Bonneville Power Authority.

6 This is likely a reporting mistake by customers reporting reassignments to transmission providers.

Section 7

Infrastructure Additions Ease Gas Grid Congestion and Alter Transportation Differentials

Natural gas infrastructure burgeoned in 2008. There were significant additions in both interstate and intrastate infrastructure. EIA estimated that in 2008, new interstate and intrastate gas infrastructure projects added an unprecedented 43.9 billion cubic feet per day (Bcfd) of pipeline capacity, almost three times the capacity additions from previous years.

Introduction

The magnitude of the pipeline projects, with 15 projects each designed to transport more than 1 Bcfd, is significant. The Commission certificated over 35 interstate pipeline projects. In addition, three new North American LNG terminals – Freeport and Sabine Pass in Louisiana and Northeast Gateway (NEG) offshore Boston[1] – began service.

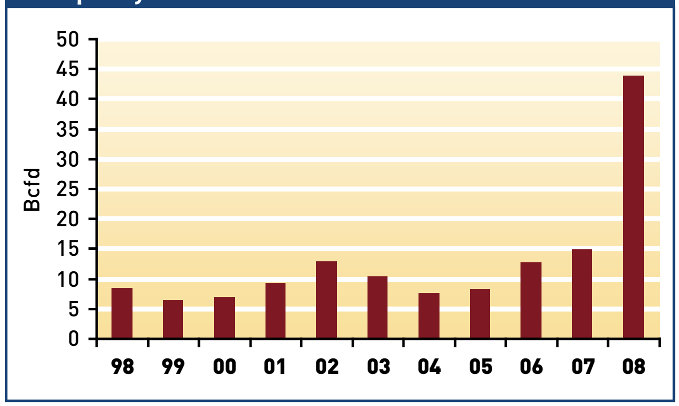
Many of the new pipelines served to better integrate robust unconventional natural gas production into the national pipeline grid. As a result, some of the most significant pipeline capacity additions altered traditional flow patterns and transformed physical transportation price relationships. These changes were especially noteworthy in the Western, Northeastern and Gulf regions (see Figure 41).

1 Freeport and Sabine Pass are under the jurisdiction of the FERC and the Northeast Gateway LNG facility is under the jurisdiction of the United States Coast Guard and the Maritime Administration.

Natural gas storage capacity also experienced robust growth in 2008. The Commission approved 216 Bcf of additional storage capacity and 7.8 Bcfd of deliverability.[2] Nearly 73 percent of the additional storage capacity was concentrated in the Gulf and Midwest regions (see Figure 40).

Figure 40

EIA Estimates Total Natural Gas Pipeline Capacity Additions

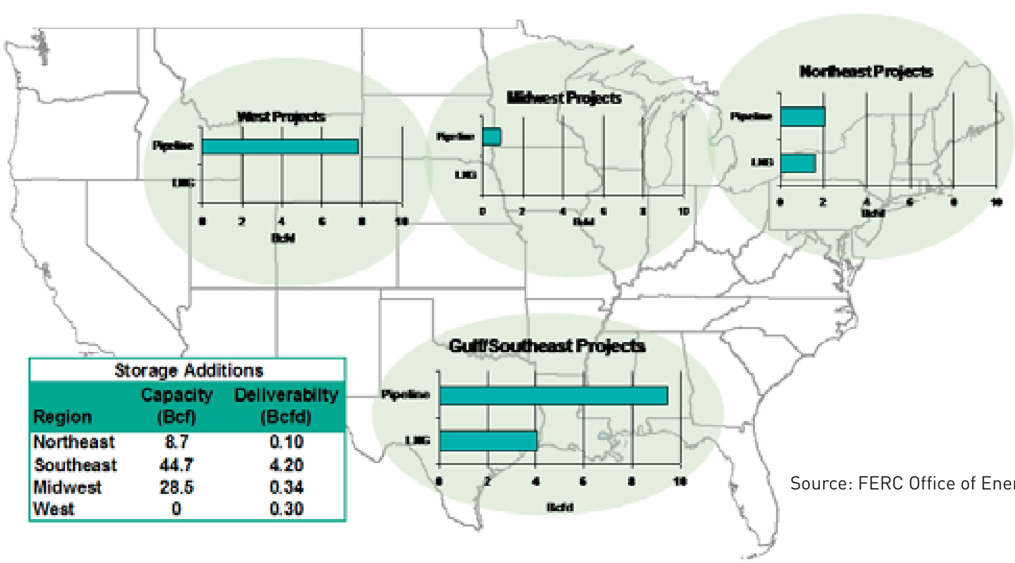


Source: Derived from EIA,GasTran Natural Gas Transportation Information System, Natural Gas Pipeline Projects database as of Jan 2009.

2 Of the projects the Commission approved, 82 Bcf of additional storage capacity was placed in service and 5 Bcfd of storage deliverability was placed in service in 2008. Nearly 90 percent of the additional storage capacity placed in service was located in the Gulf and Midwest regions.

Figure 41

2008 Natural Gas Storage, Pipeline, and LNG Projects



Storage Additions

Region	Capacity (Bcf)	Deliverability (Bcfd)
Northeast	8.7	0.10
Southeast	44.7	4.20
Midwest	28.5	0.34
West	0	0.30

Source: FERC Office of Energy Projects.

Regional Analysis

New infrastructure had pronounced effects on regional gas flows and pricing in 2008, especially in the Gulf-Ohio Valley, Rockies-Midwest and East Texas-to-Southeast corridors.

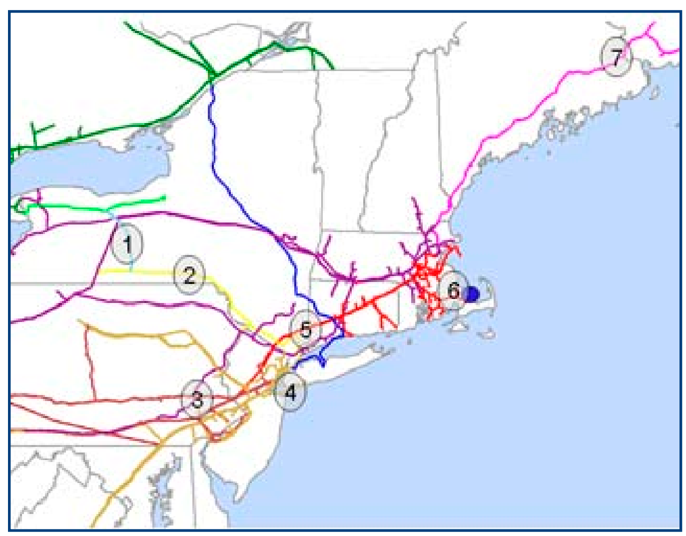
Gulf – Ohio Valley Corridor

Northeast pipelines have added little new capacity in recent years and periodic winter cold snaps have constrained the pipeline system. In 2008, pipelines added more than 2 Bcfd of capacity to transport additional Canadian LNG, Mid-Atlantic shale and Gulf gas into the Northeast market. Much of the newly added capacity was instrumental in transporting gas directly into the New York City metro area. During peak demand days, the New York City market area can become heavily constrained, and natural gas spot prices can become extremely elevated at the Transco Zone 6 New York (NY) pricing hub. A series of pipeline projects in the Northeast helped alleviate such gas bottlenecks into the Transco Zone 6 NY market and moderate price volatility.

Figure 42 details the recent major Northeast pipeline and LNG projects addressing pipeline congestion and growing Northeast winter demand. To provide context for the size of the these projects, during winter 2008 natural gas demand peaked at 35.1 Bcfd and averaged 20.3 Bcfd. A series of new pipeline additions and expansion projects enabled more Canadian gas to make its way into the New York metro area. For example, the Empire Connector came into service in December 2008, adding 250 MMcfd to the existing pipeline. Most of this gas comes from TransCanada PipeLines at the Canadian border and gets delivered into the Millennium Pipeline at Corning, N.Y., which transports the Canadian gas farther south into the New York metropolitan area. The Millennium Pipeline entered service in December 2008 and is currently flowing on average 270 MMcfd of its 525 MMcfd capacity. Algonquin's Ramapo Expansion was built to take advantage of market opportunities provided by the Millennium project. The Ramapo Expansion receives gas from an interconnect with Millennium. The expansion enables it to flow gas from Millennium and deliver it to the new Brookfield interconnect with Iroquois or, if needed, it can deliver the additional gas farther downstream to Boston.

In addition to the natural gas pipeline expansions, there were several LNG import projects. In May 2008, Excelerate Energy's Northeast Gateway (NEG) LNG facility began commercial operations and received its commissioning cargo. In January 2009, the New England Maritimes Phase IV pipeline expansion increased capacity by 418 MMcfd to help the Northeast market access LNG at the Canaport facility in New Brunswick when it began receiving cargos.

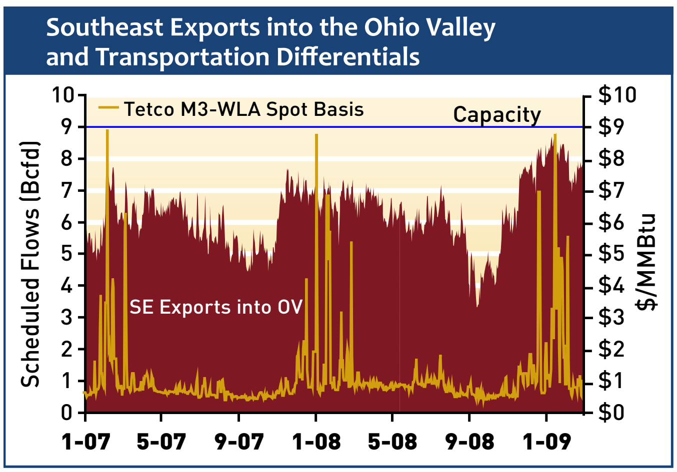
Figure 42
Recent Major Northeast Interstate Natural Gas Pipeline and LNG Projects



	Pipeline	In service	MMcfd
1	Empire Connector	12/15/08	250
2	Millennium Pipeline	12/22/08	525
3	TETCO Time II	12/10/08	150
4	Sentinel Project	12/23/08	40
5	Algonquin Ramapo	11/01/08	352
7	Maritimes Phase IV	1/15/09	480
	LNG		
6	Northeast Gateway LNG	05/17/08	800

Transportation cost differentials (basis) from Transco Z3 on the Gulf Coast to Transco Z6 NY during winter 2008-09 changed dramatically from the previous winters. Winter 2008-09 basis averaged $1.90/MMBtu compared with the winter 2007-08 basis that averaged $2.60/MMBtu. This 27% drop in average daily basis resulted from a decline in commodity prices and an increase in infrastructure throughout the region and into the New York metro market area. This drop occurred despite Transcontinental Gas Pipe Line (Transco) operating at reduced capacity for much of the winter due to a rupture on its system near Appomattox, Va.

Figure 43



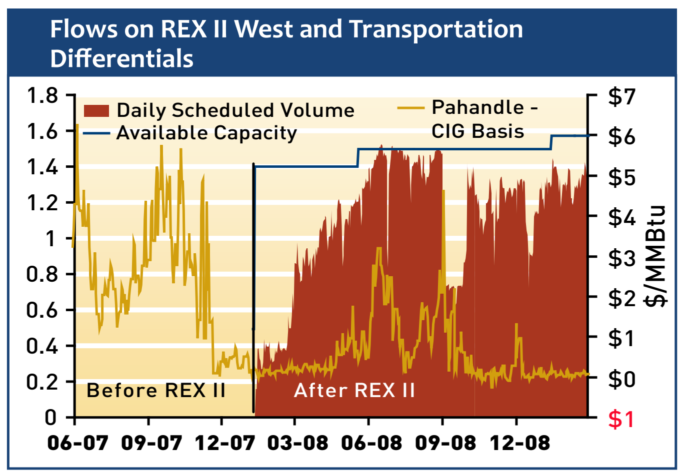
Source: Derived from Bentek Energy and IntercontinentalExchange data.

Conversely, transportation differentials between Texas Eastern Transmission's Tetco WLA (in western Louisiana) and Tetco M3 (near New York) during winter 2008-09 averaged $1.55/MMBtu, $0.15/MMBtu greater than winter 2007-08. This 10 percent increase in average daily basis cost was the result of more gas flowing through the Ohio Valley on Texas Eastern and into the Northeast market (see Figure 43), thus increasing the frequency of constraint-driven price spikes during a colder-than-normal winter. Gas flows through the Ohio Valley increased by 723 MMcfd, or 11 percent, with a portion of the additional supply being made up of shale gas from the Marcellus region. Overall, average 2008 gas flows into the Northeast increased by 476 MMcfd, or 3 percent, despite supply decreases from Canada and the Midcontinent (both were off 9 percent from the previous year).

Rockies – Midwest Corridor

The western region of the country also experienced significant growth in new pipeline capacity. In January 2008 Kinder Morgan finished Phase II of the Rockies Express Pipeline (REX), which is capable of transporting 1.5 Bcfd of natural gas from the Cheyenne Hub in Wyoming to Audrain County, Mo. REX established new interconnections with a number of pipelines serving the Midwest market, including Northern Natural, Panhandle, ANR and Kinder Morgan Interstate Gas Transmission (KMIGT).

Figure 44



Source: Derived from Bentek Energy and IntercontinentalExchange data.

REX's extension into the Midwest has had substantial effects on gas flows and Midcontinent basis differentials. As expected, REX provided shippers in the Midwest greater access to Rockies gas. Exports from the Rockies to the Midwest via REX grew by 1.1 Bcfd in 2008 (see Figure 44). As Rockies gas flowed into the Midcontinent region, transportation differentials between the Rockies and Midcontinent fell. For instance, the basis between the CIG Mainline (in Colorado) and Panhandle (in Oklahoma) markets fell by 68 percent ($1.39/MMBtu) from the previous year.

The increased flow of gas out of the Rockies displaced up to 600 MMcfd of natural gas from Midcontinent and Permian basins along the El Paso, Transwestern, Northern Natural and NGPL pipelines. Gas from Midcontinent basins was rerouted to markets in California and the desert Southwest. In 2008, gas deliveries from the Midcontinent on El Paso and Transwestern contributed to an average increase of 550 MMcfd of gas available for the Southwest market. In turn, this increased flow into the Southwest and Southern California reduced prices in Southern California. Shippers fully utilized PG&E's Baja Path linking Southern California receipt points with delivery points farther north in California to take advantage of lower-cost gas. As the Baja Path became constrained, transportation differentials between the SoCal border and PG&E citygate markets reached historically large levels. On Oct. 12, 2008, that transportation differential reached an all-time peak of $3.60/MMBtu compared to the previous year's daily peak of $2.44/MMBtu. Average daily utilization along the Baja Path increased 86 percent (to 982 MMcfd of 1,140 MMcfd of design capacity) in 2008 compared to 74 percent in 2007, with daily flow often reaching maximum capacity. In addition, displaced Western Canadian Sedimentary Basin gas and additional supplies to the Southwest together established big storage surpluses in Canada and the western United States.

Rockies gas flows into the Midcontinent regions also marginalized Canadian gas imports, especially in the Midwest. Natural gas imports into the Northern Border pipeline fell 13 percent to 1.63 Bcfd from 1.87 Bcfd between 2007 and 2008. Average daily flows into the Northern Border interconnect with Northern Natural at Ventura, Iowa, averaged 0.5 Bcfd lower in June 2008, when REX deliveries into the Midwest peaked. In short, Canadian gas – formerly the lowest-cost gas supplied to the Midwest – became the marginal source of supply.

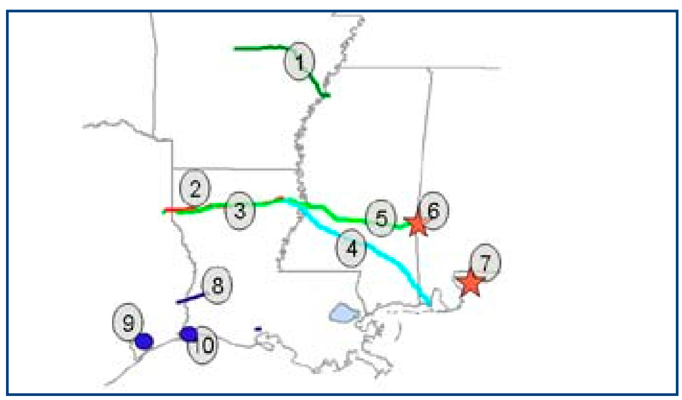
The next REX phase, REX III East, pushed beyond the previous terminus in Missouri to Lebanon, Ohio. Service began in June 2009. REX III East is expected to be fully operational by Nov. 1, 2009, with a capacity of 1.8 Bcfd.

East Texas – Southeast Corridor

Unprecedented construction of gas infrastructure took place along the Gulf Coast in 2008. A slew of pipeline projects came online, intended primarily to deliver increased shale gas volumes from the Woodford, Barnett, Haynesville and Fayetteville plays to downstream markets in the Southeast like FGT Zone 3 and Transco Station 85 (see Figure 45). Four new FERC-jurisdictional storage facilities expanded to add 36 Bcf of working capacity and the expansion of three existing facilities expanded to add 9 Bcf. Storage capacity increases in the Gulf Coast accounted for more than 50 percent of storage capacity increases in the nation in 2008.

Figure 45

2008 Major Gulf and Southeast Interstate Natural Gas Pipeline and LNG Projects



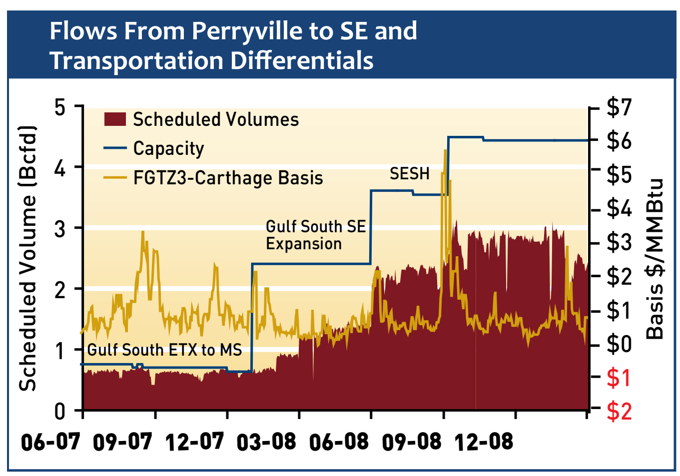
	Pipeline	In service	MMcfd
1	Texas gas Fayetteville Lateral	12/24	850
2	Centerpoint CP Line Phrase III	5/01	280
3	Gulf South E. TX to MS	1/1	1700
4	Southeast Supply Header	9/6	1140
5	Gulf South SE Expansion	5/30	560
8	Trunkline Field Zone Expansion	1/1	510
	LNG		
9	Freeport LNG	7/01	1500
10	Sabine Pass LNG	4/01	2600
	Pricing Hubs		
6	Transco Station 85		
7	Florida Gas Transmission Zone 3		

Nearly 4 Bcfd of takeaway capacity out of the Gulf region was added during 2008. Gulf South's Southeast Expansion project and Southeast Supply Header (SESH) added 1.7 Bcfd of delivery capacity (see Figure 46). These new Gulf South projects (Southeast Expansion and East Texas-to-Mississippi) and other similar Gulf pipeline projects transport Texas and Oklahoma shale gas farther east to Transco Station 85 and beyond. The more northern Fayetteville Lateral, which began service last December, flows gas from the Arkansas Fayetteville Shale. Initially, the pipeline delivered most of its gas into NGPL but subsequent tie-in work with the Texas Gas Mainline shifted flows and now most of the 700 MMcf is delivered into Texas Gas Mainline. These new pipelines provide significant interconnectivity with many larger pipelines such as Transcontinental, Texas Gas Mainline, Texas Eastern and Columbia Gulf, whose routes terminate in the Ohio Valley and Northeast markets.

The influx of cheaper shale gas into the pipeline grid altered basis relationships throughout the region. The SESH delivers 90 percent of its gas to serve Florida load. The added diversity of East Texas shale gas to the Florida supply mix has helped to stabilize Florida prices, decrease the severity of Florida natural gas price spikes and reduce overall 2008 average basis between Carthage, Texas, and Florida Zone 3. In 2008, there were fewer days of high basis compared to 2007. In 2008, the number of days where the basis between Carthage and Florida Zone 3 exceeded $0.50/MMBtu declined 26 percent (71 days) from the prior year (see Figure 46). While September 2008 basis reached $5/MMBtu because of pipeline shut-ins following hurricanes Gustav and Ike, the new pipeline capacity helped keep average 2008 basis 17 percent ($0.15/MMBtu) lower than the previous year. With all the additional pipeline capacity that transports gas farther east into Transco Station 85, the 2008 Transco Zone 4 transportation differential to the Henry Hub was $0.17/MMBtu, the lowest it's been since 2004.

We will likely see another year of extraordinary capacity additions in 2009. Phase I of Gulf Crossing pipeline began service in January 2009 and peak sendout to Texas Gas Pipeline reached 800 MMcfd in early May. The 1.8-Bcfd Midcontinent Express pipeline entered partial service on April 10, 2009, and follows the same path as the Gulf Crossing pipeline. Two pipelines of this magnitude positioned along the same corridor are indicative of the abundance of shale gas supply. Texas Gas Greenville Lateral received authorization to begin flowing volumes and in conjunction with the Fayetteville Lateral, provides Arkansas Fayetteville Shale gas to more premium markets in the Southeast, Gulf and Northeast via pipelines such as Texas Eastern and Columbia Gulf. Dockets on file with FERC's Office of Energy Projects confirm that the next few years will continue to show robust growth in Gulf and Southeast natural gas infrastructure.

Figure 46



Source: Derived from Bentek Energy and IntercontinentalExchange data.

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