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Natural Gas in North America: Markets and Security

The share of natural gas use worldwide has grown from 19 percent of total world primary energy to 23.3 percent during the past 25 years. In the United States, natural gas is an important fuel, representing 22 percent of total primary energy use in 2006. Natural gas holds an important place in the U.S. electricity market as the second largest source of fuel after coal and the fastest growing fuel for power generation. Approximately 19 percent of all electricity generated in the United States derives from the burning of natural gas, up from only about 10 percent in 1986 when wellhead natural gas prices were fully decontrolled. Around 52 percent of all new power stations built since 1995 have been gas-fired, but those plants have been larger than the average new plant (many of which were small wind generators), and as a result, natural gas accounts for 90 percent of all new megawatts of capacity installed in the United States since 1995. In addition, many industrial users switched to natural gas in the 1980s, and it now represents 41 percent of the fuel used in that sector. It also has become a popular fuel among residential users for heating and cooking. More than 50 percent of Americans heat their homes with natural gas, compared to 40 percent who use heating oil or electricity. Natural gas' share in the overall U.S. residential market stands at around 43 percent today. Natural gas has been favored as a fuel for all these purposes because it is considered more secure than oil, environmentally cleaner than coal, and competitively priced compared to oil, nuclear power and renewable energy. The widespread adoption of combined-cycle technology in power generation has particularly favored the use of natural gas due to increased efficiency in electricity production.

At the same time that natural gas has become more important to industrialized economies like the United States, significant developing economies, including China and India, also have begun to use more natural gas while the costs of producing, shipping and regasifying liquefied natural gas (LNG) have fallen. The result has been a steady increase in the volume of gas traded in international markets, and a greater focus on the security and availability of natural gas supplies. Maintaining a secure supply of reasonably priced natural gas, which up to now has taken a back seat to oil, will increasingly be viewed as a vital national interest. In fact, an inability to increase natural gas supply in the face of rising demand in recent years in the U.S. market has prompted concern about the future of U.S. natural gas supply, both domestically and from abroad.

In 2006, U.S. natural gas imports represented about 20 percent of end-use demand. Most of those imports — or 85.7 percent — arrived by pipeline from Canada. However, the increasing demand for natural gas in the tar sands industry in Canada is likely to limit Canadian pipeline exports to the United States in the future. Further growth in U.S. gas demand, coupled with constraints on domestic natural gas supply arising from a variety of factors, therefore, is likely to increase imports substantially in the form of LNG. Already, LNG imports have risen from virtually zero in 1986 to just in excess of 0.5 trillion cubic feet (tcf), or 2.9 percent of total U.S. natural gas consumption in 2006 (14 percent of total imports). Moreover, with the construction of three new LNG import facilities on the U.S. Gulf Coast with a total send out capacity of more than 5.5 billion cubic feet per day (bcfd) well underway, imports are expected to rise substantially in the coming years. The United States imports LNG from a variety of countries, which in 2006 included Trinidad and Tobago (66.7 percent), Egypt (20.5 percent), Nigeria (9.8 percent), and Algeria (3.0 percent).

The United States has a premier energy resource base, but it is a mature province that has reached peak production in many traditional producing regions. In recent years, environmental and land-use considerations have prompted the United States to remove from energy development significant acreage that once was available for exploration. Twenty years ago, nearly 75 percent of federal lands were available for private lease to oil and gas exploration companies. Since then, the share has fallen to 17 percent. At the same time, U.S. demand for natural gas has grown from 16.2 tcf in 1986 to 21.7 tcf in 2006, representing an average growth of about 1.5 percent per year. Demand growth for natural gas in the U.S. power generation sector has averaged 4 percent a year during the last decade, while residential and industrial demand has dipped slightly in recent years in response to rising prices. Baker Institute modeling indicates that demand for natural gas will grow by about 1.3 percent per year during the next two decades. While some regions in the Lower 48 are seeing strong growth in production, the overall domestic supply is not growing because other regions are experiencing dramatic declines. As a result, U.S. natural gas imports are expected to rise significantly in the next two decades, raising concerns about supply security and questions about appropriate national natural gas policy.

Adding to the U.S. supply challenge is the increase in natural gas demand in Canada and Mexico. Increasingly, Canadian demand for natural gas is rising due to industrial operations in the production of oil from heavy tar sands in Alberta. This has led some analysts to predict that Canadian supplies to the United States will decline during the next two decades. In addition, in Mexico, demand for natural gas as an industrial feedstock and for electricity generation is soaring, and Mexico is increasingly looking to LNG imports despite its bountiful natural gas resource base. In 2006, Mexico imported 0.88 bcfd (or 16.2 percent of Mexican demand) from the United States, which is up from only 5 million cubic feet per day (mmcfd) in 1986 and is three times higher than the volumes in 2000. Moreover, Mexican demand is expected to increase by 3.4 percent a year, leaving Mexico increasingly dependent on foreign imports unless it can reform its energy sector. One LNG receiving terminal with a send out capacity of about 500 mmcfd recently opened on the east coast at Altamira, and another, Sempra's Energia Costa Azul LNG, with a send out capacity of 1 bcfd currently is being constructed on the west coast on the Baja Peninsula. The Baja terminal is expected to be in operation late in 2008.

The changing supply picture for North America has created a tighter, and hence more volatile, market in recent years. Periods of extreme price movements occurred as recently as winter 2005–06, when daily prices at the Henry Hub spiked to all-time highs of more than $15/million British thermal units (MMBtu) in December 2005, reflecting production dislocations from hurricanes in the U.S. Gulf of Mexico and infrastructure and other constraints that prevented adequate supplies from reaching U.S. markets. A number of factors contribute to the volatility in U.S. natural gas prices. Extreme weather can result in wide price swings, especially when supply is constrained. Conversely, if U.S. demand is relatively low due to mild weather conditions, prices can fall substantially, as was the case in the United States in

2006, when prices dipped below $5/MMBtu. Earlier this autumn, with U.S. storage at record-high levels, natural gas prices averaged around $6.50/MMBtu. In the current world market context, swings in U.S. prices also can propagate to other regions by altering LNG flows. Similarly, high demand due to cold weather in Europe, for example, can increase demand for LNG imports. This, in turn, lowers the amount of supply flowing into the U.S. market, which will tend to exert upward pressure on U.S. prices.

Another important issue to consider is the linkage between crude oil and natural gas prices. In particular, with oil prices soaring to new levels near the $100-per-barrel range, it is timely to revisit the question of the linkage between oil and natural gas prices and whether a run-up in oil prices is likely to similarly affect U.S. natural gas prices. This is important in light of the fact that the U.S. Federal Reserve Bank has estimated that a doubling of natural gas prices, when sustained as it has been in recent years, could cost the United States a reduction of gross domestic product (GDP) growth of between 0.6 percent and 2.1 percent. Sharp upward price movements in natural gas prices affect U.S. consumers directly through higher residential costs for heating and indirectly through higher electricity prices. Thus, rising North American natural gas prices could put the U.S. economy at a disadvantage to other competing trading partners, such as the European Union, China and India, particularly when end-user prices are controlled, as they are in China and India.

Already, the United States has seen some industry sectors move offshore in response to high natural gas costs. Chemicals and energy are important inputs into industrial manufacturing (more than one-third of total costs in some industries). High and volatile energy prices, therefore, impact the industrial sector, driving down demand for chemicals. Rising natural gas prices have adversely affected the U.S. olefins industry, for example. About 65 percent of U.S. ethylene production is based on natural gas. The consulting firm Accenture estimates that investment in new ethylene production capacity by U.S. companies during the next 10 years will shift to the Middle East and Asia-Pacific, with only 2 percent of new capacity built in the United States. In 2004, the United States saw the closing of several chemicals plants, including one Terra Industries Inc. fertilizer facility and one Mississippi Chemical Corporation ammonia plant. Both companies cited high natural gas prices as a primary reason for their decision to shut down. Similarly, The Dow Chemical Company has shut down more than 20 plants across the country, while PotashCorp recently built a facility in Trinidad, a low-cost source of natural gas supply. As a result of such shutdowns, there has been a 36 percent drop in fertilizer production in the United States since 2002. Such examples raise questions about the future of the U.S. petrochemical industry as feedstock costs become prohibitive.

Given the importance of the changing outlook for North American natural gas supply and U.S. oil and natural gas prices, the Baker Institute embarked on a two-year study, "Natural Gas in North America: Markets and Security," to investigate the future development of the North American natural gas market and the factors that will influence security of supply and pricing. This study considers how access to domestic resources and the growth of international trade in LNG will impact U.S. energy security. It also analyzes the outlook for growth in natural gas demand given fuel competition in the power generation sector and the price relationship between oil and natural gas. The aim of the study is to help market participants and policymakers understand the risks associated with various policy choices and market scenarios and the factors that will influence natural gas supply and pricing in the coming decades.

U.S. Supplies: Domestic and Foreign

Despite popular beliefs on the subject, the United States has not actually run out of natural gas. There are tremendous unexploited natural gas resources in Alaska that could be shipped by pipeline south to the Lower 48 states and huge potential resources exist off the U.S. Atlantic and Pacific coasts, in the majority of the Eastern Gulf of Mexico and in many sections of the Rocky Mountain outback. These areas are estimated to contain more than 125 tcf of natural gas resource, the equivalent of six times U.S. natural gas demand in 2006. Nearby, Mexico is home to proven gas reserves of up to 14.6 tcf and an estimated 69.2 tcf of undiscovered gas resource that could be exploited if political barriers to increased investment could be resolved.

The United States also is concerned about growing dependence on the Middle East for oil and gas supplies. Under a business-as-usual scenario, where U.S. lands are not opened up for drilling, U.S. end-use natural gas demand would climb to 23.9 tcf in 2015 and 26.9 tcf by 2025, up from 20.0 tcf in 2006. This represents a gain of about 1.3 percent per year. Rising demand from the electricity sector would be the largest contributing factor to this rise, with electricity demand for natural gas rising from 6.2 tcf in 2006 to 9.4 tcf in 2015, and 12.0 tcf in 2025.

At the same time, under this base case, U.S. natural gas production is projected to be roughly 20.8 tcf in 2015 and 21.2 tcf in 2025. In the short term to 2015, dependence on Middle East supply will not be large. In fact, LNG imports are projected only to climb to 2.42 tcf by 2015, or about 10.0 percent of U.S. demand by 2015. However, under the same business-as-usual scenario, U.S. LNG imports accelerate beyond 2015 as domestic supplies become increasingly expensive. As a result, the United States will rely on imports for 20.0 percent of total natural gas consumption by 2025, growing to 31.1 percent by 2030. Of these imports, direct LNG imports (via U.S.-based terminals) account for 80 percent in 2015, falling to 73 percent and lower in 2025 and beyond, with indirect LNG imports (those coming through Mexican and Canadian terminals and reshipped via pipeline to the United States) accounting for the growing remainder, according to Baker Institute calculations.

Similarly, under this same business-as-usual scenario, the share of total world gas production coming from the Middle East will rise from current levels of about 10 percent to just over 14 percent by 2025 but will represent about 25 percent of all LNG shipments globally. According to Baker Institute estimates, roughly half of Middle East LNG production will flow into the Atlantic Basin, with the United States likely to receive about 20 percent to 25 percent of its LNG supplies from the Middle East. That is on top of 24.6 percent of the United States' oil imports from the Middle East for the transportation sector.

To best analyze the alternative scenarios that may face U.S. natural gas consumers under different policy choices, the Baker Institute used its world gas trade model. The Baker Institute World Gas Trade Model (BIWGTM) simulates future development of North American natural gas trade based on the economics of resource supply, demand and commodity transportation, and it determines a market clearing price in the process. The base model can be adjusted to study various scenarios for the future of the North American gas market.

In this study, we use the BIWGTM to indicate which resources are optimal for development and transportation to North American demand centers on the basis of efficiency and competition. LNG resources will compete against all other potential resources serving regionally discrete end-use markets. Thus, heterogeneity in development costs and resource size, as well as transportation costs and distance to market, will determine which resources are developed first. Furthermore, the return on capital required by investors in the resource sector will influence how rapidly new sources of supply are brought on stream. Costs, anticipated prices and required rates of return also determine transportation routes to market and whether the resources move by pipeline or LNG tanker or simply not at all. Thus, the potential supplies that lie in regions in the United States with restricted access do not simply add to the overall supply if restrictions are lifted. Rather, the resources in those areas must compete for market share against all other potential sources of supply.

More particularly, the study investigates how the supply picture is influenced by change in the dispensation of areas currently facing drilling access restrictions inside the United States. As discussed, environmental and land-use considerations have prompted the United States to remove significant acreage that once was available for exploration from energy development. But what if these areas were reopened for energy development?

The study investigates the outcomes of different scenarios in both a “restricted” and “unrestricted” investment climate for U.S. resources. The “restricted” case is defined to be one in which the Eastern Gulf of Mexico, the Outer Continental Shelf in the Pacific and Atlantic Oceans, restricted regions of North Alaska, and acreage in the Rocky Mountains all remain unavailable for development. The unrestricted world allows all of these areas to be available for exploration and development. This study considers various scenarios, in both the restricted and unrestricted versions of the model, with a focus on examining the influence of access restrictions on U.S. security of natural gas supply. It is important to note that under both the restricted and unrestricted versions of the model in all scenarios, we also allow for the potential influence on the natural gas market of rapid adoption of alternative technologies. In some cases, the effects of removing restrictions are dampened by induced changes in the speed of adoption of such alternative technologies.

Access Restrictions in the United States

For key offshore areas in the Eastern Gulf of Mexico, Pacific and Atlantic Outer Continental Shelf and Alaska, access restrictions are in place due to explicit federal prohibition of drilling in environmentally sensitive areas. Elsewhere, burdensome requirements and restrictions exist as conditions for obtaining drilling permits, such as in the Rocky Mountain region.

The Outer Continental Shelf (OCS) on the Atlantic and Pacific coasts is defined as the offshore areas that stretch between three miles and 200 nautical miles from the U.S. coastline. In all states except Texas and Florida, areas within the first three nautical miles of the shoreline are managed by the state. In Texas and Florida, state waters extend to approximately nine nautical miles. Beyond 200 nautical miles, we move into international waters, except where the geological continental margin extends beyond 200 nautical miles, as is the case in areas off Alaska and the Atlantic coast and in the Gulf of Mexico. In these instances, the federal jurisdiction is extended beyond 200 nautical miles. The total area of the Federal OCS is about 1.76 billion acres. Of this acreage, about 46 percent is under active lease for oil and gas exploration, and about 20 percent of these active leases are in production.

The Mineral Management Services (MMS) estimates that the East Coast OCS holds resources of about 37 tcf, roughly equally divided between New England, the Middle Atlantic, the Carolinas, Georgia and northern Florida. The first OCS moratorium, covering 736,000 acres of coastal California, was passed by Congress in fiscal year 1982 as part of the U.S. Department of the Interior appropriations bill. Between 1982 and 1992, several more annual moratoria were passed, which covered only the year in which they were enacted. These moratoria covered disparate parts of the OCS including the North and Middle Atlantic, Eastern Gulf of Mexico, and California coast. President George H.W. Bush issued a Presidential Directive in 1990 that created a 10-year blanket moratorium, which included most of the Eastern Gulf of Mexico, estimated to hold about 26 tcf reserves of natural gas. In 1998, President Bill Clinton extended the Eastern Gulf of Mexico moratorium to 2012.

In 2005, the U.S. Congress passed an Energy Policy Act that required the MMS "to conduct a comprehensive inventory and analysis of the estimated natural gas and oil resources of the OCS," including areas currently off-limits due to the federal moratorium. In 2006, the U.S. House of Representatives voted in favor of the Deep Ocean Energy Resources Act, which would have lifted the moratorium on drilling off most of the U.S. coastline. According to the proposed legislation, states would retain the option to keep offshore drilling off-limits within 100 miles of their coastlines. The Senate rejected the scope of the House's bill and instead passed a more restrictive bill, the Gulf of Mexico Energy Security Act, which the House later approved as well.

In December 2006, Congress passed and President George W. Bush signed, the U.S. Gulf of Mexico Energy Security Act into law. The measure opened access to 8.3 million acres in the Eastern and Central Gulf, while providing a 125-mile buffer for the Florida coast. Gulf Coast states will receive 37.5 percent of the royalties generated from the leases. The MMS has proposed holding lease sales 206 and 224 for the Central and Eastern Gulf of Mexico on March 19, 2008, which would be the first sale in the Eastern Gulf of Mexico planning area to offer these blocks since 1988.

In July 2007, the U.S. House of Representatives affirmed its annual moratorium on drilling in most of the OCS as part of its discussions for 2008 appropriations for the U.S. Department of the Interior.

Certain regions in the Rocky Mountains also are closed to exploration and development under federal access or no surface occupancy rules. In addition, the National Environmental Policy Act (NEPA) passed in 1969, the Endangered Species Act (ESA) passed in 1973 and the National Historic Preservation Act (NHPA) passed in 1966, restrict the conditions for approval for oil and gas development in the key Rocky Mountain areas such as the Wyoming Thrust Belt, the Green River and Powder River basins and the San Juan and Uinta-Piceance basins. These various restrictions result in about 29 percent of natural gas resources being off limits to development in the region, according to the National Petroleum Council (NPC). The NPC has examined both areas where exploration and development are totally restricted and those where limitations on the time of the year when firms can operate is so restrictive that it renders the acreage inaccessible by commercial standards. In other cases, these environmental restrictions result in one- to two-year delays in permitting projects instead of barring them completely.

U.S. Supply Outcomes under Different Scenarios

Diversity of supply is an important aspect for promoting the resiliency of the global natural gas market in the face of temporary supply disruptions and to ensuring security of supply for large natural gas-consuming countries such as the United States. U.S. natural gas production can be adversely affected by hurricanes in the Gulf of Mexico, causing temporary disruptions in supplies, and the ability of the United States to replace lost production via imports is an important element to rebalancing supply with demand. Notwithstanding import capacity constraints, the ability of the United States to tap global markets for incremental supply has not been overly problematic because global markets currently benefit from a multitude of suppliers, reducing the vulnerability to a cut-off of any one source of supply and broadening the number of suppliers that can be approached for incremental imports. Moreover, North America and Western Europe currently produce about 36 percent of global natural gas output, meaning that much of the world's natural gas is being produced precisely near the markets where it is being consumed, reducing geopolitical risks to supply.

Significant growth in trade in natural gas has been a major feature of international energy markets in recent years. Despite a concentration of large gas reserves among several producing countries in the former Soviet Union and the Middle East, an examination of the current supply situation in world natural gas markets indicates that it will take many years to work off a plethora of supplies from within major consuming regions and small competitive fringe producers, thwarting the formation of an effective gas cartel in the short- to intermediate-term. New entrants, or capacity expansion by existing producers who are not in the natural gas cartel, would, unless their size is small relative to market growth, undermine the effectiveness of the cartel.

This healthy diversity of potential suppliers means that a loss of any one particular supply source can be offset by increases from another supplier or even multiple suppliers. It might be possible for a large gas producer to gain short-term rents in particular markets by manipulating availability of immediate supplies. However, at least for now, competition from other fuel sources as well as from other natural gas suppliers is effectively lowering the risk that such market manipulation could be sustained over anything but a short period of time. The existence of many substitutes for natural gas increases the elasticity of demand for gas, both in the aggregate and for the output of any potential cartel. A higher elasticity of demand translates into reduced market power of a potential cartel.

Over time, as natural gas demand grows and as small producers' output declines, production shares in the global natural gas market will become more concentrated. The resulting reduction in the supply elasticity of the fringe producers will reduce the elasticity of demand facing the largest natural gas exporters and increase their market power. So, as the potential for increasing fringe supplies over time diminishes, the result will be to give a very large producer (for example, Russia) or a group of larger producers (the Middle East suppliers) greater ability to manipulate price through decisions about resource development or production.

To determine whether the United States and its allies will become vulnerable to increasing market power of major international natural gas suppliers, like Russia and countries of the Middle East, and the role that existing drilling restrictions in the United States play in this question, scenario analysis is utilized to determine the possible effects of a complete lifting of restrictions on drilling in the Rocky Mountains and OCS. The aim of these scenarios is to examine whether the impact of the increase in natural gas production from these now blocked U.S. regions would reduce the monopoly power of any potential large supplier or group of large suppliers and, similarly, would ameliorate the impact of a major accidental disruption of natural gas supply.

The outcome of a complete lifting of restrictions in drilling in the Rocky Mountains and OCS is considered under four different conditions:

1) Where there are no artificial or geopolitical restrictions on U.S. natural gas imports

2) Where the cost of alternative energy is greatly reduced

3) Where there are sporadic temporary disruptions of natural gas supply from the Middle East

4) Where there is a major permanent disruption of natural gas supply from the Middle East

Under the scenario where there is a complete lifting of restrictions on drilling in the Rocky

Mountains and OCS but no artificial or geopolitical restrictions on U.S. natural gas imports, LNG imports into the United States (including LNG imports into Mexico and Canada that ultimately arrive to the United States via pipeline) would fall by 0.85 tcf in 2015 expanding to a maximum reduction of 1.59 tcf by 2030. This is from a base of 2.42 tcf in 2015 and 8.79 tcf in 2030, or a 35 percent and 19 percent reduction, respectively, from the reference case where the Atlantic, Pacific and Eastern Gulf of Mexico OCS, as well as areas in the Rockies, remain restricted to access for drilling.

As might be expected, the lower requirements for LNG under this scenario stem from larger, low-cost U.S. Lower 48 natural gas production. Modeling predicts that lifting access restrictions would lead to an increase overall in Lower 48 production of about 1.5 tcf in 2015 (or a 7.5 percent increase), increasing to 3.1 tcf greater production (or a 10.1 percent increase) in every year from 2015 through 2030. More specifically, OCS production would total 5.0 tcf in 2015 and 6.1 tcf in 2025 as compared to only 3.5 tcf in 2015 and 3.9 tcf in 2025 if the restrictions remain in place. Lifting restrictions in the Rocky Mountains adds another 0.10 tcf by 2015 and 0.93 tcf by 2025.

The reduced U.S. requirement for LNG is not extremely large in a volumetric sense, and it certainly would not eliminate imports of natural gas under any scenario examined by the study. Moreover, the price impact of lifting access restrictions in the OCS and Rockies also is limited. The shift in the near term from exploitation of high-cost natural gas resources to lower-cost OCS development would lower annual domestic prices by only roughly 10 percent. The effect is greater in some "end-of-pipe" markets such as the West Coast and the Middle Atlantic, particularly where restricted resources have a direct impact on regional supply. Average prices at the SoCal border (Southern California) market area and in the Tetco-M3 market area (Philadelphia and New Jersey) could be as much as $0.50 per MMBtu lower by 2017, but even this does not represent a large percentage change in average prices.

Similarly, in the scenario where natural gas supplies from the Middle East are sporadically disrupted by accidental events, lifting restrictions on OCS Atlantic, Pacific and Eastern Gulf of Mexico would have only negligible impact in the near term. That is because, during the next 10 years or so, the share of the global market held by Middle East producers is not very large and in addition, as discussed previously, there would remain many fringe producers who could respond to the shortfall. For example, an unexpected disruption that reduces supply from the Middle East in 2020 by 15 percent (a cutoff of about 1.2 tcf of natural gas), only increases U.S. natural gas prices at the Henry Hub by around $0.20 per MMBtu.

However, the contribution of expanded OCS and Rockies natural gas production could, nonetheless, be geopolitically important in combating the rise of a cartel in the international natural gas market, a so-called "GasOPEC." Reducing U.S. demand for LNG helps lower global natural gas prices and enhances available supplies for other major buyers in Europe and Northeast Asia. The wider swath of alternative supplies for Europe and Northeast Asia translates into significantly reduced market power of producers in Russia and the Middle East. Furthermore, the higher elasticity of supply from alternative sources as a result of allowing greater access to resources in the United States also reduces market power in the sense that a larger reduction in cartel supply would be needed to achieve any given increase in price.

In fact, under this higher U.S. Lower 48 natural gas production scenario, LNG exports from the more marginal producers, which tend to be OPEC countries (Iran, other Middle East exporters, Venezuela and, to a lesser extent, countries in North and West Africa), would decline at the margin, falling collectively by 0.27 tcf in 2015, but eventually by as much as 0.43 tcf by 2030. Even though the volumes are small, additional scenario analysis shows that this less-constrained supply picture for the global market can make a sound contribution to rendering the United States and its allies less vulnerable to the will of any one producer or the collective will of any group of producers. In fact, opening access more fully in the OCS and Rocky Mountains not only enhances U.S. supply, and thereby energy security at home, but also positively impacts the global energy security situation, reducing the market power of key natural gas producers and thereby lowering the risks that vital natural gas supplies could be withheld for geopolitical ends or to garner exorbitant short-term rents (see working paper titled "North American Security of Natural Gas Supply in a Global Market").

In order to better demonstrate the potential benefits of removing impediments to access in the case in which there exists the possibility of an international natural gas cartel, scenario analysis was performed where Middle East producers cut their exports of natural gas by 60 percent relative to the reference case for all years.

Under this dire scenario of a major, organized cutoff of supply, and under conditions where access restrictions are lifted, the United States is better equipped to draw from its own incremental reserves, raising the ability of U.S. domestic production to respond to replace withdrawn Middle East production. Under such a GasOPEC scenario, U.S. production would increase by an additional 1 bcf/day, leaving the market less vulnerable in the longer term to a GasOPEC cutoff. Domestic supplies effectively substitute for lost LNG imports, limiting the effects on price and demand. Thus, removing access impediments domestically can render constraints on supplies outside the United States much less harmful to the welfare of domestic consumers and consumers in allied countries. The point is that the possibility of *incremental,* latent increases in U.S. production capability restrain the options of a GasOPEC or dominant supplier like Russia. Increased access in the Lower 48 thus also could yield additional benefits in so far as it can reduce the impact of dominant suppliers of natural gas by increasing the elasticity of the demand curve net of other supplies that they face.

It should be noted that the ability of higher-cost U.S. production to respond to a GasOPEC cutoff scenario could be even greater in a high oil price environment. The results presented here assume future oil prices based on U.S. Energy Information Administration (EIA) forecasts of $57.50 a barrel (in 2005 dollars) for 2007, $44.41 a barrel for 2014 and $51.63 a barrel for 2030. But oil prices in 2007 and beyond may exceed the EIA's forecast. If so, both the demand for natural gas and natural gas prices also would be higher, and the potential effects of having a more elastic U.S. supply curve would be even greater.

The situation of Alaska under various policy and market conditions illustrates the point about the impact of oil prices on outcomes. The Alaska question is more complex and thereby illustrates the challenges facing energy policymaking in the United States. Many remaining natural gas resources in the United States, such as unconventional resources or distant resources such as those in Alaska, are high-cost resources that would have trouble competing with low-cost sources of supply. Under a moderate oil price, unrestricted drilling market scenario, Alaskan resources would not get fully developed. That is because these more expensive domestic resources would, in effect, take a back seat to low-cost Atlantic, Pacific and Eastern Gulf of Mexico OCS natural gas production as well as to cheap, marginal supplies of LNG from long-standing exporters. This is particularly true of Alaska, where the greater access to resources in the Lower 48 delays the development of the Alaska gas pipeline, reducing Alaskan production by as much as 0.95 tcf in 2025 (or a 40 percent reduction) relative to the case where access restrictions are in place.

On the surface, this seems to argue against a change in U.S. natural gas drilling policy. If all that would happen from opening up restricted acreage is a shift from higher-cost, unconventional U.S. natural gas plays in Texas and Louisiana to cheaper plays along environmentally sensitive coastlines, why bother? But the fact is that these higher-cost resources would remain as a sort of under-the-ground "security inventory," available to be tapped in times of extended, severe market stress. Unlike deepwater OCS resources that take many years to organize for exploration, drilling and development, higher-cost onshore resources (such as those in the Barnett Shale and some areas in the Rocky Mountain region, or those potentially associated with well work-overs and enhanced recovery) can be activated relatively quickly in a market crisis or in response to cartel actions, giving the United States more flexibility.

It might be argued that it would be preferable to reduce foreign gas suppliers' monopoly power — not through domestic drilling but through the wider option of alternative energy in the electricity sector. Indeed, modeling indicates that the lower prices ushered in with a lifting of OCS and Rocky Mountain restrictions also reduce the extent to which alternatives, such as coal-gasification and nuclear energy, are deployed. For example, alternative technologies for gas services, so-called backstop technologies, would meet 1.1 tcf of demand by 2030 in the case where access is restricted and 0.8 tcf when access is unrestricted.

Under a scenario in which technological cost breakthroughs allow alternative energy to compete more effectively with fossil energy, LNG import requirements would be further reduced, indicating that lifting drilling restrictions or promoting alternative energy have similar effects. Whereas in the open drilling access scenario LNG imports were reduced by 0.85 tcf in 2015 and 1.6 tcf in 2030, adding the availability of an alternative energy resource at a lower cost creates additional reductions in LNG imports. Lower-cost alternative energy supply reduces LNG imports by an *additional* 0.25 tcf in 2015 and 0.6 tcf in 2030 beyond the 0.85 tcf and 1.6 tcf reductions seen in 2015 and 2030, respectively, following the opening of drilling. The maximum incremental reduction in LNG imports as a result of lower-cost technology occurs in 2027, at about an *additional* 0.8 tcf (or 2.2 bcfd). Furthermore, increased availability of backstop technologies would increase the elasticity of excess demand facing the Middle East, as consumers have more alternatives to natural gas at lower prices. Thus, the availability of an alternative low-cost source of energy has the potential to bring about a similar set of benefits as opening more lands in terms of combating the potential monopoly power of a GasOPEC or a single, very large gas supplier such as Russia (see working paper titled "North American Security of Natural Gas Supply in a Global Market").

The U.S. Crude Oil/Natural Gas Price Link

The recent run-up in crude prices to nearly $100 per barrel raises the important question of whether there is an ongoing linkage between crude oil prices and natural gas prices and whether continued upward pressure on oil prices will be matched by similar movements in U.S. domestic natural gas prices.

Historically, it was thought that the prices of West Texas Intermediate (WTI) crude oil and natural gas delivered at the Henry Hub, which are the most widely quoted energy prices in the United States, maintained a 10-to-1 relationship, so that one barrel of WTI crude oil was priced at roughly the equivalent of 10 times 1 MMBtu of natural gas. More recently, this appears to have declined by about 40 percent to a 6-to-1 ratio, which is close to thermal parity. However, the observed variability in the relative price relationship has led some to question whether the natural gas price has decoupled from the crude oil price, or whether there is a relationship at all.

Simultaneous to the modeling of scenarios for U.S. natural gas supply, a group of scholars at the Baker Institute also studied the long run relationships between the U.S. natural gas price, the residual fuel oil price and the WTI price. In order to thoroughly investigate the relationship between the prices of natural gas, residual fuel oil and WTI — and adjustments to deviations from that relationship — researchers estimated the cointegrating relationship between fuels and then developed and estimated an error correction model (ECM) that includes some stationary exogenous variables, allowing for identification of some of the shocks that lead to departures from the long run equilibrium between prices. The estimated ECM also permits identification of a causal ordering in price adjustment and how fast that adjustment occurs (see working paper titled "The Relationship between Crude Oil and Natural Gas Prices").

Through this modeling exercise, it is demonstrated that U.S. natural gas and crude oil prices remain linked in their long-term movements but that this link is indirect, acting through competition at the margin between natural gas and residual fuel oil. In addition, the study found that technology is critical to this long run relationship between WTI and Henry Hub natural gas prices. The widespread adoption of combined cycle gas turbines has, in effect, increased the efficiency of using natural gas to generate electricity relative to using oil-based fuel. Specifically, the study finds that the adoption of more efficient, combined cycle gas turbines has contributed to a reduction of the long-term equilibrium price relationship between WTI and Henry Hub natural gas prices by about 40 percent from levels seen more than a decade ago. One implication is that future technological innovations will influence the long run relationship between crude oil and natural gas in a way that simple time trends cannot identify.

Since crude oil is easily transported and is relatively fungible, there exists a strong price correlation between different types of crude oil produced across the globe, including U.S. crude oil benchmark West Texas Intermediate. As a result of this relationship, the study is able to determine the effect of the international crude oil markets on U.S. domestic natural gas prices. The study results suggest that U.S. natural gas and residual fuel oil prices tend to respond to movements in the international crude oil markets but that the reverse is not true. Thus, disequilibria in the long run relationship between natural gas and residual fuel oil prices can be driven by random shocks to the international crude oil market, which themselves influence disequilibria in the long run relationship between the prices of residual fuel oil and crude oil. Such long run relationships will ultimately be reached after some period of adjustment. Therefore, an increase in a global crude oil price will ultimately result in a higher residual fuel oil price and, hence, a higher natural gas price.

One implication of this finding is that, if international crude oil prices remain at current highs, U.S. natural gas prices will likely rise substantially in the coming months if short-term pressures, such as very large inventory levels, subside. However, there tends to be a time lag between a significant change in U.S. crude oil prices and the adjustment of natural gas markets to that change. In addition, prolonged, high international oil prices will likely mean that U.S. natural gas prices are unlikely to collapse substantially over the long term. According to the Baker Institute analysis, a $70 per barrel WTI average price (expressed in real 2000 prices) is likely to promote a long run equilibrium natural gas price at the Henry Hub of around $9.40 per MMBtu. It also is important to note that our analysis shows that the long run relationship between the crude oil price and the natural gas price acts through residual fuel oil prices. Thus, if the spread between residual fuel and crude oil prices increases, this will result in the natural gas price falling relative to crude oil. (see working paper titled "The Relationship between Crude Oil and Natural Gas Prices").

Short run departures from the long run equilibrium price relationship of a 6-to-1 ratio are influenced by product inventories, weather, other seasonal factors and supply shocks such as hurricanes. For example, the study reveals that historical experience implies that, for each billion cubic feet of natural gas production per day that is shut in as a result of a hurricane in the Gulf of Mexico, natural gas prices at the Henry Hub increase approximately by $1.03 per MMBtu (again expressed in real 2000 prices).

To further explain the price linkages between crude oil and natural gas prices in the United States, empirical evidence was examined to see whether the postulated substitution thought to underlie the aggregate results could indeed be seen at a more micro level. Specifically, we sought evidence that some generators and cogeneration facilities consider the relative costs of using oil products and natural gas when choosing fuel inputs and which plants to operate (see working paper titled "Electricity Sector Demand for Natural Gas in the United States"). Through direct microeconomic evidence based on a combined time series and cross-sectional analysis, it is demonstrated that grid-level and plant-level fuel switching between natural gas and oil products as inputs to electricity generation plays a key role in determining the relationship between natural gas and oil prices. Analysis revealed that positive deviations from the long run relationship between the cost of using natural gas to generate electricity relative to the cost of using petroleum products exert a significant negative effect on natural gas demand in power generation. Moreover, while the effect is present in half of the North America Electric Reliability Council (NERC) regions as a result of movements of plants up or down the supply stack as fuel prices change, it is strongest in regions where plant-level switching is more available, such as Florida. So long as both natural gas and oil products continue to be used to generate electricity, fuel prices have to adjust to keep both fuels competitive at the margin.

There are several reasons why substitutability between natural gas and oil products is higher in the electricity sector than in other industries. Some electricity generating plants can substitute fuel oil for natural gas at relatively low cost. More importantly, however, the relative position of different types of plants in the dispatch order, the so-called "supply stack," will change as fuel prices vary. When natural gas costs in power generation are high relative to oil costs, natural gas-fired generation will shift up in the supply stack so that it will be dispatched later than cheaper oil-fired generation capacity. Accordingly, natural gas plants will be used for shorter periods of time within a day, greatly reducing the demand for natural gas and increasing the demand for oil products. For combined-cycle plants, the competing fuel likely will be residual fuel oil, while for gas turbines, the competing fuel likely will be distillate fuel. Competition between natural gas and oil products in the electricity sector thus is likely to be critical for understanding future movements in natural gas prices.

Increasing demand for natural gas as an input into electricity generation, along with maturing domestic production and limitations on imports, has tended to raise natural gas prices in the United States in recent years. While rising natural gas prices have tempered demand growth in other sectors during the last few years, there remains a tremendous latent capacity to burn natural gas. Thus, whenever natural gas prices fall, even temporarily for seasonal or other reasons, these lower prices trigger a rapid increase in consumption. For example, a heat wave in summer 2006, coupled with natural gas prices that were below parity with residual fuel oil prices, spurred two weeks of withdrawals from natural gas storage to fuel an increase in utilization of natural gas peaking capacity.

The combined cross-sectional and time series data analysis also implies that weather and other seasonal effects alter the demand for natural gas as an input to electricity generation independent of any response to departures of the relative prices of fuels from their long run equilibrium relationship. In every NERC region except one, increases in overall electricity demand also are met at the margin by burning more natural gas (see working paper titled "Electricity Sector Demand for Natural Gas in the United States").

As natural gas markets become more global, the U.S. oil-natural gas price link will be influenced by international trends. The price impacts of interfuel substitution in overseas markets will create arbitrage opportunities between regional markets that will be exploited via increased trade in LNG, transmitting an oil-natural gas price linkage internationally. Changing supply economics, gas sales contracting practices and other geopolitical factors also could influence the relationship between crude oil and natural gas prices. One supply-side mechanism reflects oilfield operating decisions. The value of natural gas relative to crude oil can influence the amount of gas that is ultimately supplied to international markets and how much is used for enhanced recovery and/or lease operations, particularly if the gas is associated. These production decisions, however, generally require some capital outlay and therefore influence price adjustment only over a longer period of time. The wider adoption of gas-to-liquids (GTL) production is another growing supply-side factor that may increasingly influence the link between crude oil and natural gas prices. GTL output is forecast to grow from 165,000 barrels a day currently to 1 million to 2 million barrels a day in the coming decades, mainly from proposed projects in Qatar and other low-cost gas production areas (see working paper titled "A Brief Narrative on the International Influences on the Link between U.S. Crude Oil and Natural Gas Prices").

Another factor that potentially could alter the long run relationship between natural gas and oil is the adoption of a tax on carbon. For example, a carbon tax would penalize petroleum more heavily than natural gas. For a power producer, this would alter the cost of generating electricity in favor of natural gas, effectively raising the marginal cost of using the petroleum products with which gas competes. This could permanently raise natural gas prices relative to oil prices since the fuels compete on a cost basis in the electricity sector. It would act somewhat like the changes in heat rates that lowered the relative cost of using gas to generate electricity. Thus, the equilibrium relationship between natural gas and crude oil prices could be shifted so that the gas-oil ratio is higher.

Conclusions and Policy Implications

In this study, we have concluded that natural gas will become an increasingly important part of the U.S. energy mix. Under a business-as-usual scenario where U.S. lands are not opened for drilling, U.S. natural gas demand would climb to 23.9 tcf in 2015 and 26.9 tcf by 2025, up from 20.3 tcf currently. This represents a gain of about 1.3 percent per year. Rising demand from the electricity sector would contribute to this rise, with electricity demand for natural gas rising from 6.2 tcf currently, to 9.4 in 2015 and 12.0 tcf in 2025.

U.S. natural gas production is projected to be roughly 20.8 tcf in 2015 and 21.2 tcf in 2025. In the short term to 2015, dependence on Middle East supply would not be large. LNG imports would only climb to 2.42 tcf by 2015 or about 10 percent of U.S. demand by 2015. However, under the same business-as-usual scenario where U.S. lands are not opened up for drilling, the United States will rely on LNG imports for 20 percent of total natural gas consumption by 2025, and 31 percent by 2030. Of these imports, direct LNG imports (via U.S.-based terminals) account for 80 percent in 2015, falling to 73 percent and lower in 2025 and beyond, with indirect LNG imports (those coming through Mexican and Canadian terminals and reshipped via pipeline to the United States) accounting for the growing remainder, according to Baker Institute calculations.

Similarly, under this same business-as-usual scenario, the share of total global natural gas production coming from the Middle East will rise from current levels of about 10 percent to just over 14 percent by 2025 and about 25 percent of all LNG shipments globally. According to Baker Institute estimates, this means that roughly half of Middle East LNG production will be coming to the Atlantic Basin, with the United States likely to receive about 20 percent to 25 percent of its LNG supplies from the Middle East. That is on top of 24.6 percent of oil imports for the transportation sector coming from the Middle East.

This supply picture has raised questions about growing dependence on the Middle East for both oil and gas supply. However, scenario analysis shows that opening restricted areas in the OCS and Rocky Mountains to drilling and natural gas resource development will not render the United States energy independent nor will it even lower U.S. dependence on LNG imports in 2015 by a significant volume. Price impacts also are limited, with U.S. prices only registering marginal reductions. And, in scenarios of a temporary or sporadic cutoff of Middle East supply, higher OCS and Rocky Mountain production again only produce limited benefits in pricing and supply diversification. In the intermediate term, supply diversity is available at a relatively reasonable cost from a wide variety of alternative fringe exporters in the global market.

Strategically, however, there is some benefit to opening restricted areas in the OCS and Rocky Mountains to drilling in terms of reducing the potential monopoly power of large foreign gas producers from the Middle East or former Soviet Union in global gas markets. This is especially true in the coming 20 to 25 years, when it is expected that the monopoly power of major natural gas producers like Russia and countries in the Middle East will be rising. As demonstrated by scenario analysis, higher OCS production would weaken the market power of large foreign natural gas exporters in the global market, and to the extent that it displaces higher-cost U.S. unconventional and conventional onshore natural gas in the intermediate term, those domestic resources could be called on more quickly during a period of market supply strain. However, as demonstrated by scenario analysis, this strategic benefit also might be achieved through technological breakthroughs that allow cost reductions in alternative energy.

In the immediate term, creating a system where the U.S. government could "borrow" natural gas inventories from domestic storage during a supply crisis or to counter a natural gas supply shutoff from a major gas producer or group of producers — a strategic natural gas reserve — might be more politically expedient than opening up environmentally sensitive lands to immediate drilling. Longer term, a push to support the development of alternative energy can offer similar benefits to expanding the U.S. domestic natural gas production base.

Another alternative would be to exploit the potential for "net conservation benefit trades" in lands that have potential for natural gas resource development. Essentially, a net conservation benefit trade is an exchange of resources that results in a *net* gain in conservation outcomes, while at the same time releasing resources for other uses.

Examples of net conservation benefit trades include multiple land use, where productive practices are adjusted to maintain or enhance conservation values in situ. For example, new offshore development techniques allow most well infrastructure to be placed on the ocean floor, allowing gas resources to be exploited with little or no scenic degradation. In sequential land use, productive land activities with a limited life span (for example, a mine) are pursued and followed by investments to restore the conservation benefit of the land after the activity is completed. Both multiple and sequential land use envisage a range of activities on the one piece of property. A third alternative involves using offsets, whereby a productive activity in one location is used to finance a conservation activity, or purchase conservation rights, elsewhere. Indeed, the trade of increased Lower 48 production for reduced Alaskan production could be viewed as an implicit net conservation benefit offset.

Mechanisms for conservation trading would employ something akin to a barter process. As long as environmental objectives can be specified in a measurable way (or even given an ordinal ranking) — for example, the area of habitat land available for a particular endangered species — trades can be negotiated without the need for expressing all values in dollar terms. Parties wishing to use current conservation resources in a different way could pay for the privilege with actions, or by swapping for land areas that have higher conservation value.

While companies could voluntarily enter into offset agreements, it is risky to do so in the absence of suitable enabling legislation and widespread community debate and agreement about the value of such agreements. In particular, clear and transparent rules and procedures are needed to determine in advance, and as objectively as possible, the conservation cost of any damage from drilling activity and the value of any offsets financed by the energy company.

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Working Papers in the Study:

These working papers can be found on the Baker Institute Energy Forum Web site at www.rice.edu/energy/.

"A Brief Narrative on the International Influences on the Link between U.S. Crude Oil and Natural Gas Prices"

"Electricity Sector Demand for Natural Gas in the United States"

"North American Security of Natural Gas Supply in a Global Market"

"The Relationship between Crude Oil and Natural Gas Prices"

James A. Baker III Institute
for Public Policy–MS40
Rice University
P.O. Box 1892
Houston, Texas 77251-1892