U.S. Department of Energy
Washington, DC 20585

Date: **July 17, 2014**

To: **Members of the Public**

From: **Quadrennial Energy Review Task Force Secretariat and Energy Policy and Systems Analysis Staff, U.S. Department of Energy**

Re: **Stakeholder Meeting on Natural Gas Transmission, Storage and Distribution**

1. Introduction

On January 9, 2014, President Obama issued a Presidential Memorandum establishing a Quadrennial Energy Review (QER). The Secretary of Energy provides support to the QER Task Force, including coordination of activities related to the preparation of the QER report, policy analysis and modeling, and stakeholder engagement.

On Monday July 21, 2014 at 10:00 a.m. in the Rashid Auditorium Hillman Center at Carnegie Mellon University, located at 4902 Forbes Avenue, in Pittsburgh, Pennsylvania, the U.S. Department of Energy (DOE), acting as the Secretariat for the QER Task Force, will hold a public meeting to discuss and receive comments on issues surrounding the development of the natural gas industry in the United States and North America. Three expert panels will explore evolving trends in the U.S. electricity sector, and there will be an opportunity for public comment via an open microphone session following the panels. Written comments can be submitted to QERcomments@hq.doe.gov. The session will also be webcast at www.energy.gov/live.

The Secretariat will also convene related meetings to discuss gas-electric interdependence in Denver, Colorado; infrastructure siting in Cheyenne, Wyoming; rural energy in Iowa; and state, local and tribal issues in Santa Fe, New Mexico. Information on all QER stakeholder meetings is posted at www.energy.gov/qer as it becomes available.

Over the past decade, America has undergone a dramatic transformation in its energy profile. At the core of this shift has been the ability to unlock fossil fuel resources from diverse shale formations around the country. America's economy and infrastructure will continue to adapt to the abundance of accessible shale and natural gas resources and the resulting low natural gas prices, decreased carbon emissions, lower imports and enhanced industrial competitiveness. The effects of the shale revolution are already rippling through the natural gas industry and the broader economy.

The shale boom is rife with economic and geopolitical opportunities, but it also raises challenges that could define our nation's political, social and environmental future. With appropriate technologies that can cost-effectively extract natural gas, North America has enough natural gas resources for at least the next 100 years.[1] A key goal of the QER is to understand the infrastructure policies that will be necessary to support this transition.

2. Background

The United States has long had the world's most extensive natural gas infrastructure network (Figure 1). In addition to supply-related facilities (producing wells and gathering lines), this network encompasses:

[1] "Natural Gas in a Smart Energy Future", GTI and ICF, 2011.

- More than 500 natural gas processing plants to separate dry natural gas from liquids.
- Over 300,000 miles of high pressure pipelines comprising 210 pipeline systems to deliver large natural gas volumes to market.
- About 419 underground natural gas storage facilities, most of which are primarily for seasonal use to meet winter demand, and the remaining are high deliverability facilities used to inject and withdraw large natural gas volumes flexibly for short periods.[2]
- Over 2.1 million miles for distribution lines comprising 1,437 distribution systems that deliver gas to over 68 million residential and 5 million commercial customers.[3]
- Eight LNG import facilities and 100 LNG peaking facilities. Many of these re-gasification import terminals are planning to add liquefaction trains to support potential LNG exports from the United States to other countries.

Natural gas infrastructure in the United States is highly integrated with infrastructure in Canada and to a lesser extent with Mexico to form an integrated North American market.

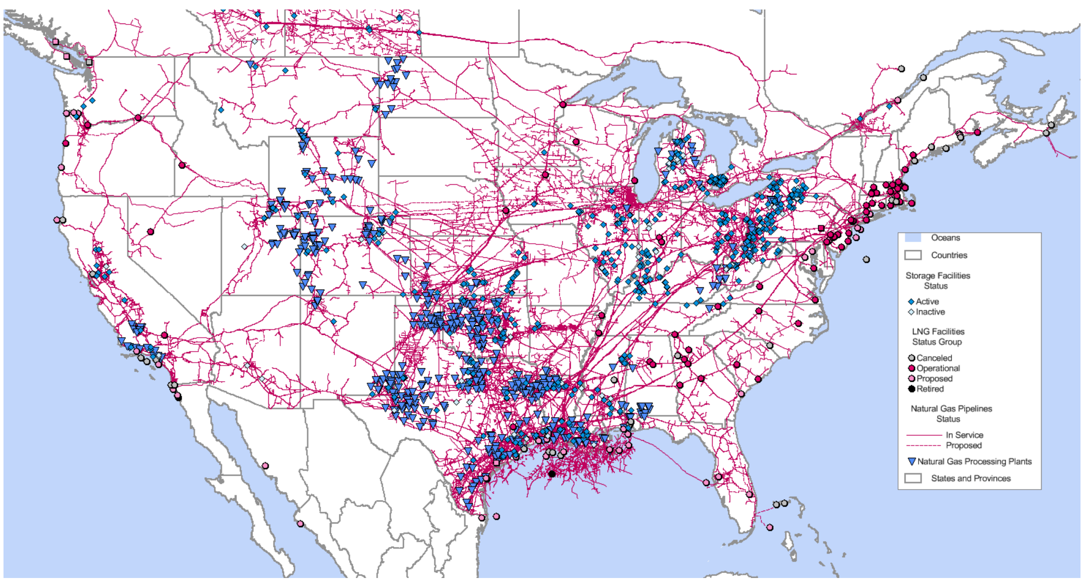

Figure 1. U.S. natural gas infrastructure.

Source: U.S. Energy Information Administration derived from Ventyx.

Over the last decade, the rapid development of hydrocarbon production from shale resources has radically changed North America's energy outlook, especially for natural gas. To see how large the change has been, it is important to consider the situation in 2004. At that time:

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[2] EIA, Office of Oil and Gas, Natural Gas Division, Gas Transportation Information System, December 2008. http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/undrgrndstor_map.html.
[3] U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration, Annual Report Mileage for Gas Distribution Systems.

- Most observers expected natural gas production in the United States to stagnate or fall gradually in coming decades. The Energy Information Administration's (EIA) Annual Energy Outlook 2004 predicted an average rise of 0.6 percent per year between 2004 and 2025, or just 2.3 trillion cubic feet overall.
- About a quarter of United States gas production came from the Gulf of Mexico and was subject to interruption from hurricanes, the effects of which would be emphasized by Hurricanes Katrina and Rita a year later. The largest source of new onshore natural gas was coming from Wyoming, where pipeline building tended to lag behind production gains, leading to intermittently low prices for producers.
- Spot prices at Henry Hub, the central location for the pricing of New York Mercantile Exchange natural gas futures contracts in use since 1990, averaged $5.91 per million British thermal units (MMBtu) for the year.
- Developers were building 10 new LNG import terminals and had proposed 33 additional terminals.
- Electric companies had just finished a major build-up of natural gas fired capacity, most of which was being used at low levels. Developers had proposed 13 gigawatts (GW) of new coal-fired capacity to take advantage of the large, long-lasting price advantage that even relatively expensive Appalachian coal enjoyed over natural gas.
- In the winter of 2003 to 2004, pipeline constraints delivering natural gas into New England led to spot prices as high as $74 per MMBtu on the InterContinental Exchange, and strains were evident between the natural gas and electric power systems.

Primarily because of the shale revolution, this profile has dramatically changed for the natural gas industry in the United States since 2004—although there are still constraints in the Northeast. The shale revolution represents a series of technological advances that have increased natural gas productivity rapidly and in ways that have been sustained throughout the decade. The results have included a 35 percent rise in dry natural gas production between 2005 and 2013, about a 55 percent fall in average annual spot natural gas prices, an approximately 39 percent increase in the use of natural gas to generate electric power, and the prospect of substantial LNG exports from the United States and North America more generally.

Many of the regulations that govern the industry today are the outgrowth of the gas shortages of the 1970s, resulting controls and regulations, and the subsequent deregulation efforts of the 1980s. Prior to the deregulation of the 1980s, natural gas exploration and production companies would drill for natural gas and sell it from the wellhead to pipeline companies. Pipeline companies would sell the natural gas to local distribution companies (LDCs), which would distribute and sell gas to their customers. Today, pipeline companies are paid for transporting natural gas, but do not take ownership of the natural gas they transport. Natural gas producers sell directly to LDCs, end users (such as power plants or industrial users) and gas marketing companies. Gas marketers may own the natural gas being transferred, or may simply act as a middle-man between buyers and sellers. The gas marketer or the LDC may sell natural gas to the end user, or to other marketers and LDCs. [4]

[4] Naturalgas.org Industry and Market Structure http://naturalgas.org/business/industry.asp#overview.

The United States has made $10 billion in average annual investments in midstream natural gas infrastructure over the past decade.[5] This included major pipeline projects that relieved constraints from Wyoming and from major shale basins in Texas, Oklahoma and Arkansas to Eastern markets.

3. Shale Gas Production

Some natural gas has been produced from shale formations since the 19th century, but the amounts were fairly small – about 5 percent of the United States total in 2004. Since then, shale gas production in the United States has grown more than tenfold from 2.7 billion cubic feet per day (Bcf/d) in January 2004 to about 35 Bcf/d in May 2014 (Figure 2). Natural gas production from traditional formations has fallen over the same period, by about 14 Bcf/d. As a result, overall production has grown significantly (18 Bcf/d) but somewhat less than the increase of shale production, and shale gas now accounts for about half of overall gas production in the United States. This shift to large scale shale production is the result of new developments in the process of hydraulic fracturing (fracking), to open spaces to let gas flow in very tight geological formations, and horizontal drilling to take advantage of the horizontal nature of shale deposits.

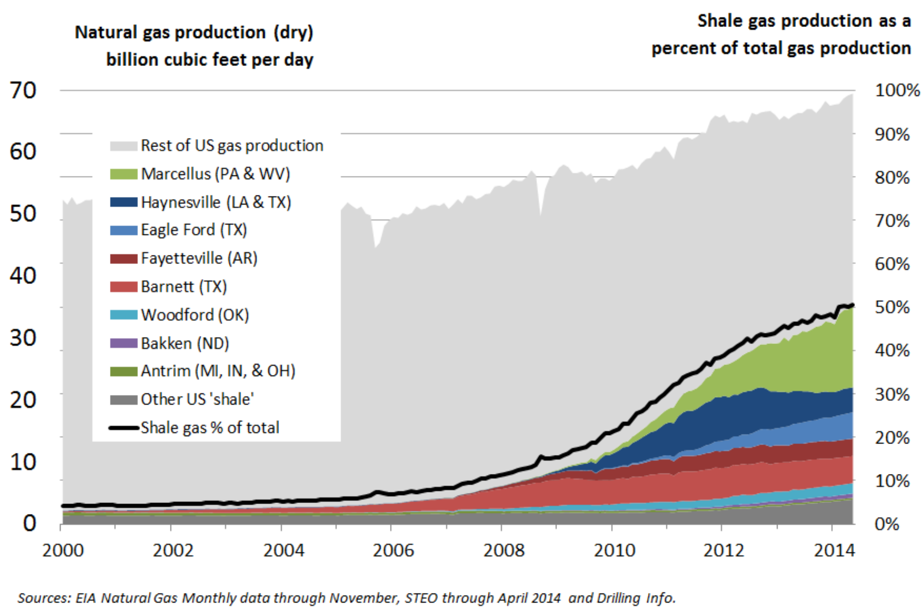


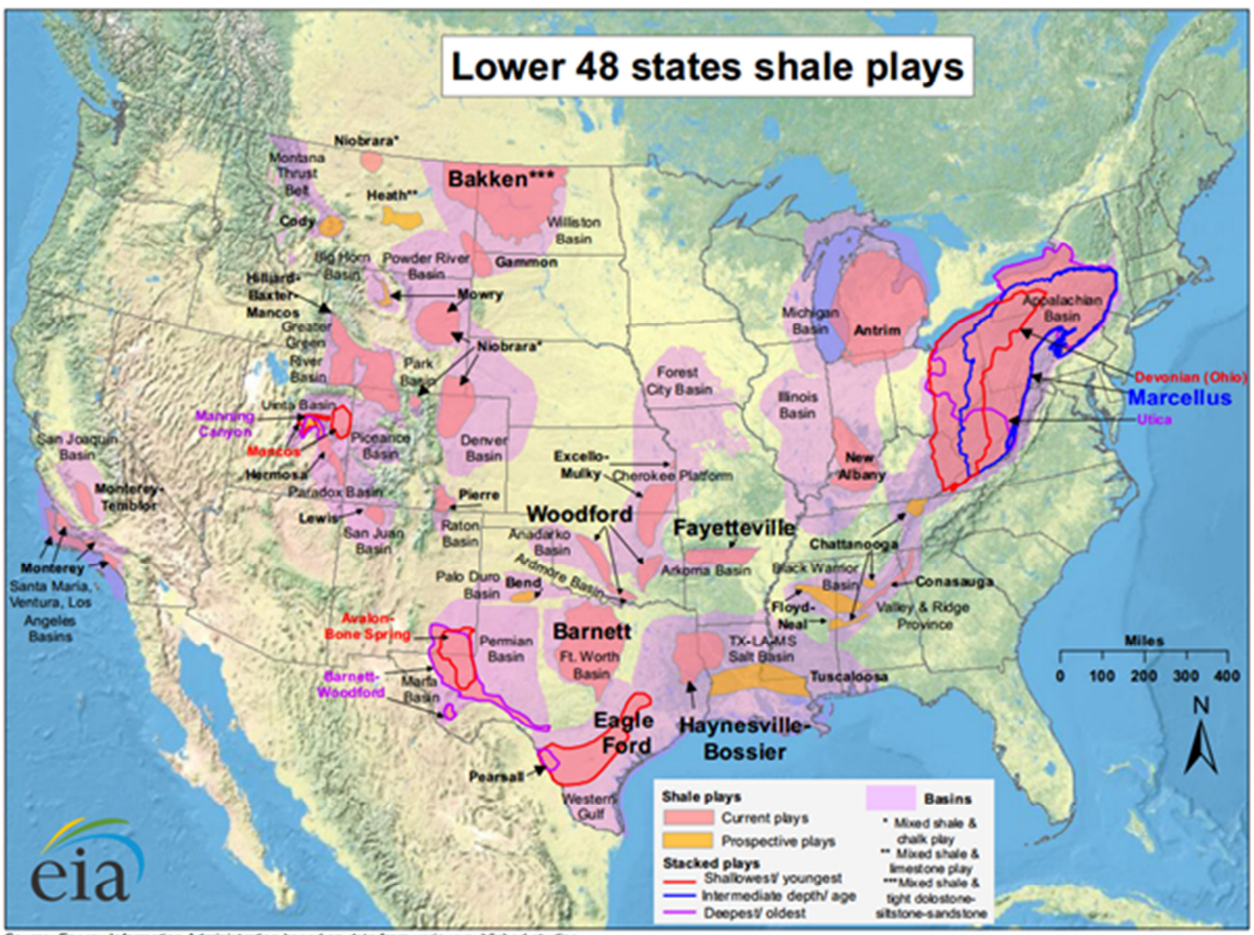
Figure 2. Trends in U.S. natural gas production by play and type, January 2000–April 2014.

[5] ICF International, " North American Midstream Infrastructure through 2035: Capitalizing on Our Energy Abundance, " for the INGAA Foundation, March 2014. http://www.ingaa.org/Foundation/Foundation-Reports/2035Report.aspx.

3.1 Regional production profiles

Geographically, increased shale production has come in a series of waves. From 2005 until 2009, most of the increase came from the Barnett formation in east Texas (see Figure 3 for map of U.S. natural gas plays). Beginning in 2009, production stabilized in the Barnett, and increased rapidly in the Haynesville formation in Louisiana and east Texas. Beginning in 2012, production gains shifted to very rapid growth in the Marcellus formation in the Northeast and the Eagle Ford formation in Texas. Meanwhile, Haynesville production fell as producers moved to the more profitable basins.

A key feature of the later years of shale gas production is that wells typically produce both gas, comprised primarily of methane, and liquid hydrocarbons, specifically natural gas liquids (NGLs) including ethane, propane, butane, isobutene, and pentane. The higher the methane concentration, the "drier" the gas is. The five largest dry gas-producing states are Texas, New Mexico, Louisiana, Oklahoma and Wyoming. Table 1 shows the dramatic increases in production of dry gas from these states from 2004 to 2012. The higher the percentage of NGL's, the "hotter" or "wetter" the gas is. The five highest-yielding wet gas states include Pennsylvania, Texas, Louisiana, Oklahoma and Colorado.



Source: Energy Information Administration based on data from various published studies.
Updated: May 9, 2011

Figure 3. Lower 48 states shale plays.

NGLs are used across nearly all sectors of the economy as inputs for petrochemical plants, burned for space heat and cooking, and blended into vehicle fuel.[6] Many of the best rates of return in the U.S. can be found in plays rich in liquid hydrocarbons. Rising natural gas liquids production, however, has taxed the existing infrastructure and contributed to needs for new or expanded infrastructure: natural gas processing plants, storage facilities, pipelines, and refineries.

Table 1. Dry Natural Gas Production Trends

Dry Natural Gas Production Trends, 2004 and 2012 (in Billion Cubic per Day)		
States with Major Shale Plays	2004	2012
Texas	12.86	18.84
Louisiana	3.33	7.97
Pennsylvania	0.54	6.13
Oklahoma	4.29	5.15
Arkansas	0.51	3.13
North Dakota	0.13	0.42
Sub-total	21.67	41.64
Federal Gulf of Mexico - Offshore	10.85	3.89
Other States	18.28	20.20
Total U.S.	50.79	65.73

Source: U.S. Energy Information Administration.

3.2 Changes in estimated resources and reserves

At the same time that production has increased, estimates of both resources and proved reserves have grown. The Potential Gas Committee—a longstanding industry authority on the assessment of the technically recoverable natural gas resource base of the United States—estimates that potential gas resources have more than doubled since 2004 from about 1,100 trillion cubic feet to nearly 2,400 trillion cubic feet. In 2012, the PGC estimated that total potential shale gas resources in the United States topped 1,000 trillion cubic feet.[7]

Proved reserves have also increased (Figure 4). During the early years of the shale revolutions, proved reserves (those supplies that can be economically produced at current prices) increased by more than 50 percent, even as natural gas prices fell. This reflects the increased productivity that allows more natural gas to be produced even at lower prices. The latest year for which proved reserve estimates are available is 2012, a year in which mild weather led to exceptionally low natural gas prices. Proved reserves finally fell, as the low price proved more important than continuing productivity gains.

[6] Compiled from: http://stateimpact.npr.org/pennsylvania/2012/01/26/what-makes-wet-gas-wet/, "Natural Gas: Dry vs. Wet", www.usedc.com, and EIA Today in Energy, http://www.eia.gov/todayinenergy/detail.cfm?id=16191.

[7] Potential Gas Committee, "Potential Supply of Natural Gas in the United States," Presentation in Washington, D.C., April 9, 2013.

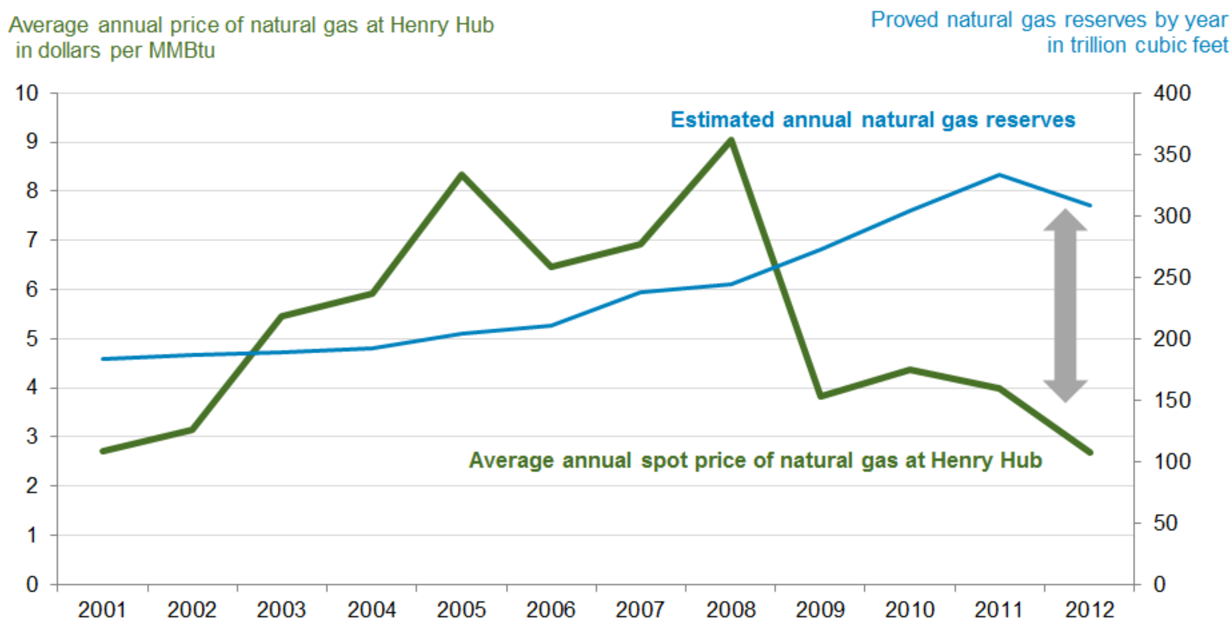


Figure 4. Trends in proved natural gas reserves and average annual spot prices for natural gas. ***Source: U.S. Energy Information Administration based on Ventyx.***

4. Effects of the Shale Revolution

The shale revolution has affected the whole natural gas industry and the broader economy, and has led to falling prices with increased production, expansion in the industrial and manufacturing sectors, lower imports (especially of LNG), reduced emissions, and rapid increase in natural gas used to generate electric power. A major result of these developments is the substantial investment in new infrastructure.

The oil and natural gas supply boom during the past decade has contributed to significantly higher supplies of natural gas liquids (NGLs). Increased natural gas production has been the main contributor to higher NGL output (Figure 5).

Upstream operators increasingly target places rich in hydrocarbons for drilling because they can improve the economics of drilling. Many of the best internal rates of return in the United States can be found in plays rich in liquid hydrocarbons. Most wells now being drilled for hydrocarbons produce a mixture of oil and natural gas. Relatively high oil prices and low natural gas prices make the oil-rich portions of reservoirs more desirable for production, and therefore increasingly the targets for the drilling of new wells.

However, rising natural gas liquids production has taxed the existing infrastructure and contributed to needs for new or expanded infrastructure: natural gas processing plants, storage facilities, pipelines, and refineries. The processing capacity and geographical layout of the existing U.S. natural gas processing infrastructure cannot adequately accommodate the volume of natural gas currently being extracted.[8] Therefore, many companies have announced plans to construct new natural gas and NGL processing plants, most of which will be located near important shale plays (Figure 6 and see Section 6.3).

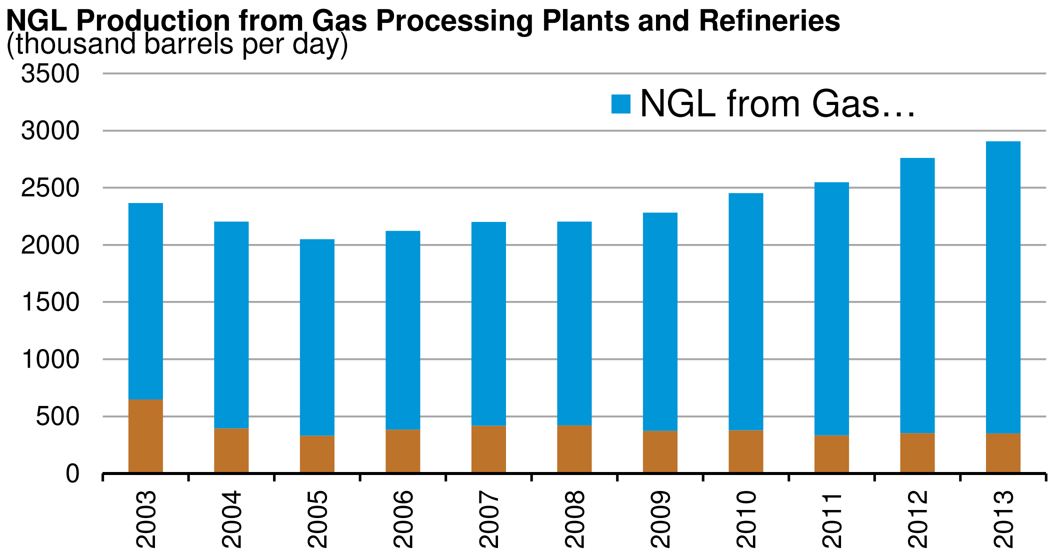


Figure 5. NGL production from gas processing plants and refineries (thousand barrels per day). ***Source: Bentek Energy, LLC.***

[8] IHS, 2013. America's New Energy Future: The Unconventional Oil and Gas Revolution and the U.S., http://www.ihs.com/info/ecc/a/americas-new-energy-future-report-vol-3.aspx.

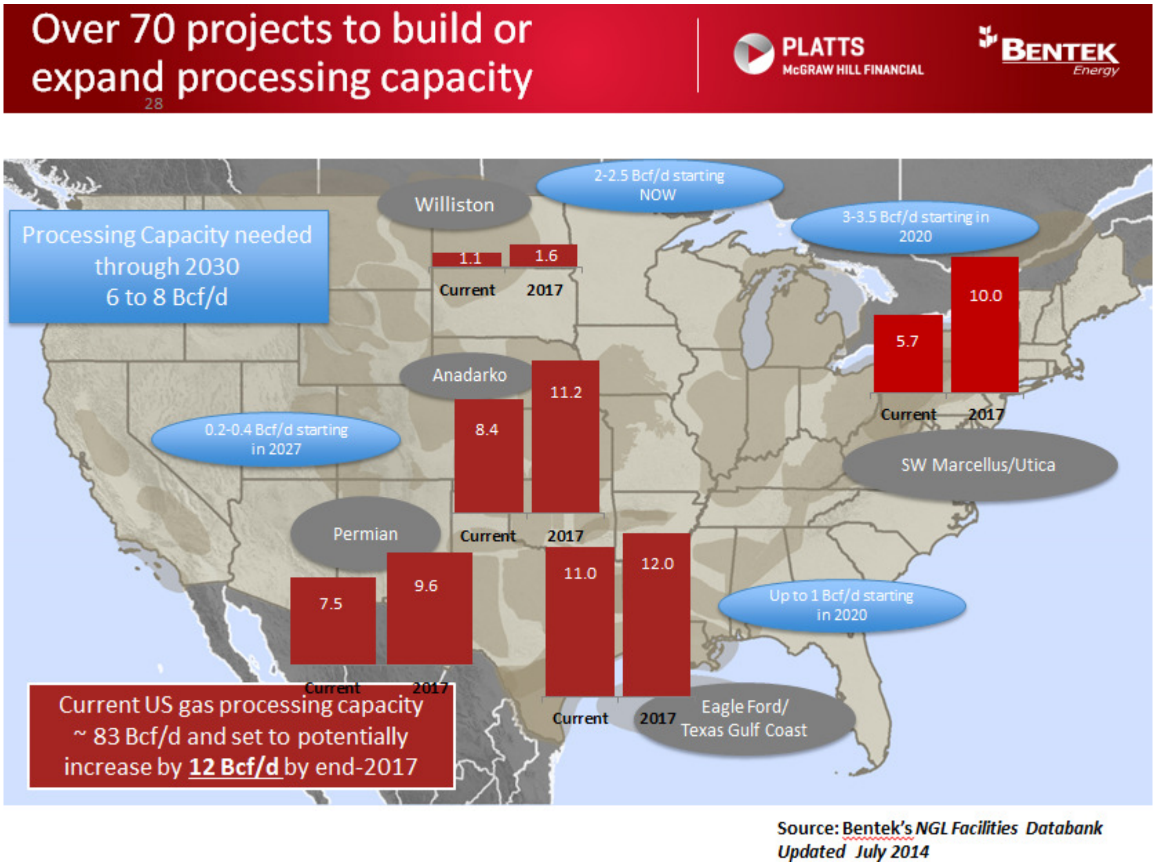


Figure 6. Over 70 projects to build or expand processing capacity. ***Source: Bentek Energy, LLC.***

4.1 Falling prices

Between 2003 and 2007, the United States appeared to have entered a time of increasing scarcity of natural gas. Prices stayed mostly in a range between $4 and $7 per MMBtu – except for an excursion into considerably higher prices after Hurricanes Katrina and Rita (Figure 7). In 2008, prices for almost all commodities rose to extremely high levels duirng the first half of the year and then crashed to very low levels as a result of the financial crisis. This extreme volatility masked a fundamental change in natural gas prices. Between 2007 and 2009, the "Shale Era" arrived in earnest. As a result, after 2008, natural gas prices have traded mainly in a band between $2 and $5 per MMBtu. Very low prices in the spring of 2012 reflected a warm winter that left storage considerably fuller than usual. This meant less demand for natural gas to inject into storage in the spring and summer of 2012, and spot prices fell to the point that natural gas sometimes competed with inexpensive Western coals for electric generation loads in markets like the Southeast. Conversely, after the "Polar Vortex" of 2013-2014, demand for gas to inject into storage has been high, and prices have remained at the high end of their multi-year range. Even as prices fell in the Shale Era, production continued to rise, reaching 69 Bcf per day in April 2014, an increase of 35 percent over the January 2004 level.

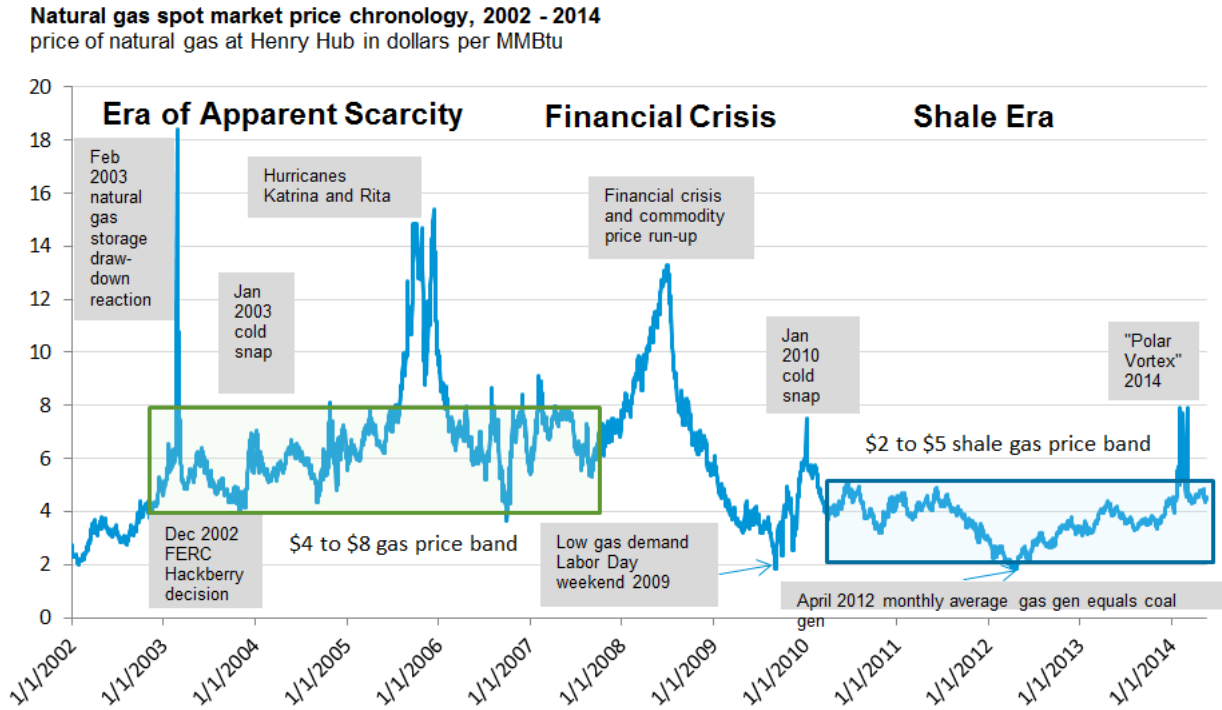


Figure 7. Natural gas spot market price chronology, 2002–2014. ***Source: U.S. Energy Information Administration based on Ventyx.***

4.2 Industrial and manufacturing expansions

U.S. and foreign manufacturers that construct equipment for the natural gas industry, convert natural gas into commodities like propylene for petrochemicals, and rely on natural gas for power production are relocating and moving their facilities to the United States to take advantage of the steady and low prices. The nation is experiencing increased investments in facilities for producing petrochemicals and fertilizer, planning and construction of infrastructure to export LNG and build new processing plants and pipelines, and environmental and economic opposition to some of these projects. In key manufacturing sectors like plastics, rubber, machinery, electrical equipment, computers and electronics, the U.S. could have an export cost advantage over other major industrialized nations if prices remain low.[9]

The 36% decrease in the average natural gas price paid by manufacturers between 2006 and 2010, from $7.59 to $4.83 per million Btu, was large enough[10] that the total cost of energy from all sources fell by 11% between 2006 and 2010, from $9.19 to $8.22 per million Btu (in 2005 dollars), according to data

[9]IEA predicts that over the next decade the United States will enjoy an export cost advantage of 5 to 25 percent over Germany, Italy, France, the United Kingdom, and Japan in a range of industries, including plastics, rubber, machinery, electrical equipment, computers, and electronics—as long as U.S. natural gas prices stay low. http://news.nationalgeographic.com/news/energy/2014/01/140131-natural-gas-manufacturing-jobs/.
[10] Natural gas accounts for 40% of total purchased energy when all sources are converted to Btu.

from the 2010 Manufacturing Energy Consumption Survey (MECS). Since that survey was conducted, natural gas prices have fallen further.[11]

Dow Chemical—one of the biggest chemical companies in the U.S.—plans to invest over $4 billion to construct ethylene and propylene plants to tap into the low feedstock costs.[12] The EIA expects natural gas consumption by the U.S. industrial sector to increase from around 18 Bcf/day in 2012 to over 23 Bcf/day by 2040. Incremental natural gas use from new or expanded industrial facilities could represent significant future demand between 2014 and 2021 (Table 2). Facilities are concentrated in the Gulf, Southeast and Midwest (Figure 8).

Table 2. Dry Natural Gas Production Trends. Source: *Bentek Energy, LLC.*

Year	# Projects	Gas Demand (MMcf/d
2014	237	247
2015	105	728
2016	43	110
2017	16	1207
2018	6	70
2019	1	226
2020	2	0
TBD	14	109

[11] EIA, Natural Gas Prices, June 2014. http://www.eia.gov/dnav/ng/ng_pri_sum_dcu_nus_a.htm.
[12] Trefis, "Dow Continues Its Expansion In The Gulf Coast On Favorable Feedstock," August 2013. http://www.trefis.com/stock/dow/articles/203877/dow-continues-its-expansion-in-the-gulf-coast-on-favorable-feedstock/2013-08-30.

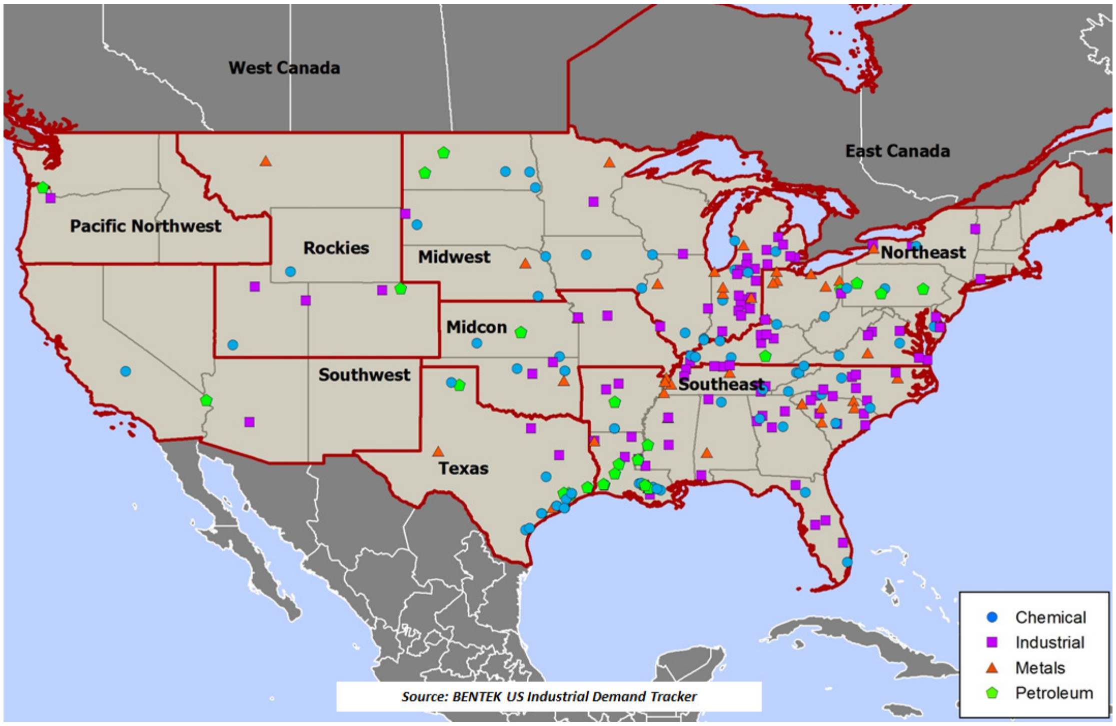


Figure 8. New or expanded industrial facilities that representing increased gas use, 2014-2021 by type. *Source: Bentek Energy, LLC.*

4.3 Decreasing net imports

The mix of imports and exports of natural gas for the United States is changing because of the lower natural gas price regime. U.S. net imports of natural gas into the United States fell 14% in 2013, continuing a decline that began in 2007.[13] In fact, total U.S. net imports of energy, measured in terms of energy content, declined in 2013 to their lowest level in more than two decades.[14]

Natural gas production growth in the United States was a major contributor to this decline.[15] Imports of LNG have fallen almost to zero everywhere except in New England. This reflects the fact that prevailing prices for natural gas on the world market are considerably higher than prices in the United States, except in the Northeast when pipeline transportation is constrained. Nearly all (97%) of U.S. natural gas imports arrived via pipeline from Canada, which decreased from the previous year by 6% to 2,785 Bcf in 2013.[16] Net imports from Canada remain significant, but have fallen considerably from 9 Bcf/day in 2007 to 5.1 Bcf/day in 2013. This reflects the growing competitiveness of supplies from the United States and the proximity of Marcellus natural gas production to Eastern Canadian markets. The United States imports a

[13] EIA, July 8, 2014 http://www.eia.gov/forecasts/steo/report/natgas.cfm.
[14] EIA, April 2, 2014. http://www.eia.gov/todayinenergy/detail.cfm?id=15671.
[15] Ibid.
[16] EIA, U.S. Natural Gas Imports and Exports 2013, May 2014. http://www.eia.gov/naturalgas/importsexports/annual/.

minimal amount of gas via pipeline from Mexico. Exports to Mexico, however, rose by 6% in 2013 to 658 Bcf total (or 1.80 Bcf/day), a record level.[17]

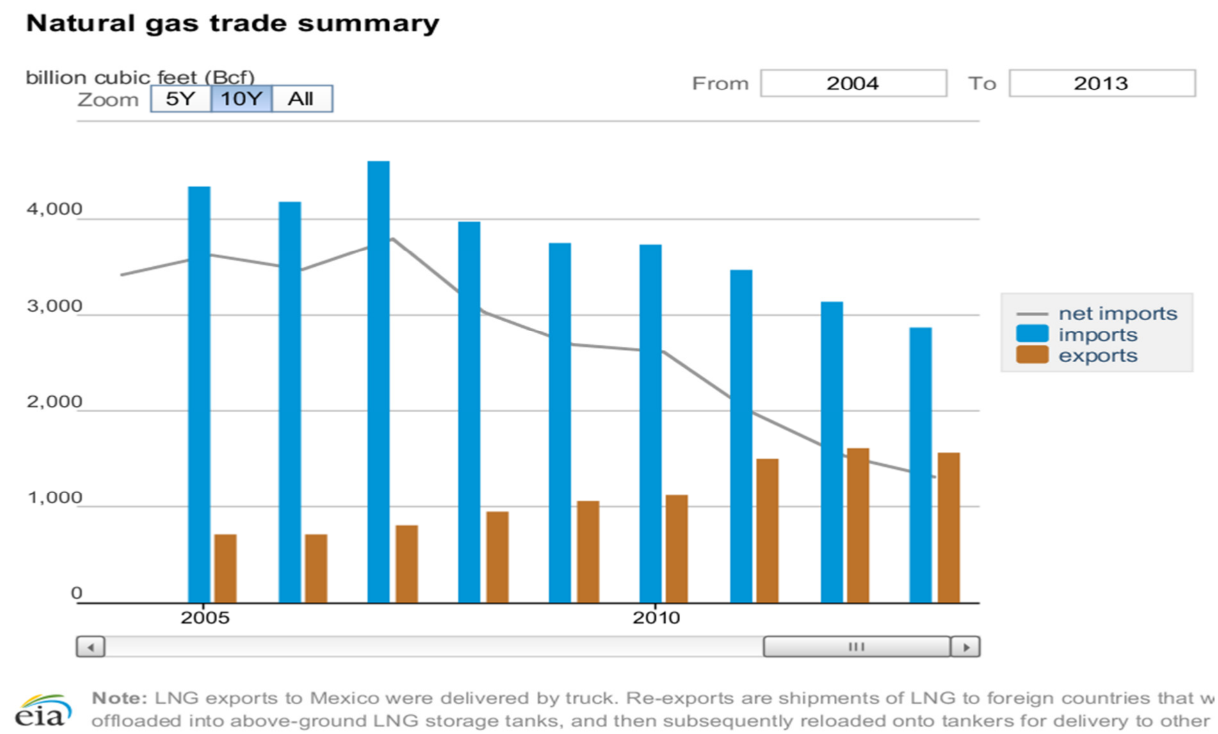


Figure 9. Recent trends in natural gas imports and exports and imports, 2004–2013. ***Source: U.S. Energy Information Administration.***

5. Rapid Growth in Gas Used for Power

Growing natural gas production, lower prices and the retirement of coal-fired power plants have considerably increased the use of natural gas in electricity generation. In April 2012, the U.S. Energy Information Administration (EIA) reported that monthly shares of coal- and natural gas-fired generation were equal for the first time, with net electric generation from natural gas at 95.9 million megawatt hours.[18] While this was special case given the market circumstances at the time, it signaled the growing opportunity for natural gas for power generation. Natural gas-fired power plants accounted for just over 50% of new utility-scale generating capacity added in 2013.[19]

In general, neither natural gas nor Eastern coal has been able to establish and maintain a consistent pricing advantage over the other fuel. In fact, total natural gas use for power generation in the United States was down 11% in 2013 compared to 2012, mostly because of higher natural gas prices relative to coal prices.[20]

[17] Ibid.
[18] EIA, July 6, 2012. http://www.eia.gov/todayinenergy/detail.cfm?id=6990.
[19] EIA, April 8, 2014. http://www.eia.gov/todayinenergy/detail.cfm?id=15751.
[20] EIA, Natural Gas Summary, June 2014. http://www.eia.gov/dnav/ng/ng_sum_lsum_dcu_nus_a.htm.

The supply stacks in both Northeast and Southeast have been intermixed much of the time. Gas use for power generation in the United States has generally risen since 2008.[21]

A cost differential between Eastern and Powder River Basin (located in Montana and Wyoming) coal exists and may be attributable to existing rail policies beyond the scope of this briefing. In any case, this competition between Eastern coals and natural gas is primarily based on price. It has occurred even without new emissions controls. Trends in natural gas use for power vary by region because of differences in the availability of generating plants, generating plant age and efficiency, and the relative cost of fuels to operate power plants.

Accommodating growth in natural gas use for power will likely require changes to natural gas infrastructure: repurposing and reversals of existing pipelines; laterals to gas-fired generators; more looping and compression to the existing network; possibly some new pipelines; and additional processing plants and high deliverability storage.

6. Infrastructure Implications of Changing Production Patterns

The industry dynamics have had major implications for infrastructure:

- New pipelines were needed to bring some of the new shale gas to market. This was especially true of the need to build lines from Texas, Oklahoma and Arkansas to the west and Louisiana and eastern markets to the east. New pipelines also completed the connection of traditional supplies from Wyoming to Eastern markets.
- New processing plants were needed to serve increasingly profitable wet gas, for example in the Eagle Ford and parts of the Marcellus.
- Pipelines have become less vulnerable to disruptions from hurricanes and more vulnerable to freeze-offs—a production stoppage that results from water or hydrocarbon liquids freezing and thus plugging the head of a producing well—especially for liquids-rich wells.

6.1 Recent pipeline capacity expansion

EIA estimates that between 2004 and 2013, the natural gas industry spent about $56 billion expanding the natural gas pipeline grid.[22] Approximately 10 percent of this investment was dedicated to the completing the Rockies Express pipeline—a 1,768 mile system 1.8 billion cubic feet per day linking production fields in Wyoming to natural gas markets as far east as Clarington, Ohio. But a substantial part of the investment went to hook up shale basins in Texas (Barnett, part of Haynesville, and later Eagle Ford) and Arkansas (Fayetteville) to markets in the East. For many years, the country had seen frequent price divides between Western supplies (less expensive) and Louisiana supplies including Gulf of Mexico production (more expensive). With the growth of production in shale basins on the Western side of this divide, the value of new pipeline capacity spurred the new construction. Figure 10 shows recent and proposed pipeline capacity since 1996. Even with this new capacity, over 1,800 wells in the Utica and Marcellus are drilled but not producing due to infrastructure constraints; those wells have an estimated production capacity of 10 bcfd (Figure 11).

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[21] Ibid.

[22] Based on analysis from EIA data, http://www.eia.gov/naturalgas/data.cfm#pipelines.

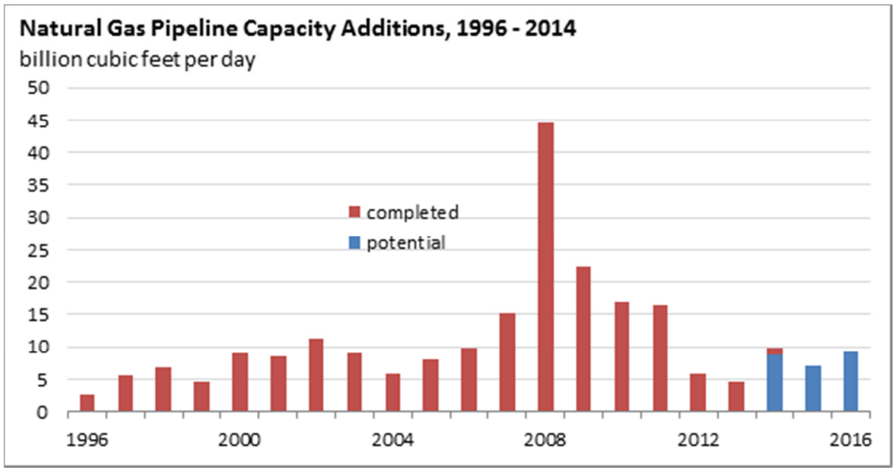

Figure 10. Natural gas pipeline capacity additions, 1996–2014. ***Source: U.S Energy Information Administration.*** **Note: "Potential" pipeline capacity additions include projects that have been announced, applied for, approved, or are under construction.**

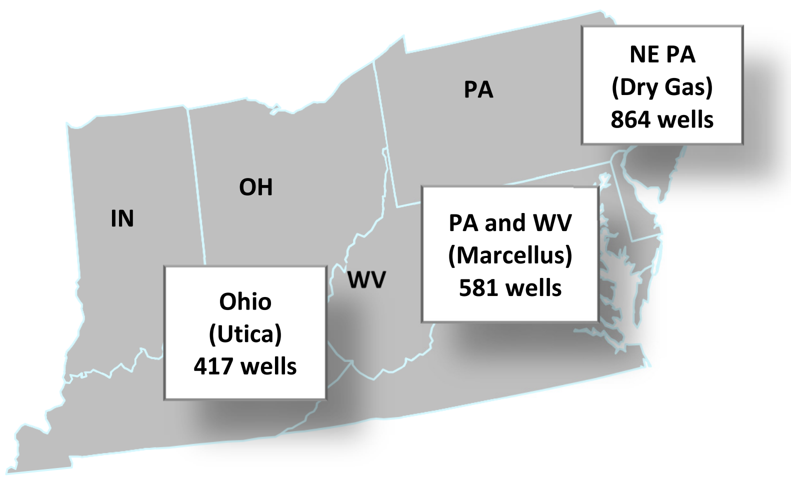

Figure 11. Recently drilled but not producing wells because of infrastructure constraints. ***Source: Bentek Energy, LLC.***

6.2 Aging infrastructure and safety

Aging infrastructure, particularly in local distribution systems, poses safety as well as supply and environmental risks. Despite the recent massive investments in new gas transmission, over 50% of the nation's gas transmission and gathering pipelines were constructed in the 1950's and 1960's, during the post-WWII economic boom.[23] Over 90% of the pipe is made from protected coated steel and plastic to prevent corrosion and leakage. Approximately 9% of distribution mains services in the U.S. are

[23] US Department of Transportation, *The State of the National Pipeline Infrastructure,* Washington, DC, 2011.

constructed of materials that are considered leak-prone, especially cast iron.[24] The American Gas Foundation estimates that it will take several decades for many operators to replace this infrastructure.[25]

The replacement of aging natural gas infrastructure is on the agenda of regulators, distribution companies, local officials, and consumer groups. Although the industry has been improving its safety performance, replacement efforts have increased partly in response to recent high-profile incidents, including a fatal explosion in San Bruno California, in 2010. In 2013, the Board of Directors of the National Association of Regulatory Utility Commissioners passed a resolution that "encourages regulators and industry to consider sensible programs aimed at replacing the most vulnerable pipelines as quickly as possible.[26]" The American Gas Association, the trade association for investor-owned LDCs, has largely embraced these efforts to improve the safety and deliverability of natural gas distribution systems and 38 states have now adopted accelerated pipeline replacement programs, including mechanisms for utilities to recover costs associated with replacing leak-prone pipe.[27]

About 85% of pipeline incidents reported to the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA) from 2002-2009 occurred irrespective of the age of the pipeline, with just 15% related in some way to the age of the pipeline.[28] The integrity of those pipelines for which the fitness for service may degrade with the passage of time can be assessed periodically. Timely repairs and replacement where necessary—and other mitigation efforts—based on those assessments will ensure the pipeline's continued fitness for service. Under the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, PHMSA must conduct a state-by-state survey on the progress of cast iron pipeline replacement, which are some of the oldest and leakiest pipelines still in use,[29] and hazardous leaks must be promptly repaired. [30]

6.3 New natural gas processing plants

Movement of the volume of natural gas currently being extracted is constrained by the processing capacity and geographical layout of the existing U.S. natural gas processing infrastructure.[31] As a result, many companies have announced plans to construct new natural gas and NGL processing plants, most of which will be located near important shale plays, especially in Eagle Ford, the Anadarko, Permian in west Texas and parts of the Marcellus (See Figure 6). U.S. natural gas processing capacity showed a net increase of about 12 percent between 2004 and 2009 (not including the State of Alaska), with the largest

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[24] American Gas Foundation, 2012. *Gas Distribution Infrastructure: Pipeline Replacement and Upgrades*. Washington, D.C. http://www.gasfoundation.org/ResearchStudies/AGF-Infrastructure-2012.pdf

[25] ibid

[26] http://www.naruc.org/Resolutions/Resolution%20Encouraging%20Natural%20Gas%20Line%20Investment%20and%20the%20Expedited%20Replacement%20of%20High%20GAS%20AND%20CI.docx.pdf

[27] http://www.aga.org/Newsroom/news-releases/2014/Pages/Natural-Gas-Utilities-Take-Steps-to-Further-Reduce-Emissions.aspx

[28] Kiefner, J. and Rosenfeld, M, "The Role of Pipeline Age in Pipeline Safety," The INGAA Foundation, Inc., 2005, http://www.ingaa.org/File.aspx?id=19307.

[29] Pipeline Replacement Updates, USDOT http://opsweb.phmsa.dot.gov/pipeline_replacement/.

[30] 49 C.F.R. Sec. 192.703(c).

[31] IHS, 2013. America's New Energy Future: The Unconventional Oil and Gas Revolution and the U.S., http://www.ihs.com/info/ecc/a/americas-new-energy-future-report-vol-3.aspx.

increase occurring in Texas, where processing capacity rose by more than 4 Bcf per day.[32] Since 2004, 24 processing plants have been added. The United States is now in the midst of a rapid expansion of its gas processing capacity, especially in the Northeast, where currently planned projects would almost double capacity by the end of 2016.

Increased production of domestic natural gas has created numerous ripple effects in different industries across the country. One of these effects is the increased availability of natural gas liquids like ethane and propane. The surplus of ethane is so great that many U.S. manufacturers are planning to construct new facilities or expand existing ones to process that ethane into ethylene for use in a range of plastics and consumer products. A key challenge is the lack of infrastructure to move ethane and other NGLs to manufacturers and other domestic and export markets.[33] Planning infrastructure expansion is a collaborative effort between public and private sectors, as well as federal, state and local governments. There is a delicate balance in achieving the safety and economic potential of new pipeline systems.

6.3 Growing importance of freeze-offs

Because of shifts in oil and natural production, the United States is now less vulnerable to supply disruptions from storms than in the late 90s when the majority of supplies came from production offshore in the Gulf of Mexico (GOM). In 1997, 26% of the nation's natural gas was produced in the federal GOM; in 2012, that number was 6%. As the bulk of natural gas production moves inland, the potential disruptions associated with freeze-offs—a production stoppage that results from water or hydrocarbon liquids freezing and thus plugging the head of a producing well—have grown, contributing to initial daily disruptions as much as all but the largest hurricanes (Figure 12).

In the future, as production continues to shift to areas nearer major load centers like the Northeast, freeze-offs could become more important. Indeed, during the Polar Vortices—when historically cold winter weather in 2014 triggered a number of challenges for consumers and electric and gas utilities, including record high natural gas and electricity demand, high natural gas prices, and extreme stress on the electric grid, generation resources, and pipeline infrastructure—freeze-offs occurred in the liquids-rich parts of the Marcellus basin, and led to estimated outages totaling as much as 0.86 Bcf per day.

[32] EIA, Natural Gas Processing Plants in the United States: 2010 Update, June 2011, http://www.eia.gov/pub/oil_gas/natural_gas/feature_articles/2010/ngpps2009/overview.cfm.
[33] EIA, July 2013, http://www.eia.gov/todayinenergy/detail.cfm?id=12291.

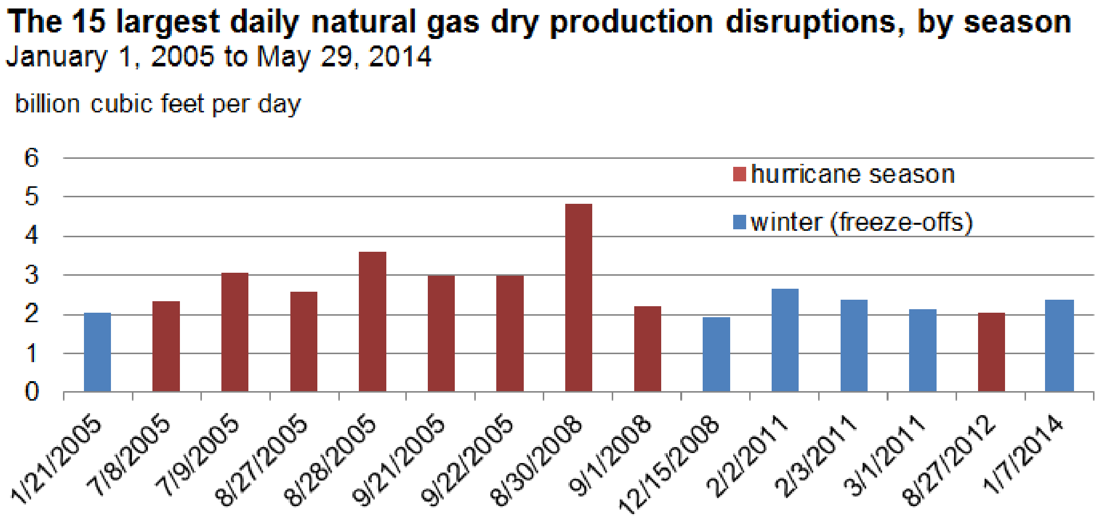

Figure 12. The 15 largest daily natural gas dry production disruptions, by season. ***Source: U.S. Energy Information Administration based on Bentek Energy, LLC.***

6.4 New LNG export terminals are being proposed

As late as the mid-2000s, the U.S. was expected to import ever-growing volumes of liquefied natural gas (LNG). Today, American gas producers expect to start *exporting* LNG linked to Henry Hub prices from the Sabine Pass terminal in Louisiana as soon as late 2015. Many importers (e.g. Japanese utilities) believe U.S. gas exports will act as a counterpoint to oil-linked prices prevalent elsewhere in the world and potentially exert significant downward pressure on global LNG prices.[34]

7. Emissions from Natural Gas Infrastructure

The substantial shift from coal-fired to natural gas-fired electric generation has contributed to lowering key emissions related to combustion – carbon dioxide, nitrogen oxide and sulfur oxide. At the same time, the natural gas industry as a whole has lowered fugitive methane emissions from pressurized equipment, mostly from industrial activities, even as production and use of natural gas has risen substantially (Table 3).

The composition of pipeline quality natural gas is over 90% methane, which contributed roughly 9% to total greenhouse gas emissions from U.S. anthropogenic emissions in 2012. Methane emissions occur in all segments of the natural gas industry—production, processing, transmission, storage and distribution—and are emitted during normal operations, routine maintenance, intentional venting, unintentional leaks and system upsets.[35] Intentional venting and unintentional leaks occur "in all parts of the infrastructure, from connections between pipes and vessels, to valves and equipment".[36]

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[34] Johnson, K. and LeFebvre, B., (2013, May 18). U.S. Approves Expanded Gas Exports. *The Wall Street Journal*. Retrieved from http://online.wsj.com/news/articles/SB10001424127887324767004578489130300876450.
[35] EPA, Natural Gas Star Program, http://www.epa.gov/gasstar/basic-information/index.html.
[36] Ibid.

Table 3. Methane Emissions from Natural Gas Systems

Methane (C4) Emissions from Natural Gas Systems (Tg CO_2 equivalent)

	1990	2005	2008	2010	2011	2012	Absolute change 1990-2012	Percent change 1990-2012
Field-Production	56.0	67.3	64.0	48.2	42.6	41.8	-14.2	-25%
Processing	17.9	13.7	14.9	15.1	17.9	18.7	0.8	4%
Transmission-and-Storage	49.2	41.2	43.1	43.4	45.2	43.5	-5.7	-12%
Distribution	33.4	29.7	29.6	28.1	27.5	25.9	-7.5	-22%
Total	**156.4**	**152.0**	**151.6**	**134.7**	**133.2**	**129.9**	**-26.5**	**-17%**

Source: *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2012. U.S.* EPA, 2014.[37]

Nearly one-quarter of the methane emissions in the United States come from the natural gas sector (Figure 13), including gas production wells, gathering lines, processing, transmission pipelines and gas storage, and distribution to end users. [38] The U.S. Environmental Protection Agency estimates that natural gas systems in the U.S. emitted 144.7 teragrams of carbon dioxide equivalent (Tg CO Eq.) in 2011, which is down from 161 Tg CO Eq. in 1990. [39] About 32% of these methane emissions come from gas wells, 14% are emitted from gathering lines and in processing, nearly 34% are emitted from transmission pipelines and storage and 20% is emitted from distribution to end users.[40] Making up just 2.8% of the distribution pipelines, cast-iron pipes currently rank as the 2nd largest source of methane emissions from the entire natural gas distribution network[41].

[37] Ibid.
[38] EPA (2014). Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990 - 2012, Table 3-43: CH4 Emissions from Natural Gas Systems (Gg). USEPA, April, 2014.
[39] Ibid.
[40] Ibid.
[41] EPA Inventory, 2014 (Table A-140: Potential CH4 Emission Estimates from the Natural Gas Distribution Stage, and Reductions from the Natural Gas STAR Program, and Regulations (Gg))

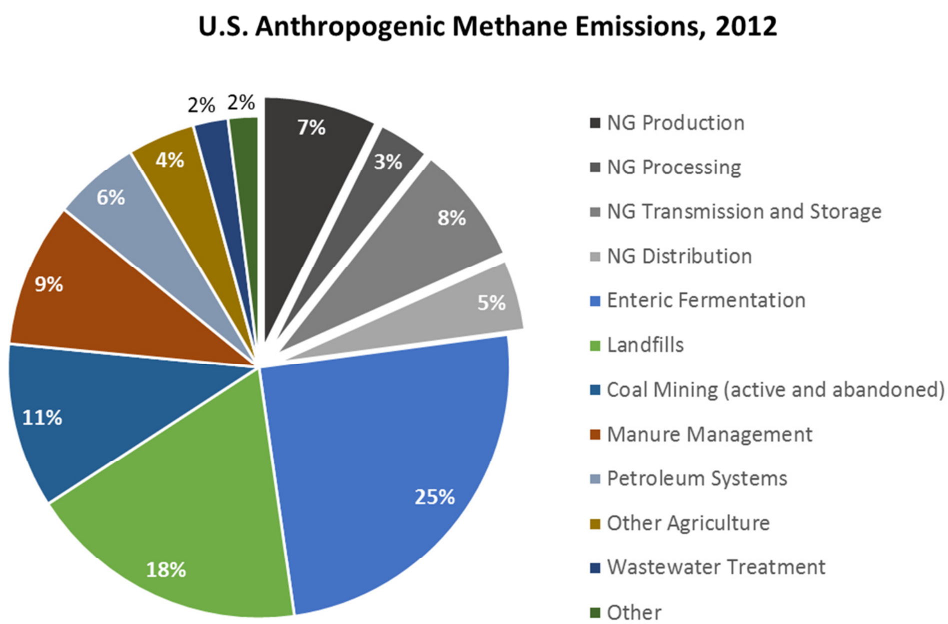

Figure 13. U.S. anthropogenic methane emissions (CO_2e), 2012. ***Source: Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2012. U.S.*** **EPA, 2014.**

Carbon dioxide emissions from the combustion of fuel in natural gas facilities constitute an additional significant source of GHG emissions. In particular, The compressors used to enable pipeline transmission of natural gas vary in their energy requirements. In 2012, natural gas consumed at natural gas compressors stations consumed nearly over 2 Quads of energy[42], or roughly seven percent of total U.S. natural gas end-use. Compressor stations located on the interstate natural gas pipeline network typically contain 4 units per station (a compressor "unit" consists of an engine or motor attached to a gas compressor; e.g., a natural gas-fired turbine to turn a centrifugal compressor). These are often large facilities with emissions control equipment (i.e., scrubbers), tanks (for collecting and storing liquids that are removed before the gas is passed through a compressor) and other control equipment located on site. Other segments with significant compression capacity include production gathering (i.e., "Boosting" stations), processing plants and storage facilities.

Oil, which is the principal economic driver for energy producing companies in the Bakken, cannot be produced without natural gas co-production. Because of a lack of natural gas infrastructure in North Dakota, about 30% of the natural gas produced North Dakota is flared into the atmosphere. The gas being flared releases significant carbon dioxide into the atmosphere every year, an environmental and public health concern that the state is currently attempting to tackle.

As natural gas production and distribution continues to expand, these environmental issues will remain a priority for the industry stakeholders.

[42] http://www.eia.gov/dnav/ng/ng_cons_sum_dcu_nus_m.htm.

7.1 Lost and unaccounted for gas and cost recovery

Lost and unaccounted for gas (LAUG) "is the difference between the gas measured into the distribution system and the gas measured out of the utility system or otherwise accounted for." Gases are more difficult to measure than liquids because changes in pressure and temperature cause large changes in volume.[43] The term includes actual leaks of methane and meter differences that do not reflect actual leaks.[44]

Pipeline companies have been able to recover costs from their customers for leaks and LAUG since the early days of the American natural gas industry. The U.S. Supreme Court discussed this issue in a 1934 case that dealt with natural gas rates: "The company made claim to an allowance for 'unaccounted for gas,' which is gas lost as a result of leakage, condensation, expansion or contraction. There is no dispute that a certain loss through these causes is unavoidable, no matter how carefully the business is conducted."[45] In current natural gas sales contracts, shippers (e.g. local distribution companies and marketers) pay for the cost of natural gas transmission. Pipeline companies publish a tariff for recovering "prudently incurred costs" through cost of service rates for transmission service. Cost of service rates include a charge to the shipper purchasing the gas for LAUG and natural gas used as fuel for the compressors on the pipeline. Typically the charge is for .5% of throughput for LAUG and 3% of throughput for compressor fuel. This means a hypothetical shipper that needs 1Bcf (1 billion cubic feet) of natural gas would pay for 1.035 Bcf of natural gas.

State utility commissions regulate rates and enforce safety standards for natural gas pipelines and distribution lines under their jurisdiction. States generally allow gas distributors to recover costs of shipping natural gas to their customers, including gas lost between the transmission hub and the gas meter. Massachusetts, for example, passes the cost of LAUG on to ratepayers using the state's cost of gas formula in its utility regulations.[46] This reduces the incentive for gas distributors to repair gas leaks or replace old gas lines that are especially prone to leaking. The Massachusetts Department of Public

[43] American Gas Association Rate Round-Up, December 2009, available at http://www.aga.org/SiteCollectionDocuments/RatesReg/RateDesign/LUAF%20Cost%20Recovery%20Mechanisms.pdf (accessed on January 8, 2014).

[44] Lost and unaccounted for gas is not necessarily gas leaked into the air. Unaccounted for natural gas is defined as "differences between the sum of the components of natural gas supply and the sum of components of natural gas disposition. These differences may be due to quantities lost or to the effects of data reporting problems. Reporting problems include differences due to the net result of conversions of flow data metered at varying temperatures and pressure bases and converted to a standard temperature and pressure base; the effect of variations in company accounting and billing practices; differences between billing cycle and calendar-period time frames; and imbalances resulting from the merger of data reporting systems that vary in scope, format, definitions, and type of respondents." EIA Tech Dictionary, available at http://energy.techdictionary.org/EIA-Energy-Dictionary-C-2/Unaccounted_for_natural_gas (accessed January 7, 2014).

[45] West Ohio Gas Co. v. Pub. Util. Com'n of Ohio, 294 U.S. 63, 67, 55 S.Ct. 316, 319 (1935) citing Consol. Gas Co. v. Newton, 267 F. 231, 244 (S.D.N.Y. 1920) and Brooklyn Union Gas Co. v. Prendergast, 7 F.2d 628, 652, 671 (E.D.N.Y. 1926).

[46] Conservation Law Foundation, Into Thin Air at 10-11 (citing 220 C.M.R. 6.00) available at http://www.clf.org/static/natural-gas-leaks/WhitePaper_Final_lowres.pdf (accessed January 7, 2014).

Utilities recently implemented incentive programs to encourage distributors to replace old cast iron and bare still lines, which, as mentioned above, are more likely to leak. [47]

8. Conclusion

A confluence of economic and regulatory factors are likely to drive an increasing proportion of America's power generation, transportation, industrial and space heating fuel use toward natural gas. Facilitating this transition while balancing some of the inherent benefits of natural gas against safety, economic and environmental concerns will be a key policy focus for federal, state and local regulators and the natural gas industry on the whole.

9. Key questions

Significant changes will be required to meet the transformational challenges posed by the Shale Era. DOE is seeking public input on key questions relating to gas-related infrastructure including:

- Who should pay for new pipeline capacity and how should those costs be allocated? How can electricity markets incentivize flexibility and reliability of gas-fired generators, to ensure they have fuel when they are most needed?
- What have been the key safety trends recently in the natural gas transmission, storage, and distribution segment of the gas industry? What are chief actions that could be taken to improve safety for this segment?
- What could be the impact of distributed natural gas generation on infrastructure demands?
- Are there conflicts between federal, state, regional and local policies and regulations that serve as a barrier to improving gas-electric coordination? If so, what's the best way to resolve them?
- What natural gas-related interdependencies should be examined form an energy security and resilience perspective?
- What existing policies are problematic for maintaining system reliability, adaptability and resilience?
- What emerging technologies offer opportunities or pose challenges to improving the delivery of natural gas?
- What information could better inform policy decisions about natural delivery infrastructure?
- What investments, if any, need to be made in natural gas infrastructure to backstop growth in intermittent supplies like wind and solar generation?
- What new Will distributed energy resources at the distribution level increase or decrease the need for fast-ramping natural gas generators?
- Are gas pipeline compressors stations vulnerable to power outages, and to what degree would gas TS&D systems be affected by a relatively long-term regional power outage?

[47] America Pays for Gas Leaks: Natural Gas Pipeline Leaks Cost Consumers Billions, A Report Prepared for Senator Edward J Markey, p. 2 (August 1, 2013) available at http://www.markey.senate.gov/documents/markey_lost_gas_report.pdf (accessed January 8, 2014.