Natural Gas Markets: An Overview of 2008

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Summary

In 2008, the United States natural gas market experienced a tumultuous year, and market forces appeared to guide consumers, producers and investors through rapidly changing circumstances. Natural gas continues to be a major fuel supply for the United States, supplying about 24% of total energy in 2008.

The year began with a relatively tight demand/supply balance, and this generated upward spot price movement. For the 2007-2008 heating season, the Energy Information Administration (EIA) reported a price increase of more than 30% (beginning to end of season). The key "benchmark" price for the United States, the Henry Hub spot price, generally rose through the first half of 2008 to a peak of $13.32 per million British thermal units (Btu) on July 3, 2008. By the end of 2008, the Henry Hub spot price had decreased 56% to $5.83 per million Btu, lower than the $7.83 per million Btu price on January 2, 2008.

Closer to consumers, the EIA average citygate price increased 47% from January to $12.08 per million Btu in July and then decreased to $7.94 per million Btu as of December, a 2% drop from the start of 2008. Residential consumers saw a 68% increase through July and then a decline that had December 5% above January's average price.

The supply outlook for the lower-48 states began a potentially important change in 2008. Onshore production in Texas and the Rocky Mountain region increased by 15%, especially because of the production of unconventional natural gas (e.g., deep shale gas).

Noteworthy events in 2008:

- The national natural gas market experienced an unusual price pattern in the first half of the year, with EIA reporting average citygate (delivery area) prices lower than Henry Hub (supply area) spot prices. The normal pattern is the prices in delivery areas, which include transportation costs, are higher than supply area prices.
- Lower-48 onshore natural gas production increased 10% to reach more than 20.5 trillion cubic feet, a level not achieved since 1974. This production, along with other factors such as the weakened economy, appears to have prevented the 350 Bcf of lost gas production due to Hurricanes Gustav and Ike in the Gulf of Mexico from increasing prices.
- Liquefied natural gas (LNG) imports decreased 54% from the record level in 2007. Average use was less than 10% of reported capacity at operational LNG import facilities. The Federal Energy Regulatory Commission (FERC) approved another 2 Bcf per day of new import facilities in 2008.
- Gas for power use decreased 2.4% from 2007 and electric power remained the largest end use category for natural gas consumption for a second year.

Going forward, current economic turbulence may contribute to natural gas market challenges, in terms of investment or attempts at market mischief. Vigilance in market oversight could grow in importance.

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Introduction

Natural gas markets in North America had a tumultuous year in 2008. This contrasted with the relative stability of 2007. In early 2008, the market tightened and prices moved up. In the summer, supply area spot prices went much higher than in the past, then decreased through the rest of the year to end lower than at the start of the year.

This report examines current conditions and trends in the U.S. natural gas markets. Key market elements examined include prices, consumption, production, imports, and infrastructure. Expectations about the future, as reflected in recent official forecasts, are also incorporated here.

Natural gas remains an important and environmentally attractive energy source for the United States and supplied approximately 24% of total U.S. energy in 2008. Domestic supply has recently increased significantly. New developments in Alaska increase the likelihood that a pipeline from the North Slope will proceed, although uncertainty remains regarding this undertaking. The natural gas industry continues to attract capital for new pipeline and storage infrastructure to link shifting loads and supply sources.

In 2008, liquefied natural gas (LNG) imports decreased 54% from the record levels of 2007, decreasing already low utilization factors at import facilities. The Federal Energy Regulatory Commission (FERC) approved two more major import terminals in 2008.

Given the generally adequate functioning of natural gas markets, congressional attention may address development of new supply sources (such as deep shale gas), unexpected price volatility or behavior, or import and other supply issues. In the longer term, industry pressure for increased access to public lands for exploration and production may continue as a policy concern.

This report reviews key factors likely to affect market outcomes. These factors include weather, the economy, oil prices, and infrastructure development. **Table A-1** to **Table A-6** (in **Appendix A**) present selected highlight statistics that illustrate current market status.

Briefly, important developments in natural gas markets during 2008 include the following:

- Domestic natural gas production increased to 20.5 trillion cubic feet, the most since 1974.[1] Hurricanes Gustav and Ike reduced Gulf of Mexico production but did not affect market prices significantly.
- There was an unusual price pattern in the first half of 2008, with citygate (delivered) prices lower than Henry Hub spot prices. Citygate prices have seldom exceeded Henry Hub prices.
- The natural gas spot price at Henry Hub peaked on July 3, 2008, at $13.32 per million Btu and declined to under $6 by end of year.[2]
- During the 2007-2008 heating season (October to March), average wellhead prices increased more than 30%, according to the U.S. Energy Information Administration (EIA) estimates.[3]

[1] EIA, *Natural Gas Monthly*, February 2009, Table 1, Annual Summary of Natural Gas Production.

[2] Federal Energy Regulatory Commission, *Market Snapshot*, January 2009, p. 4.

- Natural gas for power has reduced seasonal variation in use because gas-for-power peaks in summer, versus the total natural gas use peak in winter.
- The power generation sector used more natural gas than any other sector in 2008 and 2007.
- Storage levels towards the end of the 2007-2008 heating season dropped below five year averages. In the first storage report after the 2007-2008 heating season, working gas storage was at 1,234 billion cubic feet (Bcf) – the lowest level since April 30, 2004.[4] However, as of December 2008, working gas storage was at 2,840 Bcf.[5]
- LNG imports in 2008 dropped 54% from the 2007 record level of 77.1 billion cubic feet. The future outlook is uncertain. FERC approved 2 import facilities in 2008, with an import capacity increase of 2 billion cubic feet per day.
- Natural gas infrastructure development continued to advance, with more pipeline and storage projects successfully completed in 2007 and more underway in 2008.
- Industrial gas use had some growth in 2008, continuing increases since 2006.

Background

Unlike the global oil market, natural gas markets remain generally regional, with global trade in LNG growing. For the most part, North America has a continent-wide market that is integrated through a pipeline network that connects the lower-48 states, the most populous provinces of Canada, and parts of Mexico. Prices throughout this integrated market are influenced by demand (which may be influenced by weather, economic conditions, alternative fuel prices, and other factors), supply, and the capacity available to link supply sources and demand loads (transmission and distribution systems).

The U.S. natural gas market is the major component of the North American natural gas market. It accounts for about 81% of North American consumption and about 70% of North American supply.

The key price point in North America is Henry Hub. Henry Hub is a major pipeline hub near Erath, Louisiana, that is used as the designated pricing and delivery point for the New York Mercantile Exchange (NYMEX) gas futures contracts and other transactions. The price difference between other locations and Henry Hub is called the "basis differential." When there is spare capacity available to move natural gas from Henry Hub, or the Gulf of Mexico region in general, to the relevant price point area, the basis differential tends to be low, approximating the costs of fuel used to move the gas to the location. When capacity availability is tight, basis differentials can grow because the driving force can become the value of the natural gas at the delivery point, rather than the cost of getting the natural gas to that point.

(...continued)

[3] EIA, *Natural Gas Weekly Update*, February 5, 2009.

[4] EIA, *Natural Gas Weekly Update*, February 5, 2009.

[5] EIA, *Natural Gas Navigator*, Underground Natural Gas Storage by All Operators, February 26, 2009.

Natural gas prices also incorporate costs for distributing the gas from the wholesale marketplace to retail customers. These rates are generally determined by state regulators and involve both (1) the approval of costs and rates of return and (2) the allocation of costs among customer classes (e.g., residential, commercial, industrial firm, industrial interruptible).

Although the North American natural gas market remains a distinct regional market, it is connecting to a global gas marketplace through international LNG trade. Oil prices still affect U.S. natural gas prices and this evolving relationship is discussed later in this report.

Market Conditions

The key elements of the market are prices, consumption, and supply. This section provides highlights from recent market developments relating to these factors.

Prices

The price stability of 2006 and 2007 ended in 2008. Early 2008 prices increased at a faster pace than in 2007. According to EIA figures, spot prices at Henry Hub increased about 70% from January 1 to July 3, 2008, peaking at $13.31 per million Btu (MMBtu).[6] The price then decreased to $5.83 per MMBtu by the end of December 2008,[7] ending the year about 28% below the start-of-year price. (See **Figure 1** for price graph.)

The U.S. Energy Information Administration reports producer price data for its wellhead price series. During the 2007-2008 heating season (October to March), EIA estimates the average wellhead price increased more than 30%, to $8.06 per MMBtu.[8] The highest monthly value was $10.52 per MMBtu in June.

The EIA citygate price series reflects the unit prices delivered to consuming areas.[9] The average U.S. citygate price increased $1.03 to $9.15 per thousand cubic feet (mcf) from 2007 to 2008.[10]

From 2006 to 2007, LNG import prices continued to decrease, from $7.19 per mcf to $7.07. (EIA full year 2008 LNG price data are not yet available.)

[6] EIA data is recorded as dollars per thousand cubic feet; the EIA provided conversion factor for 2008 (based on 2007 consumption) is 1 Cubic Foot = 1,028 Btu.

[7] Energy Information Administration (EIA), *Short-Term Energy Outlook*, February 2009, Table 5c.

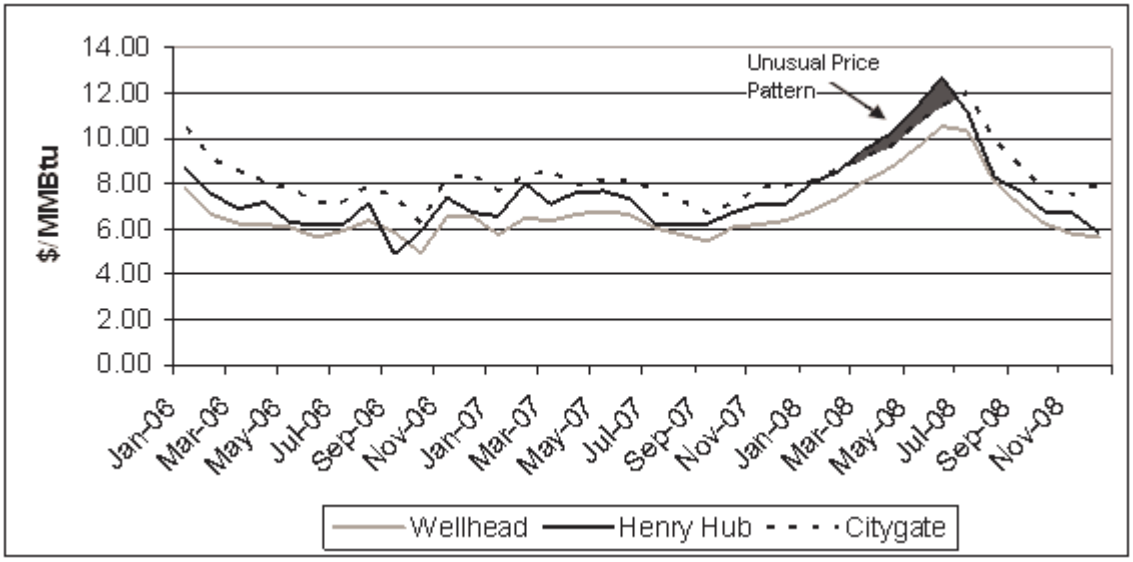
[8] EIA, *Natural Gas Weekly Update*, February 5, 2009.

[9] The "citygate" is the transfer point from a high pressure natural gas pipeline to a local distribution company.

[10] EIA, *Natural Gas Monthly*, February 2009, Table 3.

Figure 1. U.S. Natural Gas Wholesale Price Overview

($ per million Btu)



Source: EIA, *Natural Gas Monthly* (NGM), January 2009, Table 3 for citygate and wellhead; EIA, *Short-Term Energy Outlook*, February 2009, Figure 4 and archive, for Henry Hub.

Notes: See **Table A-1** for source data.

At the retail level, average U.S. residential natural gas prices were $13.52 per MMBtu in 2008, with a high of $19.74 in July. This average was about 5% increase from 2007. The average commercial price was $11.76 per MMBtu, an increase of about 6% from 2007. Industrial prices increased about 25% to $9.61 per MMBtu. Yearly totals are not yet available for natural gas sold for electric power; as of September 2008, prices had increased 25% versus September 2007 however. (See **Figure 2** for price chart.)

An Anomalous Price Pattern

The spot price of natural gas is a key indicator of the price that producers or LNG importers are receiving for spot sales in the major producing area of the Gulf of Mexico. From there, the gas generally moves to markets to the north (e.g. Chicago), to the east (e.g. New York), or around the Gulf (e.g. Florida). This transmission to market generally leads to a transport cost add-on and a higher price at the delivery point.

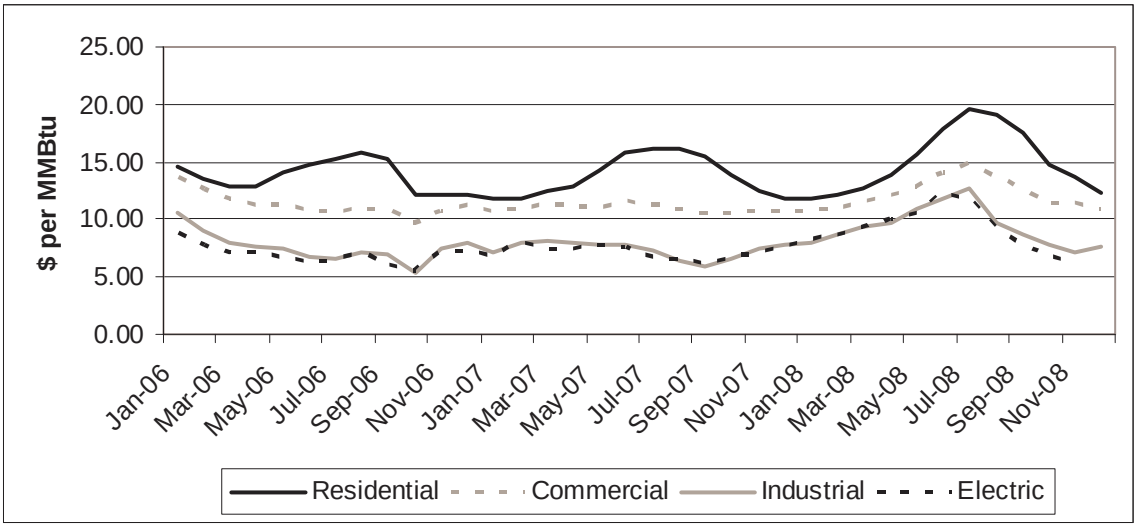
Since the Henry Hub spot price was first reported in 1993 until 2008, this price has exceeded the EIA citygate (delivered price) in only eleven months (see **Figure A-1** in **Appendix A**). In the first half of 2008, the Henry Hub spot price exceeded the EIA reported citygate price in three consecutive months (April, May, and June).

The spot price at Henry Hub appears to have increased quickly in the first half of 2008, and this price at Henry Hub (a supply area price benchmark) actually exceeded the EIA estimated average citygate (the "delivery points" in consumption areas) price. CRS has found no discussion of this price anomaly in market monitoring documents from that period. One possible explanation for this anomaly is that the citygate price includes multi-month contracted-for supplies that would include natural gas from earlier months when prices were lower than the current spot price.

Greater production from shale areas near markets or storage gas withdrawal could be other explanations.

Figure 2. U.S. End Use Price Overview

($ per million Btu)



Source: EIA, Natural Gas Monthly, February 2009, Table 3.

Notes: See **Table A-3** for source data.

Consumption

Total U.S. consumption of natural gas grew almost 1% from 2007 to 2008, according to EIA. Power sector use of natural gas decreased about 2.8% in 2008. Commercial and residential sectors grew more than 3% each and industrial use (without lease and plant use) increased 0.3%. The power sector led end-use consumption for the first time in 2007 and maintained its position as the sector using the most gas in 2008. Power and industrial use were essentially equal for 2008. (**Table 1** shows the consumption data.)

Table 1. U.S. Natural Gas Consumption Overview

Billion cubic feet (Bcf)

Year	Residential	Electric	Commercial	Industrial	Other	Total
2006	4,368	6,222	2,832	6,512	1,750	21,685
2007	4,717	6,841	3,017	6,625	1,847	23,047
2008	4,879	6,649	3,126	6,644	1,944	23,242
% change 2006/07	8.0%	10.0%	6.5%	1.7%	N.A.	6.3%
% change 2007/08	3.4%	-2.8%	3.6%	0.3%	N.A.	0.8%

Source: EIA, *Natural Gas Monthly*, February 2009, Table 2 and CRS calculations.

Supply

U.S. natural gas supply comes from domestic production, pipeline imports, imported LNG, and net withdrawals from storage. In a major shift, domestic supplies increased more than 7% between 2007 and 2008. Total production for 2008 exceeded 20.5 trillion cubic feet, the most since 1974.[11] Net imports decreased in 2008.

The dry gas production increased 7.8% to 20,571 billion cubic feet in 2008,[12] reflecting in part the increase in drilling activity in response to price increases, as indicated in the natural gas rig count. The U.S. natural gas rig count has trended upward since 2002. In 2002, the average monthly rig count was about 600. The count reached 1,606 in September 2008, before decreasing to 1,366 late in the year.[13] Recent news accounts report that natural gas rigs have declined about 45% since September 2008, the most rapid decline since 2002.[14]

In 2008, U.S. consumers received most of their supply, 91%, from domestic production. Net imports (pipeline and LNG) decreased over 20% to 2,996 Bcf in 2008. Imports via pipeline from Canada decreased 5%. LNG imports in 2008 decreased 54% from 2007 after increasing 32%, to a record level, between 2006 and 2007.[15] (See **Table 2**.)

Table 2. U.S. Natural Gas Supply Overview

(Bcf)

Year	Dry Gas Production	Net Imports	Net Storage Withdrawals	Other/ balancing	Total
2005	18,051	3,612	52	296	22,011
2006	18,504	3,462	-436	155	21,685
2007	19,089	3,785	193	-19	23,047
2008	20,571	2,996	32	-357	23,242
% change 2006/07	3.2%	9.3%	N.A.	N.A.	6.3%
% change 2007/08	7.8%	-20.8%	N.A.	N.A.	0.8%

Source: EIA, *Natural Gas Monthly*, February 2009, Table 1 and CRS calculations.

In 2008, available LNG supplies were sometimes bid away to European terminals for higher prices. Nevertheless, new U.S. LNG infrastructure went into service in 2008 and still more received approvals from FERC. To compete effectively for supply in the global LNG market, natural gas prices at the U.S. delivery points would have to increase to attract LNG deliveries.

[11] EIA, *Natural Gas Monthly*, February 2009, Table 1, Annual Summary of Natural Gas Production.

[12] EIA, *Natural Gas Monthly*, February 2009, Table 1.

[13] Baker Hughes, *North American Rotary Rig Count*, U.S. Oil & Gas Split.

[14] Bloomberg.com, March 16, 2009, available at http://www.bloomberg.com/apps/news?pid=20670001&refer=home&sid=a3PoNVnytrgo.

[15] EIA, *Natural Gas Imports by Country*, available at http://tonto.eia.doe.gov/dnav/ng/ng_move_impc_s1_m.htm.

Location of import facilities is an important factor in the value of landed LNG.[16] The United States appears more likely to be receiver-of-last-resort for LNG shipments in the near-to-mid term than to outbid Europeans, given the recent interruptions in Russian supplies. On the other hand, lack of storage in Europe and Asia may lead to continued U.S. receipts of LNG, even at relatively low prices, because new LNG export facilities serving the Atlantic Basin are expected to reach completion soon.

Table 3. Lower-48 LNG Overview

(Bcf/d)

Terminal	Average Deliveries 2008	Deliverability EOY 2008	Average Deliveries 2007	Deliverability EOY 2007
Cove Point, MD	N.A.	1.00	0.41	1.00
Everett, MA	N.A.	1.04	0.50	1.04
Elba Island, GA	N.A.	1.20	0.47	1.20
Lake Charles, LA	N.A.	2.10	0.69	1.80
Gulf Gateway, TX[a]	N.A.	0.50	0.05	0.50
Northeast Gateway, MA[a]	N.A.	0.80	N.A.	0.80
Freeport, TX	N.A.	1.50	N.A.	N.A.
Sabine, LA	N.A.	2.60	N.A.	N.A.
Total	0.96	10.74	2.11	7.34

Source: EIA, Short-Term Energy Outlook Supplement: U.S. LNG Imports – The Next Wave, January 2007, pp.9-10; FERC, North American LNG Terminals, Existing, Office of Energy Projects, February 6, 2009; EIA.

a. Offshore.

EIA forecasts an increase of less than 20 Bcf of LNG for 2009 to 369 Bcf.[17] In addition, an LNG import facility in eastern Canada largely focused on exporting to the United States was originally expected to enter service in 2008, but remains under construction. It may enter service in 2009.

Market Trends

There are several trends under way in natural gas markets of interest to policy makers. They include:

- strong lower-48 onshore production
- a decrease in seasonal demand swings
- strong gas-for-power use
- changing international trade in LNG

[16] This siting issue is discussed in greater detail in CRS Report RL32386, *Liquefied Natural Gas (LNG) in U.S. Energy Policy: Infrastructure and Market Issues*, by (name redacted)

[17] EIA, *Short-Term Energy Outlook*, February 10, 2009, p.5.

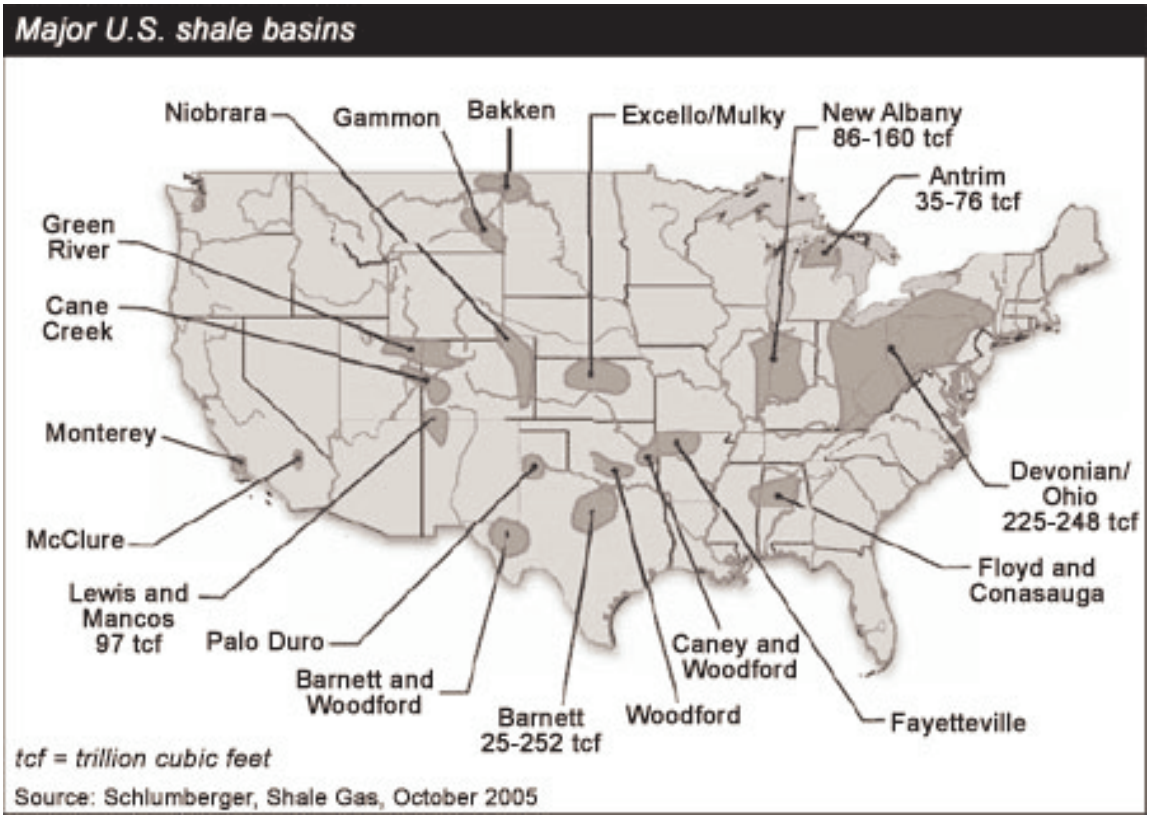
- continuing progress in natural gas infrastructure development

Strong Production

The natural gas supply picture for the lower-48 improved during 2008. Advances in unconventional gas production led to a 7.7% increase in lower-48 production, even though outer continental shelf (OCS) production lost almost 350 billion cubic feet due to hurricanes Gustav and Ike.

Figure 3. Estimated Recoverable Natural Gas for Select Shale Basins

(trillion cubic feet)



Source: EIA, *Energy in Brief: What Everyone Should Know*, June 11, 2008, available at http://tonto.eia.doe.gov/energy_in_brief/natural_gas_production.cfm.

The domestic supply has shifted from shallow Gulf of Mexico to deep Gulf of Mexico and unconventional sources in Texas, the Rocky Mountains and elsewhere.[18] As new resources grow in importance, the need for increased gas leasing of on- and offshore federal lands is evolving.[19]

[18] Conventional natural gas supplies are produced by conventional drilling and extraction. Unconventional gas involves more advanced technology, such as extraction of methane from coal beds or from tight formations and shales requiring fracturing and other techniques.

[19] For more discussion, see CRS Report RL33493, *Outer Continental Shelf: Debate Over Oil and Gas Leasing and Revenue Sharing*, by (name redacted).

The U.S. natural gas reserve base has recently continued to increase. EIA reserves and production data indicate that the latest reserves-to-production ratio[20] (2007) is 12.2, an increase from the prior year's ratio of 11.4 and 2000's ratio of 9.2.[21]

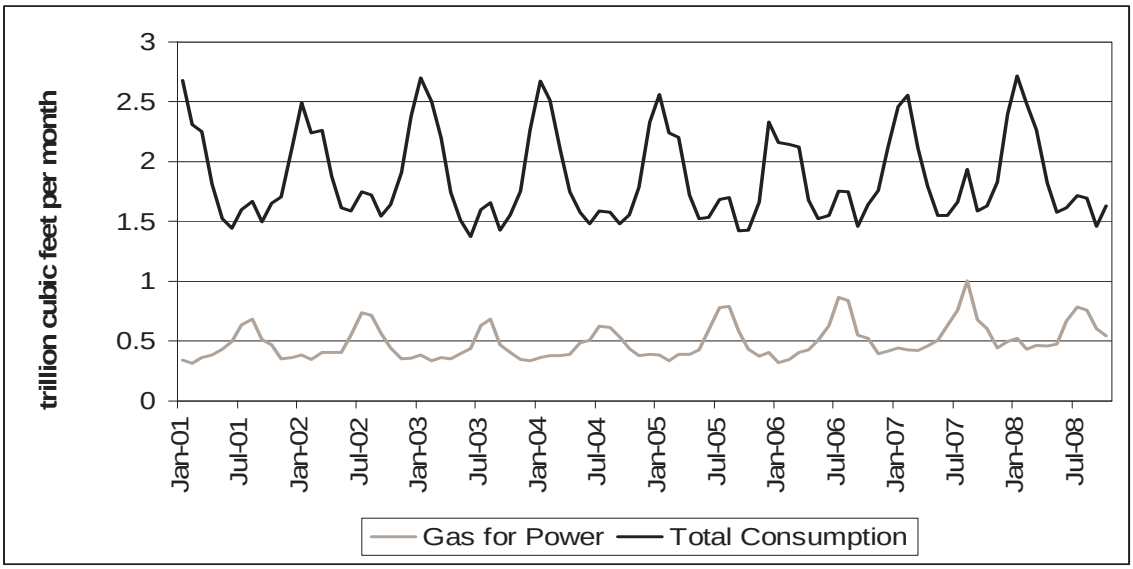
The Potential Gas Committee (PGC) is expected to release an assessment of the nation's natural gas supplies in the spring of 2009. This will provide an authoritative update on the natural gas supply situation for the United States. The PGC consists of more than 100 "voluntary experts" from industry, academia, and government. They are primarily geologists or engineers recruited because of their experience preparing resource estimates within their area. It was created in 1964 to address conflicting predictions of long term gas supply at that time.[22]

Seasonality

Consumption of natural gas in the United States remains highly seasonal for three major sectors, reflecting the importance of space heating; residential and commercial use of natural gas peaks in winter. Reflecting the importance of air conditioning load and the role of natural gas as the marginal fuel source for power generation, electric power use of natural gas peaks in summer. (Industrial use is relatively stable throughout the year.)

Figure 4. Monthly Natural Gas Consumption: Total and Electric Power Use

(Tcf/month)



Source: EIA, *Natural Gas Navigator*, Consumption for End Use, December 2008.

[20] The reserves-to-production ratio divides the nation's proven reserve figure by the annual production to calculate this metric of supply inventory.

[21] EIA, *Dry Natural Gas Proved Reserves*, available at http://tonto.eia.doe.gov/dnav/ng/ng_enr_dry_dcu_NUS_a.htm.

[22] Potential Gas Committee, *History and Present Status*, available at http://inside.mines.edu/research/pga/aboutpgc.html.

Figure 4 illustrates that the combination of these seasonal patterns has led to a decrease in the overall seasonal swing and the development of a secondary peak in the summer due to gas-for-power use. Interestingly, some continue to call for more storage because of the growing consumption of natural gas, thinking that higher consumption levels require more storage volume. The decrease in the seasonal swing, however, through a decrease in the high month volume and an increase in the low month volume, means that less storage may be capable of serving the annual seasonal cycling needs of the U.S. markets. Those trading natural gas may want additional storage for arbitrage uses, but the fundamental needs related to system reliability may decrease somewhat with a decrease in the difference between minimum and maximum consumption rates.

The secondary peak in gas for power was less in 2008 than in the previous years. This is explained by a decrease in the number of cooling degree days for summer 2008, ending a trend of increasing cooling degree days for several years. (See **Table A-7** for data.)

Another noteworthy seasonal feature observed by EIA was that as of 2007, natural gas price volatility was "considerably higher" in colder months than in other times.[23] The pattern in 2008, however, appears contrary to this observation.

Gas-for-Power Use

From 2006 to 2007 deliveries to electric power customers increased by 615 Bcf, more than 45% of the consumption growth for the year. For the first time, electric power use of natural gas became the largest end use sector for natural gas.[24] In 2008, gas-for-power use declined but this sector remained the largest gas user.

The relative increase in electric generator use of natural gas during winter is also significant. In 2007, FERC's Division of Energy Market Oversight noted that November-March volumes increased 14% between winter 2005/06 and winter 2006/07.[25] More recent data are not yet available.

Industrial Gas Use

Industrial gas use in 2006 was approximately 13% lower than the 7,507 Bcf consumed in 2002. In 2007, industrial use increased by 2% over the 2006 level. In 2008, industrial gas increased about 0.3%.

Global LNG Trade

LNG monthly imports in 2008 varied from a high of 35.4 Bcf in August to a low of 22.8 Bcf in November. Because little of the LNG is imported under long term contracts, U.S. importers compete on the global LNG spot market for deliveries.

[23] EIA, *An Analysis of Price Volatility in Natural Gas Markets*, August 2007, p.2.

[24] This excludes lease and plant gas use from the industrial sector, where it sometimes is included.

[25] FERC, Division of Market Oversight, *Winter 2007/2008 Energy Market Assessment*, Item No.: A-3, October 18, 2007, "Electric Generators Using More Winter Gas," no page.

In December 2008, European natural gas prices were in the $7.80-$9.50 per MMBtu range. New England citygates were at $10.06 per MMBtu and Henry Hub was at $8.85 per MMBtu. Thus, some import points could compete successfully in the global spot market for LNG and others could not.[26] There is excess physical capacity at existing LNG import facilities to handle about ten times the imports of 2008.

Infrastructure Progress

The North American natural gas industry has continued to add new infrastructure to the system. As noted in **Table 4** and **Table 5**, FERC identifies facilities that went into service in 2007 and 2008. These facilities appear responsive to serving fundamental market needs, such as new capacity from the growing production areas.

Table 4. Infrastructure Completed in 2007

Type of Project	Number of Projects	Capacity
Pipelines	more than 50	14.9 Bcf/d
LNG import terminals	0	—
Storage facilities	9	1.8 Bcf/d

Source: EIA, Office of Oil and Gas, *Natural Gas Year-In-Review,,* March 2008, p.5 and FERC, *Winter 2007/2008 Energy Market Assessment*, Item No.: A-3, October 18, 2007, "What has been placed into service," no page.

Table 5. Infrastructure Completed in 2008

Type of Project	Number of Projects	Capacity
Pipelines	N.A.[a]	15.4 Bcf/d
LNG import terminals	3[b]	5.7 Bcf/d
Storage Facilities	N.A.[a]	4.6 Bcf/d

Source: FERC, by CRS request.

a. Despite CRS requests for an update on the 2007 project data, FERC has not provided these figures.

b. These new LNG import terminals are Northeast Gateway Deepwater Port, Freeport Texas and Sabine, LA. Additionally, the Lake Charles, LA facility was expanded in 2008; that new capacity is included in the 5.7 Bcf/d.

Forecasts

Given the major economic shock to the energy markets during 2008, forecasts mean even less today than they usually do.

In its Short Term Energy Outlook, EIA forecasts a 1% decrease in natural gas use for 2009, relative to 2008 because of weak economic conditions. A small increase in residential use will be

[26] FERC, Division of Market Oversight, Office of Enforcement, *OE Energy Market Snapshot*, February 6, 2009, National Version, p. 13.

offset by a larger decrease in commercial, industrial, and electric power demand. EIA forecasts increased U.S. production of less than 1%, primarily because of lower natural gas prices and decreased demands because of the economic downturn. EIA expects LNG imports to increase 20% in 2009, rebounding somewhat from the 42% drop in 2008. However, low summer demand in Europe could mean the United States will receive more LNG than forecast. EIA forecasts average Henry Hub prices to decrease roughly 35% in 2009, to $5.62 per MMBtu, due to weak economic conditions, increased U.S. production, and lower demand.

Uncertainties

EIA's forecast of natural gas prices depends on certain assumptions embedded in the forecast. These factors have uncertainty associated with them, as discussed next.

Weather

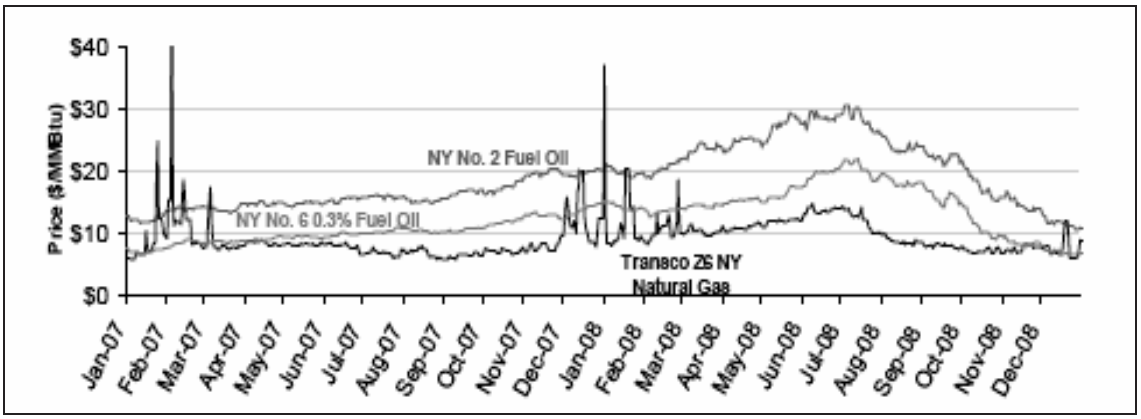
Weather affects natural gas consumption through both the significant space heating loads in the residential and commercial sectors and the cooling load served by gas-fired power generation. EIA incorporates National Oceanic Atmospheric Administration (NOAA) weather forecasts in its short and long term forecasts. To the extent that actual heating degree days exceed the temperature scenario from NOAA, that will tend to increase demand for natural gas in the heating season and increase prices for natural gas during those periods. Similarly, if the actual cooling degree day requirements exceed those incorporated in the EIA scenario, then this will increase natural gas use in the cooling season via increased gas-fired power for air conditioning and increase the price for natural gas in the relevant cooling season.

Oil Prices

Natural gas prices and oil prices have long had a correlation. As the extent of oil/gas fuel switching has declined, this linkage has changed. For many years, the key relationship was between the delivered price of natural gas to New York and the price of alternative fuels (residual fuel oil, No. 6, or distillate fuel oil, No. 2). Historically, when natural gas prices in the northeast market area reached a price at which a significant industrial or utility load could save fuel costs by switching to a petroleum alternative, the users would switch fuel. This would limit the price to this alternative. There was a time when almost 1 trillion cubic feet of natural gas load could switch. As illustrated in **Figure 5**, natural gas prices have generally been lower than either alternative fuel since the beginning of 2007. The exceptions have been limited periods of extreme cold in the Northeast. This suggests a delinkage in prices that may have resulted from environmental restrictions limiting the quantity of fuel-switchable load.

The convergence of No. 6 oil and natural gas prices appears more likely to be due to oil prices falling more drastically than natural gas prices in the second half of 2008.

Figure 5. Comparison of Natural Gas and Competing Oil Product Prices



Source: FERC, Division of Market Oversight, *OE Energy Market Snapshot*, National Version - December 2008 data, January 2009, p. 41.

Economy

Economic growth affects consumers' demand for natural gas and their ability to purchase it. EIA appears to have incorporated an economic outlook that expects less growth than in its recent forecasts. Given the relative stability in the residential and commercial sector consumption, the changed economic outlook would most likely affect industrial and power generation natural gas use most directly.

Conclusion

Natural gas markets in North America continue to function well relative to other energy markets. Consumers and producers managed the tumultuous prices of 2008 without suffering major apparent damage.

This market appears to continue responding appropriately to price signals. New pipelines and storage facilities have been built where price differentials have indicated need and value for these facilities.

Current investment in LNG import capacity may prove excessive for the 2008-2009 heating season.

There is the potential, given the higher prices in summer than in the heating season, that retail customers may face prices higher than spot prices because of risk management contracts signed by local gas utilities during the 2008 period of high prices.

Weather and the overall economy remain important factors for natural gas demand and price levels. These factors remain uncertain and beyond human forecasting capability.

Appendix A. Selected Statistics

Table A-1. U.S. Natural Gas Wholesale Price Overview

($ per MMBtu)

Month	2008			2007		
	Henry Hub	Wellhead	Citygate	Henry Hub	Wellhead	Citygate
January	8.02	6.80	8.11	6.56	5.76	7.68
February	8.53	7.34	8.63	8.02	6.48	8.36
March	9.48	8.06	9.19	7.12	6.38	8.57
April	10.20	8.70	9.59	7.62	6.65	7.97
May	11.34	9.54	10.66	7.65	6.79	8.16
June	12.71	10.53	11.40	7.36	6.67	8.15
July	11.13	10.33	12.03	6.23	6.02	7.72
August	8.27	8.09	9.88	6.20	5.74	7.26
September	7.66	7.07	8.72	6.26	5.46	6.70
October	6.75	6.19	7.67	6.75	6.08	7.16
November	6.68	5.81	7.54	7.11	6.20	7.83
December	5.83	5.65	7.94	7.12	6.35	7.91
Average	8.88	7.84	9.28	7.00	6.22	7.79

Source: EIA, *Natural Gas Monthly*, February 2009, Table 3 for Wellhead and Citygate; EIA, *Short Term Energy Outlook*, February 2009, Figure 4 for Henry Hub.

Notes: EIA provides data in dollars per thousand cubic feet; EIA conversion factor for 2008 (based on 2007 consumption) is 1 Cubic Foot = 1,028 Btu.

Table A-2. U.S. Natural Gas Wholesale Price Overview

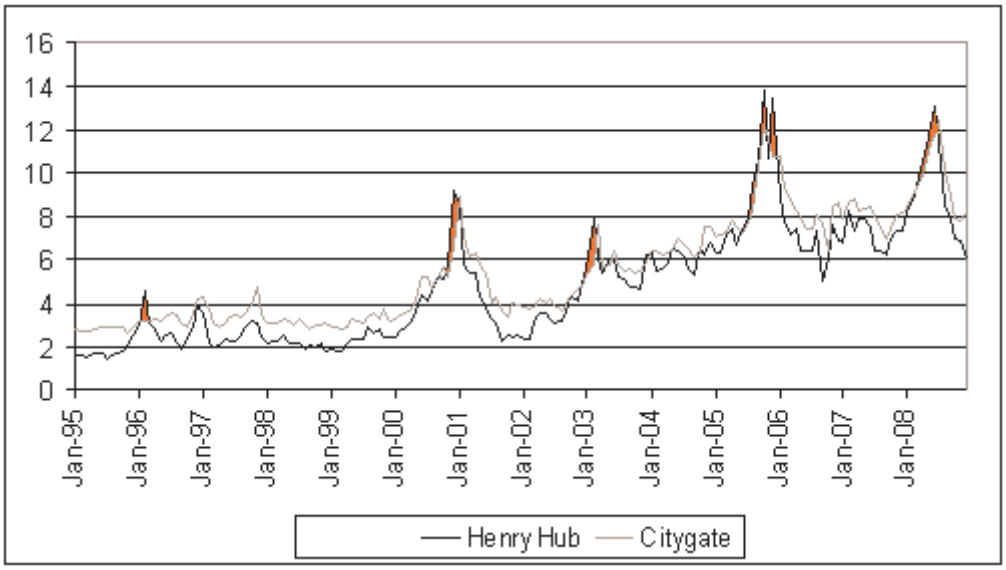
($ per mcf)

Month	2008			2007		
	Henry Hub	Wellhead	Citygate	Henry Hub	Wellhead	Citygate
January	8.25	6.99	8.34	6.75	5.92	7.89
February	8.76	7.55	8.87	8.24	6.66	8.59
March	9.74	8.29	9.45	7.32	6.56	8.81
April	10.49	8.94	9.86	7.83	6.84	8.19
May	11.65	9.81	10.96	7.87	6.98	8.39
June	13.06	10.82	11.72	7.57	6.86	8.38
July	11.45	10.62	12.37	6.40	6.19	7.94
August	8.51	8.32	10.16	6.37	5.90	7.46
September	7.88	7.27	8.96	6.44	5.61	6.89
October	6.94	6.36	7.88	6.94	6.25	7.36
November	6.87	5.97	7.75	7.31	6.37	8.05
December	5.99	5.81	8.16	7.32	6.53	8.13
Average	9.13	8.06	9.54	7.20	6.39	8.01

Source: EIA, *Natural Gas Monthly*, February 2009, Table 3 for Wellhead and Citygate; EIA, *Short Term Energy Outlook*, February 2009, Figure 4 for Henry Hub.

Figure A-1. Henry Hub and EIA Citygate Prices (1995-2008)

$ per thousand cubic feet



Source: CRS graphic with data from **Table A-2** and archived data.

Notes: Shaded area indicates times when Henry Hub spot prices exceeded citygate prices.

Table A-3. U.S. End Use Price Overview

($ per MMBtu)

Month	2008				2007			
	Residential	Commercial	Industrial	Electric Power	Residential	Commercial	Industrial	Electric Power
January	11.77	10.76	7.97	8.25	11.76	10.84	7.14	6.86
February	12.10	11.04	8.68	8.66	11.79	10.93	8.01	7.94
March	12.62	11.46	9.37	9.30	12.51	11.50	8.17	7.43
April	13.91	12.11	9.75	9.99	12.91	11.20	7.92	7.55
May	15.58	12.87	11.02	10.66	14.21	11.20	7.89	7.74
June	17.82	14.02	11.74	12.26	15.76	11.55	7.77	7.59
July	19.65	15.01	12.71	11.83	16.20	11.31	7.35	6.82
August	19.10	13.68	9.68	9.08	16.19	10.88	6.40	6.61
September	17.45	12.68	8.67	7.81	15.51	10.60	5.95	6.18
October	14.82	11.50	7.86	6.83	13.86	10.51	6.67	6.85
November	13.36	11.15	7.00	6.48	12.47	10.74	7.43	7.07
December	12.30	11.00	7.63	N.A.	11.84	10.72	7.77	7.71
Average	15.04	12.27	9.34	9.20	13.75	11.00	7.37	7.20

Source: EIA, *Natural Gas Monthly*, February 2009, Table 3.

Table A-4. U.S. End Use Price Overview

($ per mcf)

Month	2008				2007			
	Residential	Commercial	Industrial	Electric Power	Residential	Commercial	Industrial	Electric Power
January	12.10	11.06	8.19	8.48	12.09	11.14	7.34	7.05
February	12.44	11.35	8.92	8.90	12.12	11.24	8.23	8.16
March	12.97	11.78	9.63	9.56	12.86	11.82	8.40	7.64
April	14.30	12.45	10.02	10.27	13.27	11.51	8.14	7.76
May	16.02	13.23	11.33	10.96	14.61	11.51	8.11	7.96
June	18.32	14.41	12.07	12.60	16.20	11.87	7.99	7.80
July	20.20	15.43	13.07	12.16	16.65	11.63	7.56	7.01
August	19.63	14.06	9.95	9.33	16.64	11.18	6.58	6.80
September	17.94	13.04	8.91	8.03	15.94	10.90	6.12	6.35
October	15.23	11.82	8.08	7.02	14.25	10.80	6.86	7.04
November	14.11	11.78	7.40	6.66	12.82	11.04	7.64	7.27
December	12.64	11.31	7.84	N.A.	12.17	11.02	7.99	7.93
Average	15.49	12.64	9.62	9.45	14.14	11.31	7.58	7.40

Source: EIA, *Natural Gas Monthly*, February 2009, Table 3.

Table A-5. Selected Natural Gas Market Regional Prices

($ per mcf)

	2008		2007		5-year range (2003-2007) (annual average)
	Annual Average	December	Annual Average	December	
Wellhead	8.07	5.87	6.39	6.53	4.88-7.33
NY citygate	10.07[a]	9.24	8.61	7.35	4.91-12.40
IL citygate	8.48	6.73	7.89	7.82	4.98-10.89
CA citygate	8.16	5.86	6.82	7.35	4.03-12.98
U.S. citygate	9.15	8.16	8.11	8.13	5.85-8.67

Source: EIA, *Natural Gas Prices*, Area: US, CA, IL, NY; available at http://tonto.eia.doe.gov/dnav/ng/ng_pri_sum_dcu_nus_m.htm.

a. Excluding November 2008; Data not available according to EIA.

Table A-6. Consumption of Natural Gas

(Trillion cubic feet)

	2008	2007	5 year range (2003-2007)
Total	23.2	23.0	21.7-23.0
Electric Power	6.6	6.8	5.1-6.8
Residential	4.9	4.7	4.4-5.1
Commercial	3.1	3.0	2.8-3.2
Industrial	6.7	6.6	6.5-7.2

Source: EIA, *Short Term Energy Outlook*, February 10, 2009, Table 5a.

Table A-7. Heating and Cooling Degree Days

	2008	2007	Normal
Heating Degree Days (Oct.-Jan.)	2,579	2,388	2,555
Cooling Degree Days (April-Sept.)	1,174	1,246	1,128

Source: EIA, *Short-Term Energy Outlook*, February 10, 2009; Figure 23 and 24.

Table A-8. Supply of Natural Gas

(Trillion cubic feet)

	2008	2007	5 year range (2003-2007)
U.S. Dry Gas Production	20.5	19.1	18.1-19.3
Net Imports	2.9	3.8	3.3-3.8

Source: EIA, *Short Term Energy Outlook*, February 10, 2009, Table 5a.

Appendix B. Acronyms

Bcf	Billion cubic feet
Bcf/d	Billion cubic feet per day
Btu	British thermal units
EIA	U.S. Energy Information Administration
FERC	Federal Energy Regulatory Commission
LNG	liquefied natural gas
mcf	thousand cubic feet
MMBtu	Million British thermal units
NOAA	National Oceanic and Atmospheric Administration
NYMEX	New York Mercantile Exchange
OCS	outer continental shelf
PGC	Potential Gas Committee
Tcf	Trillion cubic feet

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