Energy Security Initiative
at BROOKINGS

Evaluating the Prospects for Increased Exports of Liquefied Natural Gas from the United States

An Interim Report

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About The Brookings Energy Security Initiative

The Energy Security Initiative (ESI) is a cross-program effort by the Brookings Institution designed to foster multidisciplinary research and dialogue on all aspects of energy security today. ESI recognizes that public and private choices related to energy production and use will shape the global economic, environmental and strategic landscape in profound ways and that achieving a more secure future will therefore require a determined effort to understand the likely consequences of these choices and their implications for sound policymaking. The ESI Policy Brief Series is intended to showcase serious and focused scholarship on topical issues in one or more of these broad research areas, with an emphasis on targeted policy recommendations.

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Preface

In May 2011, The Brookings Institution Energy Security Initiative (ESI) began a year-long study into the prospects for a significant increase in liquefied natural gas (LNG) exports from the United States.

The study is divided into two parts: the first analyzes the factors that affect the feasibility of natural gas exports; the results of this stage of the project are presented in this interim report. The second will analyze the domestic and international implications of these potential exports.

To inform its research ESI assembled a Task Force of independent natural-gas experts, whose expertise and insights provided the foundation for this study. The authors are grateful to the Task Force for their substantive inputs to this interim report and their careful review of the manuscript.

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Executive Summary

Owing to breakthroughs in drilling and production technology over the past five years, the United States finds itself facing a long period of abundant, low-cost natural gas supplies. As the U.S. economy reorients itself to take advantage of greater use of natural gas, there is interest on the part of the public and private sector in the prospect of significant exports of U.S. natural gas in the form of liquefied natural gas (LNG).

A wide range of factors will inform the feasibility of U.S. LNG exports. On the supply side, the principal consideration is the sustainability of unconventional gas development. This includes the continued availability and accessibility of economically recoverable gas resources; and the presence of federal, state, and local regulatory regimes conducive to sustained production and investment. Other supply-related factors include the physical capacity of the U.S. natural gas system to transport gas volumes to export facilities and the availability of capital equipment and human resources.

On the demand side, natural gas exports will have to compete, both economically and politically, with incumbent and potential newcomer domestic end-users, including the power-generation sector, the petrochemical and industrial sector, and the transportation sector. As emissions-related regulations begin to come into force, a significant portion of the country's coal-fired electricity generation capacity is likely to be retired, leading to a projected increase in the use of natural gas in the power sector. Natural gas use is also likely to increase in the petrochemical and industrial sectors as the United States finds itself with a competitive advantage relative to countries using oil-based feed stocks. Despite enthusiasm on the part of some policy makers for increased use of natural gas in the transportation sector, the latter is likely to provide less domestic demand than in the power and petrochemical sectors. The rate and scale of domestic emissions-related regulations, the price of crude oil – as a feedstock for competing petrochemical industries and as a source of liquid fuels in the transportation fleet – as well as the political influence of domestic end users of natural gas are all likely to affect the case for LNG exports.

To be economically feasible, U.S. LNG exports will have to be competitive with those from other suppliers in global markets. While the differential between current domestic U.S. natural gas prices and those in target markets in the Atlantic and Pacific basins presents an attractive economic rationale for exports, several factors have the potential to change the global natural gas landscape, including policy decisions in LNG-importing nations; the rate of capacity growth among competing LNG exporters, and the rate of development of unconventional gas resources overseas. The extent to which U.S. exports themselves affect the cost of domestic gas and the costs of other aspects of the LNG supply chain such as liquefaction equipment and transportation costs will also have a bearing on the feasibility of U.S. LNG exports.

Introduction

Less than a decade ago, the United States was facing a major shortfall in the supply of natural gas as declining conventional production and reserves were outpaced by rising demand. The situation was so acute that private companies, encouraged by federal-government policies, began constructing import terminals for liquefied natural gas (LNG), which was regarded as the only way to meet growing demand.[1] Since 2005, however, the situation has dramatically reversed. Driven by advances in exploration and production technology and a precipitous rise in the floor price of natural gas to 2008, the U.S natural gas sector has undergone a revolution as vast amounts of previously uneconomic "unconventional" resources in shale formations across the Northeast, Midwest, and South have been developed.

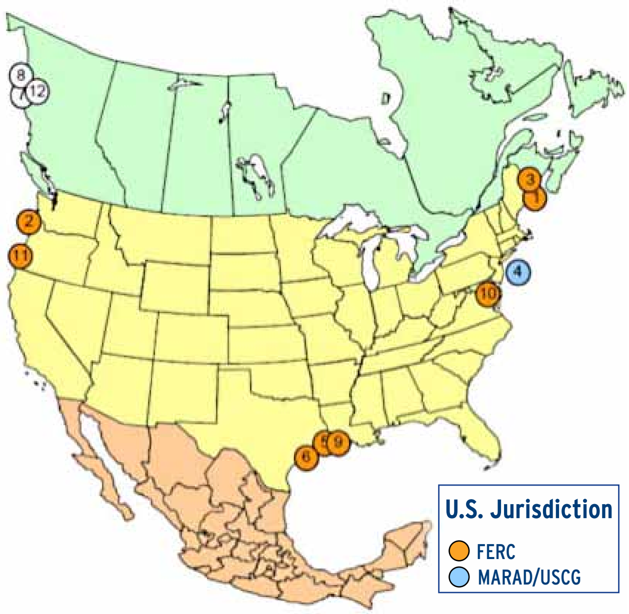
Early estimates of the size of the unconventional gas resource have varied. However, it is clear to producers and end users alike that the increased available volumes of shale gas mean that there is far more potential for natural gas in the U.S. energy mix than previously estimated. While the domestic focus has been on the potential for increased natural gas use in the power, industrial, petrochemical, and transportation sectors, there is also increased interest among policy makers and private investors in the prospect of the United States becoming a significant exporter of LNG (see Figure 1).

The United States already exports modest volumes of natural gas via pipeline to Mexico and Canada and, until November 2011, in the form of LNG from the Kenai Terminal in Alaska to Japan, although the latter facility has recently been temporarily idled.[2] Several projects currently under consideration would involve the development of liquefaction facilities to enable the export of LNG in increased quantities. These proposed projects, some of which have been given partial approval by the federal government over the past year, are currently evaluated by energy and environmental regulators on a case-by-case basis.

[1] The 2005 Energy Policy Act demonstrated Federal government support for a streamlined LNG import process through both codification of the 2002 "Hackberry Decision" by the Federal Energy Regulatory Commission (FERC), which absolved U.S. LNG import terminals from open-access requirements and allowed them to charge market based rates; and by granting FERC exclusive authority to approve siting, construction, expansion and operation of such import terminals.

[2] The Kenai liquefaction plant, inaugurated in 1969, exported to Japan modest amounts (30 bcf in 2010) of gas produced from the Cook Inlet. ConocoPhillips, the owner and operator of the facility, had initially planned on closing the plant in March 2011 due to an inability to renew supply contracts; however, following the earthquake and subsequent nuclear disaster in Japan, it decided to extend operations of the plant for six months to allow for additional shipments to Japan.

Figure 1: Proposed/Potential North American LNG Import/Export Terminals (as of November 1, 2011)



Import Terminal

PROPOSED TO FERC

1. Robbinston, ME: 0.5 Bcfd (Kestrel Energy – Downeast LNG)
2. Astoria, OR: 1.5 Bcfd (Oregon LNG)
3. Calais, ME: 1.2 Bcfd (BP Consulting LLC)

PROPOSED TO MARAD/COAST GUARD

4. Offshore New Jersey: 2.4 Bcfd (Excalibur Energy – Liberty Natural)

Export Terminal

PROPOSED TO FERC

5. Sabine, LA: 2.6 Bcfd (Cheniere/Sabine Pass LNG)
6. Freeport, TX: 1.8 Bcfd (Freeport LNG Dev/Freeport LNG Expansion/ FLNG Liquefaction

PROPOSED CANADIAN SITES IDENTIFIED BY PROJECT SPONSORS

7. Kitimat, BC: 0.7 Bcfd (Apache Canada Ltd.)
8. Douglas Island, BC: 0.25 Bcfd (BC LNG Export Cooperative)

POTENTIAL U.S. SITES IDENTIFIED BY PROJECT SPONSORS

9. Lake Charles, LA: 2.0 Bcfd (Southern Union & BG LNG)
10. Cove Point, MD: 1.0 Bcfd (Dominion – Cove Point LNG)
11. Coos Bay, OR: 1.2 Bcfd (Jordan Cove Energy Project)

POTENTIAL CANADIAN SITES IDENTIFIED BY PROJECT SPONSORS

12. Prince Rupert Island, BC: 1.0 Bcfd (Shell Canada)

Source: Federal Energy Regulatory Commission

Supporters of these projects maintain that they will provide a valuable source of economic growth, gains from trade, and job creation for the United States. Opponents contend that they will raise domestic natural gas prices to the detriment of U.S. consumers and negatively affect U.S. energy security.

The Brookings Institution's Energy Security Initiative (ESI) is at the midpoint of a year-long study to assess the feasibility and implications of an increase in U.S. LNG exports. To inform its research, ESI assembled a Task Force of independent natural gas experts, whose discussions and deliberations provide the basis of the project's conclusions. This interim report presents the findings of the first half of the study, and focuses on feasibility: the factors that are likely to have a bearing on the ability of the United States to export more gas. The complete report, with the findings on both the feasibility and the implications of significantly increased LNG exports from the United States, will be released in the spring of 2012.

What Influences Feasibility?

For the purpose of this study, the Brookings research team identified the various factors that affect the feasibility of increased U.S. LNG exports. These factors were divided into four main categories: domestic supply, domestic demand, international gas markets, and economic rationale. On the supply side, feasibility is defined as the physical capacity of the United States to have gas volumes available for export. Factors in this regard include: resource availability and production sustainability; regulatory and environmental considerations; and infrastructure issues, including pipeline availability, storage, and shipping capacity. On the demand side, feasibility of exports is defined by the extent to which potential exports compete with various domestic end uses for increased natural gas, including electricity generation, transportation, and industrial and petrochemical production. With regard to international markets, feasibility is the extent to which potential U.S. exports can compete with other LNG sources to meet demand, and includes an assessment of the potential markets that U.S.-origin LNG would serve. It also includes an assessment of the nature of contractual pricing agreements, particularly the linkage between natural gas prices and oil prices in target markets. Economic feasibility is the extent to which LNG exports have a long-term positive return on investment, and includes the effects of exports on domestic gas prices; the costs of liquefaction, transportation, and regasification; and the availability of financing.

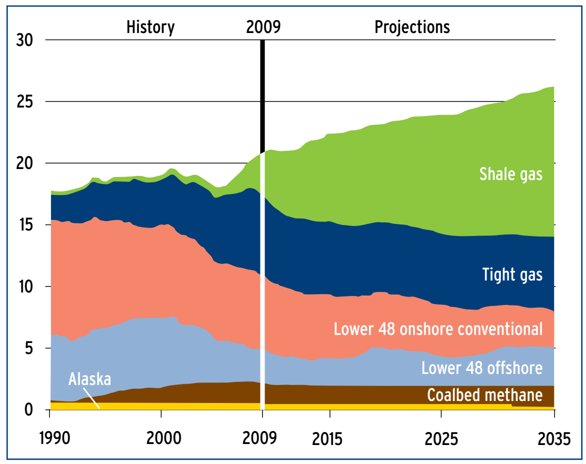
Domestic Supply Factors

The domestic U.S. natural gas supply situation is determined primarily by three sets of factors: resource availability and production sustainability; policy, regulatory, and environmental considerations; and capacity and infrastructure constraints.

Resource Availability and Production Sustainability

For an increase in U.S. exports of LNG to be considered feasible, there has to be an adequate and sustainable domestic resource base to support it. Natural gas currently accounts for approximately 25 percent of the U.S. primary energy mix. While it currently provides only a minority of U.S. gas supply, shale gas production is increasing at a rapid rate: from 2000 to 2006, shale gas production increased by an average annual rate of 17 percent; from 2006 to 2010, production increased by an annual average rate of 48 percent (see Figure 2).[3] According to Energy Information Administration (EIA), shale gas production in the United States reached 4.87 trillion cubic feet (tcf) in 2010, or 23 percent of U.S. dry gas production. By 2035, it is estimated that shale gas production will account for 46 percent of total domestic natural gas production.[4]

Figure 2: U.S. Natural Gas Production by Source, 1990-2035 (tcf/year)



Source: U.S. Energy Information Administration, Annual Energy Outlook 2011

Given the centrality of shale gas to the future of the U.S. gas sector, much of the discussion over potential exports hinges on the prospects for its sustained availability and development. For exports to be feasible, gas from shale and other unconventional sources needs to both offset declines in conventional production and compete with new and incumbent domestic end uses. There have been a number of reports and studies that attempt to identify the total amount of technically

[3] "Annual Energy Outlook 2011 with Projections to 2035," Energy Information Administration, April 2011. pp. 37, 39. (EIA, April 2011a)
[4] Ibid.

recoverable shale gas resources—the volumes of gas retrievable using current technology irrespective of cost—available in the United States. These estimates vary from just under 700 trillion cubic feet (tcf) of shale gas to over 1,800 tcf (see Table 1). To put these numbers in context, the United States consumed just over 24 tcf of gas in 2010, suggesting that the estimates for the shale gas resource alone would be enough to satisfy between 25 and 80 years of U.S. domestic demand.[5] The estimates for recoverable shale gas resources also compare with an estimate for total U.S. gas resources (onshore and offshore, including Alaska) of 2,543 tcf. Based on the range of estimates below, shale gas could therefore account for between 29 percent and 52 percent of the total technically recoverable natural gas resource in the United States.

Table 1. Comparison of shale gas estimates for the Lower 48 States, (Technically Recoverable Resources, excluding proven reserves; in tcf)

Report	Reserve Estimate
ICF	1,842
Advanced Resources International	1,189
Energy Information Administration (EIA), 2011	827
Potential Gas Committee	687

Source: ICF International, Advanced Resources International, EIA, Potential Gas Committee

The Importance of the Marcellus Shale

The Marcellus Shale, a geologic formation in the Appalachian Basin underlying parts of Kentucky, Maryland, New York, Ohio, Pennsylvania, Tennessee, Virginia, and West Virginia, is a lynchpin of the U.S. shale-gas sector. The Marcellus Shale currently accounts for a relatively minor proportion of U.S. gas production: around 4.5 billion cubic feet per day (bcf/day) in July 2011 out of an estimated average total production of around 65.5 bcf/d" should be "65.5 bcf/day nationwide. However, the rapid growth rate in production—around 60 percent in the past year—and its large size make the Marcellus a critical part of the country's shale gas potential.[6] According to the EIA, the reserves of the Marcellus Shale are estimated to be 410 tcf, nearly half of what the agency estimates for total U.S. shale gas reserves.[7] In August 2011, the United States Geological Survey (USGS) released a new assessment of the available gas resources in the Marcellus Shale, which estimated that the formation held 84 tcf of "undiscovered, technically recoverable" natural gas. This estimate represented a large increase relative to the 2 tcf estimated by the USGS in its previous assessment of the Marcellus in 2002. However, the USGS estimate is also significantly below the 410 tcf figure of Marcellus reserves estimated by the EIA, and below the estimates of other analysts.[8] At the time of writing, the methodology and definitions employed by the USGS in its 2011 assessment of the Marcellus Shale have not been made public. When they are, they will shed important light on the discrepancy between estimates of the resource.[9] As with other shale plays, the aggregate resources in place in the Marcellus Shale are less critical a factor than the economically recoverable volumes of gas and the sustainability of production growth and resource development.

[5] "U.S. Natural Gas Production, Consumption, and Net Imports," Energy Information Administration, (http://www.eia.gov/todayinenergy/detail.cfm?id=770)

[6] "Pennsylvania drives Northeast natural gas production growth," U.S. Energy Information Administration, August 30, 2011. (http://www.eia.gov/todayinenergy/detail.cfm?id=2870)

[7] "Review of Emerging Resources: U.S. Shale Gas and Shale Oil Plays," U.S. Department of Energy, July 2011, p. 5.

[8] The Massachusetts Institute of Technology, in its "The Future of Natural Gas" report estimated that between 35 and 40 percent of the U.S.'s shale gas resources are in the Marcellus Shale. ("The Future of Natural Gas," Massachusetts Institute of Technology, 2011. p. 39.) (MIT, 2011)

[9] According to one interpretation by Resources for the Future, the two estimates of the Marcellus Shale could be complementary, with the EIA estimate referring to recoverable gas in known, but unproven fields ("inferred reserves"), and the USGS estimate referring to undiscovered resources portions of which, when eventually discovered and evaluated, can be added to the EIA's 410 tcf figure. See David McLaughlin, "Undiscovered Resources and Inferred Reserves," Resources for the Future, October 2011.

Sustainability of Shale Gas Production

In addition to the size of the economically recoverable resources, two other major factors will have an impact on the sustainability of shale gas production: the productivity of shale gas wells; and the demand for the equipment used for shale gas production. The productivity of shale gas wells has been a subject of much recent debate, with some commentators suggesting that undeveloped wells may prove to be less productive than those developed to date and that the production performance of existing wells has been exaggerated. However, a prominent view among independent experts is that sustainability of shale gas production is not a cause for serious concern, owing to the continued rapid improvement in technologies and production processes.

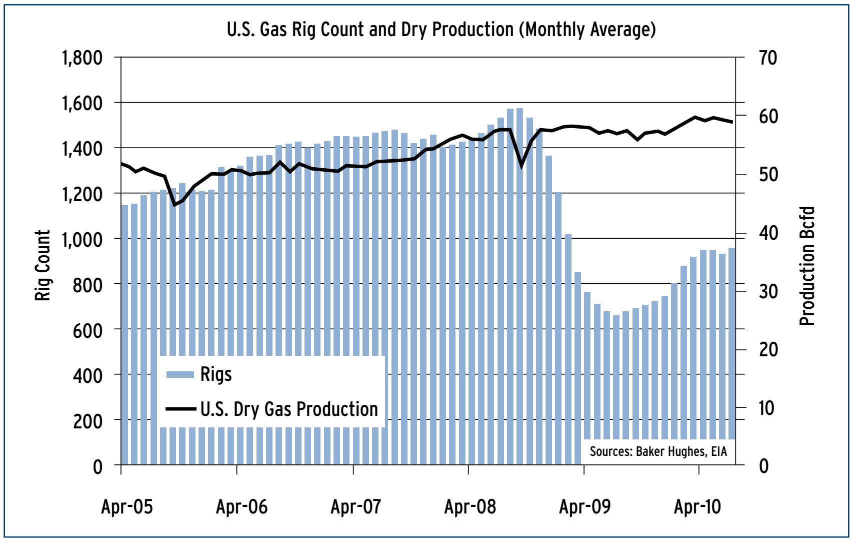
The sustained productivity of shale gas wells rests primarily on technological developments in two areas: the hydraulic fracturing ("fracking") process, in which water, sand, and other chemicals are forced at high pressure into rock formations to free trapped gas; and the length of horizontal wells ("laterals") drilled into the shale layer. Shale gas technologies and production processes have been developing rapidly in recent years, improving the economics of extraction. For instance, companies now are drilling longer laterals and are increasing the number of frac stages—the number of different fracking sections in each lateral section—per well, leading to an increase in available reserves and well productivity.[11] An analysis of well-specific-data illustrates that both initial production rates and ultimate well recovery have been growing across all plays, thereby driving down per unit costs of production. On the issue of exaggeration of current well productivity, it is impossible to verify the performance of wells operated by private corporations. It is, however, likely that most producers have a portfolio of wells that realize varying degrees of productivity.

A more immediate consideration with regard to production sustainability is the availability of drilling equipment and skilled labor. In addition to the demands for the latter from an increasing number of shale gas prospects, there is increasing competition from producers of shale oil, which use the same equipment to yield a product that is more valuable than gas at current market prices, and from producers who are more interested in plays rich in natural gas liquids, a valuable by-product of dry gas production. Formations such as the Eagle Ford Shale in Texas and the Utica Shale in Ohio and New York, which have higher condensate ratios—the ratio of liquids produced with gas production—have seen increasing interest from producers over the past two years. The displacement of rigs from "dry gas" prospects, such as the Haynesville Shale in Louisiana, to "wetter" prospects such as the Bakken field in North Dakota, is already occurring, as evidenced by the declining gas rig count in the gas sector (see Figure 3). Owing to the previously mentioned technological improvements, gas production is keeping pace despite the declining rig count.[11] However, a continued migration of drilling equipment and manpower to liquid-rich plays could present a near-term constraint for continued increases in shale gas production.

[10] "U.S. Natural Gas Resources and Productive Capacity," Advanced Resources International, prepared for Cheniere Energy, April 26, 2010. "Exhibits to Application of Sabine Pass Liquefaction, LLC for Long-Term Authorization to Export Liquefied Natural Gas," U.S. Department of Energy. p. 275. Also see "Natural Gas Industry Fakes the Moon Landing," EPRINC Briefing Memorandum, Energy Policy Research Foundation, Inc., July 1, 2011. (EPRINC, July 2011)

[11] EPRINC, July 2011.

Figure 3



Source: Navigant Consulting

Environmental, Regulatory, and Stakeholder Considerations for Natural Gas Production

The case for U.S. LNG exports depends entirely on the continued development of unconventional gas. This development itself depends on the safe and sustainable continuation of the practice of fracking, a process that has been under intense public scrutiny since shale gas production has increased. The recent conclusions of a report conducted by the Secretary of Energy's Advisory Board (SEAB) into the practices and oversight of shale gas development found that "[a]bsent action there will be little credible progress in reducing in the environmental impact of shale gas production, placing at risk the future of the enormous potential benefits of this domestic energy resource."[12] Concern around the negative environmental impact of shale gas development has led to the formation of local opposition groups, some of which call for outright bans on fracking. For its part, industry views the regulatory uncertainty around shale gas as among the greatest challenges to development.

Environmental Issues

There are three main environmental issues that need to be addressed if shale gas production is to continue at scale and provide the benefits many foresee: water, emissions, and other pollution such as noise and disruption caused by work-site activity.

The issue of water has been the most prominent to date, with the main focus being on the risk of contamination of surface water and water tables, the volume of water used in the process of fracking, and the disposal of waste water from the fracking process. The risk of groundwater contamination from fracking has been the subject of vigorous debate. Some environmental advocates charge that the technique can lead to seepage of gas and chemicals into water supplies, while energy companies maintain that correctly installed

[12] "The SEAB Shale Gas Production Subcommittee Second Ninety-Day Report," Natural Gas Subcommittee of the Secretary of Energy Advisory Board, November 18, 2011. p.3. (SEAB, 2011)

well casings combined with the depth of fracking operations—most of which are many thousand feet beneath the water table—make the process safe for drinking water supplies.

With regard to emissions, the major focus has been on unintentional leaks of natural gas, or "fugitive emissions," intentional venting of gas, and flaring. The latter issue is a particular concern in light of the developments at some shale oil plays, such as the Bakken and Niobrara. At both sites, the production of oil requires the production of large volumes of associated natural gas. Given the focus on the higher-value liquids production and the pace of development of these fields, the infrastructure for gathering and transporting this associated gas has not been adequately developed. The result is that large amounts of gas are being flared. In North Dakota, home of the Bakken shale oil field, roughly 30 percent of gas produced—over 3 bcf per month—is currently flared; the percentage of flared gas from production at the Niobrara shale formation that straddles Colorado, Wyoming and Nebraska is considered by industry experts to be much higher.[13] There are concerns that the rapid development of NGL-rich shale plays, such as Eagle Ford and Utica, may similarly result in the flaring of associated dry gas, which is less valuable than NGLs.

Other environmental issues that have been raised by opponents of fracking include the possibility of a link between fracking and seismic disruption, and issues of potential "fracture communication" through which fracking operations interact with existing natural geologic fractures, leading to a higher risk of groundwater contamination. There are also concerns that the disposal of wastewater through injection wells may cause seismic disruptions. The causal link between fracking-related processes and increased seismic activity has yet to be proved and is the subject of further investigation.

Regulatory Oversight for Natural Gas Production

A range of state and federal government agencies have jurisdiction over fracking and other aspects of natural gas development, and the extent to which, and the ways in which, these agencies implement regulations on shale gas production will have a major impact on the viability of exports.

Environmental Protection Agency

The Environmental Protection Agency (EPA) has a number of statutory authorities that apply to the regulation of shale gas production, including ensuring that harmful gases and pollutants are not released into the air (through the Clean Air Act) and that water supplies are kept free from waste water or methane leakages (through the Clean Water Act and Safe Drinking Water Act). The principal concerns for the EPA regarding shale gas production relate to water consumption, treatment, and storage.[14] Owing to the provisions of the 2005 Energy Policy Act, the EPA's regulation of underground injection of fluids relating to fracking under the Safe Drinking Water Act is limited to those operations that use diesel-based fracking fluids. However, the agency is addressing the issue of fracking through a variety of other statutory authorities.

[13] From the "Director's Cut" by the North Dakota Industrial Commission Department of Mineral Resources, July 21, 2011. (https://www.dmr.nd.gov/oilgas/directorscut/directorscut-2011-07-21.pdf)

[14] In November 2011, the EPA released its plan to study, at the request of Congress, the impacts of hydraulic fracturing on water resources. The report states that "many concerns about hydraulic fracturing center on potential risks to drinking water resources, although other issues have been raised." ("Plan to Study the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources," U.S. Environmental Protection Agency, November 2011. p. viii.)

As required by Congress, the EPA has begun a study on shale gas and fracking that focuses on five areas of water usage: water withdrawals, surface spills of fracking fluids, impacts of injection on drinking water, impacts of flowback and produced water, and wastewater treatment and disposal. The results of the study are due by the end of 2014, with an interim report scheduled for release in 2012. In October 2011, the EPA announced it would use the Clean Water Act to regulate the disposal of waste water produced by fracking. The agency is currently engaged in discussions with the various stakeholders and will announce a proposed rule by 2014.[15]

The EPA has also recently announced that it will use the Toxic Substances Control Act (TSCA) to "[initiate] a proposed rulemaking process … to obtain data on chemical substances and mixtures used in hydraulic fracturing."[16] Acknowledging that some states already engage in this practice, the EPA announced that it would complement, not duplicate, such efforts and that it would provide an "aggregate picture" of the chemical compounds used in fracking fluids.

In December 2011, the EPA released a draft analysis of data from an investigation into ground water quality in Pavillion, Wyoming. The draft report indicates that ground water in the aquifer under review contained "compounds likely associated with gas production practices including hydraulic fracturing," and that chemical samples were "generally below established health and safety standards."[17] The draft report, which, at the time of writing, is in a public comment and peer review period, has galvanized opponents of fracking. Responses from gas industry representatives focus on the inconclusiveness of the findings and the possibility of the natural occurrence of some of the chemicals discovered in the samples.

In addition to its focus on water, the EPA has several initiatives that focus on air quality and pollution. In July 2011, it proposed rules for regulating air pollutants from fracking-related operations intended to significantly cut the amount of volatile organic compound (VOC) emissions from the completion of hydraulically fractured oil and gas wells; following an extension of the public comment period in October 2011, final rules are expected in April 2012.

The EPA's regulation of shale gas development is complicated by a lack of clarity around the definition of "fracking." Some industry representatives prefer a narrow characterization of the term, comprising only the process of hydrostatic pressure shattering rocks at depth, while environmentalist argue for a definition that includes the entire lifecycle of fracking-related operations including the drilling of wells, installation of casings, and treatment and disposal of waste water and chemicals. The merits of the varying definitions are beyond the scope of this report. However, it is clear that any future EPA definition and regulation of fracking will have significant potential to affect the feasibility and pace of shale gas development, and therefore the feasibility of exports. An outright ban on fracking would shut down the unconventional gas industry, while high additional costs from regulation could make marginal shale gas prospects uneconomic, reducing the size of the economically recoverable resource. Conversely, well developed regulations, possibly based on sustainable best practice, could provide benefit to the public, the environment and industry.

[15] "Natural Gas Extraction—Hydraulic Fracturing," U.S. Environmental Protection Agency. (http://www.epa.gov/hydraulicfracture/).
[16] Letter from Stephen Owens, Assistant Administrator, U.S. Environmental Protection Agency, to Deborah Goldberg, Earthjustice, on November 23, 2011. (http://www.epa.gov/oppt/chemtest/pubs/EPA-Letter-to-Earthjustice-on-TSCA-Petition.pdf)
[17] "EPA Releases Draft Findings of Pavillion, Wyoming Ground Water Investigation for Public Comment and Independent Scientific Review," Environmental Protection Agency, November 8, 2011

Bureau of Land Management

The Bureau of Land Management (BLM) within the U.S. Department of Interior oversees the development of oil and gas resources on Federal land. While BLM does not need to approve "routine" fracking operations, such operations must be reported to the Bureau by the companies carrying them out within 30 days. Non-routine fracking operations require prior approval by the Bureau. However, as with the EPA's oversight of fracking, there is currently no definition for what constitutes a "routine" or a non-routine operation. Currently, BLM recommends and encourages the best land and water management practices for shale gas production. Secretary of the Interior Ken Salazar has also publicly stated that he considering possible regulations for the disclosure of chemicals used in fracking on federal lands.

Regional and State-Level Regulation

As large-scale shale gas production is a relatively new phenomenon, several aspects of the regulatory regime—including issues of federal-versus-state jurisdiction—have yet to be resolved. Currently, most states implement their own regulatory requirements for oil and gas production with the EPA having responsibility for ensuring that shale gas production meets national standards for air, dust, and water consumption and treatment. While many companies agree that a degree of regulation is necessary for certain practices, they are divided in their opinion on whether federal or state regulators should have jurisdiction over them: some think comprehensive federal oversight would stifle shale gas production, while others see the prospect of a single set of regulatory requirements as preferable to a patchwork of state-level rules.

Some notable state- and regional-level regulatory activity on shale gas production includes:

- The Texas Railroad Commission's June 2011 legislation that requires the development of regulations that mandate the disclosure of the composition of fluids used in hydraulic fracturing.[18]

- A commitment by Pennsylvania Governor Tom Corbett in October 2011 to implement a range of recommendations of that state's Marcellus Shale Advisory Commission, including provisions extending liability periods, increasing impact fees, and increasing the distance of shale-gas wells from private and public bodies of water.

- New York's temporary moratorium on fracking, which halted new fracking operations in the state. The Governor's office has put forward a draft environmental impact study for public comment, the results of which will inform a decision on whether to permit fracking to continue with specific exemptions.

- West Virginia's Joint Select Committee on Marcellus Shale's passage of a bill that increases drilling permit fees, with increased revenues allocated to the hiring of more well inspectors. The bill, which also lays out new terms for compensation to surface owners for damage to property, and minimum distances between wells from homes and drinking water, still needs to be voted on by the full state legislature.

[18] Bill H.B. No. 3328, "An Act relating to the disclosure of the composition of hydraulic fracturing fluids used in hydraulic fracturing treatments," the 82nd Legislature, Government of the State of Texas. (http://www.capitol.state.tx.us/BillLookup/History.aspx?LegSess=82R&Bill=HB3328).

- Colorado and Wyoming's mandatory requirement for "green completion" of natural gas wells, through which gas and vapors that would usually escape into the atmosphere during the completion phase of a well are captured and sold.

- The Delaware River Basin Commission's (DBRC, a federal interstate government agency comprised of the four basin states), consideration of new regulations on oil and gas production—and the attendant water consumption and disposal—within the basin. According to the DRBC, about 36 percent of the Marcellus Shale lies beneath the basin.[19]

The importance of state-level regulation of shale gas development was highlighted by the SEAB report, which recommended increased federal funding for the State Review of Oil and Natural Gas Environmental Regulations (STRONGER), and the Ground Water Protection Council, two existing organizations that help states to develop regulations and best practice.[20]

Other inter and intrastate authorities with influence over the regulatory environment for the development of shale gas include other river basin commissions; and municipal, town and village governments. The extent to which state law supersedes or conforms to local-level rulings on fracking and other aspects of shale gas production will have a significant bearing on the sustainability of shale-gas development operations.[21]

Enforcement and Public Perception

Irrespective of the regulations in place or under consideration, an important aspect of the discussion around responsible and sustainable shale gas development is the effectiveness of enforcement and public perception on the safety of fracking. The interim findings of the SEAB report found that "while many states and several federal agencies regulate aspects of these operations, the efficacy of the regulations is far from clear."[22] The report emphasized the role for industry in the responsible development of shale gas and called for the formation of a "shale gas industry production organization" that would establish best practice for operations, share information with regulators, and act to build public trust. The latter consideration was of particular concern to the authors of the interim report, who noted that "some concerted and sustained action is needed to avoid excessive environmental impacts of shale gas production and the consequent risk of public opposition to its continuation and expansion."[23] The extent to which industry can act as a responsible stakeholder and standard setter and the extent to which public confidence in fracking can be retained will have a large bearing on the feasibility of continued shale gas development and therefore the feasibility of U.S. LNG gas exports.

Regulatory Approvals for Export Facilities

Companies looking to construct or expand facilities for the export of LNG from the United States need to satisfy a number of federal regulatory requirements. These include the requirement for

[19] "Natural Gas Drilling in the Delaware River Basin," Delaware River Basin Commission. (http://www.state.nj.us/drbc/naturalgas.htm)
[20] SEAB, 2011, p.3.
[21] For an excellent analysis of the range of regulatory actors in the Marcellus Shale, see Andrew Blohme et al, "Impact of shale gas policy on domestic and international natural gas markets," Center for Integrative Environmental Research, University of Maryland, October 2011.
[22] SEAB, 2011.
[23] Ibid.

companies to seek export authorization from the Department of Energy's Office of Fossil Energy if the importing country is not subject to a free-trade agreement (FTA) with the United States.[24] Operators looking to modify existing LNG import terminals (currently comprising five out six of the entities that have applied to export LNG) must obtain approval from the Federal Energy Regulatory Commission (FERC).[25] (See Table 2) Other federal agencies that have a role in approving LNG export facilities include the U.S. Coast Guard, and the Office of Pipeline Safety. Under the National Environmental Policy Act, LNG export facilities may also be subject to environmental reviews in the form of an Environmental Impact Statement, an Environmental Assessment or under the terms of Clean Air Act, or Endangered Species Acts.[26] (See Box 1.)

Table 2: Status of Selected LNG Export Projects to Non-FTA Countries

Facility	Location	Non-FTA approved
Sabine Pass	Louisiana	Yes
Freeport	Texas	No
Lake Charles	Louisiana	No
Dominion Cove Point	Maryland	No
Carib Energy		No

Source: U.S. Department of Energy

Capacity and Infrastructure Constraints

The feasibility of U.S. LNG exports depends upon the ability of the country's natural gas infrastructure to support the production, transportation, storage, and shipment of natural gas.

Pipeline and Storage Capacity

The development of shale gas plays is likely to have a profound effect on the regional dynamics of the U.S. natural gas market. Increased production from the Marcellus Shale is likely to displace some supplies from the Gulf Coast and other regions that currently serve the Northeast.[27] Moreover, if significantly increased LNG exports from the Gulf Coast go ahead, there may be a need to reverse the pipelines to allow gas to flow toward the Gulf Coast.

To maximize the economic potential of the U.S. shale gas endowment, whether for exports or for domestic use, there will be a requirement for significant expansion in the nation's continental natural gas pipeline network, particularly in the vicinity of the Marcellus Shale. In 2010, Marcellus producers predicted that fewer than half of the 1,100 wells drilled had pipeline access.[28] ICF International, a consultancy, estimates that 3,300 additional miles of pipeline will be built in the Northeast between 2009 and 2035.[29] There is currently 6 bcf/day of FERC-approved proposed pipeline capacity that will deliver gas from the Marcellus to demand centers. More than 2 bcf/day of this capacity is scheduled to be completed by the summer of 2012.[30] Another concern is whether a gas pipeline infrastructure network will be developed quickly enough in liquid-rich plays, such as the Eagle Ford and Utica Shales, to fully capture the natural gas being produced. As outlined above, vast quantities of natural gas are currently being flared at some shale sites in the

[24] This distinction was given greater weight by the November 2011 FTA between the United States and Korea, the world's second largest importer of LNG.

[25] Michael Ratner, Paul W. Parfomak, Linda Luther, "U.S. Natural Gas Exports: New Opportunities, Uncertain Outcomes," Congressional Research Service, November 2011. (Ratner, November 2011)

[26] See Ratner, November 2011 for a thorough examination of the federal regulations and approvals needed by LNG exporters.

[27] Tom Choi and Peter Robinson, "Navigating a fractured future: Insights into the future of the North American natural gas market" Deloitte Center for Energy Solutions, September 2011. (Deloitte, 2011a)

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

[29] Kevin Petak, David Fritsch, and E. Harry Vidas, "North American Midstream Infrastructure Through 2035—A Secure Energy Future," presentation and report prepared by ICF for the INGAA Foundation, June 28, 2011. (http://www.ingaa.org/File.aspx?id=14900)

[30] "Winter 2011-12 Energy Market Assessment," Federal Energy Regulatory Commission, Item No: A-3, October 20, 2011.

Box 1: Approval Process for Natural Gas Exports[31]

Under the Natural Gas Act (NGA) Section 3 (15 USC §717b), exporting natural gas from the United States requires authorizations from the Department of Energy's Office of Fossil Energy and from FERC. Below are some of the permits that must be approved before a facility can export natural gas:

File application with the DOE's Office of Fossil Energy for export authorization

1. Issuance of an export authorization is dependent upon the export being deemed consistent with the public interest. DOE can also limit the amount of cumulative LNG exports (meaning each successive project may be limited by the volume of previously approved projects).
   a. A project is deemed consistent with the public interest if a free trade agreement exists between the U.S. and the LNG-recipient nation.
   b. If the U.S. does not have free trade agreements with the countries to which LNG is to be exported, the Office of Fossil Energy must make the public interest determination after publishing a notice of the application in the Federal Register to seek public comments, protests, and notices of intervention.

File application with FERC for authorization to site, construct or operate LNG export facilities

1. Any proposals to site, construct or operate facilities for the use of exporting natural gas—or to amend an existing FERC authorization—must obtain approval from FERC. Certain activities may also require regulatory oversight from the U.S. Coast Guard or the Department of Transportation. Approved applications are issued a Certificate of Public Convenience and Necessity.

Environmental Review and Assessment

1. Both authorizations require an evaluation of the project's anticipated impact on the public and on the environment, in accordance with the National Environmental Policy Act (NEPA).
2. An **Environmental Impact Statement** is needed for every proposed major federal action that is expected to *significantly* affect the quality of the environment. Once the impacts are declared, the statement must be approved before a final **Record of Decision** can be issued.
3. Projects with less-than-significant impacts still require documentation. If the environmental impacts are uncertain, then an **Environmental Assessment** must be prepared in order to determine if an Environmental Impact Statement is necessary. If the Environmental Assessment finds that the project under consideration has no significant environmental impact, then a **Finding of No Significant Impact** report is provided.
4. Projects that are perceived to have no significant impacts at all on the environment can be processed as **Categorical Exclusions**. This means that those projects do not require the preparation of either an Environmental Impact Statement or an Environmental Assessment.

Other Considerations

1. During preparations for the documentation required under NEPA, the Department of Energy and FERC must also identify any other compliance requirements applicable to the authorization.
   a. For example, other regulations that are to be considered include the Clean Water Act, the Clean Air Act, the Endangered Species Act, and the National Historic Preservation Act. This may require the involvement or approval of other agencies at the federal, state or local level.
   b. Besides environmental requirements, LNG export projects may require compliance with safety or security-related requirements from various other agencies, including the Department of Transportation's Office of Pipeline Safety (which is situated within the Pipeline and Hazardous Materials Safety Administration), the National Fire Protection Association, and the Federal Emergency Management Agency.

[31] Adapted from Ratner, November 2011.

U.S. mid-continent. One way to reduce such flaring is being considered by Wyoming's Office of State Lands and Investments, which has proposed a policy through which royalties payments would be required from operators of wells on state lands that continue to be flared for more than 15 days after completion. Absent strong state action on flaring, it is possible that the federal government will seek to regulate flaring at oil and natural gas wells.

In addition to constraints on pipeline capacity, there are also concerns about the adequacy of natural gas storage infrastructure, particularly in the Northeast, although the investments in pipeline capacity should prompt similar investments in increased storage capacity.[32]

Drilling and Production Infrastructure

Even if there is sufficient transportation infrastructure to handle increased volumes and new regional bases for natural gas production, there may be limits on the amount of available equipment and qualified petroleum engineers to develop the gas. To date, concerns about a shortage of drilling rig availability in the U.S. natural gas sector have not materialized. Horizontal drilling (for both oil and gas) increased 27 percent in the year to October 2011 and the number of rigs allocated to unconventional oil and gas production is at record levels.[33] The increased productivity of new drilling rigs has also served to ensure that supply has kept pace with demand. In the Haynesville Shale play in Louisiana, for example, the rig count fell from 181 rigs in July 2010 to 110 rigs in October 2011, yet production increased from 4.65 bcf/day to 7.58 bcf/day during the same period.[34] A similar trend is occurring in the Barnett Shale in Texas, where production has remained flat despite a declining rig count.[35] However, while the supply of drilling rigs remains adequate, the market for other equipment and services used for fracking – particularly high-pressure pumping equipment – is tight and likely to remain so for the near term, according to industry analysts.[36]

Human Capacity

Human capital in the unconventional oil and gas development sectors is also in short supply. According to the National Petroleum Council (NPC), there has been a 75 percent decrease in petrochemical-related course enrollment since 1982 in the United States.[37] Moreover, within the next ten years, about 50 percent of the workforce in this industry will be eligible for retirement. The high demand for petroleum engineers, reflected in the high salaries of recent graduates in the field, is set to continue, with the NPC warning of a "considerable human resource challenge" in the oil and gas industry.[38]

Faculty at leading universities with petroleum-engineering departments point to a lack of research and development (R&D) funding, which they say is negatively affecting their capacity to adequately train people for jobs in the hydrocarbons sector. While some of the shortfall in public R&D funding has been made up by private-sector

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[32] MIT, 2011. p. 145.
[33] According to Baker Hughes rig count.
[34] "Production Rises in Barnett, Haynesville Shales Even as Rig Counts Fall," *Platts,* October 11, 2011. (http://www.bentekenergy.com/InTheNews.aspx#Article5402)
[35] From an interview with Kenneth Medlock, Fellow, Energy Studies, James A. Baker III Institute for Public Policy, and member of the Brookings Energy Security Initiative Natural Gas Task Force, November 15-16, 2011.
[36] "Commodity Prices, Service Costs and Hedging: A guide to profit planning and protection in 2012", Maquarie Equities Research, November 11, 2011.
[37] "Prudent Development - Realizing the Potential of North America's Abundant Natural Gas and Oil Resources," National Petroleum Council, September 15, 2011. p. 1.
[38] Ibid.

support, academics note the frequent mismatch between the specific needs of individual companies and the long-term needs of the sector. Moreover, even if sufficient funding for R&D and training is now provided, there may also be a time lag before there is an adequate supply of petroleum engineers in the market.

Shipping Capacity

The successful export of LNG will depend upon the necessary shipping infrastructure and capacity being in place. Cheniere Energy is looking to export up to 2.2 bcf/day of gas from its Sabine Pass LNG terminal in Louisiana.[39] Depending on the size of the LNG vessel, this would require between three and five supertankers per week. In order to accommodate this volume of large ships, some domestic U.S. ports will require additional dredging. Other shipping-related concerns include security of vessels and the adequacy of Coast Guard capacity to provide that security (exporters must meet Coast Guard Waterway Suitability, Security, and Emergency standards prior to approval); and the capacity of sea lanes, particularly to Asia. Increasing shipments to Asia will depend on the capacity of the Panama Canal, which is currently too small to accommodate most LNG tankers. However, after the planned expansion of the canal is completed—expected to be in 2014—roughly 80 percent of the world's LNG tankers will be able to pass through the isthmus, resulting in a dramatic decline in shipping costs to Asia.[40]

[39] Cheniere Energy's export permit from the Department of Energy allows for initial production of 1bcf/day with the possibility of expansion to 2.2 bcf/day.

[40] "Medium-Term Oil and Gas Markets 2010," International Energy Agency, 2010. p. 264.

Domestic Demand Factors

In the United States, potential natural gas exports will compete with two primary markets for the consumption of natural gas: the power-generation sector and the industrial sector, including petrochemical production. The prospects for increased natural gas demand in the transportation, commercial and residential sectors as a result of increased shale gas production are less strong.

Power Generation

Demand for natural gas in the electricity sector has been stimulated by the increased supply—and therefore lower prices, and by environmental concerns over coal-fired generation. The EIA estimates that natural gas power plants will account for 60 percent of new electric capacity additions between 2010 and 2035.[41]

New and revised EPA regulations will play an important role in determining the amount of coal-fired generation that remains online in the United States, and, therefore, the number of natural gas power plants to be built. The EPA's Cross-State Air Pollution Rule (CSAPR) and Mercury and Air Toxics Standards (MATS) are scheduled to go into effect in January of 2012 and 2015, respectively. CSAPR is aimed at controlling sulfur dioxide (SO_2) and nitrous oxide (NOx) emissions from power plants in 27 U.S. states that contribute to fine-particulate pollution and ozone in adjacent states.

The MATS will apply to hazardous air pollutants (HAPs)—including mercury, hydrogen chloride, and other particulate matter—from all power plants. These standards, which will be issued on December 16, 2011, are projected to result in a 90 percent reduction in mercury emissions. December 16, 2011 is also the court-mandated deadline for the issuance of the Maximum Achievable Control Technology (MACT) rule. The rule, to be promulgated under the Clean Air Act, requires coal-fired power plants to achieve pollution controls for mercury, acid gasses and other pollutants equal to the best 12 percent of operating plants. Other regulations proposed by the EPA include:

- Section 316b of the Clean Water Act: requiring cooling water intake structures to reflect Best Technology Available (BTA) to minimize environmental impacts;

- Coal Combustion Residuals (CCRs): changing the regulation of coal ash and waste by-products disposal;

[41] EIA, April 2011a. p. 74.

- Greenhouse Gas (GHG) standards: proposing rules for GHG emissions standards for new and existing electric generation facilities.

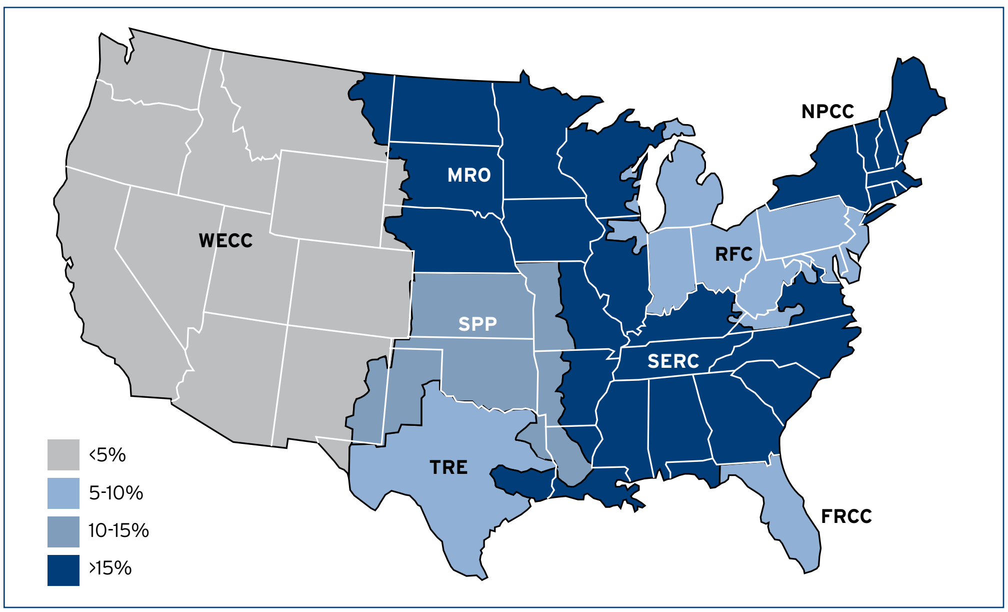
ICF, a consultancy that has modeled gas penetration in the electricity sector and has made projections based on EPA's proposed regulations and the age of the existing coal power plant fleet, estimates that roughly 40 gigawatts (GW)—equivalent to around 12 percent of the current coal-fired installed capacity—will be retired by 2020.[42]

Coal power plant retirements will vary by region: plants in the Southeast and Midwest (where many coal plants are located) will account for the bulk of reduction [as they are also located close to regions where natural gas is produced in larger volumes and the distribution networks are better developed (see Figure 4)].

Various models have projections for what the displacement of coal-fired generation would mean for natural gas demand, which will be the primary replacement fuel. The estimates for the increase in natural gas demand in the power sector ranges from 1.1 tcf/year to 3.5 tcf/year. ICF projects that the increase in gas demand—either through the construction of new natural gas power plants or the use of existing idle natural gas combined cycle (NGCC) plants—could equal between 1.6 and 2 tcf/year.[43] Deloitte, a consultancy that also runs models on gas consumption, projects that gas demand for power generation can increase by as much as 10 bcf/day, or roughly 3.5 tcf/year.[44] Deutsche Bank estimates that roughly 3 bcf/day of gas could replace roughly 80 of the least efficient, smaller, and older coal-fired power plants.[45]

While additional federal environmental policies inimical to coal-fired power plants are likely to

Figure 4: Percentage of Existing Coal Retired by Region, 2020



Source: ICF International

[42] "Domestic Gas Usage in the Power Sector," presentation by John Blaney of ICF to the Brookings Natural Gas Task Force, August 3, 2011. A previous ICF assessment projected 51 GW of retirements, but the newly proposed regulations have shown more flexibility than earlier proposals, and more coal plants are expected to remain online.

[43] Ibid.

[44] Deloitte, 2011. p.5.

[45] "Unconventional Gas," presentation by Adam Sieminski of Deutsche Bank to the Cross Border Forum on Energy Issues, May 13, 2010.

be met with staunch opposition, most projections assume that such stringent environmental regulations will eventually be implemented. The result is likely to be additional retirements of older, less efficient coal-fired power plants, many of which will be replaced by NGCC power plants.

Industrial Sector

The other major potential beneficiary of more abundant U.S. natural gas is the industrial sector. The sector currently consumes roughly 32 percent of total natural gas demand, 85 percent of which is consumed in manufacturing.[46] Demand for natural gas in the industrial sector is projected to grow by 27 percent between 2009 and 2035.[47]

The industrial sector is highly price-sensitive with respect to energy inputs. Because natural gas is a primary feedstock for many industrial consumers such as manufacturers or petrochemical producers, the industrial sector was heavily affected by the volatility in the natural gas market in the late 1990s and 2000s. According to Congressional testimony by a senior executive at Dow Chemical, "from 1997 to 2008 U.S. industrial demand fell by 22 percent as average annual [gas] prices rose 167 percent. Over the same time, demand for power rose by 64 percent. The loss in U.S. manufacturing jobs was significant…government data show that more than six million jobs were lost in the U.S. manufacturing sector since 1997."[48]

The shale gas boom has many industrial producers and chemical companies anticipating an increase in U.S. industrial and manufacturing competitiveness and petrochemicals production. A December 2011 report by PricewaterhouseCoopers, conducted in association with the National Association of Manufacturers, notes an increase in U.S. manufacturing activity due to shale gas development and suggests one million additional manufacturing jobs could be created in EIA's high-shale gas recovery scenario (in which 50 percent more shale gas is recovered relative to the reference case) compared with its low shale recovery scenario (in which 50 percent less is recovered).[49] A particular area of interest is the resurgence in ethylene production and the manufacturing of ethylene-based goods in the United States. Ethylene, which is a principal component in a variety of goods ranging from anti-freeze to trash-bags, is produced from ethane, a byproduct of natural gas. Cheap domestic natural gas has provided chemical producers a global competitive advantage in ethane— and therefore ethylene—production, particularly compared with producers in Europe where ethylene is derived principally from naphtha, an oil-based product. Because crude oil prices have not dropped in parallel with gas prices in the United States, U.S. industrial producers are thus globally competitive again. As a result, a number of industrial producers are looking to reinvest in plants in the United States.[50] Bayer MaterialScience is opening an ethane cracker in West Virginia (the first cracker in the Marcellus) and Dow Chemical and Shell Chemical have announced plans to expand and open, respectively, crackers on the Gulf Coast. According to analysis by the American Chemistry Council (ACC), an industry trade association, a 25 percent increase in the supply of ethane in the United States could result in 17,000 direct new jobs in the chemical industry, 395,000 indirect jobs, and around $44

[46] Ibid., p. 101.
[47] EIA, April 2011a. p. 68.
[48] U.S. Senate Committee on Energy and Natural Resources; "The Future of Natural Gas," testimony of George Biltz, Vice President, Energy and Climate Change, Dow Chemical; July 19, 2011.
[49] "Shale Gas: A Renaissance in U.S. Manufacturing," PricewaterhouseCoopers, December 2011.
[50] "Shale Gas and New Petrochemicals Investment: Benefits for the Economy, Jobs, and U.S. Manufacturing," American Chemistry Council, March 2011. p. 19. (American Chemistry Council, March 2011)

billion in additional federal, state, and local tax revenue over 10 years.[51] To achieve such returns ACC presumes an infusion of over $16 billion of private capital, and includes an assessment of induced impacts—"employment and output supported by the spending of those employed directly or indirectly by the sector." While the ACC does not make explicit assumptions about the shape of the U.S. natural gas supply curve of the future price of natural gas, it also assumes sustained low gas prices, and resultantly high oil-to-gas price ratio.

While some analysts take issue with the assumptions behind the projected job-creation figures, it is clear that the U.S. petrochemical and manufacturing sector will be a prominent competitor and potential beneficiary of abundant domestic natural gas.

Transportation Sector

Natural gas has also attracted a substantial amount of attention as a fuel for the transportation sector. The introduction of the New Alternative Transportation to Give Americans Solutions (NATGAS) Act in 2011 proposed legislation that would provide tax incentives to encourage the use of natural gas in the commercial trucking sector, has focused attention particularly on LNG use in the heavy duty vehicle (HDV) fleet.

Federal incentives have already been enacted for the purchase and operation of compressed natural gas (CNG) vehicles. The 2005 Energy Policy Act authorized credits for up to 80 percent of the incremental cost of purchasing CNG vehicles (the credits expired at the end of 2010); and federal tax credits for 30 percent of the cost of natural gas home refueling equipment, up to $1000, are in place until the end of 2011. However, despite the variety of existing and proposed policy incentives, a large-scale shift away from oil toward natural gas in the vehicle fleet is unlikely in the near term.

While LNG-powered HDVs can demonstrate competitive cost effectiveness and relatively short payback periods under certain circumstances, in most instances they require large fuel differentials between gasoline and LNG, and high numbers of vehicle miles per year to realize savings that buyers would find acceptable.[52] A range of operational and cost issues—including limited range, a lack of existing refueling infrastructure, and an incremental cost premium for LNG trucks of around $70,000—are therefore likely to prevent a widespread conversion to natural gas absent the introduction of significant subsidies or mandates.[53] Moreover, many trucking companies depend on the truck resale market for revenues, particularly in Asia. Without a large LNG distribution infrastructure in Asia, LNG trucks will be unlikely to gain significant market penetration, further limiting U.S. interest in LNG trucks.

The logistical challenge of converting a large proportion of the passenger vehicle fleet to natural gas is even higher. Obstacles include those of range (the energy density of natural gas is lower than that of gasoline, requiring more frequent refueling in NGVs than in gasoline-powered cars) and longer refueling times for NGVs than their gasoline equivalents.

The prospects for vehicular fuels derived from gas-to-liquids (GTL)—a process that converts natural gas into high quality middle distillates that can serve as a supplement or substitute for diesel—in the transportation sector are also uncertain. There are significant upfront costs associated with

[51] Ibid.
[52] Alan Krupnick, "Will Natural Gas Vehicles Be in Our Future?," Resources for the Future, May 2011. p.13.
[53] MIT, 2011. pp. 123-124.

GTL production, with a 20,000 barrel production plant costing the equivalent of $115,000 per barrel per day.[54] Liquid fuels produced by GTL would compete directly with crude oil-derived fuels. A sharp fall in crude-oil prices would therefore make GTL instantly uneconomic. While the prospect of cheap and abundant shale gas has renewed interest in GTL production in the United States—with SASOL of South Africa announcing plans for a feasibility study of a $10 billion plant in Louisiana—the long lead time and substantial capital investment required, together with the risk of competing with a volatile oil market, present significant challenges to GTL-products in the vehicle fleet. Despite its technical feasibility and high public profile, natural gas usage in the U.S. commercial and passenger fleets—either as LNG, CNG, or derived from GTL production—is therefore likely to see limited growth in the foreseeable future in the absence of major policy incentives.

Commercial and Residential Sector Demand

The prospects for increased natural gas use in the commercial and residential sectors as a result of the availability of abundant shale gas reserves are also modest. EIA estimates show that widely varying assumptions for shale gas production levels in 2035 (5.5 tcf/ year in the "Low Shale EUR" scenario versus 17.1/ year tcf in the "High Shale EUR" scenario) result in relatively small changes in commercial and residential gas consumption (0.5 and 0.3 tcf, respectively).[55]

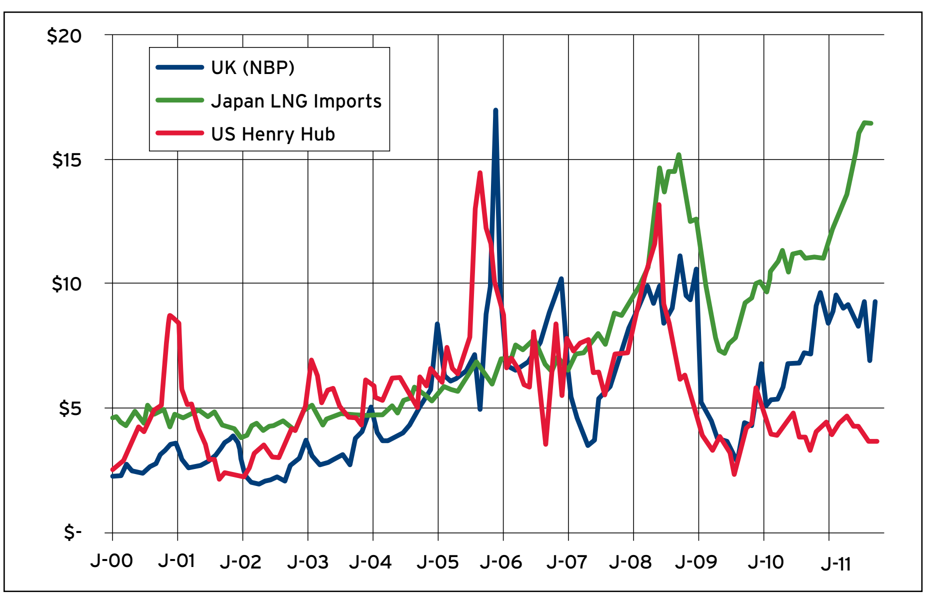
[54] A ClearView Energy Partners, LLC Working Draft.
[55] EIA, April 2011a

Global Gas Market

U.S. natural gas exports will not only compete with the domestic sources of demand listed above; they will also compete with other sources of gas—both LNG and pipeline gas—in the global market. The fundamental rationale for exporting natural gas is that the U.S. price is lower than the price in target markets, where natural gas is often purchased on more expensive long-term contracts that are indexed to the price of oil, leading to an opportunity for arbitrage. (See Figure 5 for the difference between the three major global natural gas price benchmarks.)

A well-supplied global gas market will give U.S. exporters fewer opportunities for exports; similarly, a "tight" gas market, one where supplies are limited, will provide an economic opportunity for U.S. exporters. On the demand-side, gas exports will have to compete with other fuel substitutes such as coal, oil, and nuclear energy for electricity generation, and oil for transportation. Demand for gas imports may also be affected by the spread of unconventional gas development to additional countries.

Figure 5: Benchmark Natural Gas Prices in the U.S., U.K. and Japan



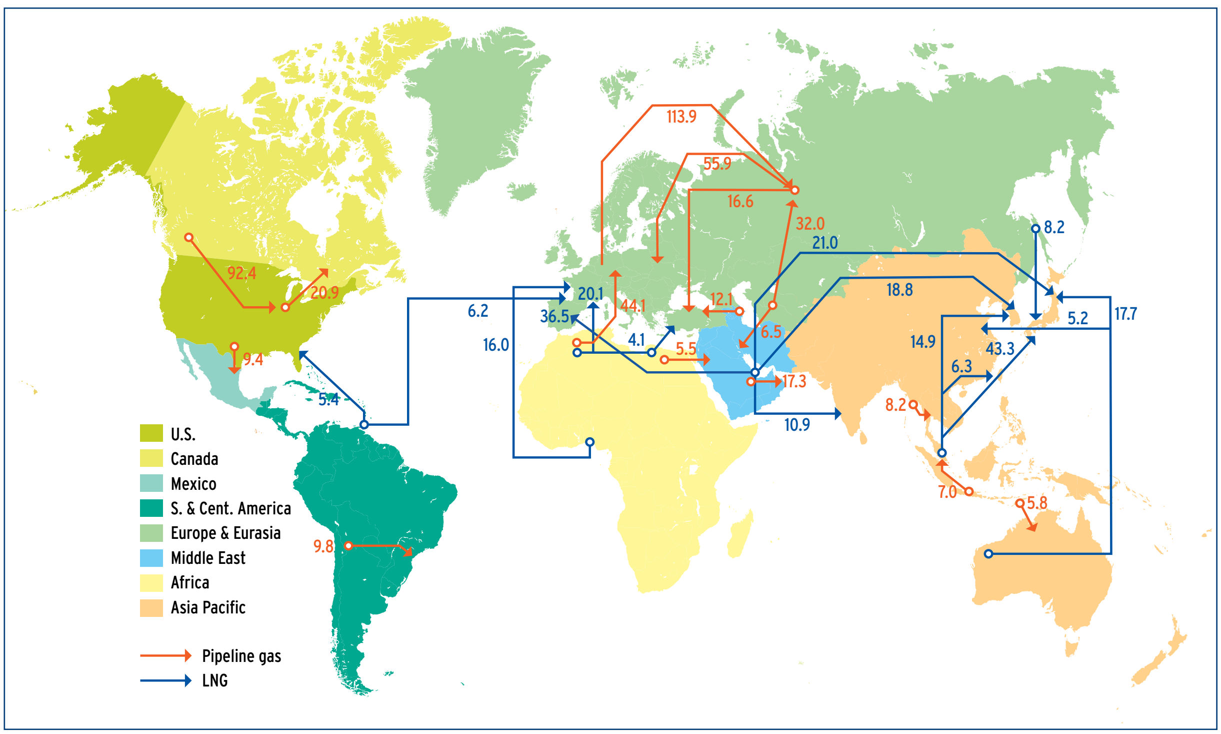
Source: ICF International

The international gas market can be divided into two major regions in addition to North America: the Pacific Basin and the Atlantic Basin. Both of these markets are supplied by LNG shipments (much of which come from Qatar, Indonesia, Malaysia, Nigeria, and Australia) as well as by pipeline gas. Each importer and exporter has different supply and demand characteristics that will have a bearing on whether the United States will be able to compete against other sources of supply.

Pacific Basin

The Pacific Basin has historically been the cornerstone of the global LNG market. During the early and mid-1990s, Indonesia and Malaysia accounted for roughly half the LNG export market, and Japan and South Korea accounted for approximately 70 percent of the import market.[56] Today, Indonesia and Malaysia's supply dominance has been eroded by the emergence of new LNG exporters including Qatar (which has the largest liquefaction capacity in the world), Nigeria, and Australia. As a result, although both Indonesia and Malaysia were still, respectively, the second and third largest exporters of LNG in 2010, their share of the global natural gas market has dwindled to roughly 20 percent, and may decline further as domestic gas consumption increases. Nevertheless, Pacific Basin exports, which almost exclusively serve Pacific markets, are still projected to increase in quantity as a result of major liquefaction capacity additions in Australia. Vast resources of both conventional and unconventional gas will enable Australia to become a significant exporter in the coming years. There are five liquefaction projects currently under construction in Australia, four of which are projected to be online

Figure 6: World Natural Gas Trade Flows, 2010



Source: BP Statistical Review of World Energy 2011

[56] "World LNG Report 2010," *International Gas Union (IGU)*, September 2011. pp. 6-9 (International Gas Union, September 2011)

by 2015.[57] Australian LNG will likely only be able to service the Pacific Basin markets because it is a relatively high-cost producer of LNG.

While about 45 percent of the Pacific Basin's total gas demand is met by LNG imports from within the region, an additional 40 percent of its demand is met by LNG imports from outside the region, primarily from the Middle East and Russia.[58] Qatar alone accounted for 11 percent of Japanese LNG imports in 2010. Qatari production predominantly serves both the European (mostly the U.K.) gas market and the Pacific Basin gas market. Current uncontracted supply available on the spot market is likely to be sent to Asia to take advantage of the Pacific Basin's higher prices. However, other than meeting the existing spare capacity for LNG production, the Middle East will have little excess supply capacity. This is in part because Qatar is trying to preserve its price structure with the East Asian market and partly because there is a moratorium on further development of Qatar's North Field, the largest gas field in the world. Another reason for the limited excess supply from the Middle East is that Oman, which is the second largest Middle Eastern LNG exporter to Asia, is experiencing declining LNG exports as more gas is being consumed domestically.

Gas demand in Asia remains strong, led by Japan, South Korea, and Taiwan, which accounted for more than half of all global LNG imports in 2010.[59] Japan, the world's largest importer of LNG, has seen a particular increase in projected natural gas demand as a result of the accident at the Fukushima nuclear power plant following the earthquake in March 2011. The nuclear accident, which has caused a short-term shutdown of most of Japan's nuclear reactors, has also prompted a review of Japan's nuclear energy policy. The review comes largely at the demand of the public, which is wary of Japan's reliance on atomic power.[60] In the event of a move away from nuclear power, a significant amount of Japan's electricity production will likely be met by additional LNG shipments. It is estimated that in 2012, Japan will require an additional 974 bcf of LNG to make up for the electricity shortfall resulting from the Fukushima accident and the reduction in nuclear power generation.[61]

While Japan has traditionally been the focal point for natural gas consumption in Asia, the economic rise of China and India has begun to have an increasing impact on forecasts for the Asian gas market. Although energy and electricity supply in both countries has been dominated by coal, both countries have expressed interest in expanding the role of natural gas. The International Energy Agency predicts that gas demand in China and India may grow as fast as 7.7 percent and 6.5 percent, respectively, per year to 2035 from 2009 levels.[62] Over the past five years, both countries have become significant importers of natural gas, mostly—exclusively, in the case of India—in the form of LNG. Both China and India have made significant investments in LNG regasification infrastructure with six LNG import terminals

[57] "World Energy Outlook 2011: Are We Entering a Golden Age of Gas?" International Energy Agency, 2011. pp. 67-68. (IEA, 2011)

[58] "BP Statistical Review of World Energy 2011," BP, June 2011. (BP, June 2011)

[59] Ibid. It is important to note that the United States in November 2011 entered into a free-trade agreement (FTA) with South Korea as all but one of the projects that have been approved for the export of natural gas are only allowed to export LNG to countries with whom the United States has a FTA. Other than South Korea, the only countries which have regasification capacity and an FTA with the United States are Canada, Chile, the Dominican Republic, and Mexico.

[60] A recent poll in Japan demonstrated that the majority of the Japanese public is in favor of phasing out the country's existing nuclear reactors. "Japan poll finds 74% support nuclear phase-out," *Nuclear Power Daily,* June 14, 2011. (http://www.nuclearpowerdaily.com/reports/Japan_poll_finds_74_support_nuclear_phase-out_999.html)

[61] "Energy Challenges in Japan after 3.11,"presentation by Ken Koyama, Chief Economist, Institute of Energy Economics—Japan, to a private meeting at Harvard University, October 21, 2011, in Boston, Massachusetts.

[62] IEA, 2011. p. 23.

currently under construction in China and two in India (with an existing terminal also undergoing expansion), and more expected in the near future. In addition to the LNG imports, China imports gas from Turkmenistan via a pipeline that traverses Uzbekistan and Kazakhstan, is in the process of developing a pipeline interconnection with Myanmar, and has long been engaged in discussions with Russia over a potential pipeline interconnection. India, which does not currently share a pipeline with any other country, is working to finalize various international pipeline projects, from Turkmenistan, Myanmar, Oman, and Iran.

How the demand for gas in these countries continues to grow will depend on a number of factors, including the pace of economic growth, the policies for substitute fuels—primarily coal, nuclear power, and oil—and the speed and scale at which unconventional gas can be developed. While coal and oil will continue to make up a large part of the energy mix, natural gas demand is projected to increase steadily, prompting the need for more investment in imports and in supporting domestic production, particularly of unconventional gas. The EIA's recent global estimate for shale gas reserves suggests that India and China have roughly 63 tcf and 1,275 tcf of shale gas reserves, respectively.[63] For both countries, the estimates for unconventional gas have stimulated national interest in unconventional gas production; China is projecting that 50 percent of its natural gas consumption in 2050 will come from unconventional gas. Developing these resources, however, will take time. The regulatory and policy environment in both countries will need to be amended to accommodate shale gas production and to address issues related to hydraulic fracturing, such as water consumption, treatment, and disposal. The extent to which natural gas prices are deregulated will also have a bearing on how quickly domestic shale gas will be produced as production companies will require economic incentives to begin and sustain production. Shale gas production will also require technical capacity and physical infrastructure, both of which are currently in short supply in both China and India. The former concern is partially being addressed through Chinese and Indian investments in North American shale plays. The latter concern will require significant attention, particularly as the pipeline networks in both China and India are inadequately developed and as the investment climate for foreign operators remains unclear.[64] In both countries, therefore, large-scale shale gas development is likely to be a mid-to-long term proposition.

Export Feasibility to the Pacific Basin

Owing to growing gas demand, limited domestic supply, and a more rigid and expensive pricing structure, Asia represents a near-to-medium term opportunity for natural gas exports from the United States. As previously mentioned, the expansion of the Panama Canal by 2014 will allow for LNG tankers to traverse the isthmus, thereby improving the economics of U.S. Gulf Coast LNG shipments to East and South Asian markets and potentially allowing for an even shorter shipping route than from the Gulf Coast to the U.K. This would make U.S. exports competitive with future Middle Eastern and Australian LNG exports to the region.

However, challenges and uncertainties remain on both the demand and supply side. The development of indigenous unconventional gas in China or India may occur at a faster rate than currently forecast, dampening demand for LNG imports to the region. A change in sentiment in Japan may see nuclear power restarted at a greater rate than currently anticipated; alternately, a greater-than-

[63] "World Shale Gas Resources: An Initial Assessment of 14 Regions Outside the United States," U.S. Energy Information Administration, April 2011. p. 4. (EIA, April 2011b)

[64] According to a report from Bernstein Research, a consultancy, July 7, 2011.

expected penetration of coal in the Japanese electricity sector would suppress gas demand. A change in the cost of Australian LNG production or a reversal of the Qatari moratorium on gas development could disrupt the current supply projections, as could the discovery of new conventional or unconventional resources. For instance, on December 29, 2010, Noble Energy, a U.S. oil and gas exploration company, discovered an estimated 16 tcf of gas in Israel's offshore Leviathan gas field. Since then, other nations on the Eastern Mediterranean are exploring for potentially similarly large gas fields. In November 2011, Anadarko Petroleum reported a large natural gas discovery in Mozambique, prompting early interest in building significant liquefaction capacity in the Southeastern African nation. Finally, the expansion of LNG export capacity from Alaska and the development of LNG export capacity in Western Canada may provide a source of strong competition for U.S. Gulf-coast origin LNG. Although Alaska's Kenai LNG export facility, which has been exporting small quantities of LNG to Northeast Asia for over 40 years, has been idled temporarily, it appears that some companies have demonstrated interest in large-scale exports of LNG from Alaska to East Asia. According to FERC, there are currently three Canadian export facilities under consideration in British Columbia: a proposed 1.4 bcf/day terminal at Kitimat (initial production would start at 0.7 bcf/d), which received a 20-year export license in October 2011; a proposed 0.25 bcf/day facility at Douglas Island; and a potential 1 bcf/day facility at Prince Rupert Island. Given the comparably low cost of Canadian natural gas to continental U.S. gas and the lower transportation costs (as a result of the shorter distance—LNG shipments from Alaska or Kitimat to Japan would take roughly 8-9 days, compared to more than 20 days from the U.S. Gulf Coast through the Panama Canal), Alaskan and Canadian exports may prove to be a source of strong competition at the margin for U.S. LNG in the Pacific Basin.

Atlantic Basin

The Atlantic Basin comprises predominantly the gas markets in Europe, particularly the European Union. Other than Spain and the United Kingdom, which import 76 percent and 35 percent of their natural gas in the form of LNG, respectively, most European countries are dependent on pipeline imports from Russia, Norway, and Algeria. Algeria, Qatar, and Nigeria are the principal LNG exporters to the continent.[65] Much of the discussion of natural gas imports rests on Russian production and the sale of Russian gas to European consumers at high, oil-indexed prices. Despite declines in Russia's two largest natural gas fields (Urengoy and Yamburg), its natural gas production is projected to increase by roughly one-third between 2010 and 2035.[66] According to the International Energy Agency, exports from Russia will increase by roughly 67 percent over the same period, with much of the growth coming from increased pipeline and LNG exports to Asia.[67] Norway is also an integral producer of natural gas for Europe and its production is projected to increase over the next two decades before reaching a plateau.[68] However, this will not compensate for the precipitous decline in domestic production in the U.K. and the Netherlands, two historically substantial producers of natural gas.[69]

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[65] BP, June 2011.
[66] IEA, November 2011. p. 306.
[67] Ibid., p. 312.
[68] Ibid., p. 165.
[69] It is important to note that although U.K. production is declining, the exports from the U.K. to continental Europe through the Interconnector pipeline between the U.K. and Belgium continue to increase. ("Revolution in European Gas?" presentation by Pierre Noël, University of Cambridge to the Electricity Policy Research Group Energy Policy Dinner on February 24, 2011 in Cambridge, U.K.

As a result, for the near future it appears that the reliance on natural gas from Russia will continue. (The commissioning of the Nord Stream pipeline, the first pipeline that directly connects Russia with the EU, underlines this relationship.) Russia accounts for about 31 percent of Europe's natural gas imports.[70] While it is clear that the gas relationship between Russia and European consumers will continue, the pricing relationship between the two parties will determine how much gas will be imported, and whether or not there will be an opportunity for U.S. LNG exports. Historically, most Russian gas exports to Europe are underpinned by long-term contracts with gas sold at oil-indexed prices. However, with new LNG cargoes previously destined for the U.S. now available on the global market, there has been an increase in spot-market trading of gas—with consumers in some cases finding it more economic to pay penalties for non-receipt of contract gas and to buy alternate supplies via LNG. The result has been increased pressure on the price of Russian gas exports and increased market power on the part of consumers to renegotiate oil-indexed contracts with Gazprom, the Russian state-owned gas company. Gazprom has agreed to renegotiate some contracts with its customers, primarily in Germany; however it has a number of arbitration cases under review and appears reluctant to renegotiate the terms for a large number of its contracts. Moreover, given Germany's recent decision to accelerate the phase out of its existing fleet of nuclear reactors, there is a strong likelihood that much of the resultant electricity shortage will be made up through increased natural gas consumption, thereby supporting demand and gas prices.

In addition to Russian imports, Europe is likely to increase its LNG imports. Despite having excess regasification capacity—terminals ran at a 42 percent load factor in 2009—new regasification facilities are planned in a number of European countries.[71] In contrast to the developments in adding LNG import capacity, some of the international pipeline connections under consideration are experiencing development difficulties. Many of the various proposed pipelines from the Middle East, Central Asia and Russia, (Nabucco and South Stream, for instance) are considered to have either difficult economics or face technical and logistical obstacles and are not expected to be completed in the near term. However, some analysts find that other pipeline interconnections, such as the Interconnector Greece Italy (ITGI) pipeline and the Trans-Adriatic Pipeline (TAP) are more likely in the mid-term. Both the ITGI and the TAP pipelines would transport gas from Azerbaijan's Shah Deniz gas field to continental Europe through Turkey, where the existing Southern Corridor Pipeline (SCP) ends.

As is the case in Asia, unconventional gas development in Europe may play a large role in the future of the Atlantic Basin gas market. Given Eastern Europe's dependence on Russia for natural gas supply, the prospect for shale gas resources holds not only a potential economic boon for countries in the region, but also a potential geopolitical asset. Ukraine and Poland—with an estimated 42 and 187 tcf of shale gas resources, respectively—have been particularly interested in developing their shale gas assets. However, similar to unconventional gas development in Asia, regulatory and infrastructure obstacles will make large-scale shale gas production in the near-term difficult. Moreover, in pockets of Europe there is an active public opposition to shale gas production in Europe, which may threaten the development of domestic resources in some countries and regions.[72]

[70] BP, June 2011.

[71] Anouk Honoré, *European Natural Gas Demand, Supply, and Pricing: Cycles, Seasons, and the Impact of LNG Price Arbitrage,* Oxford Institute for Energy Studies, (Oxford, UK: Oxford University Press, 2010). p. 167.

[72] At the European Autumn Gas Conference in Paris on November 15-16, many speakers stated that the public opposition to hydraulic fracturing threatens to hinder shale gas production in Europe. ("Shale gas development to be slow in coming, speakers warn," *Platts Oil & Gas Journal,* November 28, 2011.)

France has banned hydraulic fracturing and some environmental and public opposition groups are looking for sweeping, continental legislation against shale gas production.

Export Feasibility to the Atlantic Basin

The prospect for U.S.-origin exports to the Atlantic Basin rests on a range of factors. It primarily depends on the availability of pipeline gas from Russia, Algeria, and Norway and the availability of LNG from Algeria, Nigeria, and Qatar. It also depends on the demand for gas in the electricity sector. Germany's decision to accelerate the phase-out of its nuclear reactors was copied by Switzerland, which decided to phase out its nuclear reactors, and Italy, which decided against building new reactors. In the case of Italy, much of this demand will therefore be met by natural gas. A similar decision in France, a country that currently generates more than three-quarters of its electricity from nuclear power but which is in the midst of a presidential election where nuclear energy policy is one of the primary issues, would result in a significant demand disruption for the Atlantic Basin. The development of gas transportation infrastructure—both within the continent and with outside suppliers in Russia, the Middle East, and North Africa—will also have an impact on the prospect for LNG imports from the United States. With a greater diversity of gas supply leading to lower spot prices in Europe, the opportunity for LNG arbitrage of U.S. gas into the region is lower than in the Pacific Basin. Moreover, with the expansion of the Panama Canal, U.S. exports from the Gulf of Mexico and Alaska would not only benefit from higher Asian prices but also from potentially shorter shipping time (just over 20 days from the Gulf Coast to Japan compared with nearly 30 days from the Gulf Coast to the U.K.). Lastly, the potential for Atlantic Basin shale gas development will have a significant bearing on the long-term prospect for LNG imports to the European continent.

Central and Latin American Gas Markets

In addition the Pacific and Atlantic basins, there are several smaller LNG export options for U.S. sourced-natural gas in the Caribbean, Mexico, and Chile. Many of the Caribbean nations currently burn refined oil products for power generation, which is becoming increasingly expensive as oil prices rise. To diversify its energy mix, Jamaica is considering the construction of a floating LNG terminal; other Caribbean nations may follow. In addition to these smaller markets, both Mexico and Chile are potential markets for U.S. natural gas. While an increase in exports to Mexico would likely come via pipeline from Texas, Chile represents a potential opportunity for LNG imports from the United States. Chile, which has a free-trade agreement with the United States, currently imports more than 90 percent of its natural gas in the form of LNG (83 percent of which came from Equatorial Guinea, Egypt, and Trinidad and Tobago in 2010).[73] One factor that would impact Chile's natural gas imports will be the development of shale gas in Argentina. The EIA estimates that Argentina's shale gas reserves are 774 tcf—the third largest shale gas reserves in the world.[74] If Argentina develops this resource in a timely manner, one logical export destination would be Chile, thereby reducing Chile's potential LNG import needs.

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[73] BP, June 2011.
[74] EIA, April 2011b.

Economics and Financing

The fundamental economic calculation for natural gas exports is the price differential between domestic gas and that in overseas markets. Many of the issues listed in previous sections can have a bearing on the price of domestic gas. However, exports themselves are also likely to have an effect on the price of natural gas as they represent an additional source of demand. The extent to which the price of gas interacts with its supply and demand is a cause of much speculation, and the possibility of exports leading to higher domestic natural gas prices or increased production volumes is one of central importance.

Effects of Exports on Domestic Prices

Over the long run, an increase in the demand for—and therefore the price of—domestic natural gas is likely to increase supply. Several analysts have attempted to model the aggregate U.S. supply curve and the price elasticity of natural gas supply. A 2010 analysis by Navigant Consulting estimated that exports of 2 bcf/d would result in an increase in domestic natural gas prices by $0.49 per MMBTU by 2035. A 2011 study by ICF estimated that exports of natural gas of 2 bcf/day and 6 bcf/day would increase Henry Hub natural gas prices by $0.22 and 0.64 per MMBTU between 2015 and 2035. In November 2011, Deloitte released an economic analysis based on its World Gas Model that showed the impact of LNG exports of 6 bcf/day to be a rise in the price of average citygate natural gas prices of $0.12 per MMBTU between 2016 and 2035, corresponding to a 1.7 percent increase compared to the average citygate price over the time period of $7.06 per MMBTU. The Deloitte analysis showed that the impact of 6 bcf/day of U.S. LNG exports on power-generation cost would be less than the "quite small" impact on natural gas prices in general. The range of domestic and international implications of an increase in U.S LNG exports will be the focus of the second half of this project; however, it is clear that the extent to which LNG exports affect the price of domestic natural gas will have a bearing on their feasibility.

Other Costs

In addition to the cost of the feedstock, there are several additional fixed costs that must be taken into consideration when assessing the economic feasibility of LNG exports, including those of liquefaction, transportation, and regasification. The construction of dedicated liquefaction facilities cost between $2 billion and $8 billion each, depending on capacity.[75] In order to secure financing

[75] Ratner, November 2011.

for such facilities companies looking to export gas must have in place long-term contracts for the sale of LNG.

Transportation costs depend on the size of vessel used to move the LNG, the cost of shipping fuel, and the distance the cargoes have to travel. Regasification can be the responsibility of either the supplier or the receiver according to the specific terms of a contract. While individual costs can very as a function of size, local conditions, and fuel costs, MIT provides a profile of a typical cost structure for an LNG supply chain: for each MMBtu of gas, it estimates liquefaction costs at \$2.15, shipping costs at around \$1.25 (depending on fuel costs and transportation distance), and regasification costs at \$0.70.[76] It is also important to consider that companies interested in exporting LNG will need to ensure that the price spread will need to remain for at least 10 to 12 years, to budget for pre-planning and facility construction.

[76] MIT, 2011. p. 25.

Summary and Conclusions

Driven by technological breakthroughs in unconventional gas production, major increases in North American natural gas reserves and production have led to supply growth significantly outpacing forecasts in recent years. As a result, natural gas producers have been looking for new and additional sources of demand to absorb the excess supply. Domestic interest for this natural gas has centered on the power sector, the transportation sector, and the industrial and petrochemical sectors. However, recently, there has been increasing interest in developing large-scale natural gas export capacity, either in the form of liquefied natural gas (LNG) exports from coastal liquefaction terminals or in the form of pipeline exports to Mexico and Canada.

While the United States already exports modest quantities of natural gas, both via LNG and pipeline, current proposals, some of which have received partial approval from the federal government, would aim to increase this amount substantially. There is a growing debate between policymakers, industry, and energy analysts as to the merits of exporting greater quantities of U.S. natural gas. Some domestic natural gas consumers contend that exporting U.S. gas would result in an increase in domestic natural gas prices and therefore in higher prices for businesses and households. Proponents of natural gas exports argue that it would provide valuable foreign exchange and would be a source of economic growth and job creation.

Domestic supply factors: For exports to be feasible, a number of domestic supply criteria must be met. First, adequate resources must be available and their production must be sustainable over the long-term. Second, the regulatory and policy environment will need to be favorable for natural gas production to ensure that resources are developed. Third, the capacity and infrastructure required to enable exports must be in place: this includes the capacity and logistics of the pipeline and storage network, the availability of shipping capacity, and the availability of equipment for production and qualified engineers.

- Given the importance of shale gas to current and future domestic natural gas production, much of the domestic supply discussion focuses on the availability of shale gas and the sustainability of its production. While most assessments agree that the country's shale gas reserves are large, there are still a number of factors that can affect the sustainability of shale gas production. The improvement of shale gas drilling technologies can, and has, been able to improve well productivity. Conversely, the displacement of rigs from "dry" gas plays to more valuable, liquids-rich plays might curb domestic dry gas production. While this hasn't been a concern to date, a continued migration of rigs away from dry gas plays may, in the future, impact domestic production.

- Regulators and policymakers have tried to keep up with the growth in shale gas activity. The EPA, BLM, and several regional and state-level regulators all have varying responsibilities for attempting to ensure that shale gas production does not result in environmental damage and protects the public's interests. Because the scale of shale gas production is a relatively new phenomenon, and because the process is water-intensive, it has attracted substantial public attention. Future regulations or policies—possibly stemming from public opposition groups to shale gas—might have a significant impact on future shale gas production.

- Finally, infrastructure and physical and human capacity must be available for sustained shale gas production and, therefore, exports to occur. Domestic pipeline and storage infrastructure must have adequate capacity to transmit, distribute, and store new gas resources; ports should have the capacity to harbor large LNG vessels; the Coast Guard must have sufficient capacity to patrol increased LNG traffic; and there must be a consistent availability of rigs and other infrastructure as well as the technical capacity (i.e., qualified petroleum engineers and operators) to safely and effectively operate equipment.

Domestic demand factors: Exports of natural gas would represent an additional source of demand for domestic supplies. In this respect, they will compete with three main other end uses for natural gas: the power-generation sector, the industrial and petrochemical sector, the transportation sector, and the commercial and residential sector.

- According to many projections, the U.S. electricity sector will see an increased demand for natural gas as it seeks to comply with policies and regulations aimed at reducing carbon-dioxide emissions and pollutants from the power-generation fleet. While the shift from coal to gas has been steadily occurring for several years now as utilities anticipate stringent emissions regulation, the existing political stalemate and current economic conditions have tempered some of the near-term projections for coal power plant retirements. The extent to which gas accelerates its penetration in the power sector largely depends on if and how quickly new environmental regulations will be implemented in the power sector.

- Similar to the power sector, the industrial sector has also been galvanized by the prospect of abundant volumes of inexpensive shale gas. Cheaper natural gas in the industrial sector has the potential to lower the cost of petrochemical production and to improve the competitiveness of a range of refining and manufacturing operations. Natural gas-dependent manufacturers are anticipating a potential resurgence of domestic competitive advantage when compared with high-cost producers in Europe and are arguing that a prolonged period of low natural gas prices will return prosperity, jobs, and economic vitality to America's once declining industrial sector.

- Advocates of natural gas usage in the transportation fleet—particularly in heavy-duty vehicles (HDVs)—see it as a way to decrease the country's dependence on oil. The appeal of gas as a substitute for oil has resulted in a number of policies and incentives to promote natural gas penetration in the vehicle fleet. Yet, while natural gas in the transportation fleet enjoys some political backing, it faces some significant technical and economic hurdles, for both CNG passenger vehicles and LNG heavy-duty vehicles. These challenges make it unlikely that the transportation sector will constitute a significant source of demand for natural gas in the near- to medium term.

International Market Dynamics: For increased U.S. LNG exports to be feasible, they will need to be competitive with supplies from other sources. The major demand centers that would import U.S. LNG would be the Pacific Basin consumers (Japan, South Korea, and Taiwan, and increasingly China and India), and the Atlantic Basin consumers, mostly Europe and the United Kingdom.

- The Pacific Basin has long been the cornerstone of the LNG market. The major producers (Indonesia and Malaysia) and the major consumers (Japan and South Korea) once accounted for the majority of global LNG trade. With an increase in the capacity of LNG liquefaction and regasification capacity around the world, the situation is changing. Today, Japan and the rest of the Pacific Basin LNG importers are relying less on Southeast Asia and more on the newcomer LNG export powers of Qatar and Australia. The emergence of China and India as large demand centers for gas indicates that the Pacific Basin will remain central to the global gas market. China and India, as well as the rest of the Pacific Basin, will be increasingly accessible for U.S. Gulf Coast exports upon expansion of the Panama Canal, expected in 2014.

- The Atlantic Basin, which is mostly comprised of Continental Europe and the United Kingdom, is currently dependent on pipeline imports of natural gas from Russia and Norway, and on LNG imports from Qatar and Algeria. Russia, which accounts for roughly one-third of all European gas imports, currently exports gas at high, oil-indexed prices. This practice will likely continue as German demand for gas increases following its decision to phase out nuclear power and as production declines in the Netherlands and the U.K. However, Russia has agreed to renegotiate some of its oil-indexed prices with Europe due to the availability of surplus LNG cargoes that were once destined for the United States. Russian contract renegotiations follow the other major producers who have shown flexibility. Qatar, a substantial exporter of LNG to the U.K., exports LNG at lower rates and Norway has already renegotiated fixed contracts with the European continent.

- The supply and demand balance in the Atlantic and Pacific Basins and the feasibility for natural gas exports from the United States depend heavily on the uncertain outlook for international unconventional production. Recent assessments in countries such as China, India, Ukraine, and Poland indicate that each country has significant domestic shale gas reserves. If these reserves are developed effectively—which is likely to be difficult in the short-term due to a lack of infrastructure, physical capacity, and technical capacity—many of these countries would dramatically decrease their import dependence, with negative implications for existing and newcomer LNG exporters.

Economic considerations: The rationale for natural gas exports from the United States is based on the arbitrage opportunity that exporters of cheap U.S. natural gas have in more expensive demand markets, where natural gas is priced at oil-indexed rates. The largest component of this cost is the domestic price of the natural gas. Early analysis suggests that exports of up to 6 bcf/day will have modest impacts on domestic prices. Other additional costs include the costs of natural gas liquefaction and transportation, and the availability of financing.

Final Report

This report represents the midpoint of the Brookings ESI study and only looks at the feasibility of U.S. natural gas exports. It does not make any policy prescriptions or recommendations. Policy recommendations will be in the final report and will consider both the feasibility of U.S. natural gas exports

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