A Brief Examination of the Adequacy of Future U.S. Natural Gas Infrastructure and Resources

and

The Role of Public Lands in U.S. Natural Gas Production

A Report to The Wilderness Society

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I. Introduction and Layout

This paper gives a concise description of some of the known and undiscovered natural gas resources that may underlie this nation's public lands. Included in this paper is an outline of current producing areas and a discussion of the locations of likely future producing areas—with distinctions drawn between Federal, non-Federal, onshore and offshore lands. Also found in this study is a summary of some of the constituents of U.S. natural gas infrastructure and recent trends in the sector. This paper additionally gives descriptions of the magnitude of existing, planned, and permitted natural gas pipeline projects. This information informs the reader about imminent additions to near-term future gas capacity and increased deliverability. Finally, this study briefly summarizes projected future U.S. natural gas supply, prices, and conclusions.

Section II describes locations of currently producing areas. Section III looks at a statewide summary of the locations of current major gas reserves. Section IV examines the likely areas where future gas production will occur, with a brief discussion of contributions from Federal, non-Federal, onshore, and offshore lands. Section V briefly explains the components of the nation's natural gas supply network and summarizes recent trends in gas prices and consumption. Section VI lists recent and planned near-term future natural gas infrastructure improvements, with an analysis of their planned impacts on increasing the total quantity and efficiency of national natural gas supplies. Section VII summarizes the Department of Energy's projections on future price and availability of natural gas in the Untied States. Finally, Section VIII gives a summary and major conclusions of this report and Section IX discloses selected references.

II. Current Gas Production from Onshore Federal Lands

Total onshore- and offshore-marketed U.S. gas production in 2000 was about 20.1 trillion cubic feet (Tcf) (DOE/EIA, 2001a). Gas production from all onshore Federal gas leases amounted to approximately 2.0 Tcf, or about 10 percent of national gas production. New Mexico public lands produced about 5.5 percent of all U.S. gas production in 2000.

Approximately 53 percent of all onshore Federal gas royalties can be traced to New Mexico producing wells, 33 percent from Wyoming, 4 percent from Colorado, 4 percent from Utah, 2 percent Texas, 1 percent Oklahoma, and about 0.1 percent Louisiana. Sixteen other states accounted for the other 3.6 percent of Federal gas royalties from onshore production. Using an average annual citygate price for all U.S. natural gas production of $4.70 per Mcf, total marketed value in 2000 was about $94 billion. Total receipts from these onshore Federal gas royalties gas were about $611 million in 2000—approximately 0.7 percent of the value of total U.S. natural gas output.

III. Current U.S. Natural Gas Reserves

Detailed data are not readily available to show the Federal/non Federal breakdown of current natural gas reserves. An examination of gas reserves on a statewide basis shows that the seven largest concentrations of reserves, comprising 75 percent of total U.S. gas include onshore Texas (24 percent), followed by New Mexico (9 percent), Wyoming (9 percent), Oklahoma (7 percent), Alaska (6 percent), and Louisiana (6 percent). Offshore Federal areas in the Gulf of Mexico collectively contain about 15 percent of current U.S. natural gas reserves.

IV. Undiscovered Economically Recoverable Gas Reserves

All Onshore Lands and State Offshore Lands

USGS data show that there is about 196.3 Tcf of natural gas yet to be discovered in onshore and state offshore (up to three miles out to sea) areas at a gas price of about $3.90 per Mcf (2001 dollars) (USGS, 1995). About 70.5 Tcf (36 percent) of this gas is expected to come from the onshore and state offshore areas bordering Texas and Louisiana. Another 29.1 Tcf (15 percent) is expected to be found in the Rocky Mountains and Northern Great Plains regions, about 35.2 Tcf (18 percent) from the Colorado Plateau and Basin and Range provinces, as well as about 13 Tcf (7 percent) from West Texas and Eastern New Mexico, and about 14.2 Tcf from Midcontinent areas (7 percent).

Federal Onshore Lands

According to USGS estimates there is likely about 36.9 Tcf of economically recoverable gas at prices of about $3.90 per Mcf to be found in all onshore Federal lands--about 19 percent of total undiscovered U.S. onshore gas and 12 percent of total economically recoverable undiscovered U.S. gas resources. The region with the largest amount of the gas in Federal onshore lands is the Colorado Plateau and Basin and Range Province (parts of CO and NM, AZ, UT, NV) with about 19.4 Tcf. Also, the Rocky Mountain and Northern Great Plains Province (MT, ND, ID, WY, parts of CO) contains about 14.3 Tcf. The remaining 3.2 Tcf of economically recoverable gas that is expected to be found underneath other Federal onshore lands is scattered throughout the rest of the country (including Alaska).

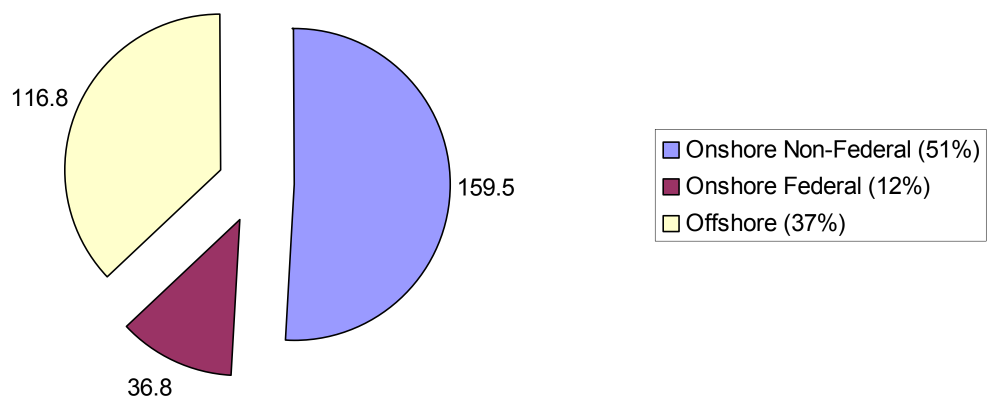
Federal Offshore Lands

The Minerals Management Service (MMS) gives estimates of undiscovered economically recoverable gas from Federal offshore lands of 116.3 Tcf (MMS, 2001). However, the agency uses a gas price of only $2.11 per Mcf. As a result, the MMS estimate of 116.3 Tcf at $2.11 per Mcf almost certainly significantly underestimates the amount of undiscovered natural gas that would be economically recoverable at gas prices of $3.90 per Mcf. Combining the very conservative MMS estimate with USGS estimates yields a total estimate of economically recoverable gas in all onshore and offshore lands of at least 313.1 Tcf with gas prices of about $3.90 per Mcf.

Gas Resource Distribution by Land Categories

Figure 1 graphically shows the relative contributions of undiscovered economically recoverable natural gas reserves from onshore Federal and non-Federal lands, and from offshore Federal lands. The relative endowment of economically recoverable natural gas from offshore lands is likely to be very underestimated relative to onshore estimates. Offshore resource estimates from MMS assume a gas price of just $2.11 per Mcf gas. In contrast, the USGS onshore resource estimates assume a gas price of $3.90 per Mcf gas.

Figure 1 – Economically Recoverable Natural Gas at $3.90 per Mcf (onshore) and $2.11 per Mcf (offshore), (Tcf)



Sources: USGS, 1995, OF 95-75-N, and MMS, 2001, News Release, January 17, 2001.

Despite the different gas price estimates, Figure 1 gives some indication of the relative importance of the different types of land for natural gas resource estimates. Figure 1 shows that the maximum contribution of economically recoverable natural gas from onshore Federal lands is about 12 percent of the estimated total undiscovered gas resource of 313 Tcf. Non-federal onshore lands likely hold at most 51 percent, and offshore lands hold at least 37 percent of total undiscovered economically recoverable natural gas.

Likely locations of future reserves of as-yet-unidentified bodies of natural gas have been detailed by the USGS. About 33.7 Tcf of undiscovered economically gas (at $3.90 per Mcf) is likely to be found underneath western Federal onshore lands. This quantity represents about a maximum of 11 percent of the nation's total future gas reserves. Most of the expected undiscovered economically recoverable gas is expected to be found within non-Federal onshore lands (<51 percent), and from Federal offshore lands (>37 percent).

V. Natural Gas Infrastructure and Trends

Infrastructure

Several entities collectively comprise the U.S. natural gas system. Producers are individuals and companies that find and produce natural gas from the ground. Prices at the wellhead (point at which the gas emerges from the ground) are unregulated. Producers have freedom to negotiate any mutually agreeable prices and terms with downstream parties.

Gathering lines from multiple wellheads transmit gas to processing plants where noxious gases and natural gas liquids are removed prior to the gas entering transmission pipelines. Most gathering pipelines fall under state jurisdiction.

Transmission pipelines convey processed gas to specific delivery points that may include storage facilities, other transmission pipelines, or a “citygate” (entry point of gas from transmission pipeline to a Local Distribution Company [LDC]). Pipelines that span more than one state have their rates and terms and conditions of service regulated by the Federal Energy Regulatory Commission (FERC). Pipelines confined to one state are typically regulated by that state’s Public Utility Commission (PUC).

Natural gas is not consumed at a uniform rate throughout the year. It is used at a much greater rate during winter months, primarily for space heating. In anticipation of the greater drawdown of gas during the winter months, much of the gas produced during other seasons is “parked” in storage facilities. Gas can then be drawn at a greater rate from storage facilities than from initial production and processing areas as it is needed throughout the year.

Local Distribution Companies (LDCs) move the gas from citygates to intermediate and final users of natural gas. Much of the end-user cost of natural gas can be traced to the capital and operating costs of building and maintaining the spider-web of small pipeline networks that convey the gas to the multitude of end users.

Marketers are companies that perform “packaging” functions for natural gas consumers. These firms may contract with a variety of producers, pipelines, LDCs, and other companies to sell a discrete package of natural gas supply, storage, and delivery under various prices and conditions.

<u>Recent Trends</u>

Consumption

Consumption of natural gas reached a record level of 22.8 trillion cubic feet (Tcf) in 2000—a growth of about five percent over 1999 (DOE/EIA, 2001b). Most of the annual variation in natural gas consumption can be attributed to winter temperatures. Colder winters produce a greater demand for gas.

But, trends in natural gas consumption are more complex than weather patterns. In 2000 about 40 percent of gas consumption came from the industrial sector. Gas is primarily used in this sector for cogeneration (combined power and heating), and as a feedstock to produce other hydrocarbon-based goods. Seasonal demand in this sector is the least temperature-sensitive. Although some industrial users of natural gas can switch between fuels (a typical gas substitute is fuel oil) with energy price changes, most industrial users of natural gas do not have that capability.

The residential and commercial sectors collectively consumed about 40 percent of gas in 2000. Increases in natural gas demand in the residential sector can be linked to increases in the average size of homes and the fact that in 1999 more than 70 percent of new homes use natural gas for heat, compared with 47 percent in 1986. Commercial use of natural gas has increased even faster than residential use. Both of these sectors’ natural gas consumption is quite temperature sensitive. Peaks in gas consumption almost invariably occur during January and February for these users.

The other 20 percent of natural gas consumption in 2000 can be traced to the electrical generation sector. Natural gas is used as a fuel for at least two types of electrical generators (1) combustion turbines and (2) combined-cycle plants. Combustion turbines have the advantage of being relatively cheap and quick to build, have high efficiencies, and can be turned on and off quickly to satisfy short-term peaks in demand for electricity. But, combustion turbines are not usually the only source of electricity at generating stations because they are relatively expensive to operate. Combined-cycle plants use gas-fueled boilers and apparatus to combine power-generation and heating functions. Seasonal peaks in natural gas demand occur during the summer months in the electrical generation sector (air-conditioning demand), with smaller peaks during the winter months (space-heating demand). Thus, to some extent, seasonal peaks in the electrical generation sector are not coincident with industrial, commercial, and residential sectors.

Prices

Prices of natural gas reached unusually high seasonal peaks during the winter months of 2000-2001, particularly natural gas prices in the Western U.S. and California. Citygate prices during the winter ranged from about \$6.60 in Chicago, to more than \$15.00 in Southern California. In the third quarter of 2000, prior to the winter of 2000-2001, natural gas prices varied from about \$4.50 in Chicago to \$5.30 in Southern California.

While it is common for natural gas prices to rise during the winter months, the amount of seasonal and regional variation seen last winter is unusual. Most experts attribute the large price increases to several factors; (1) a long-term trend of relatively low natural gas prices during most of the 1990s that limited producers' cashflow and led to low levels of natural gas exploration and production, resulting in decreases in the natural gas supply; (2) increases in gas consumption that were encouraged by the relatively low gas prices (see the preceding sections); (3) unusually cold winter months over much of the U.S. during January and February 2001; (4) uncharacteristically low levels of rainfall in the western U.S. that led to smaller-than-normal amounts of hydropower available for electrical generation in the Western U.S.; and (5) an August 2000 rupture in an El Paso natural gas pipeline connecting natural gas from producing centers in Colorado, Texas, Wyoming, and New Mexico to consuming centers in California, Arizona, and New Mexico.

Natural Gas Supply

In a free market economy prices represent an investment signal. Increases in natural gas prices that commenced in about 1999 were interpreted by natural gas producers as a call for increasing natural gas supplies. With the increased cashflow available from higher natural gas sales revenues, producers stepped up their natural gas drilling campaigns. The *Oil and Gas Journal* reported that 154 independent U.S. producers increased capital spending by 48 percent from 1999 to 2000 and planned a further increase of 35 percent in 2001 (as reported in DOE/EIA, 2001b).

The frenzied pace of natural gas exploration and production in this country shows no signs of abating soon. As a matter of fact, as reported by *Natural Gas Week*, U.S. contractors and service companies are "flinging themselves into a headlong rush for rigs as the boom is beginning to take on fabled proportions." First quarter 2001 profits reported by one of the largest natural gas service companies, Baker and Hughes, rose by 600 percent compared with a year earlier (as reported in DOE/EIA, 2001b).

In 2000 there were about 720 rotary rigs working, an increase of 45 percent from 1999. There are now few or no inactive drilling rigs now available in this country. Clearly, the natural gas sector is now in the midst of a boom fueled by the relatively high natural gas prices. There is not apparent shortage of available targets in the U.S. for producers that are completely utilizing available natural gas drilling rigs.

Only now are the results of the increased exploration and production actions commencing in late 1999t beginning to be seen in the marketplace. The lag between drilling and the addition of natural gas reserves is usually about 6 to 18 months. After hitting a low of 18.6 Tcf of production in 1999, natural gas production increased by 0.7 Tcf in 2000, with significant additional production increases likely as time goes on.

In tandem with recent increasing domestic activity, imports and exports of natural gas from Canada and Mexico, and imports of Liquified Natural Gas (LNG) from abroad have increased as well. About 94 percent of all gas imports into the United States came from Canada in 2000. Our northern neighbor has very extensive deposits of the fuel. Canada continues to link its large natural gas resources with major U.S. consuming centers. Imports of Canadian gas showed annual increases of 5 percent in 2000, 10 percent in 1999, 5 percent in 1998, 1 percent in 1997, and 2 percent in 1996. Most of the import increases were due to increased pipeline capacity within and between the two countries.

VI. Natural Gas Infrastructure Improvements

The large price differential between citygate prices of natural gas of Southern California and Chicago in early 2001 discussed above ($15.00 vs. $6.60), shows the importance of natural gas infrastructure in determining end-user natural gas prices. The natural gas infrastructure was not able to deliver enough gas from the wellhead to the end users in Southern California. The result was a more than $8.00 price differential between citygate prices. Improvements in the natural gas infrastructure will help ensure that gas delivery flexibility will exist in the future to help eliminate very large regional price differentials. The problem was not an inadequacy of natural gas at the wellhead, but a deficiency in the natural gas delivery mechanism to the end user.

More than 165 U.S. inter- and intra-state pipelines contain about 278,000 miles of transmission lines along with many related structures and facilities. About 1,300 LDCs deliver gas to intermediate and end users through another 700,000 miles of pipelines.

Most often, the sources of natural gas are not located near the population centers containing the majority of the users of natural gas. As new sources of gas are found and developed they must be linked with new and existing pipelines to deliver the gas to the ultimate users. The natural gas infrastructure must also be linked with extensive storage facilities in order to maximize the efficiency in delivering this fuel whose demand has so much seasonal variation. Pipeline utilization levels in some parts of the West (particularly California) have recently been consistently above 95 percent (DOE/EIA, 2001b). Such high utilization rates leave little time for essential maintenance and capital improvements.

Since 1999, more than 60 natural gas pipeline projects have been completed and placed in service. These projects have increased capacity by more than 12.3 billion cubic feet per day (bcfd)—an increase of 15 percent over the 1998 level (DOE/EIA, 2001b). Most recent pipeline capacity additions have focused on bringing more Canadian gas into the U.S. Northeast and Midwest.

Also, increases in coalbed methane production from the Rocky Mountains in Wyoming and Montana have created the need for more pipeline capacity from that region to end users. Only recently have proposal been made to move the large increases in gas seen in the Rocky Mountain region to areas where it is can be used.

In the last five years there have been very extensive pipeline improvements made in order to transport the huge amounts of gas found in the Gulf of Mexico to consuming regions. From 1997 to 1998, 14 gas pipeline projects added about 6.4 billion cubic feet per day of capacity to the region.

The Department of Energy reports that there are 88 announced pipeline projects proposed over the next several years. These proposals would add an additional 20.8 billion cubic feet per day of capacity. The Midwest would add the most capacity (5.1 bcfd), followed by the Northeast (4.8 bcfd), Southeast (4.2 bcfd), Far West (2.6 bcfd), Southwest (2.0 bcfd), and Centeral (2.0 bcfd). These projects would collectively increase the nation's gas transportation capacity by about 22 percent.

LDCs have also been expanding at a rapid rate. American Gas Association estimates show that construction projects by distribution companies increased by 16 percent in 1998 and 1999 compared with 1996 and 1997 (as reported in DOE/EIA, 2001b).

VII. Natural Gas Price and Supply Projections

The energy sector is notorious for going through periods of boom-and-bust, especially in the last three decades. One only has to look backwards to 1998 to early 1999 to see that the natural gas industry in a bust cycle. The booms and busts in oil and gas are not necessarily coincident.

The Department of Energy (DOE) projects that the natural gas sector will continue to in a "boom period" during the near term. The next few years will likely exhibit relatively high natural gas prices and concomitant high levels of domestic exploration and development, as well as elevated levels of capital spending on infrastructure improvements. From 2000-2002 natural gas consumption is projected by DOE to grow at an annual level of 3.6 percent, compared with the 1994-1999 annual level of 0.9 percent (DOE/EIA, 2001c).

But, the same relatively high prices that encourage increased activity on the natural gas supply side will also discourage new and existing investments in natural-gas-using equipment. Also, high gas prices will especially encourage the industrial sector to invest in fuel-switching capabilities that would allow them to decrease their natural gas demand during periods of high prices.

DOE estimates that natural gas resources are expected to be adequate to meet future gas demand through 2020 (the last year of the forecast). In concert with this conclusion, long-term prices of natural gas in this country are expected to return to a lower price path in 2005 and then gradually increase to about $3.05 per Mcf in 2020. Advances in drilling and production efficiency applied to domestic gas resources, greater availability of imports from Canada and Mexico, and LNG imports from abroad are expected to adequately satisfy U.S. demand for natural gas to at least 2020.

The National Petroleum Council (NPC) agrees with DOE in its assessment of the size and availability of natural gas resources, saying that "the estimated natural gas resource base is adequate to this increasing demand for many decades, and technological advances continue to make more of those [natural gas] resources technically and economically available (NPC, 1999)."

VIII. Conclusions

Gas production from all onshore Federal gas leases in 2000 amounted to approximately 2.0 Tcf, or about 10 percent of national gas production. New Mexico public lands produced about 5.5 percent of total U.S. gas output and 53 percent of all onshore Federal gas royalties. Wyoming, Colorado, Utah, Texas, and Oklahoma Federal lands also contributed Federal royalties from gas production Total receipts from these onshore Federal gas royalties gas represented about 0.7 percent of the market value of total U.S. natural gas output in 2000.

Future contributions from onshore Federal lands to domestic natural gas production is likely to be limited to about 37 Tcf--about 12 percent of the estimate of total national economically recoverable undiscovered gas resources of 313 Tcf. Non-federal onshore lands likely hold at most 51 percent, and offshore lands hold at least 37 percent of likely future gas production.

Natural gas in the ground is usually found by producers, fed into gathering lines that move the gas to processing facilities, and then route it into gas pipelines. These pipelines then typically convey the gas to (1) storage facilities, or (2) citygates where it is further distributed by Local Distribution Companies (LDCs), or (3) other pipeline nodes.

Consumption of natural gas reached a record level of 22.8 trillion cubic feet (Tcf) in 2000—a growth of about five percent over 1999. Prices of natural gas also reached unusually high seasonal peaks during the winter months of 2000-2001.

While it is common for natural gas prices to rise during the winter months, the amount of seasonal and regional variation seen last winter is unusual. Most experts attribute the large price increases to several factors; (1) a long-term trend of relatively low natural gas prices during most of the 1990s that limited producers' cashflow and led to low levels of natural gas exploration and production, resulting in decreases in the natural gas supply; (2) increases in gas consumption that were encouraged by the relatively low gas prices; (3) unusually cold winter months over much of the U.S. during January and February 2001; (4) uncharacteristically low levels of rainfall in the western U.S. that led to smaller-than-normal amounts of hydropower available for electrical generation in the Western U.S.; and (5) an August 2000 rupture in an El Paso natural gas pipeline connecting natural gas from producing centers in Colorado, Texas, Wyoming, and New Mexico to consuming centers in California, Arizona, and New Mexico.

With the increased cashflow available from higher natural gas sales revenues, producers stepped up their natural gas drilling campaigns. The *Oil and Gas Journal* reported that 154 independent U.S. producers increased capital spending by 48 percent from 1999 to 2000 and planned a further increase of 35 percent in 2001. Clearly, the natural gas sector is now in the midst of a boom fueled by the relatively high natural gas prices. There is no apparent shortage of available prospective natural gas drilling targets, as evidenced by the almost complete utilization of available drilling rigs.

After hitting a low of 18.6 Tcf of production in 1999, natural gas production increased by 0.7 Tcf in 2000, with significant additional production increases likely as time goes on. In tandem with recent increasing domestic activity, imports and exports of natural gas from Canada and Mexico, and imports of Liquified Natural Gas (LNG) from abroad have increased as well.

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The Department of Energy estimates that natural gas resources are expected to be adequate to meet future gas demand through 2020 (the last year of the forecast). In concert with this conclusion, long-term prices of natural gas in this country are expected to return to a lower price path in 2005 and then gradually increase to about $3.05 per Mcf in 2020. Advances in drilling and production efficiency applied to domestic gas resources, greater availability of imports from Canada and Mexico, and LNG imports from abroad are expected to satisfy U.S. demand for natural gas up to at least 2020.

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