Chapter 6: Infrastructure

In the United States, the availability, reliability and price of natural gas are inextricably linked to its production and delivery infrastructure. As seen in Figure 6.1, major components of the system include inter-state and intra-state transmission pipelines, storage facilities, liquefied natural gas (LNG) regasification terminals and gas processing units, all of which establish the link between gas producers and consumers. This system is both mature and robust.

This chapter will describe and discuss:

- Trends with implications for the U.S. natural gas infrastructure;
- The components and sub-sectors comprising the natural gas infrastructure, with a focus on pipelines, LNG import terminals, processing and storage;
- New and proposed environmental regulations affecting the natural gas infrastructure; and
- Specific gas infrastructure issues associated with the development of the Marcellus shale.

Figure 6.1 Schematic of the U.S. Natural Gas Infrastructure

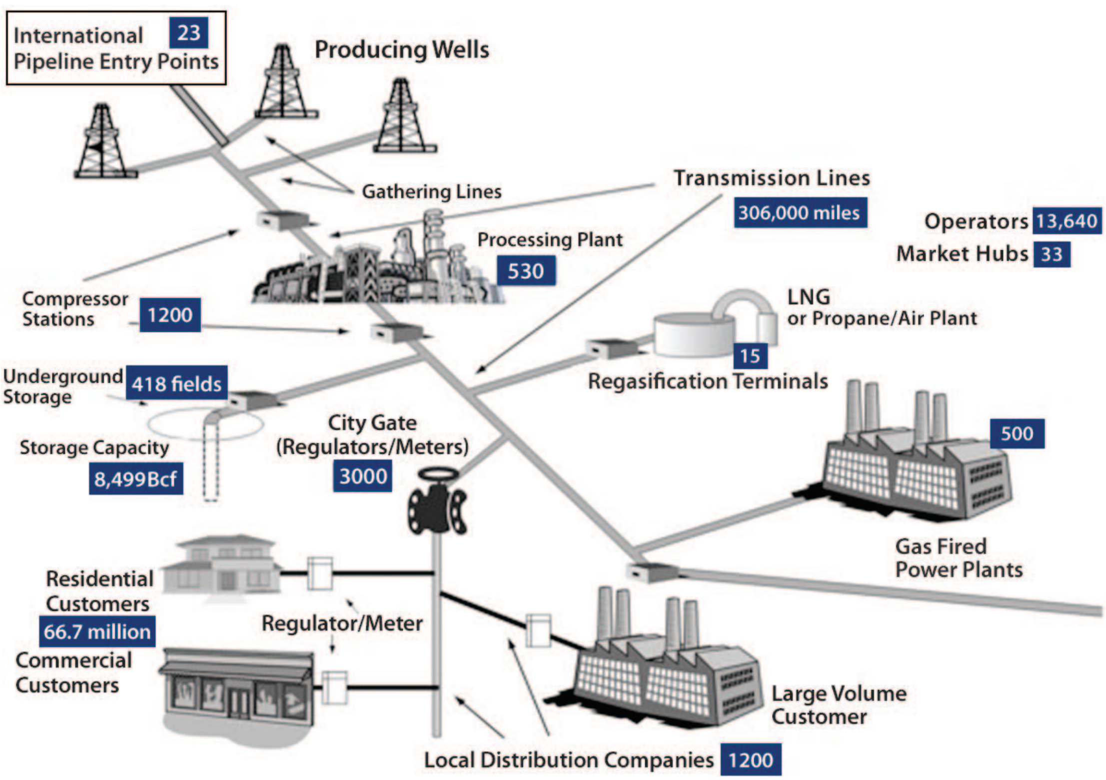


Image modified from CHK

TRENDS AFFECTING U.S. NATURAL GAS INFRASTRUCTURE

Several trends are altering the landscape of U.S. gas markets with implications for infrastructure needs and requirements. These include: changing production profiles; shifts in demand/consumption patterns; and the growth of LNG markets.

Changing Production Profiles

As described in Chapter 2, production from large onshore shale basins is shifting the focus of U.S. production from the Central and Western Gulf of Mexico (GOM), where it has been for the last two decades, back to onshore regions. While GOM production declined by 42% between 2004 and 2008, onshore production in the lower 48 states (L-48) increased by 22% over the same time period.[1]

Areas with the most marked production increases include the relatively immature Rocky Mountains, where production increased 103% between 1998 and 2007; and parts of Eastern Texas, where production increased by 177% over the same time period. This shift is expected to be more pronounced as production increases from the Marcellus shale, concentrated in New York and Pennsylvania, with additional production potential in Ohio and West Virginia.

Shifts in Demand Patterns

There has also been a shift in U.S. gas demand patterns over the last decades, associated in part with relative population shifts to the South and West from the Northeast and Midwest, the two regions in the country where population as a percent of total U.S. population has declined.

Population growth has been especially pronounced in the Western U.S., where the population increased by 42% between 1980 and 2008. This growth, coupled with stricter air quality regulations, has led to increased demand for gas in the West, where gas consumption has outpaced population growth, increasing by 68% in the last three decades. In the Northeast, environmental concerns and a shift away from oil in power generation and home heating has led to increased gas consumption; between 1980 and 2008 the population in the Northeast U.S. increased by 19% but gas consumption increased by 50%.[2]

These demand increases, largely for residential, commercial and electricity uses, have been accompanied by a reduction in demand from industrial customers; this is illustrated by the relative decline in gas consumption in the Southwest U.S., largely Texas, the only region of the country where gas consumption in absolute terms and as a percentage of the U.S. total actually dropped. This 15% decline in consumption over the last three decades can be attributed in part to high natural gas prices over the last several years which drove refineries, and ammonia and other chemical plants offshore.[3]

The U.S. and LNG Markets

Growing gas demand and significant differences in gas prices between global regions has increased the desirability of a global gas market. As seen in Chapter 3, gas prices are significantly lower under an Emissions Prediction and Policy Analysis (EPPA) scenario where there is a relatively unconstrained global market in natural gas compared to the current regionalized market. While the U.S. represents around 24% of global gas consumption, its engagement in the development of a global LNG market is tempered by dramatic increases in the U.S. producible gas resource base, largely enabled by the affordable production of new unconventional gas resources.

Currently, the U.S. permits proprietary access to LNG suppliers for new regasification terminals; this would allow the developer of a regasification facility to give preference to the import of its own LNG or the LNG of its affiliates at that point of entry.[4] This policy decision was made to incentivize construction of substantial import infrastructure in the U.S. creating opportunites for increased global LNG trade.

GHG EMISSIONS FROM THE NATURAL GAS INFRASTRUCTURE

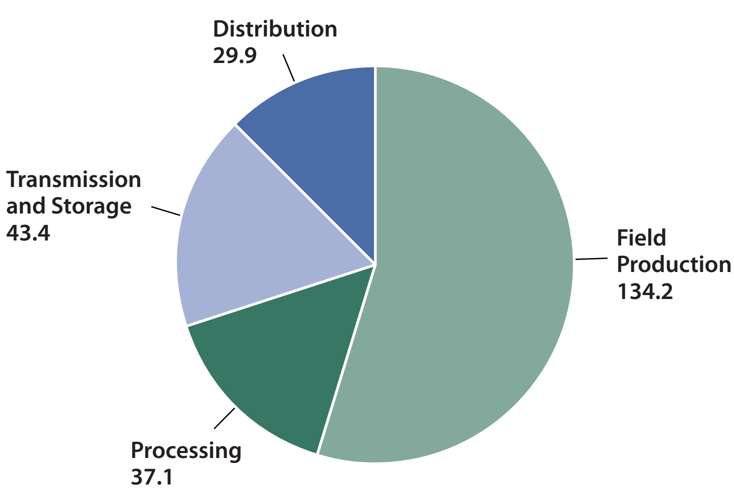
Natural gas is the cleanest burning fossil fuel, enhancing its desirability as a fuel option in a carbon-constrained environment. As a fossil fuel, however, natural gas also emits greenhouse gases (GHG), including CO_2 emissions from gas combustion and CO_2 and methane emissions from the gas system, including production, processing, transmission and distribution.

According to EPA inventories released in 2010, in 2008 GHG emissions from natural gas systems were 126 teragrams (one teragram is equivalent to one million metric tons) of CO_2 equivalents (CO_2e), less than 2% of total CO_2 equivalent emissions from energy sources and activities. Of this total, 96 teragrams of CO_2e were CH_4 emissions; the remainder are from non-combustion CO_2. The draft EPA inventory, released in late February 2011, doubled the EPA's estimates of methane emissions from gas systems for 2008. A breakout of EPA's estimated emissions from gas systems is seen in Figure 6.2 (from EPA's revised draft inventory estimates also discussed in Appendix 1A).

Methane leaks from gas systems, particularly at the levels indicated by the new EPA estimates, could prompt efforts to capture those emissions for both environmental and business reasons. Reducing emissions from well completions can, for example, create value for producers and can have a very short payback period (3 to 8 months).[5] While many larger producers and pipelines have already deployed relatively inexpensive methane detection and capture technologies and are able to realize profits from use of these technologies, smaller producers may need new, more affordable technologies to detect and capture methane emissions.

The EPA has also issued a final rule on mandatory reporting of GHG emissions from natural gas systems, after the Supreme Court determined the EPA could regulate GHGs as air

Figure 6.2 Estimated CO_2e Emissions from Natural Gas Systems



Source: EPA Draft GHG Emissions

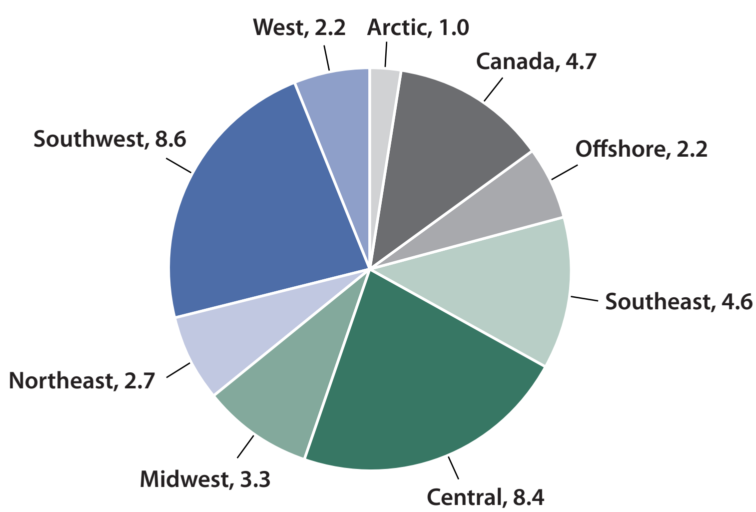
pollutants and the EPA issued an endangerment rule in 2010, indicating that GHGs posed a threat to public health and welfare. This rule would require reporting from well pad equipment both onshore and offshore, gas processing, pipelines, city gates, LNG import and export facilities, underground storage and compressor stations. The rule covers annual reporting of CO_2, methane, and nitrous oxide emissions from facilities emitting 25,000 metric tons of CO_2e per year or more. The EPA estimates the cost to the industry of implementing the rule to be $61 million for natural gas and oil systems (the EPA does not separate gas from oil) and $20 million a year in subsequent years in 2006 dollars.

The EPA has deferred direct emitter identification until confidentiality issues can be resolved. All other elements of the rule are now in effect.[6] The EPA estimates that this will affect around 2,800 facilities. The EPA is careful to point out that the 25,000 metric ton limit will exclude small businesses from the requirements of the rule. It is unclear how many small producers would be exempt by the emissions limit. Although the EPA recently postponed deadlines for mandatory emissions reporting, the ultimate regulation of GHGs by the EPA implied in the promulgation of this rule could have major impacts on gas system operations, particularly on production, transmission and storage, if the estimates in Figure 6.2 are reasonably accurate. EPA recently extended the deadline for application of best available monitoring methods for gas systems.

COMPONENTS OF THE NATURAL GAS INFRASTRUCTURE

To move gas from production to demand centers over the next 20 years, it is estimated by the Interstate Natural Gas Association of American (INGAA) that the U.S. and Canada will need approximately 28,900 to 61,900 miles of additional transmission and distribution natural gas pipelines depending on assumptions for gas demand — its base case identifies almost 38,000 miles of pipelines with the regional distribution depicted in Figure 6.3.[7] INGAA also projects a need for 371 to 598 billion cubic feet (Bcf) of additional storage capacity, a 15% to 20% increase over current levels and consistent with the rate of additions between 2005 and 2008.[8]

Figure 6.3 U.S./Canada Pipeline Capacity Additions, 2009–2030 (in 1,000 of miles)



Source: INGAA, 2009

Table 6.1 Total Expected Gas Pipeline, Midstream and LNG Expenditures, 2009–2030 (billions $)

Region	Transmission	Storage	Gathering	Processing	LNG	Total	%
Canada	33.0	0.4	1.2	1.0	-	35.5	**17**
Arctic	24	-	1.0	3.5	-	25.5	**14**
Southwest	27.6	1.3	4.2	7.5	0.4	41.1	**20**
Central	24.8	0.2	0.7	4.8	-	30.5	**15**
Southeast	15.4	1.4	0.4	2.3	1.3	20.8	**10**
Northeast	10.1	1.0	2.3	1.6	-	15.1	**7**
Midwest	12.9	0.4	0.2	-	-	13.4	**6**
Western	8.7	0.5	0.1	1.0	-	10.4	**5**
Offshore	6.3	-	7.8	-	-	14.1	**7**
Total	162.8	5.2	18.0	21.7	1.8	209.5	**100**
Percentage	**78**	**2**	**9**	**10**	**1.0**	**100**	

Source: INGAA, 2009

There will also be additional requirements for gas processing, especially in light of the changes in production patterns in the U.S. Investment requirements by sector for gas infrastructure between now and 2030 are summarized in Table 6.1.[9] Note that these figures assume success in bringing arctic gas to the L-48 from Alaska and the Mackenzie delta; the Alaska gas pipeline has remained illusory for the last two decades and its realization remains uncertain.

There are several federal and state agencies involved in siting gas pipelines and other gas infrastructure. The Federal Energy Regulatory Commission (FERC) regulates interstate pipeline construction while states regulate intra-state pipeline construction. Other federal agencies play significant roles in construction permitting, including the EPA, the Fish and Wildlife Service, and the Office of Pipeline Safety (OPS) at the Department of Transportation (DOT); the OPS regulates the safety of pipeline operations over the infrastructure's lifespan, starting with up-front safety certifications for permitting by FERC. The EPA ensures that a pipeline development project meets federal environmental guidelines. The Coast Guard and Maritime Administration (MARAD) at the Department of Homeland Security have responsibility for offshore LNG facilities. In addition to these federal agencies, there is a range of state entities involved in the permitting process.

The long lead times required to site and build gas infrastructure, driven in part by these complex regulatory decision-making structures for gas infrastructure siting, not only add to the cost, but mean that many of the additions and expansions we are seeing today were originally contemplated as much as a decade ago. This highlights the ongoing tension between the needs of policy makers and regulators for more accurate data and information on supply and demand trends and patterns, the associated infrastructure needs, and the status of technology development; and the inherent uncertainties and risks that accompany investment in natural gas infrastructure across the supply chain.

The U.S. Natural Gas Pipeline Network

The U.S. natural gas pipeline network includes:

- Gathering pipelines at, or adjacent to, production sites;
- Inter-state and intra-state transmission pipelines which move processed gas over long distances from production sites to major centers of demand; and
- Smaller diameter distribution pipelines, which carry natural gas on to end users.

Major changes in U.S. gas markets have prompted significant additions to the U.S. pipeline network over the last several years. Between 2005 and 2008, pipeline capacity additions totaled over 80 Bcfd, exceeding those from the previous four-year period by almost 100%.

In this discussion, we focus largely on transmission pipelines additions, although safety, which is briefly discussed, is also an important issue for distribution pipelines and to some degree, for gathering pipelines as well.

Pipeline Additions. Major changes in U.S. gas markets have prompted significant additions to the country's pipeline network over the last several years. Between 2005 and 2008, for example, pipeline capacity additions totaled over 80 billion cubic feet per day (Bcfd), exceeding those from the previous four-year period by almost 100%. Additions of 44.5 Bcfd in 2008 alone exceeded total additions in the five-year period between 1998 and 2002. The rate of additions in 2009, while slower than in the previous several years, was still brisk with 3,000 miles of pipelines added. Figure 6.4[10] highlights major inter-state pipeline additions over the 11-year period from 1998 to 2008.

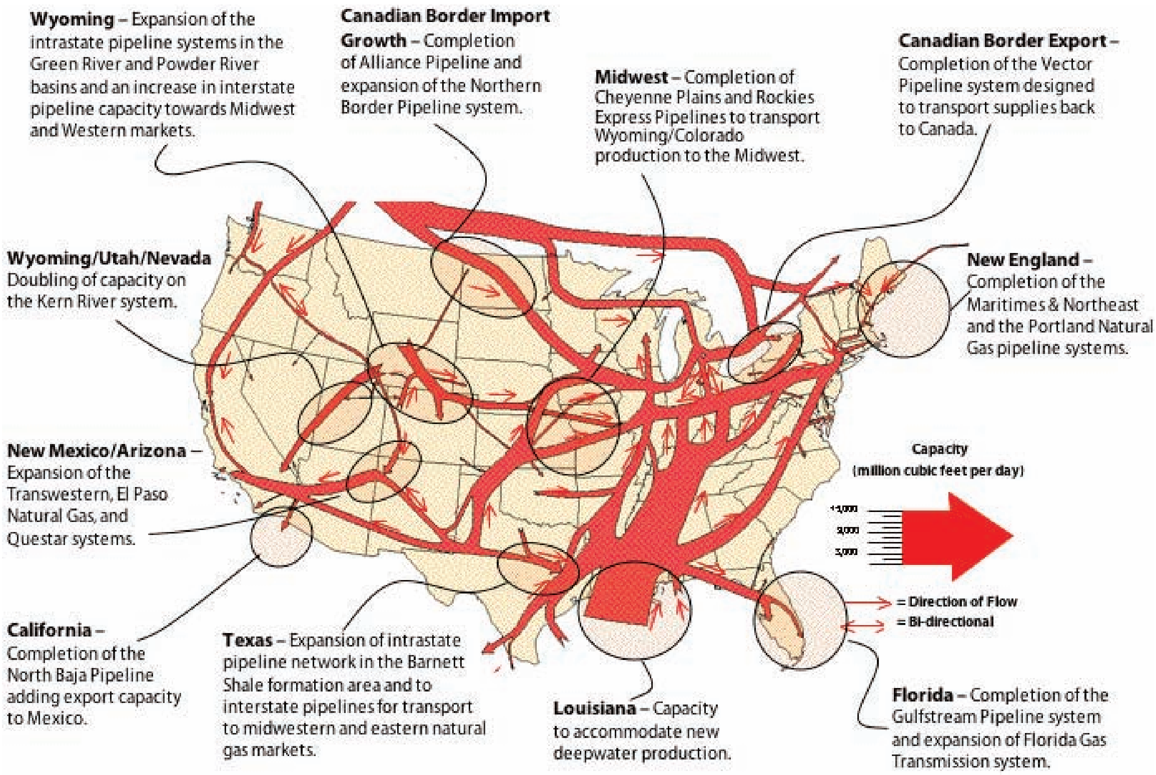
The largest single addition to the pipeline system between 2005 and 2008 was the Rocky Mountain Express pipeline (REX) with a capacity of 1.8 Bcfd. This pipeline has effectively linked Western producer markets to Eastern consumer markets. Other notable additions include Gulf Crossing (1.4 Bcfd) and Midcontinent Express (1.2 Bcfd), both taking gas from the shale regions in Texas and Oklahoma to Alabama and Mississippi; and two expansions to move gas into the Southeast U.S., the 1.6 Bcfd Gulf South Southeast Expansion; and the 1 Bcfd Southeast Supply header.[11]

The largest regional capacity increase in this time frame was from the Southwest region to the Southeast, where almost 6.7 Bcfd of pipeline capacity was added, in part to move shale supplies to markets. Capacity to move supply from the Midwest to the Northeast increased by 1.5 Bcfd, a 30% jump, followed by exports from the Central to Western U.S., at 1.4 Bcfd.

West-to-East expansions are contributing to major changes in the general direction of pipeline flows in the U.S., which have historically moved from south to north. 2030 forecasts suggest the need for an additional 20% of interregional transport capacity.[12] While forecasts and historical pipeline expansions offer a portrait of a robust and adequate response to growth in gas demand, the potential for large increases in gas-fired power generation, either for fuel substitution from gas to coal or as firming power for intermittent renewable generation, could increase the need for gas pipeline infrastructure.

Figure 6.4 depicts total pipeline capacity and directional flows; the circled areas highlight additions between 1998 and 2008, with volumes added and directions indicated by the key in the lower right-hand corner.

Figure 6.4 Major Additions to Natural Gas Transportation Capacity 1998–2008



Source: Presentation of James Tobin, EIA, Major Changes in Natural Gas Transportation Capacity, 1998–2008, November, 2011.

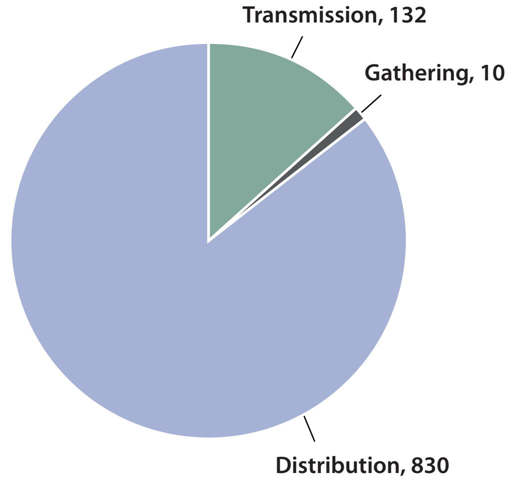
West-to-East expansions are contributing to major changes in the general direction of pipeline flows in the U.S.

In Chapter 4 we discuss the need for increased gas peaking units to firm intermittent renewable generation even though their capacity factors would most likely be very low. Similarly, recent analysis by the INGAA Foundation suggests that in the event of large-scale penetration of intermittent renewable generation, gas pipelines may need to dedicate firm capacity to provide service to backup generators even though this capacity would be used infrequently and the per-unit cost of the infrastructure is likely to be very high.[13] The INGAA study also forecasts an incremental delivery capacity requirement of around 5 Bcfd of gas for new firming generation though utilization would be only around 15%, with implied transportation costs that could be around six times more than full-rate utilization costs.[14]

Pipeline Safety. Recent gas pipeline explosions in California and Pennsylvania, which caused loss of life and property, underscore pipeline safety as an ongoing issue. There is a range of reasons for pipeline accidents, from pipeline/construction defects to third-party accidents to corrosion. Figure 6.5 shows the number of incidents by type of pipeline over the last 20 years. According to statistics compiled by the DOT, corrosion is the most common cause of leakage for transmission pipelines, and third-party excavation incidents are the most common cause of leakage for distribution pipelines.[15] Leakage is responsible for most serious incidents.

The DOT's Pipeline and Hazardous Materials Safety Administration (PHMSA) has the primary federal responsibility for ensuring gas pipeline safety. In 2003, the PHMSA implemented a rule that required an integrity management program (IMP) for transmission

Figure 6.5 Serious Gas Pipeline Incidents by Pipeline Type, 1991–2010



Source: PHMSA

Existing pipeline safety research programs within the federal government and within industry are small and the task of ensuring the integrity of the 306,000 miles of transmission pipelines and 1.2 million miles of distribution pipelines is enormous and essential.

pipelines. This rule required operators to test transmission pipeline integrity in highly populated areas by 2012. Between 2003 and 2009, after the implementation of the rule, there were six total fatalities; tragically, there were 10 fatalities in 2010 from the explosion and fire in San Bruno, California.

As noted, distribution pipelines are responsible for the largest number of serious gas pipeline safety incidents. Distribution pipelines also pose more difficult problems for integrity management compared to transmission pipelines as they are much smaller in diameter, are shorter, include a significant amount of plastic pipe, and have major branching of pipes to serve end use customers. A PHMSA rule for distribution pipelines, which went into effect in February 2010, requires IMPs to be implemented by August 2011. While plans are required, they will reflect the different challenges of distribution pipeline safety compared to transmission pipelines; they will likely be less prescriptive and will also cover the operator's entire area, compared to the requirements for transmission pipelines to cover only "high consequence areas."

The DOT has noted the lack of incentives for distribution pipeline operators to assess the safety of distribution pipelines, writing that "…there are no robust market signals or incentives to prompt operators to thoroughly assess the condition of the pipelines or to implement integrity management programs."[16] Also, according to the U.S. Department of Energy's (DOE) Office of Fossil Energy almost one-quarter of U.S. gas pipelines are more than 50 years old.[17] In addition, demand for natural gas is expected to increase over the next couple of decades.

Finally, existing pipeline safety research programs within the federal government are small and the task of ensuring the integrity of the 306,000 miles of transmission pipelines and 1.2 million miles of distribution pipelines is both large and essential. The PHMSA identifies $33.25 million in federal funding for pipeline

Table 6.2 PHMSA Technology Research 2002–present (in millions of $)

Category	PHMSA	Industry	Total
Damage Prevention	$2.79	$2.33	$5.12
Pipeline Assessment and Leak Detection	$25.08	$32.77	$57.86
Defect Characterization and Mitigation	$0.80	$1.20	$2.00
Improved Design, Construction and Materials	$4.58	$5.40	$9.98
Grand Totals:	**$33.25**	**$39.37**	**$72.62**

Source: PHMSA Web site

safety technology development since 2002, around $4 million per year (Table 6.2). The PMHSA also identifies $16.94 million in "strengthening standards" research and $29.98 million in "knowledge document" research; the last two categories could be characterized as "regulator's science."

IMPs are necessary but may not be sufficient to meet safety needs. The gas industry noted the need for additional transmission and distribution R&D in a 2007 report.[18] Specific focus areas could include:

- Improving the monitoring and assessment of system integrity;
- Enhancing system flexibility and throughput and reliability;
- Reducing the incidence and cost of subsurface damage;
- Improving the capability of cost-effective construction, maintenance and repair; and
- Improving data quality and timeliness for system, operation, planning and regulatory acceptance and mitigating environmental issues.[19]

Pipelines and Regional Prices. With respect to pipelines and regional prices, in general, the difference between daily prices at regional hubs compared to Henry Hub prices (the market center in Louisiana that serves as the price point for New York Mercantile Exchange (NYMEX) futures contract) is the basis differential or "basis." The basis differentials are often small, reflecting the short-run variable cost of transporting gas or of displacing shipments of gas to one market center instead of another. Occasionally, when transportation bottlenecks are long term, the basis differentials become large and reflect the different prices at which demand is being rationed in the different locations.

A differential that greatly exceeds the cost of transportation suggests system bottlenecks. According to FERC, Rockies tight gas and Marcellus shale will compete with traditional supplies from the Gulf of Mexico. FERC anticipates that this new supply will help moderate severe basis spikes on peak demand days in the winter.[20]

The relationship of the price differential to infrastructure is observed in the basis differentials at the Cheyenne and Algonquin hubs before and after the opening of the REX pipeline, which is now moving gas supplies from the region to Eastern markets (Figure 6.6). These fairly dramatic changes demonstrate how alleviating pipeline infrastructure bottlenecks can incentivize production and lower consumer prices overall.

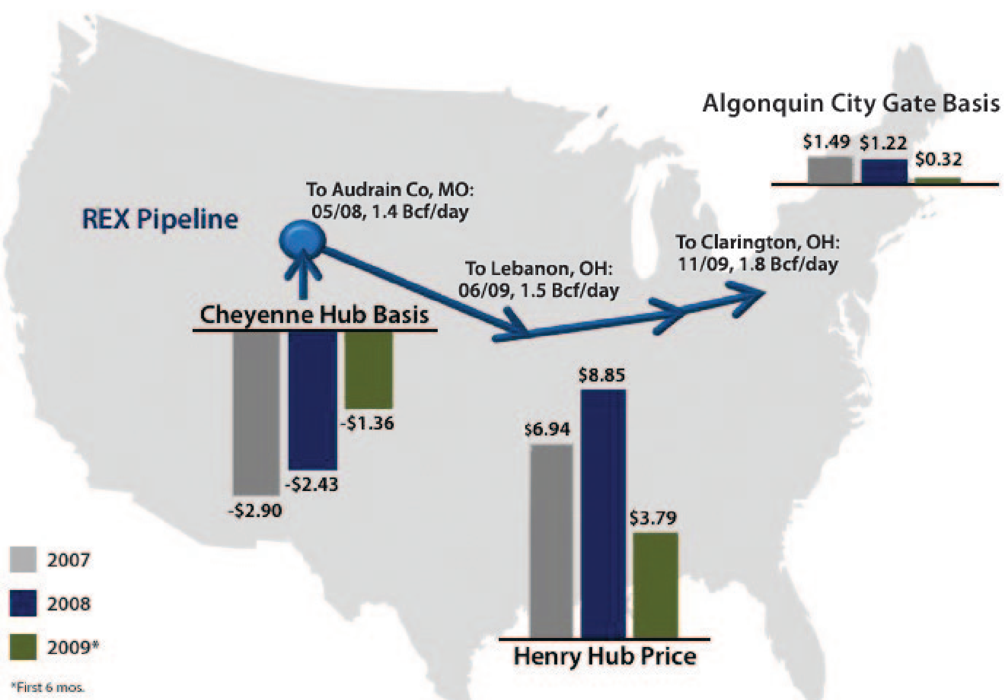
…alleviating pipeline infrastructure bottlenecks can incentivize production and lower consumer prices overall.

Before the construction of the REX pipeline, natural gas transportation out of the Rockies region was very constrained, leading to lower gas prices than those at most of the other natural gas market centers. As of November 2009, REX had the capacity to move 1.8 Bcfd of natural gas from the Rockies to Ohio, then to the Northeast. As noted, REX was the largest addition in the U.S. pipeline system between 2005 and 2008 and has effectively joined Western producer markets with eastern consumer markets, a long-time goal of Rocky Mountain producers. This pipeline has had a major impact on gas flows in the Midwest and has reduced the basis differential at both the Algonquin and Cheyenne hubs.

Natural Gas Processing

Each year in the U.S. some 530 natural gas processing plants process around 16 trillion cubic feet (Tcf) of raw natural gas. These facilities have an average capacity factor of around 68%. Natural gas often requires processing because gas in its raw form can contain impurities which may include sulfur, CO_2, water

Figure 6.6 Impacts of 2008 Pipeline Capacity Expansion on Regional Prices and Average Basis



Source: Bentek, Beast in the East, 2010

and other contaminants that need to be removed before transport through pipelines to demand centers. Removing impurities such as sulfur, CO_2 and water to produce pipeline-quality gas is the primary role of such processing facilities.[21] Understandably, gas processing units are largely located in gas-producing regions of the country. Currently, around 82% of gas-processing capacity is in six states: Louisiana, Texas, Wyoming, Kansas, New Mexico and Oklahoma.

As noted, gas production is increasing dramatically and production patterns in the U.S. are changing. The need for gas processing additions is likely to be more pronounced in regions where gas production is relatively immature, such as in the Uinta Basin of Eastern Utah and the Piceance Basin of Western Colorado. Gas processing is very limited in the Marcellus Shale Basin where, for example, Western Pennsylvania and Northern West Virginia combined have 530 million cubic feet (Mmcf) of processing capacity, with 435 Mmcf of planned processing additions and a new 37,000 bpd fractionation plant.[22]

Gas processing units also produce natural gas liquids (NGLs) from heavier hydrocarbons contained in unprocessed "wet" gas. If there are sufficient quantities of NGLs, the market conditions are right, and the processing facility has the capacity to both treat and separate NGLs from gas streams, consumer products can be produced, including ethane, propane, butane and pentanes. These products can add value for gas producers, especially important in a low gas price environment. In 2009, the U.S. gas industry produced 714 million barrels of NGLs, a 16% increase over the 2005 levels of production.

Natural Gas Storage

Natural gas is stored in underground storage facilities to help meet seasonal demand fluctuations, accommodate supply disruptions and provide operational flexibility for the gas system, including power plants. Gas storage is also used to hedge price variations.

There are around 400 storage facilities in the L-48 owned by 80 corporate entities and managed by 120 operators. Depleted reservoirs account for most storage facilities (82%), followed by aquifers (9%), with salt caverns making up the remainder. Working gas storage capacity nationwide in 2009 was around 4.2 Tcf, which represents about 20% of annual gas production. Over 53% of this capacity is found in just five states: Michigan, Illinois, Louisiana, Pennsylvania and Texas.[23]

There has been a great deal of interest in the relationship between storage and short-term price volatility. In 2005, the FERC chairman noted that gas storage capacity had increased only 1.4% in almost two decades, while U.S. natural gas demand had risen by 24% over the same period, and speculated that there was a link to the record levels of price volatility that were being experienced.[24] In 2006, FERC issued Order 678 which, among other things, sought to incentivize the building of more storage by changing its regulations on market power requirements for underground storage. Since the order was issued, total storage capacity has increased by 169 Bcf, or 2% of overall storage capacity. This compares to a 1% increase in the previous three-year period.

There is also growing interest in high-deliverability gas storage. Storage facilities are classified as either baseload or peakload facilities. Baseload storage facilities, most often in depleted reservoirs, typically support long-term seasonal requirements primarily for commercial, residential and industrial customers. These facilities are large and are designed to provide steady supply over long periods of time; their injections (typically over 214 days, April to Oct) and withdrawals (151 days, Nov to Mar) are slow.[25]

[The] growing relationship between the gas and power infrastructures is highlighted by the increased need for high-deliverability gas storage to match the growth in gas-fired power generation associated with fuel. The degree to which this interdependency stresses both the gas and power infrastructures and creates conditions where the infrastructures and related contracting, legal and regulatory structures may be inadequate is not fully understood.

The operational characteristics of baseload storage may be inadequate as storage needed for gas-fired power generation where gas demand varies greatly, not just by season but daily and hourly. Managing this variability is especially important, for example, when, as seen under the carbon price scenario in Chapter 2, natural gas becomes a more critical component of the generation mix. Also, gas peaking units serve as backup for intermittent renewables which may have relatively low load. This type of demand also requires greater variability in storage withdrawals than is found in baseload storage units.

High-deliverability storage provides an option for handling high-demand variability associated with an increased role or natural gas in power generation.[26] High-deliverability storage, typically in salt caverns, is only about 5% of overall gas storage, although capacity increased 36% between 2005 and 2008, compared to 3% for all gas storage.[27] More important than capacity, however, is the withdrawal period. Table 6.3 highlights the much shorter, multi-cycle capabilities of salt formation storage facilities compared to depleted reservoirs and aquifer storage.[28]

Salt caverns are typically located in the Gulf Coast region and are not found in many areas of increased gas demand, where geology limits both baseload and peakload storage options; this is particularly true in the Northeast, the West (areas of high gas demand for power generation) and parts of the desert Southwest.

The growing use of natural gas for power generation, including the potential near-term displacement of coal with Natural Gas Combined Cycle (NGCC) generation and increased penetration of intermittent renewables, discussed in detail in Chapter 4, underscores the growing interdependencies of the gas and electric infrastructures. This growing relationship between gas and power infrastructures is highlighted by the increased need for high-deliverability gas storage to match the growth in gas-fired power generation. The degree to which this interdependency stresses both the gas and power infrastructures and creates conditions where the infrastructures and related contracting, legal and regulatory structures may be inadequate is not fully understood.

Table 6.3 Gas Storage Facility Operations

Type	Cushion Gas	Injection Period (Days)	Withdrawal Period (Days)
Depleted Reservoir	50%	200–250	100–150
Aquifer Reservoir	50%–80%	200–250	100–150
Salt Cavern	20%–30%	20–40	10–20

Source: FERC Staff Report

RECOMMENDATION

A detailed analysis of the growing interdependencies of the natural gas and power generation infrastructures should be conducted. This should include analysis of the system impacts of increased use of natural gas for power generation and the degree to which this stresses the infrastructure or creates conditions where storage may be inadequate to meet power generation needs.

LNG Infrastructure

LNG regasification terminals are the last link in a long supply chain that enables international trade in natural gas and U.S. LNG imports. In 2000, the U.S. had four LNG regasification facilities with a combined capacity of 2.3 Bcfd.[29] High natural gas prices in the first decade of the 21st century, coupled with concerns about declines in domestic supplies and reserves, sparked a wave of construction of new LNG regasification terminals and expansions of existing ones. North America now has 22.8 Bcfd of LNG regasification-rated capacity either operating or under construction (with original planning expectations of capacity factors of around 50%), 89% of which is in the U.S.

These facilities are expensive. The EIA estimated in 2003 that a typical new regasification terminal would cost \$200 to \$300 million for a sendout capacity from 183 to 365 Bcf (3.8 to 7.7 million tons) per year of natural gas but acknowledged a wide variation in cost, which is very site specific. [30]

In 2009, U.S. consumption of imported LNG was 1.2 Bcfd, leaving most of this new capacity unused and the investment stranded. Demand is, however, geographically uneven. The Everett import facility in Boston, for example, meets around half of New England's gas demand. Gulf Coast terminals however have been forced to seek authorization to re-export gas.[31] On a positive note, the large excess of import capacity provides options for supply diversity in the event of unexpected shortfalls in indigenous supply. Also, LNG supplies initially intended for U.S. markets have been diverted to other countries, with European importers and consumers, including some key U.S. allies, as the main beneficiaries.

Federal Policy and LNG. During the last decade, federal policy facilitated the expansion of LNG import capacity. In 2002, as already noted, FERC issued the so-called Hackberry decision which aided investment in LNG import capacity by allowing LNG developers proprietary access to import facilities. To address delays in LNG import terminal siting associated with jurisdictional conflicts, the Energy Policy Act of 2005 granted FERC exclusive jurisdiction over permitting of onshore LNG regasification facilities, clarifying federal primacy in this process. Later that year, FERC, in an effort to expedite siting of LNG facilities, established mandatory pre-filing procedures designed to help resolve NEPA and other community issues prior to the filing of a formal application with FERC by the developer to site a regasification facility.[32] These statutory and regulatory actions helped enable the permitting of substantial additional regasification capacity in the U.S. Together with additional volumes from Canada and Mexico, 48.65 Bcfd was licensed to supply U.S. markets (but not all of this capacity was built).

These actions by FERC and other agencies illustrate a willingness on the part of the federal government to expedite the building of energy infrastructure in order to achieve a policy objective; in this instance, adequate and affordable supplies of natural gas were deemed to be in the public interest as it was widely believed at the time that North American gas production had peaked and that imports would be necessary to affordably meet demand.

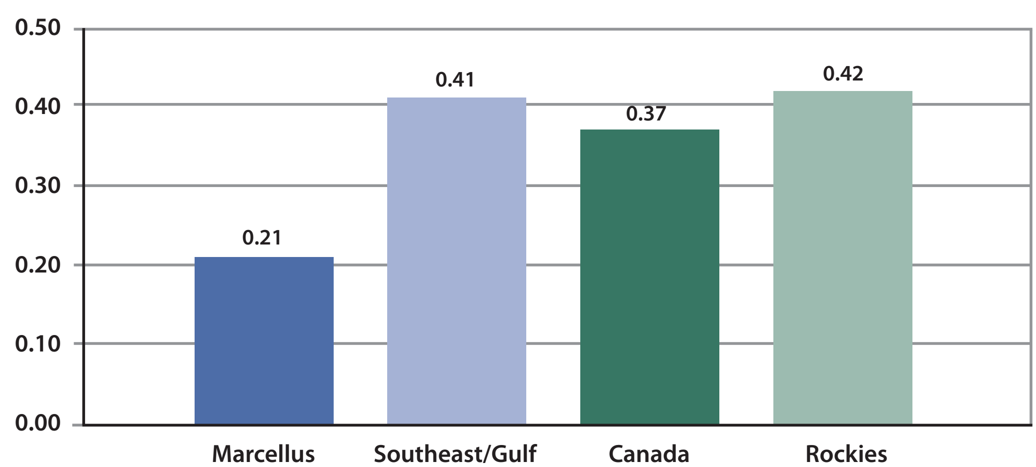
This unused capacity has prompted facility owners and investors to explore opportunities for using them as export as well as import terminals; this would require the building of substantial new liquefaction infrastructure. Cheniere, the owner of the Sabine regasification facility for example, has entered into non-binding agreements with two potential purchasers of LNG volumes, and is seeking funding to build four LNG trains at the site. The U.S. DOE recently approved a permit for export of LNG from this project to free trade agreement countries only and FERC has initiated an environmental review of the proposal. Others such as Dominion at Cove Point are reviewing export opportunities as well.

INFRASTRUCTURE NEEDS AND THE DEVELOPMENT OF THE MARCELLUS SHALE

As noted in Chapter 2, the natural gas production profile of the U.S. has been altered by the ability to produce natural gas from large U.S. shale basins. The Marcellus shale may be the largest contiguous shale basin in the world, underlying significant acreage in New York, Ohio, Pennsylvania and West Virginia, but it is also the least developed of major U.S. shale basins. These Northeastern and Midwestern states are generally more densely populated and less accustomed to natural gas production than Texas, Oklahoma, Arkansas and Louisiana, the locations of other major producing shale basins. Production in these other basins will continue to alter U.S. gas supply forecasts regardless of the development of the Marcellus. Its sheer size, its under-development, its unique environmental issues and its proximity to major demand centers and the associated consumer benefits warrants a brief discussion of some key infrastructure issues affecting the development of the Marcellus.

The economics of shale production and the size of the Marcellus shale basin have created enormous interest in the development and production of this vast resource. The location of Marcellus production in the Northeast, with the resulting lower transportation costs to this market, could translate into lower gas prices for the region's consumers, who have typically relied on LNG imports, and Canadian and GOM gas via pipeline.

Figure 6.7 Average Transportation Costs to Northeast Markets ($ per Mmcf)



Source: Bentek, Beast in the East, 2010

It could also shift GOM gas movements to the southeast, an attractive option for the region's consumers who are on the high-priced end of the Western coal supply chain. Figure 6.7 shows the average and typical transportation costs for producing regions supplying Northeast markets.[33]

The Marcellus, however, needs substantial infrastructure additions to move its gas to markets. There are three transmission pipelines to serve the region either under construction or certified for construction with a combined capacity of over 1 Bcfd, and another 4.8 Bcfd of planned additions to existing pipelines. These additions are essential: Marcellus producers estimated that, as of early 2010, less than half of the 1,100 wells drilled in the Pennsylvania Marcellus had pipeline access.[34]

It is expected that planned investments in pipelines, which are in the several billion dollar range, will also drive investments in underground storage. This is critical for the region as the geology of the Northeast precludes significant storage in this key demand region, which could create a storage bottleneck when moving gas from points West to Northeastern markets, particularly in the peak demand months in the winter.

There is also wet gas in the Marcellus, particularly in Southwestern Pennsylvania. The condensate and NGLs from wet gas enhance the economics of production, assuming favorable market conditions and adequate infrastructure to move NGL products to markets. A significant percentage of this wet gas in the Marcellus requires processing to provide pipeline quality gas. The shortage of processing capacity and outlets for wet gas products could place constraints on the production of pipeline quality gas, and could effectively shut-in significant gas production in the Marcellus. If all planned gas processing capacity additions for the Marcellus were to come on-line, on schedule, the region would have 800 million cubic feet per day (Mmcfd) of gas processing capacity by 2012. Also, two NGL pipeline projects have been proposed from Pennsylvania to Chicago and Ontario which could ease the pressure for NGL outlets. Planned pipeline expansions appear to be adequate.

Minimizing flowback water, on-site treatment options, water re-use, and new local and regional water treatment facilities are all necessary in managing the environmental impacts of flowback and produced water, water transport, and the stress on existing water treatment facilities in the region.

Finally, of major interest and concern is the development of a water disposal infrastructure to mitigate the environmental impacts associated with wastewater from drilling which includes flowback water and produced water. Water disposal options in the Marcellus are limited. Strict regulations and complicated geology, particularly in Northeast Pennsylvania, limit the development of disposal wells close to drilling sites. There is extremely limited pre-treatment capacity in the region and the climate is not conducive to evaporation options. Minimizing flowback water, on-site treatment options, water reuse, and new local and regional water treatment facilities are needed to reduce the environmental impacts of flowback and produced water and water transport.

NOTES

[1]EIA, Table 5a, U.S. Gas Supply, Consumption and Inventories.

[2]EIA, U.S. Census data.

[3]Bernstein Research report, Natural Gas: Method in the Madness, February, 2009.

[4]CRS Report, Liquefied Natural Gas (LNG) in U.S. Energy Policy: Issues and Implications, May 2004, the so-called "Hackberry decision", "…allowed terminal developers to secure proprietary terminal access for corporate affiliates with investments in LNG supply." Terminals that existed at the time of the ruling in 2002 were exempted. Congress codified Hackberry in the 2005 Energy Policy Act.

[5]EPA Methane to Markets presentation, International Workshop on Methane Emissions Reduction Technologies in the Oil and Gas Industry, Lake Louise, 14-16 September 2009.

[6]See EPA Web site, *Petroleum and Natural Gas Greenhouse Gas (GHG) Reporting Rule (40 CFR Part 98)*, EPA Climate Change Division.

[7]http://www.ingaa.org/cms/15.aspx, Dec 17 2009, 38,000 is base case for gas demand.

[8]http://www.ingaa.org/cms/15.aspx, Dec 17 2009, ranges represent high and low cases in forecasts.

[9]Ibid, high gas demand case.

[10]November 2008, Presentation of James Tobin, EIA, *Major Changes in Natural Gas Transportation Capacity, 1998–2008.*

[11]Bentek, The Beast in the East: Energy Market Fundamentals Report, March 19th, 2010.

[12]Ibid.

[13]INGAA Foundation study, *Firming Renewable Electric power Generators: Opportunities and Challenges for Natural Gas Pipeline*, March 16, 2011.

[14]Ibid.

[15]Serious incident is defined on PHMSA Web site as an event involving a fatality or injury requiring hospitalization.

[16]PHMSA-Research and Special Programs Administration, U.S. Department of Transportation Web site, 2004-19854.

[17]See DOE Fossil of Energy Web site, *Transmission, Storage and Distribution program description*, as of January 23, 2009.

[18]American Natural Gas Foundation study, *Research and Development in Natural Gas Transmission and Distribution*, March 2007.

[19]Ibid.

[20]FERC Northeast Natural Gas Market, Overview and Focal Points.

[21]EIA report, Natural Gas Processing: the Crucial Link Between Natural Gas Production and Its Transportation Market, January, 2006.

[22]Bentek, The Beast in the East: Energy Market Fundamentals Report, March 19th, 2010.

[23]EIA Table 14, Underground Storage Capacity by State, December 2009.

[24]December 15, 2005, Statement by FERC chairman Joe Kelliher on the Notice of Proposed Rulemaking Announcement on Natural Gas Storage Pricing Reform.

[25]FERC Staff Report, *Current State of and Issues Concerning Underground Natural Gas Storage*, 2004.

[26]INGAA Foundation Web site notes that, "additional conventional storage will be needed to meet growing seasonal demands and high deliverability storage will be required to serve fluctuating daily and hourly power plant loads."

[27]EIA, Table Underground Natural Gas Storage by Storage Type.

[28]FERC Staff Report, *Current State of and Issues Concerning Underground Gas Storage*, 2004.

[29]Gas Technology Institute, LNG Sourcebook, 2004.

[30]EIA Report #:DOE/EIA-0637, December 2003.

[31]FERC report, *State of the Markets*, 2009.

[32]FERC order 665's discussion of pre-filing procedures noted that it is "desirable to maximize early public involvement to promote the wide-spread dissemination of information about proposed projects and to reduce the amount of time required to issue an environmental impact statement (EIS)."

[33]Bentek, The Beast in the East: Energy Market Fundamentals Report, March 19th, 2010.

[34]Ibid.