Congressional Research Service

U.S. Offshore Oil and Gas Resources: Prospects and Processes

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February 10, 2012

Congressional Research Service
7-....
www.crs.gov
R40645

CRS Report for Congress
Prepared for Members and Committees of Congress

Summary

Access to potential oil and gas resources under the U.S. Outer Continental Shelf (OCS) continues to be controversial. Moratoria on leasing and development in certain areas were largely eliminated in 2008 and 2009, although a few areas remain legislatively off limits to leasing. The 112th Congress may be unlikely to reinstate broad leasing moratoria, but some Members have expressed interest in protecting areas (e.g., the Georges Bank or Northern California) or establishing protective coastal buffers. Pressure to expand oil and gas supplies and protect coastal environments and communities will likely lead Congress and the Administration to consider carefully which areas to keep open to leasing and which to protect from development.

The oil spill that occurred on April 20, 2010, in the Gulf of Mexico brought increased attention to offshore drilling risks. Consideration of offshore development for any purpose has raised concerns over the protection of the marine and coastal environment.

On December 1, 2010, the Obama Administration announced its Revised Program (RP) for the remainder of the 2007-2012 OCS Leasing Program. Among other components, the RP eliminates five Alaskan lease sales (sales 209, 212, 214, 217, and 221) that had been contemplated in the current lease program. Lease sale 219 in the Cook Inlet (scheduled to be held in 2011) was cancelled because of a lack of industry interest. Further, the Obama Administration, under executive authority, withdrew the North Aleutian Basin Planning Area from oil and gas leasing activity until June 30, 2017. Public hearings began in 2010 on the scope of the 2012-2017 OCS oil and gas leasing program, but three planning areas in Alaska (Cook Inlet, Chukchi, and Beaufort Sea) are being scoped as well. On November 8, 2011, the Administration announced its second draft proposed oil and gas leasing program for 2012-2017, which excludes all three Atlantic and all four Pacific Coast planning areas at least through 2017. On December 14, 2011, the Obama Administration held lease sale 218 in the Western Gulf of Mexico, the first sale since the oil spill. A combined lease sale in the Central Gulf of Mexico (sale 216 and 222) is scheduled for June 20, 2012, the final sale of the 2007-2012 leasing program.

Three bills that were passed in the House in May 2011 would address permitting efficiencies (H.R. 1229), enforce certain lease sales in the current five-year planning period (H.R. 1230) and require lease sales in the "most promising" OCS Planning Areas during the 2012-2017 Lease Program (H.R. 1231). Most recently, legislation introduced in the House—the Energy Security and Transportation Jobs Act (H.R. 3410) on November 14, 2011—combines some of the language from bills passed earlier by the House (H.R. 1230 and H.R. 1231, discussed below) and incorporates this proposal into H.R. 7, the American Energy and Infrastructure Jobs Act of 2012, as Title XVII – Subtitle B.

Exploration and production proceed in stages during which increasing data provide increasing certainty about volumes of oil and gas present. The Bureau of Ocean Energy Management (BOEM) conducts assessments of undiscovered technically recoverable resources (UTRR) on the U.S. OCS. The statistical certainty of these assessment estimates varies by region because the availability of geologic data varies widely by region. One characteristic of the U.S. oil market, as well as of world oil markets, is that the access to supply tends to be sequential. Normally, the first source of oil used by a nation is domestic production, if available. The ultimate impact of oil and gas development in offshore areas will depend on oil and gas prices, volumes of resources actually discovered, infrastructure development, and restrictions placed on development, all of which currently carry significant uncertainties.

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Introduction and Background

In the wake of the Deepwater Horizon explosion and oil spill in the Gulf of Mexico on April 20, 2010, Congress continues to debate how much of the outer continental shelf (OCS) should be available for oil and gas development. Having all of the OCS available is seen by some as a way to increase domestic supply and improve U.S. energy security; others contend that OCS development has risks for the coastal environment and coastal communities, and that other options are available for energy security. The issue remains contentious, as industry would prefer that the entire OCS remain available without any area exclusions such as buffer zones (e.g., 25 or 50 miles from the coastline) or withdrawals. Industry might be reluctant to invest in any new resource assessments unless they are confident that the OCS will remain open for long-term leasing and development. Environmental groups have argued to retain the OCS moratoria as previously specified and that industry already has access to areas in the Gulf of Mexico with large oil and gas reserves as well as several thousand leases not yet developed.

Following the Deepwater Horizon oil spill the Obama Administration saw an immediate need to review and upgrade drilling and safety rules for offshore oil and gas development. The 2010 oil spill changed the landscape for offshore oil and gas development. It has led to the reorganization of the Minerals Management Service (MMS) (discussed below), rewriting safety rules for drilling offshore, a suspension of permitting and drilling operations for some, review of the role of the National Environmental Policy Act (NEPA) and use of categorical exclusions, and a revised leasing program (announced December 1, 2010). Many in the oil and gas industry asserted that the six-month suspension that was announced on May 28, 2010 (called a "de-facto" moratoria) caused significant disruption of development activities and will lead to a reduction of oil and gas production and other economic losses at least in the short term. However, according to the EIA reference case, crude oil production from the lower 48 offshore region is estimated to increase from 1.71 million barrels per day (mb/d) in 2009 to 1.81 mb/d in 2015.[1] New deepwater drilling permits were not issued until February 28, 2011.

The Former MMS[2]

On May 11, 2010, Secretary of the Interior Ken Salazar announced a plan to separate the safety and environmental functions of the Minerals Management Service (MMS) from its leasing and revenue collection function. The goal was to improve the efficiency and effectiveness of the agency. Subsequently, on May 19, 2010, a decision was made by the Secretary to establish the following three new entities to perform the functions of the MMS: Bureau of Ocean Energy Management (BOEM), Bureau of Safety and Environmental Enforcement (BSEE), and the Office of Natural Resources Revenue (ONRR).[3] The transition to the new framework was completed on October 1, 2011. Each of the three new entities has a director under the supervision of an assistant secretary.[4]

[1] Annual Energy Outlook, 2011, US. Energy Information Administration, April 2011.

[2] This report may refer to the MMS in various references or elsewhere when unavoidable.

[3] Additional information on the reassignment of MMS's responsibilities is contained in Secretarial Order No. 3299, on the DOI website at http://www.doi.gov/deepwaterhorizon/loader.cfm?csModule=security/getfile&PageID=32475.

[4] Additional information on the reassignment of MMS's responsibilities is contained in Secretarial Order No. 3299, on the DOI website at http://www.doi.gov/deepwaterhorizon/loader.cfm?csModule=security/getfile&PageID=32475, and in a September 30, 2011, DOI news release on the DOI website, at http://www.doi.gov/news/pressreleases/Interior-

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BOEM manages development of the nation's offshore resources, including administering offshore leasing, conducting environmental and economic analyses, and preparing resource evaluations. BSEE enforces safety and environmental regulations. Functions include offshore regulatory programs, research, and oil spill response. Field operations include permitting, inspections, and environmental compliance. ONRR was established under the Office of the Department of the Interior (DOI) Secretary to collect, account for, analyze, audit, and disburse revenues from energy and mineral leases on the outer continental shelf, federal onshore, and American Indian lands. Prior to the establishment of BOEM and BSEE, the Bureau of Ocean Energy Management, Regulation, and Enforcement (BOEMRE) temporarily handled the activities now being performed by BOEM and BSEE.

OCS Moratorium[5]

Oil and gas development moratoria in the OCS along the Atlantic and Pacific coasts, parts of Alaska, and the Gulf of Mexico had been in place since 1982, as a result of public laws and executive orders of the President. On July 14, 2008, President Bush lifted the executive moratoria, which included planning areas along the Atlantic and Pacific coasts. On September 30, 2008, moratoria provisions in annual appropriations laws expired, allowing these areas to potentially open for oil and gas leasing activity. The eastern Gulf of Mexico and a portion of the central Gulf of Mexico, however, continue under a moratorium established by separate statute. The Gulf of Mexico Energy Security Act of 2006 (GOMESA, P.L. 109-432), placed nearly all of the eastern Gulf of Mexico under a leasing and drilling moratorium until 2022 but allowed leasing in designated portions of the eastern Gulf. Thus, most of the eastern Gulf of Mexico remains off limits to development because it was not part of the executive OCS ban that was lifted by President Bush, nor part of the annual congressional ban that was not continued.

On December 1, 2010, the Obama Administration announced its Revised Program (RP) for the remainder of the 2007-2012 OCS Leasing Program. Among other components, the RP eliminates five Alaskan lease sales (sales 209, 212, 214, 217, and 221) that had been contemplated in the current lease program. Lease sale 219 in the Cook Inlet (scheduled to be held in 2011) was cancelled because of a lack of industry interest. Further, the Obama Administration, under executive authority, withdrew the North Aleutian Basin Planning Area from oil and gas leasing activity until June 30, 2017. The RP excludes all three Atlantic and all four Pacific Coast planning areas at least through 2017.

Public hearings began in 2010 on the scope of the 2012-2017 OCS oil and gas leasing program, but three planning areas in Alaska (Cook Inlet, Chukchi, and Beaufort Sea) are being scoped as well. On November 8, 2011, the Administration announced its second draft proposed oil and gas leasing program for 2012-2017, which excludes all three Atlantic and all four Pacific Coast planning areas at least through 2017.

After the Deepwater Horizon oil spill, President Obama cancelled the August 2010 lease sale (215) and the 2011 Mid-Atlantic lease sale (220). On December 14, 2011, the Obama Administration held lease sale 218 in the Western Gulf of Mexico, the first sale since the oil spill.

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Department-Completes-Reorganization-of-the-Former-MMS.cfm.

[5] For a comprehensive review of the OCS moratorium see CRS Report R41132, *Outer Continental Shelf Moratoria on Oil and Gas Development*, by (name redacted).

A combined lease sale in the Central Gulf of Mexico (sale 216 and 222) is scheduled for June 20, 2012, the final sale of the 2007-2012 leasing program.

Recent high oil and gasoline prices have led to some renewed calls by some Members of Congress for increased domestic oil development, a push to include more of the OCS in the next five-year leasing program, and an assurance of already scheduled lease sales to go forward in the current five-year program. These legislation proposals are discussed below.

This report examines questions around lifting the moratoria on OCS exploration and production and the significance of the change on U.S. oil and natural gas supplies and markets. The report presents the current U.S. oil and gas supply and demand picture and provides a discussion of legislative issues, resource assessments, the leasing system, and environmental and social issues associated with offshore oil and gas development.

Legislative Issues

Although reinstatement of a blanket moratorium on the OCS is unlikely in the 112th Congress, some Members of Congress have argued for open but restricted access. The President has the administrative authority to place areas of the OCS under a leasing and development moratoria,[6] whereas legislated moratoria must be signed by the President. To open the Eastern Gulf of Mexico, GOMESA would need to be amended or repealed. Congress and the Administration are likely to give careful consideration to which parts of the OCS to keep open and which to protect through leasing moratoria.

The Revised Program confirms plans to conduct a programmatic environmental impact statement to determine if seismic studies should be conducted in the Mid and South Atlantic Planning Areas. Would this additional information on the OCS prior to lease sales generate more interest in those areas and possibly generate more revenue in higher bonus bids and high royalty rates (16.7% or 18.75%) as part of the lease terms? A related controversial legislative issue is whether coastal producing states should receive a greater share of those revenues. Revenue sharing is discussed in more detail below.

Generally, proponents and opponents alike would argue that some sense of certainty is desirable. Industry proponents, for example, want to know, if the industry invests in exploration and development and finds oil and natural gas, whether it could then move forward with production. And conversely, if certain areas are placed off limits or restricted, would those limitations remain in place for the long term? The balance of this report provides information to inform this debate.

There are numerous House and Senate bills that would restructure the way the OCS is managed, improve safety standards, make permitting more efficient, prevent or enforce lease sales, and address oil spill and deepwater production issues.

Most recently, legislation introduced in the House—the Energy Security and Transportation Jobs Act (H.R. 3410) on November 14, 2011—combines some of the language from bills passed earlier by the House (H.R. 1230 and H.R. 1231, discussed below) and incorporates this proposal into H.R. 7, the American Energy and Infrastructure Jobs Act of 2012, as Title XVII – Subtitle B.

[6] OCSLA Section 12(a).

Subtitle B of this act would require BOEM to offer lease sales in the most prospective areas in each of the OCS Planning Areas for the 2012-2017 5-Year Leasing Program specifically, areas that contain more than 2.5 billion barrels of oil or more than 7.5 trillion cubic feet of natural gas. Increased production goals would be established at 3 million barrels per day (mb/d) of oil and 10 billion cubic feet (bcf) of natural gas per day by 2027. The bill would also require BOEM to offer lease sales 216, 220, and 222 all within a year of enactment.

The bill would require a lease sale in southern California under Section 8 of Outer Continental Shelf Lands Act (OCSLA), using onshore-based drilling technology by July 2014 and a lease sale in the North Aleutian Basin (lease sale 214, which was cancelled by the Obama Administration). There is a provision that would amend Section 18 of OCSLA allowing the Secretary of the Interior to hold lease sales in areas identified by the Secretary to have the greatest potential for oil and gas. The current moratorium in the Eastern Gulf of Mexico (EGoM) would be repealed, the boundaries in the EGoM shifted, extending the moratorium until 2025, but allowing limited leasing in years 2013, 2014, and 2015 in certain areas that would be considered exempt and with the most oil and gas potential.

Provisions for revenue sharing with the coastal states would be phased in for new leasing revenue (12.5% in the first leasing program 2012-2017 and 25% in the second leasing program) defined in the bill, following enactment. The application of OCSLA would apply the U.S. Territories.

Title XV of H.R. 7 (also H.R. 3864) would appropriate the net increase in federal revenues from offshore and onshore energy revenue from leasing and production based on enactment of Title XVII of H.R. 7 (Subtitle B explained above) to the Highway Trust Fund.

Other earlier legislation (H.R. 1230—Restarting American Offshore Leasing Now Act) before Congress would require the Secretary of the Interior to conduct four lease sales (lease sales 216, 218, 220, and 222) within about a year of the bill's enactment. The Administration's Revised Program is scheduled to hold three more lease sales (sales 216, 218, and 222) in the Central or Western Gulf of Mexico as part of the 2007-2012 Leasing Program. H.R. 1230, which would reinstate lease sale 220, passed the House on May 5, 2011, by a vote of 266-149.

Another bill (H.R. 1229—Putting the Gulf of Mexico Back to Work Act), would provide a new safety review and seek to expedite the drill permitting process by providing a new timeline for the Secretary to make a final decision on the permit application. The bill includes language on judicial reviews that would provide timelines, an exclusive venue for civil actions, and limits on relief and attorney fees. The House passed H.R. 1229 on May 11, 2011, by a vote of 263-163. A third bill (H.R. 1231—Reversing Presidents Obama's Offshore Moratorium Act), which passed the House on May 12, 2011 (243-179), would require BOEM to offer lease sales in the most prospective areas in each of the OCS Planning Areas for the 2012-2017 5-Year Leasing Program, specifically, areas that contain more than 2.5 billion barrels of oil or more than 7.5 trillion cubic feet of natural gas. Increased production goals would be established at 3 million barrels per day (mb/d) of oil and 10 billion cubic feet (bcf) of natural gas per day by 2027.

U.S. Oil and Gas Supply and Demand

U.S. Oil Markets

Consumption of petroleum products in the United States has averaged more than 20 million barrels per day (mbd) over the last seven years.

Table 1. U.S. Petroleum Consumption, 2004-2010

(millions of barrels per day)

	Gasoline	All Petroleum Products
2004	9.10	20.73
2005	9.16	20.80
2006	9.25	20.69
2007	9.29	20.68
2008	8.97	19.50
2009	8.98	18.77
2010	9.03	19.15

Source: Energy Information Administration, April 28, 2011, http://www.eia.doe.gov/petroleum/data.cfm#consumption.

Table 1 shows that almost half of petroleum consumption has been in the form of motor gasoline used in automobiles and light trucks. The data for 2008 through 2010, which show declines in both gasoline and total petroleum product consumption, reflect two economic conditions. In the second and third quarters of 2008, the price of oil increased to record-high levels, reaching over $145 per barrel in July 2008. The high price of oil caused the price of gasoline to rise to over $4 per gallon in June and July 2008. High prices reduced consumer demand. In addition, the recession and associated financial market problems that affected the U.S. economy in 2008 also contributed to the decline in petroleum product demand by reducing consumer income and wealth. The recession, which continued through 2009, resulted in negative demand growth. Uncertainty surrounding supply disruptions resulting from political turmoil in the Middle East and North Africa has again driven oil and gasoline prices up in 2011.

To meet the demand for oil to fuel the U.S. economy, the oil industry draws on two primary sources: domestic production of crude oil, and imports. Other sources include natural gas condensates and refinery expansion. The data in **Table 2** show that domestic production of crude oil declined through 2008, which is likely part of a sectoral decline in crude oil production that has occurred since the mid-1970s when U.S. production peaked. Production increases in the Gulf of Mexico and in the Bakken Formation in North Dakota have increased domestic production over the last two years.

A characteristic of the U.S. oil market, as well as the world oil market, is that the access to supply tends to be sequential. Normally, the first source of oil used by a nation is domestic production, if available. Typically, the next source of U.S. supply is imports from countries that are not party to the Organization of the Petroleum Exporting Countries (OPEC). Finally, residual demand is met by OPEC.[7] This behavior implies that, if the United States were to increase domestic production of crude oil and natural gas condensates, the result is likely to be an equal decrease in imports (all else being equal).

Table 2. U.S. Petroleum Supply, 2005-2010

(millions of barrels per day)

	Crude Oil Production	Net Imports
2005	5.18	12.55
2006	5.10	12.39
2007	5.06	12.04
2008	4.95	11.11
2009	5.36	9.68
2010	5.51	9.44

Source: Energy Information Administration, April 28, 2011, available at http://www.eia.doe.gov/dnav/pet/pet_crd_crpdn_adc_mbblpd_a.htm and http://www.eia.doe.gov/dnav/pet/pet_move_neti_a_ep00_IMN_mbblpd_a.htm.

Notes: Net imports includes both crude oil and petroleum products, net of U.S. exports.

The data in **Table 2** suggest that even the price spike of 2008 was not sufficient to cause U.S. crude oil production to increase, or even stop its decline. The reduction in consumption that resulted from high prices and declining incomes in 2008 did contribute to the decline in imports observed in 2008 and 2009, and increased domestic production contributed to further decline in imports into 2011.

Offshore production of crude oil accounted for approximately 31% of total U.S. production of crude oil in 2010, down from 35% in 2004. Offshore production, as shown in **Table 3**, is divided between production in federal and state waters.[8] Within the federal waters category, 96% of crude oil production is from the Gulf of Mexico, and 3% is from waters off the coast of California. The state offshore production is largely raised from the waters off Alaska, where 51% of the state offshore total of crude oil was produced in 2010.

[7] This viewpoint is substantiated by Energy Information Administration data which shows that excess supply in the world tends to reside in OPEC.

[8] State jurisdiction is typically limited to three nautical miles seaward of the baseline from which the breadth of the territorial sea is measured. However, the state jurisdiction off the Gulf Coast of Florida and Texas extends nine nautical miles and for Louisiana, three imperial nautical miles. Federal jurisdiction extends, typically, 200 nautical miles seaward of the baseline from which the breadth of the territorial sea is measured.

Table 3. U.S. Offshore Crude Oil Production, 2004-2010

(millions of barrels per day)

	Federal Offshore	State Offshore
2004	1.528	0.356
2005	1.355	0.358
2006	1.371	0.331
2007	1.344	0.312
2008	1.218	0.280
2009	1.584	0.119
2010	1.695	0.118

Source: Energy Information Administration, available at http://www.eia.doe.gov/dnav/pet/pet_crd_crpdn_adc_mbblpd_a.htm.

Production of crude oil depends on the existence of a proved reserve base. The data in **Table 4** show that, while the total of U.S. proved reserves has varied over a narrow range, total reserves were about 8% lower in 2009 than 2004. The reserve base in the federal offshore areas declined by approximately 17% in the five-year period 2004-2009. The decline in the proved reserve base occurred during a period of high crude oil prices, suggesting that the economic incentive existed to explore and develop new reserves, but other constraints might have prevented this activity in federal OCS areas until recently.

Table 4. U.S. Proved Crude Oil Reserves, 2004-2009

(billions of barrels)

	Federal Offshore	Total Reserves
2004	4.691	21.371
2005	4.483	21.757
2006	4.096	20.972
2007	3.905	21.317
2008	3.903	19.121
2009	4.129	20.682

Source: Energy Information Administration, available at http://www.eia.doe.gov/dnav/pet/pet_crd_pres_dcu_RUSF_a.htm.

As the reserve base in any field declines, and natural pressures within the reserve deposit weaken, the result is declining output of crude oil. This decline in production from the declining reserve base can be mitigated through the use of enhanced recovery methods, but the result is higher production costs.

U.S. Natural Gas Markets

Consumption of natural gas in the United States has averaged more than 22 trillion cubic feet (tcf) over the last six years.

Table 5. U.S. Natural Gas Consumption, 2004-2010

(trillion cubic feet)

	Delivered to Consumers	Total Consumption
2004	20.725	22.388
2005	20.315	22.010
2006	19.958	21.685
2007	21.249	23.097
2008	21.400	23.268
2009	20.965	22.839
2010	22.168	24.132

Source: Energy Information Administration, available at http://www.eia.doe.gov/dnav/ng/ng_cons_sum_dcu_nus_a.htm.

Notes: The difference between total consumption and quantities delivered to consumers is gas used in the production and distribution of natural gas.

Of the total natural gas delivered to consumers in 2010, approximately 22% was used by residential customers, 14% was used by commercial customers, 30% was used by industrial customers, and 33% was used in electric power generation. Over the six-year period 2004-2009, residential consumption was relatively constant, with variations attributable to weather conditions and the price. Commercial consumption was also relatively constant, while industrial consumption declined by about 15% but rebounded in 2010. The use of natural gas for electric power generation increased by approximately 26% over the period 2005-2010.

The 2004-2010 consumption patterns in the United States reflect the different reactions to price variations within the various sectors. Derived demand (indirect demand) from residential, commercial, and electric power generation sources are not very price sensitive, because the primary, ultimate uses of natural gas in these sectors are considered necessities: space heating, lighting, and appliances. Industrial consumption tends to be more price sensitive because when natural gas is used as a production input, as, for example, in the fertilizer industry, the produced goods are subject to international competition, and as a result passing on cost increases to consumers is difficult.

Table 6. U.S. Natural Gas Supply, 2004-2010

(trillion cubic feet)

	Domestic Production	Imports
2004	18.59	4.26
2005	18.05	4.34
2006	18.50	4.19
2007	19.27	4.60
2008	20.16	3.98
2009	20.58	3.75
2010	21.58	3.74

Source: Energy Information Administration, available at http://www.eia.doe.gov/dnav/ng/ng_move_impc_s1_a.htm.

In 2010, the United States produced about 85% of the natural gas it consumed (see **Table 6**), with 90% of the imported volumes arriving from Canada via pipeline. Liquefied Natural Gas (LNG) accounted for about 10% of imports, or about 1.3% of total U.S. consumption. LNG imports largely come from Trinidad, although Egypt, Norway, and Yemen also exported to the United States in 2010.

U.S. production of natural gas has increased since 2005 as production from unconventional sources such as shale gas has increased. As a result of increased domestic production, and the effects of the economic recession, imports decreased in 2008 through 2011. LNG, which some had forecast to become a major source of natural gas for the U.S. economy, has remained a minor component in natural gas supply, at about 1%-2%.

U.S. proved natural gas reserves have increased over the period 2004-2009 by approximately 42% (see **Table 7**), even though the nation has relied heavily on domestic supplies for consumption over the period. This result can be attributed to the development of new, non-conventional deposits of natural gas, such as shale gas. Offshore reserves have declined by about 35% over the period.

Table 7. U.S. Natural Gas Proved Reserves, 2004-2009

(trillion cubic feet)

	Offshore State	Offshore Federal	Total Reserves
2004	0.79	19.3	192.5
2005	0.77	17.8	204.4
2006	0.82	15.4	211.0
2007	0.72	14.3	237.7
2008	1.17	13.5	244.6
2009	0.99	12.6	272.5

Source: Energy Information Administration, available at http://www.eia.doe.gov/dnav/ng/ng_enr_dry_dcu_NUS_a.htm.

Notes: Reserves are proved, dry gas.

Economic Effects: Oil Market

The oil market is global in scope. Changes in demand and/or supply that take place anywhere in the world are likely to affect virtually all consumers. The key measure of price, in many cases, has responded with high upward volatility to increases in demand. This price behavior is the result of the short-run inelasticity of demand for oil and petroleum products. In the short run, inelastic demand implies that an increase in price will have a relatively smaller effect on the quantity demanded. This conclusion starts with a price change and traces through how the change affects quantities. The reverse logic is also true: that small changes in quantity can lead to relatively larger changes in price. During the period of high oil prices from 2004 through 2008, the actual quantity of oil demanded was exceeding forecast demand due to higher-than-expected world growth rates of gross domestic product. High growth in demand reduced excess capacity to minimal levels and resulted in substantial oil price increases. The economic recession moderated world growth of gross domestic product and led to stabilized demand for petroleum, but demand is rising again as the global economy emerges from the recession.

Another factor that increased in importance over the 2004 through 2010 period was the emergence of oil contracts as financial assets through commodity market investment. The extent to which this factor has contributed to the volatility of oil prices is still being debated, but the emergence of "financial oil" has introduced the role of expectations more directly into oil prices.

Both the short-run inelasticity of demand and the increased sensitivity of the oil market to expectations are likely to play a role in determining the degree to which opening offshore areas with potential resource deposits affects the price of oil.

Analyses of the effect on oil markets of opening offshore restricted areas to exploration, and ultimately, production, are complicated by the uncertainties inherent in existing reserve estimates. Since no exploration, or assessment of reserves, has taken place using modern technology, the available estimates are likely to be speculative (see detailed discussion below). Time is also a factor. Even if exploration of the tracts began this year, it would likely be 5 to 10 years before significant production reached the market. For these reasons, rigorous quantitative estimates on the effect on the price of oil of opening these offshore areas are not possible.

Qualitative observations are possible. If the oil markets are slack when the key decision points (leasing, exploration, production, etc.) are reached, meaning significant excess capacity exists, and oil exporting nations are restricting production, the effect on oil prices will likely be minimal. If the markets are tight, the effects could be noticeable, and contribute to lower prices. The inelasticity of demand plays a role here, as a relatively small increase in expected reserves and production could have a disproportionate effect on price.

However, a lower price of oil will generally also encourage consumption. Increased consumption of cheaper oil could lead to increased carbon emissions. As long as the increased consumption due to lower price was met through the use of new domestic supplies, energy dependence would not increase. The development of the offshore areas would be unlikely to eliminate U.S. dependence on foreign energy sources, and may not even reduce it. Other, older fields are likely to have experienced further declines in production by the time the new offshore sources go into production, meaning that it is likely that these new sources of production might only replace other lost output, thereby reducing the rate of increase of foreign dependence.

The cost of developing these resources also depends on the state of the oil market at the key decision points. Construction and development costs for petroleum investment projects have escalated sharply in recent years, reflecting the high market prices for oil. Delays and rapidly increasing costs reduced the economic viability of many projects. Although a low oil price environment might reduce the tightness in construction and development markets, reducing costs, it may also reduce the likelihood that the oil companies would find development of these resources to be economically viable.

Economic Effects: Natural Gas Market

Natural gas markets differ from the oil market in that they are not global, but regional. As shown in **Table 6**, above, virtually all U.S. natural gas consumption comes from U.S. or Canadian sources. The only link between regional natural gas markets is through LNG, but the rapidly growing market for LNG predicted earlier in this decade has failed to materialize. LNG is still largely characterized by long-term, two-party supply and purchase agreements. In the North American market, LNG plays the role of making up marginal short-falls in the demand and supply balance. As production from domestic onshore shale gas deposits increases, the role of LNG in the U.S. market will likely be small.

In this regional market structure, the development of new, offshore U.S. supplies could have a significant impact on the domestic price of natural gas, as well as contributing to U.S. energy independence of this fuel. Although the price of natural gas has not shown the same degree of volatility as oil, the United States has been among the highest-priced regions in the world. High prices have caused residential consumers to allocate a greater portion of their budgets to home heating expenses. Industrial users either lose sales to overseas competitors, or cease U.S. production when domestic natural gas prices rise too much beyond those observed in other regions of the world.

The development of offshore natural gas resources is likely to further retard the development of a growing LNG system in the United States. Terminals for the re-gasification of LNG have proven to be difficult to site and permit, and expensive to build. If domestic natural gas resources, close to existing collection and distribution systems, at least in the Gulf of Mexico, could be developed, the LNG terminals might prove to be redundant, depending on the volumes of natural gas that ultimately might be recovered. Offshore natural gas development, though commonly associated with offshore oil production, will likely be less competitive in a market environment dominated by onshore shale gas development.

Greater OCS Access and Supply

The Energy Information Administration (EIA) of the Department of Energy projects that U.S. oil production would increase from today's 5.3 million barrels per day (mbd) to 6.0 mbd by 2035 with complete OCS access.[9] Because of its significant reserves and resource potential, most of the projected increase in production would reportedly come from the OCS. The EIA projected that offshore crude oil production would increase from about 1.7 mbd to 1.9 mbd by 2035 when including complete access to the OCS. The EIA projected that production from the Atlantic and Pacific planning areas after 2014 and from the Eastern Gulf of Mexico after 2025 would add 500,000 barrels of oil per day to U.S. supply. Offshore natural gas production in the lower 48 states is expected to remain roughly stable out to 2035. The EIA estimates are uncertain as to how much of the increased natural gas production would come from the formerly restricted areas.[10]

Based on mean resource estimates by the Bureau of Ocean Energy Management (BOEM), a report prepared for the American Petroleum Institute by ICF International estimates an increase in OCS production from areas formerly off limits of 286,000 barrels per day in 2030.[11] When ICF assumed a much larger resource base for the OCS (and without the leasing moratoria), oil production from those areas formerly off limits were estimated to increase 900,000 barrels per day in 2030.

A National Petroleum Council (NPC) study estimated that 1 million barrels of oil and 3.8 billion cubic feet of natural gas per day could be added to U.S. oil and gas supply by 2025 from areas formerly off limits if the OCS remains open along with a cumulative investment of as much as $98 billion in exploration and development projects.[12]

Prior to lifting the OCS moratoria, the BOEM projected a rise in U.S. domestic production on federal lands coming primarily from deepwater offshore areas in the Gulf of Mexico. According to the BOEM, deepwater oil already accounts for more than 70% of offshore production and 18.5% of total U.S. crude oil production. The number of shallow water lease sales dropped from 418 in 2002 to 264 in 2008, while the number of deepwater lease sales rose from 281 to 633 during that same period. Deepwater (1,000 feet or 305 meters) lease sales spiked in 1997 at 1,110, following the Deepwater Royalty Relief Act of 1995. Further, it is notable that there has been increasing exploration activity and an increase in reported finds in the Gulf of Mexico in ultra-deep (5,000 feet or more) waters since 2003.

However, new production realized from newly opened areas would depend on many factors, such as oil and gas prices; investment in exploration, discoveries, and infrastructure; and regulatory requirements. Is the development scenario likely to change much if the OCS remains open?

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[9] U.S. DOE/EIA, Annual Energy Outlook, 2011.

[10] Testimony of Dr. Howard Gruenspecht, Acting Administrator, EIA, U.S. Department of Energy, before the Subcommittee on Energy and Minerals, Committee on Natural Resources, U.S. House of Representatives, March 5, 2009.

[11] ICF International, *Strengthening Our Economy: The Untapped U.S. Oil and Gas Resources*, prepared for American Petroleum Institute, December 5, 2008.

[12] National Petroleum Council, *Facing the Hard Truths About Energy,* p.168, July 2007.

Development of deepwater leases is much more expensive than shallow water leases, but the reserve potential and payoff are likely to be much greater in the deeper water. The Gulf oil spill of April 2010 and the associated changes in regulation of deepwater development has slowed offshore development in the short term, but the long-term impacts on offshore oil and gas development are uncertain.

Oil and Gas Reserves and Resources in the OCS

Meaningful projections or forecasts of the impact of offshore oil and gas production from areas previously under moratorium must rely on technical estimates of the oil and gas resources in those areas. The quality of those assessments depends on the methodology used and the data available. This section provides an overview of the quality of current assessments of the unexplored offshore areas and the uncertainties associated with those estimates.

Resource Estimation and Technological Change

Estimation Techniques in the OCS

Exploration and production proceed in stages during which increasing data provide increasing certainty about volumes of oil and gas present. Prior to discovery by drilling wells, the estimated volumes of oil and gas are termed undiscovered resources. When oil and/or gas has been discovered, the volumes of oil and gas are measured within pools or fields via well penetration or other technology, and are called reserves. Measured reserves are reported to the Securities and Exchange Commission by the owners of the wells.[13] Reserves have been reported for U.S. OCS areas that have been developed, such as the central and western Gulf of Mexico and some parts of the California coast, but no reserves of oil or gas have been reported along the Atlantic OCS, because there have been no discoveries, and only modest oil reserves have been reported on the Alaska OCS (30 million barrels of oil and no gas as of 2006).

In frontier areas or in undeveloped areas around existing production where little or no geophysical exploration or drilling has occurred, volumes of undiscovered oil and gas resources may be estimated based on the geological characteristics of the area. The quality of those estimates (or assessments) depends largely on the abundance and quality of geologic data available to the geologists making the estimates. The geologic characteristics of a remote area, to the extent they are known, can be compared to the oil and gas production history in a geologically similar or analogous area. The number and size of oil and gas fields vary with geologic environment, so an appropriate geologic model must be applied to the remote area. Again, more geologic information allows a more reliable assessment of undiscovered resources, whereas less geologic information results in greater uncertainty in the estimates. Secretary of the Interior Ken Salazar instructed departmental scientists from the BOEM and U.S. Geological Survey (USGS) to produce an updated estimate on conventional and renewable offshore energy resources. The report, published in early April, drew primarily from previous BOEM and Department of Energy

[13] For a full glossary and explanation of oil and gas reporting terms, see Securities and Exchange Commission: 17 CFR Parts 210, 229, and 249 [Release Nos. 33-8935; 34-58030; File No. S7-15-08] RIN 3235-AK00, Modernization of the Oil and Gas Reporting Requirements.

studies. The report concluded that there are a number of significant gaps related to environmental and energy resource data in the OCS.[14]

Because undiscovered resources of oil and gas in new areas are estimated using historical production in known areas, and because production in known areas is based on current exploration and production technology, these estimated volumes are called "technically recoverable" and are therefore referred to as undiscovered technically recoverable resources (UTRR). UTRR are estimates of the volumes of oil or natural gas likely to be recovered using currently available technologies without considering price. UTRR changes as available technology changes, but not as prices change. If an economic analysis is conducted to determine the volumes of oil and gas that could be profitably recovered under current economic conditions, those volumes are referred to as undiscovered economically recoverable resources (UERR). Estimates of UERR vary with the price of oil or gas.

Because these numbers are estimates and have been derived using probabilistic methods, three values for UTRR are normally reported: the volume of oil or gas that is 95% likely to be present, the volume that is 5% likely to be present, and a mean value. The 95% probability is the smallest number because it has the greatest certainty, and the 5% probability is the largest volume but carries great uncertainty. Many users of these assessments rely on the mean value for volumes of oil or gas present, but it is important to examine all three values to judge the uncertainty with which the volumes of oil or gas are likely to be present.

Analysis of Estimates

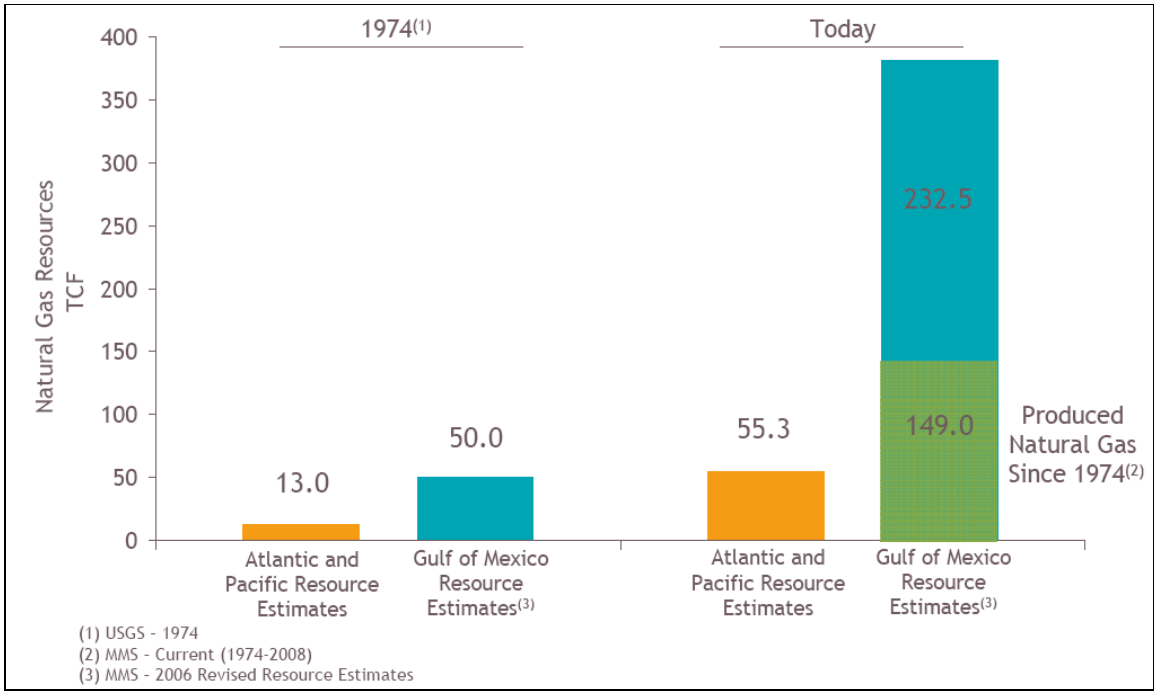
The assessments of UTRR on the U.S. OCS by the BOEM provide estimates whose statistical certainty varies by region, because the availability of geologic data varies widely by region.[15] For example, the extensive exploration and production histories of the central and western Gulf of Mexico and Southern California provide a comparatively greater amount of geologic data to use for assessments. In contrast, much of the remainder of the U.S. OCS has seen little exploration and production of oil and gas. Therefore, estimates of UTRR along the Atlantic Coast, much of the Pacific Coast, and coastal Alaska carry significant uncertainties. BOEM attempts to acquire geophysical exploration data (primarily seismic data) along these coasts, and purchases data to the degree they are available and if possible within their budget, but good data are difficult to acquire and much of the existing data are old.[16] Typically, initial estimates of UTRR change, sometimes dramatically, as the quantity and quality of data improve as exploration progresses. See **Figure 1**. Furthermore, no estimate of UERR has been attempted for U.S. OCS outside the currently producing areas. Therefore, caution must be exercised when attempting to forecast future production and resulting revenues from the OCS.

[14] U.S. Department of the Interior, *Survey of Available Data on OCS Resources and Identification of Data Gaps*, Report to the Secretary, OCS Report MMS 2009-015. http://www.doi.gov/ocs/report.pdf.

[15] U.S. Department of the Interior, Minerals Management Service, Fact Sheet RED-2006-01b, *Assessment of Undiscovered Technically Recoverable Oil and Gas Resources of the Nation's Outer Continental Shelf*, 2006.

[16] U.S. Department of the Interior, Minerals Management Service, OCS Report MMS 2007-049, *Geological & Geophysical Data Acquisition, Outer Continental Shelf Through 2004-2005*, 2007.

Figure 1. OCS Natural Gas Resource Estimates



Source: Figure 1. American Petroleum Institute, 2009.

Notes: Changes in estimates for undiscovered technically recoverable resources of natural gas in the Atlantic and Pacific regions (under moratorium) and the Gulf of Mexico (developed) between 1974 and 2006. Natural gas production from the Gulf of Mexico between 1974 and 2008 is shown in green.

OCS Resource Estimates

For offshore oil, under the Known Resources category (proved reserves, unproved reserves, and reserve appreciation), the BOEM estimated proved and unproved oil reserves in the OCS to be 8.55 billion barrels (3.9 Bbbl proved and 4.65 Bbbl unproved). The BOEM categorized 6.88 Bbbl of oil as reserve appreciation. Offshore proved (14.3 tcf) and unproved (14.96 tcf) natural gas reserves are estimated to be 29.26 tcf, plus 30.91 tcf in reserve appreciation.

In the UTRR category, the BOEM estimated oil resources to be nearly 86 billion barrels. Of this, about 41 Bbbl oil would potentially come from the central and western Gulf of Mexico and about 25.3 Bbbl of oil would come from Alaska. With that total, roughly 66.4 billion possible barrels out of 84.24 billion possible barrels are available (about 79%) for leasing in the current BOEM five-year leasing program.

BOEM estimates the amount newly available (with the moratoria ended) at around 13.9 Bbbl.[17] For natural gas, the BOEM estimates a total of 420 tcf of which about 55 tcf is newly available since the lifting of the moratoria. All of the newly available areas could be included in the next BOEM five–year leasing program under current law. About 3.88 Bbbl of oil and 21.51 tcf in the eastern Gulf of Mexico would remain off limits.

[17] Statement of C. Stephen Allred, U.S. Department of the Interior, before the Senate Committee on Energy and Natural Resources, Resource Estimate Table, January 25, 2007.

Of the total 1.7 billion acres of the OCS, there are about 131 million acres available for leasing in the current five-year leasing program.[18] About 76% of the total acreage, but only 21% of the UTRR, was unavailable under the OCS moratoria, according to BOEM estimates. There are 1,600 leases in production (10.5 million acres) out of 8,124 leases (on 43 million acres) administered by the BOEM in the OCS.

In the near term, additional offshore reserves are likely to come from deepwater fields in the Gulf of Mexico, an area where the vast majority of leases are held and where the largest resource potential exists. Deepwater discoveries are typically much larger than those found in shallow water fields. Annual volume additions to unproved reserves, resources, and industry-announced discoveries in deepwater reached an all-time high in 2006. When it becomes apparent that a field will go into production, those unproved reserves then become proved reserves. Since 2006, there has been a 44% increase in proved deepwater discoveries in the Gulf of Mexico. But at the same time, there are vast numbers of deepwater leases going undrilled. Of the nearly 1,900 ultra-deepwater (depths of 5,000 feet or greater) leases, only 272 were drilled between 1996-2007. If the oil and gas industry continues to commit significant capital for OCS exploration and development, and deepwater discoveries are made, then the decline in offshore reserves could be slowed or reversed.

Resource Estimates by Planning Area

The BOEM has divided the OCS into 26 planning areas within four regions (Atlantic, Gulf of Mexico, Pacific, and Alaska). **Table 2** below lists resource assessments by Planning Area. According to the BOEM assessments, the areas of greatest resource potential are located in the central and western Gulf of Mexico. Taken together, these two planning areas account for about 48% of the UTRR oil and 50% of the UTRR natural gas in the OCS. Alaska accounts for about 31% of the estimated oil and natural gas potential in the OCS.

Table 8. BOEM Assessment of UTRR in the OCS by Planning Areas

Planning Area	Oil (Bbbl)	Natural Gas (Tcf)
Atlantic		
North Atlantic	1.91	17.99
Mid Atlantic	1.50	15.13
South Atlantic	0.41	3.86
Total Atlantic	3.82	36.99
Gulf of Mexico		
Eastern	3.88	21.51
Central	30.32	144.77
Western	10.70	66.25
Straits of Florida	0.02	0.02

[18] The amount of acreage available in the OCS under the 2007-2012 leasing plan was listed at 181 million acres in the U.S. DOI, MMS, *Budget Justifications*, FY2010, p. 9, but the April 2, 2010 announcement to eliminate five Alaskan sales reduced the available acreage by about 50 million acres.

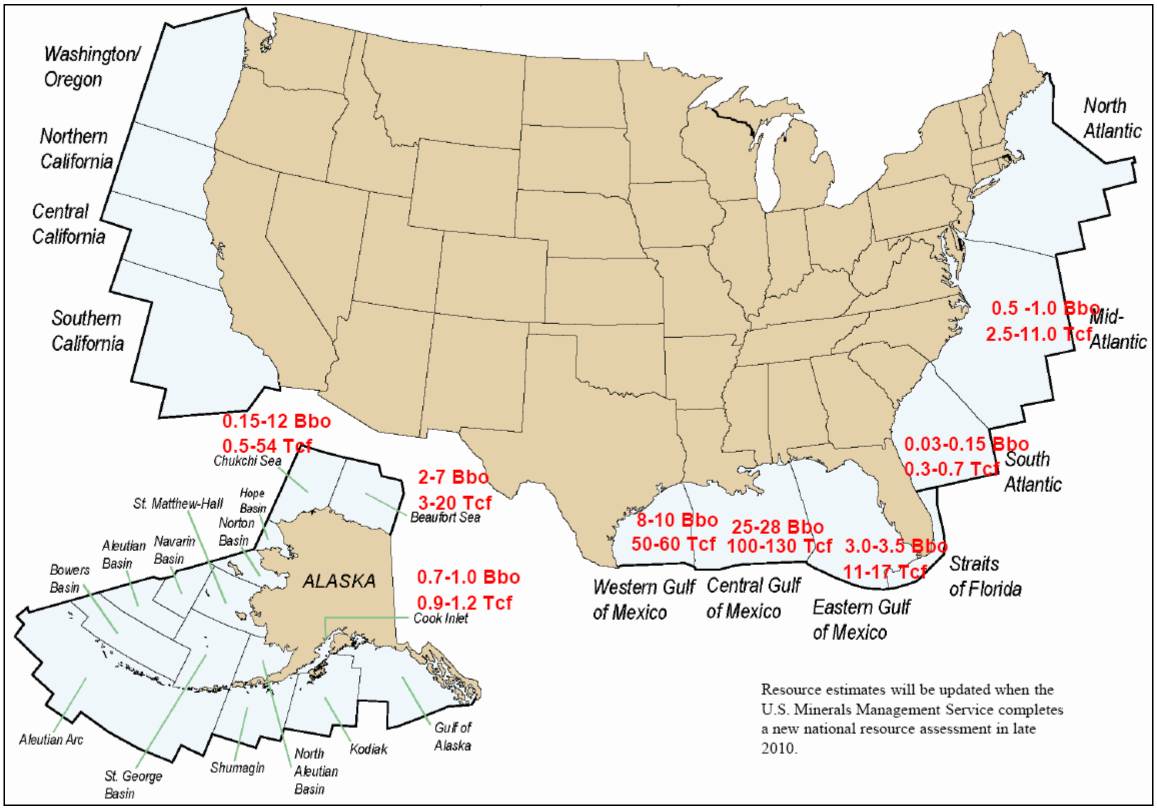
Planning Area	Oil (Bbbl)	Natural Gas (Tcf)
Total Gulf of Mexico	44.92	232.54
Pacific		
Washington/Oregon	0.40	2.28
Northern California	2.08	3.58
Central California	2.31	2.41
Southern California	5.74	5.74
Total Pacific	10.53	18.29
Alaska		
Beaufort Sea	8.22	27.64
Cook Inlet	1.01	1.20
Gulf of Alaska	0.63	4.65
Kodiak	0.05	1.84
North Aleutian Basin	0.75	8.62
Shumagin	0.01	0.49
St. Georges Basin	0.21	2.80
Navarin Basin	0.13	1.22
Norton Basin	0.06	3.06
Hope Basin	0.15	3.77
Chukchi Basin	15.38	76.77
Aleutian Arc	na	na
Bowers Basin	na	na
Aleutian Basin	na	na
St. Matthew-Hall	na	na
Total Alaska	26.61	132.06
Total U.S. OCS	**85.88**	**419.88**

Source: Statement of Stephen C. Allred, DOI/MMS, January 25, 2007.

In addition, the economically recoverable resources of oil and natural gas, based on an oil price of $80 per barrel, are provided on the map in **Figure 2** for the planning areas proposed for EIS scoping under President Obama's recent directive.

Figure 2. Estimated Undiscovered, Economically Recoverable Resources

(Resources at $80/bbl)



Source: BOEM, http://www.BOEM.gov/revaldiv/PDFs/NA2006BrochurePlanningAreaInsert.pdf.

Note: No price for natural gas was specified for economically recoverable natural gas resources.

Resource Estimates by Water Depth

BOEM Planning Areas differ considerably based on both water depth and distance from shore. (See BOEM website 2006 Resource Assessment Maps at http://www.mms.gov/revaldiv/NatAssessmentMap.htm.) For example, in the North Atlantic, over half of the potential oil and gas might be located in water depths of 200 meters or less, whereas in the South Atlantic, over 70% of the oil and gas is located between 200-800 meters of water and, based on BOEM maps, appears to be more than 50 miles from the coast. Because of the narrow shelf off the California coast, most of the potential oil and gas resources would likely be found within 50 miles of the coast and in water depths between 0-800 meters. The eastern Gulf of Mexico is vastly different than both coasts in that the vast majority of the potential oil (84%) and gas (68%) resources are beyond 2,400 meters of water depth and beyond 100 miles from the coast. Estimates show about 15% of the potential oil and 22% of the potential natural gas might be found in less than 200 meters of water (which could also be beyond 100 miles from the coast).

The OCS Leasing Process and Program

The Outer Continental Shelf Lands Act of 1953 (OCSLA), as amended, provides for the leasing of OCS lands in a manner that protects the environment and returns revenues to the federal government. Revenues come in three ways: bonus bids, rents, and royalties. Lease sales are conducted through a competitive, sealed, bidding process, and leases are awarded to the highest bidder. A minimum bid is determined for each tract offered. Successful bidders make an up-front cash payment, called a bonus bid, to secure a lease.

During the past 17 years, annual bonus revenues have ranged from $85 million in 1992 to $1.4 billion in 1997. Bidding on deepwater tracts in the mid-1990s led to a surge in annual bonus revenue.[19] Offshore bonus bids totaled $374 million in FY2007. But as a result of high oil and natural gas prices and the significant possible resources in the Central Gulf of Mexico, record-setting bonus bids of $3.7 billion were accepted by BOEM/ONRR at a lease sale in March 2008.

In addition to the cash bonus bid, a royalty rate of 12.5% or 16.7% is imposed on the value of production, depending on location factors, which can be cash or "in-kind."[20] The rate could be higher than 16.7% depending on the lease sale. For instance, lease sales 224 (March 2008) and 213 (March 2010) will require a royalty rate of 18.75% in all water depths. According to BOEM Congressional Affairs representatives, this higher rate (18.75%) is likely to remain in place for future lease sales. The Secretary of the Interior may reduce or eliminate the royalty established by the lease to promote increased recovery.

Annual rents are $5-$9.50 per acre (depending on water depth), with lease sizes generally ranging from 2,500-5,760 acres.[21] However, annual rental rates for the March 2009 sale in the Central Gulf of Mexico began at $11 per acre for leases in water depths over 200 meters. Bonding requirements are $50,000 per lease and as much as $3 million for an entire area.

OCSLA requires the Secretary of the Interior to submit five-year leasing programs that specify the time, location, and size of the areas to be offered. Each five-year leasing program entails a lengthy multistep process that includes an environmental impact statement. After a public comment period, a final proposed program is submitted to the President and Congress, which may be approved by the Secretary after 60 days if there is no objection by Congress.

Under current law, the primary offshore lease terms are 5, 8, or 10 years depending on water depth.[22] However, new lease terms, for blocks between 400 meters and 1,599 meters water depth, were imposed beginning with the March 2010 sale.[23] Leases continue as long as commercial quantities of hydrocarbons are being produced. If the lease is not producing oil or gas in commercial quantities by the end of its primary term, the lease reverts to the government for a possible future lease sale—unless the lessee is granted an extension. Extensions can be granted for offshore leases under 30 CFR 250.180. The regulation for offshore extensions does not

[19] U.S. Department of the Interior, FY2002 Budget Justifications, p. 63.

[20] A royalty-in-kind payment would be in the form of barrels of oil or cubic feet of natural gas.

[21] The annual rental rate prior to 2009 was usually $5-$6.25 per acre in water depths less than 200 meters and $7-$9.50 per acre in water depths of 200 meters or more. After 2009, the rental rates begin at $7/acre and escalate to $28/acre in year 8 and beyond for water depths less than 200 meters. In water depths between 200-400 meters, rental rates escalate from $11 per acre in year one to $44/acre in year 8 and beyond. For deep water over 400 meters, rates begin at $11/acre and escalate to $16/acre in year 8 and beyond.

[22] The primary term is 5 years for shallow water (<400 meters deep), 8 years for leases in water 400-799 meters deep, and 10 years for deepwater leases 800 meters and beyond.

[23] Initial lease terms for blocks between 400 meters to 799 meters water depth would be for five years which could be extended to eight years with a spudded well. Blocks between 800 meters to 1,599 meters water depth would receive a seven-year initial lease which could be extended to 10 years with a spudded well.

specify the length of the extension nor the conditions or requirements for an extension. Also, it is not clear how often the BOEM grant extensions.

Many leases expire before exploration or production occurs. Data from BOEM on the development status for existing leases has not been made available; thus, it is difficult to classify the amount of acreage that has had no activity, is in the permitting stage, or is under exploration but not producing.

Table 9. Lease Expirations and Relinquishments, 2001-2007

Year	Expired	Relinquished	Total
2001	496	248	744
2002	432	224	656
2003	208	352	560
2004	155	252	407
2005	352	303	655
2006	711	280	991
2007	938	241	1,179

Source: DOI/BOEM.

Nineteen lease sales were scheduled for the 2007-2012 leasing program.[24] Nine lease sales have occurred to date. Two lease sales were held in 2007 (sales 204 and 205), lease sale 193 in February 2008, and lease sales 206 and 224 in March 2008. Lease sale 207 was held in August 2008, lease sale 208 occurred in March 2009 and lease sale 210 in August 2009. The most recent sale (lease sale 213) took place in March 2010. The August 2011 lease sale 215 was cancelled. There are three lease sales remaining in the Revised Program.

Revenues from lease sale 224 will be shared with coastal states (Mississippi, Alabama, Texas, and Louisiana) as required by the Gulf of Mexico Energy Security Act (GOMESA). Thirteen of the 348 tracts (leases) bid on in lease sale 207 (located in sale area "181 South") also fall under the revenue sharing agreement in GOMESA (see revenue-sharing section of this report).

The Obama Administration had generally expressed support for BOEM efforts to facilitate development of deepwater and ultra deepwater oil and gas in the Gulf of Mexico and in the Alaskan OCS. With the moratoria lifted, leasing can occur in the newly opened areas. If the OCS remains open, it could be as much as five years or longer for lease sales to be held in the newly opened areas. Production might begin 5-10 years from the lease sale if commercial quantities are found. New infrastructure requirements (e.g., pipelines, roads, and onshore facilities) are likely to be needed, particularly along the East Coast where there has been no leasing activity in decades.

Generally, a number of concerns arise in the oil and gas leasing process that delay or prevent oil and gas development from taking place, or might account for the large number of leases held in non-producing status. There could be a lack of drilling rigs or other equipment availability, and financing and/or skilled labor shortages. Legal challenges might delay or prevent development.

[24] Since 1983, a typical OCS lease sale would consist of thousands of leases/tracts being offered (as high as 8,800 tracts offered in a 1984 lease sale), but only as many as several hundred receiving bids.

There are typically also many leases in the development cycle (e.g., conducting environmental reviews, permitting, or exploring) but not producing commercial quantities.

OCS Revenues

Revenue Sharing or Not?

Federal revenues from offshore leases were estimated at $6.5 billion in FY2011 by the Office of Natural Resources Revenue (ONRR). During the previous 10 fiscal years (2001-2010), revenues from federal OCS leases ranged from a low of $4.1 billion in FY2002 to a high of $18 billion in FY2008. Of the $18 billion offshore revenue in FY2008, $8.3 billion was from royalties and $9.5 billion came from bonus bids. Changing prices for oil and gas are the most significant factors in the revenue swings.

Overall, revenues from federal energy and mineral leases were estimated at $11.2 billion in FY2011 by the Office of Natural Resources Revenue (ONRR). Offshore receipts have accounted for between 55% and 75% of the total mineral and energy leasing revenues received by the federal government during the past 10 fiscal years.

OCS leasing revenues are split among various government accounts. Revenues from the offshore leases are statutorily allocated among the coastal states, the Land and Water Conservation Fund,[25] the National Historic Preservation Fund,[26] and the U.S. Treasury. States receive 27% of all OCS receipts closest to state offshore lands under Section 8(g)[27]of the OCSLA amendments of 1985 (P.L. 99-272). A dispute over what was meant by a "fair and equitable" division of the 8(g) receipts was settled by the 1985 OCSLA amendments.[28] In FY2011, this share was about $42.0 million out of about $2 billion in total state on-shore and offshore disbursements. States have argued for a greater share of the OCS revenues based on the significant impacts on infrastructure and the environment. According to the coastal producing states, the revenues are needed to mitigate environmental impacts and to maintain the necessary support structure for the offshore oil and gas industry. Revenue sharing provisions in the Gulf of Mexico Energy Security Act of 2006 (GOMESA) allow for Gulf producing states (defined as Alabama, Mississippi, Louisiana, and Texas) to receive 37.5% of revenues generated from certain leases beginning FY2007. Beginning in FY2017 and thereafter, the Gulf producing states would also receive 37.5% of the revenues generated from leases awarded within the 2002-2007 planning area, including historical

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[25] For details on the Land and Water Conservation Fund, see CRS Report RL33531, *Land and Water Conservation Fund: Overview, Funding History, and Issues*, by (name redacted).

[26] Under the National Historic Preservation Act (16 U.S.C. 470 et. seq.), the National Historic Preservation Fund is authorized to receive $150 million annually from OCS receipts. Authorization for this act expired at the end of FY2005, thus no funds were disbursed from OCS receipts in FY2006. After reauthorization in December 2006, funding from OCS receipts resumed in FY2007.

[27] The 8(g) revenue stream is the result of a 1978 OCSLA amendment that provides for a "fair and equitable" sharing of revenues from Section 8(g) common pool lands. These lands are defined in the amendments as submerged acreage lying outside the standard three-nautical-mile state-federal demarcation line, typically extending to a total of six nautical miles offshore (or three miles beyond the state's boundary) but that include a pool of oil common to both federal and state jurisdiction. The states' share of the revenue (27%) was established by the OCSLA amendments of 1985 (P.L. 99-272) and is paid directly to the states. Payments to the states previously had been placed in escrow, which were then paid out between 1986 and 2001.

[28] U.S. Department of the Interior, Minerals Management Service, *Mineral Revenues 2000*, p. 95.

leases (described in the statute). The Land and Water Conservation Fund (currently funded from OCS revenues) would receive 12.5% of the qualified revenues for state programs and the federal General Treasury would receive 50% of those revenues. BOEM/ONRR estimated that the states' share would total $3.1 billion through 2022 and increase to a total of $59.6 billion through 2067.

Revenues derived from lease sale 224, held in March 2008, and 13 OCS tracts in lease sale 208, held in March 2009, have been split with the four coastal states under GOMESA. Coastal Impact Assistance Program (CIAP) revenue, derived from OCS leasing revenues, is shared with coastal producing states. Based on the formula and authority in the Energy Policy Act of 2005 (Section 384, P.L. 109-58), $250 million of OCS revenues is shared annually for a four-year period ($1 billion from 2007-2010). Revenues from both GOMESA and CIAP are authorized for specific purposes (identified in the statutes) such as for the conservation, protection, and restoration of coastal areas; mitigation of damage to fisheries; and the implementation of a federally approved marine, coastal, or comprehensive conservation management plans.

For onshore public domain leases, states generally receive 50% of rents, bonuses, and royalties collected. Alaska, however, receives 90% of all revenues collected on public domain leases. There was language in the proposed draft five-year lease program (2010-2015) to encourage Congress to pass legislation that would expand revenue sharing agreements with states from future lease sales.

Royalty Revenue Estimates

The ICF International report[29] estimated that opening the OCS to production would increase federal revenues by $360 billion to $1.4 trillion (including royalties and bonuses of about $180 billion). This increase represents an increase over projected revenues (given the OCS moratoria) of 15% to 60% over the area that was classified as accessible, and assumes development of the entire economic resource base over a 30-year period.[30]

The Draft Proposed Leasing Program (DPP), 2010-2015, projected leasing revenues of $368 million based on the 30 lease sales (which includes 10 sales in areas formerly off limits) in the DPP. An additional $1.1 billion would be generated from taxes. The DPP was not implemented.

These estimates should be viewed with caution, as there are major uncertainties involved. First, the amount of recoverable resource is an estimate based on assumptions and probabilities; they are in fact educated guesses. Second, projecting the price of oil for a few years is difficult and complex; projecting prices for decades is highly uncertain. Lastly, possible future legislation and its terms are not known at this time, and could significantly alter revenue arrangements.

[29] *Strengthening Our Economy: The Untapped U.S. Oil and Gas Resources*, December 5, 2008.

[30] Ibid, p. 9.

Environmental Concerns Associated with Offshore Exploration and Development

The environmental risks of offshore oil and gas development are being vividly displayed in the Gulf of Mexico as a result of the recent and ongoing oil spell there. In addition, historical events associated with offshore oil production, such as the large oil spill off the coast of Santa Barbara, CA, in 1969, cause both opponents and proponents of offshore development to consider the risks and to weigh those risks against the economic and social benefits of the development. Despite the use of more sophisticated drilling and monitoring tools by oil companies, the recent offshore oil spill resulting from the explosion and subsequent sinking of the Deepwater Horizon mobile drilling rig has demonstrated that catastrophic accidents may still occur, particularly associated with the more complex process of drilling in deep water. (For a full description of that event and related issues, see CRS Report R41262, *Deepwater Horizon Oil Spill: Selected Issues for Congress*, coordinated by (name redacted) and (name redacted); CRS Report R41407, *Deepwater Horizon Oil Spill: Highlighted Actions and Issues*, by (name redacted) and (name red acted); CRS Report R41684, *Oil Spill Legislation in the 112th Congress*, by (name redact ed); CRS Report RL33705, *Oil Spills in U.S. Coastal Waters: Background and Governance*, by (name redacted); and CRS Report R41311, *The Deepwater Horizon Oil Spill: Coastal Wetland and Wildlife Impacts and Response*, by (name redacted) and (name redacted).)

This section describes some of the general environmental risks associated with offshore oil and gas development, and considers how those risks have changed over time. A more detailed discussion of offshore environmental issues is included in OCS Report MMS 2009-015 (see footnote 11), which describes potential impact of offshore oil and gas development on seafloor habitats, coastal habitats, marine fish resources, marine mammals, sea turtles, and marine and coastal birds.

Offshore Areas Currently Protected

In addition to limited areas in shipping lanes and military reserves, certain portions of offshore U.S. waters remain off limits to development even when moratoria are lifted. The National Marine Sanctuaries System, administered by the National Oceanic and Atmospheric Administration, was originally created under the Marine Protection, Research, and Sanctuaries Act of 1972 (MPRSA) and later amended most significantly as the National Marine Sanctuaries Act of 1992.[31] This legislation provides authority for the Secretary of Commerce, under certain conditions, to:

> designate as marine sanctuaries those areas of the oceans, coastal, and other waters, as far seaward as the outer edge of the Continental Shelf ... which he determines necessary for the purpose of preserving or restoring such areas for their conservation, recreational, ecological, or esthetic values.

The National Marine Sanctuary System comprises of 14 sanctuaries ranging in size from less than one square mile to 137,792 square miles. Of the 14 sanctuaries, 10 are currently or potentially

[31] Listed in order of creation. For more information, see Legislative History of the National Marine Sanctuaries Act at http://sanctuaries.noaa.gov/about/legislation/leg_history.html.

located within areas that might be attractive for oil and gas exploration. See box below. Oil and natural gas exploration and development are not permitted within the boundaries of the National Marine Sanctuaries, but such activities may be allowed nearby depending on specific provisions of the BOEM leasing programs.

Because of ongoing concerns about the effects of nearby oil and gas development on the health of the National Marine Sanctuary habitat, the BOEM has monitored the effects of oil and gas activities on a coral reef area of the Flower Garden Banks National Marine Sanctuary in the Gulf of Mexico for over 25 years. This effort is ongoing and conducted in partnership with the National Oceanic and Atmospheric Administration (NOAA), who administers the sanctuary. Although a buffer zone of three miles is maintained, oil and gas activities have increased in the surrounding area with no observable effects to the corals. BOEM requires that the nearby industry shunt wastes (dispose of through a pipe to near the seafloor) away from the banks. This mitigation was developed based on oceanographic research that indicated this would prevent these materials from coming in contact with the coral reefs.

National Marine Sanctuaries Located in Continental U.S. Coastal Waters[32]

Monitor National Marine Sanctuary protects the wreck of the famed Civil War ironclad USS *Monitor* off Cape Hatteras, NC. Established Jan. 30, 1975.

Channel Islands National Marine Sanctuary encompasses the waters surrounding San Miguel, Santa Rosa, Santa Cruz, Anacapa, and Santa Barbara Islands off the coast of California. Established Sept. 22, 1980.

Gray's Reef National Marine Sanctuary is 23 square miles just off the coast of Georgia. Established Jan. 16, 1981.

Gulf of the Farallones National Marine Sanctuary covers more than 1,200 square miles of coastal and ocean wilderness west of San Francisco. Established Jan. 16, 1981.

Cordell Bank National Marine Sanctuary gets its name from the underwater mountain that rises to within 120 feet of the ocean's surface off Point Reyes, CA, 526 square-miles. Established May 24, 1989.

Florida Keys National Marine Sanctuary is 3,700 square miles surrounding the Florida Keys. Established Nov. 16, 1990.

Flower Garden Banks National Marine Sanctuary is 50 square miles, 100 miles off the Texas-Louisiana coast. Established Jan. 17, 1992.

Monterey Bay National Marine Sanctuary is the nation's largest marine sanctuary, spanning more than 6,000 square miles of coastal waters off central California. Established Sept. 18, 1992.

Gerry E. Studds Stellwagen Bank National Marine Sanctuary sits at the mouth of Massachusetts Bay, just 25 miles from Boston. 824 square miles. Established Nov. 4, 1992.

Olympic Coast National Marine Sanctuary spans 3,310 square miles of marine waters off the Olympic Peninsula. Established July 16, 1994.

[32] http://sanctuaries.noaa.gov/welcome.html.

General Environmental Regulations and Requirements for Offshore Exploration and Production

All environmental aspects of offshore exploration, development, drilling, production, transportation, and decommissioning are subject to regulation. In addition to the general legal and regulatory framework that includes the OCLSA,[33] several environmental laws and executive orders have been enacted or amended since the first congressional moratorium for offshore areas in 1982, including:

- The 1990 Clean Air Act Amendments (P.L. 101-549) transferred jurisdiction over air quality from BOEM to EPA for all OCS areas outside the Central and Western Gulf of Mexico, and require BOEM to coordinate air pollution control activities with EPA. The regulations are the same as onshore leasing requirements. EPA also is setting emission limits on diesel engines and marine vessels to decrease emissions.
- The Oil Pollution Act of 1990 (P.L. 101-380), in part, revised Section 311 of the Clean Water Act to expand federal spill-response authority; increase penalties for spills; establish U.S. Coast Guard pre-positioned oil-spill response equipment sites; require vessel and facility response plans; and provide for interagency contingency plans.
- On February 11, 1994, President Clinton issued Executive Order 12898, entitled *Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations*, which directs federal agencies, including BOEM, to assess whether their actions have disproportionate environmental effects on people of ethnic or racial minorities or with low incomes.
- National Fishing Enhancement Act of 1984 (P.L. 98-623), also known as the Artificial Reef Act, establishes artificial reef development standards and a national policy to encourage the development of artificial reefs that will enhance fishery resources and commercial and recreational fishing. BOEM adopted a national Rigs-to-Reefs policy that supports and encourages the reuse of oil and gas structures for offshore artificial reef developments, which provide valuable habitat for species of fish in areas devoid of natural hard bottom. It is anticipated that approximately 10% of OCS platforms installed would become a rigs-to-reef after decommissioning.
- President Clinton issued Executive Order 13089 on Coral Reef Protection on June 11, 1998. BOEM carries out the mission of E.O. 13089 by supporting coral reef research and developing mitigation measures to protect these fragile and biologically rich ecosystems.
- Other acts, such as the Shore Protection Act of 1988 (P.L. 100-688) and Marine Plastic Pollution Research and Control Act of 1987 (P.L. 100-220), require containment of trash and debris, and restrict its disposal offshore. As a result of these acts, BOEM has issued Notice to Lessees on awareness and elimination of

[33] For more information on the legal aspects of offshore oil and gas development, see CRS Report RL33404, *Offshore Oil and Gas Development: Legal Framework*, by (name redacted).

marine trash and debris, which pose a threat to fish, marine mammals, sea turtles, and other marine animals.

- The 1996 amendments to the Magnuson-Stevens Fishery Conservation and Management Act (P.L. 94-265, as amended) emphasized the need to protect fisheries habitat for long-term conservation of fisheries. Under its authority, Fishery Management Plans designate essential fish habitat (EFH) for managed species. The act requires that federal agencies consult with NOAA (National Marine Fisheries Service) about actions that could damage EFH. This process ensures consultation on fisheries of concern in a given project area.
- The National Environmental Policy Act of 1969 (NEPA, P.L. 91-190, as amended) requires that all federal agencies use a systematic, interdisciplinary approach to assess the impacts of proposed actions on the human environment; this approach is intended to ensure the integrated use of the natural and social sciences in any planning and decision-making that may have an impact upon the environment. Since its enactment, thousands of environmental assessments and environmental impact statements have evaluated the potential impacts of OCS oil and gas exploration and development on environmental and socioeconomic resources.

Environmental Impact Statements

As with many development activities, offshore oil and gas exploration and development requires environmental impact statements (EIS). The EIS provides the public with an opportunity to comment on the estimated environmental impacts of development alternatives. The OCS Report MMS 2009-015[34] summarizes the EIS process:

> As required in Section 20 of the Outer Continental Shelf Lands Act (OCSLA), the MMS has established a tiered process that evaluates the potential environmental consequences for each successive management decision starting with the proposed program, then individual lease sales, and finally project-specific plans. The 5-Year Programmatic Environmental Impact Statement (EIS) analyzes the proposed leasing schedule, focusing on the size, timing, and location of proposed lease sales for the 5-year period identified in the proposed program document. The Programmatic EIS takes a broad overview of the environmental effects from the potential activities.
>
> Once the 5-year lease sale schedule is approved, a more detailed environmental analysis is conducted for each proposed lease sale in a given area. These lease sale EISs are more detailed, including analyzing scenarios of potential activities that could result, should a lease sale occur. At this point, MMS identifies lease stipulations, which are protective of the environment, to be included in the leases granted to industry. In some cases, an EIS is prepared for multiple lease sales in a program area. This Multisale EIS is the only environmental review conducted for the first sale held in a program area. An additional environmental review, in the form of an Environmental Assessment (EA) or supplemental EIS, is conducted for each subsequent proposed lease sale to address any new relevant information. Along with the preparation of a lease sale EIS or EA, the MMS carries out informal and formal consultations with other Federal Agencies, the affected States, and the public. This includes the ESA Section 7 consultations with the National Oceanic and

[34] Op. cit.

> Atmospheric Administration (NOAA) and the U.S. Fish and Wildlife Service (FWS), an Essential Fish Habitat (EFH) consultation with NOAA, government to government consultations with tribes, and preparation of a consistency determination for each affected coastal State, as required in the CZMA.
>
> After leases are issued, the MMS conducts environmental reviews for every exploratory and development plan to ensure that the proper environmental protective measures (mitigations) are employed. The MMS identifies site-specific mitigation measures in the form of conditions of approval. The mitigations may include avoidance of sensitive biological communities and archaeological resources, or inclusion of specialized discharge requirements.

Oil Spills and Leaks

Perhaps the greatest environmental concern associated with offshore oil production is oil spills or "blowouts." A blowout is the potentially catastrophic loss of control of the fluids in a well during drilling that releases drilling fluids, oil, and natural gas into the water, such as the Deepwater Horizon blowout and oil spill that occurred on April 20, 2010. With the drilling of oil wells and the production and transport of oil offshore, there is always some risk of oil leakage or spillage, and the serious damage that crude oil has on wildlife and on wildlife habitat is extensively documented in a number of environments. Prior to the Deepwater Horizon oil spill in the Gulf of Mexico, the industry had demonstrated some progress in reducing the risk of oil spills, as described in BOEM's *Draft Proposed Outer Continental Shelf (OCS) Oil and Gas Leasing Program, 2010-2015*:[35]

> Since the Santa Barbara Channel OCS oil spill in 1969, measures have been underway continuously to improve the technology of offshore operations, and the Federal government has developed more stringent regulations governing OCS operations. Each OCS facility is subject to an announced inspection for compliance with environmental and safety regulations at least once a year and MMS also conducts periodic unscheduled inspections. The result of all of these efforts is an excellent record that has been documented in detail in previous 5-year program analyses and in several MMS publications. In the fifteen year period between 1993 and 2007, Federal OCS operators produced 7.49 billion barrels of oil (crude oil and condensate). During that same period, the amount of oil spilled totaled about 47,800 barrels (crude & refined petroleum spills of 1 barrel or greater) (0.0006% of that produced) or about 1 barrel of petroleum spilled for every 156,000 barrels produced.

Despite improvements in the offshore technologies such as improved blowout protectors and subsurface safety shutoff valves (SSSV)[36] and the accompanying reduction in the risk, equipment may fail, drilling procedures may be not be followed, and oil spills may still occur. In addition to spills that occur during general drilling operations such as the recent spill, the number of spills generally increases during hurricanes in the Gulf of Mexico, as reflected in the high number of spills in 2004 (Hurricane Ivan) and 2005 (Hurricanes Katrina and Rita). See **Table 10**. Of course,

[35] Department of the Interior, Minerals Management Service, *Draft Proposed Outer Continental Shelf (OCS) Oil and Gas Leasing Program 2010-2015*, January, 2009: http://www.mms.gov/5-year/PDFs/2010-2015/DPP%20FINAL%20(HQPrint%20with%20landscape%20maps,%20map%2010).pdf.

[36] MMS published in December of 2000 the final rule (Section 30, Code of Federal Regulations, Part 250) which included the international standard that specifies the minimum acceptable requirements for subsurface safety valve equipment. The SSSV will shut off flow of hydrocarbons in the event of an emergency and is considered the last line of defense in securing a well and/or preventing pollution.

the number of spills per year does not fully communicate the impact of individual spills such as the Deepwater Horizon incident.

Table 10. Number of Spill Incidents Between 1996 and 2008

(more than 50 gallons per incident)

Year	OCS Spill Incidents
1996	4
1997	3
1998	9
1999	5
2000	7
2001	9
2002	12
2003	12
2004	22
2005	49
2006	14
2007	4
2008	5
2009	11
2010	6

Source: U.S. Department of the Interior, Bureau of Ocean Energy, Regulation and Enforcement, *Spills - Statistics and Summaries 1996-2008*, http://www.BOEM.gov/incidents/IncidentStatisticsSummaries.htm.

Notes: Data are for the oil and gas producing regions of the Gulf of Mexico and Southern California OCS. Hurricane Ivan entered the Gulf of Mexico in 2004, and most of the 2005 spills were associated with Hurricanes Katrina and Rita in the Gulf of Mexico.

The BOEM regulations require that the producers be prepared for oil spills:

> The MMS requires that all drilling or production operations on the OCS have an approved oil spill contingency plan that describes where the nearest equipment is located, where the trained personnel are, and how everyone is notified. Additional site-specific information as to response capabilities specific to a worst case spill will be required. During drilling operations, a company can be required to have equipment staged on a dedicated vessel located at the rig, which can immediately contain and clean up a spill. There is also oil spill equipment available at onshore bases. The MMS conducts frequent inspections of all OCS activity—both at the drilling stage and at production. It also requires the use of subsurface safety valves that shut-in the flow of oil in emergencies such as loss of the entire rig or platform.[37]

Of course, the effectiveness of such measures depends upon compliance and enforcement of the regulations.

[37] Ibid.

Seismic Surveys and Industrial Noise

Virtually every oil and gas exploration program involves the gathering of two-dimensional or three-dimensional reflective seismic data. Seismic data are collected by generating intense sound waves using percussive air guns towed by ships. The sound waves are propagated through seawater into the underlying sediment and rocks, and reflected sound waves are detected using an array of hydrophones towed behind the ship. These data provide images of subsurface rock strata and structures and guide exploration and development.

The impact of seismic surveys on fish and marine mammals is mixed. One study indicates that there is a local and temporary reduction in the catch of cod by fishermen after seismic data collection,[38] whereas other studies suggest little or no effect on other fish species.[39] In neither case is permanent damage to individual fish or to fish populations ascribed to seismic surveys. The effects of seismic surveys on whales and other marine mammals have been more carefully studied and have received more public attention. The rigorous study by Jochens et al. of whales and other cetaceans found no unusual effects of experimentally controlled exposure to seismic exploration on the swimming and diving behavior by sperm whales in the Gulf of Mexico.[40] A more complete discussion of environmental issues associated with offshore oil and gas exploration and development can be found in Section III of OCS Report MMS 2009-015.

[38] A. Engas, et al., "Effects of seismic shooting on local abundance and catch rates of cod (Gadus morhua) and haddock (Melanogrammus aeglefinus)," *Canadian Journal of Fisheries and Aquatic Sciences*, vol. 53, no.10, 1996, pp. 2238-2249.

[39] J. Dalen and G.M. Knutsen, "Scaring effects in fish and harmful effects on eggs, larvae and fry by offshore seismic explorations." In: H.M Merklinger (ed.), *Progress in Underwater Acoustics*, Plenum Press, NY, 1986.

[40] A. D. Jochens et al., *Sperm whale seismic study in the Gulf of Mexico: Synthesis report*. U.S. Dept. of the Interior, Minerals Management Service, Gulf of Mexico OCS Region, New Orleans, LA., OCS Study MMS 2008-006, 2008, 341 pp.

Appendix. Definition of Terms[41]

Proved reserves. The quantities of hydrocarbons estimated with reasonable certainty to be commercially recoverable from known accumulations under current economic conditions, operating methods, and government regulations. Current economic conditions include prices and costs prevailing at the time of the estimate. Estimates of proved reserves do not include reserves appreciation.

Reserves. The quantities of hydrocarbon resources anticipated to be recovered from known accumulations from a given date forward. All reserve estimates involve some degree of uncertainty.

Reserves appreciation. The observed incremental increase through time in the estimates of reserves (proved and unproved) of an oil and/or natural gas field as a consequence of extension, revision, improved recovery, and the additions of new reservoirs.

Resources. Concentrations in the earth's crust of naturally occurring liquid or gaseous hydrocarbons that can conceivably be discovered and recovered.

Undiscovered resources. Resources postulated, on the basis of the geologic knowledge and theory, to exist outside of known fields or accumulations.

Undiscovered technically recoverable resources (UTRR). Oil and gas that may be produced as a consequence of natural pressure, artificial lift, pressure maintenance, or other secondary recovery methods, but without any consideration of economic viability. They are primarily located outside of known fields.

Undiscovered economically recoverable resources (UERR). The portion of the undiscovered technically recoverable resources that is economically recoverable under imposed economic and technologic conditions.

Unproved reserves. Quantities of hydrocarbon resources that are assessed based on geologic and engineering information similar to that used in developing estimates of proved reserves, but technical, contractual, economic, or regulatory uncertainty precludes such reserves from being classified as proved.

[41] Definitions of terms taken from Report to the Secretary, op. cit., MMS 2009-015, Appendix A, List of Terms Used.

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Acknowledgments

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