The U.S. Shale Revolution: Global Rebalancing?

“We have a supply of natural gas that can last America nearly one hundred years, and my Administration will take every possible action to safely develop this energy.”

— President Barack Obama, 2012 State of the Union Address

“The production of shale gas through fracking is the most significant development in the U.S. energy sector in generations.”

— George P. Mitchell and Mayor Michael R. Bloomberg

On September 11, 2013, the Department of Energy (DOE) approved Dominion Cove Point LNG to export liquefied natural gas (LNG) to countries that did not hold a free trade agreement (FTA) with the United States. The Dominion Cove Point project was the fourth such approval granted, and cumulatively, the four projects could export nearly 6.4 Bcf/d (billion cubic feet per day). An additional 20 applications to export to non-FTA countries awaited approval, seeking a combined export capacity of 26 Bcf/d—over a third of current daily production (see Exhibit 1). Many wondered what the DOE would decide regarding the remaining applications.

Less than a decade earlier, the idea of exporting domestically produced LNG was nearly unimaginable. In the early 2000s, the U.S. looked destined to be a net importer of natural gas, relying on foreign nations for 20% of its gas consumption. Yet, by the middle of the decade, technological advances rapidly increased accessible natural gas resources by 47% through the inclusion of shale plays and other traditionally difficult to recover reserves. Optimism over an emerging North American energy revolution soared as the Energy Information Administration (EIA) significantly expanded its estimates of technically recoverable natural gas reserves in the U.S.—up to 100 years of additional resources based on current production rates. This so-called ‘Shale Revolution’ also

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Applications to export to FTA and non-FTA countries were treated separately by the DOE. Legislation required that applications to export to FTA countries be granted ‘without modification or delay,’ and the DOE had already approved 26 projects to export up to 29.9 Bcf/d to these nations. In contrast, proposals seeking to export to non-FTA countries were treated on a case by case basis. All but one of the non-FTA export projects had already been approved for LNG trade with FTA nations.

While the DOE had already approved an export capacity of nearly 30 Bcf/d to FTA nations, the actual export volume was significantly limited by several factors. Of the 20 countries with which the U.S. held a FTA, only five had LNG import terminals. Additionally, only one of these five nations, South Korea, was among the world’s top ten importers of LNG. Consequently, natural gas producers were eager to expand their potential consumer base by opening trade with non-FTA countries.
increased high-value natural gas liquids (NGLs) production, as well as innovating oil extraction from shale plays—so called “tight oil.” Total U.S. oil production grew by over a million barrels a day in 2012, the largest increase in U.S. history.7

As projections of U.S. natural gas resources became increasingly optimistic, a heated debate emerged over what the country should do with this new abundance of shale gas and who should primarily benefit—producers or manufacturers. By 2013, U.S. natural gas prices hovered around $3 per thousand cubic feet, well below $12 in Europe and $18 in Japan (see Exhibit 2). As U.S. prices remained significantly below those in Europe and Asia, producers sought to arbitrage the price differential by exporting LNG. Investors appeared willing to bet big on U.S. natural gas; of the $135 billion worth of investments tracked by Ernst and Young in 2011, 20% were directed toward the natural gas industry (excluding pipeline transport).8

However, domestic manufacturers and utilities worried that exporting LNG would globalize the natural gas market, pushing up the prices in the U.S (see Exhibit 3). Some manufacturers had already expanded their domestic production sites, such as Cenex Harvest States’ $1.2 billion fertilizer facility and Chevron Phillips Chemical Company’s $5 billion ethylene production plant.9 Many utilities, furthermore, had replaced planned nuclear and coal power plants with natural gas combined cycle facilities. Yet, rising gas prices would drive up electric rates and cause manufacturers to lose their current cost advantage, reducing competitiveness in the international market.

The decision of whether to continue authorizing greater volumes of LNG exports loomed large for policymakers as economists contended that the U.S. Shale Revolution may have substantial macroeconomic effects on the U.S. economy (see Exhibits 4a through e). Analysts suggested that increased shale gas production could aid GDP growth, lessen the current account deficit by closing the trade deficit, and raise employment. Yet few agreed on the extent of these outcomes, how impacts on employment would vary by region and sector, or even how regulators would evaluate the “best” strategy moving forward.

President Obama was optimistic about the promises of natural gas: “The bottom line is natural gas is creating jobs. It’s lowering many families’ heat and power bills. And it’s the transition fuel that can power our economy with less carbon pollution.”10 Moreover, the shale boom gave a robust boost to Obama’s goal of doubling exports by 2015; by June 2013, gas and oil exports had grown 68.3% since the President’s announcement of the goal in January 2010.11

Internationally, governments kept a careful watch on developments in U.S. energy policy. Major natural gas importers, such as Japan and South Korea, hoped the White House would support LNG exports, as cheaper U.S. gas could reduce their trade deficits. Conversely, the largest exporters, including Russia and Qatar, sought to hold onto their market share. Because American energy companies were also producing more oil from shale, the world’s leading oil exporters, Saudi Arabia, Russia, Iran, UAE, and Nigeria, were vulnerable to increased competition from U.S. shale-fuels. In a letter to the nation’s oil minister, Saudi Arabia’s former finance minister and billionaire investor, Prince Alwaleed bin Talal warned, “The world is increasingly less dependent on oil from OPEC countries, including the kingdom.”12 While tight oil could be refined in the United States (and then the product exported), U.S law forbade exporting crude without a license.13

This left the Obama administration facing major policy decisions concerning U.S. energy exports. Would American shale resources be capable of reviving, or even transforming, the U.S. economy? Would the DOE place a cap on authorized LNG exports, and if so, at what volume? Should Congress liberalize crude oil trade? Given the growing controversy and potential surrounding U.S. shale
resources, policymakers, producers and manufacturers—both domestically and abroad—wondered what the Energy Secretary would recommend.

**Shale Gas and Tight Oil Production**

Shale gas is a natural gas which resides in fine-grained sedimentary rock formations, known as shale. Unlike traditional natural gas formations, shale gas forms directly within the pore space between the grains of organic-rich shale. Given the surrounding shale’s low-permeability, the gas is unable to migrate (even over geologic times) to neighboring, more permeable—and hence more producible—reservoir rocks. Tight oil is a crude oil that forms in a similar manner to shale gas.

At any point in time, shale gas and tight oil are only economically producible from specific types of shale formations, which contain significant accumulations of fossil resources and share the similar geological characteristics of enhanced brittleness, layering and porosity. As such, determining the economic viability of a particular geographic area often required a significant exploratory drilling program. Some geographic areas lived up to their promise, while others proved elusive, failing to have the “right” combination of characteristics.

The two most important shale gas plays were the Barnett play in Texas and the Marcellus play in the northeast, while the most crucial tight oil plays were Bakken in Montana and North Dakota and Eagle Ford in Texas. Shale plays were located throughout the U.S., and shale resources were being produced in 16 states (see Exhibit 5). The majority of tight oil produced in the U.S. was light crude.

Both shale gas and tight oil production were significantly more complex than conventional production methods. The impermeability of shale combined with the fluid properties of oil and gas often prevents the gas or oil in the shale deposits from flowing easily into the well bore, such as in traditional production. Consequently, the majority of shale formations have long been considered commercially unviavle. Due to these difficulties in production, shale gas and tight oil were often referred to as unconventional resources.

Hydraulic fracturing (referred to as ‘fracking’) is a method of extracting these fossil resources from shale plays in which a slurry mixture of water, chemicals and sand is injected at very high pressures into horizontal wells, up to 10,000 feet in depth and penetrating hundreds of meters into surrounding shale beds. The high-pressure injection enters the formation through perforations in the well bore and fractures the brittle shale. The injected slurry mixture widens and props open the fractures in the shale, releasing the natural gases and oil which are trapped within the shale formations. Once the resources are released, they begin to flow back to the well bore for extraction.

Fracking usually entails horizontal drilling, in which a well is drilled vertically into the shale formation before extending horizontally through the shale layer, dramatically increasing the area from which a drilling operation can extract natural gas or oil. Together, fracking and horizontal drilling have allowed drillers to extract commercial quantities of fossil fuels, turning shale production into an economical venture.

**History of Shale Gas**

While shale gas only began being produced on a wide scale in the mid-2000s, it was first commercially produced in 1821 in Fredonia, NY, using shallow, low-pressure fractures. For the next hundred years, natural gas was produced from shallow shales close to oil producing fields, primarily located in the Appalachian and Illinois basins. In 1947, the first experimental hydraulic fracturing
took place in Grant County, Kansas. Two years later, hydraulic fracturing was first used to commercially produce natural gas in Stephens County, Oklahoma. By the mid-1950s, hydraulic fracturing was a widely accepted commercial process, with more than 100,000 treatments in operation.18

Yet, by the 1970s, only a marginal volume of natural gas came from shale.19 For the next four decades, private entrepreneurs and government agencies worked on developing the technological breakthroughs which ultimately sparked the Shale Gas Revolution. In 1976, amid fears that natural gas resources were diminishing, the DOE launched the Unconventional Gas Research Program, including the Eastern Gas Shales Project, which mapped the sizes of deposits and brought together universities and private companies to demonstrate gas recovery techniques for improved extraction. From 1978-1981, the DOE was funding between $20-30 million per annum on R&D projects.20 Throughout the decade, the DOE and its partner agencies developed early shale fracturing, directional drilling technologies, and 3-dimensional seismic mapping. Fred Julander of the National Petroleum Council commented on the role of the federal government, “The Department of Energy was there with research funding when no one else was interested and today we are all reaping the benefits. Early DOE R&D in tight gas sands, gas shales, and coal-bed methane helped to catalyze the development of technologies that we are applying today.”21

With help from the federal government, the ‘Father of Shale,’ private entrepreneur and head of Mitchell Energy, George Mitchell was responsible for developing the means for efficient gas recovery from large-scale hydraulic fracturing. While others within the energy industry believed that fossil fuel resources were quickly draining, Mitchell relied on the federally funded mappings of shale reserves as proof that ample resources remained for those capable of getting gas to flow in economically viable quantities. Mitchell recalled the opposition he faced, “My engineers kept telling me, ‘You are wasting your money, Mitchell’… And I said, ‘Well damn it, let’s figure this thing out because there is no question there is a tremendous source bed that’s about 250-feet thick.’ We made it to be the hottest thing going.”22

In 1991, Mitchell Energy began working with the DOE and the Gas Research Institute (GRI) to develop crack mapping and the re-fracturing of wells, in addition to building the firm’s first horizontal well in the Barnett shale play. By the late 1990s, the firm was economically producing shale gas, turning the Barnett shale region into one of the most active gas producing plays in the U.S. Larry Nichols, the then chairman and CEO of Devon Energy, recalled, “We turned our noses up because we didn't think it would work.”23 Devon Energy later acquired Mitchell Energy for $3.1 billion. Following Mitchell’s death, energy scholar Daniel Yergin reflected, “It is because of him that we can talk seriously about ‘energy independence.’”24

A North American Energy Revolution

From the early 1990s to the mid-2000s, the future of the United States’ natural gas supply looked increasingly dependent on imports. Between 1993 and 2005, the annual amount of natural gas imports doubled to more than 4,340 Bcf, representing roughly 20% of domestic gas consumption (see Exhibit 6). By the early 2000s, there were over 47 regasification terminals planned for construction in order to handle increased volume of LNG imports from overseas.25 Driving the growth in imports was a stagnating domestic supply, both in terms of known reserves and production rates, which failed to keep pace with burgeoning demand. Since the early 1990s, proven reserves remained at constant levels as discoveries of new reserves barely matched the annual volume extracted (see Exhibit 7). 2004 saw the lowest increase in new gas fields in the previous 12 years, while production in 2005 measured the same it had been a decade earlier.26
However, new data from the U.S. Energy Information Administration (EIA) suggested that the state of the U.S. natural gas supply was changing. The EIA found that proven reserves of natural gas had increased 6% in 2005, the biggest increase since 1970. Driven by rising prices, over 32,000 exploratory and developmental wells were drilled per year between 2006 and 2008 (see Exhibit 7). Until the end of the decade, natural gas production showed robust growth, while the increase in proven reserves was more than 35% higher than the previous ten-year average.

In 2010, the proven reserves of natural gas and oil reached the highest levels recorded since the EIA began publishing reserve estimates in 1977. The dramatic shift in natural gas production was assisted by technological advances, which opened up new sources of natural gas, such as shale, which had previously been technically or economically unrecoverable. As George Mitchell observed, it’s not a surprise that our fracking technology has helped turn American gas markets upside down. We were confident in its upside potential. What’s surprising is how quickly it’s happening. In 2000, shale gas represented just 1% of American natural gas supplies. Today, it is 30% and rising.

The EIA declared that shale gas was a ‘game changer’ for the U.S. natural gas market, expected to account for 46% of U.S. natural gas production by 2035 (see Exhibit 8).

North America’s natural gas revolution was matched by an equally optimistic trend in tight oil. In 2012, U.S. oil production grew by one million barrels per day, the largest annual increase since commercial crude production in the U.S. began in 1859 (see Exhibit 9). Tight oil production was expected to grow rapidly in the three decades up to 2040; the EIA projected that tight oil might account for one-third of U.S. petroleum production by 2014, reaching a peak production of 2.8 million bpd in 2020 (see Exhibit 10). Additionally, the U.S.’s technically recoverable tight oil reserves were the second largest in the world, only behind Russia. Moreover, tight oil appeared capable of even surpassing shale gas’ rapid productivity growth. A McKinsey study found that tight oil output was growing more quickly in its first seven years of production than shale gas during its early development (see Exhibit 11).

Within the U.S., two tight oil formations – the Bakken Shale and the Eagle Ford Shale – were producing significant quantities of oil. The Bakken field, which occupied 200,000 square miles underlying Montana, North Dakota and Saskatchewan, was thought to hold 3 to 4 billion barrels of recoverable oil. Oil output, in mid-2012, was nearly 21 million barrels per month. The Eagle Ford Shale, first discovered by Petrohawk in 2008, covered 20,000 square miles in Southeast Texas. The area was developed for a mix of oil and natural gas; in July 2012, production exceeded 310,000 bpd (9.3 million barrels per month).

Several other regions in the U.S. had high potential for tight oil production. For example, an IHS report in October 2012 suggested that the Utica-Point Pleasant formation in Ohio might someday be as productive as the Eagle Ford formation. The Monterey Shale in California was an especially high-potential but uncertain tight oil play. EIA described the Monterey/Santos play as “the largest shale oil formation [in the contiguous U.S.] … estimated to hold 15.4 billion barrels of oil.”

An Arbitrage Opportunity?

Due to the high cost of transport, natural gas markets were highly regionalized. The majority of natural gas trade occurred over land, meaning gas contracts were confined by geography and pipeline capacity. In the late 1950s, the first LNG tanker proved that natural gas could also be
transported by sea. In order to be economical to do so, natural gas was liquefied by reducing the temperature to minus 162.2 degrees Celsius, resulting in a 600-fold reduction in volume. Yet, overseas trade also required substantial capital investments, including liquefaction plants, cargo ships, and regasification facilities. Initial capital expenditures for liquefaction plants amounted up to $2 billion, while LNG tankers cost roughly $200 million (see Exhibit 12). In 2011, BP estimated that roughly 30% of natural gas was traded as LNG.

Traditionally, natural gas markets have been dominated by state-controlled firms in major exporting nations, such as Qatar and Russia. However, in the United States, the natural gas market was largely deregulated during the 1970s and 1980s. Following the signing of the North American Free Trade Agreement (NAFTA) in 1994, North America developed a continent-wide trade in natural gas dictated by market forces. While natural gas was a traded commodity in the U.S. with prices usually linked to a benchmark called the ‘Henry Hub,’ the majority of natural gas trade in Europe and Asia occurred via long-term contracts indexed to oil. These contracts were ‘take-or-pay,’ which guaranteed buyers would purchase a minimum volume of gas at a certain price point, regardless of spot price variations.

During the 2008-2009 financial crisis, natural gas prices plummeted internationally. However, in comparison to prices in Asia and Europe, the U.S. Henry Hub price failed to rebound after the crisis (see Exhibit 2). As natural gas supplies in North America continued to increase over this period, prices in the U.S. and Canada remained low, creating a substantial gap with those in Asia and Europe. In 2012, the average prices in Europe and Japan were $12.00/mmbtu and $18.10/mmbtu, respectively, as compared with a low of $2.80 in the U.S. While the increased gas abundance pushed down the price of natural gas in the U.S., there was limited effect elsewhere due to the regionalized nature of the natural gas market.

By 2011, natural gas producers in the U.S. recognized an opportunity to arbitrage the sizeable differential between domestic production costs and prices in Asia and Europe. Goldman Sachs estimated that the differences between natural gas prices in the U.S. and the U.K meant a potential arbitrage opportunity worth $188 billion, or 1.2% of GDP, per year.

Hovering around $18, prices in Asia were more than six times greater than those in the U.S. It cost an estimated $6 to liquefy and ship a thousand cubic feet of natural gas to Asia, making each marginal export profitable after the upfront investments had been recouped, assuming constant prices. However, exporting LNG required billions of dollars’ worth of infrastructure, meaning companies needed to guarantee a strong enough demand in advance.

In order to be financial viable, proposed projects needed the ability to export to non-FTA countries. Since 1938, natural gas exports from the U.S. had been carefully regulated by the Department of Energy according to the Natural Gas Act. The Act required any firm seeking to import or export natural gas to obtain the approval of the DOE to ensure that the proposed trade did not conflict with ‘public interest.’ The Natural Gas Act distinguished between applications seeking to export to countries with free-trade agreements with the U.S. (FTA nations) and those without (non-FTA nations). The Act specified that all FTA applications, “shall be deemed to be consistent with the public interest, and applications for such importation and exportation shall be granted without modification or delay.” Of the 17 countries with which the U.S. held free-trade agreements, only five—Canada, Chile, Dominican Republic, Mexico, and South Korea—had LNG import terminals. Non-FTA countries that had re-gasification terminals included Belgium, China, France, Greece, India, Italy, Japan, Portugal, Puerto Rico, Spain, Taiwan, Turkey, and the UK.
Companies seeking to export to non-FTA countries underwent careful additional consideration by the DOE. All applications were publicly posted, followed by a comment period of 45 days. Submitted applications were reviewed on a case by case basis, according to the date they were received. Additionally, a Federal Energy Regulatory Commission (FERC) permit was needed before construction could begin on any new or expanded facilities. Finally, an environmental assessment had to be completed according to the National Environmental Policy Act (NEPA).

However, the determination of whether increased volumes of natural gas exports were in the ‘public interest’ remained unclear, as analysts began insisting that greater exports would raise U.S. gas prices. In May 2011, the DOE issued a conditional approval to Sabine Pass Liquefaction LLC, the first long-term authorization for the exportation of LNG to non-FTA nations. Before reviewing the two additional applications awaiting approval, the DOE requested that the EIA and NERA Economic Consulting study the potential effect on domestic prices and the macroeconomic impact of increased LNG exports. As these two outside organizations assessed the net benefits of LNG exports, the DOE took a nearly two year hiatus from considering further applications.

The waiting period ended in May 2013 when the DOE approved the Freeport LNG expansion project in Texas. Three months later, the DOE authorized the Lake Charles project in Louisiana, followed by the Dominion Cove Point LNG project in September. The four approved projects had a collective export capacity of over 6 Bcf/d. Twenty other proposals had been submitted to the DOE, requesting an additional export capacity of roughly 26 Bcf/d (see Exhibit 1). Several analysts contended that the DOE should only determine the capability of exporting LNG rather than the capacity, which would be self-regulated according to the markets.

Price Impact

Most analysts were in agreement that permitting increased LNG exports would reduce the differential between U.S. and international prices for natural gas. The ability to transport large quantities of LNG was transforming natural gas into a globally integrated market. The executive vice president of GDP Suez’s Global Gas and LNG Business line stated, “There is a certain globalization in this market, which is improving the ability to use gas as a global commodity.” Consequently, the existing system of regional pricing was eroding.

Many believed that the diversification of supply sources was causing oil-indexed contracts to give way in Europe. U.S. LNG exports were expected to be pegged to the Henry Hub price, which would open up more opportunities for a global transition to competitive, market-dictated prices. About half of European gas supply was already sold under Hub prices, while the other half was under long-term contracts, linked to movements in oil prices. Deloitte predicted that increases in U.S. gas exports could cause prices in Europe to drop by $0.69/MMBtu, while Asian prices could fall by $0.60/MMBtu by 2030.

As LNG exports were expected to lower prices in Europe and Asia, supply & demand suggested that domestic prices would likely rise. However, there was widespread disagreement over how much. As compared with the price impact of no more additional exports, the EIA estimated that wellhead prices could see maximum increases of between 14% ($0.70/Mcf caused by increasing exports by 6 Bcf/d over 6 years) and 36% ($1.58/Mcf caused by increasing exports by 12 Bcf/d over 4 years; see Exhibit 3). ICF found that prices would increase 13% ($0.59/MMBtu caused by 8 Bcf/d of exports by 2035). However, Deloitte argued that the average price increase would be quite small, only rising 2% from 2016 to 2035 (an increase of $0.12/MMBtu caused by 6 Bcf/d of exports).
By early 2013, higher gas prices were already hitting the U.S. During the first half of 2013, average spot prices for natural gas at most trading points increased 40-60% over the same period in 2012. Critics pointed to the rise in the Henry Hub price from $2.39 to $3.75/MMBtu over this period as a warning of future trends. However, EIA analysts contended that the unusually warm winter of 2012 caused an abnormal drop in natural prices, and the 2013 price near $4.00/MMBtu was just a return to the pricing trend seen in 2009-2011.

Although the international price differential was expected to decrease, it was highly unlikely for a global gas price to emerge. Prices for LNG exports were partially dictated by transportation, liquefaction, and re-gasification costs, making convergence unlikely.

The Japanese Perspective The reduction in international prices would have a direct economic benefit for the world’s largest importers of LNG, including Japan, South Korea, and Spain (see Exhibit 13). As the top importer of LNG, importing more than 3.2 Tcf in 2012, Japan was the biggest potential buyer for increased U.S. LNG exports.

In February 2013, Shinzo Abe, the prime minister of Japan, urged President Obama to permit U.S. exports of LNG to Japan. Japan had a strong demand for cheaper energy; in March 2013, the Ministry of Finance announced that the country’s trade deficit had reached 8.17 trillion yen or $83.4 billion—this was the largest deficit since the government started collecting such data in 1979. Japan’s emergent trade deficit was particularly hard hit by the 2011 nuclear disaster at Fukushima, which required the shutting down of all of the country’s nuclear reactors. Since the nuclear disaster, Japan experienced a 14.9% growth in LNG imports.

Getting access to a cheaper energy supply was a central problem for the Japanese government over the past two years. The acting trade minister, Yukio Edano commented in early 2013, “How we can buy LNG is an important factor for Japan’s government to tackle with the private sector... Procuring the fuel at low cost, has become a key challenge for us.” His replacement, Toshimitsu Motegi, further argued, “A new flow of LNG supply from the U.S. to Asia would be an essential game changer that would contribute to energy security as well as to economic and geopolitical stability in (the region).” In March 2013, Japan entered negotiations over the proposed Trans-Pacific Partnership, a trade agreement between the U.S. and ten other nations, which could help minimize trade barriers regarding future imports of American LNG.

Yet, the recent global upsurge in natural gas sources gave Japan’s ministers greater bargaining power. By 2025, global LNG capacity was expected to jump from 296 to 450 million tons. Wood Mackenzie summarized, “To some extent, buyers can pick and choose their preferred projects.” With natural gas prices predicted to drop internationally, while the cost of oil would continue growing, Japan was less willing to negotiate long-term contracts based on oil indexing. The head of gas research at the Oxford Institute for Energy Studies commented on the Japanese utility companies, “They recognize how dangerous it is to sign up to any contracts on the old formula... They can see the degree of commercial exposure, which is huge.”

Already Japanese companies looked to the U.S. for cheaper, market-based supply. Chubu Electric Power Co. and Osaka Gas Co. held a 20-year preliminary contract with the Freeport LNG project in Texas to import up to 4.4 million tons of LNG beginning in 2017. Although the project was still awaiting DOE approval, Mitsui, Mitsubishi, and Nippon Yusen took a one-third joint stake in the proposed $10 billion Cameron LNG terminal in Hackberry, Louisiana in May 2013. A company spokesman commented, “Mitsui will contribute to stable LNG production as well as stable energy supply to the global market, including Japan.” However, the chairman of the Oxford Institute for
Energy Studies commented, “We think it’s going to take the rest of this decade for Asia to really begin to price on a market basis.”

**Macroeconomic Impacts in the U.S.**

This unexpected expansion in domestic energy supply earned the tagline, ‘North American Energy Revolution,’ for the anticipated benefits to the American economy. By 2012, the energy boom had already made positive influences on the U.S. economy. The nominal energy deficit—that is, the negative balance of trade in energy at unadjusted prices—stood at 2.7% of GDP in 2008 before dropping to 1.9% in 2012. Employment in the gas and oil industry increased by 50,000 employees in both 2011 and 2012, although this was a small portion compared to the 2.2 million new jobs created just in 2012. Additionally, significant improvements were made to the energy intensity of GDP, which dropped 15% over the decade. Goldman Sachs further found that over the past decade, energy output was driving industrial productivity, and the oil and gas sector was one of the few sectors to see payroll growth (see Exhibit 14). The share of oil and gas drilling in industrial production rose from around 3% to 10.3% over the past decade.

Future projections also looked promising. An IMF study forecast that the most direct impact would be on the energy trade balance, which was expected to improve as a percentage of GDP between 0.5-1.8% by 2040, also leading to a slight drop in the current account deficit (see Exhibit 15). Future production increases and efficiency improvements were expected to increase overall GDP by .5-1% over the decade. The dollar was expected to appreciate slightly.

McKinsey estimated that by 2020, shale gas and tight oil could contribute between $380 and $690 billion per year to GDP. Additionally, the McKinsey study estimated total job growth of 1 to 1.7 million jobs in direct and indirect industries. Furthermore, shale resources were capable of driving net energy imports to zero (see Exhibit 16). Another study predicted that tax revenues would exceed $1.6 trillion between 2012 and 2025, while household incomes would have a net savings benefit of $3,500 by 2025 due to the lower prices of natural gas.

A study by Citi Group was even more positive. Citi Group estimated that new production, reduced consumption and all associated activities could result in a 2.0-3.3% growth in GDP. The U.S. would also benefit from an estimated 3.6 million new jobs, resulting in a reduction in the national unemployment rate by 1.1% by 2020. Citi optimistically concluded, “North America is becoming the new Middle East.”

As shale gas appeared an increasingly valuable asset for the U.S. economy, the question emerged over what should be done with the burgeoning natural gas supply. Manufacturers welcomed the supply surplus, as it would reduce their production costs, thus improving competitiveness. Cheaper energy also had the potential to create significant job growth both in primary and secondary industries. Others saw the natural gas boom as an opportunity to use less coal in electricity production or reduce petroleum dependency, through gas liquefaction, within the transportation sector. Gas producers, however, saw a larger profit opportunity by exporting natural gas as LNG.

**U.S. Energy Security** Since 2010, the EIA’s positive projections over U.S. shale gas reserves raised hopes for improving the nation’s energy security. President Obama’s senior energy advisor, Carol Browner, commented, “Taking advantage of the new natural gas finds, the shale finds, would be an important piece of how we begin to break our dependence on foreign oil.” A Goldman Sachs report similarly confirmed that within the next decade, the U.S. energy revolution would “drastically reduce the country’s dependence on imported petroleum.” Furthermore, greater energy security...
could alter U.S. priorities in foreign policy. The deputy head of the Danish delegation to NATO’s Parliamentary Assembly, Jeppe Kofod, projected, “North America as a whole could be heading towards energy self-sufficiency which might render it ever less concerned with events in the Persian Gulf.”

With the anticipated rapid growth in tight oil, the U.S. energy boom generated hopes that the U.S. could be energy independent within the next two decades (see Appendix A).

**Foreign Direct Investment** The sizeable number of proposed LNG projects was attracting significant levels of foreign direct investment (FDI) to the United States. In early 2012, the French firm, Total SA, invested $2.32 billion for 25% of Chesapeake Energy Corp.’s holding in the Utica Shale region in Ohio. Shortly after, Sinopec, a Chinese oil and gas company, acquired a third stake in five of Devon Energy Corp.’s natural gas fields for $2.2 billion. A year later, Sinopec purchased half of Chesapeake Energy Corp.’s Mississippi Lime shale field in Oklahoma for an additional $1 billion.

In addition to the financial benefits of shared ownership of projects, there was potential for future collaborations internationally. When Devon Energy accepted Sinopec’s offering of $2.2 billion, George Mitchell speculated that Devon was “trying to get a deal in China.” China’s expected shale gas reserves were the largest in the world, yet the country was lagging in access to fracturing technology. Shale gas was a technologically intensive sector, requiring a high level of specialized knowledge regarding cost effective extraction techniques. As the development site for the majority of these procedures, the U.S. was well ahead of its foreign competitors in economically feasible techniques. While U.S. firms foresaw potential business opportunities abroad, international firms sought to learn from U.S. expertise. The director of energy and natural resources at the Eurasia Group commented, “Chinese investments appear more motivated by knowledge acquisition for now.”

Others speculated that increased natural gas exports from the U.S. could result in a net decrease in FDI abroad. By pushing down prices in Asia and Europe, U.S. exports had the potential to diminish the rate of return on international projects, reducing their financial feasibility. U.S. exports also reduced the need for additional natural gas suppliers. Furthermore, U.S. manufacturing firms were beginning to relocate their international production facilities back to the U.S.

Australia was particularly worried about the impact of increased competition from U.S. shale resources on its $160 billion of investments. Australia long had its eyes set on being the main supplier of LNG to Asia. However, Australia was struggling with an appreciating dollar and labor shortages, which raised the costs of producing facilities domestically. For example, Chevron, Exxon, and Royal Dutch Shell experienced a US$15 billion increase in the construction costs of the Gorgon project, bringing the total investment to US$52 billion. Additionally, U.S. suppliers were undercutting Australian gas contracts by offering cheaper prices. Some analysts speculated that Australian export prices would have to drop by 25% in order to compete with U.S. shale gas. These higher investment costs paired with lower gas prices caused many to question the profitability of the country’s existing and potential LNG projects. Roy Krzywosinski, a managing director for Chevron commented, “The industry has more than US$160 billion of liquefied natural gas investments currently in flight [being built]. But upwards of another US$100 billion in potential future projects could be at risk.”

**Manufacturing Renaissance**

In 2011, natural gas comprised over 40% of the energy used within the industrial sector, and the recent drop in natural gas prices served as a significant boost to the competitiveness of U.S. manufacturing. Low natural gas prices were directly benefiting American manufacturers by driving down the costs of generating electricity. For the past two decades, natural gas use in electrical generation had grown substantially from 11% in 1990 to 28% by 2012, largely through the
displacement of coal (see Exhibit 17). Furthermore, in the near future, the cost of natural gas plants with combined-cycle facilities were expected to remain below other forms of electrical generation (see Exhibit 18). Natural gas was also a key component used in the production of plastics, polymers, petrochemicals, steel, cement, and fertilizer.

In early 2011, the Boston Consulting Group (BCG) predicted that within five years, the United States would undergo a manufacturing renaissance as companies reconsidered moving their manufacturing operations back to North America. The report concluded that the cost advantages of producing manufactured goods overseas had dropped dramatically over the decade. In 2003, manufacturing costs were 18% lower in China than in the US; by 2011, there was only a 7% difference. Naxitis, a French corporate and investment bank, found that the competitive advantages afforded to U.S. industrial manufacturers from cheap natural gas had the equivalent benefits as a 17% reduction in wages among Eurozone firms.

Shale gas also appeared to pave the way for a re-industrialization of the American economy. The chemical industry stood to benefit from lower fuel and feedstock prices, and the EIA suggested that low real natural gas prices were driving upward industrial productivity and confidence within the sector (see Exhibit 19). A professor at INSEAD commented, “The U.S. petrochemical sector is now among the most competitive in the world and attracts major investment... this is a real game changer.” The American Chemistry Council predicted that over the next five to seven years, investments in the chemical industry would top $16 billion, adding 17,000 jobs directly and another 400,000 indirectly.

Similarly, shale gas aided the struggling steel industry by raising demand for drills and pipelines. John Ferriola, chief executive of Nucor, one of the U.S.’s largest steelmakers, stated of shale gas, “It’s going to create a need for more steel that goes into the pipes to bring the gas to the user... But in addition to that, it will allow manufacturing to re-source back into the US... and that provides a greater demand for our product.” Yet, equipment for the oil industry accounted for only 5% of the steel market, making it unclear whether shale gas could revitalize the struggling sector.

As producers pushed for the right to sell LNG abroad, policymakers wondered about the spillover effects into the manufacturing industry, particularly as there was broad consensus that increased exports would raise domestic gas prices. In a press release in December 2012, Senator Ron Wyden of Oregon emphasized, “It is critical that exports do not squeeze out or price out the billions of dollars of new, natural gas-related investments that have been proposed in the U.S. chemical, industrial, and electric generation sectors.” Congressman Ed Markey from Massachusetts commented, “I am worried that exporting America’s natural gas would raise energy costs for American consumers, reduce the global competitiveness of U.S. businesses, [and] make us more dependent on foreign sources of energy.” In January 2013, a group of the largest gas users, including Dow Chemical, Eastman Chemical, Nucor and American Public Gas Association, formed America’s Energy Advantage as part of a political campaign to limit gas exports. One policy researcher summarized, “At the core of the issue is whether or not the U.S. should export the raw material or the manufactured good. In this context, the political debate is really a matter of who collects the rents associated with an abundance of domestic natural gas resource.”

While the energy boom was expected to have many positive effects on the U.S. economy, the question remained whether the country would benefit more from directing natural gas toward manufacturing or exporting it internationally. Charles River Associates, in a study commissioned by the Dow Chemical Company, compared the impacts on the economy from 5 Bcf/d of natural gas used in manufacturing versus the same amount directly exported. The study concluded that the U.S.
economy received the greatest contributions under the high manufacturing scenario. Directing gas toward manufacturing would result in $4.9 billion in direct value added, 180,000 new jobs and a $52 billion benefit to the trade balance. In comparison, exports would result in direct value added of $2.3 billion, 22,000 new jobs, and an $18 billion boost to the balance of trade. An economist at the U.S. Business and Industry Council further argued that the nation needed to focus on the type of jobs created rather than just the number: “When the president talks about trade, when he talks about creating middle class jobs, when he talks about turning the US economy into an economy that lasts, he usually talks about manufacturing, those are the classic American living wage jobs. There’s no chance that he’s been thinking mainly about petroleum.”

Yet others worried how restricting LNG exports would influence perceptions of the U.S.’s commitment to free trade. Amidst the debate, the National Association of Manufacturers (NAM) wrote in a letter to the DOE, “The NAM fundamentally supports free trade and open markets. We support a natural gas policy process that is open, transparent and objective.” Furthermore, there was the risk that a limitation of LNG exports would be regarded as a violation of the World Trade Organization (WTO)’s General Agreement on Tariffs and Trade’s Article XI, which stated that no prohibition other than duties or taxes can be instituted on the ‘export of any product destined for the territory of any other contracting party.’ While an exception could be granted to Article XI on the grounds that natural gas is an exhaustible resource, the U.S. had been a vocal critic of China’s restriction on exports of its rare earth metals. In July 2012, the U.S. prompted a WTO investigation into China’s export quotas. If the WTO concluded that China was in violation of WTO rules, China would have to revise its export policies.

Substitute for Oil?

While the trade balance in energy had been declining since 2006, the U.S. still remained deeply dependent on foreign oil and petroleum (see Appendix A). By mid-2013, the United States produced about 7.4 million barrels of petroleum domestically while refining about 15.1 million; thus net imports were about 7.7 million barrels. While net imports were at a record low since the second oil shock, oil comprised the majority of the U.S.’s energy imports. Natural gas represented the next largest import category, making up an additional 12% of imports. In order to improve energy security in the U.S., there was a strong incentive to reduce U.S. dependency on oil and petroleum imports.

As predictions over natural gas reserves and production rates proved increasingly optimistic, the question emerged whether natural gas could serve as a substitute for oil. A report from Citi’s commodities group argued, “The shift from oil to gas is already underway in the U.S., where the shale gas revolution is giving a large economic incentive to make the switch. As the U.S. shift gains pace, politics, greater natural gas availability and environmental concerns are facilitating the trend into the global market.” Domestically, roughly three-quarters of petroleum was used within the transportation sector, followed by industrial uses (see Exhibit 20). However, analysts disagreed about the extent to which natural gas could make headway into these sectors.

Transportation As of 2011, there were roughly 120,000 natural gas-powered vehicles (NGVs) within the U.S. The majority of NGVs were medium and heavy weight vehicles, including trucks and one-fifth of the nation’s transit buses. Natural gas provided a small proportion—only 3%—of the total energy consumed in the transportation sector. However, the U.S. lagged behind the international adoption rate of NGVs. At the end of 2011, there were 15.2 million NGVs in use worldwide. Iran held the largest number of NGVs followed by Pakistan, Argentina, and Brazil (see Exhibit 21).
Natural gas substitution could displace a substantial amount of oil in the transportation sector. One billion cubic feet of natural gas, amounting to 1.2% of total production, could replace 150,000 barrels a day of refined petroleum. The EIA predicted that natural gas use in the transportation sector would grow at an average annual rate of 11.9% from 2011 to 2040. While natural gas cost $1.50-$2.00 less than the equivalent of one gallon of gasoline, converting a car to natural gas could cost thousands of dollars. Additionally, there were only 1000 fueling stations in U.S., half of which were available to the public. However, there were signs that firms might be willing to take a risk on natural gas transforming the transportation sector. One of China’s largest companies, ENN, pledged $50 million to build 50 new natural gas fueling stations in the U.S.

Industrial Use In the first five months of 2013, the amount of natural gas for industrial use grew by 3%, or .6 Bcf/d, up from the same period in 2012, a result of historically low prices. While many industrial consumers had the ability to switch between natural gas and oil as energy sources, much of the switchable capacity has already been targeted toward natural gas. In 2006, EIA figures suggested that U.S. manufacturers only could accommodate an additional 200 million cubic feet of natural gas in terms of switchable oil-based capacity. Consequently, the industrial sector had limited flexibility in adjusting to responses in energy prices. Further conversion toward natural gas within the industrial sector would have to come through new plants for manufacturing or petrochemicals, capital and time intensive investments.

Gas to Liquids (GTL) Another form of substitution could come from the implementation of gas-to-liquids technology. The most notable leader in GTL production was the South African firm, SASOL. For decades, SASOL had been manufacturing gasoline and diesel from coal and natural gas. In 2007, SASOL teamed up with Shell to build a $22 billion GTL plant in Qatar, capable of producing 100,000 barrels per day. And in April 2013, SASOL announced plans to build a $14 billion GTL plant at Lake Charles, Louisiana, capable of producing 96,000 barrels of diesel daily.

Increased Competition: Global Effects

As a result of the shale gas revolution, major natural gas exporters faced two substantial risks: price erosion and supply displacement. Newly discovered U.S. shale gas represented a substantial increase in the international natural gas supply, creating direct competition with the world’s leading exporters. In 2011, Russia was the world’s largest exporter, followed by Qatar and Canada; in contrast, the United States ranked eighth (see Exhibit 22). However, the EIA projected that as early as 2016, the U.S. could become a net exporter of LNG. By 2026, exports were calculated to reach 1.6 trillion cubic feet per year. A natural gas market economist for Deloitte commented on the leading exporters, “They’re going to have lower revenue because they’re going to get a lower price at the market, and also they could get displaced by the US export volumes.”

Other Emerging Players? Across the North Atlantic, Prime Minister David Cameron urged the UK to follow the path of the U.S. in developing its shale gas resources. In December 2012, the government lifted a temporary ban on hydraulic fracturing, which was instituted in 2011 after two small earthquakes occurred near drilling sites. Written in an article for The Guardian, Cameron argued, “Fracking has become a national debate in Britain – and it’s one that I’m determined to win. If we don’t back this technology, we will miss a massive opportunity to help families with their bills and make our country more competitive. Without it, we could lose ground in the tough global race.” Contending that shale gas would create jobs and reduce energy costs, the government worked to provide incentives, such as a sizeable tax break, to companies to begin mining. However, a senior researcher at Chatham House noted that the British government significantly lagged behind
the U.S. in terms of financing the research necessary to develop economical drilling techniques, “There appears to be no appetite in the British government for such funding and the European Commission has ruled out any such involvement.” Moreover, the U.K. was restricted by less favorable geology, restrictive land rights (shale rock was property of the Crown), and a strong environmental movement. Consequently, the prime minister’s support for fracking was met with protests and demonstrations; in late August 2013, 29 people, including a Member of Parliament, were arrested for blockading a drilling site in Sussex.

Some worried that the U.K.’s development of shale resources would be a bust, as happened in Poland. When the country’s first well was drilled in June 2010, there were high hopes that Poland would win big by sitting on the largest shale gas play in Europe, amounting to 300 years of reserves for the nation. Yet, two years later, the Polish Geological Institute slashed estimated shale gas reserves to only 35 to 65 years of demand. Although over 40 wells have been drilled, no firm was been able to get Polish gas to flow. By spring 2013, several firms, including Exxon Mobil, Talisman, and Marathon Oil, withdrew their operations due to geological constraints. Marathon commented that its decision was determined by “unsuccessful attempts to find commercial levels of hydrocarbons.” Moreover, government regulation acted as a disincentive to invest; exploratory licenses only lasted for five years, with only one opportunity to be extended for an additional two years, and firms had no legal guarantee that exploratory licenses could be transferred into production licenses without undergoing a competitive tender. The government also announced the unpopular proposal to create a state-owned company, NOKE, which would take a share in all future production efforts. Additionally, the industry struggled with corruption; in August 2013, 7 businessmen and government officers were charged with bribery over distributing shale gas licenses.

Other countries also scrambled to catch up with the U.S. shale revolution. In Mexico, President Enrique Pena Nieto shook up the industry by proposing to liberalize the country’s state-owned oil company, Petroleos Mexicanos (Pemex), and allowing private and foreign companies to produce oil domestically for the first time in 75 years. In response, Pemex announced that it planned to create a new company that would produce gas and oil in U.S. shale plays and deep-water in collaboration with foreign firms, including Royal Dutch Shell. Pemex’s CEO commented, “The geology is similar and we can benefit from numerous areas of collaboration with international oil companies.” The move was an attempt to turn Pemex into an internationally competitive firm with the technical knowhow to exploit shale and deep-water resources.

Furthermore, Mexico, particularly its manufacturers, had already been benefiting from cheap natural gas from the U.S., and there were strong incentives for the country to develop its own resources. By 2015, Mexico’s manufacturing costs were expected to drop below those in China, and several companies, including Honda, Nissan, and General Motors, had already announced new direct investments in the nation. However, Mexico’s demand was outpacing supply. In 2012, Mexico’s gas imports from the U.S. grew 19%, exceeding existing pipeline capacity and forcing the country to purchase more costly American LNG.

In Asia, shale gas looked to be a promising solution for meeting the energy needs of the swiftly growing populations of China and India. By late 2012, China had already run two license auctions for companies to exploit the world’s largest shale gas reserves. Yet, less than 150 wells had been drilled a year later, and production rates remained low. Having produced only 500 million cubic meters of shale gas in 2012, China appeared very unlikely to meet its goal of producing 6.5 billion cubic meters by 2015. And while shale gas seemed a promising fix for a country inflicted by routine rolling blackouts and power shortages, India was slow to release a regulatory framework for developing its
own resources. Throughout 2013, the government repeatedly delayed the release of its shale gas policy, which was expected to initially only allow state oil companies to drill for shale. A disagreement over the wording on contracts prohibited newer firms from drilling, and it remained uncertain whether the government would release additional licenses. Both China and India also faced challenging geology and water shortages, which hindered the use of fracking techniques.

It appeared unlikely for any other nation to catch up with U.S. shale production in the near future. BG Group, a major global supplier of LNG, warned that it would take at least a decade before other nations begin replicating the U.S. shale boom, largely due to investment and technological development constraints. An executive vice president of the firm commented, “We don’t see a big wave of shale development globally in the near term…Our view is that we’re skeptical that’s going to be fully replicated anywhere else as quickly as we’ve seen it in the US.”

**Russia’s Challenge** As the world’s largest gas exporter, Russia was expected to face the biggest trade competition with the U.S. Russia was highly dependent on natural gas revenues; an estimated 10% of Russia’s GDP resulted from gas. Politically, Russia’s top leaders, including President Putin and Prime Minister Dimitri Mevedev, had been supported by the recent success of the country’s exports; in addition to generating substantial revenues, the state-owned firm Gazprom was able to generate political support through its popular gas subsidies.

Russia appeared unwilling to jeopardize its position as the world’s largest exporter. In a statement of the country’s long-term security policy, Russia’s energy reserves were declared a means for “the Russian Federation to strengthen its influence in the world arena.” Gazprom, the country’s largest natural gas company, remained committed to quickly starting new LNG projects in order “to retain or to increase the Company’s share in the global gas market.” In 2011, the Nord Stream pipeline opened, transporting up to 2 Tcf of natural gas from Russia to Germany. Furthermore, as of 2013, Gazprom was planning to construct a new facility in Vladivostok, with an annual capacity of at least 15 million tons, and considering the expansion of the country’s only operating LNG facility, Sakhalin II. A Bloomberg Industries analyst interpreted, “The U.S. is not going to become the world’s natural gas Wal-Mart…Others that have gas to sell round the world – read: Russia -- will not simply let us take away the world’s biggest market even if we could.”

Yet, since 2012, Gazprom’s contracts in Europe had come under criticism from its customer base. Russia was responsible for providing 34% of natural gas to Europe, primarily on long term contracts indexed to oil (see Exhibit 24). However, Russia was also beholden to the European market, which purchased roughly half of the nation’s exports in 2011. As Gazprom contracts looked increasingly unattractive to consumers as oil prices inched upward, the firm gradually shed its unwillingness to renegotiate less costly contracts. In 2012, Gazprom offered a revised contract to the German utility firm, E.ON, boosting the firm’s earnings for the first half of 2012 by 1 billion euros. Shortly after, PGNiG, Poland’s biggest gas distributor, received a $930 million price cut. After winning a ten-year, 20% price cut, Simeon Djankov, the former finance minister for Bulgaria commented, “They can’t bully us in the way they could before, and their weakness in the negotiations showed that… We got the sense they need us more than we need them, and we capitalized on that.” In 2013, Gazprom announced it would charge clients an average of $370 per thousand cubic meters of gas, as compared with $402 over the previous year.

Russia’s energy dominance in Europe was also under threat from other sources. In September 2012, Gazprom was slammed with an antitrust investigation led by the European Commission on whether the firm set unfair prices in Europe and intentionally suppressed supply competition. If
found guilty, the Commission could impose a fine up to 10% of the firm’s revenue, roughly $15 billion.\textsuperscript{140} Additionally, Russia’s gas exports were challenged by the recent rise in U.S. coal exports.\textsuperscript{141}

However, Europe’s movement to a liberalized natural gas market was not without possible future problems. Even with prices dictated by the market, Russia could still manipulate supply volume in order to control prices. Additionally, the majority of European natural gas was supplied via a patchwork of state-owned pipelines; a truly liberalized market would necessitate free movement across pipelines. Coal also still remained a cheaper, albeit more environmentally damaging, resource.

**Challenges**

The promises of the North American energy revolution were not guaranteed.

**Environmental Concerns** Many were divided on the question of the environmental impact of natural gas. Natural gas was celebrated as a ‘bridge fuel’ to replace coal as a cleaner, less carbon emitting energy source, particularly in electrical generation. The EIA suggested that natural gas was a critical factor in reducing U.S. carbon emissions to a 20 year low during the first quarter of 2013.\textsuperscript{142} The newly appointed Energy Secretary Ernest Moniz similarly insisted that the U.S. was on the path to meet the 17% reduction target in greenhouse gases by 2020. He commented, “About half of that progress we have made is from the natural-gas boom, in this case the market-driven substitution for coal.”\textsuperscript{143} Meanwhile, an interdisciplinary report from a team of MIT researchers concluded that natural gas was one of the most-cost effective means to meet energy demand while still reducing the number of carbon emissions.\textsuperscript{144}

However, there was the danger that the emphasis on natural gas as a bridge fuel would direct investments from going toward developing clean energy sources, such as wind, solar, and nuclear energy. For example, in August 2013, Duke Energy announced that it was postponing the construction of its Florida nuclear power plant, in part due to the availability of low cost natural gas.\textsuperscript{145} Utility firms were wary to build more capital intensive nuclear plants when gas-fired combined-cycle generators factories afforded cheaper alternatives. An MIT report warned, “Though gas frequently is touted as a ‘bridge’ to the future, continuing effort is needed to prepare for that future, lest the gift of greater domestic gas resources turn out to be a bridge with no landing point on the far bank.”\textsuperscript{146} Analysts also wondered about the cumulative effect on carbon emissions. While the Energy Secretary insisted that natural gas was reducing carbon emissions by providing a substitute for coal, the increased use of cheap shale gas and oil, rather than clean energy sources, was adding to the number of greenhouse gases released. Furthermore, future coal prices were expected to remain lower than those for natural gas, particularly as LNG exports grew (see Exhibit 25).

Many critics were deeply concerned about the consequences of hydraulic fracturing. The Sierra Club began a publicity campaign to raise awareness of the possible health and environmental consequences of fracking. The Club’s president Allison Chin commented, “The out-of-control rush to drill has put oil and gas industry profits ahead of our health, our families, our property, our communities, and our futures.”\textsuperscript{147}

Evidence suggested that a significant level of methane was released during the fracturing process. The Environmental Protection Agency (EPA) estimated that 30% of methane emissions worldwide were a byproduct of natural gas and oil mining.\textsuperscript{148} One study found that methane concentrations were 17 times higher in drinking wells that were within one kilometer of a natural gas production site than wells further away.\textsuperscript{149} The leader of the study, Robert Jackson, commented on the high presence
of methane, “I saw a homeowner light his water on fire.” At the request of Congress, the EPA began a study on the effects of fracking on drinking water, expected to be released in 2014.

Other critics stressed the possibility of mini-earthquakes caused by forcibly injecting chemical mixtures into the earth, while some worried about the sustainability of the massive amounts of water used during production. Individuals living near shale plays were further impacted by an increase in truck activity, leading both to reduced air quality and deteriorating infrastructure.

However, few large scale studies had been completed on the impact of hydraulic fracturing, and the federal government was slow in developing nation-wide, tested regulations. Several states, including New York, New Jersey, Vermont and parts of Colorado, had placed moratoria on hydraulic fracturing. (Internationally, Bulgaria, France, Luxembourg and the Netherlands had instituted bans on fracking). George Mitchell himself urged, “A strong federal role is also necessary… This is critical since methane is a powerful greenhouse gas pollutant and uncontrolled leakages call into question whether natural gas is cleaner than coal from a global climate perspective.”

Despite critics raising concerns about the environmental consequences of natural gas, President Obama continued to place his support behind the development of the resource as a means to combat global warming. In his 2012 State of the Union address, President Obama stated, “We have a supply of natural gas that can last America nearly 100 years, and my administration will take every possible action to safely develop this energy.” In April, the president issued an executive order calling on 13 agencies to work together on developing regulations to ensure the safe development of shale gas.

Other Risks While the EIA projected international reserves of shale gas at 7,299 trillion cubic feet—665 of which resided in the U.S.—these reserves were technically recoverable. There has been no assessment on whether these resources are economically recoverable. Additional uncertainty settled over the long-term productivity of drilled wells. The EIA warned, “Because most shale gas and shale oil wells are only a few years old, their long-term productivity is untested.” In one of the most comprehensive studies to date, the Bureau of Economic Geology at the University of Texas at Austin predicted the long term productivity of Barnett, one of the nation’s longest tapped shale plays. The research team found that the Barnett Shale was likely to have a gradual decline in production from its current level of 2 Tcf/y to 900 Bcf/y by 2030 if natural gas prices stay around $4 per Mcf. While not as optimistic as some industry projections, the study suggested that many shale plays will remain economical at least for the next two decades.

Additionally, the EIA had predicted a feasible total export volume of between 6 and 12 Bcf/d. However, by September 2013, DOE approvals had already entered this range, while the remaining queue of applications sought to export an additional 26 Bcf/d. Consequently, few firms would be capable of exporting the volume for which they had applied, making their long term economic feasibility uncertain. Furthermore, many insiders speculated that the DOE was approaching an ‘unspoken line’ at which it would cease granting approvals.

As the question over whether firms could recoup their large upfront costs loomed, some have gone as far to call the shale gas industry a financial bubble. In 2011, the New York Times released a series of emails from industry insiders questioning the financial stability of the shale gas sector. An analyst at PNC Wealth Management commented on the influx of money into shale gas operations, “Reminds you of dot-coms,” while an analyst from an energy research company wrote, “The word in the world of independents is that the shale plays are just giant Ponzi schemes and the economics just do not work.”


Given the large upfront costs of LNG projects, investments had to be made based on projections spanning multiple years, sometimes decades, into the future. Many unexpected changes could pop up, such as new regulation or the bottoming out of energy prices. For both tight oil and shale gas, a significant drop in prices could turn an operation unprofitable. Due to the high degree of infrastructure, prices had to remain above a certain price point, otherwise investors would not be able to recoup their upfront investments. George Mitchell commented that other drillers had chastised him for producing natural gas for cheap: “It takes $4 for a horizontal well to be successful, so everybody said, ‘Mitchell, you ruined the playhouse, you made a big roll with the shale gas, now it is taking over.’ Prices are below $4—that is going to hurt shale efforts.” Consequently, producers had to persistently focus on innovation to reduce production costs.

Future regulation changes also posed a significant risk to investors, particularly as the debate over LNG exports grew heated. To date, four bills had been introduced to Congress regarding LNG exports. As some analysts pointed out, the heated debate over whether or not to permit LNG exports could turn public opinion against any form of shale gas production. Shale gas was expected to have many positive benefits for the U.S. economy, and placing a limit on shale production in general would have more negative impacts than the possible gains from increased exports.

Furthermore, the Obama Administration faced an additional set of questions regarding domestic oil production. U.S. production rates were skyrocketing—the International Energy Agency cited that U.S. oil output could surpass Saudi Arabia’s by 2020. However, crude oil exports remained banned, barring a Presidential approval. It also remained unclear whether tight oil producers even wished to export their light crude or refine it domestically before trading it internationally. Yet, many producers lacked the necessary infrastructure to move the rapid growth in light crude oil, or even process it, as many refineries were devoted to processing lower-quality crude. While exporting oil—whether crude or refined—could help improve the balance of payments, others argued that the increased oil supply was needed domestically to meet still growing consumption needs.

Policy Decisions

By the end of the fall 2013, the Obama administration was faced with some challenging decisions regarding the future of U.S. energy. American consumers and manufacturers were celebrating the benefits of a cheap energy supply; heating and electricity costs had dropped, jobs were being created, and firms were choosing to locate their production facilities domestically rather than overseas. However, gas producers also wanted a share in the promises of the Shale Revolution by profiting off energy exports. How could the Department of Energy reconcile the interests of both these groups? How could the Obama administration reap the greatest benefits from ‘America’s game changer’?
Appendix A: U.S. Tight Oil and Geopolitical Concerns

The sudden growth in crude oil production generated hopes that the U.S. might become energy independent within the next two decades. In summer of 2012, Ryan Lance, the CEO of ConocoPhillips, surprised his audience at a conference prior to an OPEC meeting with the announcement, “North America could become self-sufficient in oil as well (as gas) by 2025.” Citi Group had similar predictions, proclaiming North America as the new Middle East. While welcoming an improvement to its energy security, the U.S. Congressional Budget Office (CBO) stated that full energy independence was neither likely nor desirable. A CBO report read, “Even if the United States produced all of its oil, it could only cut itself off from the world market and its price fluctuations by prohibiting private firms from trading (which would violate rules of the World Trade Organization).”

By 2011, petroleum product exports exceeded imports for the first time in over 60 years. The positive trade balance in petroleum products was primarily driven by high international demand for distillate fuels, such as diesel, while the U.S. remained a net importer of crude oil. Yet, growth of crude oil production had the potential to reduce crude imports to 15% of U.S. oil supply by 2020, down from 44% in 2013. As the country’s biggest import, a reduction in crude oil imports would help the U.S. trade deficit. In 2011, crude oil imports were valued at $331.6 billion.

As the U.S. appeared increasingly capable of meeting its own energy demands through improvements in domestic production, the U.S. was becoming less dependent on OPEC supply (see Exhibit 23). This drop in U.S. demand had substantial ramifications for OPEC members. For the past decade, many OPEC nations, including Saudi Arabia and the U.A.E., had based their fiscal budgets off projected oil revenues. As oil prices rocketed upward so did social spending, a trend that could place these countries at risk of fiscal deficits if revenues fell. Moreover, the chief economist for the IMF in the Middle East and North Africa warned that for some countries, these deficits could occur as early as 2016; he commented that while oil revenues were still pouring in, “Spending is rising even faster.” In order to meet their set budgets, the United Arab Emirates would need $75 per barrel to break even, Saudi Arabia needed $80, Iraq needed $100, while Iran needed $140. Nigeria required around $87 a barrel, while Angola needed $94. Meanwhile, oil prices remained between $100-110 per barrel. Algeria’s finance minister Karim Djoudi warned that if oil revenues dropped, the government may be forced to reduce domestic spending, an act that may generate substantial political unrest. In a letter to Saudi Arabia’s oil minister, billionaire investor and former finance minister Prince Alwaleed bin Talal cautioned, “Our country is facing continuous threat because of its almost total dependency on oil.”

As countries grew less dependent on OPEC oil supply, the group’s dominancy was challenged. A report by Citi Group declared, “OPEC will find it challenging to survive another 60 years, let alone another decade.” Moreover, diversification meant importers had a more stable supply source, and thus would be less affected by events within the Middle East. A former manager at Saudi Arabian Oil Company stated, “We’ve already entered an era that’s not OPEC-centric anymore… One can anticipate now a much more stable, less volatile price environment because of the multitude of production coming on board.” This trend matched a growing sentiment among oil investors who were growing increasingly unsettled by the region’s instability. The EIA elaborated, “Increased violence by Islamist extremists and militants, combined with political instability across much of north and west Africa since the start of the Arab Spring in 2011, is changing the equation for acceptable risks for international oil companies.”
However, the impact of U.S. tight oil production would not affect all exporters equally. There are many different varieties of oil, and leading America’s oil production was light crude. Algeria and Nigeria produced a crude oil that was of similar grade and quality to tight oil, making it a ready substitute for increased U.S. production. Alternatively, Saudi Arabia produced a heavier form of crude oil, which was not readily available to U.S. producers. Consequently, exports to the U.S. from Nigeria, Algeria, and Angola fell 41% from 2011 to 2012, while Saudi Arabia’s oil trade increased 14%. While this was the highest volume of exports to the U.S. for Saudi Arabia since the financial crisis, Nigeria and Angola’s oil trade was the lowest in 25 years. However, the U.S.’s demand for Saudi crude could abruptly change if the Keystone XL pipeline were approved, capable of delivering almost 1 million bpd of heavy “tar-sands” oil from Alberta.

Despite Prince Alwaleed’s warning, Saudi Arabia’s oil minister insisted that the U.S. shale revolution would actually aid his country by stabilizing oil prices. Conversely, the African OPEC members were significantly more concerned by U.S. developments. Nigerian oil minister, Diezani Alison-Madueke commented that U.S. shale could cause African OPEC members to lose 25% of their revenues: "Shale oil has been identified as one of the most serious threats for African producers."

Given the uneven impact of the U.S. shale revolution on member states, the OPEC was divided over how to address the rise of U.S. tight oil. In one of the organization’s twice yearly meetings in June 2013, several African states, including Nigeria and Angola, argued that the group should collectively cut production in order to bolster prices. With less a financial buffer than their Gulf counterparts, these West African states needed high oil prices to cover reduced production and higher government spending. Conversely, Saudi Arabia was vocal about maintaining the current 30 million barrel per day ceiling, arguing that raising prices may reduce demand among the still financially struggling Eurozone states. The OPEC also faced supply side risks from the political uprisings in Egypt. Despite the growing disagreement, the OPEC decided to maintain current production levels during its June meeting. However, speculations persisted on whether the group would change its standpoint by its next conference in December.

While the U.S. appeared unlikely to single-handedly dismantle the dominancy of the OPEC, analysts warned that unexpected and rapid supply changes could develop in other nations. With the third largest reserves of tight oil, China could be a major future player in oil production. Paul Stevens of the Royal Institute of International Affairs at Chatham House in London warned that more changes to the industry could still be in the future: "If you had talked about North America ever being self-sufficient in oil five years ago, you would have been laughed out of court."
### Exhibit 1 Department of Energy Applications to Export LNG

<table>
<thead>
<tr>
<th>Company</th>
<th>Quantity (Bcf/d)</th>
<th>FTA Application Status</th>
<th>Non-FTA Application Status</th>
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<td>Argent Marine Management, Inc.</td>
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<td>Barca LNG LLC</td>
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<tr>
<td><strong>Total of all applications received</strong></td>
<td><strong>33.82 Bcf/d</strong></td>
<td></td>
<td><strong>32.41 Bcf/d</strong></td>
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</table>

**Exhibit 2**  Natural Gas Prices, 2000-2012

![Natural Gas Prices Chart](chart.png)


**Exhibit 3**  Projected Differences in U.S. Natural Gas Wellhead Prices from Reference Case (EIA Study), 2010-2035

![Projected Differences Chart](chart2.png)


Note: The EIA considered four scenarios in their study on LNG exports: 1.) low/slow- 6 Bcf/d phased in over 6 years; 2.) low/rapid- 6 Bcf/d phased in over 2 years; 3.) high/slow- 12 Bcf/d phased in over 12 years; 4.) high/rapid- 12 Bcf/d phased in over 4 years. The Reference case is a projection of natural gas exports, consumption and production from 2011-2035 using moderate estimates for shale recovery rates and overall economic growth (available in EIA’s Annual Energy Outlook 2011).
### Exhibit 4a  U.S. General Economic Indicators, 1990-2012

<table>
<thead>
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<tbody>
<tr>
<td>Per capita GDP (thousands 2000 dollars)</td>
<td>35.8</td>
<td>38.1</td>
<td>44.5</td>
<td>48.1</td>
<td>49.3</td>
<td>48.7</td>
<td>46.9</td>
<td>47.7</td>
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<tr>
<td>Nominal GDP (current trillions dollars)</td>
<td>6.0</td>
<td>7.7</td>
<td>10.3</td>
<td>13.1</td>
<td>14.5</td>
<td>14.7</td>
<td>14.4</td>
<td>15.0</td>
<td>15.5</td>
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<td>Real GDP growth (% change on prior year)</td>
<td>1.9</td>
<td>2.7</td>
<td>4.1</td>
<td>3.4</td>
<td>1.8</td>
<td>-0.3</td>
<td>-2.8</td>
<td>2.5</td>
<td>1.8</td>
<td>2.8</td>
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<tr>
<td>Consumer prices (% change on prior year)</td>
<td>5.4</td>
<td>2.8</td>
<td>3.4</td>
<td>3.4</td>
<td>2.8</td>
<td>3.8</td>
<td>-0.4</td>
<td>1.6</td>
<td>3.2</td>
<td>2.1</td>
</tr>
<tr>
<td>Federal deficit (% GDP)</td>
<td>-3.9</td>
<td>-2.2</td>
<td>2.4</td>
<td>-2.6</td>
<td>-1.2</td>
<td>-3.2</td>
<td>-10.1</td>
<td>-9.0</td>
<td>-8.7</td>
<td>-7.0</td>
</tr>
<tr>
<td>Stockmarket Index (annual % change)</td>
<td>-6.6</td>
<td>34.1</td>
<td>-10.1</td>
<td>3.0</td>
<td>3.5</td>
<td>-38.5</td>
<td>29.5</td>
<td>12.8</td>
<td>0.0</td>
<td>13.4</td>
</tr>
<tr>
<td>Unemployment (% civilian population)</td>
<td>5.6</td>
<td>5.6</td>
<td>4.0</td>
<td>5.1</td>
<td>4.6</td>
<td>5.8</td>
<td>9.3</td>
<td>9.6</td>
<td>9.0</td>
<td>8.1</td>
</tr>
<tr>
<td>Productivity (output/hr; index; 2005=100)</td>
<td>69</td>
<td>74</td>
<td>86</td>
<td>100</td>
<td>102</td>
<td>103</td>
<td>106</td>
<td>109</td>
<td>110</td>
<td>111</td>
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<tr>
<td>Compensation (per/hr; index; 2005=100)</td>
<td>55</td>
<td>65</td>
<td>82</td>
<td>100</td>
<td>108</td>
<td>112</td>
<td>113</td>
<td>115</td>
<td>118</td>
<td>121</td>
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<tr>
<td>Unit labor costs (index; 2005=100)</td>
<td>80</td>
<td>87</td>
<td>96</td>
<td>100</td>
<td>106</td>
<td>108</td>
<td>106</td>
<td>105</td>
<td>108</td>
<td>109</td>
</tr>
</tbody>
</table>

Source: Bureau of Economic Analysis; Department of Labor; World Development Indicators; Google Finance; Federal Reserve; accessed August 2013.

### Exhibit 4b  Breakdown of U.S. Economy by Sector (as % of GDP), 1980-2012

![Graph showing breakdown of U.S. Economy by sector from 1980 to 2012.](graph)

Exhibit 4c  U.S. Trade Balance by sector, 1979-2012

Exhibit 4d  Global Current Account Balances, 1995-2012 (billions US$)

<table>
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<tr>
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<td>United States</td>
<td>-113.6</td>
<td>-416.3</td>
<td>-745.8</td>
<td>-800.6</td>
<td>-710.3</td>
<td>-677.1</td>
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<td>-41.8</td>
<td>-41.5</td>
<td>-58.5</td>
<td>-47.1</td>
<td>-42.0</td>
<td>-37.0</td>
<td>-33.8</td>
<td>-56.4</td>
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<tr>
<td>Canada</td>
<td>-5.2</td>
<td>18.6</td>
<td>21.6</td>
<td>17.9</td>
<td>11.4</td>
<td>1.8</td>
<td>40.6</td>
<td>58.4</td>
<td>52.8</td>
<td>67.0</td>
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<td>Japan</td>
<td>111.4</td>
<td>119.6</td>
<td>166.1</td>
<td>170.9</td>
<td>212.1</td>
<td>159.9</td>
<td>146.6</td>
<td>204.0</td>
<td>119.3</td>
<td>59.0</td>
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<td>Euro Area</td>
<td>n/a</td>
<td>-35.7</td>
<td>50.3</td>
<td>53.6</td>
<td>46.1</td>
<td>-96.9</td>
<td>30.6</td>
<td>64.5</td>
<td>78.4</td>
<td>221.4</td>
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<td>United Kingdom</td>
<td>-8.1</td>
<td>-42.5</td>
<td>-47.2</td>
<td>-72.0</td>
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<td>-27.7</td>
<td>-57.6</td>
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<td>Switzerland</td>
<td>20.9</td>
<td>30.1</td>
<td>52.4</td>
<td>58.2</td>
<td>38.8</td>
<td>10.9</td>
<td>53.7</td>
<td>78.6</td>
<td>55.7</td>
<td>84.7</td>
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</table>

Exhibit 4d  Global Current Account Balances, 1995-2012 (billions US$)

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<tr>
<td>Oil exporters</td>
<td>1.7</td>
<td>89.9</td>
<td>213.8</td>
<td>278.8</td>
<td>267.5</td>
<td>349.2</td>
<td>78.2</td>
<td>204.0</td>
<td>411.5</td>
<td>416.5</td>
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<td>China</td>
<td>1.6</td>
<td>20.5</td>
<td>132.4</td>
<td>231.8</td>
<td>353.2</td>
<td>420.6</td>
<td>243.3</td>
<td>237.6</td>
<td>201.7</td>
<td>213.7</td>
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<td>Developing Asia, excluding China</td>
<td>-38.6</td>
<td>21.0</td>
<td>9.7</td>
<td>39.6</td>
<td>49.6</td>
<td>6.3</td>
<td>44.9</td>
<td>-5.6</td>
<td>-23.0</td>
<td>-83.3</td>
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<td>Latin America and Caribbean</td>
<td>-37.9</td>
<td>-48.6</td>
<td>36.1</td>
<td>47.9</td>
<td>7.3</td>
<td>-38.8</td>
<td>-28.8</td>
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<td>Russia</td>
<td>7.0</td>
<td>46.8</td>
<td>84.4</td>
<td>94.3</td>
<td>77.0</td>
<td>103.7</td>
<td>49.5</td>
<td>70.0</td>
<td>98.8</td>
<td>81.3</td>
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<tr>
<td>Rest of Central and Eastern Europe</td>
<td>-17.0</td>
<td>-75.7</td>
<td>-145.8</td>
<td>-183.3</td>
<td>-213.7</td>
<td>-263.7</td>
<td>-99.1</td>
<td>-152.9</td>
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<td>Rest of the world</td>
<td>38.6</td>
<td>115.0</td>
<td>245.0</td>
<td>314.0</td>
<td>285.2</td>
<td>294.8</td>
<td>188.4</td>
<td>281.5</td>
<td>346.1</td>
<td>287.1</td>
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</table>


a. Oil exporters include: Algeria, Bahrain, Iran, Kuwait, Libya, Oman, Qatar, Saudi Arabia, Sudan, Syria (omitted in 2011 and 2012 for lack of data), UAE, and Yemen.

b. The “rest of the world” category includes a very large statistical discrepancy. (If individual countries’ current accounts are added together, the sum indicates that “world” often runs a large current-account deficit or surplus with itself.) These data therefore should not be used with any confidence.
### Exhibit 4e  Employment by Industry (thousands of employees), 2000-2013

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<tbody>
<tr>
<td><strong>Total nonfarm</strong></td>
<td>132,015</td>
<td>133,617</td>
<td>137,682</td>
<td>130,294</td>
<td>129,932</td>
<td>131,407</td>
<td>133,762</td>
<td>136,038</td>
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<tr>
<td>Total private</td>
<td>111,148</td>
<td>111,795</td>
<td>115,512</td>
<td>107,778</td>
<td>107,351</td>
<td>109,374</td>
<td>111,871</td>
<td>114,186</td>
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<tr>
<td>Natural resources and mining</td>
<td>601</td>
<td>624</td>
<td>726</td>
<td>687</td>
<td>711</td>
<td>795</td>
<td>852</td>
<td>875</td>
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<tr>
<td>Construction</td>
<td>6,794</td>
<td>7,283</td>
<td>7,632</td>
<td>7,949</td>
<td>5,500</td>
<td>5,508</td>
<td>5,627</td>
<td>5,793</td>
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<td>Manufacturing</td>
<td>17,325</td>
<td>14,224</td>
<td>13,884</td>
<td>11,739</td>
<td>11,580</td>
<td>11,768</td>
<td>11,957</td>
<td>11,975</td>
</tr>
<tr>
<td>Wood products</td>
<td>615.6</td>
<td>553.6</td>
<td>523.4</td>
<td>352.4</td>
<td>342.8</td>
<td>328.8</td>
<td>335.9</td>
<td>346.4</td>
</tr>
<tr>
<td>Nonmetallic mineral products</td>
<td>556.2</td>
<td>501.8</td>
<td>504.4</td>
<td>393.5</td>
<td>371.6</td>
<td>367.1</td>
<td>362.0</td>
<td>368.9</td>
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<tr>
<td>Primary metals</td>
<td>625.7</td>
<td>468.1</td>
<td>456.4</td>
<td>353.8</td>
<td>365.2</td>
<td>393</td>
<td>406.7</td>
<td>392.5</td>
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<td>Fabricated metal products</td>
<td>1,761.1</td>
<td>1,521.1</td>
<td>1,564.2</td>
<td>1,291.4</td>
<td>1,295.2</td>
<td>1,355.3</td>
<td>1,418.5</td>
<td>1,436.8</td>
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<td>Machinery</td>
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<td>1,165</td>
<td>1,192.5</td>
<td>1,008.6</td>
<td>998.2</td>
<td>1,059.5</td>
<td>1,100.9</td>
<td>1,1000</td>
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<td>Computer and electronic products</td>
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<td>Electrical equipment and appliances</td>
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<td>368.1</td>
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<td>357.3</td>
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<td>Miscellaneous manufacturing</td>
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<td>Food manufacturing</td>
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<td>1,460.7</td>
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<td>Beverlage and tobacco products</td>
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<td>197</td>
<td>186.8</td>
<td>180.3</td>
<td>189.7</td>
<td>*</td>
<td>*</td>
</tr>
<tr>
<td>Textile mills</td>
<td>379.5</td>
<td>217.5</td>
<td>168.1</td>
<td>122.8</td>
<td>119.8</td>
<td>122.2</td>
<td>118.0</td>
<td>114.9</td>
</tr>
<tr>
<td>Textile product mills</td>
<td>215.7</td>
<td>172</td>
<td>157.1</td>
<td>124.9</td>
<td>119.9</td>
<td>117.6</td>
<td>116.1</td>
<td>113.6</td>
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<tr>
<td>Apparel</td>
<td>497.2</td>
<td>259.4</td>
<td>212.8</td>
<td>168.2</td>
<td>156.7</td>
<td>149.9</td>
<td>147.6</td>
<td>140.7</td>
</tr>
<tr>
<td>Leather and allied products</td>
<td>70.2</td>
<td>39.5</td>
<td>33.1</td>
<td>29</td>
<td>27.4</td>
<td>29.5</td>
<td>*</td>
<td>*</td>
</tr>
<tr>
<td>Paper and paper products</td>
<td>604.9</td>
<td>484.6</td>
<td>459.8</td>
<td>403.9</td>
<td>396.5</td>
<td>391</td>
<td>378.9</td>
<td>377.4</td>
</tr>
<tr>
<td>Printing and related support activities</td>
<td>808.8</td>
<td>646.4</td>
<td>623.3</td>
<td>517.9</td>
<td>489.1</td>
<td>468.3</td>
<td>463.5</td>
<td>448</td>
</tr>
<tr>
<td>Petroleum and coal products</td>
<td>123.4</td>
<td>113.3</td>
<td>112.5</td>
<td>115.6</td>
<td>114.3</td>
<td>111.7</td>
<td>111.9</td>
<td>114.8</td>
</tr>
<tr>
<td>Chemicals</td>
<td>976.9</td>
<td>879.4</td>
<td>862.5</td>
<td>797.3</td>
<td>782.8</td>
<td>768.8</td>
<td>782.8</td>
<td>797.2</td>
</tr>
<tr>
<td>Plastics and rubber products</td>
<td>952.5</td>
<td>800.1</td>
<td>752.4</td>
<td>615.3</td>
<td>628.0</td>
<td>659.9</td>
<td>647.4</td>
<td>659.7</td>
</tr>
<tr>
<td>Service providing</td>
<td>107,295</td>
<td>111,486</td>
<td>115,440</td>
<td>111,919</td>
<td>112,141</td>
<td>113,336</td>
<td>115,326</td>
<td>117,395</td>
</tr>
<tr>
<td>Private service providing</td>
<td>86,428</td>
<td>89,664</td>
<td>93,270</td>
<td>89,403</td>
<td>89,560</td>
<td>91,303</td>
<td>93,435</td>
<td>95,543</td>
</tr>
<tr>
<td>Government</td>
<td>20,867</td>
<td>21,822</td>
<td>22,170</td>
<td>22,516</td>
<td>22,581</td>
<td>22,033</td>
<td>21,891</td>
<td>21,652</td>
</tr>
</tbody>
</table>


Note: Beginning in 2012, these categories are included under other headings.
Exhibit 5  U.S. Shale Plays


Exhibit 6  Natural Gas Consumption and Supply (Tcf), 1980-2012

Source:  Created by casewriter using data from the U.S. Energy Information Administration database, August 2013.

Exhibit 7  Known U.S. Natural Gas Reserves (Tcf) and Number of Exploratory and Developmental Wells Drilled, 1980-2010

Source:  Created by casewriter using data from the U.S. Energy Information Administration database, August 2013.
Exhibit 8  Projected Shale Gas Production by Source (Tcf), 1990-2040


Exhibit 9  U.S. Crude Oil Production (millions of barrels), 1900-2012

Source: Created by casewriter using data from the U.S. Energy Information Administration database, August 2013.

Exhibit 10  Projected Crude Oil Production by Source (million barrels per day), 1990-2040

Exhibit 11  Tight Oil and Shale Gas Growth

**US output of light tight oil (LTO) is growing even faster than shale gas output did in its early stages**

- Production of LTO and shale gas
- LTO, thousand barrels per day (kboed)
- Gas, thousand barrels of oil equivalent per day (kboed)

![Graph showing growth of LTO and shale gas output](image)


Exhibit 12  Total Capital Expenditure to Supply: Select LNG Projects

![Bar chart showing total capital expenditure](image)

Source: Ernst & Young, 'Global LNG: Will new demand and new supply mean new pricing?', March 19, 2013. Reproduced by permission of EY.
Exhibit 13  Top 5 Importers of LNG (by volume, Bcf), 2012

Source:  Created by casewriter using data from the U.S. Energy Information Administration database, August 2013.

Exhibit 14  Productivity and Payroll Growth


Exhibit 15  Projected Energy Trade Balance, 2013-2040 (IMF Study)


Exhibit 16  Current and Projected Impact of Shale Exports (McKinsey Findings)

Exhibit 17  Fuel Share in Electrical Generation, 1990-2012

![Fuel Share in Electrical Generation, 1990-2012](image)


Exhibit 18  Predicted Levelized Cost of New Generation Resources in 2017

![Predicted Levelized Cost of New Generation Resources in 2017](image)

Exhibit 19  Manufacturing Productivity, 2001-2013


Exhibit 20  Energy Consumption by Source and Sector, 2011 (quadrillion Btu)


Exhibit 21  Natural Gas Use in the Transportation Sector

**Exhibit 22a** Top Dry Natural Gas Exporters (by volume, Tcf), 2011

![Chart showing top dry natural gas exporters by volume, Tcf, 2011.](image)

Source: Created by casewriter using data from the U.S. Energy Information Administration database, August 2013.

**Exhibit 22b** Top LNG Exporters, 2011

![Table showing top LNG exporters, 2011.](image)


**Exhibit 23** Top 5 Oil Exporters (by volume, million barrels per day), 2012

![Chart showing top oil exporters by volume, million barrels per day, 2012.](image)

Source: Created by casewriter using data from the U.S. Energy Information Administration dataset, August 2013.
Exhibit 24 EU Energy Consumption of Russian Natural Gas


Endnotes


3 In May 2011, the DOE approved the first project to export LNG to non-FTA countries; Sabine Pass Liquefaction, LLC was authorized to export 2.2 Bcf/d of LNG. In May 2013, the DOE approved the Freeport LNG Terminal to export 1.4 Bcf/d.

4 Calculated by casewriter using 2005 data from EIA database, July 2013.

5 EIA, “Technically Recoverable Shale Oil and Shale Gas Resources: An Assessment of 137 Shale Formations in 41 Countries Outside the United States,” June 2013.

6 Ibid.


13 The Mineral Leasing Act of 1920 effectively bans oil exports without a presidential finding, as long as such oil passes through an interstate pipeline. The Energy Policy and Conservation Act of 1975 declares, flat-out that the President may restrict hydrocarbon exports “under such conditions as he determines to be appropriate and necessary.” The OCS Lands Act of 1979 bans the export of offshore oil and gas, unless the President grants a waiver. Finally, the Export Administration Act of 1979, in Section 3, Article 2, provides that the U.S. can “restrict the export of goods where necessary to protect the domestic economy from the excessive drain of scarce materials.” Another section gives the President power to impose export licenses.

14 Shale oil is distinct from kerogen. Shale oil is crude oil that naturally develops within shale formations. In contrast, kerogen is a “synthetic fuel” produced from the sedimentary rock, oil shale. While at normal temperatures, oil shale does not contain oil; upon heating, the oil shale releases kerogen, an artificial hydrocarbon similar to petroleum. During the heating process, oil-shale gas is also produced. For more information, see Richard Vietor, “The Synthetic Liquid Fuels Program: Energy Politics in the Truman Era,” Business History Review, Vol. 54, No. 1, Spring 1980.
The U.S. Shale Revolution: Global Rebalancing?


20 Ibid.


46 U.S. Congress, Natural Gas Act of 1938, 15 USC Sec. 717b (June 21, 1938).

47 Ibid.


54 Ibid.


65 Ibid.


Ibid.

Ibid.


Ibid., p. 79.

Ibid., p. 3.


Ibid.


The U.S. Shale Revolution: Global Rebalancing?


95. Ibid.


105. “Global Oil Demand Growth—The End is Nigh,” Citi Commodities Group, March 26, 2013.


132 Ibid.


141 Ibid.


170 Ibid.


182 Ibid.
