Global Power Best Practice Series 1

New Natural Gas Resources and the Environmental Implications in the U.S., Europe, India, and China

RAP Energy solutions for a changing world

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New Natural Gas Resources and the Environmental Implications in the U.S., Europe, India, and China

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About the Global Best Practice Series

Worldwide, the electricity sector is undergoing a fundamental transformation. Policymakers recognize that fossil fuels, the largest fuel source for the electricity sector, contribute to greenhouse gas emissions and other forms of man-made environmental contamination. Through technology gains, improved public policy, and market reforms, the electricity sector is becoming cleaner and more affordable. However, significant opportunities for improvement remain and the experiences in different regions of the world can form a knowledge base and provide guidance for others interested in driving this transformation.

This Global Power Best Practice Series is designed to provide power-sector regulators and policymakers with useful information and regulatory experiences about key topics, including effective rate design, innovative business models, financing mechanisms, and successful policy interventions. The Series focuses on four distinct nations/regions covering China, India, Europe, and the United States (U.S.). However, policymakers in other regions will find that the Series identifies best — or at least valued — practices and regulatory structures that can be adapted to a variety of situations and goals.

Contextual differences are essential to understanding and applying the lessons distilled in the Series. Therefore, readers are encouraged to use the two supplemental resources to familiarize themselves with the governance, market, and regulatory institutions in the four highlighted regions.

The Series includes the following topics:

1. New Natural Gas Resources and the Environmental Implications in the U.S., Europe, India, and China
2. Policies to Achieve Greater Energy Efficiency
3. Effective Policies to Promote Demand-Side Resources
4. Time-Varying and Dynamic Rate Design
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6. Strategies for Decarbonizing Electric Power Supply
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Supplemental Resources:

12. Regional Power Sector Profiles in the U.S., Europe, India, and China
13. Seven Case Studies in Transmission: Planning, Pricing, and System Operation

In addition to best practices, many of the reports also contain an extensive reference list of resources or an annotated bibliography. Readers interested in deeper study or additional reference materials will find a rich body of resources in these sections of each paper. Authors also identify the boundaries of existing knowledge and frame key research questions to guide future research.

Please visit www.raponline.org to access all papers in the Series.
This Global Power Best Practice Series was funded by the ClimateWorks Foundation www.climateworks.org

List of Terms

Conventional gas resources – generally defined as those associated with higher permeability fields and reservoirs. Typically such a reservoir is characterized by a water zone below the oil and gas. These resources are discrete accumulations, typified by a well-defined field outline.

Economically recoverable resources – represent that part of technically recoverable resources that is expected to be economic, given a set of assumptions about current or future prices and market conditions.

Gas Play – A geological area with similar geologic properties in which an economic accumulation of gas has been determined to exist that can be targeted for production.

Proven reserves – the quantities of oil and gas that are expected to be recoverable from the developed portions of known reservoirs under existing economic and operating conditions and with existing technology.

Technically recoverable resources – represent the fraction of gas in place that is expected to be recoverable from oil and gas wells without consideration of economics.

Unconventional gas resources – defined as those low-permeability deposits that are more continuous across a broad area. The main categories are coalbed methane, tight gas, and shale gas, although other categories exist, including methane hydrates and coal gasification.

- **Shale gas and tight oil** – recoverable volumes of gas, condensate, and crude oil from future development of shale plays. Tight oil plays are those shale plays that are dominated by oil and associated gas, such as the Bakken in North Dakota.

- **Coalbed methane** – recoverable volumes of gas from future development of coal seams.

- **Tight gas** – recoverable volumes of gas and condensate from future development of very low-permeability sandstones.

Acronyms

AEO	Annual Energy Outlook
API	American Petroleum Institute
Bcfd	Billion Cubic Feet per Day
bcm	Billion Cubic Meters
BOEMRE	Bureau of Ocean Energy Management, Regulation, and Enforcement
CDA	Concentrated Development Area
CNOOC	China National Offshore Oil Corporation
CNPC	China National Petroleum Company
CO	Carbon Monoxide
CO_2	Carbon Dioxide
DEC	Department of Environmental Conservation (New York)
DEP	Department of Environmental Protection
DEQ	Department of Environmental Quality (Michigan)
DGH	Directorate General of Hydrocarbons (India)
DNRC	Department of Natural Resource Conservation (Montana)
DOE	(U.S.) Department of Energy
DRBC	Delaware River Basin Commission
ECC	Energy and Climate Change (U.K.)
EIA	(U.S.) Energy Information Administration
ENTSOG	European Network of Transmission System Operators for Gas
EPCRA	Emergency Planning Community Right-to-Know Act
EUCERS	European Center for Energy and Resource Security
EUR	Estimated (Average) Ultimate Recovery
FRAC	Fracturing Responsibility and Awareness of Chemicals (Act)
GHG	Greenhouse Gas
GREET	Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation
GWP	Global Warming Potential
GWPC	Ground Water Protection Council
HAPs	Hazardous Air Pollutants
HVHF	High-Volume Hydraulic Fracturing
INGAA	Interstate Natural Gas Association of America
IPCC	Intergovernmental Panel on Climate Change
JPAD	Jonah and Pinedale Anticline Development Area
LCA	Life-Cycle Analysis
LNG	Liquefied Natural Gas
mmcfd	million cubic feet per day
MoPNG	Ministry of Petroleum and Natural Gas (India)
MOU	Memorandum of Understanding
MSDS	Material Safety Data Sheets
NDRC	National Development and Reform Commission
NETL	National Energy Technology Laboratory
NGG	Natural Gas Grid
NOAA	National Oceanographic and Atmospheric Administration
NORM	Naturally Occurring Radioactive Material
NOx	Nitrogen Oxides
NPC	National Petroleum Council
NPDES	National Pollutant Discharge Elimination System
NSPS	New Source Performance Standards
OECD	Organization for Economic Co-operation and Development
ONGC	Oil and Natural Gas Corporation (India)
OOIP	Original Oil in Place
PNGRB	Petroleum and Natural Gas Regulatory Board

POTW Publicly Owned Treatment Works

PPC Prevention, Preparedness, and Contingency

REACH Registration, Evaluation, Authorisation, and Restriction of Chemicals (E.U.)

REC Reduced Emission Completion

REX Rockies Express (pipeline)

ROW Right-of-way

RRC Railroad Commission (Texas)

SEAB Secretary of Energy Advisory Board (U.S.)

SGEIS Supplemental Generic Environmental Impact Statement

SO_2 Sulfur Dioxide

SPDES State Pollutant Discharge Elimination System

SRBC Susquehanna River Basin Commission

STRONGER State Review of Oil and Gas Environment Regulations

Tcf Trillion Cubic Feet

TSCA Toxic Substances Control Act

UIC Underground Injection Control

USGS U.S. Geological Survey

VOCs Volatile Organic Compounds

Foreword

Recent advances in drilling and extraction technologies have fundamentally changed the economics of natural gas in the United States and have the potential to do so around the world. The implications that this has for energy policy generally—and climate change policy specifically—are profound. To help decision-makers understand the forces at work and to consider how they might be shaped to best serve the public good, we asked ICF to prepare this report. It contains a wealth of valuable information and insights.

For policymakers concerned about greenhouse gas emission and other environmental impacts associated with the burning of fossil fuels, the prospect of abundant and low-cost natural gas is a double-edged sword. On the one hand, it could displace a significant portion of coal-based electricity generation in many regions of the globe. This will certainly make it easier to meet near-term environmental objectives in a number of countries. On the other hand, reliance on low-cost natural gas comes with its own set of long-term climate risks, and forging policies to address them will be challenging, to say the least. And there is concern that abundant, low-cost natural gas supplies could delay the transition to cleaner, renewable energy sources.

This report addresses four critical risks associated with the potential benefits of increased international natural gas use. The first is the uncertainty as to how much natural gas is likely to be available in the rapidly developing countries that are also the fastest growing emitters of greenhouse gases. The second is that the failure to follow best environmental practices in the development and production of natural gas could significantly reduce or eliminate the climate benefits that gas can provide. Poor environmental practices could also lead to a public backlash that slows gas development. Third, a rush to exploit natural gas will, in some regions, likely slow the development of the non-carbon emitting renewables and other resources that are needed in the long term. And, fourth, the next fleet of gas-fired power plants may not have the operational capabilities needed for the future mix of renewable and conventional generating assets.

The task before us is to ensure that natural gas becomes a bridge and complement to a decarbonized power sector, rather than a barrier. The report leads us to conclude that this can be accomplished if policymakers take several important actions:

Adopt a comprehensive framework to address the environmental impacts of natural gas development. The report makes it clear that there are real but manageable environmental issues related to the development of gas, in particular unconventional gas. Best practices can address the environmental risks but these practices are not universally adopted. The risks are greatest in developing countries where environmental oversight may not be prepared for the challenge. For natural gas to meet the hopes of its proponents, policymakers should adopt a comprehensive environmental framework to assure best practices are used and public concerns are addressed.

Maintain long-term support for zero emission renewables. All studies show that simply replacing coal generation with natural gas will not enable any region to reduce its carbon emissions to the extent needed if the world is to avoid the catastrophic consequences of climate change. Regions will need to continue—indeed, accelerate—the development of zero-emissions resources, such as solar and wind, that are critical to a low-carbon future.

Ensure that the next fleet of natural gas-fired power plants has the operational flexibility to complement increased use of variable renewable resources. A future with large amounts of renewable energy supply will require complementary resources, including fossil generation to be flexible enough to be able to provide greater ramping, faster start-up, and a wider range of efficient, partial-load operations to balance the variable nature of many renewable electricity sources. Not all gas-fired power plants are sufficiently flexible. Policymakers need to take steps to ensure that long-lived power plant investments provide the kind of capabilities that will be needed in the renewable energy-based future.

Adopt pricing and market rules that support gas as a bridge to a renewable energy future. Having the technical capability to operate flexibly does not necessarily mean that gas plants will operate in ways that complement variable renewables. Contract terms and market rules may unintentionally reward energy production over providing reliability or ancillary services. Policymakers should ensure that contracts, pricing, and market rules are designed to encourage flexible operations.

The environmental, economic, and energy challenges facing the world are daunting, but not unsolvable. Natural gas has a role to play—rather, several roles, which will vary from region to region. Getting the rules right, so that gas can best serve our needs, should be given high priority in today's policy debates.

David Moskovitz
Principal
Regulatory Assistance Project

Executive Summary

This report reviews the implications of new unconventional natural gas resources, primarily shale gas produced through the use of horizontal drilling and multi-stage hydraulic fracturing, for resource production, coal displacement, and infrastructure requirements. The report focuses on four areas: the United States, Europe, India and China. The key findings of this report are as follows[1]:

Large shale gas potential: World natural gas resource base estimates continue to rise as new unconventional gas resources (particularly shale gas) are characterized and produced. The U.S. Energy Information Administration (EIA) estimates that global technically recoverable shale gas resources (based on assessment of shale gas resources in selected basins within 32 countries) total 6,622 trillion cubic feet (Tcf), the equivalent of 60 years of 2008 worldwide natural gas consumption.[2,3]

Resource base uncertainty: The United States and Canada remain the only countries in which commercial shale gas production is currently taking place. Given the nascent stage of the shale gas production, there is much uncertainty about the size and economics of the world's resource base. Table 1, which includes estimates from the EIA and a range of the potential resource base estimates devised by ICF, highlights the range of uncertainty.

Significant potential impact of shale gas production: Potential production of shale gas could have a significant impact on each region's energy mix. Assuming the EIA estimates for shale gas resource base, this study assumes that peak shale gas production per year through 2035 could be as high as 12.3 Tcf[4] in the United States, 11.5 Tcf in Europe, 1.3 Tcf in India, and 25.5 Tcf in China.

Ability to displace coal consumption: The peak shale gas production numbers imply a certain level of projected coal consumption displacement, which is shown in Table 1. Also shown are alternative estimates of potential coal displacement based on ICF's uncertainty range for the size of the shale gas resource base. These estimates assume that all of the shale gas development is directed to coal displacement, although in reality some gas would likely be used in other applications. The new shale gas development also would interact with other gas resources, including liquefied natural gas (LNG).

Large-scale infrastructure required for shale gas development: Shale gas production could mean improved energy security and less reliance on carbon-intensive fossil fuels. However, investment in associated gas pipeline infrastructure is imperative to any successful shale gas development. Although the United States and Europe have relatively well-developed pipeline infrastructures, other regions such as India and China will require large-scale investment in associated infrastructure to build a large shale gas industry.

Environmental impact and regulatory requirements: There are a number of issues concerning potential environmental impact and regulation of shale gas production. The main environmental issues concern air pollution (from methane emissions and production operations), groundwater contamination, water use and disposal, land use, and fracturing fluid composition and reporting. Government bodies are grappling with current and potential regulations to safely regulate the new industry, although the United States is further along than other countries. There are demonstrated measures available to mitigate the potential environmental effects.

1 Due to the availability of reported data, "Europe" in this report is defined as the European member countries of the Organization for Economic Co-operation and Development (OECD), including Austria, Belgium, Czech Republic, Denmark, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Luxembourg, the Netherlands, Norway, Poland, Portugal, Slovakia, Slovenia, Spain, Sweden, Switzerland, Turkey, and the United Kingdom.

2 U.S. EIA, 2011a

3 Based on 2008 global natural gas consumption of 111 Tcf, based on U.S. EIA estimates cited in the International Energy Outlook for 2011.

4 Based on the EIA's Annual Energy Outlook 2011 estimates. Figures for other regions based on a 2% annual production of the total technically recoverable shale gas resource base.

Table 1

Shale Gas Summary Table[5]

Region	Resource Base Source: EIA	ICF P90	ICF Mean	ICF P10
Technically Recoverable Resource Base Assessment (Tcf)				
U.S.	862	N/A	1,863	N/A
Europe	574	340	520	725
India	63	80	280	565
China	1,275	240	820	1,670
2035 Shale Gas Peak Production (Tcf)				
U.S.	12.3	N/A	17.7	N/A
Europe	11.5	6.8	10.4	14.5
India	1.3	1.6	5.6	11.3
China	25.5	4.8	16.4	33.4
2035 Peak Shale Gas Displacement of Coal Consumption (% / QBtu)				
U.S.	66% / 16.1Q	N/A	96% / 23.3Q	N/A
Europe	100% / 10.4Q	86% / 9.0Q	100% / 10.4Q	100% / 10.4Q
India	9% / 1.7Q	11% / 2.1Q	38% / 7.4Q	76% / 14.9Q
China	30% / 33.6Q	6% / 6.3Q	19% / 21.6Q	39% / 44.0Q

2035 Cumulative Incremental Pipeline Required (Pipeline Miles)

Region	Lower-bound	Upper-bound
U.S.	16,000	48,700
Europe	53,300	101,000
India	20,000	68,800
China	50,000	220,500

Current Shale Gas Development Phase

Region	
U.S.	Commercial development; assumed 2006 as commercial shale gas development start date
Europe	Exploration of selected basins; assumed 2016 as commercial shale gas development start date
India	Exploration of selected basins; assumed 2016 as commercial shale gas development start date
China	Exploration of selected basins; assumed 2014 as commercial shale gas development start date

Environmental and Regulatory Issues

Region	
U.S.	Air and water pollution, land use
Europe	Land scarcity, water use and pollution, current assessment of applicable legislation
India	Economic development and pipeline security are prioritized over environmental issues
China	Water scarcity, air emissions, economic development are prioritized over environmental issues, lack of enforcement

Note 1: *P90 indicates a 90 percent probability of that resource base estimate, the mean value represents a 50 percent probability of that resource base estimate, and the P10 value indicates a 10 percent probability that the resource base is that large.*

Note 2: *This study assumes that every 0.78 Btu of natural gas used to produce electricity is the equivalent of 1 coal-based Btu of electricity production, given the efficiency gains associated with combined cycle natural gas facilities. Thus, in calculating forecasted coal consumption that could be replaced by shale gas, 1 MMBtu of natural gas would displace 1.28 MMBtu of coal.*

5 ICF estimates, EIA Annual Energy Outlook 2011, EIA International Energy Outlook 2011

1. Introduction

In support of RAP's broader research initiative on the future of the power sector in the United States, Europe, India, and China, ICF has developed this report on the implications of new unconventional natural gas resources, primarily shale gas produced through the use of horizontal drilling and multistage hydraulic fracturing. The report provides estimates of:

- the potential shale gas resources in these countries and the gas price curve, where available;
- the gas infrastructure required to apply these resources;
- the projected growth in electricity and the potential for future displacement of coal consumption through the development of these gas resources; and
- the environmental effects of shale gas production and best practices for avoiding or mitigating these effects.

A. Background

Natural gas is recognized as the lowest emitting fossil fuel. It has low emissions of conventional pollutants (e.g., sulfur dioxide, nitrogen oxides, and particulates) and also has the lowest carbon content of the fossil fuels and therefore the lowest CO_2 emissions. Many gas-based technologies are highly efficient, further reducing the emissions per unit of output. Natural gas can be used in all sectors of the economy (residential, commercial, industrial, electric generation, and transportation) and is also an important industrial feedstock.

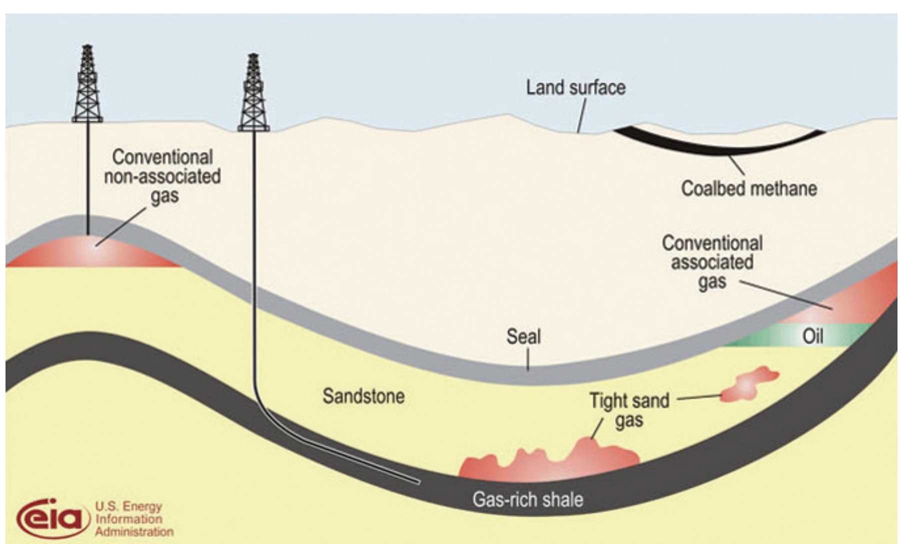
Natural gas was originally produced as a co-product of oil production. In some parts of the world, this "associated gas" is still the primary source of natural gas. Non-associated gas, not coproduced with oil, is another important source of natural gas and is produced from a variety of geologic formations, including conventional gas formations, tight sands, coal beds, and shale formations.

Figure 1 illustrates the different configuration of these resources. In conventional oil and gas resources, the oil and gas have migrated to a porous rock formation capped by an impermeable rock layer. Producers must find these pockets of oil and gas, but once they are located and tapped, the oil and gas can flow relatively freely out of the formation. Until recently, estimates of the potential gas resources were based on these conventional gas formations.

Geologists have long known that certain shale formations contain a large amount of gas, but until recently these shale gas resources were inaccessible, trapped within the impermeable shale rock. Attempts had been made to use hydraulic fracturing in vertical wells to break up the shale and allow the gas to flow out. There was insufficient surface area in a vertical well, however, for the fracturing to release enough gas to be effective. The breakthrough

Figure 1

Shale Gas Summary Table



in shale gas production came with the combination of hydraulic fracturing and horizontal drilling, also shown in Figure 1.

In the modern shale gas production process, the well is drilled down to the shale gas layer (typically 8,000 to 12,000 feet in the United States) and then turned to follow the shale formation for an additional 5,000 to 10,000 feet. The horizontal section is then fractured, allowing gas to be released along a much larger surface area. The hydraulic fracturing process uses hydraulic pressure to fracture the geologic formation, creating small fractures in the shale to release the natural gas trapped inside the rock. The fracturing (or "frack") fluid contains solid particles, or "proppants" (usually sand), to prop open the fractures to provide a pathway with higher hydraulic conductivity to convey the formation fluid or gas from the formation matrix to the wellbore.

Current practice generally relies on "slickwater fracks," a fracturing fluid consisting of about 98 percent to 99.5 percent fresh/recycled water mixed with a friction reducer and other additives.[6] Slickwater fracks typically require millions of gallons of water per well, and some wells may be fractured more than once during their producing life.[7]

Typical designs for horizontal well fracturing include stages every 350 to 500 feet of lateral length (e.g., 10 stages for a 4,000-foot lateral). Horizontal drilling allows access to a large area of the subsurface, greatly reducing the number of wells required relative to vertical drilling. In additional, multiple wells are drilled from each well-pad, further reducing the surface impact for the amount of gas produced. Hydraulic fracturing and horizontal drilling methods continue to evolve as gas producers encounter new geologic situations, experiment with different techniques, and incorporate new designs and technologies.

Shale gas extraction technology, using both hydraulic fracturing and horizontal drilling, has revolutionized the U.S. gas industry. ICF's estimate of the recoverable shale gas resource for the United States has increased from a few Tcf more than a decade ago to over 1,800 Tcf today, representing the majority of the remaining gas resources and fundamentally changing the understanding of the North American natural gas resource. This increase is primarily due to improved technology that allows the recovery of the resource that was already known to exist.

Figure 2 illustrates the dramatic increase in North American shale gas production based on ICF's analysis. Seventeen of the 18 billion cubic feet per day (Bcfd) produced at year-end 2010 were produced in the United States, representing 28 percent of marketed gas production in the U.S. lower 48 states.

As hydraulic fracturing and horizontal drilling technologies continue to improve, reducing the uncertainties associated with shale extraction, shale gas will represent an increasing share of North American natural gas production, and is expected to expand worldwide in coming decades. Shale gas represents an entirely new resource for natural gas production in regions that never had conventional gas resources or where those resources have already been produced. This creates new opportunities to expand the use of gas as an efficient and low-emitting source of energy.

Despite a high level of optimism about the future worldwide potential for shale gas, the lack of a cohesive regulatory framework, public concern over shale production's environmental issues, the limited experience with shale gas production technologies, and the varying geology of the world's shale deposits are some of the uncertainties associated with this nascent industry. These uncertainties must be addressed in order for the apparent potential of shale gas production worldwide to be realized.

B. Organization of the Report

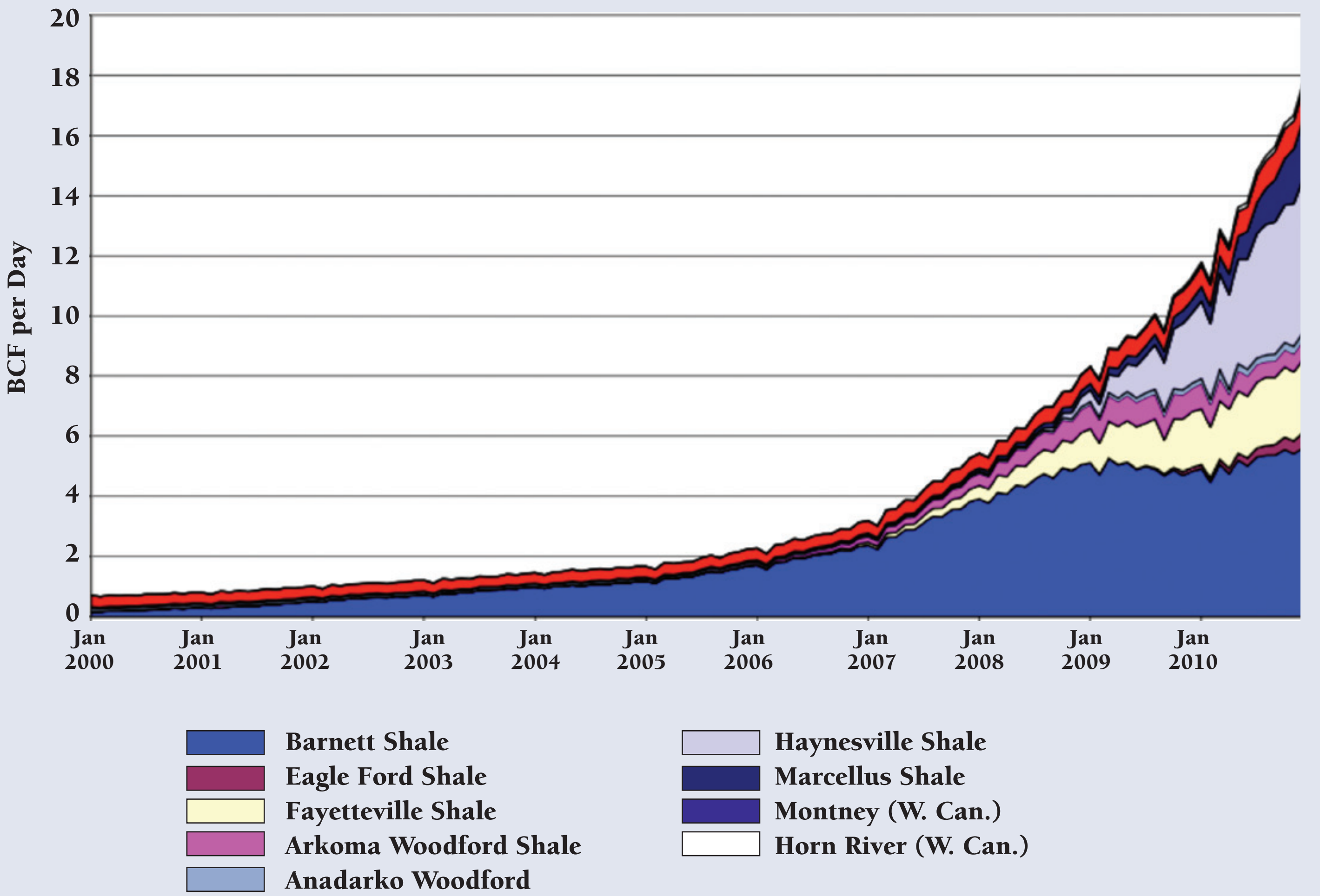
Section 3 of this report describes the methodology used to estimate the technical resource potential for shale gas in the target countries, the future mature gas production levels, infrastructure requirements, and potential for displacement of coal for electricity generation. Sections 4 through 7 present this information for the United States, Europe, India, and China. Section 8 summarizes these results. Section 9 discusses the potential environmental impact of shale gas production, including a comparison of life-cycle greenhouse gas (GHG) emissions of gas and coal. Section 10 draws conclusions and presents some best practice options for mitigation of the environmental impacts of shale gas production.

6 U.S. DOE, 2009

7 Railroad Commission of Texas, 2008

Figure 2

North American Shale Gas Production Through 2010 – Major Plays [8]



8 ICF estimates based on data from HPDI, LLC, a wholly-owned subsidiary of DrillingInfo, Inc. and state and provincial agencies.

2. Methodology

This section explains the methodologies used to estimate the shale gas resource in each country, the future mature gas production level, potential for coal displacement in electricity generation, and potential requirement for gas infrastructure.

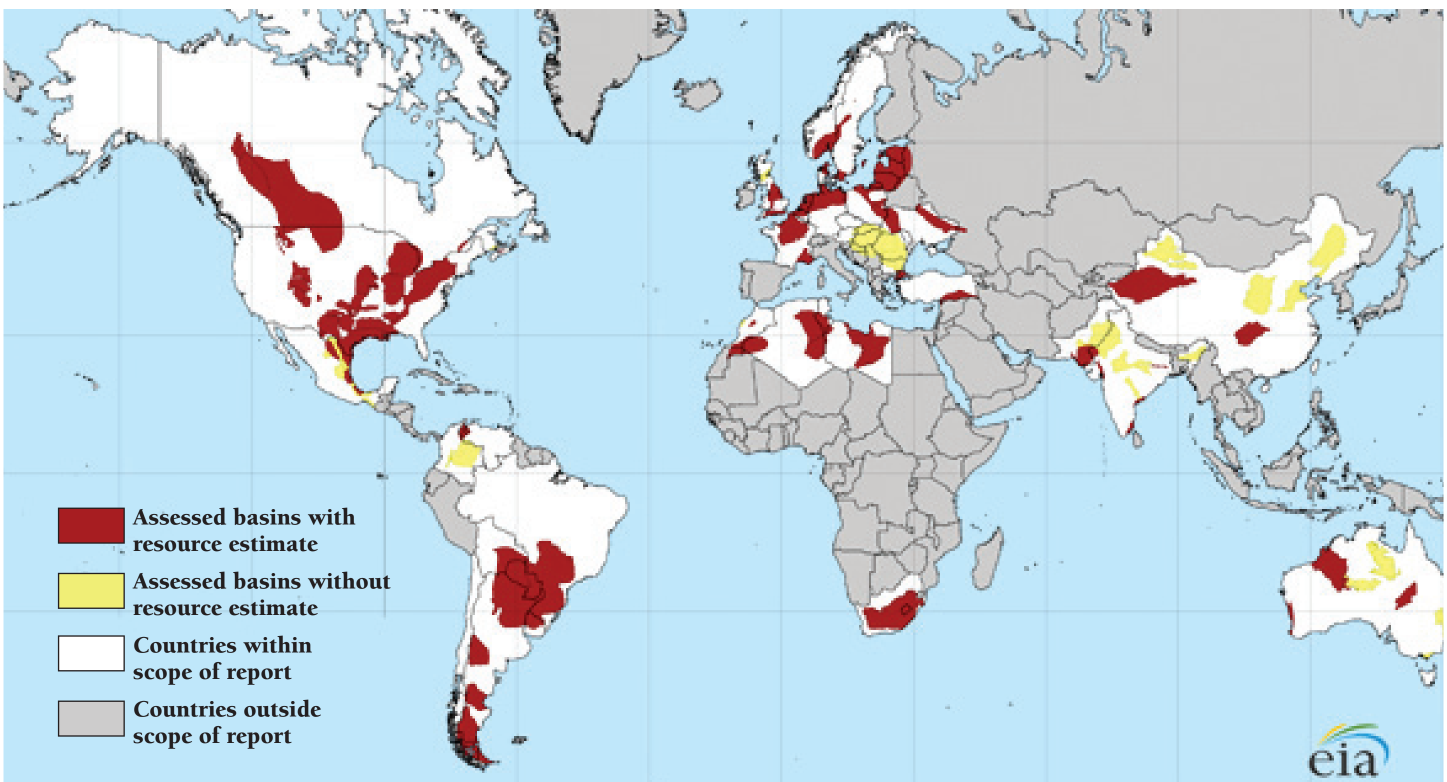
A. Shale Gas Resource Base Assessment

Estimates of world natural gas resource base have been increasing over time, particularly with the continued characterization of new unconventional gas resources (primarily shale gas). Estimates of worldwide technically recoverable shale gas resources are subject to a wide range of uncertainty due to the early stage of exploration. The United States and Canada remain the only countries in which commercial shale gas production is currently taking place. Countries such as Poland, India, China, and others, however, have recently begun experimental shale drilling ventures that will soon yield direct data on the resources. Figure 3 shows some of the world's major shale gas resource basins according to a recent U.S. Energy

9 U.S. EIA, 2011a

Figure 3

48 Major Shale Gas Basins in 32 Countries[9]



Information Administration (EIA) study.[10]

According to the EIA study, global technically recoverable shale gas resources (based on assessment of shale gas resources in 32 countries) total 6,622 Tcf, the equivalent of 60 years of 2008 worldwide natural gas consumption.[11,12] Due to the lack of complete data, the 32-country assessment represents only a fraction of the actual world resources, as only a portion of the potential was studied in the countries analyzed. Some countries, such as Russia, were excluded completely.

For this study, ICF applies two methods for gas resource assessment: the top-down and the bottom-up approaches. The top-down approach allows an approximation of the range of potential resources where detailed data are not yet available. The bottom-up approach provides a more accurate assessment on the basis of more detailed information as it becomes available.

The ICF bottom-up shale gas resource assessments are applied when detailed geologic data are available. They have been applied only to the United States and Canada and are generally higher than other published assessments, which are more conservative due to the lack of detailed data. The difference results from ICF's more inclusive and extensive geologic and engineering approach to resource assessment, which allows a more complete assessment that can be supported based on the data. This approach also includes petroleum and natural gas liquids, which are contained in some shale formations. The oil portion can contain large volumes of associated natural gas. The bottom-up approach was used for ICF's assessment of the U.S. shale gas resource base in this report. ICF's extensive bottom-up analysis of North American shale gas resources provides the analytical basis for the top-down assessments of less defined resources in other countries.

The top-down approach uses the available information at a country, province, or geologic basin level to develop resource assessments through the application of analogs or ranges of resource per unit area or volume, including factors developed through bottom-up analysis. The ICF top-down shale gas resource assessment for Europe, India, and China provides an approximate resource assessment, and illustrates the distribution of shale gas resources, based on currently available general information on basin geology and conventional hydrocarbon resources and systems. Because it takes a more comprehensive view of the potential resource, these values are sometimes higher than those in the EIA report.

The evaluation of gas-in-place, original oil in place (OOIP), and recoverable hydrocarbons provides a range of estimates with a probability distribution for the values based on the assessment of the geologic structures. The lowest value, or P90 value, is the resource base assessment with 90 percent confidence that the resource base is at least

10 Red-colored locations: "risked" gas-in-place and estimates of technically recoverable resources were provided. Yellow-colored locations: shale gas locations reviewed, but resource estimates were not provided (primarily due to lack of available data). White-colored countries: at least one shale gas basin was included. Gray-colored countries: no shale gas basins were considered.

11 U.S. EIA, 2011a

12 Based on 2008 global natural gas consumption of 111 Tcf, based on U.S. EIA estimates cited in the International Energy Outlook for 2011.

13 U.S. Energy Information Administration, ICF

14 Figure includes estimate for associated gas in tight oil of 114 Tcf.

Table 2

Shale Gas Resource Assessment [13]

Assessment Source	U.S.	Europe	India	China	Global
	Technically Recoverable Shale Gas Resources (Tcf)				
EIA*	862	574	63	1,275	6,622
ICF "Bottom-up"	1,863[14]				
ICF "Top-down"**		340-520-725	80-280-565	240-820-1,670	9,620-12,745-16,495

** Based on selected basins and countries analysed. ** Includes P90/low, mean, and P10/high values* that size. The middle value is the mean value of the resource base, whereas the highest value, or P10 value, is the resource base assessment for which there is a 10 percent probability that the resource base would exceed the P10 value.

Table 2 presents estimates of technically recoverable shale gas resources from the EIA and ICF for the areas covered in this report. ICF's estimate of the U.S. technically recoverable resource base for shale gas is based on rigorous geologic analysis and empiric evidence from the commercial development occurring in North America. Europe, India and China are at earlier stages in their natural gas exploration and have thus far only pursued experimental drilling. Thus, a higher degree of uncertainty is associated with resource base assessment in those regions. With the exception of China, the ICF mean values are comparable to or larger than the EIA estimates. This is due to a more comprehensive coverage of the potential resource areas and ICF's own analysis of the potential in each region.

B. Estimating Mature Shale Gas Production and Potential Coal Displacement

One goal of the study was to project how much of the coal projected to be used in power generation could be displaced through the development of the shale gas resource in each country. This is not a forecast of actual fuel mix but an estimate of the maximum potential displacement achievable through shale gas development compared to a business-as-usual case. Although this is a useful indication of the potential role of gas versus coal use in country, it is somewhat artificial in that some shale gas would likely be used in sectors other than power generation (e.g., residential and industrial) and development of domestic shale might displace gas otherwise imported via pipelines or liquefied natural gas (LNG).

In order to estimate the potential coal displacement, ICF made a number of assumptions on each region's potential for shale gas production once the resource is fully developed based on the available technically recoverable shale gas resource base. For the United States, this report used ICF's proprietary bottom-up estimate. For all other regions, ICF used an industry rule-of-thumb that mature annual production is 2 percent of the estimate for technically recoverable shale gas resources to assess each region's fully developed shale gas production potential. ICF has used ratios of annual peak production to potential resources ranging from 1 to 3 percent for its studies. This range is based on our own analysis of various production histories and modeling of discovery process and production models and published results of other studies.[15]

The ramp-up to peak shale production was assumed to be 20 years from the beginning of commercial shale gas production, as listed in Table 3, based on the status of each region's shale gas development and the experience in the development of North American resources. The mature production for each of these regions was projected to be 2 percent of the technically recoverable resource, developed over a 20-year period.

The baseline for estimating potential coal consumption displacement for the United States was the EIA's Annual Energy Outlook 2011, and for the other regions, the EIA's International Energy Outlook 2011, both of which include coal and gas consumption forecasts through 2035.[16] The EIA forecast already includes a share of shale gas production for each region, based on the EIA's own assessment of production growth in each region. In all cases, ICF's estimate of mature shale gas production, calculated as described previously, was higher than ICF's understanding of the EIA's projection, thus the coal displacement and gas infrastructure requirements calculated here include the sum of the EIA baseline shale gas projection plus the incremental amount estimated by ICF. The U.S. EIA figures, however, assume only the EIA's natural gas forecasts, which also include significant shale gas production forecasts.

Table 3

Assumed Start Date of Shale Gas Production

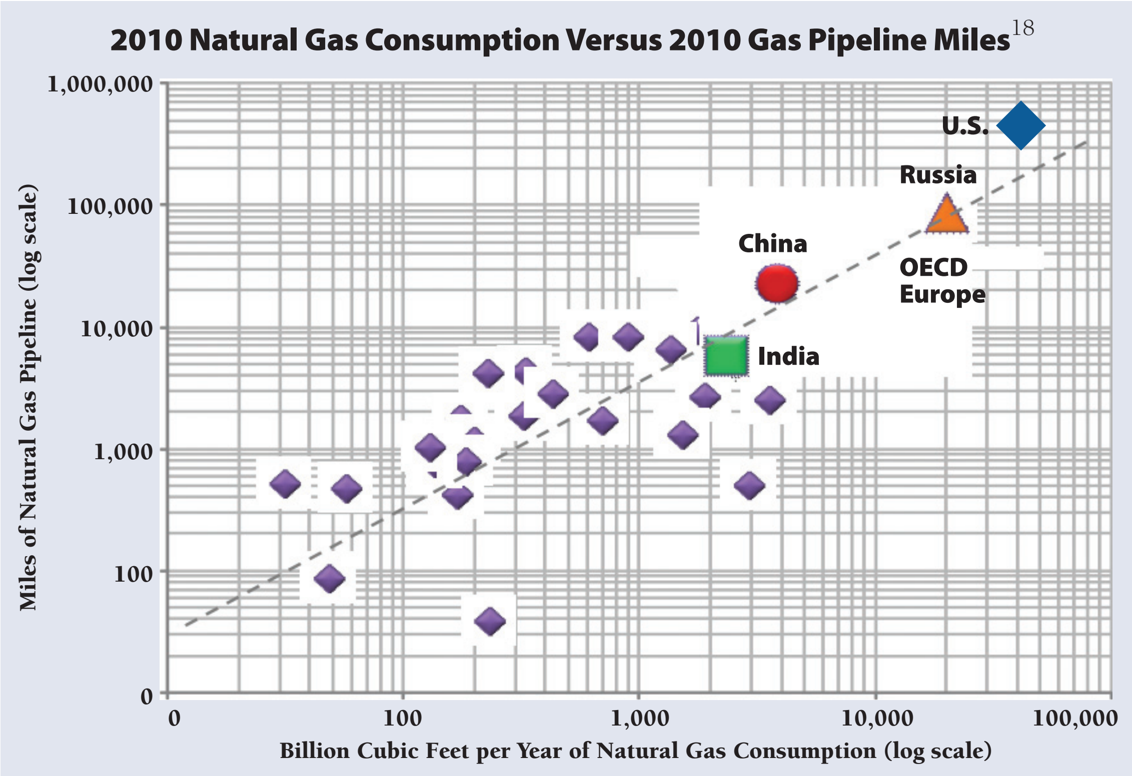
Region	Assumed Start Date of Commercial Shale Gas Production
U.S.	2006
Europe	2016
India	2016
China	2014

15 Laherrère, 2000

16 U.S. EIA, 2011b

The displacement analysis estimates the maximum amount of coal from the EIA baseline forecast that could be displaced with the projected mature shale gas production, including the gas in the EIA baseline. The coal consumption displacement is adjusted for the higher efficiency of a gas combined cycle generator relative to a coal steam plant; thus, 1 Btu of gas for electricity generation is assumed to displace 1.28 Btu of coal for electricity generation.[17]

Figure 4



C. Natural Gas Transmission Infrastructure

While development of natural gas production could provide improved energy security for growing economies and reduced reliance on more carbon-intensive fossil fuels, development of domestic shale gas resources requires parallel development of the domestic energy infrastructure. Expansion of the infrastructure to accommodate shale gas production could mean some mix of construction of gas pipelines linking the source to gas markets and expansion of the electrical grid to deliver power from plants near the shale gas resources. Depending on the existing infrastructure, it might also require the construction of local gas delivery infrastructure in local cities. This study assumes that the main focus is on delivery of gas to gas consumers in different parts of each country via transmission pipelines. It does not include the development of local gas distribution infrastructure, which is very site-dependent.

ICF estimated the required gas transmission infrastructure using a correlation between 2010 natural gas consumption and associated 2010 gas pipeline mileage for different countries and regions, used to derive a regression model for the upper-bound incremental pipeline estimate (Figure 4), which was further calibrated to reflect previous ICF infrastructure studies. The regression model indicated that the pipeline requirement increases faster than the natural gas consumption forecast, suggesting that as gas consumption increases, infrastructure development must increase at a faster rate to supply an expanding number of markets. The regression-based mileage estimate was used with the ICF P10 (high estimate) and ICF P90 (low estimate) for shale production to estimate the upper- and lower-bound estimates of pipeline requirements.

17 Coal heat rate is assumed to be 10,414 Btu of coal per kilowatt-hour (kWh) of electricity generated, while a heat rate of 8,160 Btu per kWh is assumed for a natural gas combined cycle. Thus, 1 MMBtu of gas displaces 1.28 MMBtu of coal (10,414/8,160). This information is taken from the U.S. EIA and was applied for all the other regions studied. For more information see http://www.eia.gov/cneaf/electricity/epa/epat5p3.html

18 ICF analysis of the U.S. Energy Information Administration and CIA World Factbook data

3 U.S. Shale Gas Outlook

A. U.S. Shale Gas Resource Base Assessment

North America[19] has large resources of undeveloped natural gas, including conventional onshore and offshore gas, tight gas, coalbed methane, and shale gas. Figure 5 illustrates the distribution of the major shale gas resources within the U.S. lower 48 states. The assessed volumes, even assuming current technology and accounting only for known resources, are more than sufficient to

19 Although the United States is the primary focus of this chapter, North American gas markets are integrated. The chapter therefore includes Canadian resources as part of the assessment.

Figure 5

U.S. Lower 48 States Shale Gas Plays

support robust natural gas consumption growth.

The EIA estimates the U.S. technically recoverable shale gas resource base at 862 Tcf. ICF's bottom-up approach indicates a resource base estimate of 1,863 Tcf, as shown in the table below.

Table 4

Estimates of U.S. Shale Gas Resource (Tcf)[20]

EIA Estimate	ICF Mean Estimate
862	1,863

According to the EIA's Annual Energy Outlook (AEO) for 2011, the shale gas resource base makes up 34 percent of the U.S. Reference Case natural gas resource base, and is expected to account for 46 percent of total U.S. natural gas production in 2035.[21] Table 5 summarizes the current ICF gas and crude oil assessments of the lower 48 states and Canada. Resources shown are "technically recoverable resources." This is defined as the volume of oil or gas that could technically be recovered under existing technology and stated well spacing assumptions without regard to price.

Table 5

ICF North America Gas Resource Base Assessment[22]

Lower 48	Total Gas Tcf	Crude and Condensate Bn Bbls
Proved reserves	263	19
Reserve appreciation and low Btu	219	23
Enhanced oil recovery	---	72
New fields	488	68
Shale gas and tight oil	1,863	38
Tight gas	438	4
Coalbed methane	66	---
Total remaining resource	**3,337**	**224**
Canada		
Proved reserves	61	4.3
Reserve appreciation	29	3.0
Stranded frontier	39	0.0
Enhanced oil recovery	---	3.0
New fields	219	12.0
Shale gas	601	0.3
Tight gas (with conv.)	0.0	0.0
Coalbed methane	76	0.0
Total remaining resources	**1,025**	**23**
North America total	**4,362**	**247**

The ICF mean assessment of the remaining technically recoverable total natural gas resources in the U.S. lower 48 states, including proven reserves, is 3,337 Tcf. The estimate for Canada is 1,025 Tcf. The total resource base of 4,362 Tcf represents approximately 162 years of production at the current production rate of about 27 Tcf per year. The ICF estimate for crude oil and condensate resources in the U.S. lower 48 states is 224 billion barrels, of which 38 billion are from gas-prone or oil-prone shale plays. The resource can be compared to 19 billion barrels of proven oil reserves. Shale gas plus tight oil-associated gas in the lower 48 states is assessed at 1,863 Tcf, and Canadian shale gas is assessed at 601 Tcf. The combined 2,464 Tcf of shale gas and tight oil gas represents about 56 percent of the North American gas resource base. The ICF mean shale gas assessment of 1,863 Tcf is more than twice the current EIA estimate of 862 Tcf.

U.S. shale gas estimates of technically and economically recoverable resources have increased dramatically over the past decade with continuing improvements in gas extraction technologies. Shale gas in North America represents the lowest cost resource that can produce high volumes of gas. With the exception of areas such as the deepwater Gulf of Mexico, conventional high permeability North American gas resources are now relatively high cost, due to the maturity of development. Much of the conventional resource base is either offshore or in expensive deep drilling or frontier areas. Although some coalbed methane plays are still economical to produce, most of the lower-cost resource being developed today is tight gas and shale gas or tight oil (shale formations with oil production). This is due to improved technologies and

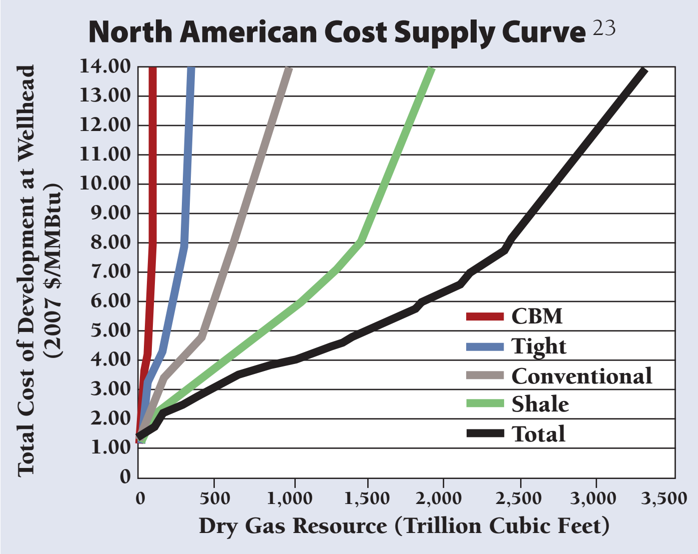
20 ICF estimates and EIA Annual Energy Outlook 2011 forecasts

21 U.S. EIA, 2011c

22 ICF estimates based on various sources, including Bureau of Ocean Energy Management, Regulation, and Enforcement (BOEMRE); National Petroleum Council (NPC); U.S. Geological Survey (USGS)

very little exploration risk (i.e., the gas is well distributed throughout the shale formation so there is less risk of "dry holes"). Figure 6 illustrates ICF's estimate of the supply costs of conventional and unconventional natural gas sources in North America.

Figure 6

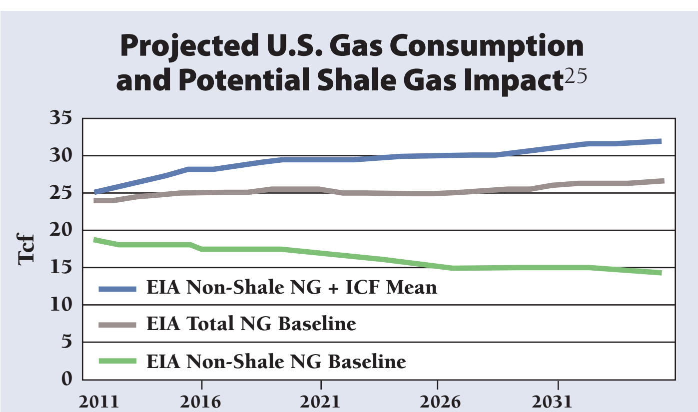


B. U.S. Mature Shale Gas Production and Potential Coal Displacement

i. U.S. Potential Mature Shale Gas Production

Because the U.S. shale gas resource is already better characterized and better developed than in other countries, ICF's estimate for mature shale gas production was based on a bottom-up assessment and current development projections rather than the "2-percent rule" used for other countries. ICF's estimate of mature U.S. shale gas production is 17.7 Tcf by 2035, versus 12.3 Tcf cited in the EIA's AEO 2011.[24] Figure 7 represents the impact of expanded shale gas production on EIA baseline forecasts for U.S. natural gas consumption, with total production exceeding 30 Tcf in 2035.

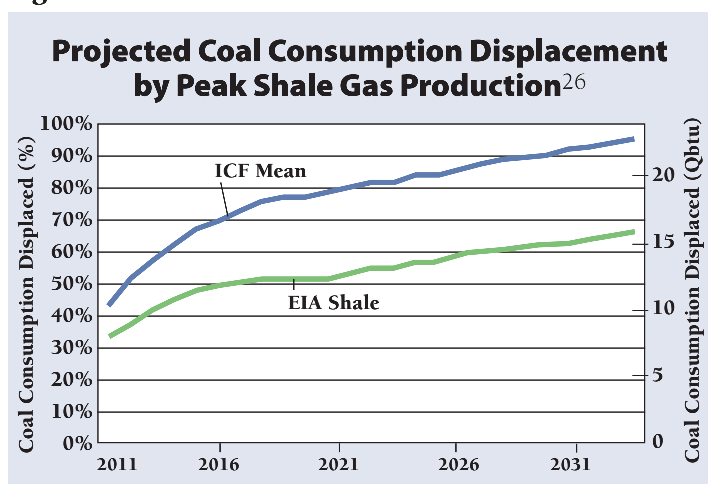
Figure 7



ii. U.S. Potential Coal Displacement

Figure 8 illustrates the total coal consumption displacement potential of shale gas production, and the share of baseline coal consumption that could be displaced. Both figures assume ICF's mature shale gas production and that all shale gas is applied to coal displacement. Total shale gas production has the potential to displace 16 Quadrillion Btu (Q) of coal or 66 percent of projected domestic coal consumption in 2035, based on the EIA shale gas projection, or 23 Q (96 percent) of projected coal consumption using ICF's shale gas estimates. The absolute magnitude of coal displaced exceeds the total shale gas production in both cases, because the natural gas used in electricity generation is more efficient than coal-fired generation, meaning that 1 MMBtu of natural gas can displace 1.28 MMBtu of coal.

Figure 8



23 ICF

24 U.S. EIA, 2011c

25 ICF estimates and EIA AEO 2011

26 ICF estimates and EIA AEO 2011 forecasts

C. U.S. Natural Gas Infrastructure

i. Shale Gas Supply and Demand

Figure 9 shows the primary U.S. shale gas supply and gas demand regions. Shale gas supplies in the United States are located relatively close to major demand areas. In terms of projected gas demand, the Northeast, Southeast, and Southwest are expected to see highest demand in 2035, estimated by ICF at 6.6 Tcf, 7.3 Tcf, and 8.0 Tcf, respectively.[27]

ii. Gas Distribution Infrastructure

In 2011, ICF produced a detailed projection of North American gas infrastructure requirements for the Interstate Natural Gas Association of America (INGAA)[29]. Figure 10 shows ICF's detailed projection for changes in required U.S. interstate pipeline infrastructure. ICF projects that the United States will see increases in natural gas flows from the Gulf Coast to the Southeast, given the increases in mid-continent shale gas production. The Rockies Express (REX) pipeline will enable increasing flows from the Rocky Mountains, while Marcellus gas production growth will displace gas flows from the Gulf to the Northeast. In addition, flows from western Canada will decline, with a decrease in

Figure 9

U.S. Projected Gas Demand and Primary Shale Supply Areas[28]

Areas circled in red indicate the primary shale gas production regions; areas circled in a blue dashed line indicate major demand areas through 2035.

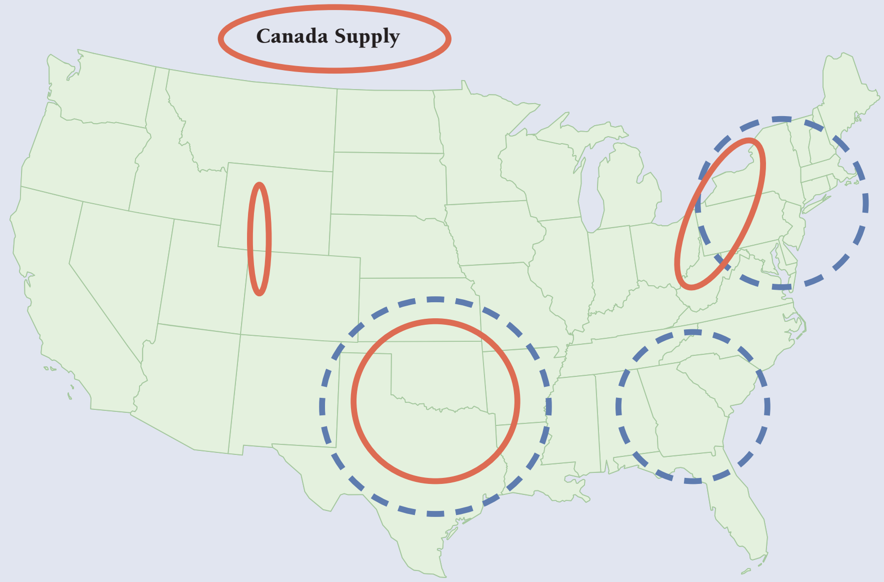
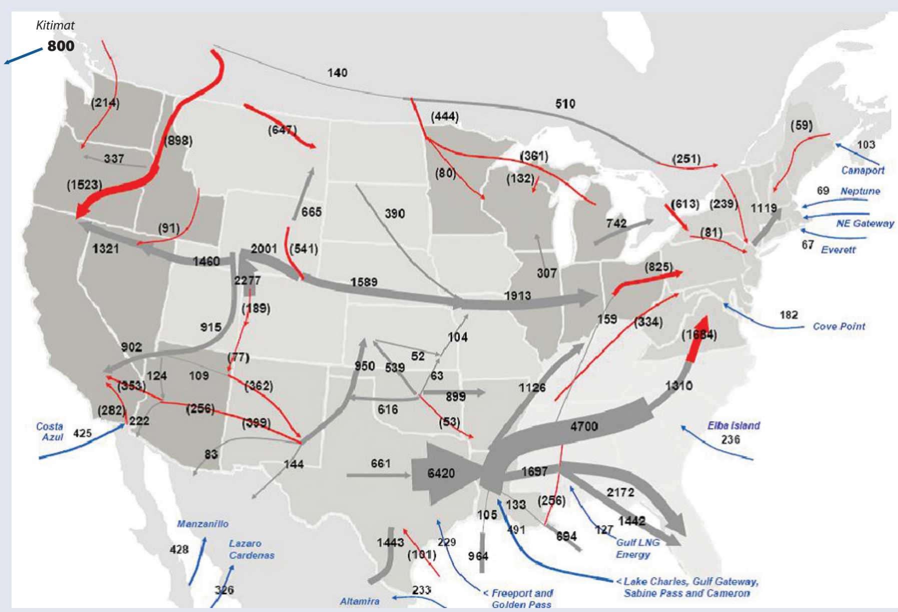


Figure 10

Inter-regional Natural Gas Pipeline Flows[30]

Change from 2010 to 2035 in million cubic feet per day (mmcfd).



Gray lines indicate increased pipeline flows
Red lines indicate decreased pipeline flows
Blue lines indictae changes in LNG flows

27 ICF, 2011a

28 Source: http://www.50states.com/cap.htm. INGAA Foundation, 2009.

29 Interstate Natural Gas Association of America (INGAA), 2011

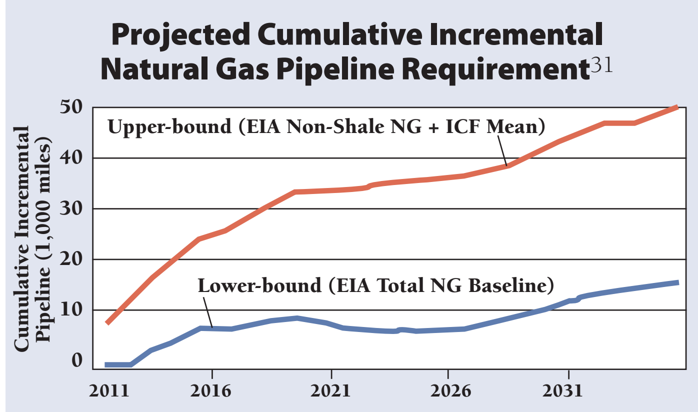
30 Interstate Natural Gas Association of America (INGAA), 2011

conventional production in Alberta, Canada and increasing gas demand from oil sand development.

The gas pipeline network in the United States is more developed than in the other countries addressed by this study. In addition, much of the potential shale gas resource is near gas demand centers. For both reasons, the amount of new transmission pipeline is less than it might be in a country that is just beginning to develop its gas resources. Nevertheless, the ICF study projected the need for the following by 2035:

- 35,600 miles of mainline transmission pipeline
- 414,000 miles of new gathering pipeline in the producing areas
- 8,520 miles of new lateral pipelines to connect power plants to the transmission pipelines.

Figure 11



31 ICF analysis of the U.S. EIA, CIA World Factbook data, and ICF estimates

4 Europe

A. European[32] Shale Gas Resource Assessment

The majority of OECD Europe's assessed shale gas resources are found in Poland, France, Norway, and Sweden, as seen in Figure 12 and Figure 13. Other large resources (non-OECD Europe) are in Ukraine, Hungary, Austria, and Romania.

The EIA estimates the OECD European technically recoverable shale gas resource base at 574 Tcf. ICF's top-down estimate for the technically recoverable resources ranges from a P90 estimate of 340 Tcf to a P10 estimate of 725 Tcf, with a mean of 520 Tcf.

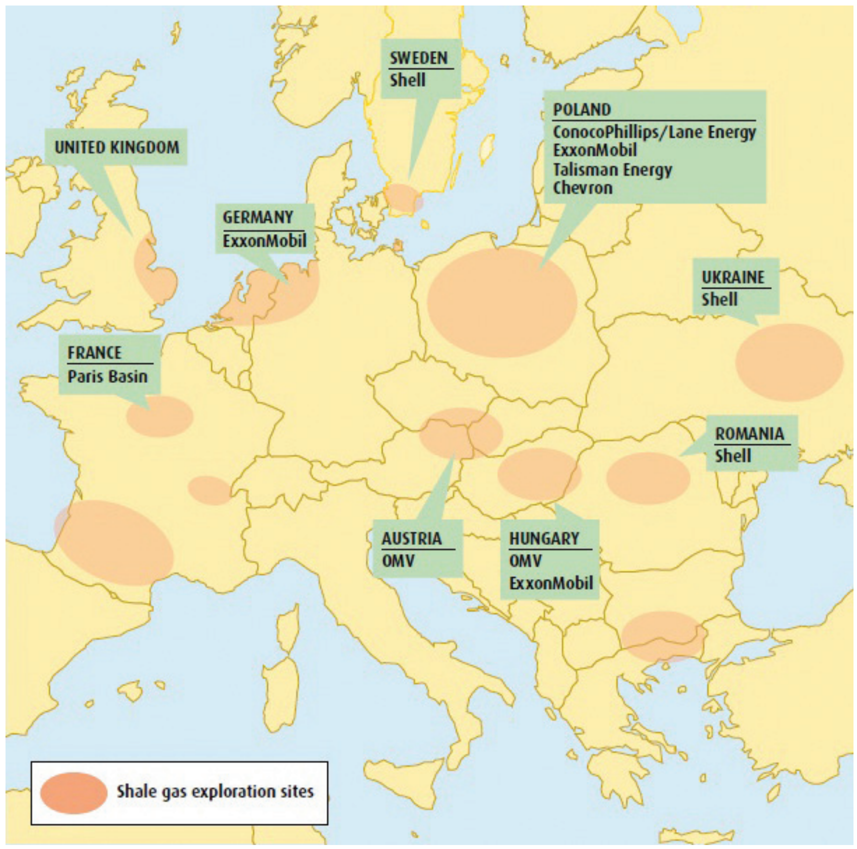
Table 6

Estimates of European Shale Gas Resource (Tcf)[34]

EIA Estimate	ICF P90 Estimate	ICF Mean Estimate	ICF P10 Estimate
574	340	520	725

Figure 12

European Shale Gas Resource Areas and Companies Exploring Basins[33]



According to the EIA international shale gas study, OECD Europe's technically recoverable shale gas resources of 574 Tcf account for 90 percent of Europe's total technically recoverable shale gas resources, which includes Ukraine (42 Tcf); Lithuania (4 Tcf); and Romania, Hungary, and Bulgaria (19 Tcf).[35]

Despite interest in shale gas development, Europe faces similar obstacles to industry development as those found in the United States. Shale gas development is limited in several countries due to public safety and environmental

32 Due to the availability of reported data, "Europe" in this report is defined as the European member countries of the OECD, including Austria, Belgium, Czech Republic, Denmark, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Luxembourg, the Netherlands, Norway, Poland, Portugal, Slovakia, Slovenia, Spain, Sweden, Switzerland, Turkey, and the United Kingdom.

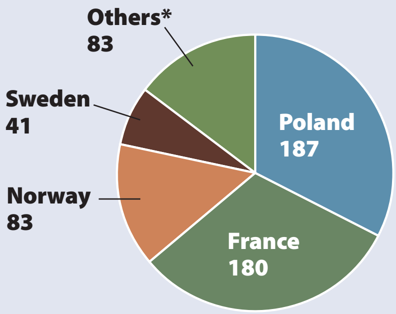
33 Gas Strategies, 2010

34 ICF estimates and EIA AEO 2011 forecasts

35 U.S. EIA, 2011a

Figure 13

EIA Estimate of OECD Europe's Shale Gas Technically Recoverable Resources (574 Tcf total)[36]

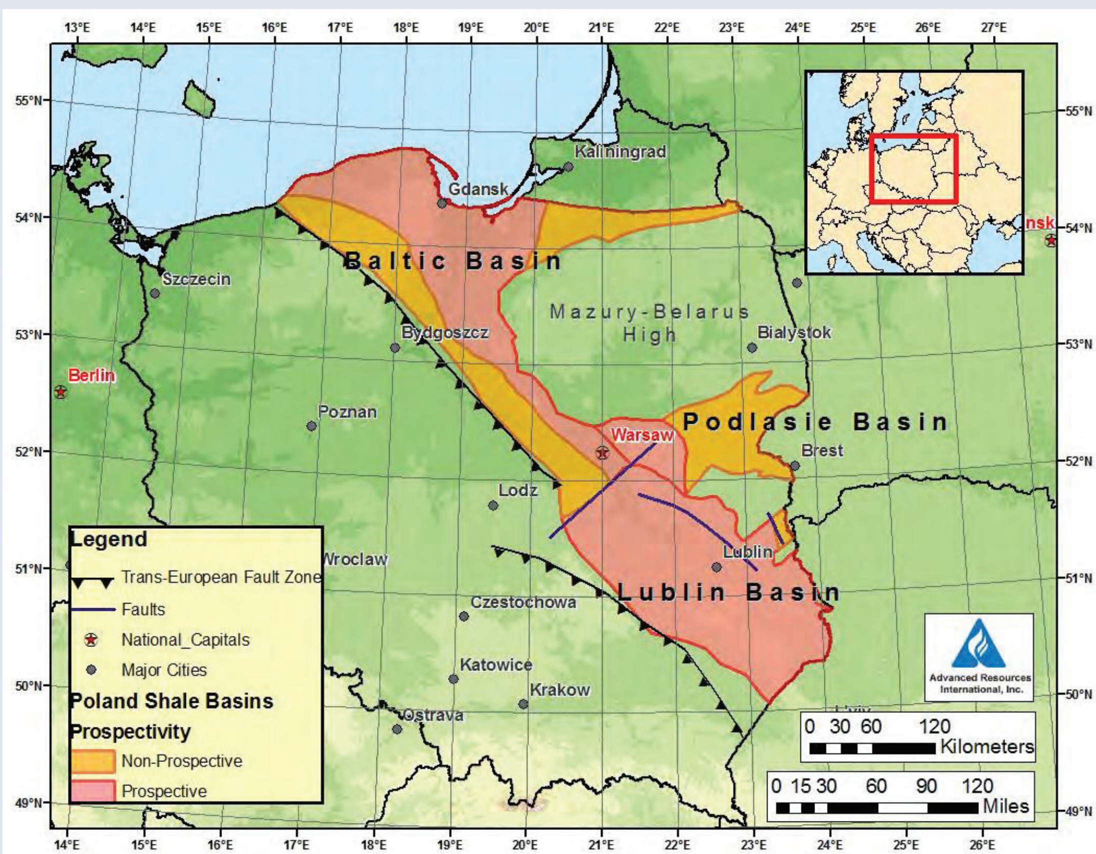


* Others include Denmark (23 Tcf), United Kingdom (20 Tcf), the Netherlands (17 Tcf), Turkey (15 Tcf), and Germany (8 Tcf)

Note: Figures exclude the resource base of Hungary (OECD member), as an estimate is unavailable. OECD Europe Shale estimate of 574 Tcf represents 90% of total Europe shale estimate. Figures exclude Ukraine (42 Tcf); Lithuania (4 Tcf); and Romania, Hungary, and Bulgaria (19 Tcf).

Figure 14

Poland's Shale Gas Resource Base[37]



concerns. Water scarcity is another issue that may curb development in some countries. Moreover, there is also a lack of shale gas production expertise and equipment, as well as requisite drilling service companies. In addition, most of Europe's gas drilling rigs are not suitable for shale gas extraction.[38]

Despite the potential obstacles to European shale gas development, a number of international oil companies, including Exxon/Mobil, Chevron, and Shell, and a number of independent producers are exploring European shale gas potential. Figure 14 shows current shale gas exploration, taking place primarily in Poland, and until recently, Germany. Poland, the major focus for European shale, currently has 70 shale gas concessions granted to the shale gas production industry, with only two wells known to have been drilled as of late 2010. Figure 15 shows Poland's shale concessions, the largest share of which is made up by U.S. oil and gas firms. Poland relies on coal rather than natural gas as a primary energy source. Poland's push for shale gas production is heightened by a desire to limit gas purchases from Russia and, if possible, develop a gas export market to neighboring countries.

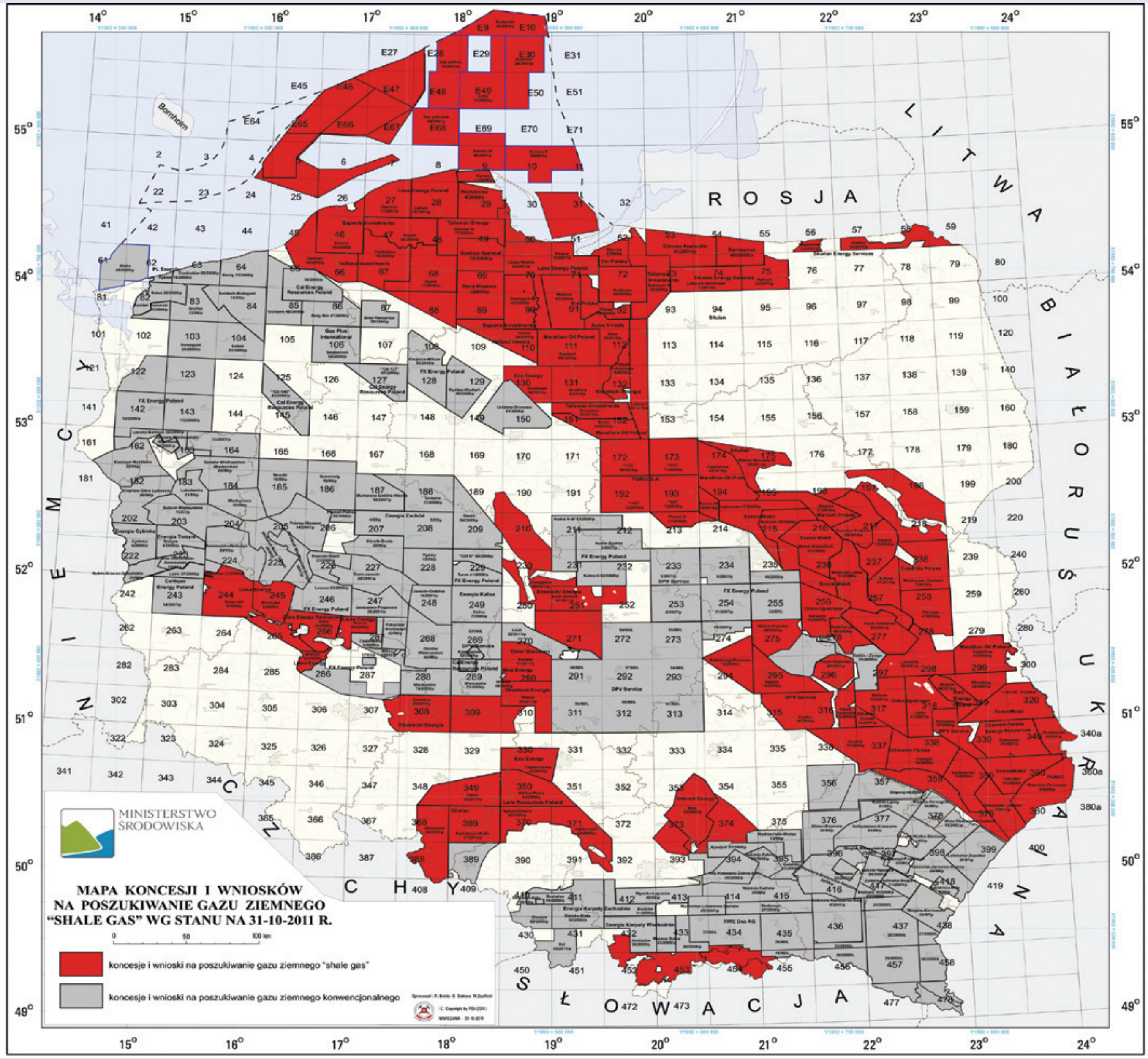
36 U.S. EIA, 2011

37 U.S. EIA, 2011

38 Kuhn & Umbach, 2011

Figure 15

Poland's Shale Concessions[39]



Note: Red-colored areas are shale gas concessions.

While Poland is experiencing the most shale gas exploration activity, other shale gas exploration is spearheaded by Cuadrilla, among others, in the United Kingdom, while exploration in Germany and France is currently on hold due to environmental concerns, with companies such as ExxonMobil, Shell, 3Legs Resources, and Total making plans to pursue drilling when possible.[40]

39 Ministry of the Environment of the Republic of Poland, 2011

40 Kuhn & Umbach, 2011

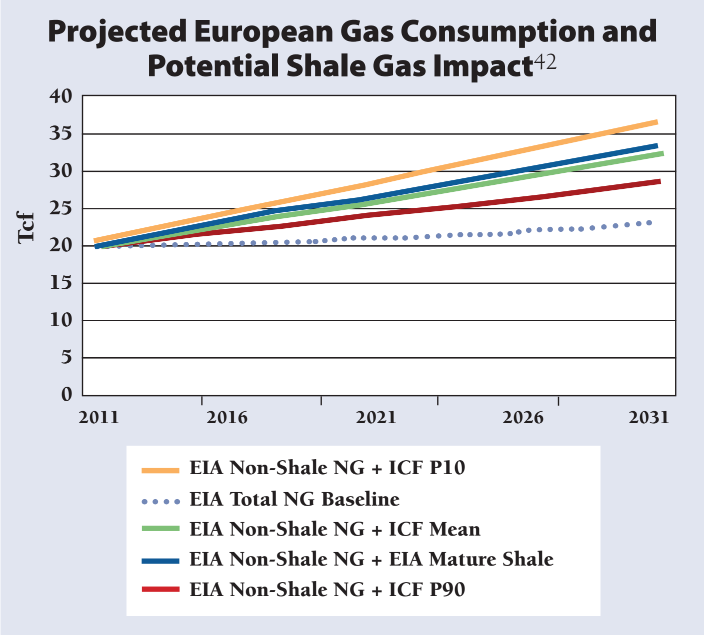
B. European Mature Shale Gas Production and Potential Coal Displacement

i. European Mature Shale Gas Production

Despite the sizable European shale gas resource, a number of sources do not see Europe's shale gas industry as optimistically as the U.S. industry, given the public opposition, varied nature of the shale gas basins around Europe (more so than in the United States), lack of auxiliary services and equipment, and anticipated higher extraction costs. Some estimate Europe's shale gas extraction costs could reach $8-12/MMBtu, versus U.S. estimates of $3-7/MMBtu (which continue to decline).[41]

Despite this, a small number of countries in Europe are in the initial stages of shale gas exploration. Successful industry development could mean a dramatic change in the structure of the region's gas trade, as the region is currently heavily dependent on gas imports. ICF's estimate for mature shale production, based on a mature production level of 2 percent of the EIA's estimate for OECD Europe's resource base of 574 Tcf, reaches nearly 12 Tcf in annual peak production. The three ICF probability estimates give a range of 7 Tcf to 15 Tcf by 2035. Given the region's nascent stage of shale gas exploration, ICF assumed a start date for the shale gas production of 2016. Figure 16 compares ICF's projected ramp-up of shale gas production to the EIA's current projection of total European gas consumption. The EIA natural gas baseline is ICF's estimation of the EIA projection of non-shale gas consumption. The other four lines show the range of potential contributions from shale gas, including the three ICF top-down estimates and an estimate based on the resource base in the EIA shale gas report.

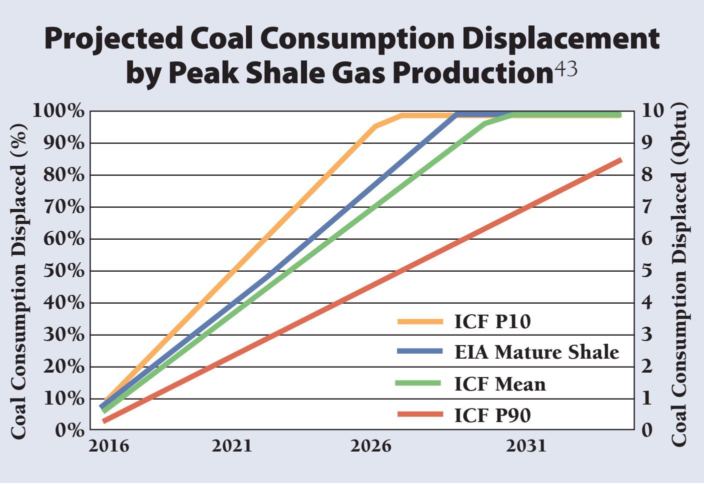
Figure 16



ii. European Potential Coal Displacement

As seen in Figure 17, Europe's potential to displace coal consumption is significant if all shale gas development were dedicated to displacement of coal in the electricity sector. Based on the EIA forecast for coal-fired generation and the mature shale gas production estimated previously, shale gas could displace all of Europe's forecasted coal consumption for power generation as early as 2028, or 11 years after beginning its shale gas production ramp-up. ICF's lowest range estimate gives a coal displacement of 86 percent in 2035. As noted earlier, the coal displacement is greater than the shale gas consumption due to the higher efficiency of gas combined cycle power plants. Also, while all gas production might not be devoted to replacing coal, the potential for shale gas production to exceed Europe's coal consumption makes it even more likely that gas would be consumed for other uses such as residential, commercial, and industrial applications or even exports.

Figure 17



41 Ernst & Young, 2011

42 ICF estimates and EIA International Energy Outlook 2011

43 ICF estimates and EIA International Energy Outlook 2011

C. European Gas Infrastructure

i. European Shale Gas Supply and Demand

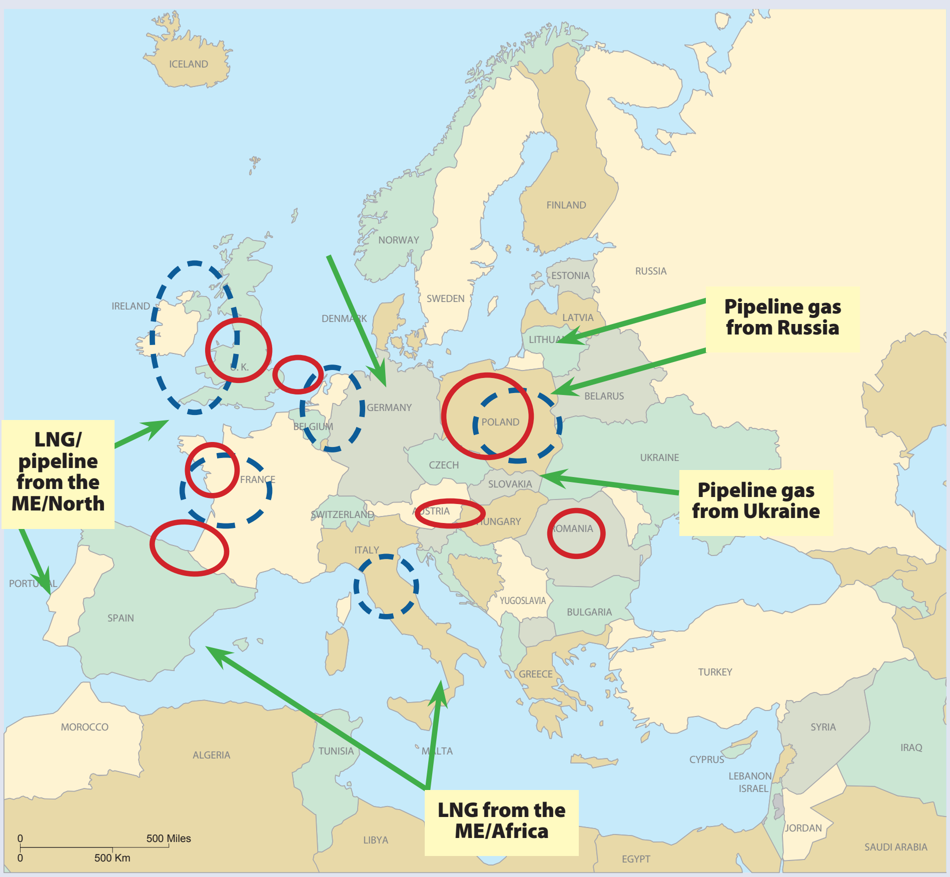
Figure 18 shows the sources of European gas supply and major consuming regions. Europe obtains its gas supplies from four major sources: Russia via pipeline, LNG shipments and pipeline gas from the Middle East/North Africa (as of 2011),[44] supplies from the North Sea, and other domestic production. European energy security is vulnerable to global energy movements, as 46 percent of Europe's 2008 natural gas was imported.[45] Europe's primary gas producers are associated with North Sea production (Norway, the United Kingdom, and the Netherlands), while imports come primarily from Russia and Algeria.[46,47]

Gas demand is expected to see continued growth in Europe, spurred by fast growth within the power generation sector, as both a replacement for coal-fired plants and as a backup for renewable sources.[49] Germany may see the highest growth, with expectations that a number of its nuclear facilities may be retired in light of Japan's recent nuclear crisis and ongoing environmental concerns.[50] Poland is expected to see high growth in gas demand, a function of both retirement of coal plants for emissions compliance and to offset increased emissions associated with rising incomes (e.g., transportation-related emissions). Spain is also expected to see fast gas demand growth to offset expected nuclear retirements (both a function of the Japanese nuclear scare and water scarcity issues, which affect nuclear generation). Other intensive users of natural gas such as the United Kingdom, France, and Italy are also expected to see rapid demand growth.

Figure 18

European Natural Gas Transport Pathways[48]

Areas circled in red indicate large shale gas basins, areas circled in a blue dashed line indicate high current/future demand areas, and green arrows show main supply sources for Europe.



ii. Distribution Infrastructure

Europe remains highly dependent upon Russian gas supplies and continues to diversify supply, despite the recent construction of the Nord Stream pipeline connecting Germany and the United Kingdom to Russia's northern Shtokman fields, which will promote continued dependence on Russian gas

44 The Medgaz pipeline from Algeria to Spain began exporting gas in 2011, and the Galsi pipeline from Algeria is expected to be completed in 2014. U.S. EIA, 2011b

45 U.S. EIA, 2011b

46 Kuhn & Umbach, 2011

47 Mearns, 2007

48 ICF

49 U.S. EIA, 2011b

50 U.S. EIA, 2011b.

Figure 19

Natural Gas Pipeline Connections to Europe[52]

supplies. The Nord Stream pipeline, flowing into the heart of Europe's industrial production centers, will mean potential vulnerability to Russian price changes. However, pipeline connections from North Africa to southern Europe have increased imports from that region (along with LNG imports).[51] Although many speculate on the potential of projects from

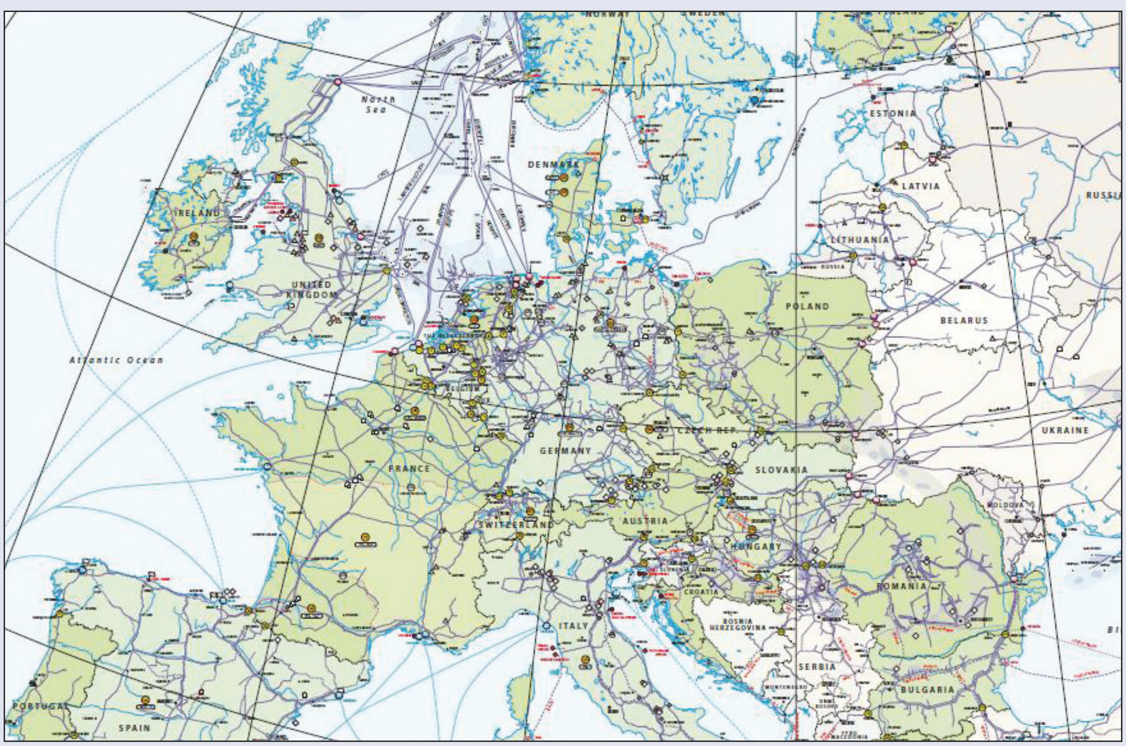
51 U.S. EIA, 2011b

52 *Economist*, 2010

53 European Network of Transmission System Operators for Gas (ENTSOG) http://www.entsog.eu/download/maps_data/ENTSOG_CAP_August2011.pdf

Figure 20

European Natural Gas Network[53]

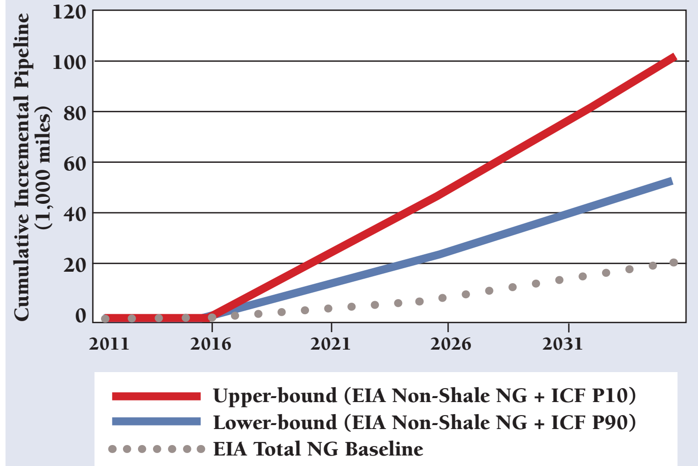


Turkey and the Caucasus states such as Nabucco (meant to rival Russian gas supplies) and South Stream (a Russian pipeline project), the abundant gas supplies from the Caspian Sea area and lack of markets for Caucasus states ensures that an interconnection between Europe and these areas will eventually be available. Figure 19 shows the main pipelines to Europe, and Figure 20 shows Europe's complete natural gas network.

Development of gas resources and expanded consumption within Europe will require additional gas infrastructure within Western Europe. Europe would need cumulative incremental pipeline of 53,000 to 101,000 pipeline miles by 2035 to meet the lower-bound and upper-bound pipeline miles for shale gas development, respectively. For reference, Europe had roughly 91,000 total pipeline miles in 2010 (see Section 2.3 for an explanation of the methodology used).[54]

Figure 21

Projected Cumulative Incremental Natural Gas Pipeline Requirement[55]



54 *CIA World Factbook*, 2012

55 ICF analysis of the U.S. EIA, CIA World Factbook data, and ICF estimates

5 India

A. Indian Shale Gas Resource Assessment

Indian gas production in 2010 totaled 1.9 Tcf, with consumption reaching 2.4 Tcf, driven by the power, fertilizer, and industrial sectors.[56] India began importing LNG in 2004, with total gas imports of roughly 0.5 Tcf in 2010. According to the EIA, Indian consumption of natural gas is expected to more than double to 5.1 Tcf by 2035.[57] In fact, the consumption of gas in India is limited only by the supply of gas, as demand is higher than supply, despite increasing LNG imports. India's push for shale gas extraction therefore is led in part by rising demand across the country, as well as energy security considerations. Shale gas is in its infancy in India, as the country's first well was completed in January 2011.[58]

Shale resources in India are not well understood at present. The EIA study suggests that India could have 63 Tcf of technically recoverable shale gas resources.[59] Figure 22 illustrates India's five main shale gas basins (in orange), along with other prospective basins. The mature shales that are more likely to have recoverable natural gas are in the Cambay, Krishna Godavari, Cauvery, and Damodar basins. The U.S. State Department and the USGS, in cooperation with India's Directorate General of Hydrocarbons (DGH) and the Ministry of Petroleum and Natural Gas (MoPNG), have begun a program to assess the shale potential.[61] As more drilling takes place, it is expected

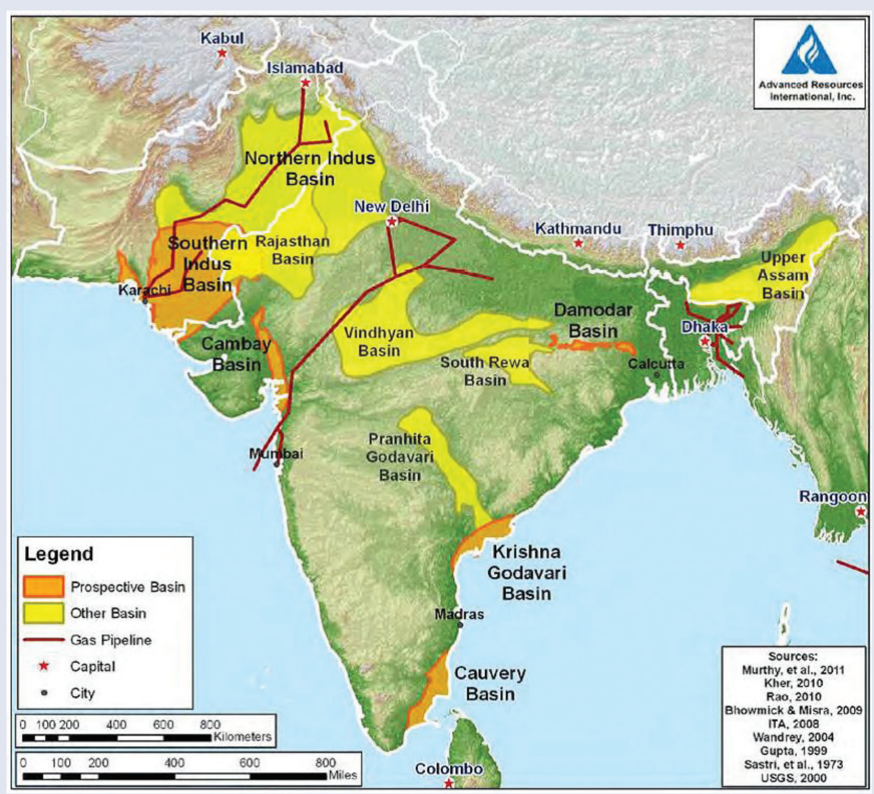
Table 7

Estimates of Indian Shale Gas Resource (Tcf)[60]

EIA Estimate	ICF P90 Estimate	ICF Mean Estimate	ICF P10 Estimate
63	80	280	565

Figure 22

Indian Shale Gas Basins and Natural Gas Pipelines[62]



56 U.S. EIA, 2011b

57 U.S. EIA, 2011b

58 U.S. EIA, 2011b

59 U.S. EIA, 2011a

60 ICF estimates and EIA AEO 2011 forecasts

61 U.S. EIA, 2011a

62 U.S. EIA, 2011

that the estimated resource base for shale gas will increase. ICF's top-down estimate for the technically recoverable resources ranges from a P90 estimate of 80 Tcf to a P10 estimate of 565 Tcf, with a mean of 280 Tcf.

India has 26 proven and prospective petroliferous basins, with an estimated areal extent of about 537,000 square miles of on-land basins, 154,000 square miles of offshore, and 521,000 square miles in deepwater. The total sedimentary area of 1.2 million square miles is categorized based on prospectivity into four categories. Shale basins in India are quite geologically complex, with extensive fault lines running through the isolated basins.[63] Although assessed shale gas basins are quite thick, little is known of the potential for gas extraction. At present, only 20 percent of India's potential gas basins are well explored, with the rest in either early stages of exploration or yet to be explored. This indicates the significant uncertainty in determining India's potential for domestic natural gas supply, particularly shale gas. The Oil and Natural Gas Corporation (ONGC), India's largest oil and gas producer, recently completed India's first experimental shale gas well in the Damodar Basin in northeastern India (near Calcutta).[64]

B. India's Mature Shale Gas Production and Potential Coal Displacement

i. India's Mature Shale Gas Production

Although India has no current production of its shale gas resources, exploration of both well drilling technologies and resource base assessments is underway. ICF's estimate for mature shale production, based on a 2-percent mature production level of the EIA's estimate of 63 Tcf for the Indian technically recoverable resource base, reaches 1.3 Tcf. The estimate based on ICF's top-down estimates ranges from 1.6 Tcf to 11.3 Tcf. A 2016 start date for the shale gas production ramp-up is assumed, given the early stage of India's shale gas exploration. Figure 23 shows the total impact of the four shale gas production estimates on the EIA's natural gas consumption forecasts.

ii. Indian Coal Displacement Potential

Figure 24 illustrates the potential power sector consumption of shale gas production and potential share of coal consumption displaced based on the mature gas production estimates. Assuming a continuous 20-year ramp-up period, total shale gas production has the potential to displace 9 percent of Indian domestic coal consumption, based on the EIA mature shale gas production estimate, or a range of 11-76 percent, based

Figure 23

Projected Indian Gas Consumption and Potential Shale Gas Impact[65]

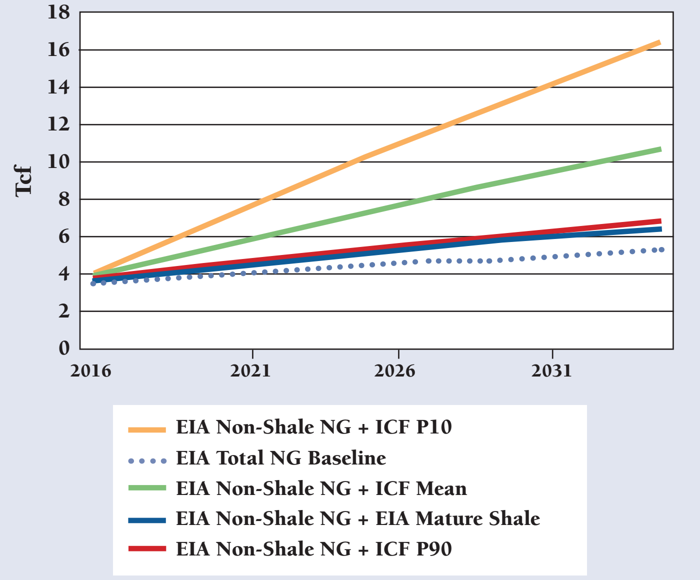
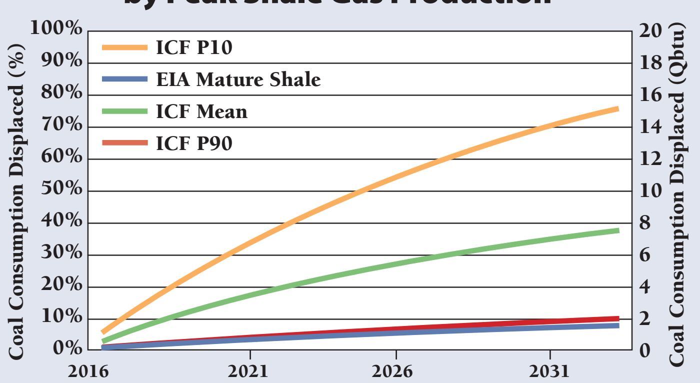


Figure 24

Projected Coal Consumption Displacement by Peak Shale Gas Production[66]



63 U.S. EIA, 2011a

64 ICF, 2011b

65 ICF estimates and EIA International Energy Outlook 2011

66 ICF analysis of the U.S. EIA, CIA World Factbook data, and ICF data

on ICF's range. The coal consumption displacement figures exceed total shale gas production due to the higher efficiency of gas combined cycle plants compared to coal plants. Displacement of coal by shale gas, as mentioned in earlier sections, is only a theoretical exercise to illustrate the potential of shale gas production. The price of coal in India is quite low, thus natural gas prices would have to remain competitive with those of coal to actually displace coal consumption.

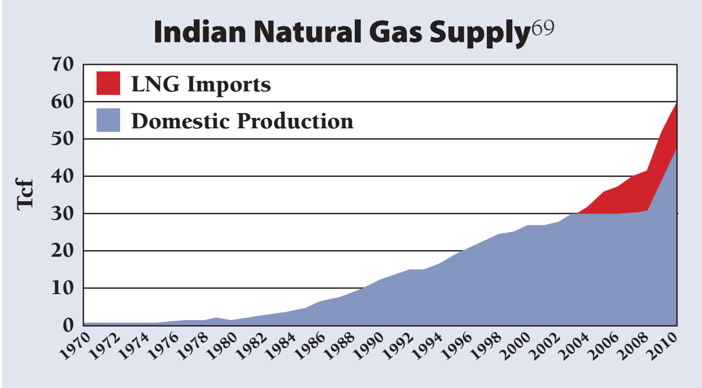
C. Indian Gas Infrastructure

i. Shale Gas Supply and Demand

India relies primarily on domestic conventional gas supplies, although LNG imports were first introduced into India in 2003 and have risen steadily since then, as shown in Figure 25.[67] Natural gas has become a vital energy source for India's economy, and has now firmly established itself in India's fuel mix. Domestic gas production increases have been driven mainly by east coast offshore resources, although production rates in the region, particularly the Krishna Godavari basin, have not met initial expectations, which may lead to domestic supply issues. Successful shale gas production may supplement the production losses seen in the Krishna Godavari basin. Domestic production as it is currently understood will be insufficient to meet the potential future consumption. To balance the total forecast demand, additional supply must be assumed to come from LNG imports, in the absence of shale gas development. In other words, the gap between potential demand and Indian domestic supply will be closed through LNG imports unless there is a major expansion of the domestic gas production. Although India is expected to see LNG imports over the foreseeable future, governmental support for development of a domestic shale gas industry continues to grow. A comprehensive shale gas policy is expected to be announced this year. One shale gas well was reported by the state-owned ONGC, in collaboration with Schlumberger.[68] The well was later shut down due to operational issues.

Gas demand in India can be expected to increase with the growth in the Indian economy, particularly growth in electricity. The Indian power system is dominated by coal generation; coal prices are not fully liberalized and are relatively low compared to international prices. Existing gas demand in the power sector is a function of gas resources and allocation policy rather than simply demand-supply

Figure 25



fundamentals. Three states, Maharashtra (northwest), Gujarat (northwest), and Andhra Pradesh (central-east), together consume more than 60 percent of the gas supplied to the power sector.[70] These states are likely to dominate gas demand in the short term because of foreseeable gas infrastructure constraints restricting emergence of new gas demand centers.

Electricity demand is, however, expected to grow faster than domestic coal supply, implying a greater requirement for fuels other than domestic coal. Given the constraints around the rapid increase of domestic coal supply due to environmental and social concerns, as well as the high price of fuel oil and naphtha, natural gas and imported coal will likely fill the demand-supply gap in the fuel mix. Indeed, the share of natural gas in the total primary energy consumption in India increased from approximately 1.3 percent in 1980-1981 to more than 9 percent in 2008-2009.[71]

As India's gas infrastructure continues to develop, there is expected to be a much wider geographic spread of gas demand. Punjab and Haryana are expected to emerge as key gas demand hubs in the North. Northeastern states are expected to double their share of gas demand in the longer run. Goa in the western region and Kerala in the southern region are the other two emerging demand centers. Figure 26 illustrates current and future demand and supply locations.

67 ICF, 2011b

68 Oil & Gas Journal, 2012

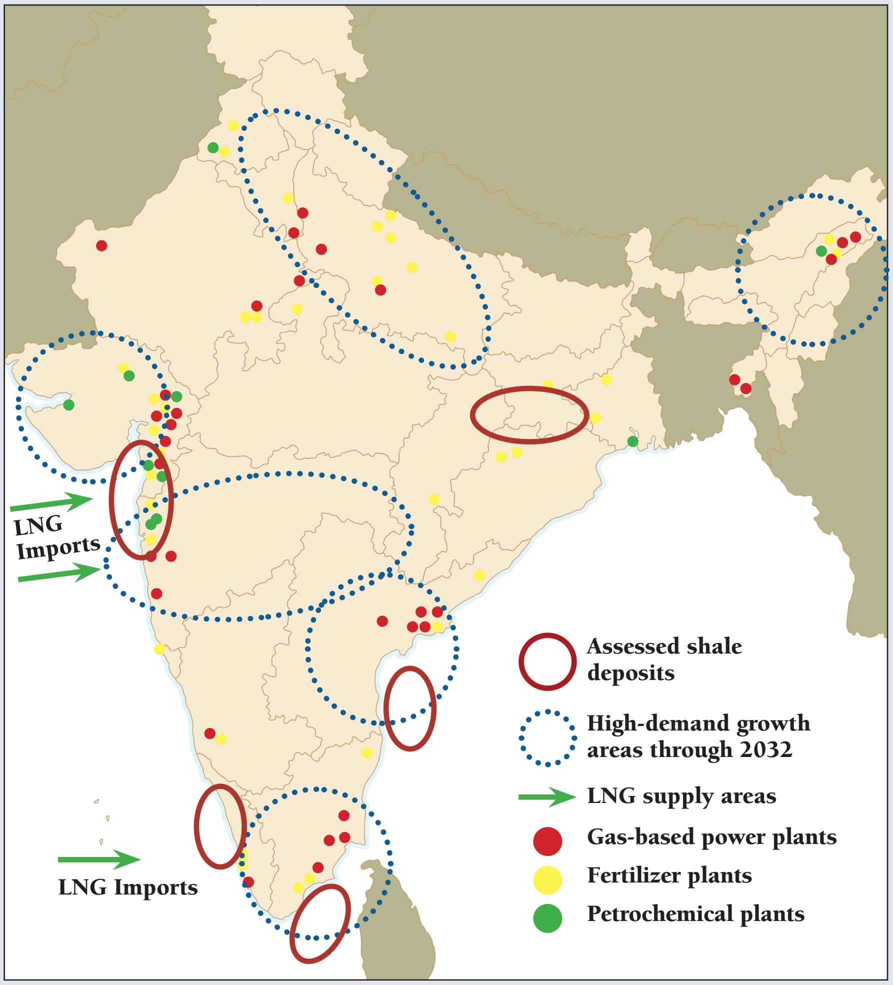
69 ICF, 2011b

70 Oil & Gas Journal, 2012

71 Oil & Gas Journal, 2012

Figure 26

Major Indian Gas Demand and Supply Areas[72]



has been slow, however, and each of them is facing uncertainty. Despite this, any additional gas supplies from these cross-border pipelines would also alleviate supply constraints in India.

Domestic gas infrastructure development is focused on linking the key demand areas along the southern part of the country to the supply regions in the east and the west, as well as expanding the pipelines in the northern areas. India is also pushing toward development of its gas infrastructure (termed National Gas Highways) as part of increasing the overall economic development in different regions of the country. These Natural Gas Highways are defined as gas pipelines to serve communities and regions that would not attract such investment without government support. Figure 27 shows existing and planned gas transmission pipelines.

In terms of cumulative incremental pipeline required to meet forecasted natural gas consumption, India may require between 20,000 and 68,000 in additional pipeline miles by 2035. The lower-bound 2035 cumulative incremental pipeline miles figure of 20,000 miles is based on the ICF P90 (low estimate) for mature shale gas production plus the EIA non-shale gas consumption estimate. The upper-bound figure is based on the EIA non-shale gas consumption forecasts plus ICF's P10 mature shale gas production forecast. For reference, India had roughly 6,000 total pipeline miles in 2010.[73] A study conducted by ICF on behalf of the Indian Ministry of Oil and Gas, a study that did not include assessment of shale gas production, found that a network of 16,400 miles of pipeline would be

ii. Gas Distribution Infrastructure

Much of the consumption of gas to date has been shaped by government policy and by limitations on gas supply and transportation capacity. Demand for gas therefore remains higher than supply, while actual consumption is limited by supply and infrastructure limitations. As natural gas supply increases, however (through increased domestic production, including shale gas and LNG imports), and continued development of a pipeline grid, more gas can be made available across India and consumption of gas can be expected to increase. The high demand for gas is one of the key elements driving the construction of new pipelines.

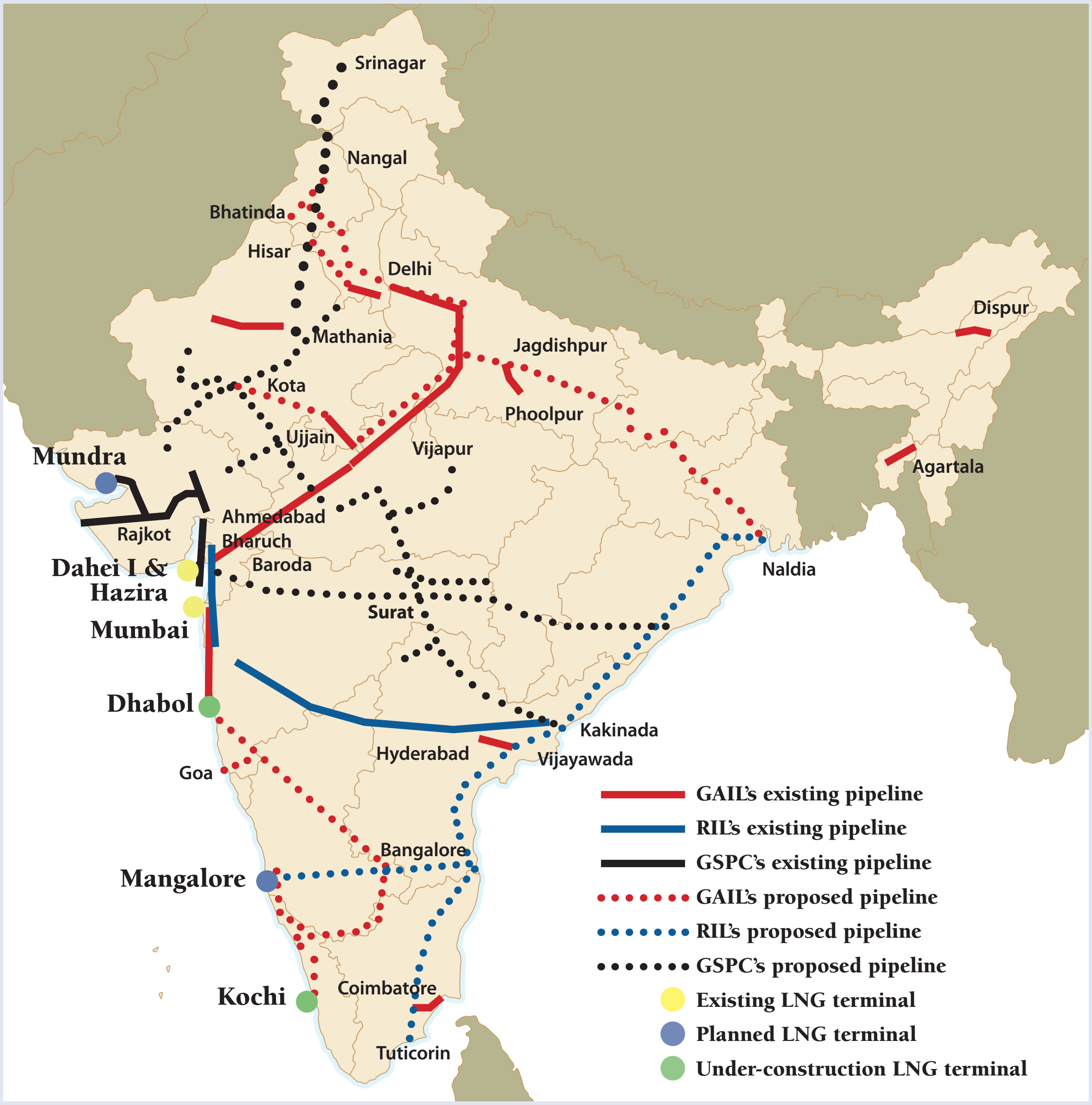
A number of cross-border pipelines from countries such as Iran, Turkmenistan, Myanmar, and Bangladesh are being explored and are attracting interest. The progress

72 Source: ICF, 2011b

73 CIA World Factbook, 2012

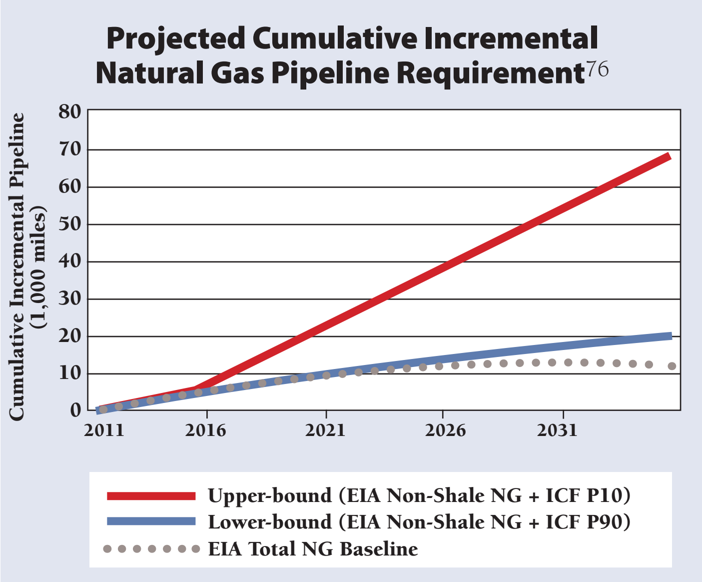
Figure 27

Existing and Planned Indian Gas Transmission Pipelines[74]



74 ICF, 2011b

Figure 28



required by 2032, with ultimate design loading of roughly 10.5 Tcf (821 million standard cubic meters per day), required to meet India's demand that year.[75] Although the study's pipeline design was not aimed at exploiting shale gas, the pipelines could potentially accept shale gas supplies. Given that the study did not include assessment of shale gas production potential, pipeline miles required are well below those estimated in this report.

75 ICF, 2011b

76 ICF analysis of the U.S. EIA, CIA World Factbook data, and ICF estimates

6 China

A. China Shale Gas Resource Assessment

China's shale gas production remains limited to experimental well drilling in the Sichuan basin, with aggressive plans for future development. Although China has seven major onshore shale basins thought to contain shale gas, just two (Sichuan in the southeast and Tarim to the northwest) are suited for near-term commercial development, given the low clay content and high organic content of the basins, which improve the quality of the natural gas.[77] Figure 29 shows China's major shale gas basins.

Table 8

Estimates of Chinese Shale Gas Resource (Tcf)[79]

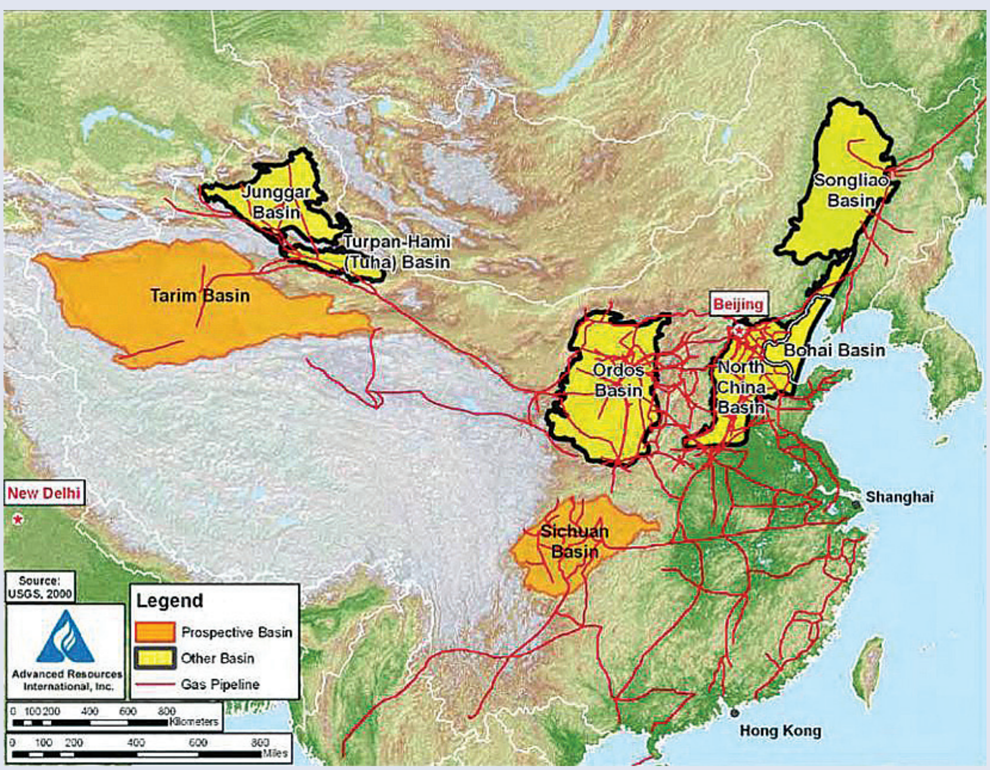
EIA Estimate	ICF P90 Estimate	ICF Mean Estimate	ICF P10 Estimate
1,275	240	820	1,670

The EIA estimates the Chinese technically recoverable shale gas resource base at 1,275 Tcf, the equivalent of 440 years of 2009 Chinese natural gas consumption.[80] ICF's top-down estimate for the technically recoverable resources ranges from a P90 estimate of 240 Tcf to a P10 estimate of 1,670 Tcf, with a mean of 820 Tcf.

Although China's natural gas use makes up just 4 percent of its energy mix currently, the government's recent 12th Five-Year Plan has a goal to increase the share of natural gas to 10 percent by 2020 in an effort to usher in cleaner fuels.[81] China's National Energy Administration has proposed a shale gas production target of

Figure 29

Chinese Shale Gas Basins and Pipeline System of China[78]



77 Hart & Weiss, 2011

78 U.S. EIA, 2011

79 ICF estimates and EIA AEO 2011 forecasts

80 British Petroleum, 2010 and U.S. EIA, 2011b

81 Hart & Weiss, 2011

229 Bcf annually by 2015 and 2.8 Tcf annually by 2020.[82] The central government, however, has not yet approved those figures.

Although China's dependence upon natural gas imports will likely grow over the next two decades, China sees shale gas as a potential source to curb energy imports. As such, the country plans to subsidize shale gas development.[83] In 2009, the United States and China developed a Sino-U.S. initiative for developing China's shale resources that will include resource assessments in northern China and Jiangsu Province. In 2010, China announced that the country will allow foreign companies to form joint ventures with Chinese firms to jointly bid on six auctions covering 40,000 square miles in 2011. Sinopec, one of China's three large oil and gas companies, anticipates 240 mmcfd of shale production (88 Bcf per year) by 2015, with a long-term production goal of 3,000 mmcfd (1.1 Tcf per year), while China National Petroleum Company (CNPC), another of China's leading oil and gas producers, estimates shale gas production alone will reach 48 mmcfd (18 Bcf per year) by 2015.[84] PetroChina, the listed (public) subsidiary of CNPC, one of China's three major state-owned oil companies, announced it has drilled 20 wells in the Sichuan basin, with favorable results.[85]

China's National Energy Administration recently released its first five-year plan for shale gas development, which will be used to implement policies and a pilot shale gas program.[86] The plan sets a goal of annual shale gas production of 228 bcf (6.5 billion cubic meters, bcm) by 2015 and 2.1 Tcf (60 bcm) by 2020, an aggressive goal that may prove difficult to meet, given the nascent stage of China's shale gas industry, as well as technologic and geologic issues and low natural gas prices (which do not promote gas development).[87] The plan highlights the importance of cooperation with foreign producers such as Shell and Chevron that are currently involved in shale gas exploration joint ventures in China.

In July 2011, China drilled its first experimental horizontal shale gas wells in the Sichuan basin in an effort to kick off a domestic shale program with its joint venture partner, Shell.[88] Given the proximity to the fast-expanding southeastern markets, better access to water supplies, and the political unrest seen in the Northwest, the smaller Sichuan Basin will likely see much faster development than its counterpart to the Northwest, Tarim.

In an effort to gain expertise in the shale gas industry, a number of Chinese oil and gas companies, including the China National Offshore Oil Corporation (CNOOC), have engaged in overseas acquisitions. CNOOC agreed to a 33-percent stake in Chesapeake Energy's Niobrara shale gas venture in Colorado and Wyoming, after paying $1 billion for ownership of one third of Chesapeake's Texas shale operations.[89]

Despite China's ambitious push for shale gas development, numerous challenges to successful production exist, including:

Limited pipeline access. Given the small share of natural gas in China's current energy mix, gas pipelines are limited. As China makes a push to expand its natural gas consumption, pipeline infrastructure will be critical to this goal.

Water access. China's impending water crisis may limit shale gas development, which requires large amounts of water for hydraulic fracturing. In light of the country's water shortage, China strictly limits water use and disposal, often shutting down industrial firms not adhering to water-related policies.[90]

Limited technical prowess. Domestic Chinese shale gas firms are largely dependent upon foreign firms for technologic knowhow on shale gas development. With shale gas extraction in the early stages in the United States, which has more favorable shale structures (see "Geologic issues" below), transplanting such technologies to China's shale fields will require adaptation. China's gas firms will depend in large part on foreign counterparts for this. Foreign firms are included in joint ventures only as minor shareholders, however, with little to no operational authority. Along with employing foreign experts, China

82 Hart & Weiss, 2011

83 Zhou, 2011

84 Seeking Alpha, 2010

85 China Mining Association, 2011

86 Hook, 2012

87 Hook, 2012

88 National Development and Reform Commission (NDRC), 2011

89 Zhou, 2011

90 Hart & Weiss, 2011

is also acquiring expertise through acquisitions abroad, evidenced in CNOOC's agreement to buy a 33-percent stake in Chesapeake Energy's Niobrara shale project in Colorado and Wyoming.[91]

Lack of regulatory enforcement. Both with regard to enforcement of intellectual property rights of foreign technology and local-level enforcement of environmental regulations (aside from water-related), lack of coherent regulations and enforcement could adversely impact China's air and water, the reputation of the industry itself, and local populations.

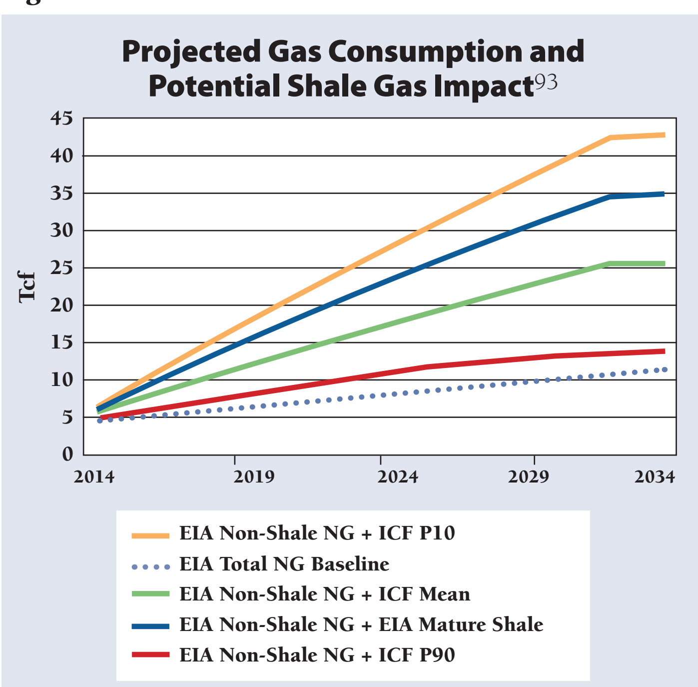
Geologic issues. China's shale formations are significantly deeper and older than those typically seen in the United States, with significantly higher hydrogen sulfide content.[92] Hydrogen sulfide is a poisonous gas that is highly corrosive and can corrode drilling equipment in addition to polluting the air. Shale gas extraction will require unique extraction technologies.

B. Chinese Mature Shale Gas Production and Potential Coal Displacement

i. Chinese Mature Shale Gas Production

ICF's estimate for mature shale production based on a 2-percent peak production level of the EIA resource base reaches nearly 26 Tcf annually at peak. A start date for the shale gas production ramp-up is assumed at 2014. ICF's estimates for 2035 mature shale gas production based on the ICF top-down resource estimate ranges from 5 Tcf to 33 Tcf, with a mean of 16 Tcf. Figure 30 represents the impact of the four mature shale gas production estimates on China's natural gas consumption.

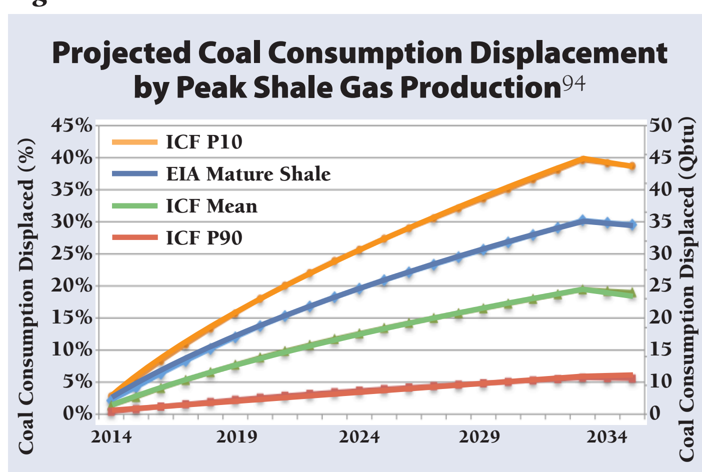
Figure 30



ii. Chinese Coal Displacement Potential

As seen in Figure 31, total projected shale gas production has the potential to displace up to 30 percent of domestic coal consumption, using the mature shale gas estimate based on the EIA resource estimate, or between 6 and 39 percent, based on ICF's resource estimates (with a mean of 19 percent displacement). Figure 31 illustrates the total coal consumption displacement potential of shale gas production. ICF assumes a 20-year ramp-up in shale gas production, beginning in 2014. Starting in 2034, displacement of coal consumption by shale gas declines slightly, as a shale gas production after 2033 remains static while coal consumption continues to grow.

Figure 31



91 Zhou, 2011

92 Zhou, 2011

93 ICF estimates and EIA International Energy Outlook 2011

94 ICF estimates and EIA International Energy Outlook 2011

C. Chinese Gas Infrastructure

i. Shale Gas Supply and Demand

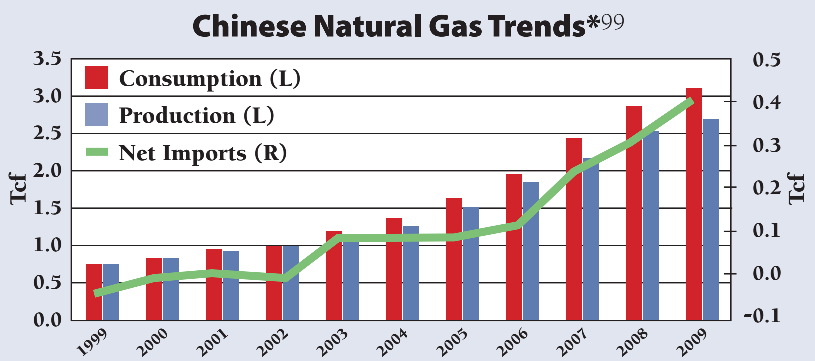
As of 2009, China was the tenth largest natural gas producer, with 2.7 Tcf of production. China's fast-growing consumption, however, which reached 3.1 Tcf that year, has meant significant and growing imports (see Figure 32). Between 1999 and 2009, China's natural gas trade grew from 40 Bcf in net exports to 420 Bcf in net imports.[95] China's natural gas consumption made up roughly 3 percent of China's total energy mix for 2009.[96]

According to the U.S. EIA, China's natural gas consumption is expected to grow an average of 5 percent annually between 2009 and 2035 to 11.5 Tcf, and is expected to make up 14 percent of the incremental increase in global natural gas consumption between 2009 and 2035 (which does not include ICF's potential shale gas production figures).[97] Chinese incremental year-on-year consumption increases will nearly quadruple those of the rest of the world through 2035, which also does not include ICF's potential shale gas production (see Figure 33). China's natural gas consumption increases will be boosted by the central government's push to increase natural gas consumption to 10 percent of the country's total energy mix by 2020, up from 3 percent in 2009 (compared to a world average of 22 percent in 2009), which does not include ICF's potential shale gas production.[98]

Electricity consumption throughout China is likely to rise faster than total energy consumption growth, spurred by expansion of the electricity grid, urbanization (and associated electrification), China's "Go West" policy of inland development, and continued industrial growth. The country's efforts to support more sustainable development through improvements in energy efficiency and use of cleaner fuels will also promote an increase in natural gas consumption. In terms of industrial production, China will continue to move from low-end industrial manufacturing to more sophisticated, value-added production and development of its services sector, which will likely coincide with higher demand for cleaner fuels and improved energy efficiency. As the country moves toward domestic consumption-led growth, more high-tech production of petrochemical processing may require natural gas, both as a petrochemical feedstock and increasingly as a fuel source.

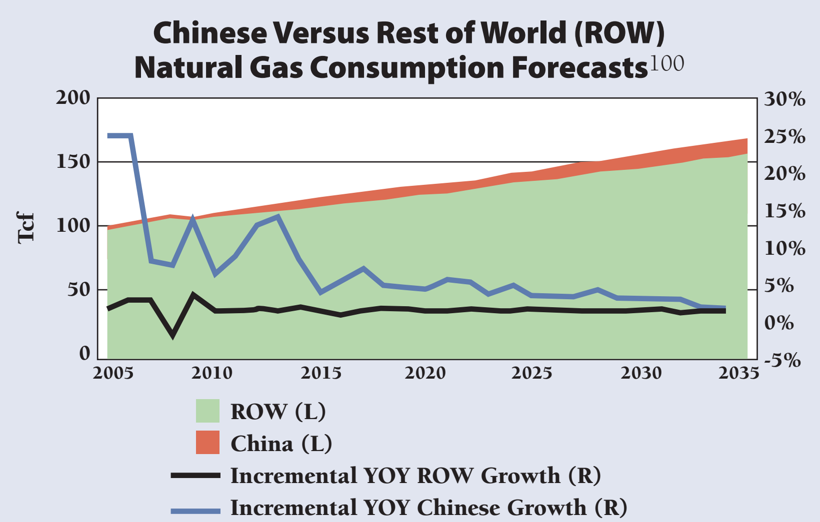
Figure 34 illustrates China's current natural gas supply sources (illustrated with green arrows), which are primarily gas pipelines from western China, Kazakhstan/Turkmenistan, and LNG imports to the coastal south. Dashed-line

Figure 32



** Figures converted from bcm to Tcf using a conversion factor of 0.035 bcm: 1 Tcf*

Figure 33



95 British Petroleum, 2010.

96 U.S. EIA, 2010

97 U.S. EIA, 2010 and U.S. EIA, 2011b

98 U.S. EIA, 2011b

99 British *Petroleum*, 2010

100 ICF Analysis of U.S. EIA's International Energy Outlook 2011

Figure 34

East Asian Oil and Natural Gas Pipelines[101]

Note: *Areas circled in orange indicate shale gas deposits, areas circled in a blue dashed line indicate major current and future demand areas, and the green arrows indicate foreign gas supply sources.*

Oil Pipeline
Oil Pipeline (planned/under construction)
Gas Pipeline
Gas Pipeline (planned/under construction)
Products Pipeline
Products Pipeline (planned/under construction)

B12 Inter-Country Oil Pipeline Label
B12 Cross-Border Oil Pipeline Label
B12 Inter-Country Gas Pipeline Label
B12 Cross-Border Gas Pipeline Label
B12 Inter-Country Products Pipeline Label
B12 Cross-Border Products Pipeline Label

arrows indicate future pipelines, discussed in the next section. The Sichuan Basin will likely supply China's current and future high-consumption areas of gas (circled in a dashed blue line) for industrial, power generation, and residential use.

ii. Gas Distribution Infrastructure

As of 2010, China's gas pipeline mileage totaled 24,000 miles, which includes a gas pipeline network from Kazakhstan that connects to the West-East pipeline from Kazakhstan to Shanghai, a substantial source of gas for China.[102] China is currently developing a second West-East pipeline from Xinjiang province (in the northeast) to Guangzhou (a fast growing market to the coastal south), as well as an expansion of the Kazakh gas pipeline to Turkmenistan.[103] China has since announced plans to potentially develop a third and fourth West-East pipeline, from western Xinjiang and either the Tarim or Sichuan Basin for the fourth, with both expected to end up in Fujian province in the coastal south.[104] China also recently began construction of a gas pipeline from Myanmar to the Sichuan area.[105] China is also in talks with Russia for gas supplies, although the two have not yet reached an agreement on pricing.[106] These efforts are intended to both

101 CIA World Factbook, 2008 and Pipelines International, 2011

102 CIA World Factbook, 2011

103 Baizhen, 2011

104 AFX News Limited, 2008 and Asiaport Daily News, 2009

105 Pipelines International, 2011

106 Reuters, 2011

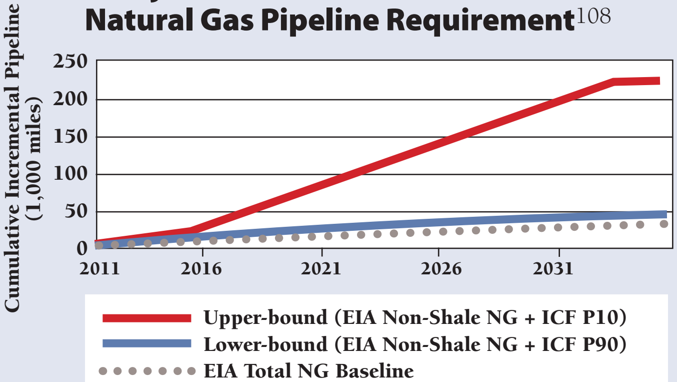
Figure 35

China's Pipeline Infrastructure[107]

increase natural gas use in China to limit use of carbon-heavy fuels while also diversifying natural gas suppliers. Figure 35 illustrates China's pipeline infrastructure.

Figure 36

Projected Cumulative Incremental Natural Gas Pipeline Requirement[108]



With the country's ample shale gas deposit estimates, China has significant potential to displace a sizeable share of its projected coal consumption. In terms of cumulative incremental pipeline required to meet forecasted natural gas consumption, China will require an additional 38,000 miles of pipeline between 2011 and 2035 to meet the EIA's base case estimates for natural gas consumption. ICF estimates, however, that inclusion of peak shale gas production will mean between 50,000 and 220,000 additional pipeline miles. Figure 36 shows the range of cumulative incremental pipeline needed through 2035.

107 U.S. Library of Congress, 1992

108 ICF analysis of the U.S. EIA, CIA World Factbook data, and ICF estimates

7. Shale Gas Resource and Infrastructure Summary

A. Shale Gas Resource Base Assessment

Reliable international shale gas resource estimates for individual countries are sparse, although it is expected that much more information on international shale gas will become available within the next several years. According to the recent EIA study, global technically recoverable shale gas resources (based on assessment of shale gas resources in 32 countries) total 6,622 Tcf, the equivalent of 62 years of 2009 worldwide natural gas consumption. Due to the lack of complete data, the 32-country assessment represents only a fraction of the actual world resources, as only a portion of the potential was studied in each region. Some countries, such as Russia, were excluded completely. Table 9 and Figure 37 show the EIA and ICF shale gas technically recoverable resource base estimates.

Table 9

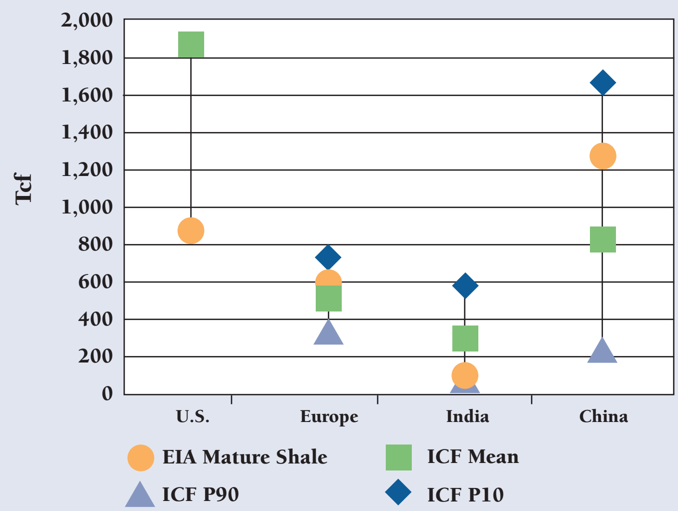
Shale Gas Resource Base[109]

Region	Resource Base Source			
	EIA	ICF P90	ICF Mean	ICF P10
Technically Recoverable Resource Base Assessment (Tcf)				
U.S.	862	N/A	1,863	N/A
Europe	574	340	520	725
India	63	80	280	565
China	1,275	240	820	1,670

Note: P90 indicates a 90-percent probability of that resource base estimate, the mean value represents a 50-percent probability of that resource base estimate, and the P10 value indicates a 10-percent probability that the resource base is that large.

Figure 37

Shale Gas Resource Base[110]



Note: Figures for Europe, India, and China each include ICF's P90 (low estimate), mean, and P10 (high estimate).

B. Peak Shale Gas Production and Potential Coal Displacement

Mature shale production as a share of EIA coal consumption forecasts range considerably. These differences were dependent upon both the total shale gas resource base assessment (used to calculate the mature shale gas production) and each region's total coal consumption.

109 ICF estimates, EIA AEO 2011, EIA International Energy Outlook 2011

110 U.S. EIA, ICF

Table 10

Shale Gas Production and Coal Consumption Displacement Potential[111]

Region	Resource Base Source: EIA	ICF P90	ICF Mean	ICF P10
2035 Shale Gas Peak Production (Tcf)				
U.S.	12.3	N/A	17.7	N/A
Europe	11.5	6.8	10.4	14.5
India	1.3	1.6	5.6	11.3
China	25.5	4.8	16.4	33.4
2035 Peak Shale Gas Displacement of Coal Consumption (%/QBtu)				
U.S.	66% / 16.1Q	N/A	96% / 23.3Q	N/A
Europe	100% / 10.4Q	86% / 9.0Q	100% / 10.4Q	100% / 10.4Q
India	9% / 1.7Q	11% / 2.1Q	38% / 7.4Q	76% / 14.9Q
China	30% / 33.6Q	6% / 6.3Q	19% / 21.6Q	39% / 44.0Q
Current Shale Gas Development Phase				
U.S.	Commercial development; assumed 2007 as commercial shale gas development start date			
Europe	Exploration of selected basins; assumed 2016 as commercial shale gas development start date			
India	Exploration of selected basins; assumed 2016 as commercial shale gas development start date			
China	Exploration of selected basins; assumed 2014 as commercial shale gas development start date			

Note 1: P90 indicates a 90-percent probability of that resource base estimate, the mean value represents a 50-percent probability of that resource base estimate, and the P10 value indicates a 10-percent probability that the resource base is that high.

Note 2: Displaced coal consumption forecasts exceed shale gas production forecasts under the efficiency assumption that electricity generation requires 0.78 Btu of natural gas for every 1 coal-based Btu (1 MMBtu of natural gas displaces 1.28 MMBtu of coal).

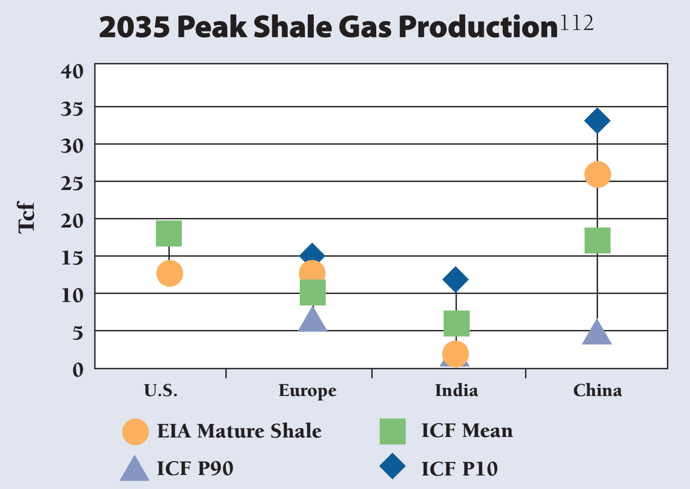
Although China has the highest estimate for shale gas resources, according to the EIA, its dependence on coal limits China's coal consumption displacement to a peak of 39 percent, based on ICF's P10 estimate. Conversely, Europe's limited (and declining) dependence on coal means that peak shale gas production exceeds the EIA's coal consumption forecasts less than 15 years. U.S. total shale production has the potential to displace between 66 and 96 percent of projected future U.S. coal consumption (based on EIA coal consumption forecasts). Although this is a useful indicator of switching potential, it is likely that natural gas would be used for other applications than power generation and there are other sources of natural gas (such as LNG) that would affect the market in each country.

Note that while peak shale production remains constant after the 20-year ramp-up, shale production as a share of EIA projected coal consumption declines slightly post-ramp-up in China, given the continued growth in coal consumption expected. Conversely, Europe's coal consumption is expected to decrease through 2035. Table 10 shows mature shale production and coal displacement potential for each region. Figure 38 shows the total shale gas production in 2035 for each region. Figure 39 illustrates 2035 shale gas displacement of coal consumption.

Figure 38 represents 2035 mature shale gas production as a share of the EIA coal consumption forecast estimates.

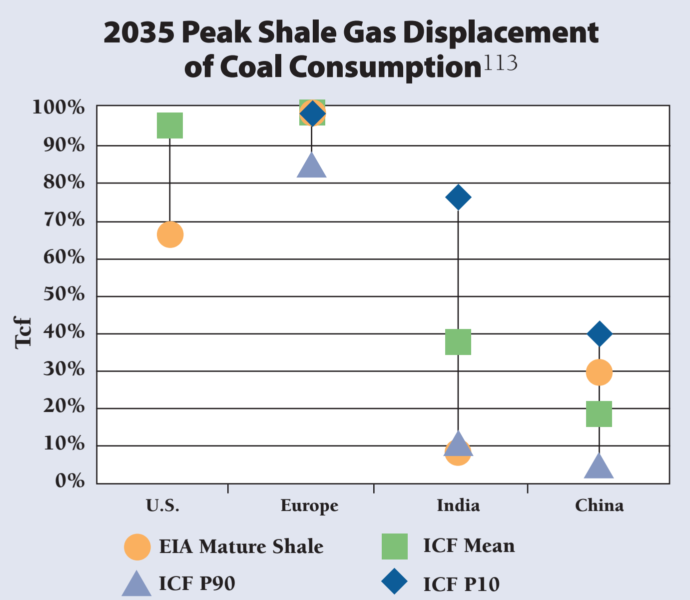
111 ICF estimates, EIA AEO 2011, EIA International Energy Outlook 2011

Figure 38



Note: Figures for Europe, India, and China each include ICF's P90 (low estimate), mean, and P10 (high estimate).

Figure 39



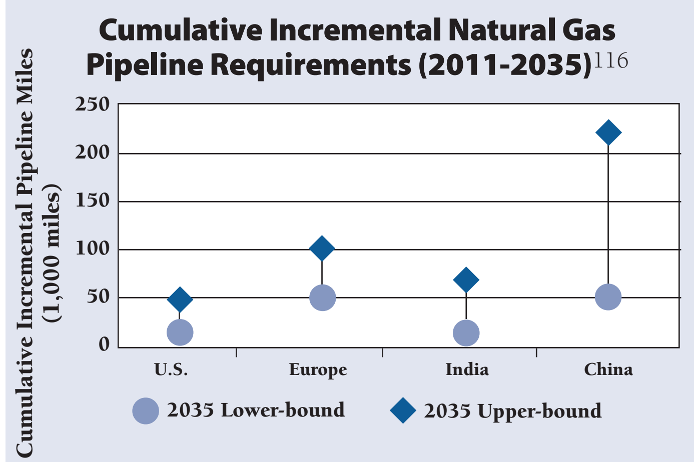
Note on calculation: Shale gas estimates divided by 0.78 to reflect efficiency gains associated with use of shale gas, as opposed to coal.

C. Natural Gas Infrastructure

Aggressive development of shale gas resources in natural gas production could mean energy security for growing economies and reduced reliance on carbon-heavy fossil fuels. Such resources, however, will parallel development of the domestic energy infrastructure. Expansion of the infrastructure to accommodate shale gas supplies would mean either construction of gas pipelines linking the source to markets, or expansion of the electrical grid to deliver power from plants near the shale gas resources. For this analysis, ICF assessed a range of pipeline mileage estimates required to carry shale gas supplies to market.

Figure 40 shows the cumulative incremental pipeline miles required from 2011 to 2035 to meet the lower-bound[114] and upper-bound[115] estimates for total natural

Figure 40



112 U.S. EIA, ICF

113 ICF estimates of U.S. EIA figures, ICF

114 Based on the EIA's non-shale natural gas baseline forecasts plus ICF P90 for Europe, India, and China, and the EIA total natural gas baseline for the United States.

115 Based on the EIA's non-shale natural gas baseline forecasts plus ICF P10 for Europe, India, and China, and the EIA total natural gas baseline for the United States.

116 ICF analysis of the U.S. EIA and CIA World Factbook data

gas consumption, including shale gas development. To illustrate the current state of each region's gas pipeline infrastructure development, relative to that required for future consumption, Figure 40 also includes 2010 total gas pipeline miles. Given the United States' well-developed pipeline infrastructure, the United States will require much less pipeline to meet robust growth in shale gas production. Conversely, China will require significant pipeline infrastructure development to meet even the EIA's estimates for gas consumption forecasts, let alone peak shale gas production. The lower-bound pipeline mileage required to meet EIA gas consumption forecasts plus peak shale gas production assumes development of supplementary infrastructure, such as additional electrical grid, whereas the upper-bound would mean development of the energy infrastructure primarily through pipeline construction.

8 Shale Gas Environmental Footprint

A. Overview

Discussions of the environmental footprint of shale gas production often include both the issues that are specific to shale gas production as well as issues with natural gas production, transmission, and distribution in general. In areas where all new gas production is shale gas, it is common for stakeholders to attribute the impacts of all aspects of gas production, delivery, and use, to "shale gas production." This chapter includes some discussion of the broader gas industry footprint with an emphasis on issues specifically associated with shale gas production through horizontal drilling and hydraulic fracturing. Table 11 identifies the potential impacts on the environment from various aspects of shale gas production, processing, and delivery categorized by medium – air (conventional air pollutants), water, land use, and climate.

B. Shale Gas Production

The shale gas production process, including well construction, drilling, and fracturing, includes the processes that are actually unique to the development of shale gas resources. It also includes some processes that are common to conventional natural gas development. Both are discussed here by medium.

i. Air

Emissions from drill and fracturing rigs. The drilling of the wells is powered by large diesel engines (1000 to 5000 hp) on portable drilling rigs. These engines emit conventional pollutants such as nitrogen oxides (NO_x), particulates, sulfur dioxide (SO_2), carbon monoxide (CO), and volatile organic compounds (VOCs). All of these are pollutants in their own right and/or contribute to formation of secondary pollutants such as ground level ozone or ultrafine particulates. Diesel engine emissions are typically regulated through emission limits applied at the manufacturer and through fuel limits (e.g., sulfur content). Emission limits for new engines are very stringent in the United States and European Union. They are less stringent for older engines in these countries and also for all engines in many other countries (e.g., China, India). Natural gas engines have lower emissions and can sometimes be used in areas that are already producing gas. Electric motors can be used when the drill site has access to the electric grid, which brings with it the environmental impacts of the electricity production and delivery, although on a smaller scale than those for drilling and fracturing rigs. The drilling process itself typically takes approximately four to six weeks per shale gas well.[117]

The fracturing process involves bringing water and chemicals to the site, mixing the water and chemicals, and pumping them into the well at high pressure to fracture the formation. Diesel engines are used to power the fracturing pumps and are another source of emissions. The fracturing is done in segments or "stages" starting at the end of the well bore. The entire multistage fracturing process typically takes two to five days, depending on the length of the wellbore and the individual stages. The actual pumping is intermittent during this time as each stage is set up and fractured and may total 40 to 100 hours.[118] The pump engines are subject to the same environmental regulations as the drill rig engines. The drilling and fracturing times depend on the specific well characteristics and can be affected by a variety of site specific factors.

Truck emissions from water delivery and removal. Each frack job requires on the order of 3 to 5 million gallons of water, although the exact amount can be more

117 ICF, 2009

118 ICF, 2009

Table 11

Environmental Effects of Shale Gas Production*

Stage	Air	Water	Land Use	Climate
Production	*Truck emissions from water delivery and removal* *Emissions from drill and fracturing rigs* *Emissions from gas venting* Emissions from tanks and dehydrators	*Water consumption for fracturing* *Groundwater contamination from fracturing process* Groundwater contamination from well casing leakage Surface water contamination from spills *Treatment and disposal of wastewater, including seismic risks* *Reporting of hydraulic fracturing chemicals*	Construction of well pads Construction of access roads and gathering lines *Increased traffic from water trucks and other supplies*	*Methane emissions from well completion* Methane emissions from liquids unloading Methane emissions from tanks
Gathering	Compressor emissions		Construction of gathering lines	Fugitive[119] and combustion emissions
Gas Processing	Combustion emissions (compressors and process heaters) Fugitive VOCs[120]	Wastewater		Combustion emissions Formation CO_2 Fugitive methane
Pipelines	Combustion emissions		Pipeline right of way	Combustion emissions Fugitive methane
Distribution Lines			Right of way	Fugitive methane

* *Italicized entries pertain specifically to shale gas production through hydraulic fracturing.*

or less depending on the well characteristics.[121] The water must be delivered to the drill site, usually by truck, although sometimes by pipeline. Assuming a 7,000-gallon capacity truck, this means between 400 and 700 water deliveries to the site. Somewhere between 10 and 30 percent of the fracturing fluid is released as wastewater after well completion (the remainder is absorbed in the underground formation). The wastewater must also be removed from the site after completion. Like the drilling engines, emissions from water and wastewater trucks are regulated at the point and time of manufacturing. New trucks in the United States and European Union have very low emissions, but older trucks and trucks in less developed countries typically have higher emissions. It is

119 Fugitive emissions are defined as pollutants released into the air from leaks in pipelines, valves, and other equipment, rather than from sources such as vents and smoke stacks.

120 VOCs are organic chemicals, many of which are harmful to human health and are regulated by the U.S. EPA.

121 A “frack job” is typically understood to mean the fracturing of one well.

quite costly to retrofit the older, high-emission engines and is typically not required or done.

Emissions from gas venting. When the well is completed, the fracking water is allowed to flow back. As the water runs out, it is accompanied by gas and the gas may be allowed to vent for some amount of time to ensure that the liquids have been removed. During flowback, volatile components of the flowback fluid may be released into the atmosphere. Some of these releases will be gases from the target formation, but there can also be volatilization of some of the hydraulic fracturing additives, such as benzene, petroleum distillates, other solvents, and alcohols. Of particular concern is the cumulative effect of the releases of VOCs and hazardous air pollutants from hundreds or thousands of drilling sites on the area or regional air quality. The content and quantity of emissions varies depending on the characteristics of the well. There are two common ways of reducing these emissions:

- Reduced Emission Completion (REC), sometimes called "green completion" – In this case, the gas is separated from the flowback water, cleaned up, and put into a gathering line for eventual sale.
- Flaring – In this case, the gas is burned at the site. The methane and VOCs are largely destroyed, but CO_2 and particulates and smaller amounts of other pollutants are created and the value of the gas is lost.

Although REC would be the preferable environmental and economic outcome, there are some limitations to its use. The most significant is that a gathering line must be in place to transport the gas. If the producer has not had time or has not planned to put the gathering line in place when the first completion is done, then REC cannot be applied. In some cases, producers may have been reluctant to install a gathering line until the resource has been proven; however, that should be less of an issue now that shale gas resources are better understood. There also can be permitting or right of way delays in putting in a gathering line that could prevent the use of REC. Once the first well at a site is completed and connected, however, subsequent wells should be able to use REC. The other potential infrastructure limitation is the REC equipment itself. This equipment is commercially available, but supplies may be inadequate to meet demand. The U.S. EPA has recently proposed regulations[122] that would require the use of REC or flaring for new shale gas wells starting in early 2012 and some states already have such requirements.[123,124,125]

Emissions from tanks and dehydrators. Water and liquid hydrocarbons are removed from the gas at the wellhead in dehydrators and the liquid is stored in tanks for later removal. VOCs and methane can be released from both the tanks and dehydrators. The emissions from both are regulated by the EPA for units above certain size thresholds. New proposed regulations[126] are making those limits more stringent in the United States.

ii. Water Issues

The hydraulic fracturing process involves the injection of large quantities of water into the drilled boreholes at high pressures, then reversing the flow and extracting the flowback water plus produced water from the geologic formation. The injected water contains a variety of chemicals. The flowback water contains many of these same chemicals. The produced water often contains high levels of dissolved solids, primarily salts, suspended particles, and hydrocarbons, and can also contain traces of naturally occurring radioactive material. There are concerns over the consumption of water as well as contamination of ground and surface water through the fracking process or through disposal of the waste water.

Water consumption for fracturing. Each frack job consumes on the order of 3 to 5 million gallons of water, depending on the specific geology and fracturing requirements. This has raised concerns over the possible depletion of local water supplies associated with greatly increased shale gas production. On the other hand, shale gas producers[127] note that in water terms, 5 million gallons may not be a large commodity, equivalent to the water consumed by:

- New York City in approximately seven minutes

122 U.S. EPA, 2012a

123 Colorado Oil and Gas Conservation Commission, 2009

124 State of Wyoming Department of Environmental Quality, 2010a

125 State of Wyoming Department of Environmental Quality, 2010b

126 State of Wyoming Department of Environmental Quality, 2010b

127 Chesapeake Energy, 2011

- A 1,000-megawatt coal-fired power plant in 12 hours
- A golf course in 25 days
- 7.5 acres of corn in a season

Because the fracking process is applied only during the initial production and potentially every 10 or more years to re-stimulate the well, this is not an ongoing requirement for each individual well. That said, widespread shale gas production could have a significant effect on the demand for water in a particular region, depending on the availability of water. There are also concerns over how to regulate the supply of water (i.e., to prevent producers from simply draining local streams and rivers or tapping local groundwater). Consumption of local water supplies is regulated in some but not all areas. Water consumption for shale gas production has not resulted in stress on regional water supply to date, but the potential exists, and planning for water supply should be required in at least some areas.

Groundwater contamination from the fracturing process. Perhaps the most common concern related to shale gas production is the potential for migration of fracking fluid from the injection zone in the target formation to upper level drinking water aquifers or into existing wells. The potential for migration depends on many factors, including the depth of the target formation, the maximum depth of drinking water aquifers, the composition of the intervening strata, and the pressure gradients. The depth of the shale gas formations is typically greater than 8,000 feet, whereas groundwater supplies are typically less than 1,000 feet deep. The rock fractures typically extend only a few hundred feet from the wellbore, so there is a significant separation between the fracture and the drinking water aquifers.

Testimony by the Ground Water Protection Council (GWPC) before the House Committee on Natural Resources in June 2009 included statements from state officials in Ohio, Pennsylvania, New Mexico, Alabama, and Texas. Each of the states confirmed that there had been no incidents of this kind of groundwater contamination due to hydraulic fracturing despite approximately 1 million frack jobs performed.[128] Separately there have been reports[129] of one occurrence of groundwater contamination through this path, although detailed information is not available. A recent EPA report[130] on possible groundwater contamination in the Pavilion, Wyoming region has also gained some attention; however, this drilling was not in shale formations, was not a horizontal drilling completion, and the potential contamination, if confirmed, seems more likely to have come from faulty well casing than the fracturing process itself.

Although such occurrences have not been documented, there are concerns that unusual geologic conditions could allow migration of fracking fluids into groundwater aquifers. The hydraulic fracturing process is exempt from the federal regulations that apply to other deep well injection processes under the Safe Drinking Water Act. This has been the source of much debate and there have been proposals to remove this exemption,[131] despite the lack of evidence of direct groundwater impacts.

Groundwater contamination from well casing leakage. The second potential source of groundwater contamination relates to leaks associated with improperly manufactured or damaged well casings or failure to properly construct and cement well casings. The vertical portions of the wells passing from the surface to the target formation are cased in steel pipes, which are cemented into the borehole. This casing often passes through drinking water aquifers and is intended to isolate the flow of materials between the surface and the target formation from any contact with the intervening strata or pore fluids. Poor casing construction or cementing practices can lead to leaks through the casing or vertical fluid movement in the annulus outside of the casing. In the event of a pipe failure, poor cement job, or other casing leak, fluids being injected into the well or extracted from the well could escape into upper level strata that form a drinking water aquifer. Proper well construction and testing is generally considered to be sufficiently protective to ensure adequate casing integrity; however, of the cases in which gas production has been shown to have caused groundwater contamination, the most common cause has been faulty well casing. Well casing is not unique to shale gas production but is common to all oil and gas production. There are industry guidelines and best practices on well casing and state regulations on casing procedures that should be followed to prevent groundwater contamination. The GWPC conducted a

128 Ground Water Protection Council, 2009

129 Ground Water Protection Council, 2009

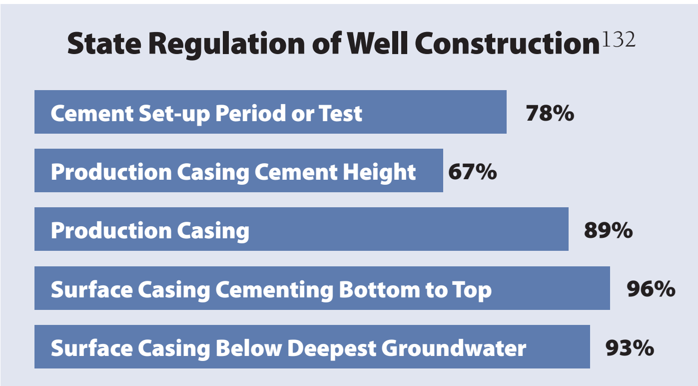
130 U.S. EPA, 2011a

131 111th U.S. Congress, 2011

review of regulations in 27 state oil and gas agencies, and found that the majority have casing and cementing requirements (see Figure 41).

Surface or groundwater contamination from spills. Surface spills of fracking chemicals, injection water, and flowback water can flow directly into surface waters, such as ponds, streams, or rivers. The introduction of fracking fluids and additives into aquatic ecosystems has the potential for detrimental effects to aquatic organisms. It could also seep into the soil and reach groundwater.

Figure 41



The most common source of such contamination is from inadequate material handling practices at the surface. Surface spills of fracking chemicals or injection water containing fracking chemicals can occur during the preparation of a hydraulic fracturing step. Each high-volume hydraulic fracturing step can use several million gallons of water. This water is typically pre-staged at the well head in 21,000-gallon tanks. The water tanks and the containers holding the hydraulic fracturing additives are connected by hoses to the mixing truck for blending, injection, and pressurization. Spills can occur from mishandled or faulty containers, leaks in the distribution system, or failure of the hoses or connections. Flowback water is usually captured in lined pits. Leakage from, failure of, or overflowing of these pits can also result in surface spills.

Many oil and gas wells produce water, and management of produced water is not unique to shale gas production, although it is a generic issue for shale gas production. Proper site management techniques can reduce or eliminate these risks. Spills on the ground or into surface waters are prohibited by Federal and state laws, including the Clean Water Act, and can result in a variety of penalties. Enforcement, however, requires adequate staffing, which is not always available.

Treatment and disposal of wastewater. The disposal of the large volumes of flowback and produced water presents additional challenges. Most of these wastes do not trigger hazardous waste regulations and some may be exempted. In the southwestern United States, where shale gas production was pioneered, the wastewater has typically been discharged into deep disposal wells, which are subject to individual review and permitting. The geology in the Marcellus shale areas of New York and Pennsylvania is not conducive to this type of disposal, and wastewater in this region was for some time transported to a local wastewater treatment facility, such as a publicly owned treatment works (POTW). POTWs designed to treat primarily domestic wastewater may not be effective in removing the salts, inorganic chemicals, and naturally occurring radioactive material (NORM) potentially present in the water from fracking operations. This has resulted in requirements or voluntary actions to halt disposal of wastewater at POTWs. New wastewater disposal facilities specifically designed to handle these wastes have been built and some wastewater is being trucked to Ohio for disposal in deep wells there. The industry has also increased the use of water recycling and reuse in the fracking operations themselves to reduce both the water consumption and disposal issues. When the wastewater is recycled, a smaller volume, more concentrated waste is produced that must be disposed of properly. These wastes are typically regulated under hazardous waste regulations.

Reporting of hydraulic fracturing chemicals. One of the high-profile issues associated with shale gas production has been calls to require companies to disclose the chemical content of their fracking fluid. The companies have disclosed some components and generic data on the types of constituents but have largely avoided full disclosure due to a desire to protect proprietary formulations.

The EPA's study of hydraulic fracturing and its impact on the nation's water supply has involved the voluntary reporting of fracking fluid components by nine oil and gas companies in an effort to examine chemicals and impact on water supplies.[133,134] In an effort to comply with the

132 FracFocus, 2012

133 U.S. EPA, 2011b

134 Junkins , 2010

federal Emergency Planning and Community Right-to-Know Act (EPCRA), the oil and gas industry have made a push for registering chemical use information at FracFocus, a chemical disclosure registry. Disclosure remains voluntary, and chemical disclosure is limited to the Material Safety Data Sheets (MSDS) database, meaning that proprietary chemical blends or chemicals not included in MSDS' database will not be reported.[135]

Although states such as Wyoming, Pennsylvania, Texas, and Arkansas require reporting of chemicals used and proportions, clauses remain for confidential proprietary blends.[136] Mandatory disclosure of fracking fluid content is also part of some Federal regulatory proposals.[137] Some companies are investigating the potential for "green" alternatives to current additives. That said, as discussed previously, the drilling wastewater is likely to contain hydrocarbons, inorganic contaminants, and NORM, regardless of the content of the fracking fluids, so proper disposal will be required regardless of the formulations.

iii. Land Use

The land use effects of shale gas production vary over time and location. The greatest effects are during the drilling and completion phases, which typically take place over a matter of months to a year. The ongoing impacts during the 20- to 30-year life of the wells are typically much smaller but still can be significant depending on the location.

Much of the initial shale gas production was in rural areas of the west, where construction of roads, drill pads, and gathering lines was not immediately noticeable to the sparse local population. On the other hand, some of these areas are viewed as pristine wildlands, so any development raises concerns.

Some of the initial development in the Barnet shale has been in developed areas of Dallas/Fort Worth Texas, and the Marcellus shale development is in more urban areas of the northeast where people have not seen extensive oil and gas production in recent years and are less open to the associated disruptions.

There is a common belief that shale gas production requires more wells than conventional wells; however, the estimated average ultimate recovery (EUR) from U.S. and Canadian shale gas plays is currently estimated at 1.5 to 6.5 Bcf per well, compared to 0.2 to 1.0 Bcf per well for conventional vertical onshore wells. In addition, shale gas producers typically drill 6 to 12 wells from one pad, so the land use effects per unit of gas produced are actually lower for shale gas production than for conventional gas production. One well pad per square mile with 8 wells per pad is typical for shale gas production, although it varies depending on the shale gas resource.

Construction of well pads. The drilling and production process is carried out in an area of 3 to 5 acres. This area is typically leveled and covered with gravel to accommodate the staging of equipment. Storage and discharge pits are installed (Figure 41). After the wells are completed, the equipment is removed, pits are filled, and the land is restored. Typically the remaining equipment is a small cluster of pipes at the wellhead and potentially some dehydration equipment and tanks, depending on the quality of the gas. Although this is the best case, restoration of the drill site is typically not regulated and is therefore up to the producer, possibly subject to contractual requirements.

Figure 42

Aerial View of Drilling Site[138]

135 FracFocus, 2011http://fracfocus.org/chemical-use/chemicals-public-disclosure

136 New York Department of Environmental Conservation, 2011a

137 111th U.S. Congress, 2011

138 U.S. DOE, 2009

Construction of access roads. Typically new roads must be constructed to provide access to the drill site. These may be temporary dirt roads, but they will affect the local environment. Regulation of these activities will typically be through local zoning and construction permitting procedures. After drilling is complete, access will need to be continued for maintenance of the wellhead and possibly for removal of liquids.

Increased traffic from water trucks and equipment. During the drilling completion process there will be increased traffic. As noted previously, the water deliveries for fracturing could require 400 to 700 truck trips, and a smaller number could be required to remove wastewater. In a remote, sparsely populated area, this might not cause much disruption but could be a relatively large percentage increase in local emissions. In a more developed area, the percentage increase in emissions might be smaller (especially if late-model, lower-emitting trucks are used), but the increase might be more noticeable to residents. The increased traffic also creates wear and tear on existing roads, which may not have been constructed with this type of heavy industrial traffic in mind.

Ongoing impacts. After the well is completed and the site is restored, there will be relatively little activity at the wellhead. There will be periodic maintenance inspections. If liquids are being collected at the wellhead, there will be periodic pick-ups by a tank truck. If there is a dehydrator, there will be continuing VOC emissions from the dehydrator and associated tanks. These are regulated as described previously. The most noticeable ongoing process would be noise from any compressors that are associated with the gathering line. The emissions from compressors are regulated under the relevant air permitting requirements.

iv. Lifecycle Greenhouse Gas Impacts

Because combustion of natural gas emits much less CO_2 than combustion of coal, there has been significant interest in replacing coal with gas (particularly in power generation) as a means of reducing greenhouse gases (GHGs). CO_2 and particularly methane, however, are emitted in both the natural gas and coal production processes, so a complete comparison of gas and coal emissions also must include these upstream emissions.

Each GHG has different characteristics and effects on climate change. In order to compare them, we use a factor called the global warming potential (GWP), which relates each GHG's effect to that of CO_2, which is assigned a GWP of 1. The GWP is a function of the gas's climate-forcing potential (its effect on atmospheric warming) and its lifetime in the atmosphere. The international standard for GWPs is established by the Intergovernmental Panel on Climate Change (IPCC).

CO_2 has a long life in the atmosphere – on the order of hundreds of years. For this reason, the primary GWPs are established on a 100-year basis. Methane has a stronger climate-forcing effect than CO_2 but has a shorter lifetime in the atmosphere (10 to 15 years). On a 100-year basis, methane is assigned a GWP of 25 by the IPCC.[139] This means that one ton of methane has the same effect as 25 tons of CO_2 over 100 years.

The IPCC also establishes 20-year GWPs. Some analysts believe that the 20-year GWP is more appropriate to use for short-lived GHGs like methane, especially to show the potential benefits of short-term mitigation options for these GHGs. Because methane is more potent over its shorter life, the IPCC 20-year GWP for methane is 72.

The upstream CO_2 in gas production is associated with the fuel consumption in trucks, drill rigs, and pipeline compressors. These have been assessed to be quite small by all analysts, on the order of 10 percent of the emissions from gas combustion. Because methane is a more potent GHG than CO_2, however, large methane emissions could offset the lower CO_2 emissions.

Major Sources of Methane in Gas Production

The major sources of upstream methane emissions from gas production and potential mitigation measures are discussed below.

Methane emissions from well completion. The largest potential source of fugitive methane emissions is the emissions during the completion/flowback process. Methane is entrained in the flowback water and is vented prior to closing off the well. There are few measured data on these emissions. The U.S. Inventory of GHG Emissions estimates the emissions at approximately 9 mmcf per completion. The options for avoiding these emissions are the same as for the conventional emissions associated with

139 Intergovernmental Panel on Climate Change, 2007

completion – REC and flaring. As noted previously, new U.S. regulations have been proposed that would require REC or flaring at nearly all shale gas completions.

Methane emissions from liquids unloading. In conventional gas wells, liquids can collect at the bottom of the well and impede gas recovery. In the past, there has been a practice of venting the well to "blow out" the liquids. This is not a very efficient way to remove the liquids and it loses valuable gas. More recently, producers have implemented other technologies, such as "plunger lifts," to remove the liquids without venting and with much lower gas losses. Venting as a means of liquids unloading has not been a common practice for shale wells because it is even less effective for long horizontal wells. Producers use pumps to remove liquids from shale gas wells without venting.

Methane emissions from tanks. As discussed previously for conventional pollutants, methane can be emitted from dehydrators and tanks. These emissions will be regulated by the same proposed regulations identified previously.

Other Processes

Although the environmental factors listed earlier are the ones that are directly associated with shale gas production, the impacts from the remainder of the natural gas stream may be associated with shale gas if the whole natural gas infrastructure in a given region is developed primarily because of the shale gas resources. The other downstream impacts are briefly discussed below.

Gathering Systems

Construction of gathering lines. A gathering pipeline is required to bring the gas to a processing plant or transmission pipeline hub. Construction and maintenance of gathering lines can be a land use issue. Right-of-way (ROW) must be acquired, often associated with the roads to access the drilling sites. The pipelines are typically buried, requiring excavation and construction along the ROW. Once completed, the gathering lines have a low environmental impact, but continued access to the gathering line is required, again often combined with access roads. Gas compressors associated with gathering will be a source of conventional air pollutants and CO_2, and could be considered a noise nuisance if located near populated areas.

Gas Processing

Natural gas often must be processed to remove impurities before being put into transmission pipelines. The impurities may include water, non-gas hydrocarbons (propane, ethane, and other "natural gas liquids"), CO_2, and other minor impurities. This is done at natural gas processing plants, which use a variety of extraction techniques to clean the gas. Natural gas liquids (e.g., ethane, propane, butane) extracted from the gas can be sold to other markets. Although the processing plants can be of different sizes, they are often relatively large industrial facilities with large compressors, process heaters, and other industrial equipment that emit both conventional pollutants, CO_2 from fuel consumption, CO_2 extracted from the gas itself (formation CO_2), and potentially fugitive methane. As large emission sources, they are typically regulated for their conventional pollutant emissions in the United States and other developed countries.

Gas Transmission

Natural gas is transported overland through long-distance pipeline systems. The pipes are 24 to 42 inches in diameter and are typically buried underground. This requires acquiring, developing, and maintaining a ROW. After construction, the ROW can be landscaped and sometimes goes through urban areas, or the ROW may become urbanized after construction.

The gas is pressurized and propelled through the pipelines by large compressors located at intervals along the pipeline. The compressors are usually powered by reciprocating engines or combustion turbines fueled by the gas in the pipeline. The conventional emissions are regulated in the United States and other developed countries. In some areas of the United States where emissions limits are very strict, electric motors are used to power the compressors.

Although the pipes themselves do not normally release methane, there are fugitive methane emissions from valves, compressor seals, and other types of equipment associated primarily with the compressor stations. The EPA Natural Gas STAR program has worked with the U.S. gas pipeline industry to identify voluntary actions and best practices that can reduce emissions from transmission as well as upstream processes. Many of these practices are being applied internationally under the U.S. Global Methane Initiative and other industry actions. Some of these same practices have been incorporated into the recent EPA New Source Performance Standards (NSPS) for new oil and gas systems.[140]

Gas Distribution

The last step in delivery of natural gas to consumers is the local gas distribution system. This is the system that delivers gas to residential/commercial and some industrial and power generation customers. The gas distribution system operates at much lower pressure than the gas transmission system and usually does not need additional compressors once the pressure is reduced from the transmission system. The most significant emissions are fugitive methane emissions from valves and meters. Some distribution systems are very old and have significant fugitive emissions from very old buried pipes. In most cases, it is prohibitively expensive to dig up and replace these pipes, but there are some technologies for lining and sealing older pipes.

Recent LCA Studies

The life-cycle analysis (LCA) issue received a lot of publicity in early 2011 when a paper by Howarth et al[141] asserted that the life-cycle emissions of shale gas are significantly higher than those of coal due to methane emissions in production. Several subsequent papers have contradicted those results, and the preponderance of research is finding that the life-cycle GHG emissions of gas-fired generation are roughly half those of coal; however, it is important to understand the background and basis for this discussion.[142,143,144]

The U.S. EPA produces an annual "Inventory of U.S. Greenhouse Gas Emissions," which is the official U.S. report to the IPCC on U.S. GHG emissions.[145] This report contains detailed information on all of the major U.S. emissions sources and is therefore the basis for many other emissions studies. During 2010, the EPA began releasing new estimates of methane emissions associated with natural gas production. These new estimates were based on modified emissions estimates for specific processes in the gas production chain. The largest increase was for liquids unloading – the process of removing water and other liquids from the bottom of conventional gas wells. The second largest increase was related to the emissions from shale gas wells during completion. These emissions come from the methane released during the "flowback" when the water used to fracture the well is released. Previously the EPA had assumed that all of this methane was being flared. The new estimates assume that roughly one third is flared, one third captured for sale, and one third vented. These estimates were also incorporated into the Technical Support Document for EPA's GHG reporting requirements for emissions from the oil and gas sectors.[146]

Although the emissions rates for some of the individual processes were increased by a factor of 100 or more, these processes make up only a small part of the total upstream GHG emissions for the gas sector. Nevertheless, after the revised estimates began to appear in EPA documents in late 2010, some analysts became concerned in early 2011 that the overall impact would be very large, resulting in high life-cycle emissions for gas, especially shale gas produced through hydraulic fracturing.[147] These concerns resulted in the release of several new studies of the life-cycle emissions of natural gas and coal in 2011, several of which are summarized and compared below.

Howarth et al (Cornell)[148] – This 2011 study from Cornell University was the first new peer-reviewed study to address the LCA issue based on the new EPA data and to specifically focus on shale gas production. The study gained a lot of attention due to its conclusion that shale gas has higher life-cycle GHG emissions than coal, due largely to methane emissions during the extraction process. Howarth et al have since released a response to recent challenges to the results of the study, but it contains no new data.[149]

Jiang et al (Carnegie Mellon)[150] – This peer-reviewed study updates several earlier LCAs done at Carnegie Mellon University to specifically address the life-cycle emissions

140 U.S. EPA, 2012a

141 Howarth, Santoro, & Ingraffea, 2011

142 Mohan, et al., 2011,

143 Hultman, Rebois, Scholten, & Ramig, 2011

144 Skone, 2011

145 U.S. EPA, 2012b

146 U.S. EPA, 2010

147 Lustgarden, 2011

148 Howarth, Santoro, & Ingraffea. 2011

149 Howarth, Santoro, & Ingraffea. 2011

150 Mohan, et al., 2011

of shale gas produced through hydraulic fracturing. The study finds that the life-cycle GHG emissions of shale gas are approximately 5 percent higher than the base case conventional gas case, and the emissions from gas-fired electricity generation are about 42 percent lower than for conventional coal generation.

Burnham et al (Argonne National Laboratory)[151] – This peer-reviewed study by researchers at the Argonne National Laboratory used a variety of detailed data sources and the Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (GREET) LCA model to develop life-cycle GHG emissions estimates for conventional gas, shale gas, and coal-based electricity generation. Unlike other studies, this one found that the emissions from conventional gas production were slightly higher than for shale gas production, due primarily to fugitive methane emissions from liquid unloading in conventional gas production. Overall the study found that life-cycle GHG emissions from gas-fired electricity production were 36 percent lower than for coal-fired electricity production.

Hultman et al (University of Maryland)[152] – This peer-reviewed study from the University of Maryland compared the life-cycle emissions of conventional gas, shale gas, and coal for electricity generation. The study found that the GHG impacts of shale gas are 11 percent higher than those of conventional gas, and 44 percent lower than for coal.

Deutsche Bank/WorldWatch Institute[153] – This top-down LCA study explicitly looked at the effect of the revised EPA methane estimates on the life-cycle emissions from natural gas production and use. The study also included adjustments for natural gas imports. The study concluded that the overall effect of the EPA adjustments is an 11-percent increase in the life-cycle emissions of natural gas, with the life-cycle emissions of gas-generated electricity still about 47 percent lower than for coal-generated electricity.

National Energy Technology Laboratory (NETL)[154] – This study is a very detailed, bottom-up study of life-cycle emissions of electricity generated from conventional and shale gas from various sources compared to the life-cycle emissions from coal-fired electricity production. The study

151 Burnham, et al., 2011

152 Hultman, Rebois, Scholten, & Ramig, 2011

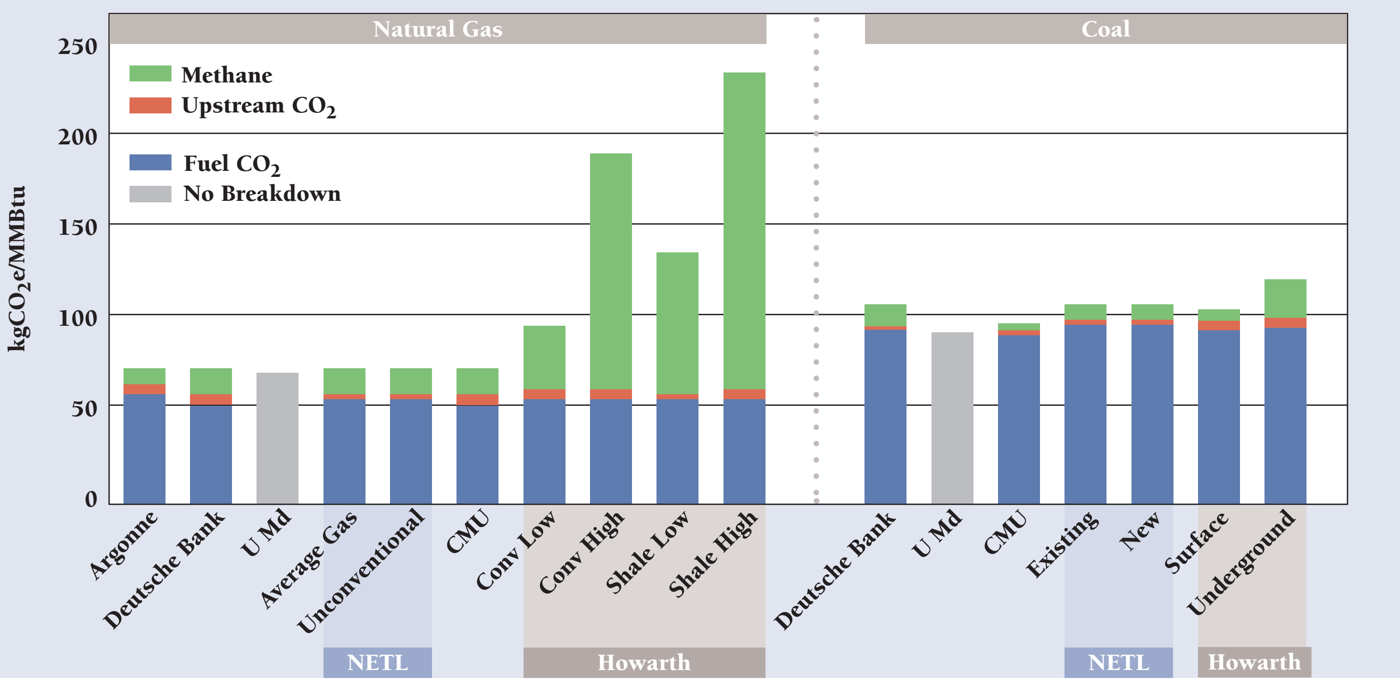
153 Fulton & Melquist, 2011

154 Skone, 2011

155 Cited studies and ICF analysis

Figure 43

Comparison of Recent Studies of Life-Cycle Emissions from Natural Gas and Coal (kg CO_2e/MMBtu)[155]



is part of a series of studies on life-cycle emissions from various energy sources. The study found that life-cycle emissions from natural gas-fired electricity generation are 39 percent less than from coal-fired electricity generation.

Figure 43 summarizes the results of the LCA studies as reported, showing the life-cycle GHG emissions of the fuel as delivered to the point of end use in kg CO_2e per million Btu (kg CO_2e/MMBtu) of delivered energy.

Because each of the studies is evaluating a slightly different case, each with a unique methodology, one can expect some variation. In all cases, the largest component of the natural gas emissions is the CO_2 released during the actual combustion of the fuel – 53 kg CO_2e/MMBtu. The upstream CO_2 emissions from drilling engines, process equipment, pipeline compressors, and other equipment are a much smaller component of total emissions, whereas the upstream methane emissions are, in some cases, quite large due to the higher GWP of the methane. The coal LCAs show a similar pattern, with the CO_2 from combustion of the fuel comprising the largest share of the life-cycle emissions and the upstream emissions much smaller but usually dominated by the methane component.

All of the studies except the Howarth study show total life-cycle emissions for natural gas delivered to consumers ranging from 69 to 75 kg CO_2e/MMBtu (including the 53 kg CO_2e/MMBtu for the gas combustion itself). The Howarth study has values two to nearly five times as high, almost entirely due to the estimates of upstream methane emissions. One reason for this difference is that Howarth used a different GWP for methane. The other studies used the standard IPCC 100-year GWP of 25. Howarth used a 20-year GWP and did not use the IPCC value of 72, but a value of 105 proposed by Shindell et al.[156] This value is based on new research and is still being evaluated by the international scientific community. This choice alone explains much of the difference between the Howarth study and the other recent studies.

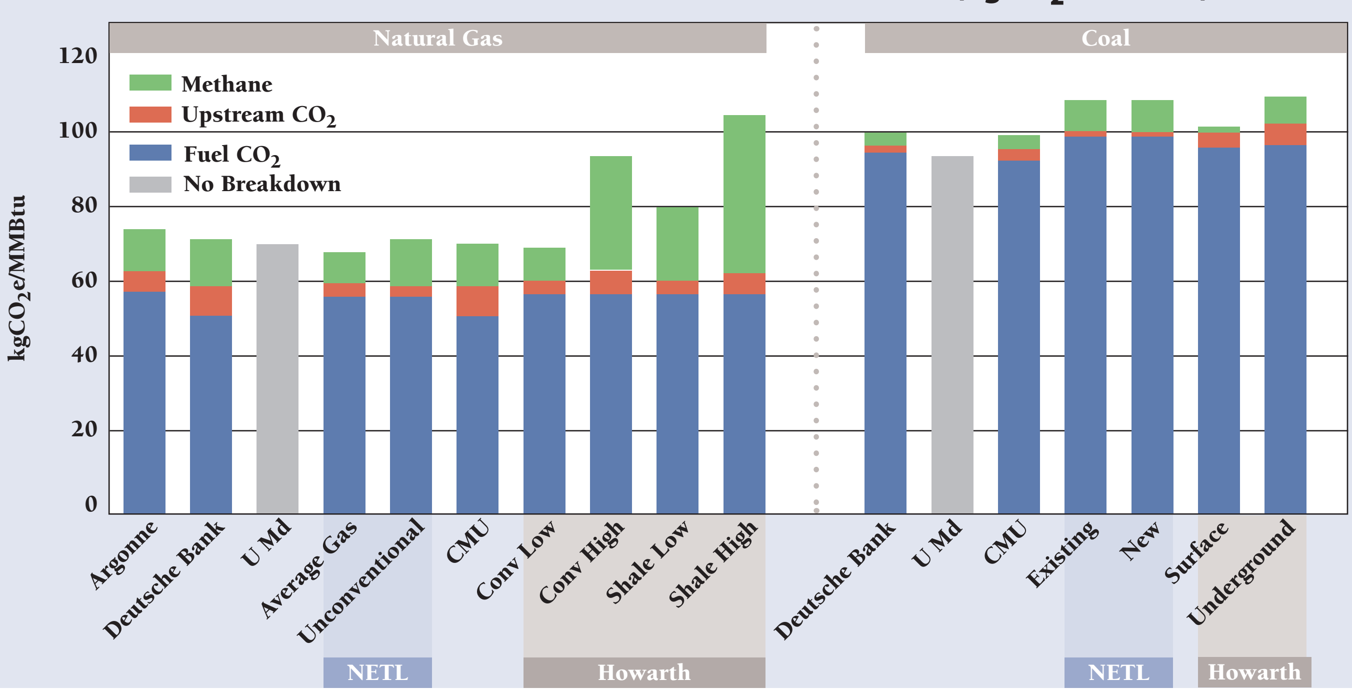
Figure 44 shows the gas LCA studies normalized to the same 100-year GWP of 25 for methane. While the Howarth values are much closer to the other studies on this basis, the shale gas values in particular are still much higher. There are several reasons for this difference.

156 Shindell, et al., 2009

157 Cited studies and ICF analysis

Figure 44

Comparison of Recent Studies of Life-Cycle Emissions from Natural Gas and Coal Normalized to Methane GWP of 25 (kg CO_2e/MMBtu)[157]



As in the other studies, the Howarth study divided the analysis into segments. Like other researchers, Howarth used EPA inventory data for several of the segments but then chose other sources with higher values for some segments. For example, the Howarth study did not use the EPA data for the methane emissions from shale gas completions (the methane released during flowback of the fracturing fluid). Although the EPA has derived a value for this process in the GHG inventory, the Howarth study derived its own higher value based on four data points.

Also the Howarth study did not, like other studies, include the potential for mitigation of the methane emissions. In particular, the completion emissions can be mitigated either by flaring or by REC. Under REC, the gas that would be vented is captured, cleaned, and put into pipelines for sale. Two states, Wyoming and Colorado, require that fracturing completions capture or flare the completion emissions; other states are considering such regulations. In 2012 the EPA published a final NSPS for the oil and natural gas industry that will require REC or flaring for most gas wells nationally.[158] The New York Department of Environmental Conservation has also proposed regulations for shale gas production that would require REC or flaring for most shale gas wells.[159] The assumption in the Howarth study that there is no mitigation of completion emissions is another primary source of the difference between that study and the other studies and also seems to indicate an overestimate of methane emissions. The Howarth study also assumed higher emission factors than the other studies for several other segments of the gas production chain, in particular methane fugitives from natural gas pipelines, which contributed to the higher overall estimate for both shale gas and conventional gas. In summary, the differences between the Howarth study and the other studies stem primarily from different assumptions and choices of data sources.

Although additional reliable emissions data are needed for some segments of the natural gas supply chain, the consensus of the recent studies other than Howarth is life-cycle GHG emissions for natural gas-fired electricity generation of 63 to 75 kg CO_2e/MMBtu. For coal-fired electricity generation, there is even less variation. All of the studies, including the Howarth study, put this at 94 to 108 kg CO_2e/MMBtu. Thus, except for Howarth, the studies estimate that the life-cycle emissions of natural gas-fired electricity range from 36 percent to 47 percent lower than for coal-fired electricity.

Although not an LCA, another recent study by the National Oceanographic and Atmospheric Administration (NOAA) found high levels of hydrocarbons in ambient air in gas-producing regions of Colorado, which imply higher fugitive and vented methane emissions than shown in other studies.[160] Further analysis needs to be done to confirm these results. In addition, new emissions control regulations on some of the sources have taken effect since the measurements were taken in 2008.

C. Shale Gas Regulation in the United States

As the primary focus of shale gas production, the United States has also seen the most activity in regulation of these activities. This section summarizes this regulatory activity to provide a basis for potential regulatory activities in other countries. Whereas many regulators in the United States have been forced to regulate "after the fact" due to the rapid growth of the industry, other countries have the potential to regulate more proactively based on the lessons learned in the United States.

i. U.S. Environmental Protection Agency Initiatives

The EPA is conducting an in-depth analysis into hydraulic fracturing and its impact on the nation's water supply.[161] The study will examine a number of fracking sites to address regulation and guidance associated with the Safe Drinking Water Act, Clean Water Act, the Clean Air Act, and Resource Conservation and Recovery Act. In addition, the study will address issues associated with water acquisition, chemical mixing and impact on drinking water, well injection and flowback, and produced water disposal.

The EPA has held public meetings on hydraulic fracturing using diesel, which will be included in guidance on underground injection and diesel-related well

158 U.S. EPA. 2012a

159 New York Department of Environmental Conservation, 2012

160 Pétron, Frost, & Miller, 2012

161 U.S. EPA, 2011

development. The permitting guidance will address issues of site characterization, area of review, well construction, well operation, monitoring, well plugging and closure, financial responsibility, and public participation.[162]

On November 23, 2011 the EPA announced plans to use the Toxic Substances Control Act (TSCA) as a basis to draft regulations requiring company disclosure of information concerning chemical substances and other mixtures used in hydraulic fracturing. The EPA plans to convene a stakeholder process to develop such regulations.[163]

ii. U.S. Department of Energy Initiatives

In May 2011 the U.S. Department of Energy (DOE) established a subcommittee of the Secretary of Energy's Advisory Board to assess the environmental and safety issues associated with hydraulic fracturing.[164] The subcommittee has heard testimony from various industry sources, such as the American Petroleum Institute (API), the Arkansas Oil and Gas Commission, FracFocus, the Texas Railroad Commission, and Earthworks.[165] Subcommittee findings and recommendations were released in August 2011. The subcommittee aims to provide guidance on safe drilling practices, evaluation of well construction standards, mechanical integrity of wells, and monitoring of fracking and wells. The U.S. DOE's Secretary of Energy Advisory Board (SEAB) organized a Shale Gas Production Subcommittee to identify measures needed to minimize the environmental impact and safety concerns associated with shale gas production.[166] In August 2011 the subcommittee released its initial 90-day report, which included recommendations on necessary measures to limit the environmental impact and safety of shale gas production. The second 90-day report, released in November 2011, focused on implementation of the 20 recommendations. The findings are included in the table on the next page.

iii. National Proposed Legislation

In an effort to repeal the hydraulic fracturing exemption under the Safe Drinking Water Act (SDWA), Congress introduced Bill 2766: Fracturing Responsibility and Awareness of Chemicals (FRAC) Act of 2009.[170] Although the bill was not voted on or reintroduced the following session, it may be reintroduced.

iv. State Actions

California

California lawmaker Bob Wieckowski (D) has been working with oil and gas companies to garner support for a bill that would require the strongest hydraulic fracturing chemical-reporting procedures in the United States.[171] A bill, AB 591, is expected in early 2012, which will likely allow oil and gas firms to maintain confidentiality of fracking chemicals, but would have significantly more stringent disclosure laws than other states.[172] Environmentalists have redoubled their efforts to push for the strongest bill possible after the EPA's recent discovery of common fracking chemicals found in a Wyoming aquifer. Many environmentalists are concerned that FracFocus, the oil and gas industry's voluntary mechanism for frack fluid chemical disclosure, is not stringent enough. The amendment may include a new procedure for disclosure of trade-secret information (similar to California's process for disclosure of pesticides). The system would call for submission of two documents to state regulators: one for public disclosure and another that includes trade secrets, which would remain confidential. The public document would include chemical family names but would not name the specific chemicals. State regulators would then decide whether the specific

162 U.S. EPA, 2011c

163 U.S. EPA, 2011e

164 US DOE, 2011

165 US DOE Natural Gas Subcommittee of the Secretary of Energy Advisory Board, 2011

166 US DOE Natural Gas Subcommittee of the Secretary of Energy Advisory Board, 2011

167 Source: US DOE Natural Gas Subcommittee of the Secretary of Energy Advisory Board, 2011.

168 State Review of Oil and Gas Environment Regulations (STRONGER), see more information at www.strongerinc.org

169 See more information at www.gwpc.org

170 111th U.S. Congress, 2011

171 Clean Energy Report, 2011

172 Clean Energy Report, 2011

Table 12

Department of Energy Recommendations [167]

No.	Recommendation	Issues	Implem. Status
1	Improve public information about shale gas operations	*Federal public website on the industry. States should also consider such public websites.*	1
2	Improve communication among federal and state regulators, as well as federal funding for STRONGER [168] and the Ground Water Protection Council [169]	*Federal funding ($5mm/y) for state regulators/NGOs/industry to plan relevant activities.*	1
3	Measures should be taken to reduce emissions of air pollutants, ozone precursors, and methane as quickly as possible	*EPA is encouraged to complete its current rule that applies to shale gas production as quickly as possible, which should include methane and existing shale gas production sources. States that have not already done so should also take action.*	1
4	Enlist a subset of producers in different basins to design and field a system to collect air emissions data	*Industry initiative in advance of regulation, with possible start in Marcellus and Eagle Ford.*	1
5	Launch a federal interagency planning effort to acquire data and analyze the overall greenhouse gas footprint of natural gas use	*The Obama Administration has taken steps to collect additional data, including through the EPA air emissions rulemaking.*	1
6	Encourage shale gas production companies and regulators to expand efforts to reduce air emissions using proven technologies and practices	*Federal funding ($5mm/y) for state regulators/NGOs/industry to encourage planning. States that have not yet taken action should do so.*	1
7	Protection of water quality through a systems approach	*Neither the EPA nor the states are engaged in developing a systems/lifecycle approach to water management.*	3
8	Measure and publicly report the composition of water stocks and flow throughout the fracturing and cleanup process	*Awaits the findings of the EPA's study on the impacts of hydraulic fracturing on drinking water sources. States should also determine ways to measure and record flowback operations data.*	2
9	Reveal all water transfers among different locations		2
10	Adopt best practices in well development and construction, particularly casing, cementing, and pressure management	*Recognized as a key practice by companies/regulators, but there is no indication of a special initiative for field measurement and reporting.*	2
11	Launch additional field studies on possible methane migration from shale gas wells to water reservoirs	*Funding required from federal agencies or from states.*	1
12	Adopt requirements for background water quality measurements	*Recognized as a valuable background measurement. Jurisdiction for access to private wells varies by region.*	2
13	Agencies should review field experience and modernize rules and enforcement practices to ensure protection of drinking and surface waters	*Reflects the subcommittee's unease that the present arrangement of shared federal and state responsibility for cradle-to-grave water quality is not working properly in every case.*	3
14	Disclosure of fracturing fluid composition	*Department of the Interior will propose a requirement; industry is amenable to mandatory, more stringent disclosure.*	1
15	Elimination of diesel use in fracturing fluids	*EPA is developing permitting guidance under the underground injection control (UIC) program. The subcommittee recommends that diesel fuel not be used in hydraulic fracturing fluids.*	1
16	Manage short-term and cumulative impacts on communities, land use, wildlife, and ecologies	*No new studies launched; federal funding is required.*	3
17 18 19	Organize for best practice Air Water	*Industry intends to establish "centers of excellence" regionally that involve public interest groups, state/local regulatory bodies, and local universities.*	3 3 3
20	R&D needs	*Office of Management and Budget/Office of Science and Technology Policy must define unconventional gas R&D limits and budgeting for the DOE, EPA, and USGS.*	1

Note: Regarding the "Implementation Status" codes column, "1" signifies that recommendation is ready for immediate implementation, "2" indicates that the recommendation requires cooperation between regulators and industry to execute, and "3" means that a new mechanism is required for successful implementation of the recommendation.

chemicals themselves should remain confidential.[173]

Colorado

Colorado requires control of methane emissions from well completion through green completion.[174] Green completion is required, although not for exploratory wells.[175] Green completion wells must include sand traps and other mechanisms during flowback to maximize recovery and limit emission releases to the environment.[176] In instances in which green completion is not feasible or required, Best Management Practices should be applied to minimize gas emissions and monitor the emissions levels and time period.[177] Temporary flaring or venting is permitted as a safety precaution during upset conditions, in accordance with all applicable regulations.

Colorado revised its Regulation No. 7, most recently in the spring of 2011, which sets standards for emissions of VOCs, primarily in the Denver area. The regulation applies specifically to oil and gas operations and natural gas-fired reciprocating internal combustion engines. The regulations can be accessed at: http://www.cdphe.state.co.us/regulations/airregs/5CCR1001-9.pdf.

Proposed Regulation

Although many states, such as California, Colorado, Michigan, Montana, New York, and Texas, have disclosure-related regulations, Colorado became one of the first states, along with Texas, to legislate hydraulic fracturing fluid content.[178] The Colorado Oil and Gas Commission made the decision after hearing 11 hours of comments at a public meeting.[179] The commission has proposed the national website, FracFocus.org, for disclosure of fracking ingredients, and recommended moving the start date from February 1, 2012 to April 1, 2012 to allow companies sufficient time to prepare. While some industry groups object to disclosure of ingredients due to chemical trade secret concerns, conservation groups contend that trade secrets should not receive special protection.

Louisiana

The STRONGER State Review of March 2011 included program recommendations for Louisiana, including an extensive review of its casing and cementing standards (DNR is currently assessing current regulations with Louisiana State University to review well construction standards), immediate reporting of problems upon completion of a well, including identification of materials and volumes, and establishment of a spill prevention and control plan.[180]

The Louisiana Department of Natural Resources adopted regulations in October 2011 requiring operators to disclose information on water used in hydraulic fracturing. The regulations require that companies make the disclosure to either the Office of Conservation or to FracFocus.[181]

Michigan

In May 2011 the Michigan Department of Environmental Quality (DEQ) issued new regulations for "high volume" hydraulic fracturing.[182,183] High-volume fracturing is defined as using more than 100,000 gallons of hydraulic fracturing fluid. The regulations will require oil and gas operators to report the source they plan to use for water and will also impose certain monitoring requirements along with disclosure of hazardous substances used in fracturing (provided through Material Safety Data Sheets), which will be made available to the public. Additionally, operators will have to provide the Michigan DEQ with records on injection pressures, volumes of fracturing fluid, and volumes of flowback.

Montana

Montana adopted disclosure requirements in September

173 Clean Energy Report, 2011

174 Green well completion procedures capture methane air emissions during well completion and send the captured gas to the sales line, rather than releasing the gases into the air or flaring.

175 Colorado Oil and Gas Conservation Commission, 2011

176 Colorado Oil and Gas Conservation Commission, 2011

177 Colorado Oil and Gas Conservation Commission, 2011

178 Nettles, 2011

179 Greenwire. 2011

180 STRONGER Inc., 2011a

181 The regulations can be found in the October 2011 Louisiana Register on page 3064. Available at: http://www.doa.louisiana.gov/osr/reg/1110/1110.pdf

182 Michigan Department of Environmental Quality, 2011a

183 Michigan Department of Environmental Quality. 2011b

2011. The regulations require operators to provide information on hydraulic fracturing fluids on a well-by-well basis.[184] If operators choose to post the information on the website FracFocus, then the Montana Department of Natural Resource Conservation (DNRC) may not require the operator to report separately to the DNRC, or may waive a portion of reporting requirements.

New Jersey

The New Jersey Legislature passed a bill in July 2011 that banned hydraulic fracturing in the state. The bill was later vetoed by Governor Chris Christie. Instead the Governor imposed a one-year moratorium on fracking.

New York

The New York Department of Environmental Conservation (DEC) released a Supplemental Generic Environmental Impact Statement (SGEIS) that addresses permit conditions for horizontal drilling and high-volume hydraulic fracturing. The draft SGEIS was first issued in 2009, a preliminary revised draft SGEIS was released in July 2011, and then further revisions were made, with the most recent version of the High-Volume Hydraulic Fracturing SGEIS released in September 2011.[185]

The New York DEC has also issued a State Pollutant Discharge Elimination System (SPDES) general permit for stormwater discharges that will authorize point source discharges from high-volume hydraulic fracturing (HVHF) operations to, in, or over waters of the State.[186] New York has sought to address other issues associated with hydraulic fracturing. Although not directly focused on the drilling community, in August 2011 Governor Cuomo signed a new law that requires a DEC permit for entities having the capacity to withdraw 100,000 gallons or more per day of surface or groundwater.[187]

New York also issued a year-long moratorium on fracking for the duration of 2011. This was required by Executive Order No. 41 issued by Governor Paterson in 2010. The state has not issued drilling permits for Marcellus Shale since 2008.[188] Governor Cuomo moved to lift the ban this summer but faced major opposition from environmental groups.[189]

Proposed Regulation[190]

Drilling. The DEC's 2011 permitting recommendations for hydraulic fracturing include prohibition of surface drilling within 2,000 feet of public drinking water supplies, drilling on the state's 18 main aquifers and within 500 feet of their area, within 500 feet of private wells (without landowner consent) or in floodplains, on principal aquifers without a site review, and within the Syracuse and New York City watersheds. Such regulation would leave more than 80 percent of Marcellus Shale available for production.

Well construction. Regarding well casing, an additional third, cemented well casing is, in most cases, required to prevent gas migration.

Fracturing fluid chemical identification. The 2011 SGEIS cites 322 chemicals proposed for use in New York, which includes health hazard information for each chemical category, identified by the N.Y. State Health Department. Applications must disclose all products and combinations used in production (including proportions), publicly identify additive names, subject to exemption where necessary (confidential business information), and evaluate alternative additives that pose less potential risk.[191,192]

Flowback water disposal. Flowback water and fracturing additive containers stored onsite require secondary containment to ensure that wastewater or chemical spills do not migrate to water supplies. A new general stormwater control permit is required to prevent water supply contamination. As for flowback water disposal, producers must seek DEC approval for disposal of

184 Montana Department of Natural Resources and Conservation, 2011

185 An overview of the Marcellus Shale and current New York State regulatory requirements is found on the NY DEC website at: http://www.dec.ny.gov/energy/46288.html

186 New York Department of Environmental Conservation, 2011d

187 New York Department of Environmental Conservation, 2011b

188 *Wall Street Journal,* 2011

189 Griswold, 2011

190 New York Department of Environmental Conservation, 2011c

191 Groundwork, 2009

192 New York Department of Environmental Conservation, 2011a

flowback water and brine water. Drilling companies have begun recycling significant amounts of flowback water to reduce the need for disposal since the 2009 SGEIS.

Waste tracking. The DEC monitors disposal of flowback water, production brine, and other drilling waste in a manner similar to the handling of medical waste.

Water treatment. Under existing federal water laws and regulation, full analysis and approval is required, including treatment capacity analysis for POTW facilities and contingency plans in the case that primary wastewater disposal is a POTW, before a water treatment facility accepts flowback water.

Water withdrawal. Under the DEC's Water Withdrawal legislation, a permit is required for withdrawal of large volumes of water for industrial or commercial uses, subject to limits, which will include an annual report issued on the total amount of water withdrawn or purchased.

Local government notification. The DEC will notify local government bodies of each high-volume fracturing well permit application, while applications must prove that drilling will remain within local land use and zoning laws.

Ohio

Proposed Regulation

Ohio is drafting a general permit that would regulate air emissions from shale gas operations.[193] The general permit is expected to cover equipment used at shale gas sites such as internal combustion engines, dehydration systems, truck-loading racks, storage tanks, flares, and unpaved roadways.

Pennsylvania

The Pennsylvania Department of Environmental Protection (DEP), Bureau of Oil and Gas Management, regulates the state's hydraulic fracturing industry.[194] In September 2010, Pennsylvania underwent an in-depth State Review of its hydraulic fracturing processes to address regulatory issues, led by the STRONGER.[195]

The Pennsylvania Senate approved a bill, SB 1100, on November 15, 2011 that would place an impact fee on Marcellus Shale natural gas wells.[196] As currently written, drilling companies would have to pay an annual decreasing fee on their wells for a period of 20 years. The fee would start at $50,000 and would be split between counties/municipalities (55% of the fee), and the state (45%). The fee would decline to $10,000 during years 11 to 20, and would increase if natural gas prices rise. Money from the fee is intended to address impacts associated with drilling in the Marcellus region and will be used to help pay for infrastructure, environmental programs, and other related areas. The bill also contains provisions associated with zoning and would allow for the Attorney General to decide whether local zoning rules are harming drilling. The bill contains environmental provisions as well, such as protections against groundwater pollution through casing and other requirements.

Other current regulation.[197] The DEP's Regulatory Basics Initiative evaluates ongoing and proposed regulation and policies.[198] The federal CWA and the Pennsylvania Clean Streams law require wastewater discharge permitting, monitoring, and reporting, regulated under the National Pollutant Discharge Elimination System (NPDES).[199]

Comprehensive Water Planning Process. Entities drawing more than 300,000 gallons of water over a 30-day period must register with DEP for water withdrawal to ensure water quality standards are maintained and protected.

Prevention, Preparedness, and Contingency Planning Process. Regulations at 25 Pa. Code §§ 78.55 and 91.34 require a Prevention, Preparedness, and Contingency (PPC) plan to identify potential risks, including risks associated with pollution, waste, disposal, chemical identification and quantities, and cleanup procedures.[200,201]

Waste Identification, Tracking, and Reporting. The DEP's Bureau of Waste Management established reporting processes with use of its Form 26R, Chemical Analysis of

193 Ohio Environmental Protection Agency, 2011

194 Pennsylvania Department of Environmental Protection, 2011

195 STRONGER Inc., 2011b

196 State Legislature of Pennsylvania, 2011

197 STRONGER Inc, 2011b

198 Pennsylvania Department of Environmental Protection, 2011b

199 Pennsylvania Department of Environmental Protection, 2011c

200 Pennsylvania Department of Environmental Protection, 2010a

201 Pennsylvania Department of Environmental Protection, 2011d

Residual Waste, including wastewater produced during oil and gas drilling and production.[202] Waste generation, transportation, and disposal tracking requirements are included in the DEP's residual waste regulation, found at 25 Pa. Code Chapter 287.[203] Waste disposal in UIC wells is not easily accessible or economically viable in Pennsylvania due to the geologic structure of the state. Thus, whereas other states take advantage of UIC waste disposal wells, producers in Pennsylvania transport wastewater to Ohio for underground disposal in addition to wastewater recycling for reinjection.

Proposed Regulation

STRONGER's State Review identified a number of recommended actions to improve Pennsylvania's regulatory process, including a casing and cementing plan (onsite during well construction for DEP review and including cement job log).

Texas

The Texas Railroad Commission (RRC) regulates oil and gas well construction and water protection.[204] The RRC issues well permits and monitors drilling, production, and completion.[205] Well construction requires three layers of steel casing and cement to protect water supplies.[206] Upon completion of well stimulation treatment, operators are required to provide fracturing data (including amount of fluid and sand injected) to the RRC's form G-1: Gas Well Back Pressure Test, Completion or Recompletion Report and Log.[207] Texas Governor Rick Perry signed H.B. 3328 into law on July 15, 2011, requiring oil and gas producers to disclose chemicals used in hydraulic fracturing fluids, although the law provides a provision for proprietary formulas.[208] Although many states, such as California, Colorado, Michigan, Montana, New York, and Texas, have disclosure-related regulations, Texas became one of the first states, along with Colorado, to legislate hydraulic fracturing fluid content.[209]

Proposed Regulation

The Texas RRC issued a memo[210] in September 2011 that includes proposed regulatory language related to the disclosure of hydraulic fracturing fluids in water. The proposal would apply to individual wells. Information must be supplied by the operator for posting on the FracFocus website.

The Fort Worth area of Texas limits well completion emissions through REC procedures to direct salable gas directly to the sales line or to shut in for later production.[211] REC procedures are not required for wells that do not have a sales line (i.e., exploratory wells), for wells permitted prior to July 1, 2009, or for the first permitted well on the pad site.[212] Flaring emissions are allowed in certain cases, in place of venting gas, with approval from the Gas Inspector.

West Virginia

A West Virginia state legislative committee approved a bill on November 16, 2011 focused on Marcellus Shale drilling. The bill would require new standards for gas well casing, would increase permit fees to help pay for increased state inspections, and would create a 625-foot buffer zone between wells and homes. Permit fees would be set at $10,000 for the initial well, and then $5,000 for additional ones. Another contentious issue is the buffer zone, which a number of landowners wanted set at 1,000 feet.[213]

In August 2011 the West Virginia DEP issued emergency regulations governing horizontal hydraulic fracturing.[214] These emergency regulations were directed by Executive

202 Pennsylvania Department of Environmental Protection, 2010b

203 Pennsylvania Code Title 25, Chapter 287 available at http://www.pacode.com/secure/data/025/chapter287/chap287toc.html

204 Railroad Commission of Texas, 2011a

205 Railroad Commission of Texas, 2011b

206 Groundwork, 2011

207 Railroad Commission of Texas, 2011c

208 Davidson, 2011

209 Nettles, 2011

210 Railroad Commission of Texas, 2011d

211 City of Fort Worth Ordinance No.: 18449-02-2009 Available at: http://fortworthtexas.gov/uploadedFiles/Gas_Wells/090120_gas_drilling_final.pdf

212 City of Fort Worth Ordinance No.: 18449-02-2009 Available at: http://fortworthtexas.gov/uploadedFiles/Gas_Wells/090120_gas_drilling_final.pdf

213 Porterfield, 2011

Order 4-11, issued by the Governor in July 2011. The rules are set to remain in effect for 15 months, until October of 2012.[215] The regulations institute provisions such as requiring operators to provide the DEP with estimates of water use – companies must develop plans for erosion and sediment control (if the well sites disturb three acres or more of surface); if companies plan to use more than 210,000 gallons of fresh water in any month, they must file a water management plan. Additionally, companies must record the quantity of flowback water, the quantity of produced water, and the method in which the produced water is disposed; they must construct wells that comply with the casing and cementing standards published by the American Petroleum Institute; and they must meet other requirements. Well site safety plans are required of applicants involving well sites that will disturb three or more acres of surface. Permit applicants within the boundaries of a municipality must publish public notice of the filing, and no permit can be issued until at least 30 days' notice has been provided to the public.

There is a bill currently being considered, SB 424, that would expand on the current emergency regulations by codifying new well cementing and casing standards, imposing permit fees, and establishing new rules for the siting of drilling requirements. The most recent version of the bill was passed by the Joint Select Committee on Marcellus Shale on November 18, 2011.[216]

Wyoming

Wyoming regulates methane emissions through its well completion and re-completion permitting process. Emissions of VOCs and hazardous air pollutants (HAPs) associated with flaring and venting of hydrocarbon production should be eliminated to the extent possible through REC procedures.[217,218] According to the permitting guidance document, REC procedures are required in the Jonah and Pinedale Anticline Development Area (JPAD) and the Concentrated Development Area (CDA), which is defined by seven counties: Sublette, Lincoln, Uinta, Carbon, Sweetwater, Fremont, and Natrona.[219]

Other Regulatory Activity

Delaware River Basin Commission

The Delaware River Basin Commission, which covers four states – Pennsylvania, New Jersey, New York, and Delaware – is expected to vote on rules that address fracking in the river's watershed. In New York State, the Susquehanna River Basin Commission (SRBC) and the Delaware River Basin Commission (DRBC) regulate the rate and volume of water withdrawals for the watersheds.

D. Shale Gas Regulation in Europe

Although Europe currently has no commercial shale gas production, a number of government bodies are assessing the potential and pitfalls associated with shale gas extraction. Europe's primary concerns regard land scarcity, water scarcity, and water contamination. A recent study published by the European Commission (the EU's executive body) stated that shale gas production needs no further legislation, at least until commercial scale production levels are achieved. The study, which focused on only four countries – Poland, France, Germany, and Sweden – stated that current fossil fuel legislation and regulations are sufficient to guarantee safe and environmentally friendly development.[220]

The EU report, carried out by the Belgian law firm Phillippe & Partners under direction of the European Commission, stated that national-level laws and regulations, which apply to both conventional and unconventional oil and gas production, are currently sufficient.[221] The report also asserted that the nascent stage of shale gas development does not yet warrant specific legislation, either at the European or national level. According to the report, water protection issues are covered under the EU's Water Framework Directive and the Mining Waste Directive, whereas chemicals use is covered under the Registration, Evaluation, Authorisation, and Restriction

214 West Virginia Department of Environmental Protection, 2011a

215 West Virginia Department of Environmental Protection, 2011b

216 State of West Virginia, 2011

217 State of Wyoming Department of Environment Quality, 2010a

218 Wyoming Department of Environmental Quality, 2010b

219 Wyoming Department of Environmental Quality, 2010b

220 Torello, 2012

221 Tolbaru, 2012

of Chemicals (REACH) regulations.[222]

The IEA has announced that it will make regulatory recommendations for a number of countries that have shale gas resources and are exploring the industry, including a number of European countries.[223] The recommendations are an attempt to ensure that shale gas exploration and production is done in a safe and environmentally friendly manner, without regard to national boundaries.[224]

At the national level, France became the first country to ban hydraulic fracturing in mid-2011.[225] In Germany, the North-Rhine Westphalia imposed a moratorium on shale gas production in March 2011, asking ExxonMobil to suspend hydraulic fracturing operations until expert opinion could be sought.[226] ExxonMobil is awaiting the research results into hydraulic fracturing's impact on groundwater, but still plans to push for unconventional gas exploration in Germany, despite opposition in a number of northern states.[227,228] Bulgaria has banned shale gas exploration amid public concerns over environmental impact.[229]

The United Kingdom's Cuadrilla, which has been exploring the U.K.'s shale gas potential, halted drilling operations near Blackpool in April and May 2011 after small seismic tremors were detected.[230] In May 2011 the U.K. Energy and Climate Change (ECC) Committee's fifth report on shale gas was supportive of shale gas development. In November 2011, however, a seismicity study indicated that fracking could trigger seismic events, although the British Geological Survey has asserted that such small earthquakes are naturally occurring or are commonly associated with mining activities. The U.K. government has not yet made a decision on resuming fracking operations.

Poland, arguably Europe's strongest shale gas supporter, with the most favorable regulations toward development, recently revised its technically recoverable resource base estimate down to 30 Tcf from that stated by the U.S. EIA of 187 Tcf.[231]

Europe's population density is three times that of the United States.[232] Issues associated with land scarcity are thus important considerations for European regulatory bodies. Whereas land leases in the United States may involve a handful of landowners, a similar negotiation in many parts of Europe could mean dealing with hundreds of landowners. Poland, which is at the forefront of Europe's shale gas exploration, enjoys a relatively rural population, particularly in shale-rich areas. Conversely, France's Paris Basin is in the heart of one of Europe's most densely populated areas. Shale gas production in that region thus would call for cooperation between thousands of residents and a repeal of the current ban. Compounding land lease issues is the mineral rights structure of Europe. Although U.S. landowners lease mineral rights directly to oil and gas companies, European governments typically own the mineral rights, giving landowners little incentive to acquiesce to exploration. Issues associated with water scarcity and potential contamination are also key to any future shale gas regulation in Europe.

E. Shale Gas Regulation in India

India is in the initial stage of shale gas production, with its first experimental shale gas well drilled recently. Given the uncertain state of India's shale gas industry, there is very little shale-specific regulatory information available. Recognizing the importance of the country's estimated shale gas resources, the Indian Minister of Petroleum and Natural Gas recently announced that the ministry plans to release a shale gas policy by March 31, 2013.[233] The policy framework will incorporate views of all concerned ministries and governmental departments; thus, completion will depend on the consultations with each governmental authority, and will consider necessary environmental measures to ensure safe operating practices. In a similar move, the Indian government signed a Memorandum of Understanding (MOU) with the U.S. government in November 2010 to support joint efforts to develop India's shale gas resources, as well as a regulatory framework. As the MoPNG expects

222 Tolbaru, 2012

223 Miles, 2012

224 Miles, 2012

225 Lacey, 2011

226 Natural Gas Europe, 2012

227 Natural Gas Europe, 2012

228 Reuters, 2012

229 Wynn, 2012

230 Richards, 2012

231 Wynn, 2012

232 Kuhn & Umbach, 2011

233 PRLog, 2012

to select blocks for the 2012 shale gas bids, the ministry will continue to work with U.S. government agencies to develop a regulatory framework for shale gas development.[234]

The Petroleum and Natural Gas Regulatory Board (PNGRB) was established in 2007 to oversee the licensing of transmission pipelines and city gas distribution systems. With these developments, the conditions to support an expanded national natural gas grid (NGG) and a workable natural gas market are essentially in place. PNGRB is the regulator in India, and it sets the rules by which natural gas pipelines are to be authorized for construction and operation. The PNGRB also sets the rules under which pipeline cost of service and tariff rates are determined. In addition, the PNGRB has set rules governing affiliate interactions where pipelines offer both merchant and transportation services.

In addition to regulatory issues associated with India's pipeline expansion, potential regulatory issues may focus on adequate pricing of natural gas markets, land access in a densely populated country, and water availability. Given the nascent stage of India's shale gas industry, other regulatory issues may also emerge as the industry advances. Given that production has not met expectations from Reliance's Krishna-Godavari Basin off the east coast of India, shale gas development could provide another avenue for India's growing demand.[235]

F. Shale Gas Regulation in China

China's shale gas industry is in the experimental stage of production, with just a few wells drilled in the Sichuan Basin. The Chinese central government has shown strong support for the development of shale gas and will likely promote regulations that streamline the industry's development. Despite this, China's water scarcity issues may limit expansion of the shale gas industry, given the ample water supplies required for hydraulic fracturing.

Given the strategically sensitive nature of the energy sector, even major international oil companies have encountered regulatory hurdles in pursuing Chinese partner firms and exploration opportunities.[236] In January 2012, China approved shale gas as independent mining resources to encourage Chinese firms to develop the resource, although foreign firms can only participate through joint ventures with Chinese companies.[237]

China's Environmental Protection Ministry is quite underfunded and struggles with local-level enforcement.[238] Economic development is often given priority over environmental protection. As the country continues to find a balance between environmental protection and sustainable economic growth, many are concerned over the negative impact that improper shale gas extraction may have on China's environment, as well as the shale gas production industry overall. The suspected high concentrations of hydrogen sulfide (relative to those seen in U.S. shale deposits) may exacerbate China's already grave pollution concerns, if sound regulatory measures are not executed. Hydrogen sulfide is a highly corrosive pollutant that can, in addition to polluting the air, erode drilling equipment, thus increasing fugitive emissions of other pollutants such as methane through leakage.[239]

While government leaders are composing comprehensive environmental protection legislation, the current version does not include shale gas development, and given the advanced stage of the legislation piece, adding in shale guidelines is unlikely.[240]

The IEA has announced that it will make regulatory recommendations for a number of countries, including China, in an effort to regulate international shale gas development.[241] The measures will include responsible operating procedures to limit environmental degradation and ensure safe production.[242]

In addition to shale-specific regulations, pipeline infrastructure development and the potential for gas price reforms create a number of uncertainties for successful development of shale gas in China.[243]

234 U.S. Department of Commerce, 2011

235 ICF, 2011b

236 Kim, 2011

237 Miles, 2012

238 Hart & Weiss, 2011

239 McDermott, 2011

240 Hart & Weiss, 2011

241 Miles, 2012

242 Miles, 2012

243 Hook, 2011

9 Best Practices

Concern over the environmental impacts of shale gas production has increased and broadened as rapidly as the practice itself. At the same time, the technology and practice of shale gas production are evolving rapidly. In response to public concern or as part of existing environmental regulatory programs or industry best practices, industry, government, and non-government organizations are increasingly focusing on best practices that will mitigate the potential environmental and health effects of shale gas production and delivery. Some of these practices are listed below. These represent currently available and cost-effective technologies that can mitigate environmental effects. They may not be sufficient to address all impacts in all cases but should be considered when evaluating the development of new shale gas resources in different countries.

A. Industry Best Practices

Although there are many potential environmental impacts of shale gas production, there is also much that can be done within existing, available technology and operating practices. For fugitive methane emissions, the EPA GasSTAR program has documented several dozen practices and technology options for all segments of the gas production and transmission sectors. These are listed at the GasSTAR website.[244] Other measures that have been identified in industry and regulatory proposals are listed below by industry segment and medium.

Shale Gas Production

Air

- Conventional emissions from trucks, including water delivery and removal – Trucks meeting the latest U.S./E.U. emission standards have very low emissions. Water recycling and reuse can reduce the need for trucks.
- Emissions from drill and fracturing equipment – Diesel engines meeting the latest U.S./E.U. emission standards have very low emissions. Gas engines or electric motors may also be cleaner alternatives to power this equipment.
- Conventional emissions from well completion – Reduced emission completion (and recompletion) and, to a lesser extent, flaring can capture or destroy these emissions. Some flaring practices are more effective than others.

Water

- Water consumption for fracturing – Water should be taken from approved ground/surface water sources. Recycled/reused water, from shale gas production or other sources, should be used wherever possible.
- Groundwater contamination from fracturing process – Monitoring of groundwater near production sites.
- Groundwater contamination from well casing leakage – Well construction and casing should meet best industry standards, such as the API or other local industry or government standard setting agencies.
- Surface water contamination from spills – Apply best practices for water management.
- Treatment and disposal of wastewater – Recycling and reuse of wastewater. Disposal in regulated deep injection wells. Disposal in water treatment plants that are designed to mitigate the appropriate pollutants.
- Reporting of chemical constituents of fracturing fluids – Report all constituents to a publicly accessible third party such as FracFocus.

244 U.S. EPA, 2011d

Climate

- Methane from well completions – Reduced emission completion and flaring can capture and/or destroy these emissions. Some flaring practices are more effective than others.
- Methane emissions from well liquids unloading – A variety of reduced emission liquids unloading techniques are available, including plunger lifts and pumps.
- Methane emissions from tanks – See GasSTAR options.

Gathering

Air

- Conventional emissions from compressors – Use lowest available emission technologies for engines and combustion turbines. These may be limited by the composition of wellhead gas. Electric driven compressors may be feasible in some locations.

Climate

- Fugitive methane emissions from gathering systems – See GasSTAR options.

Gas Processing

Air

- Conventional emissions from combustion processes – Apply best available controls for conventional emissions (NO_x, SO_2, PM, VOC) from process heaters and prime movers.

Climate

- Fugitive emissions – See GasSTAR options.

Pipelines and Distribution

Climate

- Fugitive methane emissions from gathering systems – See GasSTAR options.

B. Government Best Practices

There are a variety of government regulatory practices in place or under consideration that would affect shale gas production, processing, and delivery. Some of these are specific to the natural gas industry and others are generic environmental control policies that apply to the gas sector as well as others. Sections 9.3 through 9.6 describe some of the recent efforts by state, local, and national governments to implement such measures. Many of these are based on the cost-effective, demonstrated environmental best practices described in Section 10.1. In a regulatory context, this also means setting enforceable standards of performance based on these practices and technologies and including mechanisms and structures to monitor and enforce compliance with the standards. In setting control requirements, standards of performance are generally preferable to technology requirements, because standards are more likely to promote innovation in reducing emissions. Examples of recent government regulatory initiatives are listed below.

Shale Gas Production

Air

- Conventional emissions from trucks, including water delivery and removal – The United States and European Union have established stringent emission standards for diesel truck engines. These require ultra-low sulfur diesel as well as advanced engine controls and pollution control equipment. These types of regulations typically apply to all engines, so applying them only to the gas production sector would be difficult.
- Emissions from drill and fracturing equipment – The United States and European Union have established stringent emission standards for diesel engines. These require ultra-low sulfur diesel as well as advanced engine controls and pollution control equipment. These types of regulations typically apply to all engines, so applying them only to the gas production sector would be difficult. Gas engines or electric motors may also be cleaner alternatives to power this equipment and could be required under certain circumstances.
- Conventional emissions from well completion – Reduced emission completion and flaring can capture and/or destroy these emissions. Some flaring practices are more effective than others. U.S. states including Colorado and Wyoming have established requirements for REC and/or flaring. The U.S. EPA has proposed regulations requiring REC or flaring for new shale gas completions that could serve as a model for other countries.

Water

- Groundwater contamination from fracturing process – Monitoring of groundwater near production sites.
- Groundwater contamination from well casing leakage – Well construction and casing should meet best industry standards.
- Surface water contamination from spills – Apply best practices for water management.
- Treatment and disposal of wastewater – Recycling and reuse of wastewater. Disposal in regulated deep injection wells. Disposal in water treatment plants that are designed to mitigate the appropriate pollutants.
- Reporting of chemical constituents of fracturing fluids – Report constituents to a publicly accessible third party such as FracFocus.

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Gathering

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- Conventional emissions from compressors – Use lowest available emission technologies for engines and combustion turbines. These may be limited by the composition of wellhead gas. Electric driven compressors may be feasible in some locations.

Climate

- Fugitive methane emissions from gathering systems – See GasSTAR options.

Gas Processing

Air

- Conventional emissions from combustion processes – Apply best available controls for conventional emissions (NO_x, SO_2, PM, VOC) from process heaters and prime movers.

Climate

- Fugitive emissions – See GasSTAR options.

Pipelines and Distribution

Climate

- Fugitive methane emissions from gathering systems – See GasSTAR options.

C. Power Sector Best Practices

One of the most likely uses of newly developed natural gas is as an alternative to higher emitting fuels (oil or coal) for electricity generation. On the other hand, there is also a focus on moving to even lower-emitting energy sources, such as renewables, as quickly as possible. Design of new gas and electricity infrastructure should take these goals into account, both from a physical infrastructure design perspective and in the design of energy markets and regulation. Another study found that abundant, low-cost natural gas could delay the move to even lower-emitting technologies unless there are regulations in place to require GHG reductions.[245]

One consideration is the potential investment in new natural gas infrastructure. A large investment in pipelines could effectively "lock in" gas use for many years. An alternative would be to maximize the construction of new gas-fired power plants near the gas supply and invest in electricity infrastructure that could later be used to transport electricity from renewable sources. It also assumes that the potential sources of renewable electricity are in the same general area as the sources of natural gas. In this case also, the electricity end-users should be highly efficient so as to be more efficient than the direct use of natural gas. Finally, it requires consideration of the needs of large industrial gas consumers, who may have different locational requirements and have continuing requirements for gas infrastructure. All of these should be considerations in the design and development of natural gas infrastructure.

Integration of variable renewable energy sources into the electric grid and coordination with the natural gas infrastructure also requires broader careful planning for the design and operation of both grids.[246] Support for

244 U.S. EPA, 2011d

245 Brown, 2009

246 ICF, 2011c

the variability of renewable energy sources such as wind and solar is a key design challenge for both. A major component of this challenge is providing the proper mix of rapid-start peaking generators, conventional peakers, and highly efficient combined cycle generating plants and the appropriate natural gas infrastructure to supply them. System planners should look beyond the near-term requirements of a gas-based system and incorporate the flexibility to meet the needs of a future system with a large share of renewable generators. This would include accommodation for more rapid-start peaking capacity as well as rapid-start combined cycle facilities that are now becoming available.

In the United States and Western Europe, these challenges are being addressed in the context of a highly developed existing gas and electricity infrastructure. In other countries there may be an opportunity to plan and develop gas and renewable resources, generating facilities, and infrastructure in a coordinated way, taking into account future energy supply and environmental goals as well as the different structures, ownership, contracting, and dispatch procedures of the electricity and gas industries in each country. These considerations should be part of the planning for development of natural gas resources, integration with the power sector, and the broader discussions of future electricity infrastructure development.

10 Conclusions

The key findings of this report are:

New technology has allowed the development of the shale gas resource. Natural gas producers in North America have developed new technologies to recover natural gas from shale formations. This has resulted in large increases in U.S. shale gas production and estimates of the North American gas resource base. The sharp and sustained growth in North American shale gas production has confirmed the basis for these estimates.

Large shale gas potential. Based on this experience, estimates of the world natural gas resource base are increasing as potential shale gas resources are assessed. The U.S. EIA estimates that global technically recoverable shale gas resources (based on assessment of shale gas resources in selected basins within 32 countries) total 6,622 Tcf, the equivalent of 60 years of 2008 worldwide natural gas consumption.[247,248] ICF estimates that the world (i.e., all counties and all basins) technically recoverable resources could range from 9,620 to 16,495 Tcf.

Significant potential impact of shale gas production. Potential production of shale gas could have a significant impact on each region's energy mix. ICF estimates that mature annual shale gas production in 2035 could be as high as 12.3 Tcf in the United States,[249] 11.5 Tcf in Europe,[250] 1.3 Tcf in India, and 25.5 Tcf in China. These are theoretical production values that assume infrastructure and market constraints are overcome.

Ability to displace coal consumption. One of the major applications of increased gas production could be displacement of coal for electricity generation. This study estimates the maximum potential for coal displacement through increased production of shale gas in each country. This is not a projection of fuel mix for each country, but an estimate of the maximum potential impact achievable through increased gas production. These estimates assume that all of the shale gas development is directed to coal displacement, although in reality some gas would likely be used in other applications. The new shale gas development also would interact with other gas resources, including LNG imports. Table 13 shows the range of potential displacement.

Large-scale infrastructure required for shale gas development. Shale gas production could mean improved energy security and less reliance on more carbon-intensive fossil fuels. Investment in gas pipeline infrastructure will be required, however, to realize shale gas development. Although the U.S. and Europe have relatively well-developed pipeline infrastructures, other regions such as India and China, will require large-scale investment in associated infrastructure to build a large shale gas industry.

Environmental impact and regulatory requirements: Concerns have been raised about the environmental impacts of several aspects of shale gas production. The key issues include concerns over groundwater impacts of the hydraulic fracturing process, surface water impacts of wastewater handling and disposal, emissions of conventional air pollutants and other general environmental impacts. While there are demonstrated mitigation measures available to address all of the potential

247 U.S. EIA, 2011a

248 Based on 2008 global natural gas consumption of 111 Tcf, bwased on U.S. EIA estimates cited in the International Energy Outlook for 2011.

249 Based on the EIA's AEO 2011 estimates. Figures for other regions based on a 2% annual production of the total technically recoverable shale gas resource base.

250 Due to the availability of reported data, "Europe" in this report is defined as the European member countries of the OECD, including Austria, Belgium, Czech Republic, Denmark, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Luxembourg, the Netherlands, Norway, Poland, Portugal, Slovakia, Slovenia, Spain, Sweden, Switzerland, Turkey, and the United Kingdom.

Table 13

Shale Gas Production and Coal Consumption Displacement Potential[251]

Region	Resource Base Source: EIA	ICF P90	ICF Mean	ICF P10
Technically Recoverable Resource Base Assessment (Tcf)				
U.S.	862	N/A	1,863	N/A
Europe	574	340	520	725
India	63	80	280	565
China	1,275	240	820	1,670
2035 Mature Shale Gas Production (Tcf)				
U.S.	12.3	N/A	17.7	N/A
Europe	11.5	6.8	10.4	14.5
India	1.3	1.6	5.6	11.3
China	25.5	4.8	16.4	33.4
2035 Mature Shale Gas Displacement of Coal Consumption (%/QBtu)				
U.S.	66% / 16.1Q	N/A	96% / 23.3Q	N/A
Europe	100% / 10.4Q	86% / 9.0Q	100% / 10.4Q	100% / 10.4Q
India	9% / 1.7Q	11% / 2.1Q	38% / 7.4Q	76% / 14.9Q
China	30% / 33.6Q	6% / 6.3Q	19% / 21.6Q	39% / 44.0Q

2035 Cumulative Incremental Pipeline Required (Pipeline Miles)

Region	Lower-bound	Upper-bound
U.S.	16,000	48,700
Europe	53,300	101,000
India	20,000	68,800
China	50,000	220,500

Note 1. P90 indicates a 90-percent probability of that resource base estimate, the mean value represents a 50-percent probability of that resource base estimate, and the P10 value indicates a 10-percent probability that the resource base is that large.

Note 2. Displaced coal consumption forecasts exceed shale gas production forecasts under the efficiency assumption that electricity generation requires 0.78 Btu of natural gas for every 1 coal-based Btu (1 MMBtu of natural gas displaces 1.28 MMBtu of coal).

environmental effects, this requires appropriate regulation and regulatory oversight. There is also concern that the life-cycle GHG emissions from methane released in the shale gas production process offset the lower CO_2 emissions from gas combustion. The consensus of recent studies is that this is not the case.

Best practices for production and utilization of shale gas. Industry and regulators have demonstrated a variety of best practices for the production of shale gas, development of natural gas infrastructure, and use of gas as a cleaner fuel and as a transition fuel to zero-emitting energy sources. The practices could be applied more widely in North America and proactively in other countries as shale gas reserves are developed.

251 ICF estimates, EIA Annual Energy Outlook 2011, EIA International Energy Outlook 2011

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