Natural Gas:
Issues & Strategic Recommendations

Report of the OCS Policy Committee
Subcommittee on Natural Gas on the
U.S. Outer Continental Shelf

May 2001

Natural Gas:
Issues & Strategic Recommendations

Report of the OCS Policy Committee
Subcommittee on Natural Gas on the
U.S. Outer Continental Shelf

May 2001

Instructions: Please replace pages 21 + 22 with this updated sheet.

Canadian pipeline to the U.S. The first option enjoys the support of the State of Alaska and will require a less time-consuming permitting process. From the time a decision is made to the time gas flows through the pipeline to the lower 48 could be as much as 5 to 10 years. The first gas to be transported through the pipeline will be the 30 Tcf of reserves already discovered on the North Slope. It will be several years before the OCS gas becomes competitive, even though a sustained high gas price, such as it is today, will make the OCS natural gas economically producible.

Atlantic OCS

The Atlantic OCS offers natural gas resources that could contribute to the Nation's energy inventory. The natural gas resource base for the Atlantic margin is estimated at 28 Tcf. The Atlantic OCS has been drilled and natural gas was discovered.

Recently, off the coast of Canada, some major gas fields have been established. Sable Island gas field located on the Scotian Shelf is estimated to have 3.5 Tcf of reserves. Pan Canadian's most recent discovery of the Panuke gas field flowed at 50 to 55 MMcf of gas day per test completion. Panuke is believed to have reserves similar to those of the Sable Island field. It is believed that the pay sands in the Panuke field ranges from 100 to 325 feet in thickness. It is estimated that the undiscovered natural gas potential of the East Coast of Canada (Grand Banks and Scotian Shelf) is about 63 Tcf of natural gas (NEB 1999).

The general geologic setting of the North Atlantic Planning Area indicates the possibility that the same gas play producing in the Scotian Shelf may continue south.

Currently, the North Atlantic area is under moratoria until 2012 and under access restriction. Eight exploratory wells were drilled in the North Atlantic planning area in 1981-1982, all on the Georges Bank. No discoveries were made. The geology implies that if hydrocarbons occur in the area, they would more likely be natural gas prone.

The Mid-Atlantic planning area has experienced significantly more drilling than the North Atlantic with 32 exploratory wells drilled in 1978-1984. The drilling resulted in the discovery of natural gas but it was deemed uneconomic at the time. Like the North Atlantic, it is believed that the Mid-Atlantic area will most likely be natural gas prone. The South Atlantic planning area has six exploration wells, drilled in 1979-1980, all in the southeast Georges Embayment. Although these wells were dry, it is believed that natural gas will be the most likely hydrocarbons that will occur in this area.

If the Atlantic OCS were thoroughly explored, it is possible that economically recoverable natural gas resources would be discovered as most recently published in the *MMS Outer Continental Shelf Petroleum Assessment 2000* as well as previous assessment publications.

No change on this page.

Pacific OCS

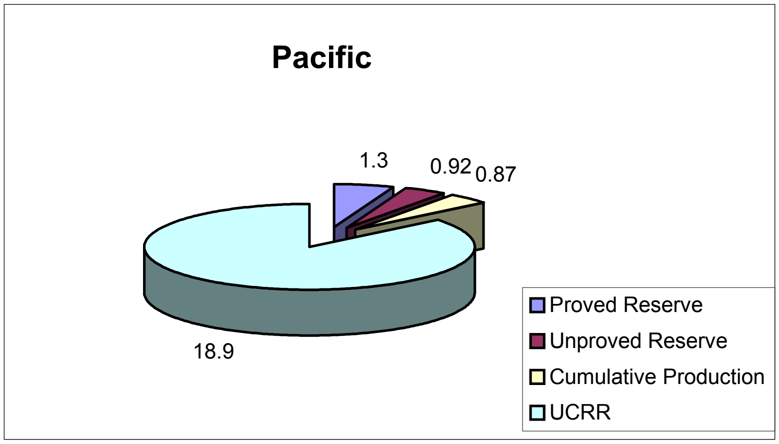


Figure 15. Undiscovered Conventional Natural Gas Resources and Reserves of the Pacific (Tcf). (UCRR = Undiscovered Conventionally Recoverable Resources)

The Pacific OCS Region contains considerable resources of natural gas. MMS has estimated that the undiscovered natural gas resources for the region are 18.9 Tcf. Of these resources, 11.6 Tcf (Table 5) would be economically recoverable at a price of $3.52/Mcf (Dunkel and Piper, 1997). Most of these gas resources are expected to be found in association with oil accumulations.

Currently, all of the Pacific OCS unleased acreage is under moratoria until 2012. The undiscovered natural gas resources on these moratoria lands will not be available until they are leased, explored, developed and produced. This is a process that requires a considerable amount of lead time in the Pacific OCS.

Existing OCS operations are in the Santa Maria Basin, Santa Barbara Channel, and Los Angeles Basin. During 1999, 80 Bcf of natural gas was produced, with 38.6 Bcf sold, 32.4 Bcf reinjected into the reservoir to enhance oil production, and 9.2 Bcf used on-lease for power generation. Pacific OCS gas sales accounted for about one-eighth of the total sales gas produced within California.

Reserves of natural gas on existing Pacific OCS leases are about 1.9 Tcf (Figure 15). At current production rates, these reserves would last for over 20 years.

Gulf of Mexico OCS

The Gulf of Mexico (GOM) accounted for 99.99 percent of the OCS gas production for the U.S. in 1998. Eighty-four percent of the undiscovered economically recoverable (@$3.52/Mcf) resources of the OCS is present in the GOM. If we add reserves appreciation, the undiscovered economically recoverable resources of the GOM accounts for 88 percent of the total OCS resources (see Tables 5 and 6 and Figure 16).

CONTENTS

Figures

Tables

I. Executive Summary

In 1998, the United States consumed 21 Tcf of natural gas but produced only18.7 Tcf; imported Canadian natural gas provided the balance of supply. The U.S. Department of Energy and others have predicted that the U.S. demand for natural gas will increase to 35 Tcf. This increase in demand is occurring mostly due to the rapid expansion of natural gas to generate electricity.

The Nation's energy comes from a number of sources. As with natural gas, each has its own unique advantages and disadvantages. Alternatives to natural gas include coal (which is used to generate most of the electricity in the U.S. at the present time), nuclear, hydroelectric, geothermal, biomass, wind power, and solar energy. Disadvantages of the alternatives may be associated environmental impacts, costs, or practicality. While natural gas resources are relatively abundant in North America, much of it is unavailable due to the lack of access and/or infrastructure and lack of financing and/or unfavorable economic conditions. On the other hand, natural gas is viewed as the cleanest and most efficient of the fossil fuels. Even in the short run, conversion of more of our fuel-burning facilities to natural gas could diminish air pollution and improve the long run sustainability of forests, waters, and farmlands now being negatively affected by acid deposition.

At the present time, the U.S. Outer Continental Shelf (OCS) accounts for 26% of the natural gas produced in the U.S. The majority of this production occurs in the Central and Western Gulf of Mexico, with small contributions from offshore California. The MMS *Outer Continental Shelf National Petroleum Assessment 2000* estimates that the Federal offshore has 362 Tcf of undiscovered, conventionally recoverable natural gas. It is also estimated that the economically recoverable natural gas at $2.11/Mcf is 116.8 Tcf and at $3.52/Mcf the estimate is 168 Tcf. However, due to conflicting priorities regarding the use of the Nation's natural resources, much of the OCS is unavailable for oil and gas activities. Among the restricted areas are the Atlantic (~28 Tcf), most of the Eastern Gulf of Mexico (8.5 Tcf), and offshore California, Washington, and Oregon (19 Tcf), as well as the North Aleutian Basin (6.8 Tcf). The total estimated amount of unavailable natural gas on the U.S. OCS is approximately 62 Tcf.

Although the OCS has significant potential and can be an important source of natural gas, concerns have been expressed regarding the ability of the OCS to maintain its current level of production over the coming decades. There is an important challenge facing the Nation regarding energy on how the supply will be made available to meet the demand. The OCS plays an important role today in meeting this challenge, and important policy decisions could be made that may impact the role that OCS natural gas will play in the future.

To address such concerns, the OCS Policy Committee of the Minerals Management Advisory Board established a Subcommittee to independently evaluate the status of production and use of natural gas in the U.S. The Subcommittee was also to provide an assessment of the contribution of the U.S. OCS in meeting the short- and long-term natural gas needs of the Nation.

This report provides the Subcommittee's findings and recommendations concerning the natural gas situation in the U.S., the potential resources that could be available from the OCS, safety and operational considerations unique to natural gas development, and the environmental and social impacts related to exploration and development.

The following are the specific recommendations the Subcommittee made to the Policy Committee.

Note: The recommendations of the Natural Gas Subcommittee, contained in this report, were **amended** by the OCS Policy Committee at it's May 23-24, 2001 meeting. The final recommendations that the OCS Policy Committee forwarded to the Secretary of the Interior are available on the Minerals Management Service website at www.mms.gov or by contacting the MMS Public Affairs Office at (202) 208-3985.

II. Recommendations

After consideration of the available information concerning the supply and demand for energy in the U.S., the Policy Committee finds that natural gas should be considered as a significant part of an energy base, which includes alternatives and conservation programs. Recognizing that natural gas is only a portion of a national energy policy, the Policy Committee makes the following recommendations:

1. The Outer Continental Shelf (OCS) should be viewed as a significant source for increased supply of natural gas to meet the national demand for the long term.

2. Congressional funding to MMS and other critical agencies should be assured to allow staff to accomplish the work necessary to increase production of natural gas from the OCS.

3. Future production will have technical and economic challenges; therefore, following on the success of the deep water royalty relief program, MMS should develop economic incentives to encourage new drilling for natural gas in deep formations, subsalt formations, and in deep water. Such incentives should be considered for both new leases and existing leases to maximize the use of the existing natural gas infrastructure on the OCS.

4. The MMS, in consultation with industry and affected States, should identify the five top geologic plays in the moratoria areas, and if possible, the most prospective areas for natural gas in the plays that industry would likely explore if allowed. These five areas would provide the basis for a pilot to see if limited activity, as described below, is possible in moratoria areas. The following process would be used:

   - Encourage congressional funding to MMS for the acquisition of seismic data to assist in narrowing down prospective areas. It is important that these data be nonproprietary, which would be the case if acquired exclusively by MMS.
   - Encourage congressional funding for environment and social/human impact studies for broad based or specific to five prospective moratoria areas to have the information available should pilot areas within moratoria areas be considered for leasing.
   - Establish a site-specific stakeholder consultation process that would permit a sharing of information and discussion of concerns regarding the pilot areas to see if there are grounds for a limited lifting of moratoria.

5. The MMS, in cooperation with industry, should encourage increased natural gas production from existing OCS leases.

6. The Policy Committee supports the existing 5-year program. However, the leasing process can be improved (dependent on congressional funding) with mitigation, including impact assistance funds, revenue sharing, and local participation in the decisionmaking process.
7. The MMS, in cooperation with DOE, should encourage international cooperation in development of gas hydrates, with a goal of a pilot program in place within 10 years.

8. Encourage congressional funding for additional education and outreach regarding the leasing program.

9. The MMS, partnering with DOE, should expand cooperative research with other agencies and industry seeking technical solutions to leading edge issues such as seismic imaging of subsalt areas and drilling in deep formations.

10. A gas pipeline from Alaska to the lower 48 States would favorably encourage an increase in natural gas production by creating favorable economics for Federal OCS production in Alaska. The Policy Committee recommends that DOI facilitate the permitting process for such a pipeline.

11. With regard to Alaska, the Policy Committee also recommends that MMS:

    - Include the mitigation of local social, cultural, and economic impacts within its policy determinations and recommendations.
    - Give special consideration to these impacts in northern Alaskan communities, in light of the unique subsistence culture in, and the remoteness of, these communities.
    - Consider how the Bureau can restructure its decisionmaking process to provide for greater input from local communities, including the opportunity for MMS, the industry, and local residents to attempt to reach agreement on controversial matters and how they should be adjusted, remedied, or mitigated—at specific times and places that various activities occur.
    - Adopt as a resource tool the 1994 NRC Committee report entitled “Environmental Information for Outer Continental Shelf Oil and Gas Decisions in Alaska” (National Academy Press, 1994).
    - Conduct a comparative assessment of environmental risk (Alaska focus) between offshore and onshore production, where onshore reserves exist in the same area as offshore reserves.
    - Encourage operators to provide natural gas to the local communities in Alaska.

12. Although the following are not under the purview of the MMS and the Policy Committee, it is recommended that a national energy policy consider:

    - Continuing to expand and develop the national pipeline infrastructure, looking at corridor access, environmental, safety and regulatory issues, and capacity.
    - Encouraging dual fuel capacity for new electricity generating plants.
    - Encouraging the review by the Administration of cost-effective tax incentives to increase the production of natural gas.

- Encouraging conservation and increasing efficiency in the use of natural gas, as part of a national energy policy portfolio.

The following information and data presented in this report are the basis, at least in part, for the Subcommittee recommendations.

Note: The recommendations of the Natural Gas Subcommittee, contained in this report, were **amended** by the OCS Policy Committee at it's May 23-24, 2001 meeting. The final recommendations that the OCS Policy Committee forwarded to the Secretary of the Interior are available on the Minerals Management Service website at www.mms.gov or by contacting the MMS Public Affairs Office at (202) 208-3985.

III. Introduction

At the Fall 2000 Outer Continental Shelf (OCS) Policy Committee meeting at Fair Oaks, Virginia, it was decided that a Subcommittee on Natural Gas would be established to independently review and evaluate information on natural gas and to provide an assessment of the contribution the U.S. OCS can make in meeting the short- and long-term natural gas needs of the Nation. Growth of U.S. consumptive demand for natural gas is currently of national interest, with projections as high as 30 trillion cubic feet (Tcf) of natural gas annually by the year 2015. This is a 50 percent increase over current national consumption. While natural gas resources are relatively abundant in North America much of it is unavailable due to lack of access and/or infrastructure and lack of financing and/or unfavorable economic conditions. There is growing concern that unless there is a dramatic change in the exploration and development scenario in the primary source of natural gas in the U.S. OCS, the Gulf of Mexico, the production from the Gulf may not be able to meet the expected share of future natural gas supply deemed necessary by the Energy Information Administration.

The Subcommittee was chaired by Jerome Selby and members included Patrick Galvin (Alaska), Robert Jordan (Delaware), Jack Caldwell (Louisiana), Lawrence Schmidt (New Jersey), Donna Moffitt (North Carolina), Bruce Vild (Rhode Island), Andrew Hardiman (Natural Gas Industry), Paul Kelly (Offshore Support Industry), and George Ahmaogak (Local Government). Staff from the Minerals Management Service provided support to the Subcommittee.

The Subcommittee and MMS staff held a telecom on February 14, 2000, to review materials sent to the Subcommittee on OCS natural gas resources, U.S. supply and demand for natural gas, potential environmental impacts of natural gas production, natural gas infrastructure, and alternative energy sources. The Subcommittee held a meeting at the Department of the Interior on February 28 and March 1, 2001, to discuss the Subcommittee's charge, to prepare the outline for the Subcommittee's report, and to draft recommendations.

This report provides the Subcommittee's findings and recommendations regarding the general natural gas situation in the Nation, the potential natural gas resources that may be available from the OCS, safety and operational considerations unique to natural gas development on the OCS, and the environmental and social impacts related to natural gas development. The Subcommittee's report includes a number of recommendations that we believe will be helpful to the Minerals Management Service and the Secretary of the Interior as they make decisions on managing the resources on the U.S. Outer Continental Shelf.

The Subcommittee's charter can be found in Appendix 1. Appendix 2 diagrams the process involved from lease sale to production. Appendix 3 provides a brief regulatory history of natural gas, and Appendix 4 contains a glossary and list of acronyms.

IV. Natural Gas Supply—What's the Situation?

Natural Gas from the field to the burner-tip

On March 19, 2001, the Secretary of the Department of Energy made a dire prediction of an impending serious energy crisis in the near future. In recent months, with the California energy crisis being exposed to the public, the natural gas supply and demand has taken the center stage in our energy need equation. Even though the California energy crisis precipitated from short-sighted partial deregulation of electricity, concerns have been raised regarding natural gas supply by industry and planners for the past few years since the federal deregulation of electricity generation. Changeover of electricity-generating plants from coal and oil to cleaner burning natural gas and a significant increase in usage of natural gas for home heating, especially during colder than normal winters, such as the winter of 2001, has increased the demand for natural gas. A breakdown of natural gas flow based on data from the Energy Information Administration (EIA) is presented in Figure 1. In 1999, about 22 percent of the total U.S. natural gas consumption was for residential use, and 15 percent was used for electricity generation. Over 60 percent of the natural gas supply was consumed by commercial and industrial sectors. The transportation sector used less than 3 percent (Figure 2).

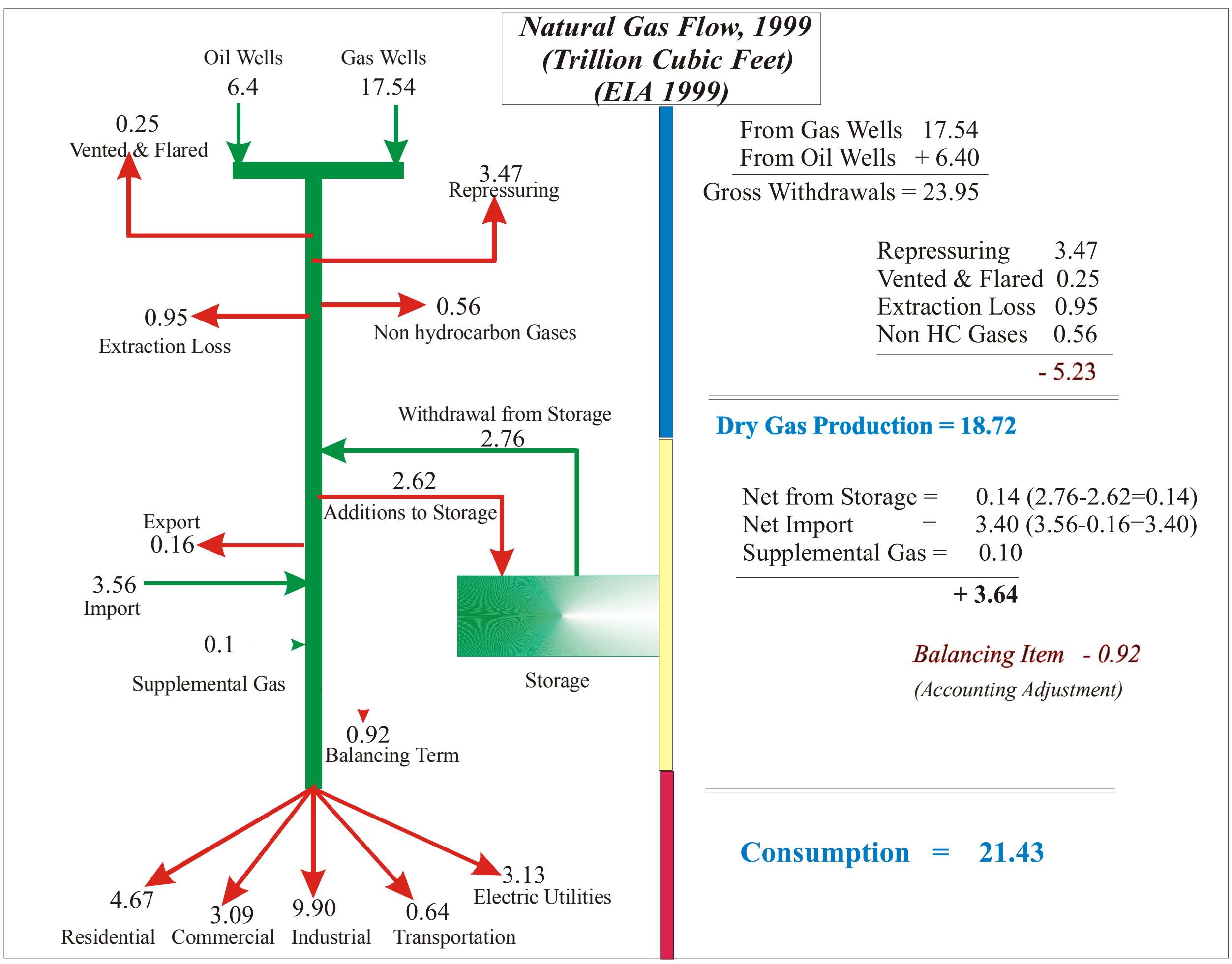


Figure 1. Natural Gas Flow (Data from EIA 2000)

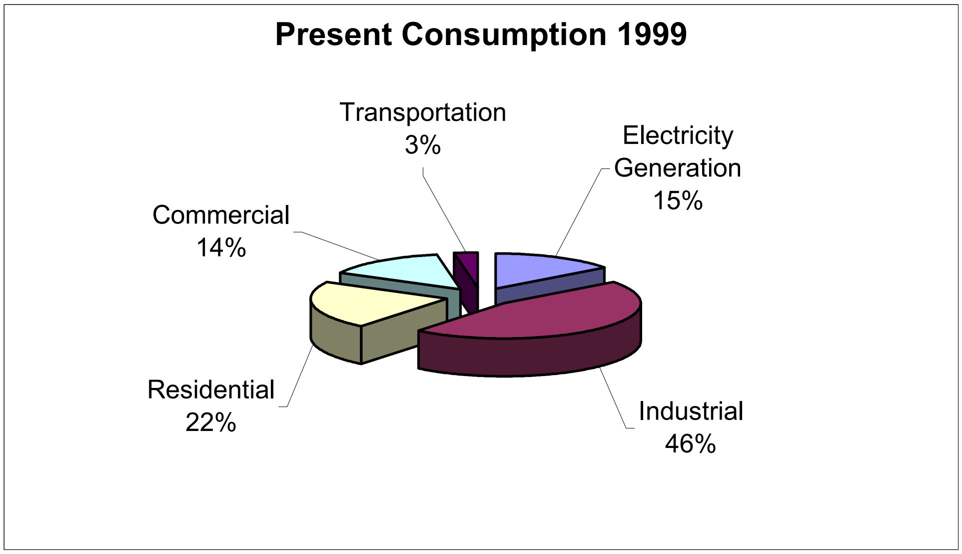


Figure 2. U.S. Natural Gas Consumption by Sector
(Data from DOE/NPC, 2001 Workshop)

The demand for natural gas is expected to continue to increase significantly during the next ten to twenty years. According to EIA the demand for natural gas by 2020 may reach as much as 35 Tcf. The challenge of meeting the natural gas demand in 2020 is evident from Figure 3, which shows the annual natural gas production of the U.S. and the demand of 35 Tcf in 2020. For reference, the 1999 U.S. production of natural gas was 18.71 Tcf. About 3.56 Tcf had to be imported to meet the 1999 demand.

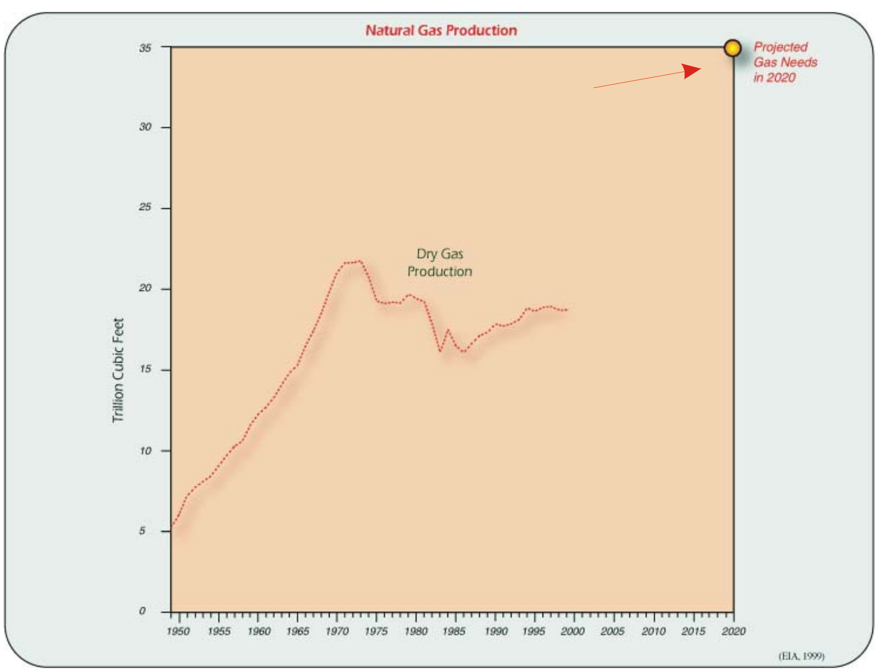


Figure 3. U.S. Natural Gas Production and Future Demand

Various organizations have conducted analyses to project the future natural gas needs for the U.S. The results of the analyses by the National Petroleum Council (NPC), EIA (Annual Energy Outlook 2000, AEO 2000), and the Gas Research Institute (GRI) are presented in Figure 4 and Table 1. According to these projections, the consumption of 21 Tcf in 1998 is expected to reach over 30 to 32 Tcf by 2015. This increase in demand is mainly from the industrial sector and from the demand for electricity generation (Figure 5).

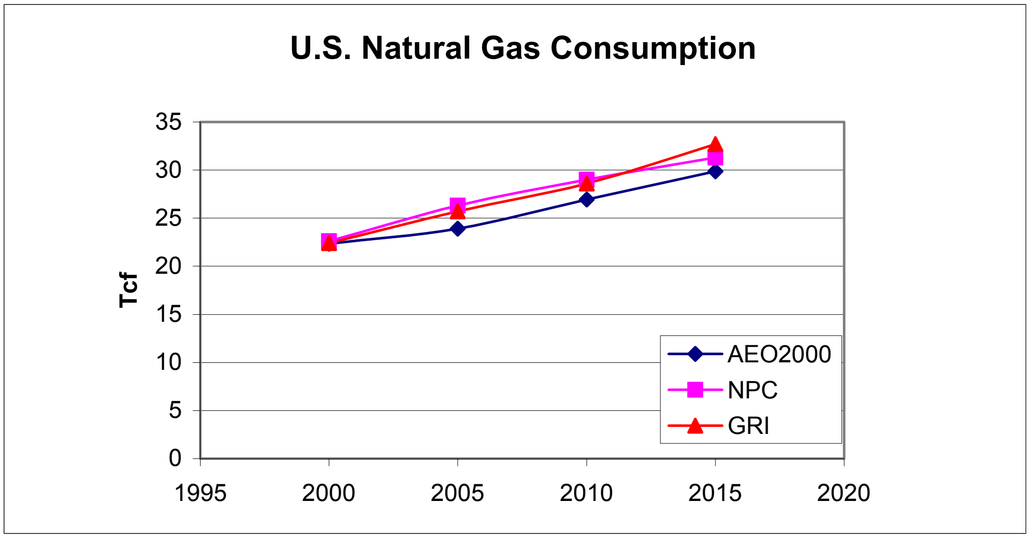


Figure 4. Growth in U.S. Natural Gas Consumption

Consumption Estimates			
Year	EIA (AEO 2000)	NPC	GRI
2000	22.36	22.6	22.4
2005	23.91	26.3	25.7
2010	26.95	29	28.6
2015	29.88	31.3	32.7

Table 1. Consumption Estimate (Tcf)

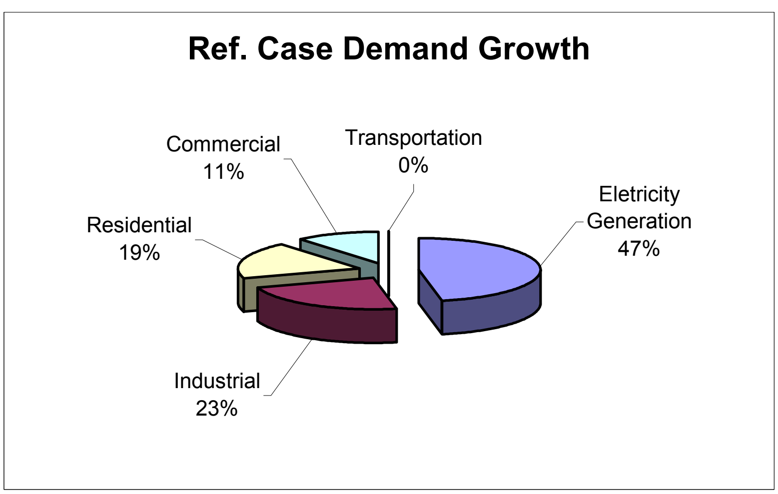


Figure 5. U.S. Natural Gas Demand Growth by Sector
(Data from DOE/NPC, 2001 Workshop)

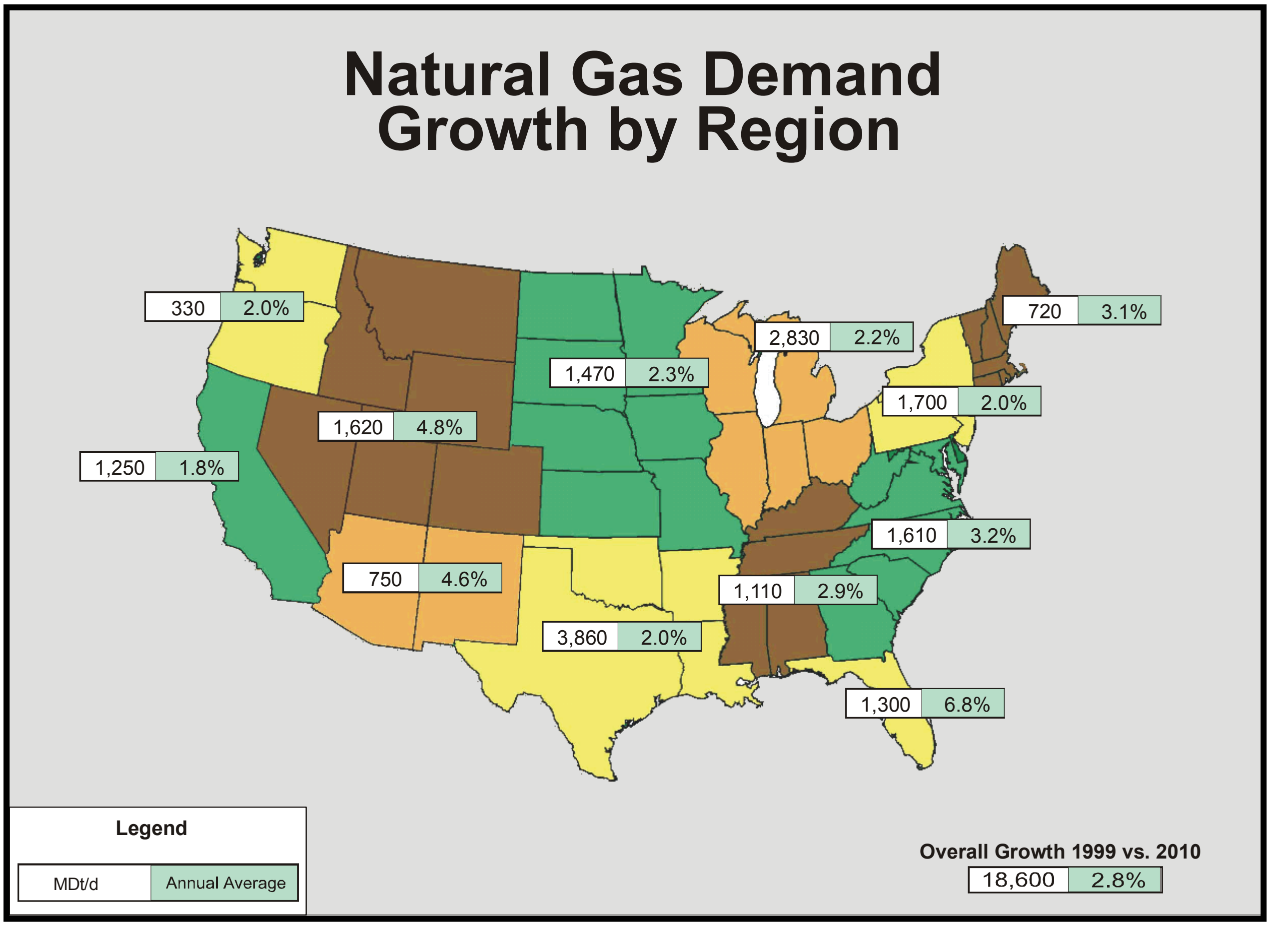


Figure 6. Annual regional demand growth of natural gas by 2010. (Hobbs, 2001). Note: demand is expressed in decatherm (1 decatherm = 1 million Btu)

Geographically, GRI anticipates an additional 11 Tcf increase in demand in the lower 48 States by 2015 (Cohener, 2000). Hobbs (2001) in a recent presentation indicated that between 1999 and 2010 the demand for natural gas in the lower 48 States will increase at an average annual rate of 2.5% (Figure 6). The majority of the increase will come from Florida and the Rocky Mountain region.

NPC (1999), in its summary report, indicated that the natural gas demand can be met from domestic resources and supplemented by imports from Canada, only if obstacles listed are overcome and significant capital investment is made in domestic exploration and development. It also indicated that the maximum growth in U.S. production would be coming from the Gulf of Mexico and the Rockies.

Price Projection of Natural Gas in the United States

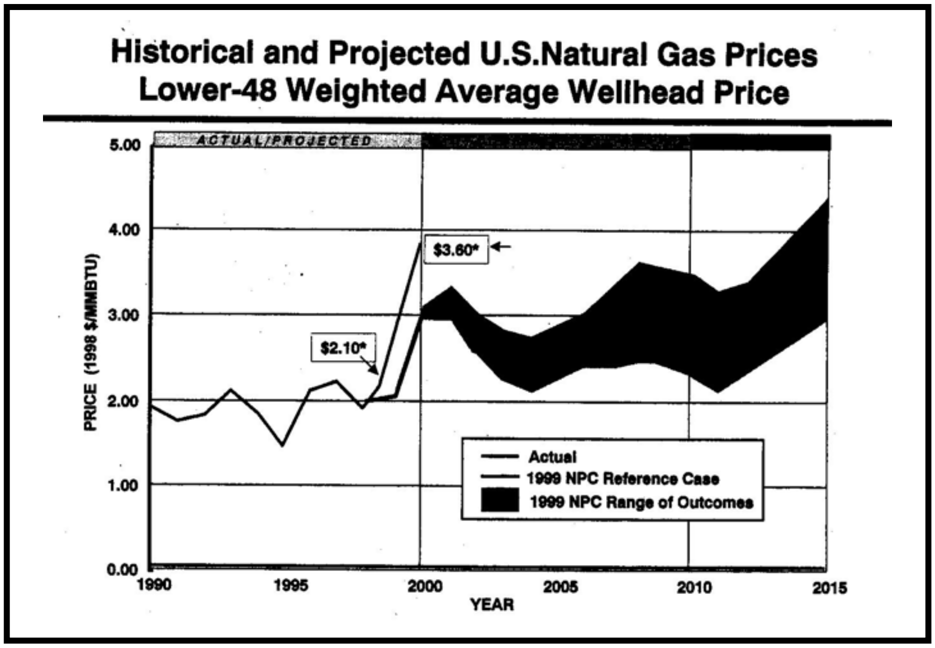


Figure 7. NPC's (1999) Projection of Natural Gas Price

Natural gas production is directly related to the performance of the economy (or "condition of the economy") as measured by GDP. However, it is rather difficult to make a long-term projection of natural gas prices and apply it in the short term. NPC (1999) projected a range of $3 to $4/Mcf wellhead price for 2015 (Figure 7). The average wellhead price as projected by the Department of Energy's *Annual Energy Outlook (AEO)* is $3.30 per thousand cubic feet in 2001, and then declines through 2004 (DOE/EIA 2001). However, the wellhead price in 2000 reached over $3.50/Mcf, possibly due to a colder winter or other factors.

Present U.S. Production Trend

The production projections presented by AEO 2000, NPC 1999 and GRI 1999, presented in Table 2 and Figure 8, indicate that the production of natural gas in the U.S. may reach 25 Tcf to over 28 Tcf by 2015. The primary difference between the production projections done by GRI and NPC is in the expected production for the year 2015. While, according to GRI, production continues to increase at a brisk pace through 2015, NPC predicts a slow down in the rate of production increase by 2015 (Figure 8).

U.S. Production (Tcf)			
Year	**AEO 2000**	**NPC**	**GRI**
2000	18.89	19.0	19.4
2005	19.7	22.6	21.9
2010	22.48	25.1	24.6
2015	25.03	26.6	28.5

Table 2. Production Projections by Different Organizations

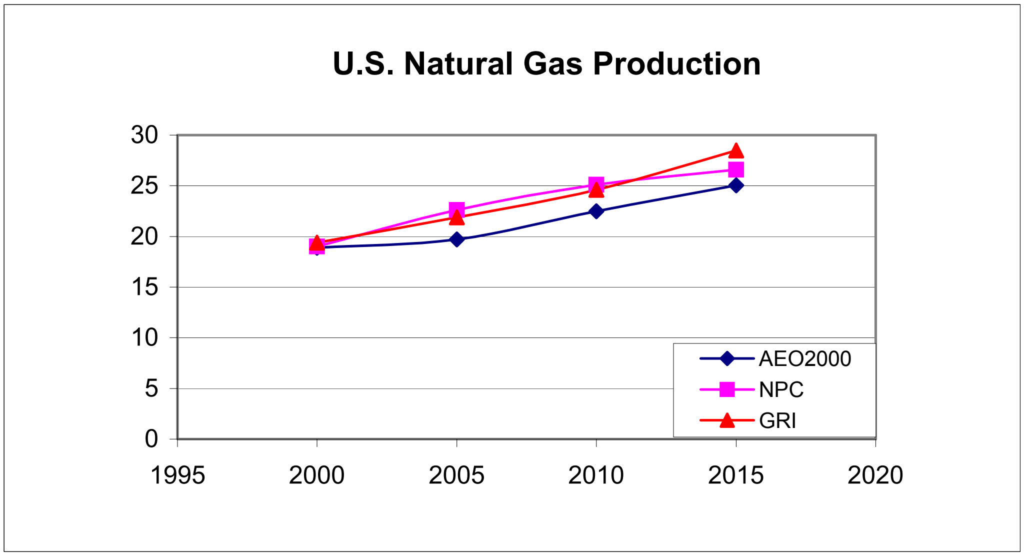


Figure 8. U.S. Natural Gas Production Projections

To meet the increasing demand, a robust 33% supply growth is envisioned for the Gulf of Mexico by NPC (1999) (Figure 9). However, in a recent testimony to Congress, MMS's Associate Director for Offshore Minerals Management raised concerns regarding the ability of the Gulf of Mexico to meet the 33% production growth.

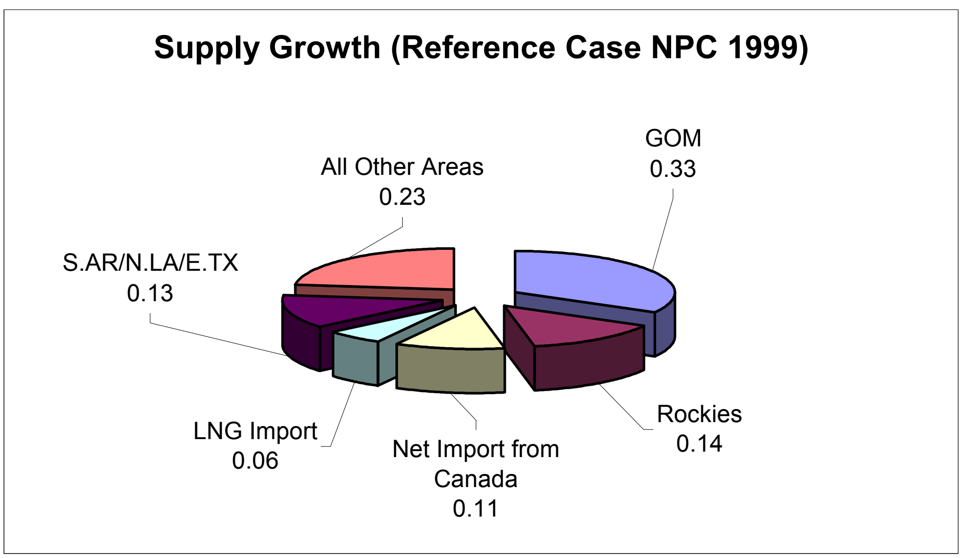


Figure 9. Envisioned Supply Growth by Region to Meet Natural Gas Demand in 2015 (NPC 1999).

Natural Gas Imports

The import of natural gas through pipelines has increased from less than 1 Tcf in 1985 to 3.5 Tcf in 2000 (GRI, 1999). Less than 0.1 Tcf of LNG was also imported in 2000 to meet the demand (Figure 10).

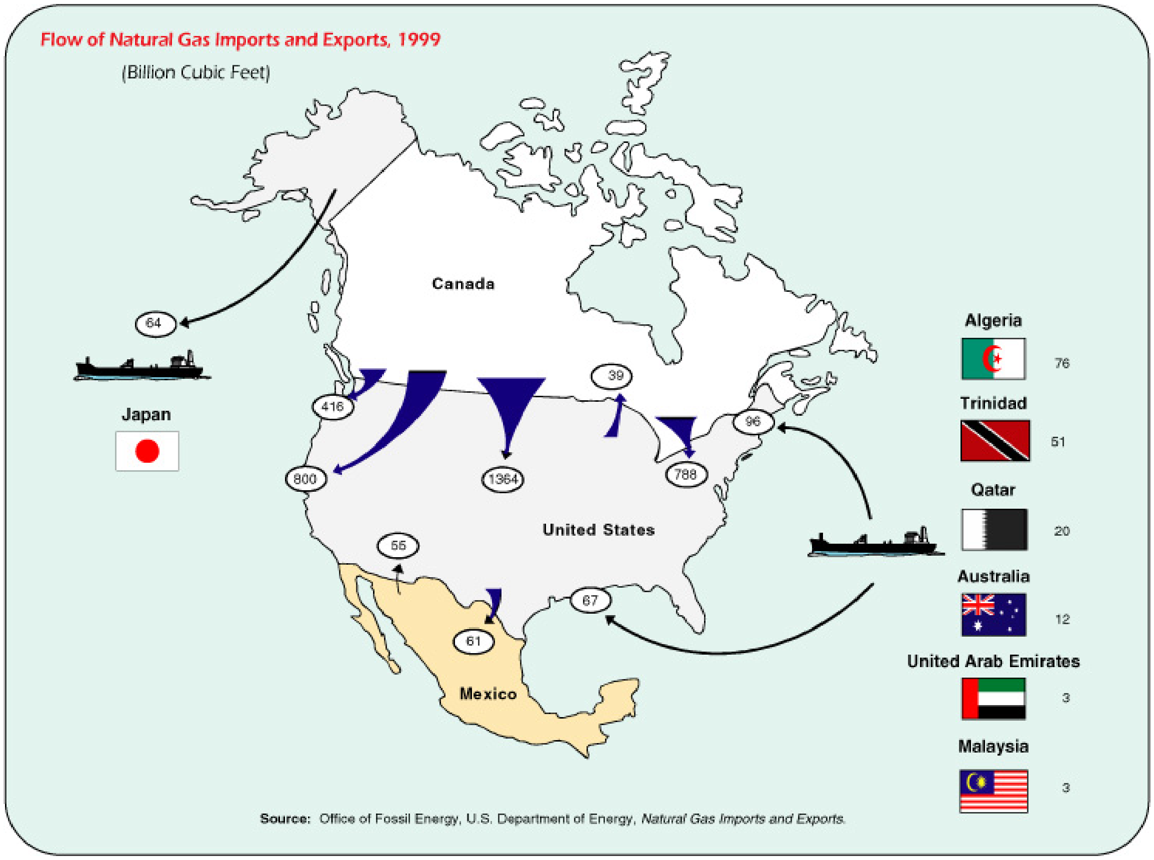


Figure 10. Natural Gas Imports (AEO, 2000)

The LNG is imported primarily from two countries, Algeria and Trinidad, with minor amounts coming from Qatar, Australia, United Arab Emirates and Malaysia. The United States exported 64 Bcf of LNG to Japan in 1999.

Growth in imports from Canada, as estimated by GRI, NPC and AEO 2000, is presented in Figure 11 and Table 3. The Canadian natural gas imports are expected to increase from 3 Tcf in 1999 (NPC) to close to 5 Tcf in 2015. The additional 2 Tcf of natural gas is expected from western Canada, and if the Alaska Pipeline is completed, from the Mackenzie Delta, and from the Grand Banks and the Scotian Shelf.

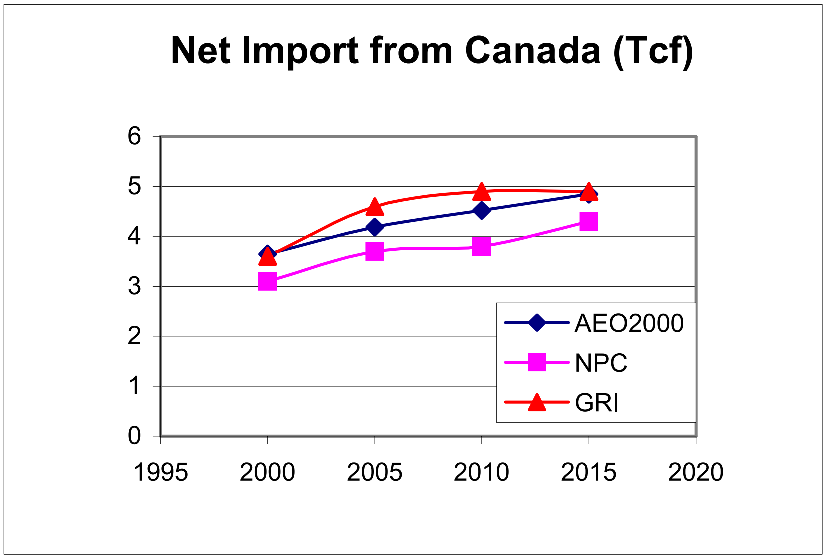


Figure 11. Net Imports of Natural Gas from Canada

Imports (Tcf)			
Year	**AEO 2000**	**NPC**	**GRI**
2000	3.65	3.1	3.6
2005	4.19	3.7	4.6
2010	4.52	3.8	4.9
2015	4.85	4.3	4.9

Table 3. Estimates of Natural Gas Imports from Canada

Natural Gas Production in Canada

Almost all of the imported natural gas is from Canada. Mexico remains a net importer. A look at the production projection of natural gas in Canada (Figure 12) indicates that as much as over 9 Tcf of natural gas can be produced in Canada annually by 2015. However, the current year's import figure from Canada (3.5 Tcf in 2000) indicates the possibility of a draw down from their storage.

Eastern Canadian Offshore Gas

In a recent natural gas workshop organized by DOE and NPC (March, 2001), Petak of Energy and Environmental Analysis (EEA) reviewed the NPC projection of 1.0 Bcf in 2010 and 2.2 Bcfd by 2015 of natural gas flow capacity from the Maritime and Northeast (M&N) where 16 fields have been discovered. Based on the 1999 performance, Petak estimates that compression could expand current capacity of 540 MMcfd to 800 MMcfd in Canada by 2004. Deep Panuke and 11 Sable Island satellite fields could add another 400 MMcfd by 2004. Thus Offshore Eastern Canada may supply as much as 1.5 to 2.5 Bcfd by 2010.

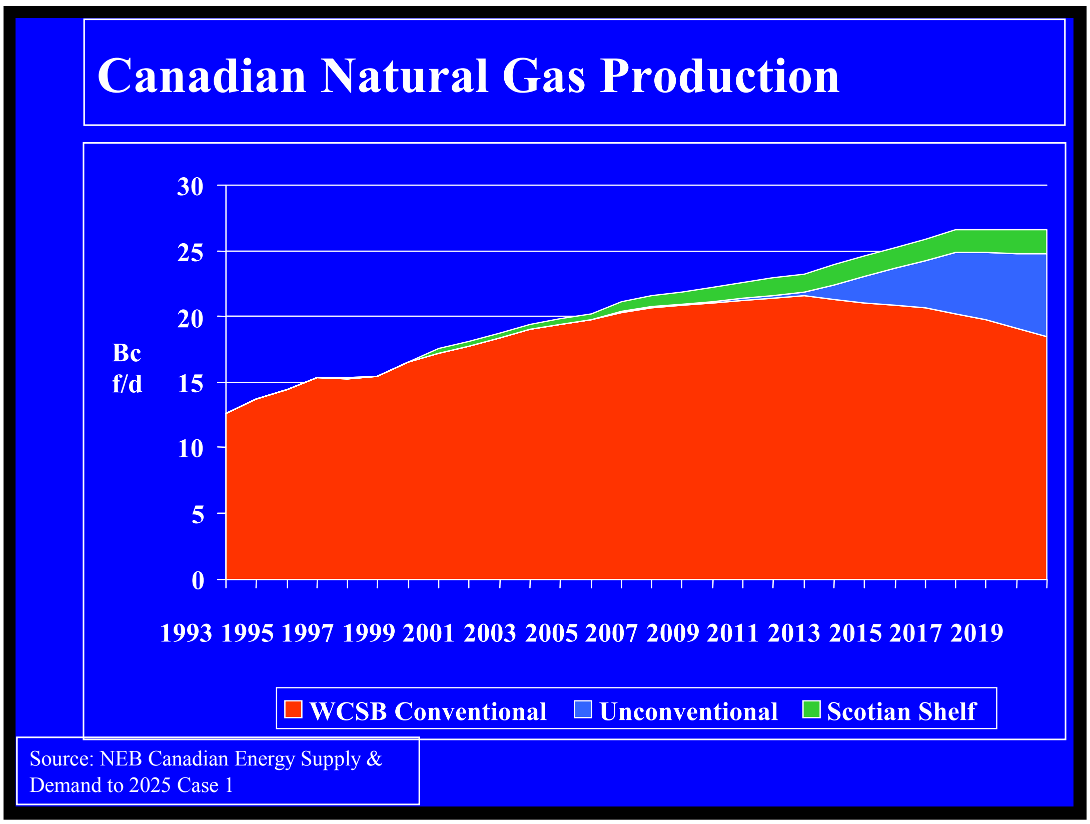


Figure 12. Natural Gas Production Projection, Canada (GRI, 1999, base on NEB data from Canada)

Bringing Alaska Gas to the Lower 48

Figure 13. Possible Pipeline Routes for Bringing Alaskan Gas to the Lower 48. (Diagram obtained from Gulf Canada, 2000.)

A number of alternative pipeline options have been suggested to bring the Alaskan gas to the lower 48 (Figure 13). A 7,700 km long Alaska Natural Gas Transportation System (ANGTS) was approved by the Canadian and U.S. Governments to transport North Slope Alaskan gas reserves to the southern U.S. markets in 1977. Between 1980 and 1982 southern parts of the pipeline system were pre-built, but due to weak gas prices and surplus gas the project became dormant. A 40-42" pipeline would follow the existing Alyeska oil pipeline to Fairbanks, then follow Alaska Highway to Whitehorse where it will be joined by 30-inch pipeline bringing MacKenzie Delta gas. The pipeline from Alaska to Alberta is expected to cost $6-12 billion ($U.S.). Three to five Bcfd gas can be carried through this pipeline. NPC estimates Alaska gas to flow in 2015. Recent high gas prices, however, may make it happen earlier. Current increasing gas prices, expected future demand, and advanced technology (Automatic Welding Technology) make the project viable. Alaskan producers are currently planning for Alaska gas to penetrate Canada/Lower 48 between 2007 and 2012 (DOE/NPC Workshop, 2001).

Other alternative pipelines include: Alaska North Slope to Mackenzie Delta (2 possible routes; Over the Top, and Under the Top) – a 1,650 mile long pipeline into Alberta of 1-5 Bcfd capacity pipeline at a cost of $5-8 billion ($U.S.).

The Alaska Highway route also received the support of the Western Governors.

North Slope Alaska

Alaska contains approximately 40 Tcf of gas remaining in developed and known undeveloped fields. Some of this gas is in fields too small or remote to justify economic development. Of the known gas reserves approximately 27 Tcf may be considered available for export at appropriate market prices and pending construction of new gas transportation systems. Most of this gas is in onshore fields and mostly beneath State of Alaska surface or submerged lands. No Federal offshore gas reserves are considered to be readily available for export at present.

Ninety-six percent (26 Tcf) of Alaska's exportable gas reserves occur within fields in or near the Prudhoe Bay field in northern Alaska. The Prudhoe Bay area gas reserve base totals approximately 32 Tcf (developed fields and Point Thomson field), but some of this gas will be consumed by future production activities at Prudhoe Bay. The stranded gas reserves at Prudhoe Bay are presently attracting proposals for construction of a gas transportation system that can take the natural gas to markets outside of Alaska.

A total of 34 exploration wells have tested prospects in the Federal waters offshore Alaska in Beaufort and Chukchi Sea since 1981. Exploration results have been disappointing, and the few significant oil and gas discoveries made in the Arctic remain undeveloped due to high capital costs and uncertain prices. Two offshore oil fields, Liberty and Northstar, will begin production in 2001-2003, but the associated gas will be used for lease operations. The Burger well, located on the Chukchi shelf 360 miles west of Prudhoe Bay, penetrated the largest gas pool found to date in the Alaska Federal offshore. However, Burger is located in a formidable setting far from existing infrastructure and is uneconomic to develop with current technology and price conditions.

Two notable areas on the North Slope are the Alaska National Wildlife Refuge (ANWR) and the National Petroleum Reserve, Alaska (NPR-A). The resource potential of ANWR, which is located east of Prudhoe Bay, was assessed by the USGS in 1998 with 8.6 Tcf of (mean) undiscovered, conventionally recoverable gas. The USGS did not conduct economic studies of ANWR oil and gas. The resource potential of a "Plan Area" in northeastern NPR-A, which is located west of Prudhoe Bay, was assessed by MMS in 1997 for a lease sale held in 1999. While geologic gas resources were reported to range from about 3 to 22 Tcf of gas (mean,10 Tcf) for the Plan Area, no economic studies were conducted for the gas.

Northern Alaska and its contiguous continental shelves are richly endowed with natural gas. However, finding and developing any significant fraction of this undiscovered resource will prove very costly. At the current slow pace of leasing, exploration, and development, a significant fraction of the undiscovered natural gas endowment of northern Alaska could remain unavailable to meet market demands for many decades.

Because of the long lead time required for major construction projects, the time may now be at hand for decisions about how to export the stranded natural gas reserves of northern Alaska and northwestern Canada. These decisions will lead to construction of a huge natural gas marketing infrastructure costing billions of dollars. Gas production strategies and new infrastructure will determine the character of oil and gas development in northern Alaska and northwestern Canada for many decades to come.

Natural Gas - Residential Use

According to 1998 statistics more than half of all homes in the U.S. and more than 60 percent of newly constructed homes use natural gas for heating and appliances (Natural Gas Information and Educational Resources, 1998b). Among the reasons given was that natural gas was the least-expensive residential energy requiring about 35 to 45 percent less energy than comparable all-electric homes; other gas appliances were also noted as highly efficient. The report states that "the most efficient natural gas furnace, for instance, has an annual fuel utilization efficiency of 97 percent." As for the home "environment," natural gas homes were viewed as environmentally friendly. "In comparison with electric homes, they are responsible for 99 percent less sulfur dioxide (which causes acid rain), 95 percent less particulate matter (which causes breathing problems) and 40 to 50 percent less carbon monoxide."

Natural Gas Alternatives

The Nation's energy for electricity and heating comes from a number of sources, each having unique advantages and disadvantages. As with natural gas, use of alternatives has to be balanced with mitigation of the impacts.

***Coal* –** More electricity is generated from coal than from any other fuel in the U.S. Coal-fired power plants are popular because they compete reasonably well with other types of generators. One significant drawback however, is concern about air quality. Air pollution control regulations require expensive pollution control equipment. The extraction of coal can cause potential damage to the environment which must be mitigated. The U.S. has vast coal resources that will be an important energy source for many years.

Nuclear – Nuclear power plants are mostly used for base-load power production. Nuclear power is not a cheap alternative to electricity generation because safety concerns require high construction costs. It is also expensive to dispose of nuclear waste in acceptable locations. An advantage of nuclear power is its high ratio of generation to capacity, and nuclear power has relatively minor environmental impacts. Within the next 15 to 20 years some nuclear plants will be decommissioned, increasing demand for other alternatives.

Hydroelectric – Because many of the best sites have been used or are off limits, hydroelectric power will not be a major player in power generation growth. Substitution for gas-fired turbines can be met by pump storage, a method for storing less expensive base-load power from off-peak hours for meeting peak demand. Environmental impacts include the disruption of stream flow and the impoundment of water covering land. However, recreational areas are sometimes created as well as habitats for fish and wildlife.

Geothermal – Electricity generation by geothermal processes is confined to certain areas of the country where geothermal resources are present. Weak technology is also a hindrance to geothermal energy.

Biomass – This power source involves the burning of wood or wood products mostly, and therefore, requires large quantities of material. Other sources of biomass could be municipal solid waste. This process is expensive and technically sophisticated.

Wind – Wind power has increased the supply of electricity over the last decade. Even though expansion has been proposed for wind power in the west, the contribution of this alternative has been minimal. The expansion has been driven by generous subsidies for building and operating the wind generators. For wind power to be effective, groups of generators called wind farms must be constructed. Impacts occur on the bird populations and interference with communication transmissions.

Solar – Electricity generated from the sun can consist of technologies employing mirrors or photovoltaic cells. Because these processes are very expensive, solar power may not make a major contribution to electricity generation. Passive solar heating may be a more practical application of this resource. If this technology ever does become viable in the future for electric generation, it would require the use of large areas of land.

Gas Hydrates – Gas hydrates are ice-like crystalline structures of water that form "cages" that trap low molecular weight gas molecules, especially methane. Gas hydrates have recently attracted international attention from government and scientific communities. Methane hydrates have been located in vast quantities around the world in continental slope deposits and permafrost. If the hydrates can be economically recovered, they represent an enormous potential energy resource. In the U.S. offshore, hydrates have been identified in Alaska, all along the West Coast, in the Gulf of Mexico, and notably, offshore South Carolina. The technology does not exist to extract methane hydrates on a commercial scale. Gas recovery from hydrates is hindered because the gas is in a solid form and because hydrates are usually widely dispersed in hostile Arctic and deep marine environments. Hydrates can also be a safety hazard. They can form on drilling equipment and in pipelines in deep water. Plugs of hydrate can stop flow and create pressure buildup that could rupture a pipeline. Drilling equipment can become frozen, creating a hazard to workers. Hydrates also occur naturally as surficial outcrops and as a cementing agent in sediments. They are metastable and can easily dissociate, resulting in slumping or slides. Hydrates also have an effect on the environment. Hydrate outcrops are associated with sensitive biological chemosynthetic communities and may be an energy (food) source for these communities. Researchers believe that slight changes in sea level and seawater temperature cause hydrates to dissociate and reform such that they could release and/or sequester large volumes of methane gas, which could have a greenhouse effect.

Fuel Cells – The concept of fuel cells originates in 1839 when Sir William Grove theorized that the process of electrolysis (splitting water into hydrogen and oxygen) could be reversed. But research on this possibility was delayed several decades because of technological limitation and the invention of the internal combustion engine. Fuel cells have the advantage of being highly reliable; require low maintenance; have high energy conversion efficiency; produce clean power; have a by-product of water, CO_2 and useful heat; are quiet; require no air conditioning; have a modular design; and have a rapid load response. But fuel cells require a fuel source. That source can be either natural gas, propane, biogas, or landfill gas. A gas fuel cell plant consists of: a fuel processor which reforms the gas to increase its hydrogen makeup, a power section which generates DC electricity and heat by joining the hydrogen with oxygen from air, and a power conditioner which changes the DC electricity to AC electricity. Fuel cells have also been used by NASA on space missions to produce electricity and drinking water for the astronauts.

Natural Gas and the Chemical Industry

According to the Energy Information Administration, the U.S. economy depends on the chemical industry to produce more than 70,000 different products. These products come from raw materials such as oil, natural gas, air, water, metals, and minerals. Chemicals are the basis for many products that support the agricultural, manufacturing, construction, and service industries. Other industrial consumers rely on the chemical industry for such items as rubber and plastic products, textiles, apparel, petroleum refining, pulp and paper, and primary metals. The chemical industry itself is the second largest user of energy consuming 26 percent of its output. The U.S. chemical industry is not only the world's largest producer of chemicals, but 170 chemical companies have 2,800 overseas facilities, and 1,700 foreign subsidiaries or affiliates are here in the U.S. More than one million people are employed U.S.-wide in the chemical industry. The chemical industry also produces chemicals for agriculture including ammonia fertilizer compounds, anhydrous ammonia, nitric acid, urea, and natural organic fertilizers. Natural gas has an important direct impact on the chemical industry and, ultimately, the consumer.

Natural Gas-fired Electricity Generation Plants

The DOE's *Annual Energy Outlook 2001* estimates domestic natural gas consumption in 2020 will range from 32.2-36.1 Tcf. In 1999, 21.4 Tcf of natural gas was consumed. Although natural gas consumption in residential, commercial, industrial, and transportation operations are all expected to increase, the largest portion of this increase, 57%, is expected to result from increased demand from electricity generators. According to the Deputy Secretary of Energy (Glauthier 2000), "The most significant new demand for gas is for electricity generation. The use of natural gas to generate electric power is expected to increase almost threefold (compared to current levels). In fact, more than half of the growth in natural gas consumption over the next 20 years will come from the electricity generation market. As many as 900 of the next 1000 new power plants to be built in the United States will likely be fueled by natural gas."

In 2017, electricity generation is expected to become the largest natural gas consumer. *Annual Energy Outlook 2001* predicts electricity generators will use 11.3 Tcf of natural gas by 2020, as compared to 3.8 Tcf in 1999. Between 1998 and 2003, the amount of natural gas consumed per year for electricity generation in the Northeast is expected to increase from 0.4 quadrillion BTU to 0.9 BTU, an increase of 125%.

According to *Monthly Energy Review, February 2001*, DOE's Energy Information Administration states in November 2000, 478 Bcf was consumed to generate electricity. That is a 21% increase from the amount consumed for the same purpose in November 1999. The electricity generation sector is expected to increase its natural gas consumption steadily between 1999 and 2020. This is due to the expected increased demand for electricity, as well as the decommissioning of some older electricity generation facilities, such as oil, some nuclear, and steam plants. Natural gas-fired operations require less capital and less time to construct than coal, nuclear, or renewable electricity generation plants; natural gas is more efficient and also has lower emissions than coal. For these reasons, natural gas electricity generators will be built to replace older facilities.

Natural Gas as an Alternative Fuel for Transportation

Alternative fuels are projected to displace about 500,000 barrels of oil equivalent a day by 2020 (about 5 percent of light-duty vehicle fuel consumption), in response to current environmental and energy legislation intended to reduce oil use. Gasoline's share is sustained, however, by low projected gasoline prices and slower gains in fuel efficiency in conventional light-duty vehicles than was achieved during the 1980's.

Sales of alternative-fuel vehicles (AFV's) should continue to increase as a result of legislative mandates at the Federal level (e.g., the Energy Policy Act of 1992 [EPACT]) and at the State level (under the Low Emission Vehicle Program). The AFV acquisitions for fleets, predominantly fueled by compressed natural gas or liquefied petroleum gas, represent the earliest legislated sales mandated by EPACT. Vehicles that use gaseous fuels will continue to capture a large share of the AFV market through 2020, according to EIA. It should be emphasized that most types of alternative fuels suitable for transportation use are derived from natural gas or crude oil (MMS 1999).

As summarized by the Department of Energy's Energy Information Administration, the use of Compressed Natural Gas (CNG) and Liquefied Natural Gas (LNG) AFV is showing a steady increase (EIA 1999). Vehicles used by state and local governments will show an increase from approximately 10,000 in 1994 to nearly 37,000 in 2001. The number of all CNG and LNG AFV used nationwide is estimated to increase from approximately 23,000 in 1992 to over 111,000 in 2001.

In 1998 six of the 110 Idaho National Engineering and Environmental Laboratory (INEEL) buses ran on LNG (DOE 1998). The vehicles reportedly transported over 3,000 employees to and from work each day with the 94 bus drivers traveling over 3.6 million miles a year. In addition to the six LNG buses, the INEEL ran 37 LNG and 35 CNG light-duty vehicles.

The use of natural gas vehicles is of course not just a U.S. phenomenon. According to the International Association of Natural Gas Vehicles (IANGV, 2001), China, for example, has shown a threefold increase in the production of natural gas vehicles in less than two years, 10,200 in 1999 to 36,000 in 2000.

Pipeline Infrastructure

The vast majority of natural gas is transported by pipeline. Two-thirds of the ton-miles of oil shipped annually travel through pipelines. Therefore, the pipeline infrastructure becomes a very important part of the energy picture.

The MMS and the Department of Transportation (DOT) each have jurisdiction over different types of pipelines. The MMS has jurisdiction over offshore production pipelines. DOT is responsible for onshore pipelines and offshore transport lines. Although uniform minimum Federal standards are established for the pipelines, if a State has an approved agreement with DOT more restrictive standards may be set. The DOT also provides oversight for all interstate pipelines. Approved States oversee transmission and distribution of intrastate pipelines.

Pipelines are the most efficient and safest way to transport hydrocarbons, but there are some concerns that should be mentioned.

- The DOT employs 107 people in its Office of Pipeline Safety. Fifty-five of these are full-time inspectors. The DOT inspections involve records and procedures checks, as well as having the functionality of required safety equipment physically validated by the inspectors. Although DOT's goal is to inspect all systems at least once every three years, most are inspected every other year, especially pipelines that are proven to be high-risk.
- The MMS requires all oil and most gas pipelines to be internally and externally inspected on a regular schedule in the Pacific region. Also, most of the pipelines have leak detection systems.
- The leading causes of pipeline incidents are from outside forces, such as construction or being hit by motor vessels, corrosion, natural forces, and human error. The MMS and the DOT have requirements addressing these factors. Since motor vessels can collide with pipelines, pipelines must be well-marked on maps. The pipelines must be periodically inspected to ensure the hydrocarbons can be safely transmitted. There can be no leaks or other potential damage that could harm people or the environment. Some of the commonly used methods to test pipeline integrity and ensure pipeline safety:

    - ♦ Smart pigs are used to determine wall thickness and integrity inside the pipeline.
    - ♦ Remotely Operated Vehicles (ROV) are used to inspect the condition of the outside of the pipeline.
    - ♦ There are pressure and volume gauges on the pipelines, allowing platform operators to monitor the lines. If a leak develops, these controls would alert the operators.

- Encroachment is another issue gaining attention with regard to pipeline development. Previously, pipelines were usually built in rural areas. Due to urban expansion, subdivisions have now arisen in these areas. Encroachment increases the possibility of outside forces, such as construction, damaging the pipeline.
- Consumers' demand must be met by the pipeline infrastructure. If demand increases beyond the supply capacity, more pipelines will have to be built. In some areas, gas supply is adequate, but the pipelines needed to transport it are not in place. In other areas, the pipelines are in place, but due to concern about pipeline safety, companies are having trouble getting permits to increase capacity.

In *International Energy Outlook 1999*, DOE predicted natural gas trade would increase between North American countries; between 1996 and 2020 imports from Canada are expected to rise 72%. Until recently, imports from Canada have been limited due to the pipeline capacity, demonstrating an inherent problem within our pipeline infrastructure. These large demand increases necessitate larger pipeline capacities. The largest capacity increases are expected to occur in areas providing access to Canadian, Gulf of Mexico, and Rocky Mountain production.

Natural Gas – Shortfall

"Shortfall" is an informal term, and it relates to short-term difficulties in obtaining supplies sufficient for existing demand at "normal" prices. In the long-term, a shortfall is resolved at some combination of new prices, new supply, and change in demand.

At this time, according to the January DOE/EIA *Natural Gas Monthly*, demand for natural gas remains historically strong. Although temperatures have declined to normal levels from unusually severe levels earlier in the winter, consumption is 13 percent higher than a year ago. Meanwhile production, which was relatively flat in early 2000, is 11 percent higher over December of last year; net imports have risen similarly; and storage volumes remain below their seasonal average. These factors combine to keep gas prices high.

Yet, both gas producers and consumers might respond to current high prices in the longer term. The Energy Information Administration evidently thinks it is possible for supply and demand to balance at more moderate gas prices within a year or two. Specifically, it forecasts gas prices will decline from year 2001 average of $5.22/Mcf to a year 2002 average of $4.57. Of course, $4.57/Mcf is still above the average of the past decade, suggesting that the current difficulties might not be completely resolved next year.

Fuel switching is another avenue of demand-side adjustment. According to DOE/EIA *Natural Gas Week* (January 29), electric utilities are switching from gas to oil in a "mass exodus" lately. Most of the boilers that can make the switch are in the Northeast and Florida. However, the switching implies increased demand for some oil products, hence possibly higher oil prices.

Natural Gas Conservation

As the Nation's designated steward of the mineral resources on the Federal OCS, the MMS is committed to the conservation of natural gas by achieving the proper balance between providing energy for the American people and protecting unique and sensitive coastal and marine environments. The continued use of a 5-year oil and gas program allows a controlled approach to leasing and development, which ensures that resources are developed in an orderly way and that any harm to other natural resources is minimized.

To ensure that there is conservation of resources, numerous rules have been adopted by MMS, including Title 30 of the Code of Federal Regulations, Notices to Lessees, and other mitigating measures.

Some regulations promote the conservation of hydrocarbon resources and prevention of waste by authorizing the reinjection and subsurface storage of gas on existing leases. Other regulations impose several requirements on the flaring or venting of gas. Deep-water and end-of-life royalty relief also support conservation of resources by allowing development of resources that would have been prematurely abandoned in the absence of relief being granted.

Demand-side response to high prices is a factor in eventually lowering the currently high gas price in both the short and long-term. Conservation can be achieved by encouraging consumers to lower thermostats, buying more efficient furnaces, adding to home insulation, etc. However, these adjustments usually carry a cost to the consumer, and conservation by itself is unlikely to give the complete solution. However conservation does produce a cost savings in terms of energy.

V. The Outer Continental Shelf—What Does it Offer?

Present Contribution from the OCS

The natural gas production from the Federal OCS contributed over 26% of the total U.S. natural gas production (5.1 Tcf out of 19 Tcf in 1998) (Table 4). All but 50 Bcf of this production came from the Gulf of Mexico (GOM). Over 84 percent of the GOM production came from the Shelf (<200 m water depth) area of the OCS. However, based on NPC's projections, the contribution from the Slope (>200 mm water depth) will grow from 16 percent in 1998 to 64 percent in 2015 of the total natural gas production of the GOM.

1998	2005	2010	2015	Source
5.3	7.4	8.0	7.6	NPC
5.1	5.0	-	-	MMS

Table 4. Gulf of Mexico Natural Gas Production in Tcf (NPC 1999 and MMS 2001, estimates)

Resources, Reserves and Expected Future Production from the OCS

Taking a look at the two major findings of the 1999 NPC study:

1. Between 1998 and 2010, an additional supply of 7 Tcf/year of gas will be needed.
2. Highest growth in U.S. production will be from the Gulf of Mexico and the Rockies.
    a. Deep-water production from the GOM will increase from 0.8Tcf/yr in 1998 to 4.5 Tcf/year in 2010.
    b. The shelf production may be reduced by a third by 2015.

In light of these conclusions, and based on the reality that the demand for natural gas can be as high as 32 Tcf/yr by 2015, the following section takes a look at the present performance of the Gulf of Mexico, Shelf and Slope, and capabilities of the future. The question that we will attempt to answer is what will it take to meet or exceed the NPC's projections. We will also look at the other OCS areas, Alaska, Atlantic and the Pacific and their possible role in meeting the Nation's natural gas demand.

Area	Undiscovered Resource	Reserves Proved	Reserves Unproved	Economic Recoverable Resource @ $3.52/Mcf	Reserve Appreciation
Alaska	122.6			3.0	
Atlantic	28.0			12.8	
GOM	192.7	30.03	5.1	140.7	68.1
Pacific	18.9	1.28	0.9	11.6	
Total OCS	362.2	31.3	6	168.1	68.1

Table 5. Undiscovered and Economic Natural Gas Resources of the OCS (Tcf)

Present Trend and Future Prospects of OCS Natural Gas Production

Alaska OCS

As can be seen from Table 5 and Figure 14, the Alaska OCS holds a significant amount (122.6 Tcf) of conventionally recoverable natural gas resources. However, due to the large distance from the usage area and the lack of a currently available transportation structure, the economically recoverable natural gas that can be delivered to the lower 48 is only 3 Tcf. A significantly large natural gas reserve (about 30 Tcf) is located in the onshore areas of Alaska.

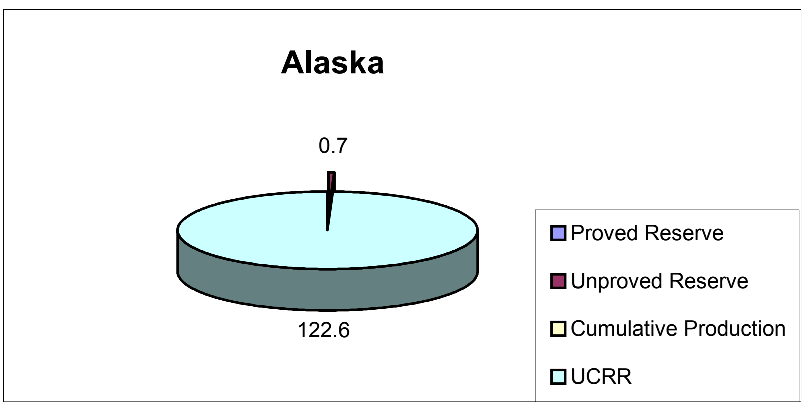


Figure 14. Undiscovered Conventional Natural Gas Resources and Reserves of Alaska (Tcf). (UCRR = Undiscovered Conventionally Recoverable Resources)

The most logical way to deliver Alaska gas to the lower 48 will be through pipelines. Two options for pipelines have been suggested and their feasibility is currently being evaluated by the industry. One route follows from the North Slope via the Alaska Highway and eventually joins another pipeline coming from the Mackenzie Delta. The second route brings northern Alaska gas through a pipeline going though the Arctic Sea to the Mackenzie Delta, then following the

Canadian pipeline to the U.S. The first option enjoys the support of the State of Alaska and will require a less time-consuming permitting process. From the time a decision is made to the time gas flows through the pipeline to the lower 48 could be as much as 5 to 10 years. The first gas to be transported through the pipeline will be the 30 Tcf of reserves already discovered on the North Slope. It will be several years before the OCS gas becomes competitive, even though a sustained high gas price, such as it is today, will make the OCS natural gas economically producible.

Atlantic OCS

The Atlantic OCS offers natural gas resources that could contribute to the Nation's energy inventory. The natural gas resource base for the Atlantic margin is estimated at 28 Tcf. The Atlantic OCS has been drilled and natural gas was discovered.

Recently, off the coast of Canada, some major gas fields have been established. Sable Island gas field located on the Scotian Shelf is estimated to have 3.5 Tcf of reserves. Pan Canadian's most recent discovery of the Panuke gas field flowed at 50 to 55 MMcf of gas day per test completion. Panuke is believed to have reserves similar to those of the Sable Island field. It is believed that the pay sands in the Panuke field ranges from 100 to 325 feet in thickness. It is estimated that the undiscovered natural gas potential of the East Coast of Canada (Grand Banks and Scotian Shelf) is about 63 Tcf of natural gas (NEB 1999).

The general geologic setting of the North Atlantic Planning Area indicates the possibility that the same gas play producing in the Scotian Shelf may continue south.

Currently, the North Atlantic area is under moratoria until 2012 and under access restriction. Eight exploratory wells were drilled in the North Atlantic planning area in 1981-1982, all on the Georges Bank. No discoveries were made. The geology implies that if hydrocarbons occur in the area, they would more likely be natural gas prone.

The Mid-Atlantic planning area has experienced significantly more drilling than the North Atlantic with 32 exploratory wells drilled in 1978-1984. The drilling resulted in the discovery of natural gas but it was deemed uneconomic at the time. Like the North Atlantic, it is believed that the Mid-Atlantic area will most likely be natural gas prone. The South Atlantic planning area has six exploration wells, drilled in 1979-1980, all in the southeast Georges Embayment. Although these wells were dry, it is believed that natural gas will be the most likely hydrocarbons that will occur in this area.

If the Atlantic OCS were thoroughly explored, it is possible that economically recoverable natural gas resources would be discovered as most recently published in the *MMS Outer Continental Shelf Petroleum Assessment 2000* as well as previous assessment publications.

Pacific OCS

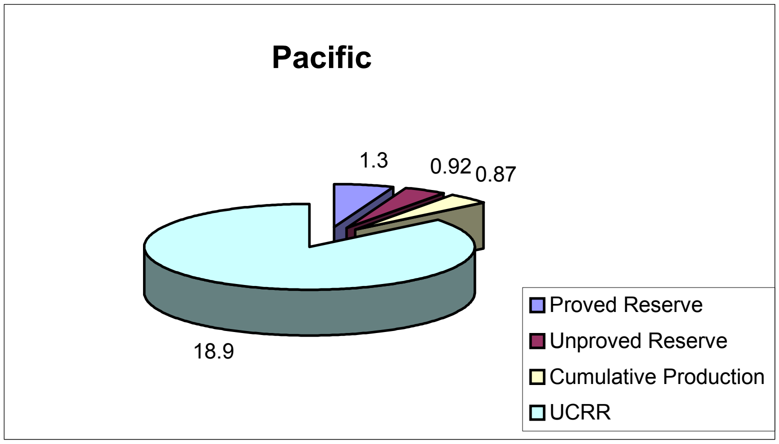


Figure 15. Undiscovered Conventional Natural Gas Resources and Reserves of the Pacific (Tcf). (UCRR = Undiscovered Conventionally Recoverable Resources)

The Pacific OCS Region contains considerable resources of natural gas. MMS has estimated that the undiscovered natural gas resources for the region are 18.9 Tcf. Of these resources, 11.6 Tcf (Table 5) would be economically recoverable at a price of $3.52/Mcf (Dunkel and Piper, 1997). Most of these gas resources are expected to be found in association with oil accumulations.

Currently, all of the Pacific OCS unleased acreage is under moratoria until 2012. The undiscovered natural gas resources on these moratoria lands will not be available until they are leased, explored, developed and produced. This is a process that requires a considerable amount of lead time in the Pacific OCS.

Existing OCS operations are in the Santa Maria Basin, Santa Barbara Channel, and Los Angeles Basin. During 1999, 80 Bcf of natural gas was produced, with 38.6 Bcf sold, 32.4 Bcf reinjected into the reservoir to enhance oil production, and 9.2 Bcf used on-lease for power generation. Pacific OCS gas sales accounted for about one-eighth of the total sales gas produced within California.

Reserves of natural gas on existing Pacific OCS leases are about 1.9 Tcf (Figure 15). At current production rates, these reserves would last for over 20 years.

Gulf of Mexico OCS

The Gulf of Mexico (GOM) accounted for 99.99 percent of the OCS gas production for the U.S. in 1998. Eighty-four percent of the undiscovered economically recoverable (@$3.52/Mcf) resources of the OCS is present in the GOM. If we add reserves appreciation, the undiscovered economically recoverable resources of the GOM accounts for 88 percent of the total OCS resources (see Tables 5 and 6 and Figure 16).

Area Values in Tcf	Conventional Resource	Economic @ $3.52/Mcf
Gulf of Mexico (Total)	192.7	140.7
Central GOM	105.5	77.5
Western GOM	74.7	54.1
Eastern GOM	12.3	9.2
Sale 181	3.9	2.7
Straits of Florida	.026	.006

Table 6. Undiscovered and Economic Resources of the GOM OCS

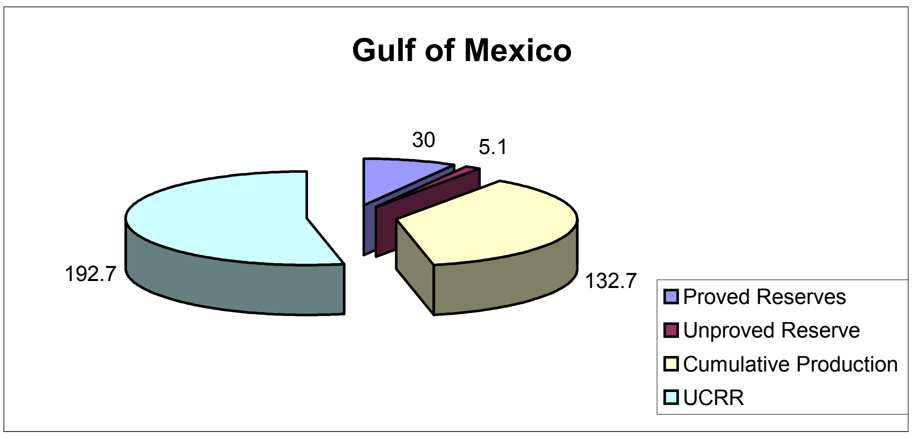


Figure 16. Undiscovered Conventional Natural Gas Resources and Reserves of the Gulf of Mexico (Tcf). (UCRR = Undiscovered Conventionally Recoverable Resources)

Natural Gas Production Projection for the Gulf of Mexico

An earlier MMS report on *Future Natural Gas Supply from the OCS* (Ray et al, 2000), based on 1998 data, estimated the future natural gas production from the shelf and slope of the Gulf of Mexico in a high case to be peaking at 6.7 Tcf in 2010 followed by a decline. At this time in 2010 the Gulf of Mexico OCS is expected to produce 4.2 Tcf and an additional 2.5 Tcf is expected from the deepwater area. However, the recently published MMS data (U.S. DOI/MMS, 2001) (Fig. 17) indicates a lower expected production from the Gulf of Mexico. The high case estimation of the recent production projection indicates that the natural gas production from the Gulf of Mexico will peak in 2002 at about 5.22 Tcf.

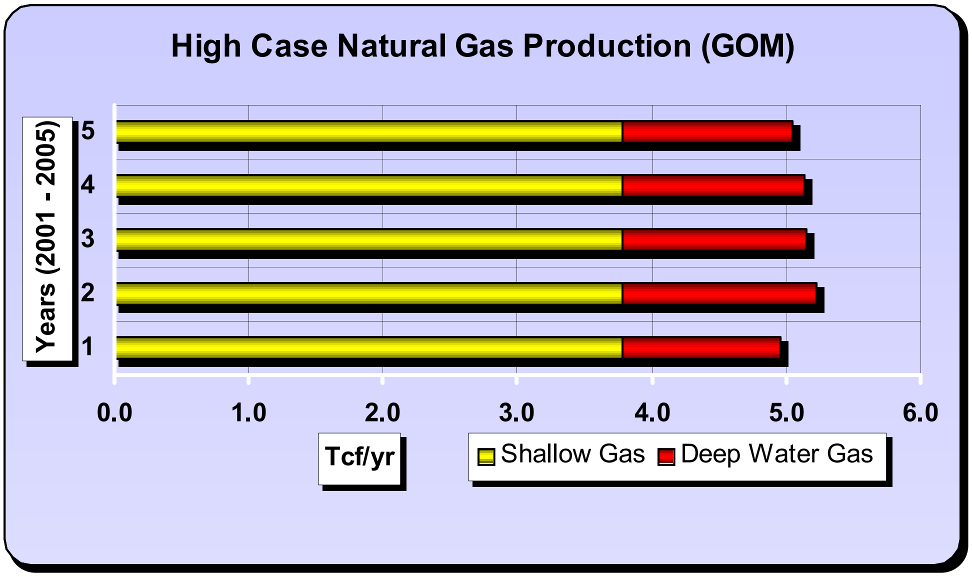


Figure 17. Natural Gas Production Projection for the Gulf of Mexico (MMS, 2001)

Based on this projection, it can be concluded that unless exploration and development scenarios in the Gulf of Mexico change dramatically, the production from the Gulf of Mexico may not be able to meet the expected share of natural gas supply to meet the expected future natural gas demand of the U.S. The House of Representative's Subcommittee was informed on this in an oral testimony in March 2001. A discussion of what it will take to reach the expected 8 Tcf of natural gas production from the Gulf of Mexico is included in this section.

At present, the GOM accounts for more than 26 percent of the total U.S. natural gas production. According to NPC's 1999 estimate, the GOM is expected to provide as much as 32 percent (8 Tcf out of 25.1 Tcf) in 2010, and about 29 percent in 2015 of U.S. gas production. More than one half of the future GOM natural gas production is expected to come from water depths greater than 200 meters. Production from water depths greater than 1,500 meters is expected to account for 15 to 18 percent of the total GOM production. At present, the production from this area is less than 1 percent of the total. The undiscovered conventional and economically recoverable natural gas resources by planning areas of the GOM are listed in table 6. To meet the ever-increasing production expectation for the rising natural gas demand of the U.S., the GOM production needs to increase over 57 percent. In the following section, a brief discussion is provided to evaluate the present production trend and what needs to happen to meet the expected production goal of 8 Tcf for the GOM.

A simple logarithmic regression analysis (Figure 18) indicates a statistically significant correlation (90%) between year of production and the amount of production. As calculated from the established production trend, a natural gas production of 7.6 Tcf may be achieved in 2015 only through a dramatic increase in production from the shelf or the slope or from a production increase in both areas of the Gulf of Mexico.

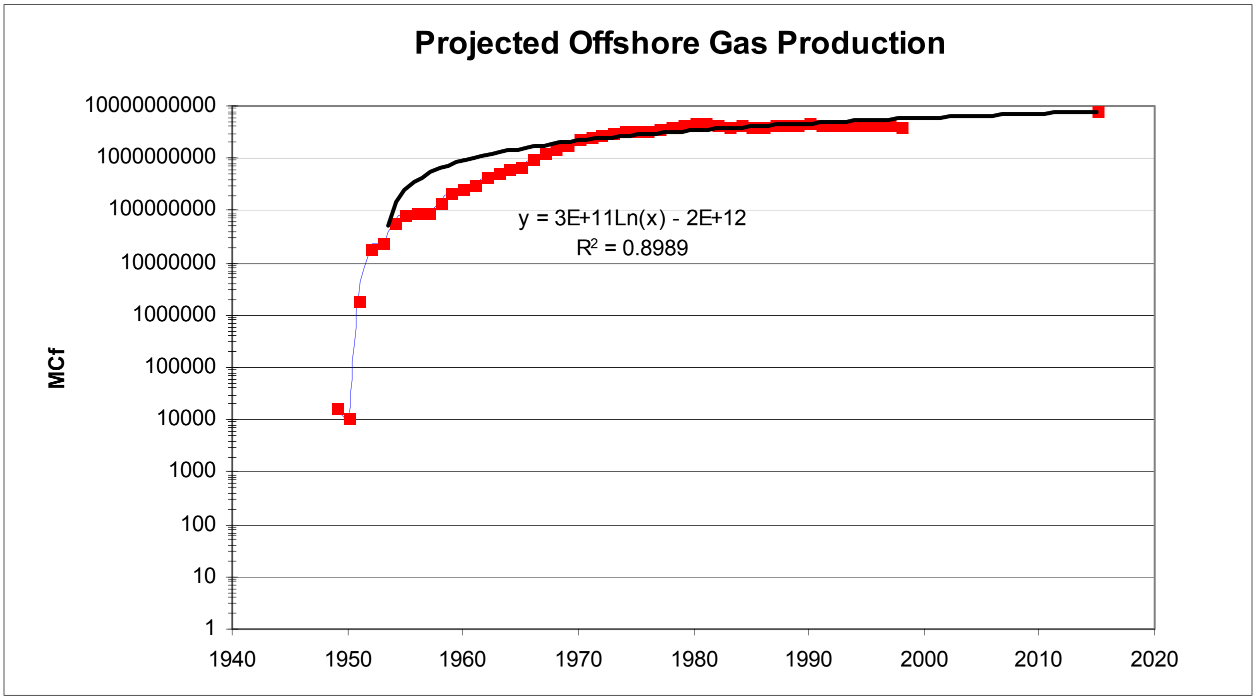


Figure 18. Getting 8 Tcf Natural Gas Production in 2015 from the Gulf of Mexico

A look at the reserves balance (difference between the annual reserves additions and the annual production) (Figure 19) of the GOM reveals that while the reserves additions fluctuate consistently with the boom and bust cycles in exploration activity resulting from price movements, on average, reserves continue to be added. However since 1985 the production has outpaced the reserves addition on an average of 2 Tcf per year, leaving (as of December 1998) a net reserve of 30 Tcf.

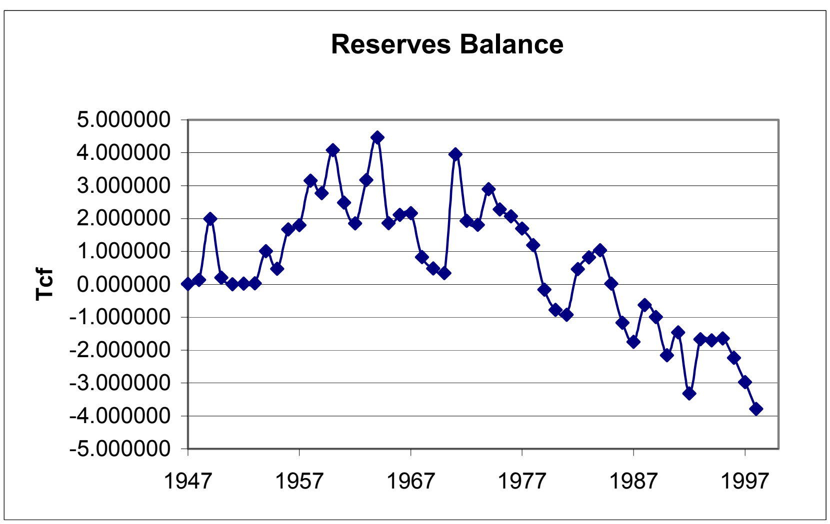


Figure 19. Reserves Balance GOM OCS. Annual difference between reserves addition and production indicates a steady draw from reserves stock.

To evaluate the feasibility of the above statistical prediction (Figure 19), based on the geologic and engineering considerations, a time dependent response of two variables (number of completions and production per completion) for associated gas (solution gas produced during oil production) and non-associated gas (dry gas) is plotted in Figure 20.

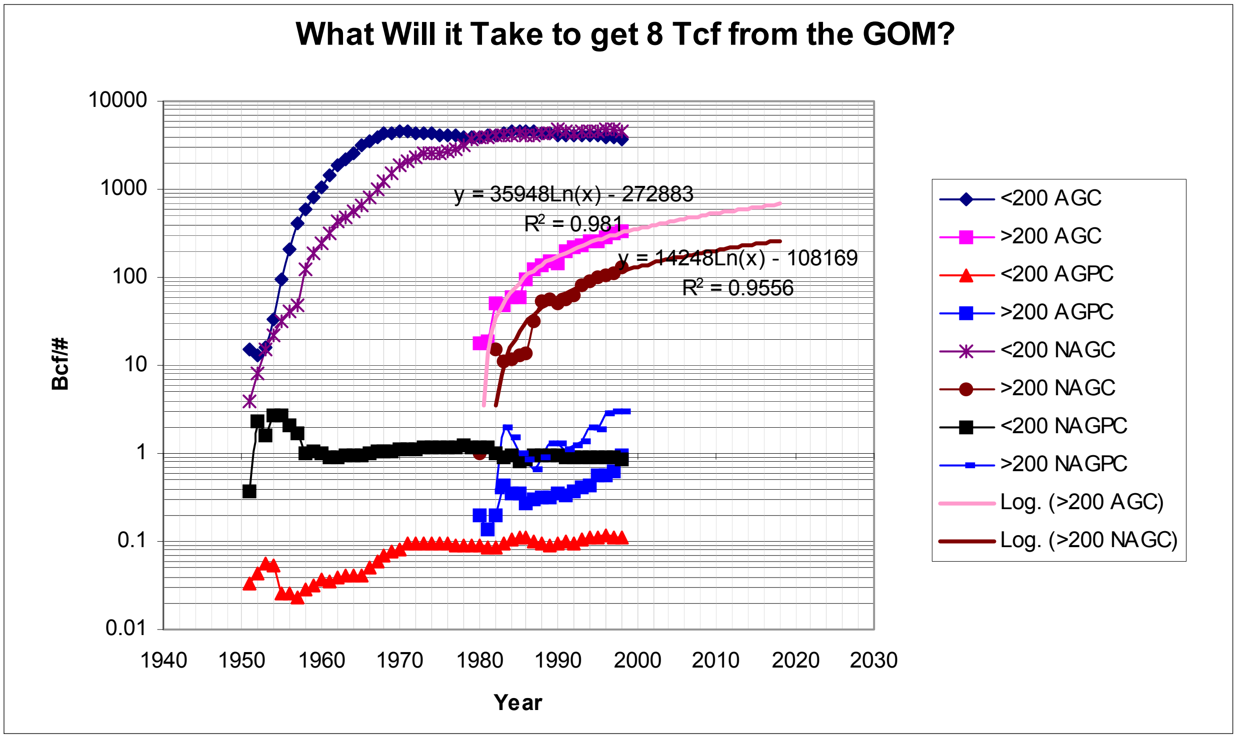


Figure 20. Response of Two Variables for Associated Gas and Non-associated Gas

(AGC = Number of Completions for Associated Gas; AGPC = Per Completion Production for Assoc. Gas; NAGC = Number of Completions of Non-associated Gas; NAGPC = Per Completion Production of Non-associated Gas; < and > 200 meters of water depth)

It is evident from Figure 20 that the basis for the projected increase in production is a steady increase in the number of completions which is directly related to the number of wells drilled, in deep water slope areas, and the shelf (<200m) for non-associated gas. The number of completions for associated gas also increases steadily in the deep water areas. An increase in drilling of the prolific offshore wells which add 30 times more reserves than the onshore wells (Cochener, 2000), will be an essential element in meeting the increased production expectation. Deep water wells add 3 times more per non-associated gas completion and 8 times more per associated gas completion in the GOM. A slight decline in per completion production of the shallow water area of the GOM can be far offset by an increase in the number of completions. A recent study by Ziff Energy (Press Release, 2001) indicates that a 10 percent decline has been successfully balanced by cost cutting measures by the industry in its drilling technology and practices. The per completion production rate of associated and non-associated natural gas has been steadily increasing in the deepwater area of the GOM. It is anticipated that if and when discoveries are made in deep (>15000') reservoirs of the GOM shelf area, per completion production rates will be comparable to the deep water area.

Major Milestones, Timeline, and Task Descriptions for OCS Oil and Gas Activities: From Consideration for Leasing to Production

1. Consideration of Areas for Leasing Begins: Announce the beginning of the 5-year program development process and request comments.

No OCS block can be leased for oil and gas activities without being included in the 5-year schedule of proposed lease sales required by the OCS Lands Act. The process of developing and adopting a 5-year program involves three mandated cycles of notice, comment, analysis, and decision, including 8.5 months of mandated comment and waiting periods. Historically, this process has taken 2 or 3 years, with the more ambitious and contested programs requiring more time for consideration and consultation. An environmental impact statement (EIS) is developed concurrently, requiring two cycles of notice, comment, analysis, and decision. By considering only areas not covered by Presidential withdrawal, MMS is planning to complete the process for the 5-year program for 2002-2007 in 1.5 years.

Elapsed time from official start to completion of 5-year development process: 1.5 – 3 years

2. The 5-year program is approved; any area to be considered for leasing must be on the 5-year schedule.

After the 5-year program has been adopted, no proposed lease sale can be held until a presale process has been completed. Like the process for developing a 5-year program, the presale planning process consists of three mandated cycles of notice, comment, analysis, and decision, including 6.5 months of mandated comment and waiting periods. An EIS is developed concurrently, requiring two cycles of notice, comment, analysis, and decision. The MMS issues Consistency Determinations, pursuant to the Coastal Zone Management Act, at the same time it publishes the Proposed Notice of Sale. The complexity of, and the time required to complete the presale process depends upon whether the area under consideration is a frontier area or a highly developed area with annual lease sales. The presale process for the Central and Western Gulf of Mexico (the only areas with annual sales) differs in two ways from the process for the others. First, the normal 2-year presale process has been shortened to 1 year. Second, the process for the initial sales in any 5-year program necessarily begins before final approval of the program.

Elapsed time from adoption of new 5-year program to lease sale: 1 month (Central and Western GOM) – 5 years

3. Lease sale is held.

After the lease sale has been held, MMS begins a detailed bid evaluation process. In Phase I, MMS evaluates the bids to determine which ones can be accepted without further analysis (those for blocks showing no evidence of economically recoverable resources and those for which certain criteria for competition are met) and which must be passed to Phase II for additional evaluation. The Justice Department and the Federal Trade Commission also analyze bidding patterns to determine whether anti-competitive conditions existed for the sale. The MMS announces the Phase I acceptance of bids within 2 weeks. Those bids undergoing the more extensive Phase II evaluations usually must be accepted or rejected within 90 days of the sale, but this can be extended to 120 days when circumstances warrant. Leases are issued within 11 days after bids are accepted.

Elapsed time from lease sale to lease issuance: 20 – 131 days

4. Leases are issued.

After the lease is issued, prior to drilling any exploration wells, a lessee must submit and receive approval of an Exploration Plan (EP), an Environmental Report, and an Application for Permit to Drill (APD). The operator can begin conducting site surveys and other activities without a permit but must file an exploration plan and environmental report with MMS within 4 years. If, after a period of comment and analysis MMS approves the EP, the operator may submit an APD. Assuming MMS approval and State coastal zone consistency concurrence, the operator may begin drilling test wells and must begin drilling within 5 or 10 years, depending upon the terms of lease. Delineation wells may be required before the exploration phase is complete. The complexity of drilling operations, environmental sensitivity, and availability of equipment will affect the time needed for an operator to prepare a plan and for State coastal zone consistency review. Shallow-water projects may take as little as 2 months. Deep-water projects may take 5 years.

Elapsed time from lease issuance to completion of exploration/delineation drilling: 2 months – 6 years

5. Exploration/delineation is completed.

After exploration is complete, prior to beginning production, the lessee must:

- evaluate exploration/delineation results and decide to pursue production,
- submit and receive approval of a Development and Production Plan (DPP), (for deep water) a Deep-Water Operations Plan, and an Environmental Report, and
- install the needed infrastructure.

An EIS, which can take up to 2 years, may also be required. Once MMS has approved the DPP and the plan has received State coastal zone consistency concurrence, the operator may begin construction and installation of platforms and pipelines. If the APD's are approved and the infrastructure is in place, the operator may begin drilling development wells and commence production. Shallow-water production may take as little as 3 months; deep-water production may take as long as 5 years.

Elapsed time from completion of exploration drilling to production: 6 months – 5 years

6. Commercial production begins.

Total Elapsed Time from formal consideration to commercial production:

Central and Western Gulf of Mexico –	1 year - 7 years
Eastern Gulf of Mexico –	3 years - 10 years
Other areas on 5-year schedule for 1997-2002 –	7 years - 15 years
Area with no sales on 5-year schedule for 1997-2002 –	10 years - 20 years

Notes:

1. The only areas with scheduled sales remaining under the current 5-year program are the three GOM planning areas. Although production of some resources leased in the upcoming Western GOM Sale 180 could be begin a year after the sale, that production would be minimal. Technically, the presale process could begin or resume at any time for the four Alaska OCS planning areas with "deferred" sales listed in the 5-year schedule (Cook Inlet, Gulf of Alaska, Chukchi/Hope, Beaufort) *if* they are carried over into the 5-year program for 2002-2007. However, no area absent from the 5-year program for 2002-2007 can have a lease sale until the following program is developed and adopted, presumably in mid-2007.

2. Delays in getting approval for plans and permits, as well as suspensions of operations, can extend these time estimates considerably.
3. Lower-priority projects can take even longer than indicated, especially for leases with 10-year terms. The elapsed-time ranges are based on many assumptions, including that there will be sufficient demand for any OCS gas produced and, therefore, that the market (perhaps in combination with Federal policies) will provide the incentives lessees need to move expeditiously to explore for and to produce any commercially viable resources.

A flow chart of these processes, from lease to production, can be found in Appendix 2.

OCS Leasing Moratoria

The Secretary of the Interior is prohibited by Presidential Executive Order from leasing off the East and West Coast, in the North Aleutian Basin, and in most of the Eastern Gulf of Mexico prior to 2012.

The first leasing moratorium was included in Fiscal Year 1982 Congressional Appropriations legislation for the Department of the Interior and covered only a portion of the Central California and Northern California planning areas (0.74 million acres). Since then, such annual moratoria covering at least one planning area have been enacted every year. In June 1990, President Bush withdrew from leasing consideration for 10 years the North Atlantic, a portion of the area off Florida, and almost all of the West Coast Planning areas. Annual Congressional moratoria were enacted to prevent leasing in portions of the Mid-Atlantic and South Atlantic, as well as a larger area of the Eastern Gulf of Mexico for Fiscal Years 1993-1997 (266.5 million acres under either form of moratorium). In 1998, President Clinton expanded the Presidential withdrawal to cover the full acreage of all planning areas then under moratoria, except for the Sale 181 area of the Eastern Gulf of Mexico (610.7 million acres[1]), and extended the withdrawal until 2012.

As a result, the following OCS planning areas have been withdrawn from leasing until after June 30, 2012, under section 12 of the OCS Lands Act[2]:

- North Aleutian Basin (33.4 million acres)
- Washington-Oregon (71.8 million acres)
- Northern California (45.1 million acres)
- Central California (44.1 million acres)
- Southern California (83.6 million acres)
- Eastern Gulf of Mexico (except for the Sale 181 area, 69.9 million acres)
- South Atlantic (127.9 million acres)
- Mid-Atlantic (82.9 million acres)
- North Atlantic (52.0 million acres)

[1] About 146 million acres of this number resulted from the addition of new protraction diagrams that increased the size of the Pacific and the South Atlantic planning areas.
[2] The congressional moratoria and section 12 withdrawal prohibit future oil and gas leasing and do not apply to existing leases. Existing leases in areas subject to the moratoria and withdrawal are located off California, northwest Florida.

Some of these areas also are covered by Congressional moratoria provisions for Fiscal Year 2001. In addition, President Clinton withdrew indefinitely all National Marine Sanctuaries. Sanctuaries are located in the following OCS planning areas:

- Washington-Oregon (*Olympic Coast)*
- Central California (*Cordell Bank, Gulf of the Farollones, and Monterey Bay*)
- Southern California (*Channel Islands)*
- Western Gulf of Mexico (*Flower Garden Banks*)
- Straits of Florida (*Florida Keys*)
- South Atlantic (*Gray's Reef)*
- Mid-Atlantic (*Monitor*)
- North Atlantic (*Stellwagen Bank*)

There also are National Marine Sanctuaries located off Hawaii and American Samoa.

The congressional moratoria and section 12 withdrawal reflect the consensus achieved by the 5-year program for 1997-2002. The program was developed based on the substantive and procedural requirements of section 18 of the OCS Lands Act, as well as three policy objectives endorsed by Secretary Babbitt and President Clinton--consensus-based decisionmaking, science-based decisionmaking, and the use of natural gas as an environmentally preferred fuel.

The congressional delegations, state and local government officials, and environmental and other interest organizations of states adjacent to areas subject to the moratoria generally support the moratoria and section 12 withdrawal. The oil and gas industry opposes the restrictions.

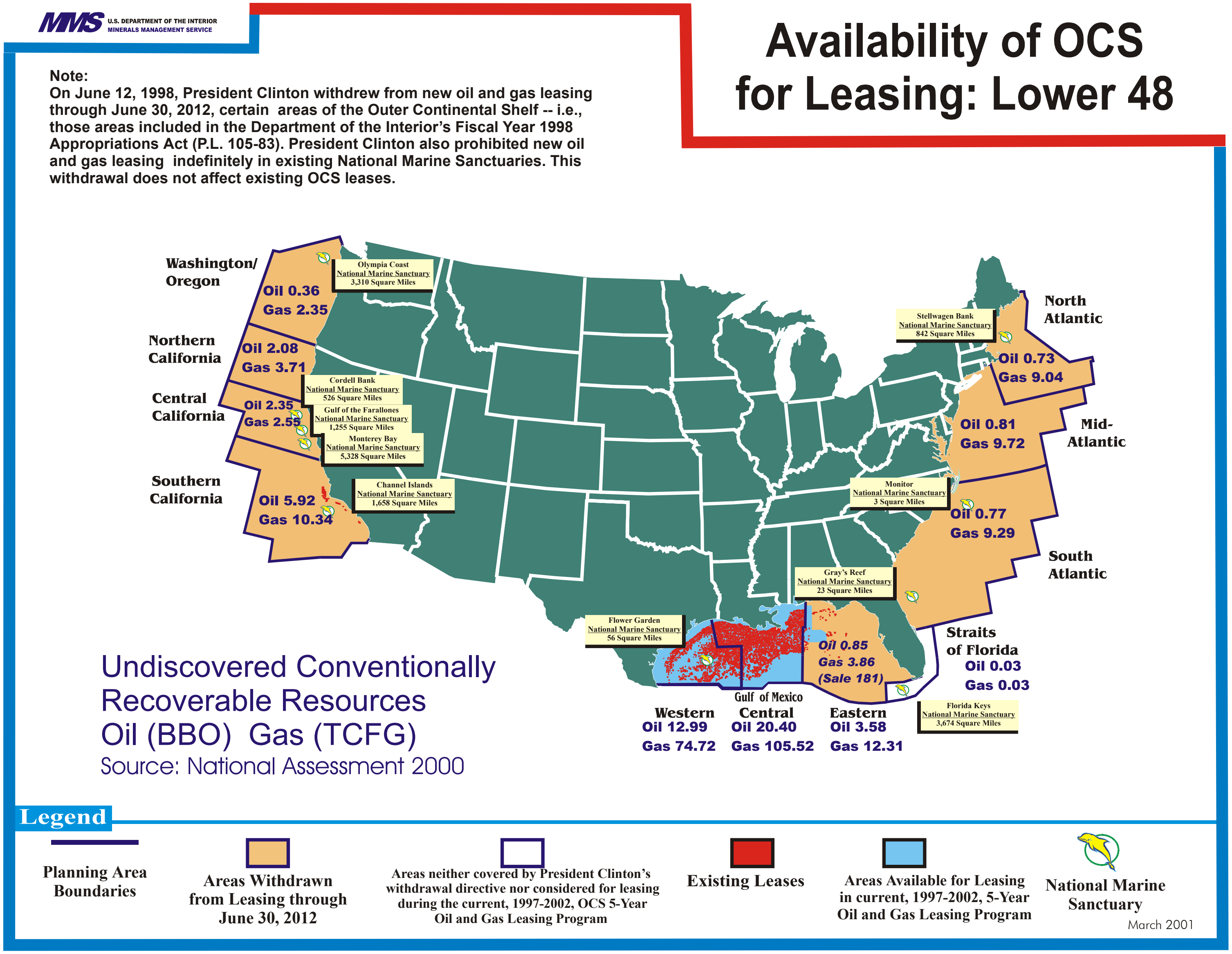


Figure 21. Availability of OCS for Leasing: Lower 48

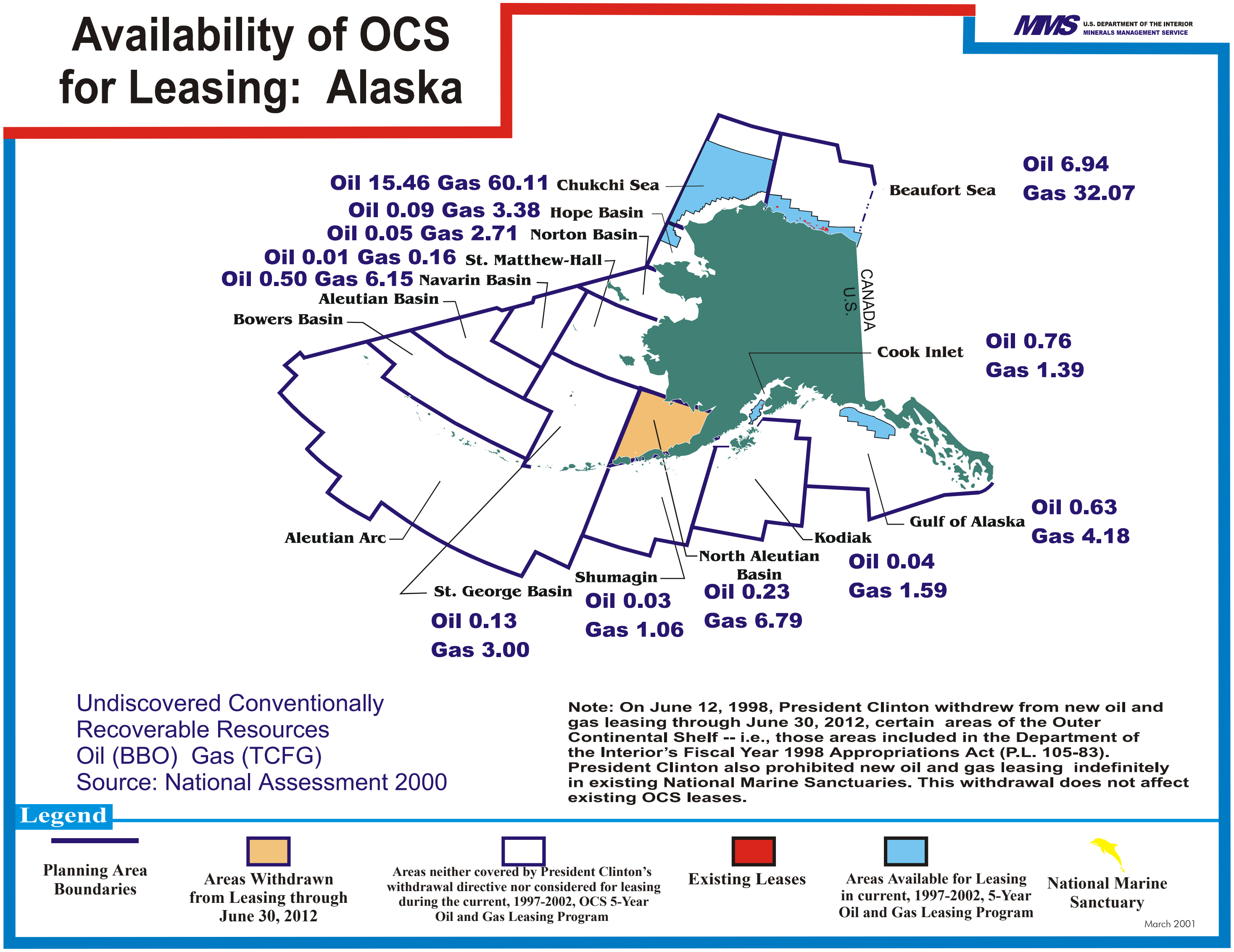


Figure 22. Availability of OCS for Leasing: Alaska

As a result of the 2000 assessment conducted by the MMS, OCS resource estimates in the moratoria areas of the Eastern Gulf of Mexico (EGOM) and Atlantic Region were updated. Moratoria areas in the North Aleutian Shelf area and Pacific Region were not updated because they lacked new data and changes since the last assessment in 1995. For areas under moratoria, the gas resources (undiscovered conventionally recoverable) removed amount to a total of 62 Tcf. The following tables give the conventionally recoverable and economically recoverable natural gas resources assessed in the moratoria areas, and acreage figures.

Table 7 shows the mean estimate of the undiscovered, conventionally recoverable natural gas resources in the moratoria areas:

Planning Area	Tcf Gas Under Moratoria
Atlantic	28.05 Tcf
Eastern Gulf of Mexico	8.45 Tcf
Pacific	18.95 Tcf
Alaska	6.79 Tcf
Total	62.24 Tcf

Table 7. Mean Estimates of the Undiscovered, Conventionally Recoverable Natural Gas Resources in the Moratoria Areas

Table 8 shows the economically recoverable natural gas resources, at the mean level, and at the \$2.11/Mcf and \$3.52/Mcf as assessed in the MMS National Assessment 2000.

Economically Recoverable Natural Gas Resources (Tcf) in Moratoria Areas		
	Mean	
Planning Area	**\$2.11 Mcf**	**\$3.52/Mcf**
North Atlantic	2.14	4.11
Mid Atlantic	2.28	4.39
South Atlantic	2.23	4.27
Eastern Gulf of Mexico	5.34	6.49
Washington-Oregon	0.65	1.04
Northern California	1.23	1.89
Central California	1.71	2.02
Southern California	4.71	6.67
North Aleutian Basin	0.88	1.27
Total	21.17 Tcf	32.15 Tcf

Table 8. Economically Recoverable Natural Gas Resources (Tcf) in Moratoria Areas

OCS Areas Under Moratoria				
Planning Area	**Acres* in Planning Area**	**Acres Under Moratoria**	**Acres of Geologic Plays in Moratoria Area**	**Percent of Moratoria Areas with Geologic Plays**
North Atlantic	48.8	48.8	22.3	45.7 %
Mid Atlantic	82.2	82.2	30.1	36.6 %
South Atlantic	114.2	114.2	22.8	20.0 %
Eastern Gulf of Mexico	77.0	71.1	48.3	67.9 %
Washington-Oregon	71.8	71.8	11.9	16.6 %
Northern California	45.1	45.1	3.4	7.5 %
Central California	44.1	44.1	2.1	4.7 %
Southern California	83.6	83.2	9.8	11.8 %
North Aleutian Basin	32.5	32.5	14.0	43.0 %
Total	599.3	593.0	164.7	27.8 %

Table 9. OCS Areas Under Moratoria
* Acres in Millions

VI. Safety and Operational Considerations Unique to Natural Gas

Natural Gas Production

The following is a list of special considerations that must be given to natural gas production.

- H_2S is a major concern when producing gas. Offshore Alabama is one area faced with this problem.
- Gas is found at higher pressures and temperatures than oil.
- Operators are not allowed to flare or reinject gas for extended periods of time. They must either transmit it by pipeline or liquify it.
- North Star is using gas for energy. The gas is transmitted by a buried pipeline in Prudhoe Bay. Pipelines in Arctic regions are of special concern because of shifting ice, freezing and thawing, etc.
- Hydrates and corrosion problems occur when producing entrained H_2S and CO_2. These problems are overcome by using chemicals, such as methanol, for hydrates and special metallurgy for H_2S and CO_2.

These are the key issues affected by natural gas production. As compared to oil production, there are relatively few problems associated with the production of natural gas. Natural gas operations are cleaner and much more efficient.

New Technology

New technologies are constantly being developed for the petroleum industry. Most of the easily found hydrocarbons have already been produced, making new technology a necessity. Advanced technology will enable many of the fields that cannot be economically produced now to be profitable in the near future. In addition, many of the advances allow for more environment-friendly operations and safer conditions for the workers in the field. Following is a list of new technologies being used or developed for oil and gas operations.
For more information on these technologies, see DOE's Environmental Benefits of Advanced Oil and Gas Exploration and Production Technology.

Exploration

- 3-D seismic and 4-D time-lapse subsurface images allow operators to have a better idea of the reservoir and how it behaves. This increases drilling success and decreases the number of wells and dry holes drilled, because the wells are more likely to be drilled in the correct areas. A lower number of wells drilled results in less waste (less drilling fluid, cuttings, etc.)
- Due to technology improvements, the average cost of finding U.S. petroleum reserves has decreased from $12 to $16 per BOE in the 1970s-80's to $4-8 per BOE now.
- New types of drilling rigs also expedite the process. There are jack-up rigs, semisubmersible rigs, and modular rigs. All of these drilling rigs can move to a new location much more quickly than older rigs could. In addition, they allow for exploration in deeper waters. The drawback with drilling rigs is they are very expensive. When industry is supporting a lot of exploration, rigs can be difficult to obtain. This will continue to be an issue until new rigs are built; this will not happen without an incentive to the industry, such as large frontier areas being developed.

Drilling and Completion

- Due to better exploration techniques, drilling has become more efficient, safer, and less expensive.
- Directional and horizontal drilling allows drilling in areas that were unavailable in the past. Some new drilling fluids are less-toxic and result in less waste.
- Horizontal, multilateral, and directional wells have become commonplace. Directional wells allow production from a reservoir that is not directly under a rig. Horizontal wells are drilled below the rig; the hole deviates approximately 90 degrees to the reservoir of interest. These two techniques allow drilling under sensitive environmental or scenic areas, without disrupting them. In addition, horizontal wells allow more of the well to be in contact with the reservoir, which can result in increased production. Multilateral wells are completed in two or more different directions from the same wellbore. This decreases the amount of well maintenance and waste.

- Light modular rigs are currently being produced. They are lighter than normal rigs and can be assembled and disassembled on site. Since they can be transported in pieces, these rigs have less impact on environmentally sensitive areas than conventional rigs.
- Slimhole drilling and coiled tubing are also lighter in weight than conventional rigs. They are also more mobile and produce less waste. In addition, they operate more quietly, which would not disrupt the wildlife in a producing area as quickly as older drilling procedures.
- New drilling fluids reduce wastes. Synthetic drilling fluids can be recycled, thereby reducing the amount of waste. They also are less-toxic than diesel-based muds, decreasing the health risks to workers.
- Pneumatic drilling doesn't require drilling fluids. Since the hole is drilled with air, the only wastes produced are cuttings. This technique can only be used in certain regions.

Production

- There is less produced water now than in the past, due to better reservoir management.
- Water that is produced can be better treated than in the past, with gas flotation or membrane separation. In some cases, it may be reused.
- Gas, thermal, and chemical injections into the reservoirs can allow half of the oil in place to be economically recovered. This technology has also crossed-over into the groundwater industry.
- In downhole separation, oil and water are separated in the wellbore. The oil is produced and the water is pumped into an injection site. This would reduce the amount of produced water and the costs associated with treating the water.
- Air pollution is better monitored now than in the past. Operators are trying to reduce methane emissions, a greenhouse gas. Gas leaks can be found because of leak detection devices and close monitoring of measuring devices on the equipment. Facilities have also become more energy-efficient.

Site Restoration

- The rigs-to-reefs program is supported by MMS. Once a field is abandoned, the wells can be plugged and the equipment removed.
- Instead of using explosives to decommission operations, which can harm marine life and neighboring installations, the platforms are collapsed into the water. The platform becomes an artificial reef, supporting marine animals. It also decreases the costs of decommissioning to the operators. States, fishermen, and divers also see benefits from this program.
- The Oklahoma Energy Resources Board has restored over 1,000 abandoned drilling and production sites with no current owner. Petroleum producers and royalty owners in Oklahoma willingly finance the clean-ups. This was the first industry-funded environmental cleanup program in the country. Several other states have instituted similar programs.
- In the North Slope, areas affected by gravel construction and drilling are seeded with native vegetation. Abandoned gravel mining sites have been flooded, creating lakes that provide wintering habitats for fish and predator-free nesting sites for waterfowl.

Operations in Sensitive Environments

Offshore

- The MMS's Safety and Environmental Management Programs (SEMP) consist of voluntary strategies to identify and reduce offshore accidents. As a result, there are fewer offshore accidents, including injuries and fatalities. (See figure 23, OCS Events by Category: 1995-2000)
- Current technologies allow safety in deepwater and hostile environments. Current deepwater blowout preventers provide well control by continuously monitoring subsurface and subseabed conditions.
- "Intelligent" subsea trees allow producing wells to be quickly shut-in in an emergency.
- Subsea production systems can connect subsea satellite wells to production facilities miles away.

Arctic Environments

- To protect the tundra in the North Slope, exploration activities occur exclusively in the winter.
- Ice-based roads, drilling pads, and airstrips have become common in North Slope projects. It is less expensive than using the conventional method of gravel and it practically leaves no trace of exploration when the ice melts.
- If an exploratory well is in a remote area, far from existing means of transportation, large all-terrain vehicles with low-pressure tires are used to carry equipment across the tundra. These tires leave practically no tracks.
- Through-tubing rotary drilling allows a new well to be drilled through an older well's production tubing, saving time and money.
- "Designer wells" are an advanced from of directional drilling. The wells weave around geological barriers to reach small pay zones.
- Production facilities have become much smaller in the North Slope. If the Prudhoe Bay oil field were developed with today's technology, its footprint would be 64% smaller, road area would be 58% less, separating facilities would be 50% smaller, and the area affected by drilling pads would be 74% smaller.

OCS Events by Category: 1995-2000

	1995	1996	1997	1998	1999	2000
Blowouts	1	4	5	7	5	9
Collisions	6	5	10	5	10	7
Explosions	0	8	10	4	7	1
Fatalities	8	10	11	14	5	5
Injuries	31	62	83	66	47	63
Fires (Total)	42	86	125	90	75	102
Catastrophic	0	0	0	0	0	0
Major	0	3	2	2	4	1
Minor	3	11	11	7	4	5
Incidental	39	72	111	81	67	95
Unknown	0	0	1	0	0	1

Figure 23. Accidental Events of the OCS by Category: 1995-2000

The above fire classifications are based on the following criteria:

Catastrophic	Destruction of a facility worth more than $10 million
Major	> $1 million in property damage
Minor	> $25,000 but <= $1 million in property damage
Incidental	<= $25,000 in property damage
Unknown	Not enough information to classify

VII. Environmental and Social Impacts—What are They?

Introduction

While the objective of this analysis is to assess the contribution of the OCS in meeting the short term and long term natural gas needs of our nation, the environmental aspects of this contribution must also be examined in regards to MMS's mandate to ensure safe operations and protection of sensitive coastal and marine environments. This means protecting marine, coastal, and human environments from significant long-term negative impacts caused by OCS operations.

A constant supply of fossil fuels not only supports the current standard of living, but also allows the creation of wealth. This, in turn, enables businesses, governments, and other organizations to develop, improve, and promote alternative energy sources, including renewable sources.
While the OCS oil and gas program can be an important part of a bridge to a sustainable future, MMS has little influence over energy consumption patterns and the way in which the wealth created by the program is used. Therefore, MMS must focus on those factors within its authority and mandate, which includes provision of an orderly process for resource exploration and

development, protection of our environmental endowment, and ensuring a fair return to the public for the use of its resources. In the end, the most important contributions MMS can make to the well being of current and future generations are likely to come from its continued efforts to become the best minerals manager possible (DOI/MMS 1999).

Even before the current situation, the demand for natural gas was expected to increase partly as a result of being viewed as the cleanest and most efficient of the fossil fuels. Even in the short run, conversion of more of our fuel burning facilities to natural gas could greatly diminish air pollution and improve the long run sustainability of forests, waters, and farmlands now being negatively affected by acid deposition (e.g. Natural Gas Information and Educational Resourses (NGIER), 1998a; Gujarat Infrastructure Development Board (GIDB), 2000).

The Report of the Secretary-General of the United Nations through the Commission on Sustainable Development stated that the development and use of natural gas are increasingly being advocated because natural gas emits lower levels of greenhouse gases and has a less adverse environmental impact. Compared to coal, for example, the use of natural gas substantially reduces the release of sulfur dioxide, nitrogen oxides, carbon dioxide, ash, particulates, and sludge (GIDB, 2000). It is estimated that use of natural gas could reduce carbon dioxide emissions by as much as 20 percent on a global basis.

This heightened interest in the global environment is demonstrated by such international treaties as the Kyoto Protocol on greenhouse gases. The U.S. Department of State established an Undersecretary for Global Affairs and regional environmental hubs at various U.S. embassies to address environmental issues that do not stop at national boundaries. This translates into a worldwide interest in increasing the production of natural gas. This is not only true in the United States, but also in Europe and Asia. The gas resources in the Caspian region and the Russian Far East will play an important role in addressing Asian environmental objectives.

Should the United States choose to make extensive commitments to reduce carbon dioxide emissions, the expanded use of natural gas is expected to play a large role in meeting emission goals (Kripowicz, 1999), contributing to strategies for mitigating global warming, as proposed in the President's Council on Sustainable Development Report (DOI/MMS 1999). More locally (nationally), natural gas homes can be viewed as environmentally friendly, generating less sulfur dioxide (a cause of acid rain), less particulate matter (which contributes to breathing problems), and less carbon monoxide. According to 1998 statistics, more than half of all homes in the U.S., and more than 60 percent of newly constructed homes, use natural gas for heating and appliances (NGIER, 1998b). Also, with the increase in electricity use in response to the demands of the new economy, natural gas is being used more extensively for power generation plants. This view is partially a reflection of the fact that it is easier to get permits for natural gas power plants than ones fueled by either coal or oil. This trend is also expected to continue if power plants, in order to comply with the lower CO_2 limitations, shift away from coal to natural gas (DOE Report #: SR/OIAF/ 2000-05).

Natural Gas vs. Oil Production: Comparison of Onshore Impacts from OCS Activities

General information regarding the impacts of offshore exploration and development for natural gas and oil maybe found in MMS Environmental Impact Statements (e.g., MMS 97-0033 and MMS 98-0008). Offshore impacts that could occur from offshore exploration and development activities are similar for both natural gas and oil. Issues concerning noise and disturbance, muds and cuttings (discharges), and space-use conflicts would be the same.

Most onshore impacts that could occur from offshore exploration and development activities are also similar for both natural gas and oil. Transport of personnel, supplies, and equipment via boats or helicopters from shore-bases to offshore facilities and back occur in a similar fashion and frequency for both oil and gas production facilities; the same shore facilities support all of the transport traffic. The potential for a fuel spill from OCS-related vessels or from the drilling rig or production platform is the same for both oil and gas operations.

Potential impacts to seafloor communities and onshore habitats from the emplacement of pipelines are similar for pipelines transporting oil or gas. Both gas-processing plants and oil refineries are highly computerized/automated so employment impacts are similar. With such similarities an operator's decision on whether to develop a natural gas discovery versus an oil discovery (assuming the operator has both) is based on the estimated reserves, the location of the field, the anticipated difficulty in developing the field, existing nearby infrastructure, and the price of oil versus natural gas; that is, it's a capital budgeting decision.

Regarding differences, exploration and development for natural gas has an extremely low likelihood of occurrence of a spill of liquid hydrocarbons. With natural gas production from a "gas only discovery" the risk of a major oil spill from a blowout or other accident is eliminated. While natural gas is transported by pipeline to gas-processing plants onshore, with no possibility of an oil spill, there is the potential for oil spills from damage to the pipelines transporting oil. Oil is also sometimes barged to refineries, which creates an additional possibility for a spill and potential, portside air-quality impacts. In general, flow assurance chemicals used for natural gas pipelines are also less toxic than those used in oil pipelines.

Pipelines transporting natural gas are also viewed as safer than those transporting oil as demonstrated by the Programmatic Essential Fish Habitat Consultation between MMS and the National Marine Fisheries Service. Oil pipelines must be 300 ft from any topographic feature; natural gas pipelines, on the other hand, must only be 100 ft away.

While a concise breakdown of petroleum hydrocarbon sources in the marine environment is beyond the scope of this report, a 1985 National Academy of Sciences study (NAS, 1985) stated that worldwide offshore oil and gas development is responsible for only 2 percent of the petroleum hydrocarbons in the world's marine environment (Figure 24).

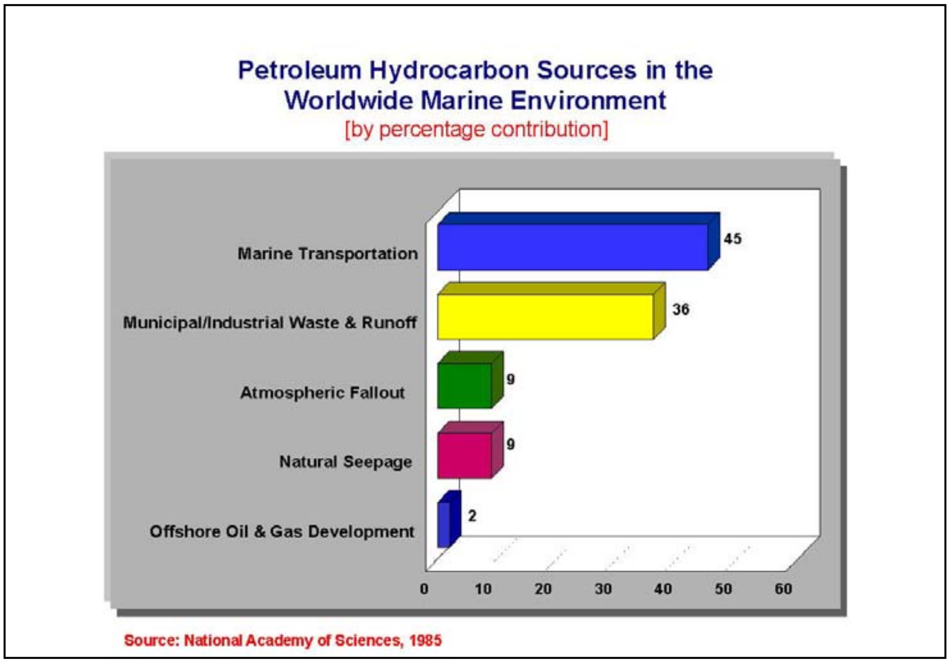


Figure 24. Petroleum Hydrocarbons in the World's Marine Environment

Produced water discharges, which may have adverse cumulative impact to coastal water quality, are also typically less in volume for natural gas production than for oil production. However, the volume of sour gas in an H_2S pipeline would generally be greater for a sour gas production facility than for any sour gas associated with an oil production facility.

Over the next 40 years no new oil refineries are projected to be built; only expansions are projected due in part to the view of "too many environmental hurdles." At the same time, as many as nine gas-processing plants are projected to be built, in addition to many expansions; major employment impacts during construction are expected.

New gas-processing plants would also necessitate new pipelines. The current gas distribution network is strained resulting in calls to accelerate federal approval of new projects (new pipelines). Plans which have been discussed include a pipeline to Florida crossing hundreds of miles of Gulf of Mexico seafloor; a pipeline from the North Slope, Alaska, to the lower 48; new pipelines in the U.S. Rockies; and possibly underwater pipelines for Lake Erie, Lake Michigan, and the coast of New England.

Space-use Conflicts with the Commercial Fishing Industry

The area occupied by structure, anchor cables, and safety zones associated with OCS activities would be unavailable to commercial fishermen and could cause space-use conflicts. Exploratory drilling rigs would spend approximately 30-150 days on site and would cause short-lived interference to commercial fishing. A bottom-founded major production platform in shallow water, with a surrounding 100-m navigational safety zone, requires approximately 6 hectares (ha) of space (14.8 acres). A floating production system in deeper water requires as much as 5 ha (12.4 acres) of space. While these production areas would also be unavailable long-term to commercial fishermen, anecdotal evidence has lead some to suggest that these commercially "unfishable" structures may function as de facto marine preserves.

Underwater OCS obstructions, such as pipelines, cause gear conflicts that result in losses of trawls and catch, business downtime, and vessel damage. However, all pipelines in water depths less than 61 m (200 ft) must be buried, and their locations made public knowledge. Although Gulf fishermen have experienced economic loss from gear conflicts, the loss for a fiscal year has historically been less than 0.1 percent of the value of the same fiscal year's commercial fisheries landings. In addition, most financial losses from gear conflicts are covered by the Fishermen's Contingency Fund.

Climate Change

To address one of the more significant and widely debated environmental issues of the coming century, global climate change, the oil and gas industry is beginning to monitor the implications of its operations.

The question of air emissions from OCS facilities and operations is one that can generate a lot of debate. Measures taken by MMS and industry to control oil spills and other sources of pollution in the ocean have been highly effective on the U.S. Outer Continental Shelf. In response to this success, the focus of environmental attention on the offshore industry has shifted to air pollution. Indeed, more stringent standards may be necessary in the future as air emissions from adjacent onshore sources increase and we learn more about the effects of air pollution on natural and human environments (DOI/MMS 1999).

The Use of Natural Gas and the Production of Greenhouse Gases

The Report of the Secretary-General of the United Nations through the Commission on Sustainable Development stated that the development and use of natural gas are increasingly being advocated because natural gas emits lower levels of greenhouse gases and has a less adverse environmental impact. In fact, one of the three guiding principles endorsed by the Secretary of the Interior in developing the current OCS 5-Year Oil and Gas Program (1997-2002) was the use of natural gas as an environmentally preferred fuel.

According to the DOE (DOE Report #: SR/OIAF/2000-05) over the next decade, power plant operators may face significant requirements to reduce emissions of not only sulfur dioxide (SO_2), nitrogen oxides (NO_x), and mercury (Hg), but also carbon dioxide (CO_2). To comply with lower NOx and SO_2 caps, power companies are expected to invest primarily in emission control equipment; however, to comply with CO_2 limitations, they are expected to shift away from coal to natural gas. The use of natural gas to generate electricity does contribute CO_2 to the atmosphere; however, natural gas has approximately 60 percent of the carbon content of coal on an energy-equivalency basis (Carlin, 2000).

Environmental Aspects of the Utilization of Naturally Occurring Gas Hydrates

Although the actual production of energy from the recovery of naturally occurring gas hydrates found on the U.S continental slope maybe a decade off, the environmental aspects of utilizing this resource are already being discussed (see Boatman and Peterson, 2000).

Methane Hydrates and Climate Change

One of the main reasons that methane hydrates are appearing in the scientific literature at present is their possible involvement in climate change. Researchers argue that increases in the concentration of atmospheric greenhouse gases, such as methane (natural gas) and carbon dioxide, will result in increases in the amount of heat retained by the Earth's atmosphere. Methane is both sequestered and released by methane hydrates, depending on the pressure and temperature conditions. There is evidence to suggest that destabilized gas hydrates can induce landslides and seafloor subsidence, and thereby release large volumes of methane into the atmosphere (Paull et al., 1991 and Dillon et al., 1998). However, mechanisms of release and the relationships between sea level, pressure changes due to sedimentation, ocean temperature, hydrate dissociation, and the frequency of methane release events have yet to be characterized (Dillon et al., 1998).

Whether or not the contribution of methane released from gas hydrates now and in the past is large enough to affect global climate is debatable. Kvenvolden (1988) concludes that the amount of methane being released at present is probably not large and will not contribute significantly to the global warming phenomenon. Paull et al. (1991), however, proposes a larger role for hydrates in climate change by suggesting that methane originating from offshore hydrates may be released to the atmosphere in large "spikes," which may have played a role in limiting past glacier advances. Max and Lowrie (1996) question how much methane released from hydrates would actually reach the atmosphere, since a significant portion may dissolve in seawater or be oxidized by the sulfates immediately after release.

Protecting Chemosynthetic Communities Associated with Gas Hydrates

The MMS has funded two large scale studies on the chemosynthetic communities that thrive, in part, on methane hydrates in the Gulf of Mexico. The study, *Northern Gulf of Mexico Continental Slope Chemosynthetic Communities Program*, was completed in 1995 (MacDonald et al., 1995). An ongoing project, Stability and Change in Gulf of Mexico Chemosynthetic Communities, was initiated in 1995. These two projects together span a decade, 1991-2001. The first study included a literature review and an examination of the regional distribution of chemosynthetic communities across the continental slope in the northern Gulf and the geologic and geophysical characterization of associated hydrocarbon deposits, including gas hydrates. It described the ages of the habitats and the general ecology of the chemosynthetic communities thriving on gas hydrates near oil and gas seeps.

The ongoing study is designed to provide MMS with the information necessary to manage these sensitive biologic communities effectively. This study will provide an understanding of the processes that control the distribution, health, and succession of these communities and the effects of oil and gas exploration, including gas hydrate disturbances, on these communities. At the regional level, this effort is focusing on the geological, chemical, and oceanographic processes that maintain the stability of these communities.

Environmental Effects of Proposed Methane Hydrate Production Methods

If plans are ever submitted to produce methane from offshore hydrates, MMS will need to develop an environmental assessment (EA) or possibly an environmental impact statement (EIS). Extraction of methane hydrates from the seafloor could lead to subsidence. A deeper understanding of the geological setting and the effects of the removal of hydrate is needed before production can begin (Max and Cruickshank, 1999). The regulations in place that govern conventional oil and gas may not apply to methane hydrates. The MMS will need to make the assessments and modify the regulations before the start of production. S. 330 proposes a commercial demonstration will be in operation by 2015. In Alaska, the permafrost hydrate resource, which may be the first to be developed, needs to be investigated.

Mitigation of Human/Social Impacts

Mitigation measures can be specifically and selectively applied at policy, program and project levels. Policy adjustments can alter the mix and balance of planning goals and objectives in accordance with public preferences. Program alterations can similarly revise planning guidelines and design specifications. Project modifications can tailor operating procedures and activities to suit local conditions, for example, by preventing industry activity from occurring during bowhead whale harvest seasons off the North Slope of Alaska.

Stipulations are another form of mitigation. The Bureau’s stipulations may cover a range of social and human impacts. These stipulations may include issues pertaining to commercial and recreational fishing, safety and technology, the military, cultural resources and subsistence. Stipulations can be put in place to avoid conflict between development practices and social institutions, organizations and structures as well as individual level conflicts.

Mitigation can also occur through the research process itself. For example, through research MMS can identify suitable areas for pipeline construction and onshore infrastructure development based on environmental and socioeconomic features of the area under investigation. Research can characterize potential impacts and recommend mitigation measures (at Federal, State and local levels) and special practices to minimize harmful impacts as well as identify areas that should be avoided.

In the Gulf of Mexico, the study *Economic Effects of Coastal Alabama and Destin Dome Offshore Natural Gas Exploration, Development, and Production* (Plater et al, 1999) concluded that no new onshore infrastructure would be needed to service offshore gas in the Destin Dome area, indicating that the carrying capacity of infrastructure is adequate in this area. Similarly in California, the *California Offshore Oil and Gas Energy Resources Study* (Dames and Moore, 2000) identified several scenarios of development. Identifying how various levels of development would demand or not demand new physical infrastructure.

In addition to these more concrete identifiers there are also forms of mitigation that exist as a by-product of good methodological research designs. Certain methodologies can empower local people through outreach and knowledge to be proactive in their own lives by learning and critiquing their situation and becoming participants in shaping the future of their communities. Many social science studies now require that special reports be written specifically to the communities where potential impacts occur so local people can incorporate this knowledge into their decisionmaking processes (the MMS ongoing study *Social and Economic Impacts of OCS Activity on Families and Individuals* is an example of this type of outreach effort). In addition, social science research designs, such as ethnographic methodologies and community participant ethnographies, have lead to a diffusion of these techniques by providing social as well as physical science with the tools necessary to capture traditional/local knowledge and juxtapose this local knowledge with scientific findings.

In this sense, this allows MMS to respond to community request and concerns. For example, in the North Slope Borough of Alaska (NSB), MMS will be conducting a new study effort titled *Quantitative Description of Potential Effects of OCS Activities of Bowhead Whale Hunting Subsistence Activities in the Beaufort Sea*. The purpose of this study is to document concerns and fears of NSB residents due to potential impacts from OCS activity and the subsistence hunt in particular. This study was manifested out of several meetings with the NSB community people and whale hunters. The study is being conducted at the request of the NSB communities.

When characterizing social impacts from OCS gas or oil activity, social science must remain objective. Impacts from industrial development of any kind can be both negative and positive. That is, a positive impact for one individual may be a negative impact for another. Therefore social science in MMS attempts to frame social phenomena as patterns over time in order to determine and identify impacts. The sociological toolbox does not contain tools to allow scientists to judge or determine what is right or wrong/good or bad, but merely tools of investigation. Conceptually, mitigation with its negative connotation exhibits immediate bias prior to investigation. Through the epochal irritations of modernization, terms such as "mitigation" have become common, yet development creates social change and affects various people in various ways, not merely those in close proximity to a particular project. This change has global, national and local affects that can be identified and dealt with by characterizing determinants of community capacity for change.

Moving Beyond Conflict to Consensus

Owing to both the benefits and cost associated with the OCS Program, there has been a great deal of controversy, including years of concern regarding the program's environmental and socioeconomic impacts. To examine these concerns, the OCS Policy Committee conducted its own review of OCS legislation. Their report, *Moving Beyond Conflict to Consensus*, was published in 1993 and included recommendations pertaining to moratoria areas, lease cancellation and buyback, impact assistance and revenue sharing, incentives to industry, and environmental science and review panels.

One Subcommittees' recommendation most pertinent to the subject at hand is that the OCS decisionmaking process should be based upon a building of consensus among all program stakeholders. The process should provide for the inclusion of interested and affected parties in more of a partnership role that would be assured over the long-term. These interested and affected parties would be brought together and encouraged to take a cooperative approach to managing OCS activities. This approach, however, would require flexibility to meet the needs of different areas of the OCS and the parties involved; but, if successful, could lead to a comprehensive approach to ocean management involving all state and federal agencies with a stake in OCS program activities and related issues.

Regarding their recommendations concerning environmental science, several of their points are pertinent today; namely, in order to support good decisions, "the existing environmental studies program is in need of adequate funding, good science, and appropriate cooperation among MMS and other involved parties." Another recommendation, that "MMS should develop a comprehensive, efficient, and accessible data management and dissemination system for the studies program' was addressed in the newly released Environmental Studies Program Information System (ESPIS) and the program's new web site, making descriptions of all ongoing environmental and socioeconomic studies available on line for the first time.

Bibliography

Boatman, M. C., and J. Peterson. 2000. Oceanic gas hydrate research and activities review. U.S. Dept. of the Interior, Minerals Management Service, Gulf of Mexico OCS Region, New Orleans, LA. OCS Study MMS 2000-017, 68 pp.

Carlin, J. 2000. Environmental externalities in electric power markets: Acid rain, urban ozone, and climate change. U.S. Department of Energy, Feature Article, March 19, 2001. http://www.eia.doe.gov/cneaf/pubs_html/rea/feature1.html.

Cochener, J. C. 2000. Diversified natural gas supply growth. Presentation at MMS Gas Conference, Houston, Texas, April 2000.

Dames and Moore. 2000. California offshore oil and gas energy resources study. U.S. Dept. of the Interior, Minerals Management Service, Pacific OCS Region, Camarillo, CA. OCS Study MMS 99-0043.

De Cort, T. et al. 2001. Future of Gulf of Mexico and Atlantic OCS gas production 2000 – 2020. Minerals Management Service.

Dillon, W. P., W. W. Danforth, D. R. Hutchinson, R. M. Drury, M. H. Taylor, and J. S. Booth, 1998. "Evidence for faulting related to dissociation of gas hydrate and release of methane off the southeastern United States." In *Gas Hydrates: Relevance to World Margin Stability and Climate Change*. Special Publication 137. Ed. J.-P. Henriet and J. Mienert. London: The Geological Society.

DOE/NPC Workshop. 2001. Surveying the milestones for meeting the challenges of the Nation's growing natural gas demand, Washington, D.C., March 5-6, 2001.

Dunkel, C. A. and Piper, K. A. 1997. 1995 National assessment of United States oil and gas resources assessment of the Pacific Outer Continental Shelf Region. OCS Report MMS 97-0019. 207 pages.

Energy Information Administration (DOE/EIA). 1999. Alternatives to traditional transportation fuels 1999. March 19, 2001. http://www.eia.doe.gov/cneaf/alternate/page/datatables/atf1-13_00.html.

Energy Information Administration (DOE/EIA). 2000. Annual Energy Outlook (AEO).

Energy Information Administration (DOE/EIA). February 2001. Monthly Energy Review.

Energy Information Administration (DOE/EIA). 2001. Annual Energy Outlook (AEO).

Glauthier, T. J. 2000. Congressional testimony to the Committee on Energy and Natural Resources, September 14, 2000. http://www.fe.doe.gov/testimony/00_glauthier_ansgas.html.

GRI. 1999. Baseline projection data book, Gas Research Institute.

Gujarat Infrastructure Development Board (GIDB). 2000. The environmental impact of natural gas, March 19, 2001. http://www.gidb.org/.

Gulf Canada. 2000. Transportation of natural gas to markets. Presentation at Potential Gas Committee Meeting, Calgary, Canada. D. Auchinleck, President and CEO.

Hobbs, W. E. 2001. Impact of new gas dynamics. Presentation at Ziff Energy's Conference – North American Gas Strategies, Houston, Texas, April 3, 2001. Williams Energy Service.

International Association of Natural Gas Vehicles (IANGV). 2001. Chinese NGV production statistics, March 19, 2001. http://www.iangv.org/html/ngv/stats.html#8.

Kripowicz, R. S. 1999. Statement before the U.S. House of Representatives Committee on Science, Subcommittee on Energy and Environment. Hearing on S. 330 and H R. 1753, The Methane Hydrate Research and Development Act of 1999, Washington, D.C., May 12, 1999.

Kvenvolden, K. A. 1988. Methane hydrates and global climate. Global Biogeochemical Cycles. 2:221-229.

MacDonald, I. R., W. W. Schroeder, and J. M. Brooks. 1995. Chemosynthetic ecosystems studies final report. Prepared by Geochemical and Environmental Research Group. U.S. Dept. of the Interior, Minerals Management Service, Gulf of Mexico OCS Region, New Orleans, LA. OCS Study MMS 95-023. 338 pp.

Max, M. D. and M. J. Cruickshank. 1999. Extraction of methane from oceanic hydrate system deposits. Proceedings of the Offshore Technology Conference, OTC 10727.

Max, M. D. and A. Lowrie. 1996. Oceanic methane hydrates: A frontier gas resource. Journal of Petroleum Geology. 19:41-56.

National Academy of Sciences. 1985. Oil in the sea: Inputs, fates, and effects. Washington D.C.: National Academy Press.

National Energy Board. 1999. Annual energy estimates. Canada: National Energy Board.

National Research Council. 1994. Environmental information for Outer Continental Shelf oil and gas decisions.

Natural Gas Information and Educational Resources (NGIER). 1998a. The environmental impact of natural gas, March 19, 2001. http://www.naturalgas.org/ENVIRON2.HTM.

Natural Gas Information and Educational Resources (NGIER). 1998b. Residential uses for natural gas, March 19, 2001. http://www.naturalgas.org/RES2.HTM.

Natural Gas in Nontechnical Language. Institute of Gas Technology. Ed. R. Bushby.
NPC. 1999. Natural gas: Meeting the challenges of the Nation's natural gas demand. A report of the National Petroleum Council.

Paull, C. K., W. Ussler, III, and W. P. Dillon. 1991. Is the extent of glaciation limited by marine gas-hydrates? Geophysical Research Letters. 18:432-434.

Plater, J. R. J. Q. Kelley, W. W. Wade, and R. T. Mott. 1999. Economic effects of coastal Alabama and Destin Dome offshore natural gas exploration, development and production. U.S. Dept. of the Interior, Minerals Management Service, Gulf of Mexico OCS Region, New Orleans, LA. OCS Study MMS 2000-044. 219 pp.

Ray, P. K. et al. April 2000. Future natural gas supply from the OCS: An assessment of the role of the OCS as supplier of the Nation's future energy needs.

U.S. Department of Energy. 1998. LNG buses, Idaho National Engineering and Environmental Laboratory. INEEL Newsletter, November 1998. http://www.inel.gov/resources/newsletters/inside/november98/main.htm.

U.S. Department of Energy. 2000. Analysis of strategies for reducing multiple emissions from power plants: Sulfur dioxide, nitrogen oxides, and carbon dioxide. DOE Report#: SR/OIAF/2000-05. Abstract. 15 pp. http://www.eia.doe.gov/oiaf/servicerpt/powerplants/index.html.

U.S. Department of Energy. Office of Fossil Energy. 1999. Environmental benefits of advanced oil and gas exploration and production technology.

U.S. Department of the Interior. Minerals Management Service. 1999. OCS resource management and sustainable development. March 19, 2001, 20 pp. http://www.mms.gov/sd/sdreport.htm.

U.S. Department of the Interior. Minerals Management Service. 2000. Outer Continental Shelf petroleum assessment 2000.

U.S. Department of the Interior. Minerals Management Service. 2001. Gulf of Mexico production projection.

U.S. Department of the Interior. Minerals Management Service. Gulf of Mexico OCS Region, New Orleans, LA. 1997. Gulf of Mexico OCS oil and gas lease sales 169, 172, 175, 178, and 182: Central Planning Area—final environmental impact statement. OCS EIS/EA MMS 97-0033. Available from NTIS, Springfield, VA.

U.S. Department of the Interior. Minerals Management Service. Gulf of Mexico OCS Region, New Orleans, LA. 1997. Gulf of Mexico OCS oil and gas lease sales 171, 174, 177, and 180: Western Planning Area—final environmental impact statement. OCS EIS/EA MMS 98-0008. Available from NTIS, Springfield, VA.

Appendix 1. Natural Gas Subcommittee Charter

Charter

This Subcommittee on Natural Gas is established by the Outer Continental Shelf (OCS) Policy Committee of the Minerals Management Advisory Board. The purpose of this subcommittee is to independently review and evaluate information on natural gas, and then to provide an assessment of the contribution the OCS can make to meeting the short term and long term natural gas needs of the United States within the framework of a national energy policy.

This assessment by the subcommittee will help guide the Secretary of the Interior and the Minerals Management Service (MMS) in identifying the role of the OCS in meeting future natural gas demand. The subcommittee will assess natural gas information and studies, including:

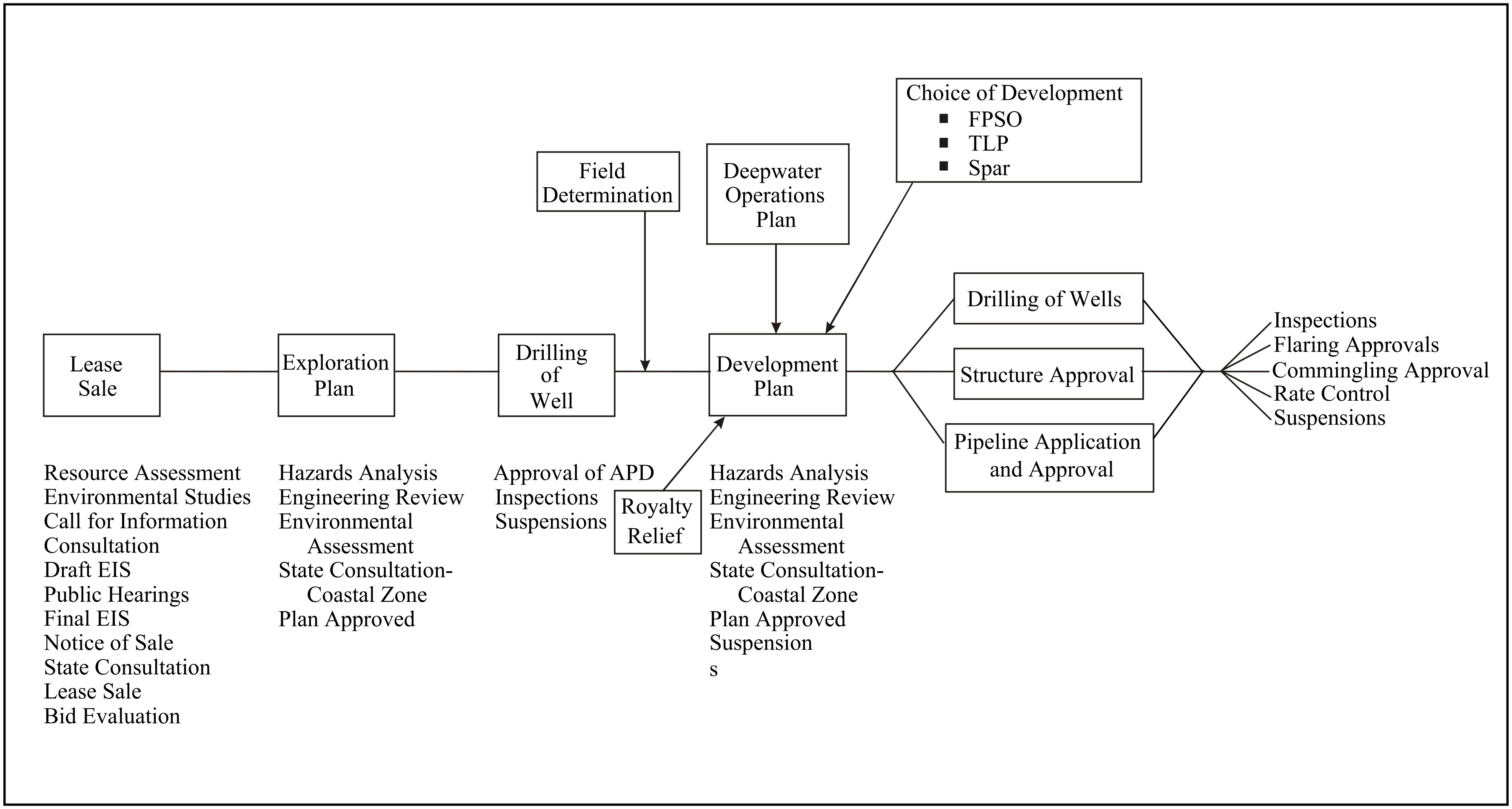
- Recent reports such as the National Petroleum Council gas study on supply, demand, and infrastructure/transport needs.
- National energy policy, including moratoria policies and policies on energy alternatives to natural gas, relevant state and regional interests regarding fuel diversity, exploration and development, and energy conservation.
- Interagency cooperation (e.g. Interagency Gas Working Group).
- The relative positions and policies on natural gas currently held by Department of Interior agencies and industry groups.
- Liaison with appropriate Canadian government bureaus.
- Information on: OCS resource potential (using the updated National Assessment and other sources), current OCS reserves, alternative sources of supply (Canada, Mexico, LNG, etc.), demand forecasts, gas hydrates, possible economic incentives, environmental aspects of natural gas production and use, possible operational concerns including the development of new environmentally responsible technologies.
- An assessment of how MMS's Offshore program goals, policies and objectives may impact these variables.

The aim of the subcommittee's efforts is to identify potential issues and assist the Department and the MMS in identifying program and policy options to address the natural gas needs of the nation. The subcommittee may suggest actions that MMS and others can take, including short term and long term efforts, to avoid energy supply shortfall. The subcommittee may also identify and evaluate outreach strategies and opportunities for the Bureau and the offshore oil and gas industry. During the course of its work, the subcommittee will keep the Policy Committee apprised of information links and sources for natural gas information that may be of interest.

Each of the above tasks would form the underpinnings for a position paper produced by the subcommittee for the OCS Policy Committee to review and discuss at the May 2001 meeting.

Members	***Jerome M. Selby (Chair)***, Consultant for the Mayor of Anchorage, Anchorage, Alaska ***Patrick S. Galvin***, Division of Governmental Coordination, Juneau, Alaska ***Robert R. Jordan***, Delaware Geological Survey, Newark, Delaware ***Lisa P. Edgar***, Department of Environmental Protection, Tallahassee, Florida* ***Jack C. Caldwell***, Louisiana Department of Natural Resources, Baton Rouge, Louisiana ***Lawrence C. Schmidt***, Department of Environmental Protection, Trenton, New Jersey ***Donna Moffitt***, Director, NC Division of Coastal Management, NCDENR, Raleigh, North Carolina ***Bruce F. Vild***, Statewide Planning Program, Providence, Rhode Island ***Andrew L. Hardiman***, Chevron Gulf of Mexico Deepwater Business Unit, New Orleans, Louisiana ***Paul L. Kelly***, Rowan Companies, Inc., Houston, Texas ***George N. Ahmaogak, Sr.***, Mayor, North Slope Borough, Barrow, Alaska Environmental Community advisor *On April 10, 2001, Florida withdrew from the Subcommittee due to workload conflict.
Subcommittee Staff	***Michael Hunt***, Minerals Management Service, Herndon, VA ***Cheri Hunter***, Minerals Management Service, Herndon, VA

Appendix 2. Workload from an OCS Lease



Appendix 3. Natural Gas Regulatory Background

It was 1885 when natural gas was first regulated by a State (i.e., the Massachusetts Board of Gas Commissioners). In 1907 the first public utility commissions were enacted in Wisconsin and New York. At the Federal level, the Interstate Commerce Act was passed in 1887. It affected operations of companies transporting products across State lines, but an amendment in 1906 specifically excluded natural gas pipeline companies. One can see that Federal and State regulation of natural gas dates back well over 100 years. The following table from *Natural Gas in Nontechnical Language* by the Institute of Gas Technology is presented as a brief history of natural gas regulations.

Natural Gas in Nontechnical Language, *Institute of Gas Technology: A Regulatory History*

Action	Year	Summary
Natural Gas Act	1938	Authorized the Federal Power Commission (FPC) to regulate interstate pipeline companies.
U.S. Supreme Court ruling in Phillips Petroleum Company Case	1954	Gave the FPC authority to regulate the price that producers charge for natural gas.
Federal Energy Administration Act	1974	Gave the administration power to allocate and control pricing of scarce petroleum products including gas.
Department of Energy (DOE) Organization Act	1974	Created the DOE and the Federal Energy Regulatory Commission (FERC).
National Energy Act (five parts) National Energy Conservation Policy Act Power Plant and Industrial Fuel Use Act Public Utility Regulatory Policies Act Natural Gas Policy Act Energy Tax Act	1978	 Encouraged utilities and their customers to conserve energy. Prohibited the use of natural gas in utility and industrial boilers Encouraged congeneration of heat and power by industrial customers. Gave producers more incentive by phasing out regulation of gas prices at the wellhead. Penalized low-mileage autos and rewarded conservation measures.
Natural Gas Wellhead Decontrol Act	1989	Completed deregulation of wellhead gas prices.
Federal Energy Regulatory Commission Orders (436, 500, 636)	1985-1993	Deregulated pipeline transportation, allowing customers to buy gas directly.
Clean Air Act Amendments	1990	Empowered the Environmental Protection Agency to set national air quality standards to curb acid rain, urban pollution, and toxic emissions.
Energy Policy Act	1992	Mandated purchase of alternative fuel fleet vehicles to reduce America's dependence on foreign oil.

Appendix 4. Glossary

Alternative fuel vehicles. Various fuels besides the conventional gasoline and diesel fuels can be used to power cars and other motor vehicles. Many of these alternative fuels are derived ultimately from natural gas or oil.

Associated gas. Natural gas is frequently found in reservoirs also holding crude oil. Solution gas is mixed with the oil and must be separated out.

Conservation. Conservation means using natural resources as efficiently as possible. Energy conservation can mean using a minimum of energy to accomplish a task, although, for many people, conservation means using less energy without regard to efficiency (e.g. lowering thermostats). Petroleum geologists and engineers typically use the term to mean producing oil and gas in a way that does not sacrifice maximum resource recovery for other goals, such as speedy production.

Consumption and demand. When used precisely, demand means the various amounts of a good that a person would take for different prices or incomes. Consumption is the amount actually used at current prices. Informally, demand can mean the same as consumption.

Deep and shallow water. Water depths of the OCS are categorized variously. The boundary between shallow and deep water is sometimes set at 1,000 feet, and sometimes at 200 meters.

Greenhouse gas. These tend to trap heat from sunlight in the atmosphere. The gases including some naturally occuring, such as water vapor, carbon dioxide, methane, and nitrous oxide, and some that are man-made, such as chlorofluorocarbons, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride.

Hydrates. These are compounds of water and hydrocarbons. Ice crystals holding natural gases, such as methane, exist on the seafloor, and the potential fuel gas resource in this form appears to be substantial.

Lease. The Federal government conveys limited rights to oil and gas land by means of contracts. OCS leases last 5 to 10 years unless extended by continuing production.

Liquified natural gas. Natural gas can be cooled to become a liquid in order to transport it in tanks.

Moratorium and withdrawal (leasing). Beginning in 1982, Congress annually established "moratoria" that prohibited the Interior Department from leasing in various areas of the OCS. The President, too, can "withdraw" Federal lands from leasing, as President Bush did in 1990 and President Clinton did in 1998.

Non-associated gas. Free gas not in contact with crude oil in the reservoir.

OCS Lands Act. The Outer Continental Shelf Lands Act, USC 43:29, authorizes leasing in the OCS and sets terms of MMS administration.

Outer Continental Shelf. The submerged lands, subsoil, and seabeds termed OCS are administered by the Federal government. It lies between the seaward extent of the States' jurisdiction (about 3 miles, more in parts of the Gulf of Mexico) and the seaward extent of Federal jurisdiction (about 200 miles).

Reserves and resources. Oil and gas reserves are amounts proven to exist, normally by drilling wells into reservoirs. Resources is a broader term, covering all the oil and gas that might, technically, be discovered and produced someday. Various divisions are made, such as discovered vs. undiscovered and economic vs. uneconomic resources.

Unconventional gas. Unconventional gas refers to natural gas extracted from coalbeds and from low-permeability sandstone and shale formations.

Acronyms

AEO	*Annual Energy Outlook*
AFV	Alternative-fuel vehicles
ANGTS	Alaska Natural Gas Transportation System
ANWR	Arctic National Wildlife Refuge
Bbl	Billion barrels (of oil)
Bcf, Bcfd	Billion cubic feet, Bcf per day (of gas)
BOE	Barrels of oil equivalent
Btu	British thermal unit
CNG	Compressed natural gas
DOE	U.S. Department of Energy
DOT	U.S. Department of Transportation
EEA	Energy and Environmental Analysis, Inc.
EIA	Energy Information Administration (of the U.S. Energy Department)
EIS	Environmental Impact Statement
GOM	Gulf of Mexico
GRI	Gas Research Institute
LNG	Liquified natural gas
Mcf	Thousand cubic feet (of gas)
MMcf	Million cubic feet (of gas)
MMS	Minerals Management Service (of the U.S. Department of the Interior)
NEB	National Energy Board (Canada)
NPC	National Petroleum Council
NPRA	National Petroleum Reserve in Alaska
NRC	National Reseach Council
OCS	Outer Continental Shelf
ROV	Remotely Operated Vehicle
Tcf	Trillion cubic feet (of gas)
TIMS	Technical Information Management System (of MMS)
USGS	U.S. Geological Survey (of the U.S. Department of the Interior)