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Oil and Gas Exploration and Development on Public Lands

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Summary

The U.S. Congress and the Administration are involved in a major policy debate over oil and gas development from federal lands and from federal mineral estate underlying certain privately owned lands. Within the framework of U.S. public lands policy, restrictions and withdrawals have affected the amount of land that can be developed. The Energy Policy and Conservation Act Amendments of 2000 (EPCA) mandated a study which was released in January 2003 to assess the oil and gas resource potential underlying restricted federal lands. It concluded that although the amount of land prospected for natural gas that was completely "off-limits" for development was 35.6%, other restrictions and lease stipulations are in place. The conference report to the Energy Policy Act of 2003 (H.R. 6) as well as the scaled-back Senate version of the bill (S. 2095) contains provisions that would address restrictions and impediments to oil and gas development on public lands. The Bush Administration has its own initiatives to expedite the permitting process — considered by some to be a major impediment — on federal lands.

As part of the oil and gas leasing system, lessees must file an application for a permit to drill (APD) for each well. The Bureau of Land Management (BLM) is required to process the APD in 30 days but delays may occur, extending the average approval time to over 120 days. Some approvals have taken over three years. A new process to expedite the APDs has been established at the BLM that includes, among other features, the processing and conducting of environmental analyses on multiple permit applications with similar characteristics.

Energy and mineral industry representatives maintain that federal withdrawals and/or restrictions inhibit mineral exploration and limit the reserve base even when conditions are favorable for development. They further contend that sufficient environmental standards are in place to protect public lands. Critics who oppose opening up more federal lands or the mineral estate under private lands argue that the general environmental requirements are not adequate and that some forms of development threaten water quality and quantity; therefore, certain restrictions and withdrawals are appropriate.

Concern exists regarding natural gas supply and declining production rates. As a result, there is increased interest in potential gas supplies in the Rocky Mountain region. Several resource estimates suggest significant amounts of natural gas on public and private lands in the region, and Rocky Mountain natural gas may become much more important to the overall supply picture.

Elsewhere, the outlook is mixed for increased oil and natural gas production on U.S. public lands. While domestic natural gas production and natural gas imports are expected to rise, it is unclear whether much of the domestic supply will come from public lands that are currently restricted or off-limits. This report will not be updated.

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Introduction

Significant amounts of technically recoverable oil and gas resources are projected to be on federal public lands (see **Table 7**). However, energy development on some of these lands has been restricted because they are considered environmentally sensitive or unique. These restricted areas may contain sizable amounts of oil and natural gas, according to the U.S. Geological Survey (USGS) and the Energy Information Administration (EIA).

The conflict between environmental concerns and the need for increased domestic energy production from public lands is a major policy issue. For example, the conference report on the omnibus energy bill (H.R. 6) and the Senate substitute, S. 2095 has provisions that would examine restrictions and impediments to oil and gas development on public lands, including an evaluation of the current permitting process. Reportedly, reflecting its Energy Task Force recommendations, the Bush Administration has its own initiative to expedite the oil and gas permitting process on federal lands.

Oil and gas development practices have generated considerable debate in Congress since the early years of the industry. Originally, oil and gas resources on public lands could be transferred to private ownership (patented) under the Mining Law of 1872 — essentially, lands containing oil were sold at a fixed price per acre to the first claimant.[1] Conservationists contended that there was widespread abuse of the Mining Law that led to wasteful use of public lands. In 1909 President Taft withdrew 3 million acres of lands prospective for oil in Wyoming and California from availability under the Mining Law of 1872. Taft requested congressional approval for his action, leading to the Pickett Act of 1910 (43 U.S.C. 141-143), which explicitly recognized executive branch authority to make such public lands withdrawals.[2]

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[1]Enactment of the Oil Placer Act of 1897 (29 Stat. 526) resolved the question of whether petroleum or other mineral oils were to be governed by the laws relating to other placer claims. Placer claims are those located on the ground, not fixed to below surface rock.

[2]The Pickett Act was repealed by the Federal Land Policy and Management Act of 1976 (FLPMA) which also modernized the law regarding withdrawals. Under FLPMA (43 USC 1702 (j)), a land withdrawal is defined as "withholding an area of federal land from settlement, sale, location, or entry under some or all of the general land laws, for the purpose of limiting activity under those laws in order to maintain other public values in the area or reserving the area for a particular public purpose or program; or transferring jurisdiction

(continued...)

Congress eventually decided that defense-related minerals — including oil and gas — should remain under federal ownership. As a result, the Mineral Lands Leasing Act of 1920 (30 U.S.C. 181, et. seq.) removed oil and gas from the patenting process and placed it under a leasing system. Under the leasing system, the federal government has raised billions of dollars in revenues from royalties, rents and bonus bids.[3]

Minerals owned by the federal government under lands held privately (patented) creates a "split-estate." There are other split-estate situations as well: surface and mineral rights held by different private interests, or state owned mineral rights and privately held surface rights. Three major federal statutes[4] allowed the federal government to issue patents to land but reserve the right to the minerals. Under these statutes the mineral estate became the dominant estate and the surface use servient. There are specific policies and procedures that must be followed by the mineral estate holder in order to develop minerals. Generally, for oil and gas, a federal lessee must meet one of the following conditions: a surface agreement; written consent or a waiver from the private surface owner for access to the leased lands; payment for loss or damages; or the execution of a bond not less than $1,000. [5] About 11% of the public lands are under the split-estate category. However, in Wyoming 50% of the lands are split-estate and in Montana about 57%.[6]

Environmentalists have supported public land withdrawals and other restrictions because of concern that the Mining Law of 1872 and then the Mineral Leasing Act of 1920 provided inadequate environmental protection. Recently, ranchers and other groups have expressed similar concerns specifically about the impact of development on water and land. Conversely, development supporters contend that numerous environmental laws are now in place to regulate oil and gas development on public lands. They note that the federal government must comply with the National Environmental Policy Act (NEPA) in leasing oil and gas and that the oil and gas industry must comply with applicable requirements of the Clean Water and Clean Air Acts, Safe Drinking Water Act, the Resource Conservation and Recovery Act, and state and federal reclamation standards, among other laws. The industry complains that environmental and other reviews often create long delays in drilling exploratory and production wells on leased lands.

The proposed conference report on a comprehensive energy bill (H.R. 6) and S. 2095 addresses some of the industry and Bush Administration concerns over

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[2](...continued)
over an area of federal land from one department, bureau or agency to another department, bureau or agency."

[3] A bonus bid is an amount paid by the lessee to the lessor for obtaining a lease.

[4] The Coal Lands Act of 1909, 30 U.S.C. 81; the Agricultural Entry Act of 1914, 30 U.S.C. 121-123 and the Stock-Raising Homestead Act of 1916, 43 U.S.C. 291-301.

[5]This information was provided in a BLM Instructional Memorandum, No. 2003-131. Also see 43 CFR 3104, 43 CFR 3814 and 48 FR 48916 (1983) for further details.

[6]Public Lands, Onshore Federal and Indian Minerals in Lands of the U.S., Appendix 7, Sie Ling Chiang, Bureau of Land Management, DOI, December 1, 2000.

increasing domestic oil and natural gas supplies. Title III of H.R. 6 and S. 2095, if enacted, would establish a White House Office of Federal Project Coordination to help expedite permitting on public lands and identify restrictions and impediments to resource development on public lands. Environmentalists and other public land users argue that these provisions would cause harm to the environment and prevent the land from being used in other productive ways. The conference report has been approved by the House but not in the Senate as a result of a cloture motion on November 21, 2003 that did not get the required 60 votes, (57- 40). The Senate's scaled-back substitute bill, S. 2095 is awaiting action.

This report provides a general overview of the oil and gas leasing system on U.S. public lands, including information on permitting, production, and reserves. The report describes the contribution of onshore oil and gas towards meeting U.S. energy demand and discusses current estimates of reserves in restricted areas. An Appendix provides some historical background on lands withdrawn from mineral development, the role of the Bureau of Land Management (BLM), and application of the Federal Land Policy and Management Act (FLPMA) in the context of oil and gas development.

For information on U.S. offshore oil and gas development, see CRS Report RL31521, *Outer Continental Shelf Oil and Gas: Energy Security and Other Major Issues*, by Marc Humphries.

Oil and Gas Leasing on Public Lands

Leasing of onshore federal public lands for oil and gas development is based on multiple-use/ sustained yield Resource Management Plans (RMPs) developed by the Bureau of Land Management in the Department of the Interior. In accordance with those land-use plans, tracts of public land with oil and gas potential are offered for competitive leasing each quarter. After a lease is awarded, a drilling permit is required for each exploratory or production well. Industry has long complained that this process is too lengthy.

In FY2002, the federal government issued 1,765 new oil and gas leases on public lands totaling about 1.4 million acres. Through the end of FY2002, about 18.6 million acres of public lands had been leased for oil and gas development.

Land Use Planning

Under the Federal Land Policy and Management Act (FLPMA), Resource Management Plans or Land Use Plans (43 USC 1712) are required for tracts or areas of public lands prior to development. The Bureau of Land Management (BLM) must consider environmental impacts during land-use planning when RMPs are developed and implemented. RMPs can cover large areas, often hundreds of thousands of acres across multiple counties.

FLPMA requires that RMPs reflect diverse uses — such as timber, grazing, wildlife conservation, recreation, and energy — and consider the needs of present and future generations.[7] Impacts of various uses are identified early in the process so that they can be weighed equitably against one another. The plans are also intended to weigh the various benefits associated with public lands to best serve the community. RMPs must be consistent with environmental regulations and allow meaningful public participation. Through the land-use planning process, the BLM determines which lands with oil and gas potential will be made available for leasing.

The Mineral Leasing Act of 1920, as amended, requires that all public lands available for lease be offered initially to the highest responsible qualified bidder by oral competitive bidding. These auctions are held quarterly by the BLM. The objective of the competitive bid is to provide a "fair market value" return to the federal government for its resources. If no bids are received or the highest bid is less than the $2/acre national minimum acceptable bid, oil and gas leases on these lands are offered on a noncompetitive basis within 30 days. The tracts remain available on a noncompetitive basis for two years.

Tracts available for noncompetitive leasing may be obtained by the first qualified applicant upon payment of a nonrefundable application fee of at least $75. Simultaneous (SIMO) noncompetitive lease applications filed on the day following the competitive lease sale are prioritized through a lottery system. Lease applicants filing on subsequent days are given priority according to the time of filing. (For more details on leasing terms, see Appendix A.)

Geophysical exploration permits on unleased public lands may be issued by BLM. Such exploration does not include drilling for core samples or drilling for oil and gas. The permittee must file a notice of intent with the BLM and must comply with specific practices and procedures spelled out by the surface managing agency (SMA).[8] Once a lease is obtained, the lessee is given exclusive rights to further explore, develop, and produce on that land.

Drilling Permits

After a lease has been obtained, either competitively or noncompetitively, an Application for a Permit to Drill (APD) must be approved for each oil and gas well.[9] As noted in the Mineral Leasing Act, section 226 (g), "no permit to drill on an oil and gas lease issued under this chapter may be granted without the analysis and approval by the Secretary concerned of a plan of operations covering proposed surface-disturbing activities within the lease area."

The application form (APD form 3160-3) must include a drilling plan, a surface use plan, and evidence of bond/surety coverage. The surface use plan should

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[7]See 43 U.S.C. 1702(c) for the definitions of "multiple-use" and "sustained yield."

[8]The surface managing agency or private surface owner has jurisdiction over surface activities including surface disturbance. A surface managing agency may be the U.S. Forest Service, or the state in which the leasing is going to take place. A private surface owner may be an institution or an individual.

[9]43 CFR 3162.3-1, Drilling Application and Plans.

contain information on drillpad location, pad construction, the method for containment and waste disposal, and plans for surface reclamation.

The APD is posted for review for 30 days. Within 5 working days after the 30-day period, the BLM consults with the surface managing agency, whose consent is also required, then notifies the applicant of the results. BLM is required to process the application within the 35-day period. The application may be approved, approved with stipulations, rejected, or delayed for additional analysis or information. The applicant is informed when final action is expected.

Despite the 35-day review requirement, a recent study by a trade association, the Independent Petroleum Association of Mountain States (IPAMS), found that in its region it took an average of 137 days to approve an APD in 2002, up from an average of 84 days in 2001.[10]

Delays in the Permitting Process

One of the major reasons for delays in the issuance of drilling permits cited by both BLM and IPAMS is the need to rewrite outdated RMPs because the surface disturbance anticipated under approved activities may exceed the limits in the old plan because increased natural gas leasing and development is taking place. In these cases, oil and gas leases may have been awarded under an old RMP that must be revised before a drilling permit can be issued. According to the BLM, there are several such plans currently being revised.

Under FLPMA, section 1712, regarding Land Use Plans: "the Secretary [of the Interior] shall with public involvement and consistent with the terms and conditions of this Act, develop, maintain and, when appropriate, revise land use plans which provide by tracts or areas for the use of the public lands." Current planning regulations require preparation of an environmental impact statement (EIS) under the National Environmental Policy Act (43 C.F.R. 1601.06).

After a draft EIS is issued for public comment, an RMP can be approved by the BLM State Director and published with an EIS and record of decision and filed with the Environmental Protection Agency (EPA).

In testimony before the House Committee on Resources, IPAMS asserted that rewriting RMPs can take as long as three years, when less than a decade ago the average time was less than one year. The Association contends that the usefulness of an RMP is now seven years, when in the past they may have been in place for as long as 20 years.[11] The rapid pace of coalbed methane (CBM) development, in particular, has generated new land use concerns that some argue have not been previously incorporated in the RMPs. Environmentalists contend that 20-year-old

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[10] Harvesting Energy: A Report on Natural Gas and Oil Development in the Inter-Mountain West, IPAMS, February 2003.

[11] Testimony of Marc W. Smith, Independent Petroleum Association of Mountain States (IPAMS), Public Lands Advocacy, before the U.S. House Committee on Resources, Subcommittee on Energy and Mineral Resources, March 7, 2001.

plans are not a good basis for land management decisions. The need for a revised/amended RMP would necessarily delay any site-specific analysis conducted in the drilling permit process by the BLM and the surface managing agency. Thus, even when an application for a permit to drill (APD) is in process, the BLM often waits until the new RMP and EIS are complete before proceeding to any site-specific analysis needed to grant the permit.

In April 2003, BLM announced new strategies to expedite the APD process. These include processing and conducting environmental analyses on multiple permit applications with similar characteristics, implementing geographic area development planning for an oil or gas field or an area within a field, establishing a standard operating practice agreement that identifies surface and drilling practices by oil and gas operators, allowing for a block survey of cultural resources, promoting consistent procedures, and revising relevant BLM manuals.[12]

Leasing Restrictions on Oil and Gas Resources

The availability of public lands for oil and gas leasing can be divided into three categories: lands open under standard lease terms, open to leasing with restrictions, and closed to leasing. Areas are closed to leasing pursuant to land withdrawals or other mechanisms. Much of this withdrawn land consists of wilderness areas, national parks and monuments, and other unique and environmentally sensitive areas that are unlikely to ever be reopened to oil and gas leasing.[13] Some lands are closed to leasing pending land use planning or NEPA compliance, while other areas are closed because of federal land management decisions on endangered species habitat or historical sites. Some of those restricted areas may be opened by future administrative decisions.

A BLM study[14] determined that of the approximately 700 million acres of federal subsurface minerals under the agency's jurisdiction in 2000, approximately 165 million acres have been withdrawn from mineral entry, leasing, and sale, subject to valid existing subsurface mineral rights.[15] Lands in the National Park System (except National Recreation Areas), Wilderness Preservation System, and the Arctic National Wildlife Refuge (ANWR) are among those that are statutorily withdrawn. Also of the 700 million acres, mineral development on another 182 million acres was subject to the approval of the surface management agency, and must not be in conflict with land designations and plans, according to the BLM. Wildlife refuges

[12]DOI/BLM Instruction Memorandum No. 2003-152, Application for Permit to Drill (APD) Process Improvement #1 — Comprehensive Strategies, 4/14/03.

[13]Statutory and other types of withdrawals are discussed in greater detail in Appendix B.

[14]Public Lands, Onshore Federal and Indian Minerals in Lands of the U.S., Responsibilities of the BLM, by Sie Ling Chiang, U.S. DOI /BLM, December 1, 2000.

[15]When valid existing rights are in place, producers are sometimes allowed to continue or begin production on these lands. Sometimes they are provided compensation either through a buyout or a land swap by the federal government.

(except ANWR), wilderness study areas, and roadless areas are examples of lands in this category, although many other wildlife refuges also are withdrawn from leasing.

Public lands that are open to leasing may be subject to a variety of restrictions imposed by the Department of the Interior. Such restrictions include leasing with no surface occupancy, areas generally off-limits with the exception of directional drilling; leasing with timing limitations, which protect wildlife during certain times of the year; and leasing with controlled surface use, which requires a mitigation plan for specific areas under the lease. Industry sources claim some of these lease stipulations are so stringent that they constitute "de facto" closures to oil and gas development. However, development has proceeded under some of these stipulations.

Energy and mineral industry representatives maintain that federal withdrawals inhibit exploration and limit the reserve base even when conditions are favorable for production. The industry argues that substantial amounts of public land have been unnecessarily withdrawn through administrative actions to pursue preservation goals. However, environmental groups and others generally contend the withdrawals are the most effective protection for the non-mineral values of public lands.

Rocky Mountain Region

The Rocky Mountain region accounts for 37% of the natural gas and 17% of the crude oil projections of the technically recoverable resource base on public lands in the lower 48 states.[16] According to the EPCA study noted below, 60% of the undiscovered resource base in the five basins studied in the Rocky Mountain region is on public lands and about 40% of that amount is not accessible or is subject to lease stipulations and restrictions.[17] Because of increased interest in access to natural gas, the protection of public lands and Bush Administration policies, the Rocky Mountain region has become a focal point for U.S. oil and gas policy.

Three recent reports have studied restrictions on natural gas in the Rocky Mountain region:

- *Natural Gas, Volume 1 Summary Report* by the National Petroleum Council (NPC); 1999.

- Energy Policy and Conservation Act Amendments (EPCA) study, 2003;[18]

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[16] *U.S. Natural Gas Markets, Mid-Term Prospects for Natural Gas Supply: Analysis of Federal Access Restrictions,* DOE/EIA, 2001

[17] Of the total federal land base used in the EPCA study, 36% is closed and 26% available with restrictions.

[18] The EPCA study, *Scientific Inventory of Onshore Federal Lands' Oil and Gas Resources and Reserves and the Extent and Nature of Restrictions or Impediments to their Development*, was required by the Energy Policy and Conservation Act Amendments of 2000, P.L. 106-469 section 604, prepared by the U.S. Departments of Interior, Agriculture, and Energy, January 2003.

- *U.S. Natural Gas Markets: Mid-term Prospects for Natural Gas Supply, 2001,* by the EIA.

While the EIA and NPC studies include data for total domestic natural gas supplies, the EPCA Report more narrowly confines itself to five major geologic basins within the Rocky Mountain region.[19] The most direct comparison of data on the Rocky Mountain region would be between the EIA and NPC studies because they define the region as essentially the same.[20]

Even though the resource base was different in each of the three studies, the relative amounts of natural gas on federal lands found to be either closed, restricted, or open to development was about the same.

Data from the 1999 NPC study indicate the natural gas resource base in the Rocky Mountain region is 335 trillion cubic feet (tcf). More recent data from EIA estimates technically recoverable[21] natural gas resources, excluding reserves, to be 293.6 tcf.[22] The EPCA study found 138.5 tcf in the five major geologic basins in the region.

Although oil and gas reserves are not included in the EIA report, the relative amounts of natural gas closed and restricted is similar to the amounts found in the other studies. For example, the NPC reports that 9% of the region's natural gas resource base is closed and 32% restricted, while the EIA data shows that 11.5% is closed and 37% restricted (see **Table 1**). The NPC and EIA studies report a more significant difference between the amount of natural gas open to leasing: 60% and 51.5% respectively, also shown in Table 1. This difference is probably because a larger portion of the proven reserves (excluded from the EIA report) are available for leasing. For instance, the EPCA study found that about 26 tcf of proven reserves are on federal lands out of 43 tcf total in the five major geologic basins. Of this total, 63% is open under standard lease terms. If the Rocky Mountain reserves were included in the EIA report, then the percentage of natural gas open under standard lease terms would likely increase, and the percentage of natural gas characterized as under restrictions would likely decline.

Oil resources in the Rocky Mountains that were examined in the EPCA study have somewhat less significance relative to U.S. oil supply. The study concludes that about 600 million barrels of oil resources (about 30 days of total U.S. consumption) fall under the "no access" category. Another 3.2 billion barrels would be available

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[19]The five major geologic basins in the interior West are as follows: the Paradox San Juan Basins in Colorado, Utah, and New Mexico; Uinta/Piceance Basins in Colorado and Utah; the Greater Green River Basin in Wyoming, Colorado, and Utah; the Powder River Basin in Montana and Wyoming; and the Montana Thrust Belt in Montana.

[20]The Rocky Mountain region includes the following states: Arizona, Colorado, Idaho, Montana, Nevada, western New Mexico, North Dakota, Utah, and Wyoming.

[21]These are in-place resources that are producible using current recovery technology but without reference to economic profitability.

[22]*U.S. Natural Gas Markets: Mid Term Prospects for Natural Gas Supply,* EIA, Department of Energy, 2001.

for leasing, of which one-third have restrictions. About 2.5 billion barrels of oil are estimated to be available on non-federal lands in the basins studied. The total oil resource included in the EPCA study represents about 7% of all technically recoverable oil in the United States.

As mentioned earlier, the numbers in the EPCA study are based on a much more selective area of the Rockies that included the five major geologic basins, and thus the numbers were smaller. However, as shown in Table 1, the relative rate with no access was similar to the other reports (11.6%), the amount of restricted gas was less (26%), and the amount of natural gas under standard lease terms was slightly higher (62.4%).

Both the NPC and EIA studies conclude that development of natural gas in the restricted land use category would be — at a minimum — likely to face costly delays. The EIA also concludes that if there were greater flexibility in some of the federal regulations, about 29 tcf could become immediately available from this restricted category. Additionally, if certain lease stipulations were removed, about 51 tcf would be less costly to develop, thus freeing up a total of 80 tcf, according to the EIA report. Environmental groups argue that there is an ecological basis for most of these restrictions and that environmental assessments or impact statements are incomplete. From this perspective, to relax these development restrictions would put the environment at greater risk.

Table 1. Rocky Mountain Natural Gas Resources

	NPC, 1999[23]		EIA, 2001		EPCA, 2003	
	TCF	% of Total	TCF	% of Total	TCF	% of Total
Rocky Mtn. Natural Gas	335[a] (federal)		293.3 (federal, excluding proven reserves)		138.5 (federal)	
Closed to oil and gas	29	9	33.6	11.5	16	11.6
Restricted	108	32	108.5	37	36	26
Open, no restrictions	198	59	151.2	51.5	86.5	62.4

[a] The NPC study estimates that 41% (137 tcf) of the total amount of gas resources in the Rocky Mountain region is either closed (29 tcf) or restricted (108 tcf). Thus, 335 tcf would be the estimated total amount of natural gas resources in the region as of 1999.

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[23] A more recent NPC study: *Balancing Natural Gas Policy Fueling the Demands of a Growing Economy, Volume 1* September 25, 2003, concluded that 69 tcf were "effectively" off-limits and an additional 56 tcf (125 tcf total) were affected by regulatory requirements which could lead to development delays or plan cancellations.

Significance of Access Restrictions

Substantial oil and gas reserves are located on public lands, but there are major policy disagreements about the potential importance of those reserves in meeting U.S. energy needs. The Rocky Mountain region represents an estimated 37% (293 tcf/788 tcf) of the unproved technically recoverable natural gas resource base in the United States, onshore lower 48.[24] If the estimated 108 tcf of natural gas in the Rocky Mountain region currently restricted were produced, it could last between 20-30 years, assuming a production rate of about 4 tcf to 5 tcf per year, according to the EIA; this would meet about 15% of projected annual U.S. demand. Currently, U.S. natural gas demand is being met with supplies from the outer continental shelf (OCS) (25%), imports (15%), the Rocky Mountain region (15%) and other onshore (45%).[25]

Testimony by The Wilderness Society (TWS) before the House Subcommittee on Energy and Mineral Resources, March 15, 2001, based on the NPC report, asserted that the United States has sufficient natural gas supply to meet domestic needs for the next 40 years.[26] This conclusion was based on annual demand growing from 22 tcf in 2001 to 31 tcf in 2015. Also, based on the NPC figure of 1,466 trillion cubic feet as "technically recoverable resources in the U.S.,"[27] of which 115 tcf is classified as off-limits (39 tcf onshore, 76 tcf offshore), TWS concludes that 1,351 tcf of natural gas could be available for development in the future. In other words, from this perspective ample supply is available now and possibly in the future without disturbing the resources in restricted or no-access areas. The NPC report estimated that about 16% of the 1,351 tcf cited by TWS is subject to restrictions that may prevent development.[28]

The NPC argues that 70 tcf of Rocky Mountain natural gas is under restriction or lease stipulations and otherwise could be brought into production in the near term. The NPC contends that there are a number of impediments that could be resolved to ensure access to this gas in a timely fashion, and proposes relaxing certain land-use constraints that would allow for more drilling on federal lands in the intermountain west. Among these constraints include the use of "no surface occupancy"designations that make resources "effectively" off-limits, use of stipulations to protect environmental resources that it believes are too restrictive, and old access restrictions

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[24]U.S. Natural Gas Markets: Mid-Term Prospects for Natural Gas Supply, EIA/DOE, 2001.

[25]Annual Energy Outlook, 2004 DOE/EIA -0383, January 2004, p.90.

[26]Testimony of David Alberswerth, The Wilderness Society, regarding "Domestic Natural Gas Supply and Demand: The Contribution of Public Lands & the OCS," before the U.S. House Resources Committee's Subcommittee on Energy and Mineral Resources, March 15, 2001.

[27] Defined as discovered and undiscovered oil and gas resources expected to be producible given current technology without regard to economic viability.

[28]This is based on 137 tcf restricted in the Rocky Mountain region and another 76 tcf restricted in the OCS. See NPC Summary Report, Volume I, December 1999, pages 12-13.

that do not consider new technology that could minimize damage to the environment.[29]

The RAND Corporation produced an Issue Paper in 2002[30] asserting that the debate needs to be more focused on the reserve category of the resource base. RAND's view is that access restrictions should be considered only for the resource category that is most viable — or most likely to be produced. Under this view, the amount of the resource considered to be restricted becomes much less. However, the analysis would be complicated by the rate at which oil and gas resources were assumed to be converted to reserves during the next 15-20 years.

Oil and Gas Resources and Production on Public Lands

Federal Onshore Oil and Gas Production

Total U.S. oil production was nearly 1.9 billion barrels in 2002, down from 2.5 billion barrels in 1991. Oil production is forecast to fall by 0.4% annually, from 5.8 million barrels per day (mbd) in 2002 to 5.3 mbd in 2025. And oil imports are estimated to account for nearly 65% of total U.S. supply in 2025. Total production of natural gas was 19.4 tcf in 2002, up from 17.8 tcf in 1993.[31]

In 2002, oil production from federal onshore leases was estimated at 5.4% of all U.S. oil production (see **Table 2**).[32] Federal onshore oil production is concentrated in three states which produce 79% of onshore federal oil: Wyoming (33%), New Mexico (29%), and California (17%). Oil production from onshore federal leases has fluctuated over the years but has generally been in decline over the past 10 years, falling from 133.5 million barrels in 1992 to about 100 million barrels in 2002.

According to the EIA, U.S. production of natural gas varied between 18-20 tcf annually between the years 1993-2002. Various projections show U.S. natural gas production reaching between 20 tcf - 24.3 tcf by 2025.[33] Imports from Canada are forecast to rise to 3.7 tcf in 2010, then fall to 2.6 tcf in 2025. Higher EIA forecasts of Canadian natural gas for the year 2025 were adjusted downward because of Canadian reports of declining gas production, less certain offshore supplies and greater use domestically in the production of oil sands, expected to triple by 2025.

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[29] Natural Gas, Volume I Summary Report by the National Petroleum Council, 1999, P. 28.

[30] A New Approach to Assessing Gas and Oil Resources in the Intermountain West, IP-225-WFHF, RAND Corporation, February 2002.

[31] U.S. DOE/EIA, U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 2002 Annual Report. p. D.-18.

[32] U.S. Department of Energy, Energy Information Administration, U.S. Crude Oil, Natural Gas and Natural Gas Liquids Reserves, 2001

[33] DOE, Annual Energy Outlook, 2004, p. 112.

Imports of liquefied natural gas (LNG) were projected to rise from 170,000 bcf in 2002 to 4.8 tcf in 2025, according to the EIA.[34]

Table 2. U.S. Oil Production, 2002

	Million Barrels	% of U.S. Total
Federal Onshore*	100	5.4
Private/State Onshore	1,261	67.3
Federal Offshore	483	25.7
State Offshore	31	1.6
U.S. Total	1,875	100

Source: EIA, 2002, p. 22.
* Based on an Minerals Management Service (MMS) estimate for FY2003.

Gas production on public lands has increased to 2.2 tcf in 2002 from 1.7 tcf in 1993 and accounts for 11.5% of all U.S. production (see **Table 3**). Of the 2.2 tcf total, New Mexico accounts for 50% and Wyoming 35%; these rank as the top two states in natural gas production on public lands, accounting for 85% (1.87 tcf) of the total. The federal onshore share of total U.S. domestic oil and gas production is not expected to change significantly in the near term.[35]

Table 3. U.S. Natural Gas Production, 2002

	Trillion Cubic Feet	% of U.S. Total
Federal Onshore*	2.2	11.5
Private/State Onshore	12.5	64.5
Federal Offshore	4.5	23.0
State Offshore	.2	1
U.S. Total	19.3	100

* Based on MMS FY2003 estimate from Mineral Revenues Report..
Source: EIA Annual, 2002, p. 30.

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[34]DOE, EIA , Annual Energy Outlook, 2002.

[35]DOE/EIA, U.S. Crude Oil, Natural Gas and Natural Gas Liquids Reserves, 2001.

U.S. Oil and Gas Reserves and Resources

Proved U.S. oil reserves[36] were 22.7 billion barrels of oil (BBO) as of December 31, 2002; natural gas liquids were estimated at 8 billion barrels and natural gas (dry) reserves are 187 tcf[37] according to EIA (see **Table 4**). Texas leads the United States in both oil and natural gas reserves (see **Table 5**). U.S. oil reserves have declined by 1.2 billion barrels over the past 10 years, while U.S. production declined by 500 million barrels.

The 2.5 billion barrels of recoverable oil discovered in 2001 was three times greater than the average annual discovery since 1976 (890 million barrels).[38] In 2002, the discoveries were about 950 million barrels or 6% over the annual discovery average since 1976. There are still substantial amounts of oil available and likely to be produced from existing fields and from undiscovered reserves in the United States, but the rate of production will likely continue declining over the long term. As indicated by EIA, technically recoverable onshore and state offshore oil resources are estimated at 92 billion barrels, not all of which is likely to be recoverable.[39]

Table 4. U.S. Proved Oil and Gas Reserves and Production, 1993-2002

	Billion barrels of oil (BBO)		Trillion cubic feet	
	Oil Reserves	Oil Production	Gas Reserves	Gas Production[40]
1993	22.9	2.3	162.4	17.8
1994	22.4	2.3	163.8	18.3
1995	22.3	2.2	165.1	17.9
1996	22.0	2.2	166.5	18.9
1997	22.5	2.1	167.2	19.2
1998	21.0	2.0	164.0	18.7
1999	21.7	1.9	167.4	18.9
2000	22.0	1.9	177.4	19.2
2001	22.5	1.9	183.5	19.8
2002	22.6	1.9	187.0	19.4

Source: EIA, U.S. Crude Oil and Natural Gas, Annual Report, 2002.

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[36]Proved reserves are defined by the EIA as the estimated quantities which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

[37]DOE, EIA 2003, p. 4.

[38]EIA, 2001, p. 7.

[39]DOE/EIA, U.S. Crude Oil, Natural Gas and Natural Gas Reserves, November 2002.

[40]Coalbed methane production is included in these totals. CBM production increased from 348 bcf in 1992 to 1.6 tcf in 2001.

Table 5. U.S. Proved Oil and Gas Reserves, by State, 2002

Leading States: Oil	BBO	Leading States: Natural Gas[41]	tcf
Texas	5.0	Texas	44.3
Alaska	4.7	Wyoming	20.5
California	3.6	New Mexico	17.3
Federal Offshore	5.0	Oklahoma	14.9
Other	4.4	Colorado	13.9
		Federal Offshore	25.2
		Other	50.8
U.S. Total	22.7	U.S. Total	186.9

Source: EIA, U.S. Crude Oil and Natural Gas and NGL Reserves 2002, Annual Report.

The natural gas story may be different, as the United States has seen its gas reserves increase by 16.5 tcf (10%) since 1991; production has also risen. At the same time, U.S. gas imports have risen to 17% from about 9% in 1991.[42] Annual discoveries were up 70% above the average since 1976 (i.e., 22.8 tcf compared to12.7 tcf). Technically recoverable gas resources onshore and state offshore are estimated by the EIA to be about 1,000 tcf, over five times the amount of current proved reserves. Over two-thirds of the total amount of onshore natural gas (proven and undiscovered) is on nonfederal land and may be available for exploration and development.

The 2002 oil and gas resource assessment records an estimated 1.9 billion barrels of oil, 183 tcf of natural gas and 3.1 billion barrels of natural gas liquids as undiscovered resources located within five priority basins in the Rocky Mountain West. Over 90% of the undiscovered gas is classified as unconventional; 25% (42 tcf) is coalbed methane. Of the proven reserves in five major basins in the Rocky Mountain region, oil and natural gas liquids[43] on public lands accounted for 53.6%, while 60.1% of natural gas was on public lands (see **Table 6**).

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[41]Coalbed methane accounts for 17.5 tcf or 9.5% of the total.

[42] DOE. EIA 2002 Annual Report G 3. For more historical data on oil and gas reserves and production (from 1977-2002) see Appendix D in the EIA report.

[43] Natural Gas Liquids are usually the heavier hydrocarbons separated out of natural gas, such as propane.

Table 6. Rocky Mountain Proved Reserves (Five major basins)

Oil and Natural Gas Liquids (million bbl)	% Federal	Natural Gas (tcf)	% Federal
799.3	53.6	42.9	60.1

Source: EPCA Study, p. A6-18, January 2003.

Recent estimates by the EIA indicate that federal onshore oil is 12.5% of all technically recoverable oil. Natural gas on public lands is estimated to account for 22.3% of all technically recoverable gas. EIA estimates undiscovered conventional oil to be 30.1 billion barrels and undiscovered conventional natural gas resources at 319.7 trillion cubic feet. The estimate for undiscovered unconventional natural gas is even greater at 358.7 tcf (see **Table 7**).

Table 7. Total Onshore Technically Recoverable Resources, 2002

	Oil (BBO)	Natural Gas (tcf)	Natural Gas Liquids (billion barrels)
Undiscovered Conventional	30.1	319.7	8.1
Undiscovered Unconventional	2.1	358.7	2.1
Discovered Ultimate Recovery	60	322.0	13.4
Total	92.2	1,000.0	**23.6**
Percent Federal	**24**	**32.0**	**34.7**

Source: EIA, Annual Report, 2002.

Growing Role of Coalbed Methane

Coalbed methane gas is natural gas dissolved in water and trapped in a coalbed. There are several important variables that determine the quantity of methane gas, including the depth of coal, pressure, temperature, thickness, and composition.

To extract coalbed methane (CBM), water must be removed from the coal by pumping, which drops the water pressure that traps the gas and allows the gas to flow. Some operators fracture coal formations and allow water and gas to move out of the coal. Concerns have arisen concerning groundwater contamination. The USGS reports that the water pumped out of coal beds can vary in quality. Some water can be discharged near the surface for reuse if "sufficiently fresh," or if the water does not meet reuse standards, it can be disposed of by subsurface injection or surface discharge into wetlands, streams, or impoundments.[44] Water quality and water disposal have become central concerns in the production of CBM.

A 1980 tax credit (section 29) for unconventional fuel production provided a major incentive for CBM development. Significant production of CBM began in 1987. Production has increased four-fold since 1991, and coalbed gas accounted for about 8% (1.6 tcf) of the 18.8 tcf of natural gas produced in 2002 in the United States.[45] In 2002 there were 10,000 CBM wells also producing 1.65 million barrels of water[46] per day. The leading producers are in New Mexico, Colorado, and Wyoming. Production rates vary widely because of the heterogenous geology of coalbeds. DOE estimates that out of the 39,000 new wells anticipated by 2010, 23,900 will be on federal lands.[47]

CBM reserves are still largely undeveloped. Of the estimated 700 tcf of coalbed methane in the United States, only about 100 tcf are classified as economically recoverable. The previously discussed EIA study of U.S. oil and gas resources found that of the 293 tcf of unproved technically recoverable unconventional fuels in the Rocky Mountain region, about 46 tcf are coalbed methane, of which about 20% would fall under the "no access" category. Coalbed methane proved reserves were 18.5 tcf in 2001, which was 10% of U.S. dry gas reserves. CBM reserves have more than doubled since 1991. Two states, Colorado and New Mexico, account for more than half of U.S. CBM reserves. Wyoming, Utah, and Alabama also have significant reserves. The San Juan Basin[48] is the most productive. It contains 65% of known reserves and 80% of production. The Warrior Basin in Alabama is the second most productive, claiming 9% of U.S. production and 8% of reserves.[49] USGS estimates CBM resources in the Powder River Basin (PRB) at 39 tcf.[50]

The federal government owns over half the mineral rights in the PRB, while the majority of the surface rights are held privately, resulting in spilt-estates. However, most of the current production of CBM is taking place on private lands. Over 80%

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[44]Coal-Bed Methane: Potential and Concerns, USGS Fact Sheet FS — 123 — 00, October 2000.

[45]USGS Fact Sheet, FS-110-01 Coalbed Gas Resources of the Rocky Mountains, 11/01.

[46] One barrel is equal to 31.5 gallons. Thus, about 52 million gallons of water were produced each day.

[47]Powder River Basin Coalbed Methane Development and Produced Water Management Study, U.S. Department of Energy, Office of Fossil Energy, DOE/NETL 2003/1184, November 2002.

[48]The San Juan Basin is located in northeastern New Mexico, parts of southwestern Colorado, and southern Utah.

[49]The Orderly Development of Coalbed Methane Resources From Public Lands, Oversight Hearing before the Subcommittee on Energy and Mineral Resources of the Committee on Resources , U.S. House of Representatives, Statement of Dr. Gene Whitney, U.S. geological Survey, September 6, 2001.

[50]Powder River Basin Coalbed Methane Development and Produced Water Management Study, U.S. Department of Energy, Office of Fossil Energy and National Energy Technology Laboratory Strategic Center for Natural Gas, DOE/NETL-2003/1184, November 2002.

of the land overlying of CBM wells is privately or state held in Wyoming, and some surface owners oppose development and others contend they are not compensated fairly for surface use.[51] A number of concerns has come up regarding surface use agreements between the surface owner and the mineral lessee or mineral owner. The central concern for the surface owner is receiving adequate compensation for damages from CBM or production from other extractive industries. In Wyoming, stakeholders such as the Petroleum Association, ranchers and the Farm Bureau Federation established the Wyoming Split-Estate Initiative in 2002. They have created a new framework to help resolve conflicts between surface owners and mineral owners or lessees.[52]

CBM Environmental Issues

Environmental concerns about CBM production focus primarily on land disturbance and water — both surface and ground water issues. Production of CBM can involve not only wells but also access roads, power lines, compressor stations, and waste water impoundments. Major issues include surface infrastructure, the net amount of water removed, effects on the water table, and the salinity levels and disposal of the water removed, which may affect wildlife, land and surface water resources.

The process of hydraulic fracturing[53] for CBM production has come under closer scrutiny because of concerns over the possible impact of the injected fluids (such as diesel fuel) used in the process on underground drinking water. A draft EPA report[54] concluded that there is no evidence of contamination of drinking water wells from CBM hydraulic fracturing. However, the EPA did express concern over the use of diesel fuel as an injection fluid because it contains many of the EPA's "constituents of concern", (chemicals). Thus, the EPA and the major companies using diesel fuel entered into an Memorandum of Agreement (MOA) in December 2003, to end the use of diesel fuel as an injecting fluid. Proposed energy legislation (H.R. 6 and S. 2095) include provisions that would prohibit EPA from regulating underground injection of fluids for hydraulic fracturing purposes under the Safe Drinking Water Act. (See CRS Report RS21673.)

Dennis Hemmer of the Wyoming Department of Environmental Quality explained in an energy newsletter that most water from CBM production does not

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[51] Oversight Hearings before the Subcommittee on Energy and Mineral Resources of the Committee on Resources, U.S. House of Representatives, Orderly Development of Coalbed Methane Resources from Public Lands, September 6, 2001.

[52] Pamphlet on the Wyoming Split-Estate Initiative, (see http://www.wysei.com for details).

[53] The technique of hydraulic fracturing consists of pumping fluids into a well until the coal formation cracks. This process allows for the easy flow of natural gas from the coal seam into the production well.

[54] Draft Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coal bed Methane Reservoirs, EPA 816-D-O2-006, U.S. Environmental Protection Agency, August 2002.

flow to surface supplies but rather seeps into underground aquifers and formations.[55] As a result, wells being used for drinking water may become polluted with sodium-tainted water.

CBM production resulted in water discharges of 602 million barrels annually or 1.65 million barrels per day in 2002, typically into surface waters or holding ponds. Water is also reinjected underground. Environmentalists contend that holding ponds are like wastewater treatment ponds that are unlined and leak into groundwater. There is concern about the lowering of the water table and the effects on wells and water sources used by wildlife. The Wildlife Management Institute of Washington D.C. argues that CBM production and the disposal of high volumes of water may lead to, among others things, the depletion of underground aquifers, the loss of natural vegetation, and aquatic life within waterways that receive CBM water. Further, the infrastructure required by CBM production may threaten wildlife habitats.[56]

In response to concerns over the impact of CBM on groundwater quality and quantity, BLM has required CBM producers to drill two monitoring wells per township with CBM leases since 1992. The cost of drilling each well is about $50,000, plus an additional $5,000 for monitoring equipment. After BLM review, it was established that one set of wells (one shallow and one deep) is required per four townships with CBM leases. The wells monitor both the water quality and water levels from CBM production. On private lands, monitoring wells are not required[57].

The Interior Board of Land Appeals (IBLA) invalidated three leases in April 2002 because environmental issues related to CBM production, as discussed above, were not evaluated sufficiently. Supplemental environmental assessments (EA) were prepared for the Powder River Basin to help determine where to develop CBM in areas already approved for leasing.[58] Generally, the results have allowed more CBM drilling to occur; however, there have been new conditions imposed upon some producers.

An environmental group, the Wyoming Outdoor Council (WOC), sued BLM to withdraw additional leases — four parcels totaling 3,800 acres — from a June 2002 sale in Wyoming because it violated an April 26, 2002, IBLA ruling that directed the BLM to update a 1985 resource management plan (RMP) before offering CBM leases in the Powder River Basin. After the suit, BLM did not proceed with any lease sales on public lands with high CBM content, including the four parcels that prompted the suit, while the IBLA ruling was being interpreted by Bureau attorneys. The IBLA dismissed the case December 18, 2003. The Wyoming BLM office finalized a new EA and RMP and reportedly is anticipating approving 39,000 permits

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[55] Inside Energy/with Federal Lands, September 10, 2001, p.10.

[56] The Orderly Development of Coalbed Methane Resources from Public Lands, Oversight Hearings before the Subcommittee on Energy and Mineral Resources, September 6, 2001.

[57] Personal communication with the BLM Field Office, Casper WY. January 2004.

[58] Inside Energy, June 3, 2002, p. 12

for new wells over a 10- year period. A decision to begin issuing permits was made by the DOI in July 2003.[59]

Outlook for Oil and Gas Development on Public Lands

Demand for oil is forecast to rise 1.6% annually to 28 mbd by 2025 in the EIA reference case. Because consumption would rise faster than domestic production, imports are projected to reach nearly 65%. U.S. demand for natural gas is forecast to rise 1.4% annually, reaching 31.4 tcf by 2025.

The outlook is mixed for increased oil and natural gas production from leases on U.S. public lands or areas where the United States holds mineral rights. While domestic natural gas production and natural gas imports are expected to rise, it is unclear how much of the domestic supply will come from public lands that are currently restricted or off-limits. The Bush Administration has initiated actions to ease restrictions in instances where this can be done administratively. How much opposition these initiatives will generate is unclear. The media has reported challenges based on alleged violations of BLM's multiple-use mandate. Areas statutorily removed would require congressional action to change their status. On available lands, production of conventional natural gas is expected to remain steady, even though significantly more wells and higher-cost deeper wells will be drilled. Onshore unconventional natural gas (over 70% located in the Rocky Mountain region) is forecast to increase its share from 32% in 2002 to 43% of production in the lower 48 by 2025. The central concern for industry is to have greater access to federal lands believed to possess oil and gas potential and to expedite the permitting process. Environmental groups and some surface owners are concerned that drilling and production would damage sensitive lands, wildlife habitat and surface water and groundwater quality and quantity.

Meeting U.S. energy demand will likely occur by using a mix of increased domestic output plus higher imports. The Rocky Mountain region might account for as much as 40% of U.S. natural gas production in 2025, up from about 25% in 2002.[60] The United States will likely rely more on natural gas imports, primarily LNG from stable countries, as well as increased production from the deepwater OCS. A proposed Alaskan natural gas pipeline, if built, could provide 2.71 tcf by 2025.

Oil and gas firms continue worldwide exploration and development seeking the best return for their investment; a significant resource base, political stability, and financing are factors considered when making investment decisions. The United States scores well for political stability and its resource endowment is still attractive, but other concerns such as the impact on the environment, on residents and society must be weighed in making public land use decisions.

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[59] Inside Energy August 25, 2003, p.1.

[60] Annual Energy Outlook, 2004, DOE/EIA-0383, U.S. Department of Energy, January 2004.

Appendix A. Terms of an Oil and Gas Lease

The terms for a competitive lease are:

- Maximum acreage — 2,500 acres, except Alaska — 5,760 acres
- $2/acre minimum bonus bid five-year term
- Bond requirement — $10,000

For noncompetitive leases, the terms are:

- Maximum acreage — 10,240 acres in all states
- No minimum bonus bid
- 10-year term
- $75 application filing fee
- Bond requirement — $10,000

Rents and royalties on competitive and noncompetitive leases are:

- Rentals — not less than $1.50/acre for 1-5 years
- Rentals — not less than $2/acre each year thereafter
- Royalty — not less than 12.5% in amount or value of the production removed or sold from the lease

Table 8. Oil and Natural Gas Production in U.S. Onshore Federal Lands, 1991-2000

Year	Oil in million barrels	Gas tcf	Royalties $ (millions)	Bonus Bids ($ millions)
1991	133.1	1.2	518	41.5
1992	133.5	1.3	524	18.8
1993	126.7	1.7	583	22.8
1994	119.2	1.8	525	41.4
1995	121.6	1.7	443	47.3
1996	121.5	1.9	542	32.0
1997	117.3	1.94	691	58.5
1998	111.6	1.92	553	77.2
1999	103.9	1.96	565	169.6
2000	108.2	2.1	968	52.3

Source: MMS, Mineral Reserves, 2000, p.80.

The onshore leasing program brings in significant annual revenues to the U.S. Treasury. Revenues include bonus bids, rents and royalties (see **Table 8**). The revenues are collected by the Minerals Management Service (MMS, an agency within the Interior Department) and distributed to states, the General Fund of the U.S. Treasury, and other designated programs. All states except Alaska receive 50% of the revenues collected from public land oil and gas leases within their boundaries. Alaska receives 90% of all revenues collected. Revenues from federal leases vary widely over the years because of price fluctuations; for example, revenues increased significantly in 2000 over 1999 because of higher oil and gas prices. The number of federal oil and gas leases stood at 23,000 and encompassed over 17 million acres of federal public lands in 2001.

Appendix B. History of Public Land Withdrawals

The first public lands withdrawal took place in 1872 to establish Yellowstone National Park, and since that time Congress has created other national parks at regular intervals.[61] The National Park System (NPS) was created in 1916 to "conserve the scenery and the natural and historic objects and the wild life [in national parks] and to provide for the enjoyment of the same in such a manner and by such means to leave them unimpaired for the enjoyment of future generations" (16 U.S.C. 1).[62] In the early days of the NPS, its philosophy was not synchronized with the Forest Service (FS). The FS philosophy was that "all the resources of the forest reserves are for use and where conflicting interests exist the issue will be resolved based on the greatest good for the greatest number of people in the long run." Early tension arose between "conservationists" promoting National Parks and "utilitarians" promoting National Forests.[63]

Sources of Withdrawal Authority

During the early 1900s the focus of the public lands withdrawal debate was on whether the Commander-in-Chief had authority to make the withdrawal order based on national security. Withdrawals were defined as an administration action/order that changed the designation of a specific parcel of land from available to unavailable for activities ranging from homesteading to resource exploitation. The President acted as chief custodian of the public lands and with tacit approval of Congress withdrew public land from entry or location by the private sector. The Constitution vests authority over public lands in Congress rather than with the Executive, but Presidents have repeatedly exercised "an inherent power to withdraw" or reserve some lands. A prime example is the establishment of military reservations out of public lands.

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[61]Federal Public Lands and Resources Law, George Cameroon Coggins, et. al., Third Edition, 1992, p. 116.

[62]Federal Public Land and Resources Law, p. 116.

[63] Ibid. p. 117.

Withdrawals also occurred under the Antiquities Act of 1906 (16 U.S.C.A. 88, 433-431), the Taylor Grazing Act of 1934 (43 U.S.C. 315 et. seq.), the Organic Act of 1897 (16 U.S.C.A. 473), the Alaska Native Claims Settlement Act of 1971 (43 U.S.C.A. 1601 et. seq.) and the Wilderness Act of 1964 (16 U.S.C.A. 1131-36). National monuments can be created by the executive branch through statutory delegation under the Antiquities Act. The President can reserve the "smallest area compatible with the proper care and management" of the protected sites on federal lands that contain historic landmarks, prehistoric structures, and other objects of scientific interest. Under the Taylor Grazing Act, 140 million acres were withdrawn from homesteading laws. The Organic Act was used to regulate and designate recreation and "primitive areas." Under FLPMA, withdrawals can be made by the executive branch or the Congress.

Congressional designations as "wilderness" were later considered essential by many because an administrative wilderness designation could be revoked administratively any time. The Alaska Native Claims Settlement Act withdrew large areas of Alaska from availability for resource use or development pending congressional disposition. The Wilderness Act required that the Forest Service study 5.4 million acres of designated primitive areas and report on wilderness suitability. Wilderness is generally defined as an area "off limits to development to avoid destruction of pristine characteristics of nature."[64] The Wilderness Act states that "no federal lands shall be designated as wilderness areas except as provided for in the Wilderness Act or by an Act of Congress" (16 U.S.C. 1131 (a)).

Currently, there are four types of withdrawal: First, there are instances where Congress has the sole authority to withdraw or reserve public lands. For example, creating National Parks and wilderness areas and in some cases national wildlife refuges can only be done by an act of Congress. Second, the executive branch has used power delegated to it by Congress under the previously mentioned Antiquities Act of 1906 and the Pickett Act of 1910. Third, Congress may withdraw specific resources such as when oil, gas, coal, and like minerals were removed from the General Mining Law of 1872. Lastly, there is the "general congressional" withdrawal,[65] which allows lands to be removed from potential development pending "final disposition."[66]

Withdrawals Under FLPMA

Modern executive withdrawals are governed by FLPMA.[67] FLPMA[68] established a federal land use management policy that includes land use planning based on a multiple-use approach that allows for significant public and congressional input. Sections of FLPMA detail procedures (see 43 U.S.C. 1714 (d)) for the sales and acquisition of public lands, withdrawals, and exchanges of public lands. Under

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[64]Federal Public Lands and Resources Law, p. 1015.

[65]Federal Public Lands and Resources Law, p. 286

[66] Ibid.

[67] See footnote 2.

[68]43 U.S.C. 1701 et. seq.

FLPMA, withdrawals can be made by the executive or the Congress. The withdrawal can be temporary or permanent.

FLPMA replaced the implied authority of the executive branch to withdraw public lands with specifically defined procedures. Withdrawals of parcels exceeding 5,000 acres require congressional approval. The land can be withdrawn for 20 years subject to renewal. Proposed withdrawals must be submitted to Congress with a report explaining the reasons for the withdrawal in detail, effects on the economy and environment, alternatives to withdrawal, how BLM is consulting with other agencies and groups, and the geological and mineral potential of the areas proposed. The Secretary of the Interior, however, can make emergency withdrawals of any size for up to three years. A report must be available three months following a withdrawal.

FLPMA mandated a review of public land withdrawals in 11 Western states to determine whether, and for how long, existing withdrawals should be continued (43 U.S.C. 1714(l)). There were millions of acres withdrawn prior to FLPMA. Under the law, the Secretary of the Interior can determine whether and for how long the continuation of existing withdrawals are consistent with statutory objectives of the programs under which lands were dedicated in the first place.

BLM continues to review approximately 70 million withdrawn acres, giving priority to about 26 million acres that are expected to be returned by another agency to BLM, or, in the case of BLM withdrawals, become available for one or more uses. As of November 2000, BLM had completed reviewing approximately 7 million withdrawn acres, mostly BLM and Bureau of Reclamation land; the withdrawals on more than 6 million of these acres have been revoked. According to the BLM Manual, retention of a withdrawal requires a compelling show of need, and an agency manager "recommending that lands not be opened to multiple use, particularly mining and mineral leasing. That manager must convince the BLM Director, the Secretary, and watchful segments of the public, that there is no reasonable alternative to continued withdrawal or classification." The review process is continuous over the next several years, in part because the withdrawals must be considered in BLM's planning process and be supported by documentation under the National Environmental Policy Act (NEPA).

Some lands, through revocation and terminations, could be developed for oil and gas resources. Other areas deemed not suitable for mineral development, will likely remained closed or restricted.