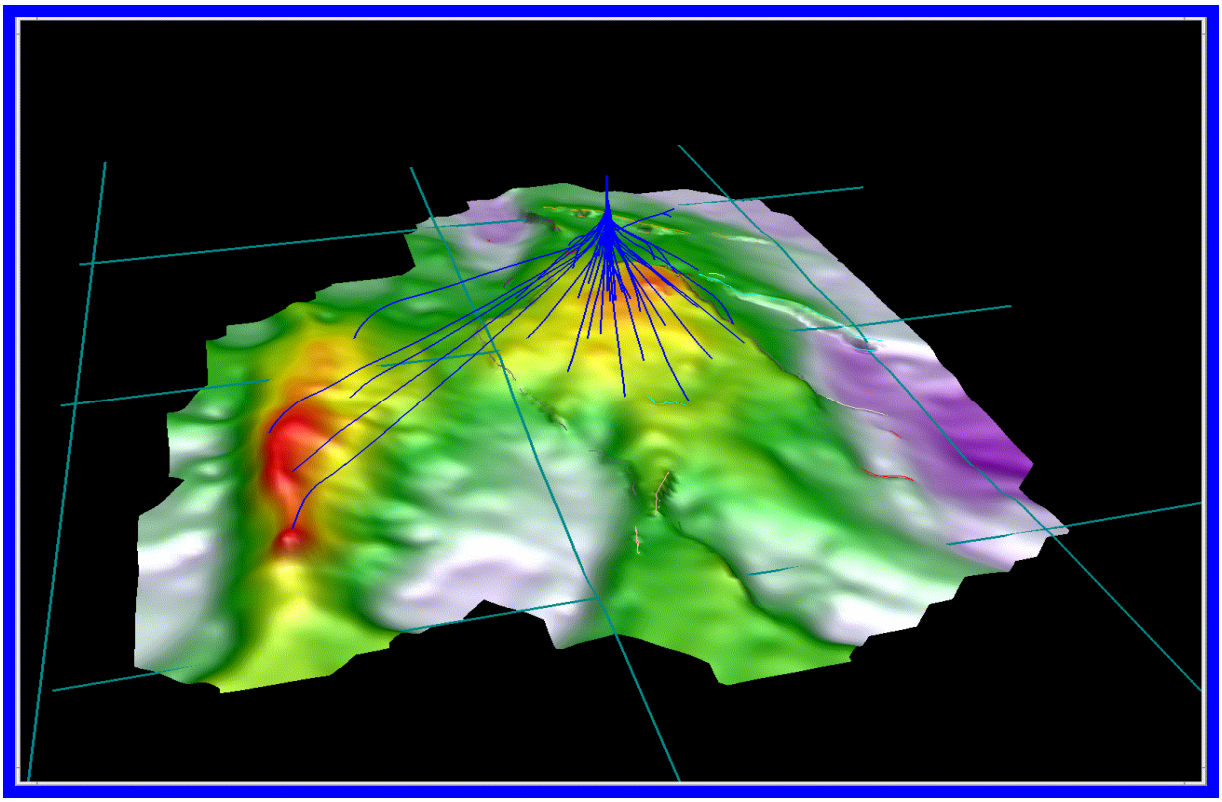
Report to Congress: Comprehensive Inventory of U.S. OCS Oil and Natural Gas Resources

Energy Policy Act of 2005 – Section 357



MMS U.S. Department of the Interior
Minerals Management Service

Cover illustration is a 3-dimensional representation of subsurface geology and possible oil and gas well development scenario. Grid lines represent OCS lease blocks.

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Report to Congress: Comprehensive Inventory of U.S. OCS Oil and Natural Gas Resources

Energy Policy Act of 2005 – Section 357

Prepared by

Minerals Management Service
Offshore Minerals Management Program

For the
U.S. Congress

U.S. Department of the Interior
Minerals Management Service

February 2006

Preface

This report is required by Section 357 of the Energy Policy Act of 2005, entitled, *"Comprehensive Inventory of OCS Oil and Natural Gas Resources."* It directs the Secretary of the Interior to provide a report to Congress within six months of the date of enactment (i.e., August 8, 2005). The statute mandates that the inventory and report:

1) incorporate available data on oil and natural gas resources in areas offshore of Mexico and Canada that are relevant to estimating the resource potential of the U.S. Outer Continental Shelf (OCS);
2) use any available technology except drilling to obtain accurate resource estimates;
3) analyze how OCS resource estimates have changed over time in relation to available data and exploration and development activities;
4) estimate the effect of understated oil and natural gas resource estimates on domestic energy investments; and
5) identify and explain how legislative, regulatory and administrative programs or processes restrict or impede resource development and affect domestic supply.

The U.S. Department of the Interior's (DOI) Minerals Management Service (MMS) assembled personnel from the Offshore Minerals Management (OMM) program to respond to this statutory directive.

Executive Summary

"... man's mind is his most valuable asset— a 'natural resource' of unlimited potential— and the key to an abundant supply of fuel in the future."
—Lewis G. Weeks, petroleum geologist

Worldwide reliance on petroleum resources, such as oil and natural gas, will continue to be the principal means to satisfy future energy demand for decades. Petroleum resources are usually considered finite since they do not renew at a rate remotely approaching their rate of consumption. Since petroleum also helps fuel the Nation's economy, there is considerable interest in the magnitude of the resource base from which future domestic discoveries and production will occur. Resource assessments are a critical component of energy policy analysis, and provide the industry and public with important information about the relative potential of U.S. offshore areas as sources of oil and natural gas available to supply the Nation's future energy needs.

This report first summarizes the results of the Minerals Management Service (MMS) 2006 assessment of the technically recoverable resources for the U.S. Outer Continental Shelf (OCS). Technically recoverable resources are hydrocarbons potentially amenable to conventional production regardless of the size, accessibility, and economics of the accumulations assessed. The OCS comprises the portion of the submerged seabed whose mineral estate is subject to Federal jurisdiction (see figure 1). The MMS and the U.S. Geological Survey (USGS) have previously completed several assessments of oil and gas resources of the OCS. The 2006 assessment represents a comprehensive appraisal that considered relevant data and information available as of January 1, 2003, and incorporated improved assessment methodologies. No new government-sponsored geological or geophysical data acquisition was undertaken for this inventory.

The petroleum commodities assessed are crude oil, natural gas liquids (condensates), and natural gas that exist in conventional reservoirs producible with typical traditional recovery techniques. The terms natural gas and gas are used interchangeably in this report. The volumetric estimates of oil resources reported represent combined volumes of crude oil and condensate. In developing these estimates it was necessary to make fundamental assumptions regarding future technology and economic conditions. The necessity to predict the future magnitude and directional impact of these factors introduces additional uncertainty to the resource assessment. Although not considered in this report, the continued expansion of the technological frontiers can be reasonably assumed to partially mitigate the impacts of a lower quality remaining resource base (smaller pool sizes, less concentrated accumulations, and more remote locations) and less favorable economic conditions.

Resource estimates are just that— *estimates*. All methods of assessing potential quantities of technically recoverable resources are efforts in quantifying a value that will not be reliably known until the resource is nearly depleted. Thus, there is considerable uncertainty intrinsic to any estimate. The estimates incorporate uncertainty, but they cannot account for the unforeseen or serendipity. As such, resource estimates should be used as general indicators and

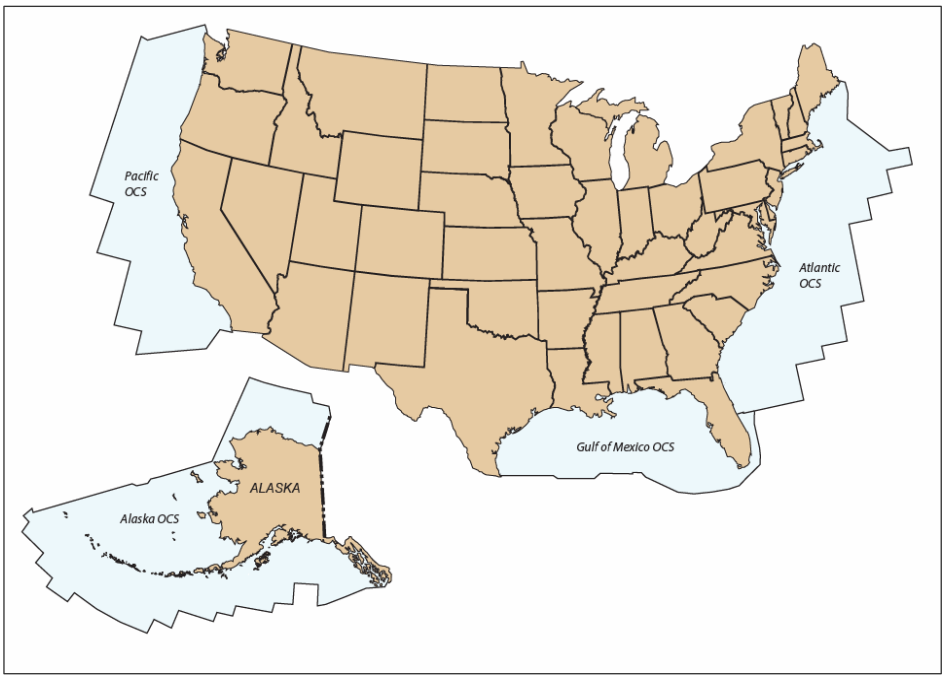

Figure 1: Map Showing the United States Outer Continental Shelf

not predictors of absolute volumes. All resource estimates are subject to continuing revision as undiscovered resources are converted to reserves and reserves to production and as improvements in data and assessment methods occur. The assessment results do not imply a rate of discovery or a likelihood of discovery and production within a specific time frame. However, uncertainty surrounding the estimates decreases as the asset progresses through this cycle. Resource estimates should be viewed from the perspective of the point in time the assessment was performed—based on the data, information, and methodology available at that time.

In general, risk and uncertainty in estimates of undiscovered oil and natural gas are greatest for frontier areas that have had little or no past exploratory effort. Resource estimates are highly dependent on the current knowledge base, which has not been updated in 20 to 40 years for certain areas under congressional moratorium and presidential withdrawal. For other areas that have been extensively explored and are in a mature development stage, many of the risks have been reduced or eliminated and the degree of uncertainty in possible outcomes narrowed considerably. As a result, resource potential can be evaluated with much more confidence. However, even in some mature producing areas, such as the Gulf of Mexico (GOM) shelf, considerable uncertainty remains about the petroleum potential at greater drilling depths. In spite of this inherent uncertainty, resource assessments are valuable input to developing energy policy and for corporate planning.

The results of the 2006 assessment are presented in table 1(a) and in section III of this report. The total endowment of technically recoverable oil and gas on the OCS is comprised of known resources—i.e., cumulative production, and estimates of remaining proved and unproved reserves and reserves appreciation—plus estimates of undiscovered resources. The estimate of the total hydrocarbon endowment (for a definition of the term “total endowment” refer to appendix B), which includes cumulative production, is 115.4 billion barrels of oil (Bbo) and

633.7 trillion cubic feet of gas (Tcfg). On a barrel of oil-equivalent (BOE) basis, approximately two-thirds of the total hydrocarbon endowment is projected for the GOM region (for a definition of the term "barrel of oil-equivalent" refer to appendix B).

Table 1(a): Total Endowment of Technically Recoverable Oil and Gas on the OCS, 2006

Regions	Known Resources			Undiscovered Resources (mean estimate)	Total Endowment (mean estimate)
	Cumulative Production	Reserves	Reserves Appreciation		
OIL (Billion Barrels)					
Alaska OCS	0.01	0.03	0.00	26.61	26.65
Atlantic OCS	0.00	0.00	0.00	3.82	3.82
Gulf of Mexico OCS	13.05	7.06	6.88	44.92	71.91
Pacific OCS	1.06	1.46	0.00	10.53	13.05
Total OCS	**14.12**	**8.55**	**6.88**	**85.88**	**115.43**
Natural Gas (Trillion Cubic Feet)					
Alaska OCS	0.00	0.00	0.00	132.06	132.06
Atlantic OCS	0.00	0.00	0.00	36.99	36.99
Gulf of Mexico OCS	152.25	27.70	30.91	232.54	443.40
Pacific OCS	1.32	1.56	0.00	18.29	21.17
Total OCS	**153.57**	**29.26**	**30.91**	**419.88**	**633.62**

Of the total endowment, about 29.6 Bbo and 213.8 Tcfg (approximately 30 percent on a BOE basis) is represented by resources in known fields— the total of cumulative production, remaining proved and unproved reserves, and reserves appreciation.

Cumulative production on the OCS through 2002 was 14.1 Bbo and 153.6 Tcfg; 97 percent of which was produced in the GOM. Historical production represents 18 percent of the estimated mean total endowment.

Estimates of the discovered resources remaining to be produced (reserves and reserves appreciation) total 15.4 Bbo and 60.2 Tcfg.

- The MMS estimates that reserves remaining within the 1,151 fields discovered as of January 1, 2003, total 8.6 Bbo and 29.3 Tcfg.
- An additional volume of reserves growth or appreciation—the projected increase in current estimates of reserves within existing fields based on historical trends—totaling 6.9 Bbo and 30.9 Tcfg is also forecast to be ultimately recoverable from this same set of existing offshore fields. This growth occurs primarily from the discovery of new reservoirs and an increase in the estimate of the recoverable portion of in-place hydrocarbons within known reservoirs, due to future advances in technology, an increased understanding of reservoir performance and improvements in economics.

The mean estimate for undiscovered technically recoverable resources (UTRR) totals 85.9 Bbo and 419.9 Tcfg. (The full range of estimates corresponding to different probabilities of occurrence can be found in section III.) On a BOE basis, more than half of the UTRR are projected in the GOM region.

Section III(B) of this report also includes a discussion on how the results of the 2006 assessment changed since the prior MMS assessment in 2001. For the entire OCS, estimates for the total endowment of oil increased 15 percent and for gas, 5 percent. Figure 2 shows the comparison for the total endowment of both oil and natural gas under each assessment.

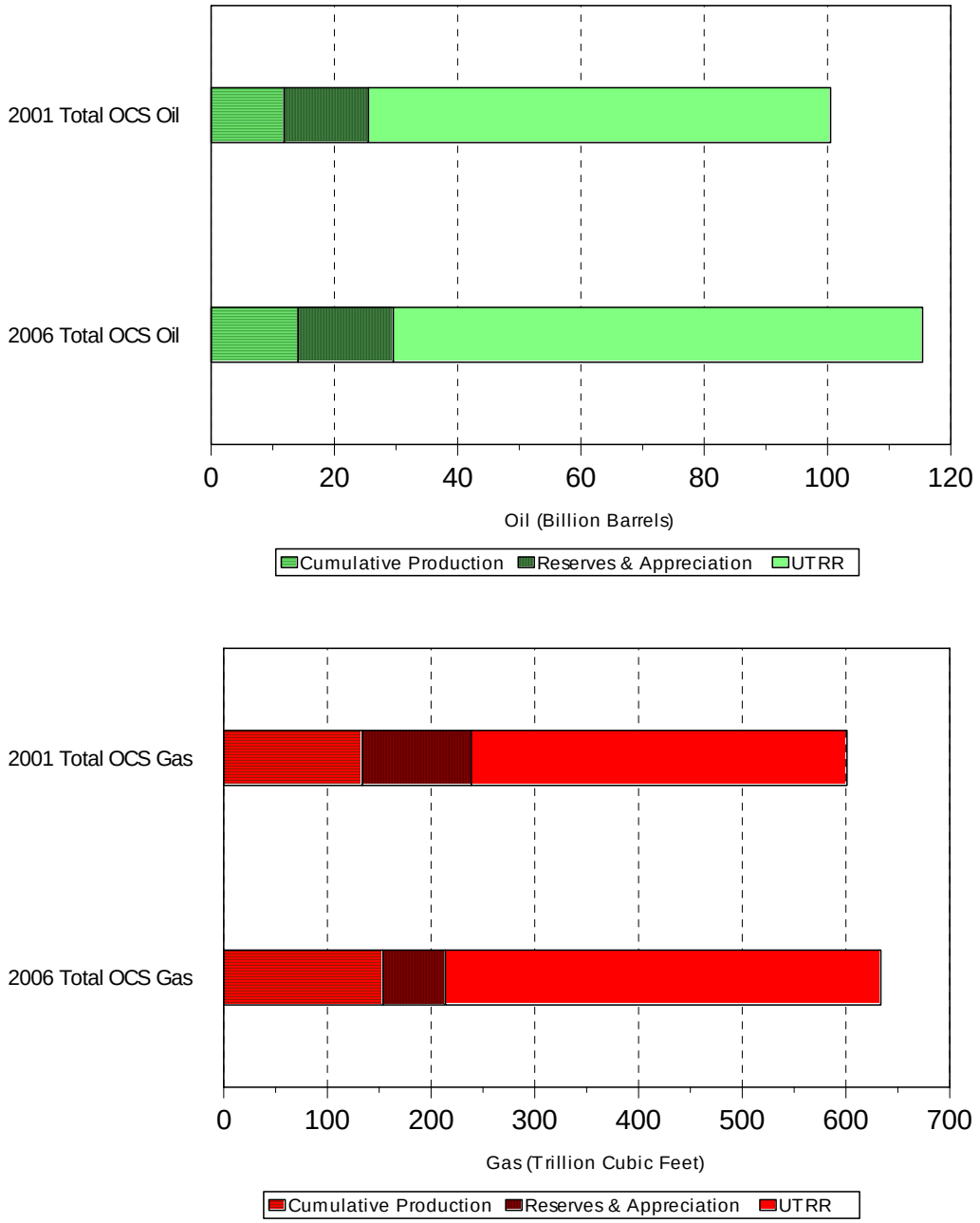

Figure 2: Comparison of Estimates of Total Technically Recoverable Oil and Gas Resources on the OCS—2001 and 2006 Assessments

During the four year period between the assessments, about 2.3 Bbo and nearly 20 Tcfg were produced from the OCS, 96 percent from the GOM. This production came from the volumes of reserves and reserves appreciation reported in the 2001 assessment.

Despite this significant volume of oil production, the estimate of oil reserves (including reserves appreciation) grew during this period, increasing by about 1.7 Bbo, meaning the industry was successful in replacing all the oil reserves produced in the GOM. This is not the case for natural gas. The estimate for gas reserves (including appreciation) decreased by 45 Tcf, yet production during this time period totaled 20 Tcf, meaning that discoveries of new sources of OCS gas are currently not keeping pace with our consumption of them. If the Nation's demand for natural gas continues at current levels or increases, as expected, new domestic sources will have to be found or imports of natural gas or liquefied natural gas (LNG) will need to increase.

The results of this assessment indicate that the OCS remains a significant potential domestic source of new natural gas resources from fields yet to be discovered. The MMS estimate for undiscovered technically recoverable gas resources on the OCS has increased by 16 percent; and the volume of undiscovered oil resources increased 15 percent when comparing the 2006 and 2001 assessments. If these volumes of oil and gas are in fact discovered, any resulting new reserves could help offset the declining gas reserve volumes on the OCS and provide new sources of domestic production. These increases in estimates of UTRR volumes are primarily attributable to the GOM region where the estimate of oil UTRR increased by 12.8 Bbo and gas by more than 40 Tcf. Not surprisingly, the increase in the oil estimate was predominately within deepwater GOM plays (water depths greater than 800 meters). The increase in gas estimates primarily is associated with deep or ultra-deep plays located beneath the shallow waters on the GOM shelf.

The Department of the Interior (DOI) has completed eight comprehensive resource assessments since 1976. Petroleum resource assessments have been performed by geologists, engineers, statisticians, and economists for decades. To be used effectively, knowledge of the terminology, commodities, regions assessed, methodology, and statistical reporting conventions is essential. Much of the confusion attending the use of published petroleum resource and reserve estimates is the result of misunderstanding or inappropriately interchanging the data and terminology. Due to changes in methodology over time and fundamental changes in the underlying data and assumptions, there is not a sound basis for comparing assessments.

Section IV of this report addresses in detail the historical change in assessments over time. During this period, the geological and geophysical (G&G) information available to government assessors has increased dramatically. These data have increased the MMS knowledge considerably regarding the resource potential of the OCS. However, much of these data exist in the central and western GOM and southern California.

Early DOI resource assessments focused on reporting estimates of undiscovered economically recoverable resources (UERR). (For a definition of UERR see appendix B). Oil and natural gas prices have experienced considerable volatility since the initial assessment was completed. As a result, assessments reporting UERR typically utilized different prices and sets of economic conditions. The frequency of developing new resource estimates could not keep pace with

changes in oil and gas prices. Beginning with the 1996 assessment, the MMS resource assessments focused primarily on reporting estimates of UTRR instead of UERR. In an attempt to present a more complete picture of the total hydrocarbon endowment, assessment reports also included estimates of cumulative production, reserves, and reserves appreciation. Over the timeframe of these assessments, the magnitude of resources believed to be technically recoverable continued to grow dramatically with each assessment.

The period covered by the assessments is also one in which the oil and gas industry's technology capabilities expanded immensely. Today the oil and gas industry possesses the ability to drill exploratory wells in water depths exceeding 10,000 feet and to exploit discoveries in over 7,500 feet. The use of three-dimensional (3-D) and other advanced seismic data and interpretation techniques has served as a catalyst to transform the geosciences and the petroleum industry. Resource assessment techniques became more sophisticated during this period.

Given the phenomenal changes that have occurred over the past 30 years, it is impossible to determine to what degree changes in the assessments are attributable to specific changes in G&G information or a particular individual technological advance. The differences in assessments do point to different perceptions concerning the resource base (or in the case of UERR the economically recoverable portion). There have clearly been major disappointments on the Alaska OCS, particularly in portions of the Bering Sea and south Alaska, and the Atlantic continental shelf that are reflected in the assessments. However, it has been 20 years or more since any exploration activity occurred in these areas. In other areas, such as central and northern California, offshore Oregon and Washington and the south Florida basin, there has been no meaningful exploration activity since the 1960's. Perceptions concerning the resource potential of the central, western, and portions of the eastern GOM areas experiencing robust levels of exploration and production effort, have continued to evolve for the better over the years.

Section V of this report addresses how the government's resource assessment results are used and the extent to which they affect domestic investment decisions. The premise of the request contained in section 357(a)(4) of the Energy Policy Act of 2005—to estimate the effects of "understated" resource inventories—suggests that the government assessments are consistently too conservative when viewed over time and in hindsight following actual discoveries in some OCS areas. However, it is important to note that each assessment reflects a snapshot in time that should not be viewed as either understated or overstated, when compared to later assessments which will reflect changed circumstances and knowledge. The actual volume of oil and natural gas resources that can be recovered from the OCS is never definitively known. As discussed earlier, evolving technological capabilities, more recent seismic evaluations and exploratory drilling, can lead to higher or lower estimates when the assessments are updated in later years. True knowledge of the actual volume of oil and natural gas resources can only come through the drilling of wells.

The MMS resource assessment is one of a number of sources of information that is used by policy-makers when considering energy policy options. Industry and private investors take into account other sources of information when considering alternative investment opportunities, and often conduct independent assessments. This includes employing their own models and

techniques for evaluating and interpreting the data. The same factors that can serve to moderate the government's assessment of the resource potential of certain OCS areas (e.g., lack of data, uncertainty) may also influence industry's assessments and conclusions, and ultimately their willingness to invest in those areas.

Some frontier areas, such as parts of the eastern GOM and other offshore areas under longstanding congressional moratoria or executive withdrawal, offer potential larger field-size discoveries, but drilling and seismic data are scarce, so estimates of potential resources will be appropriately discounted for the higher risk and uncertainty associated with the geologic model. As such, the resulting risk-based estimates of oil and natural gas in frontier areas ordinarily will have been seen as far too conservative, if later exploration demonstrates that the area is hydrocarbon-prone (and will have overstated resources in those areas that ultimately prove unsuccessful). To the extent the government relies upon resource estimates, either understated or overstated, in determining programmatic "balancing" decisions pursuant to the OCS Lands Act (OCSLA) requirements for developing lease sale schedules, some bias could be introduced into program decisions. The MMS mitigates this problem by conducting periodic assessments to reflect changing conditions and knowledge, such as new data from drilling and new seismic surveys, as well as considering advances in exploration and production technologies. The MMS leasing process also provides ample opportunities for industry to provide comments and input regarding hydrocarbon potential and their leasing interests.

The actual discovery, development, and production of oil and natural gas results not from the inventory and data compiled by the government, but from efforts by a diverse set of companies working to identify oil and natural gas prospects that warrant investment. When examining alternative investment opportunities, companies will consider not only the oil and gas potential of an area, but expected costs of development as compared to alternative investments. The expected profitability of specific projects will be affected by a company's determination of risk—geologic, economic, and political risks—which will be lower in areas with proven resource potential and where oil and gas development is more-broadly accepted. Many in the industry believe that the resource potential may be larger than reflected by present evaluations, and the more an area is successfully explored, the more its resource estimates tend to grow. However, industry will only invest in domestic oil and gas exploration and development when they have reasonable certainty of realizing a sufficient return on that investment. In those areas that are off-limits to leasing, companies will not expend capital or time attempting to evaluate the hydrocarbon potential of those areas. In the face of uncertain rights to lease and develop, industry will tend to invest elsewhere in exploration.

Although the OCS contains significant quantities of oil and natural gas resources, a number of impediments to development affect industry's ability to lease these resources for potential exploration and development. Those barriers include lack of access to large portions of the OCS, as well as legal and regulatory requirements and policies designed to ensure safety and environmental protection. Section VI of this report addresses such impediments and restrictions on OCS oil and gas development.

As a result of directives in President Bush's National Energy Policy (NEP) designed to identify and resolve impediments and restrictions on energy resource development, the DOI is already implementing a variety of initiatives to ensure continued access to Federal lands for domestic

energy development, and help expedite permits and other Federal actions necessary for energy-related project approvals. A number of DOI initiatives have improved efficiency and interagency coordination to help streamline governmental regulatory and environmental reviews. Also, the DOI has put in place a suite of incentives to encourage leasing and development in frontier areas of the OCS, where higher costs and risks can be a barrier to investment. The DOI is now responding to new provisions of the Energy Policy Act of 2005, which also are designed to encourage domestic energy investment in new offshore leasing and development.

Despite much progress on such initiatives, exploration for and development of oil and natural gas resources on the OCS is limited mainly to the western and central GOM. Important technological advancements in exploration and development have resulted in significant improvements in the safety and environmental record of the OCS program. But opposition to offshore oil and gas development still exists in many coastal communities, particularly in California, Florida, and most of the Atlantic coast. The opposition stems from longstanding concerns about potential environmental and economic damage from development in environmentally sensitive marine and coastal areas, and potential adverse socioeconomic affects on coastal communities.

Many proponents of domestic energy security consider gaining increased access to Federal resources to be one of the biggest challenges. Part or all of nine OCS planning areas, which include waters off 20 coastal states, have been subject to longstanding leasing moratoria enacted annually as part of the Interior and related agencies appropriations legislation, or are withdrawn from leasing until after June 30, 2012, as the result of presidential withdrawal (under section 12 of the OCSLA). Some of these areas contain large amounts of technically recoverable oil and natural gas resources. The MMS estimates that conventional oil and gas resources (i.e., UTRR) in OCS areas currently off limits to leasing and development total 19.1 Bbo and 83.9 Tcfg (mean estimates). There remains today, considerable uncertainty concerning the resource potential of many of these OCS areas. The availability of additional modern G&G data could reduce this uncertainty. It is instructive to note that perceptions concerning the resource potential of the central, western and portions of the eastern GOM, areas experiencing robust levels of exploration and production effort, have continued to evolve for the better over the years. Critical to the changing perception is the fact that the MMS has acquired approximately 1.75 million line-miles of two-dimensional (2-D) common depth point (CDP) seismic data and nearly 300,000 square miles of 3-D seismic data. However, the additional G&G data and information that become available to assessors between assessments is frequently mixed in terms of having a positive or negative effect on the perception of the overall hydrocarbon potential of the OCS.

The ongoing legislative and executive withdrawals mean that large portions of the OCS, covering about 611 million acres, are off-limits to oil and gas leasing, exploration and development. However, access can also be restricted to otherwise available areas of the OCS for a variety of reasons, including administrative restrictions for other purposes—such as for national defense or for protection of archaeological, cultural or environmentally-sensitive marine resources. New uses of the OCS could also affect the oil and gas industry's use of the seabed for exploration and development on existing leases, as well as restrict potential development on areas offered for lease. Many of these constraints on activity represent important and necessary regulatory or administrative requirements to protect the environment and ensure safe and effective multiple uses of ocean resources.

Many of the ocean's oil and gas resources are in environmentally sensitive areas and the development of those resources must be balanced against potential environmental impacts. Before leasing can occur and projects approved, proposed OCS oil and gas activity must comply with a variety of Federal and state statutes, regulations, and administrative orders that are designed to provide for safe and responsible resource development with appropriate environmental protection. As such, reviews and analyses under these laws are thorough and comprehensive, which can sometimes delay the leasing and permitting processes. Moreover, the effectiveness of some of the governmental review processes can become problematic if there are conflicting or unclear requirements and uncertain deadlines. Such uncertainties and any unnecessary delays can prevent or impede otherwise appropriate development. Likewise, delays in developing implementing regulations by Federal agencies, due to workload or budget constraints, can affect OCS activities.

These and other impediments and restrictions that can affect OCS resource development are discussed in section VI of this report. Additional essential information concerning impediments and restrictions, including selected comments, can be found in appendix A.

Although the MMS has already taken a number of actions to promote resource development, especially in frontier OCS areas, and help streamline and improve coordination among government agencies for permitting and administrative processes, it continues to investigate ways to promote environmentally-acceptable development and avoid unnecessary delays for OCS program activities. The MMS continues to consult with stakeholders to assess opportunities to improve the leasing program terms and its regulations.

Table of Contents

Preface iii

Executive Summary v

Sections

I. Introduction 1
II. Background on the OCS Oil and Gas Leasing Program 3
III. OCS Oil and Natural Gas Inventory 7
IV. Historical Changes to Resource Estimates 29
V. Interpreting Resource Estimates and Possible Effects of Understated Inventories on Domestic Investment 65
VI. Impediments and Restrictions Affecting OCS Oil and Gas Activities 71

Appendices

Appendix A: Impediments and Restrictions Affecting OCS Oil and Natural Gas Exploration and Development 83
Appendix B: Glossary 103
Appendix C: Abbreviations, Acronyms, and Symbols 111
Appendix D: References 113

List of Figures

Figure 1: Map Showing the United States Outer Continental Shelf vi
Figure 2: Comparison of Estimates of Total Technically Recoverable Oil and Gas Resources on the OCS—2001 and 2006 Assessments viii
Figure 3: MMS Resource Classification Schema 9
Figure 4: Sample Cumulative Probability Distribution for a Basin Showing Risked and Conditional (unrisked) Results 15
Figure 5: Distribution of Cumulative Production by Type and Region 18
Figure 6: Distribution of Reserves by Type and Region 21
Figure 7: Distribution of UTRR by Type and Region 22
Figure 8(a): Distribution of Total Hydrocarbon Endowment by Type, Region and Resource Category 23
Figure 8(b): Distribution of Total Hydrocarbon Endowment by Type, Region and Resource Category 24
Figure 9: Comparison of Cumulative Production - 2001 and 2006 Assessments (January 1, 1999 versus January 1, 2003) 25
Figure 10: Comparison of Estimates of Reserves and Reserves Appreciation – 2001 and 2006 Assessments 25

Figure 11: Comparison of Mean Estimates of Undiscovered Technically Recoverable Resources – 2001 and 2006 Assessments 26
Figure 12: Comparison of Mean Estimates of Undiscovered Technically Recoverable Resources in the Deepwater GOM – 2001 and 2006 Assessments 27
Figure 13: Distribution of Total Hydrocarbon Endowment by Type, Region and Resource Category, USGS, (1975) 34
Figure 14: Distribution of Total Hydrocarbon Endowment by Type, Region and Resource Category, USGS, (1981) 40
Figure 15(a): Distribution of Total Hydrocarbon Endowment by Type, Region and Resource Category, (MMS, 1985) 43
Figure 15(b): Distribution of Total Hydrocarbon Endowment by Type, Region and Resource Category, (MMS, 1985) 44
Figure 16: Distribution of Total Hydrocarbon Endowment by Type, Region and Resource Category, (MMS, 1990) 49
Figure 17: Distribution of Total Hydrocarbon Endowment by Type, Region and Resource Category, (MMS, 1991) 50
Figure 18(a): Distribution of Total Hydrocarbon Endowment by Type, Region and Resource Category, (MMS, 1996) 54
Figure 18(b): Distribution of Total Hydrocarbon Endowment by Type, Region and Resource Category, (MMS, 1996) 55
Figure 19: Distribution of Total Hydrocarbon Endowment by Type, Region and Resource Category, (MMS, 2001) 57
Figure 20(a): Distribution of Total Hydrocarbon Endowment by Type, Region and Resource Category, (MMS, 2006) 60
Figure 20(b): Distribution of Total Hydrocarbon Endowment by Type, Region and Resource Category, (MMS, 2006) 61
Figure 21(a): Comparison of the Results of OCS Resource Assessments, 1975-2005 63

List of Tables

Table 1(a): Total Endowment of Technically Recoverable Oil and Gas on the OCS, 2006 vii
Table 1(b): Total Endowment of Technically Recoverable Oil and Gas on the U.S. OCS, 2006 (showing ranges of results for UTRR) 20
Table 2: Summary of the Department of the Interior OCS Resource Assessments 31
Table 3: Comparison of the Department of the Interior 1975 and 1981 OCS Resource Assessments by Water Depth 37
Table 4: Oil and Gas Resources in OCS Areas Unavailable for Leasing and Development 72

I. Introduction

The U.S. OCS contains significant quantities of oil and natural gas resources, but also a number of constraints on development—including barriers on access to large portions of the OCS, as well as legal and regulatory requirements and policies designed to ensure safety and environmental protection and fair returns—that will affect industry's ability to explore for and develop these resources. Section 357 of the Energy Policy Act of 2005 directed the Secretary of the Interior to prepare and submit to Congress within six months of the date of enactment a comprehensive inventory of OCS oil and natural gas resources, together with a report.

The following sections of this report address each statutory requirement and frame the discussion with background information about the OCS program and the current energy situation:

Section II provides background discussion on the OCS oil and gas leasing program and the current energy situation.

Section III presents the OCS oil and natural gas inventory (Sec. 357(a)(1) and (a)(2)).

Section IV discusses the historical changes in resource estimates (Sec. 357(a)(3)).

Section V discusses possible effects of understated resource estimates on domestic investments (Sec. 357(a)(4)).

Section VI describes the various types of impediments and restrictions affecting OCS oil and gas activities (Sec. 357(a)(5)).

- Section VI(A) describes generally how legislative, regulatory, and administrative programs or processes can restrict or impede OCS oil and gas development and domestic supplies.

- Section VI(B) summarizes public responses received to questions posed in the August 24, 2005, Request for Comments on the Preparation of a new 5-Year OCS Oil and Gas Leasing Program for 2007–2012, relating to the OCS inventory and potential restrictions on domestic energy production on the OCS.

- Section VI(C) describes recent initiatives taken by the DOI to help reduce or eliminate any unwarranted administrative obstacles or disincentives to leasing, exploration, and development.

Appendix A presents a table entitled, "*Impediments and Restrictions Affecting OCS Oil and Gas Exploration and Development*" that annotates various legislative, regulatory, and administrative processes that can impede OCS development, and includes comments on some of these impediments.

Appendix B presents the glossary that defines relevant terms used in this Report.

Appendix C presents a list of relevant abbreviations, acronyms, and symbols used throughout this Report.

Appendix D lists the references consulted for this Report.

II. Background on the OCS Oil and Gas Leasing Program

The passage of the OCSLA in 1953 established Federal jurisdiction over the mineral resources of the OCS and authorized the Secretary of the Interior to manage oil and natural gas and other marine minerals activity seaward of state submerged lands. The Federal OCS generally extends from 3 to 200 miles offshore and covers an area of about 1.76 billion acres. Of this total area, some 46 million acres (2.6 percent) is currently under lease for oil and natural gas exploration and development, and about 20 percent of the leased acreage is in production.

The OCSLA, as amended, establishes a comprehensive framework for oil and gas resource management. It provides for development of 5-year OCS oil and gas leasing programs and supporting environmental documents that are used to establish the size, timing and location of OCS leasing over a 5-year time frame. The intensive planning process is designed to consider the laws and policies of affected coastal states and balance multiple objectives among geographic areas in terms of hydrocarbon potential, environmental sensitivity, and other factors. It involves extensive consultation and public commenting in the development of the programs and in planning for individual lease sales. Resulting sales offer industry access to OCS acreage for leasing by competitive bid, providing for potential future exploration and development of oil and gas resources.

> The OCSLA directs the Secretary of the Interior to make resources available to meet the nation's energy needs. The accompanying Congressional Declaration of Policy states, "*The OCS is a vital national resource reserve held by the Federal Government for the public, which should be made available for expeditious and orderly development.*" As DOI's offshore resource management agency, the MMS has a focused and well established ocean mandate – to balance the exploration and development of oil, natural gas, and marine mineral resources of the OCS with environmental protection and safety. The MMS manages oil and natural gas resources on the OCS to achieve national economic and energy policy goals and contribute to national security by reducing dependence on foreign sources of energy.

As the DOI OCS resource management agency, the MMS not only develops the leasing program, but also maintains a comprehensive post-lease program to ensure that mineral operations are conducted in a safe and environmentally sound manner. Today, the MMS manages about 8,200 oil and gas leases and provides regulatory oversight on development from about 4,000 offshore facilities. Principles guiding the MMS's management of the resources of the OCS include: conservation of resources by providing for its most efficient extraction; assurance of a fair and equitable return to the public for rights conveyed; protection of the human, marine, and coastal environments; involvement of interested and affected parties in planning and decision making; and minimization of conflicts between mineral activities and other uses of the OCS.

Oil and gas activities on the OCS—leasing, exploration, and production—are subject to a number of environmental reviews by Federal, state and local agencies. The OCSLA and other applicable statutes like the National Environmental Policy Act (NEPA), the Coastal Zone Management Act (CZMA), the Endangered Species Act (ESA), the Marine Mammal Protection Act (MMPA), the Clean Air Act (CAA), and the Clean Water Act (CWA), as well as authorities of other Departments, govern the conduct of the OCS program. The MMS has over two decades of experience working with coastal states on coastal zone and other issues related to offshore development.

The OCS oil and gas program provides significant benefits to the Nation as a whole by providing secure domestic supplies of oil and gas, helping to meet our growing energy needs and helping to lessen the U.S. reliance on foreign sources of energy. The offshore oil and gas industry directly employs about 42,000 workers, mostly in the vicinity of the GOM. Spending by suppliers and other companies that support the industry, as well as by employee households, account for another 90,000 or more jobs throughout the country.

> America uses about 20 million barrels of petroleum products and 60 billion cubic feet of natural gas per day to fuel automobiles and airplanes, power factories, and generate electricity needed to heat and cool homes. The Federal OCS is a major supplier of oil and natural gas for the domestic market, contributing more energy (oil and natural gas) for U.S. consumption than any single U.S. state or country in the world.

The billions of dollars in revenue collected by the MMS annually from energy companies for offshore and onshore oil and gas leasing and production is one of the largest sources of non-tax revenue to the Federal Government. The OCS leasing and production provides the majority of this revenue—about 66 percent of the $8 billion collected in fiscal year (FY) 2004. Some of the revenue from OCS leasing is used for two special funds, the Land and Water Conservation Fund (LWCF) and the National Historic Preservation Fund (HPF). Annually, nearly $900 million from OCS revenue goes into the LWCF which provides revenue for the Federal Government and state and local governments to plan, acquire, and develop land and water resources for recreational use, habitat protection, scenic beauty, and biological diversity. Additionally, the OCS revenue provides all of the $150 million transferred annually to the HPF to help protect and preserve hundreds of American battle fields, historic buildings, historic landmarks, and tribal properties and cultural traditions. From FY 1982-2004, about $19.9 billion of OCS revenue was transferred to the LWCF and about $3.2 billion to the HPF. Certain coastal states also receive a share of OCS oil and gas revenue ($76 million in FY 2004), as part of the OCSLA section 8(g) payments from OCS leases located within 3 seaward miles of state waters. From FY 1982 to 2004, about $3.2 billion was distributed to these states.

A significant amount of the Federal royalty share of oil produced in the GOM is now taken “in kind” as product instead of cash. The MMS royalty in kind program provides an efficient and cost-effective means to fill the Strategic Petroleum Reserve (SPR) which serves as the Nation’s emergency stockpile of crude oil. About 120 million barrels of Gulf royalty in kind oil has been used to support the SPR fill initiative.

Since 1954, the DOI has held 141 competitive OCS oil and gas lease sales offshore the Gulf coast, the Atlantic and Pacific coasts, and offshore Alaska. From the perspective of the Nation as a whole, the ultimate measure of the leasing program’s success, however, is the quantity of oil and natural gas produced from the leases sold. From the time OCS leasing began in 1954 through 2004, the DOI has regulated production of more than 15 Bbo and 165 Tcf of natural gas from OCS leases offshore California, Alaska and in the GOM. During this time, more than $156 billion in bonus bid, rental and royalty payments has been collected from OCS oil and gas activity.

The OCS production currently contributes about 1.5 million barrels of oil per day (MMbopd) and 11 billion cubic feet of natural gas per day (Bcfgpd) for U.S. consumption (2004 data), accounting for about 30 percent of domestic oil production and 21 percent of domestic natural gas production. Within the next five years, offshore production will likely account for more than

40 percent of oil and 26 percent of U.S. natural gas production, owing primarily to deepwater discoveries in the GOM.

About 95 percent of today's OCS production occurs in the central and western GOM where there is extensive infrastructure and general public support for offshore development. Offshore California, a small amount of production continues from 43 active OCS leases issued many years ago. It is estimated that about 315 million barrels of oil (MMbo) and over 1 Tcfg remain to be recovered from these 43 producing leases. An additional 36 non-producing leases offshore southern California are the subject of ongoing lawsuits that will dictate the ultimate fate of those leases. Offshore Alaska, there are currently183 active OCS leases, with 3 producing. The first Alaska OCS production began in 2001 from a joint Federal and state project in the Beaufort Sea, known as Northstar. To date, cumulative production for the Federal share of the Northstar Unit totals about 14 MMbo (its natural gas is not currently marketable).

According to the Energy Information Administration's (EIA) *Annual Energy Outlook 2006* (reference case), over the next 26 years, Americans' demand for crude oil and petroleum products is expected to grow at an annual rate of 1.1 percent, and natural gas is expected to grow at an annual rate of 0.7 percent. Despite a continuing emphasis on expanding renewable sources of energy, petroleum products and natural gas are projected to account for about 61 percent of domestic energy consumption in 2030, only slightly less than today's share.

Total crude oil and other petroleum demand is projected to grow from 20.74 MMbopd in 2004, to 27.65 MMbopd in 2030, but growth in domestic production will not keep pace, meeting only about 38% of the demand growth. In 2004, net imports of crude oil and refined products accounted for 58 percent of domestic petroleum consumption. Dependence on petroleum imports is projected to reach 62 percent in 2030. Natural gas consumption is expected to grow from 22.41 Tcf in 2004 to 26.86 Tcf in 2030. Domestic production, however, is predicted to grow from 18.46 Tcf to 20.83 Tcf, meeting only about half of the demand growth. In the past, any difference between the growth in demand and the growth in domestic production was predominantly met by imports of natural gas from Canada. However, Canada's future production will likely not support increased U.S. import requirements. Most additional supplies will need to come from Alaskan natural gas (if a pipeline is built), coalbed methane, the OCS, or from imports of LNG.

U.S. crude oil production is expected to increase from 5.4 million barrels per day in 2004 to a peak of 5.9 million barrels per day in 2014 as a result of increased production offshore, predominantly from the deep waters of the Gulf of Mexico. Production is then projected to fall to 4.6 million barrels per day in 2030.

Total domestic natural gas production will increase from 18.5 Tcf in 2004 to 20.8 Tcf in 2030. The decline in projected production levels (from the previous Annual Energy Outlook 2005) is entirely attributable to lower levels of offshore production. This is due at least in part to the impacts of Hurricanes Katrina and Rita, which are expected to delay offshore drilling projects because of a lack of rigs and to have a long-term effect on production levels as a result of the slow recovery of production from existing fields.

EIA, Annual Energy Outlook 2006
(data for reference case)

Much of the growth in the Nation's energy demand will have to be met by OCS production, especially from new frontier areas in the GOM, if further increases of imported supplies are to be avoided. There are two emerging frontier areas in the GOM. In shallow water areas, where

the easily reached gas is rapidly declining, companies are taking advantage of recent royalty relief offered by the MMS to drill wells below 15,000 feet and tap into new natural gas reservoirs. The second area of development is in the deep and ultra-deepwater areas of the GOM. The percentage of oil and natural gas production from water depths over 1,000 feet, and in some cases over 7,500 feet, has steadily increased over the past decade, now accounting for 63 percent of the GOM's oil production and 35 percent of the natural gas production. In the mature shallow water areas of the GOM, the rapid decline in production, especially for shallow-depth natural gas, means that deepwater output and production from other oil and natural gas-prone areas will have to increase significantly to help offset declines and help meet the projected growth in U.S. demand. Despite the recent downward trend in OCS natural gas production, current MMS projections based on deepwater discoveries and deep gas drilling on the shelf, forecast a reversal with a trend of increasing natural gas production beginning in 2007 and sustained through at least 2013. The OCS oil production could account for as much as 40 percent of domestic oil production by 2010.

III. OCS Oil and Natural Gas Inventory

"Because of the things we don't know [that] we don't know, the future is largely unpredictable."
– Maxine Singer, research scientist

A. Background

Energy is the lifeblood of the world's economy. Oil and natural gas resources are the major contributor to the world energy supply and this reliance on petroleum is likely to continue for decades. However, as mentioned earlier, petroleum resources are usually considered as finite since they do not renew at a rate remotely approaching their rate of consumption. It is, therefore, not surprising that there is considerable interest in the magnitude of the resource base from which future domestic discoveries and production will occur.

Geologists, statisticians, and economists have been performing resource assessments for decades in an attempt to provide insights regarding the future petroleum supply. The demands of and uses for these assessments have led to the evolution of increasingly complex quantitative techniques and procedures to meet the challenge. Generally, the evolution has been from deterministic to stochastic methods, incorporating uncertainty and risk analyses. Scientific disciplines involved in the assessment process have evolved in parallel with the methodology, from primarily geology in the early assessments to a complex multi-disciplinary array of geology, geophysics, petroleum engineering, economics, and statistics.

1. Purposes of Resource Assessments: Resource assessments are performed by the MMS at various scales and for many purposes. Regional assessments may be prepared simply to develop an inventory of potential oil and natural gas resources as part of an evaluation of future supply options. Assessments may be undertaken to analyze the relative merits of oil and gas development proposals and alternatives versus other competing uses. Resource estimates provide critical input to decision makers regarding the virtues of various policy alternatives. Detailed site-specific assessments provide data essential for valuing Federal lands prior to leasing or analyzing industry exploration or development proposals.

Large corporations and financial institutions use resource estimates for long-term planning, the analysis of investment options and as a guide in analyzing the future health of the oil and gas industry. Exploration companies use resource assessments to design exploration strategies and target expenditures. Increasingly, resource estimates are being used by the Administration, Congress, and the public to provide objective statements of how much oil and natural gas will be available for future domestic consumption. This report presents the results of a regional, play-based assessment of the entire U.S. OCS. It represents the results of a thorough investigation of the petroleum geology of each province and an identification of appropriate domestic and international analogs, coupled with a probabilistic methodology to estimate the remaining hydrocarbon potential.

2. Terminology and Classification Schema: A set of precise, universally accepted definitions regarding resource assessment terminology does not exist, so it is important that the terminology associated with this resource assessment is understood so that the results can be correctly interpreted.

The following are important terms related to this resource assessment. The definitions presented here should be viewed as general explanations rather than strict technical definitions of the terms.

Resources: Concentrations in the earth's crust of naturally occurring liquid or gaseous hydrocarbons that can conceivably be discovered and recovered. Normal use encompasses both discovered and undiscovered resources.

Undiscovered resources: Resources postulated, on the basis of geologic knowledge and theory, to exist outside of known fields or accumulations. Also included are resources from undiscovered pools within known fields to the extent that they occur within separate plays.

Undiscovered technically recoverable resources (UTRR): Hydrocarbons that may be produced as a consequence of natural pressure, artificial lift, pressure maintenance (gas or water injection), or other secondary recovery methods, but without any consideration of economic viability. The UTRR do not include quantities of hydrocarbon resources that could be recovered by enhanced recovery techniques, gas in geopressured brines, natural gas hydrates, or oil and gas that may be present in insufficient quantities or quality (low permeability "tight" reservoirs) to be produced via conventional recovery techniques. Also, the UTRR are primarily located outside of known fields.

Undiscovered economically recoverable resources (UERR): The portion of the UTRR that is potentially recoverable at a profit under imposed economic and technologic conditions.

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.

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.

Unproved reserves: Quantities of hydrocarbon reserves 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 being classified as proved.

Reserves appreciation: The observed incremental increase through time in the estimates of reserves (proved and unproved) of an oil and/or natural gas field. It is that part of the known resources over and above proved and unproved reserves that will be added to existing fields through extension, revision, improved recovery, and the addition of new reservoirs. Also commonly referred to as reserves growth or field growth.

Cumulative production: The sum of all produced volumes of hydrocarbons prior to a specified point in time.

Estimated Ultimate Recovery (EUR): All hydrocarbon resources within known fields that can be profitably produced using current technology under existing economic conditions. The EUR is the sum of cumulative production plus proved reserves plus unproved reserves plus reserves appreciation.

Total endowment: All technically recoverable hydrocarbon resources of an area. Estimates of total endowment equal undiscovered technically recoverable resources plus EUR.

The MMS scheme of classifying conventionally recoverable hydrocarbons (see figure 3) is modified from the well known McKelvey diagram (U.S. Bureau of Mines and U.S. Geological Survey (USGS, 1980). The scheme is dynamic with hydrocarbon resources migrating from one category to another over time. Resource availability is expressed in terms of the degree of certainty about the existence of the resource and the feasibility of its economic recovery. With increasing geologic assurance, hydrocarbon accumulations advance from undiscovered resources to discovered resources to unproved reserves.

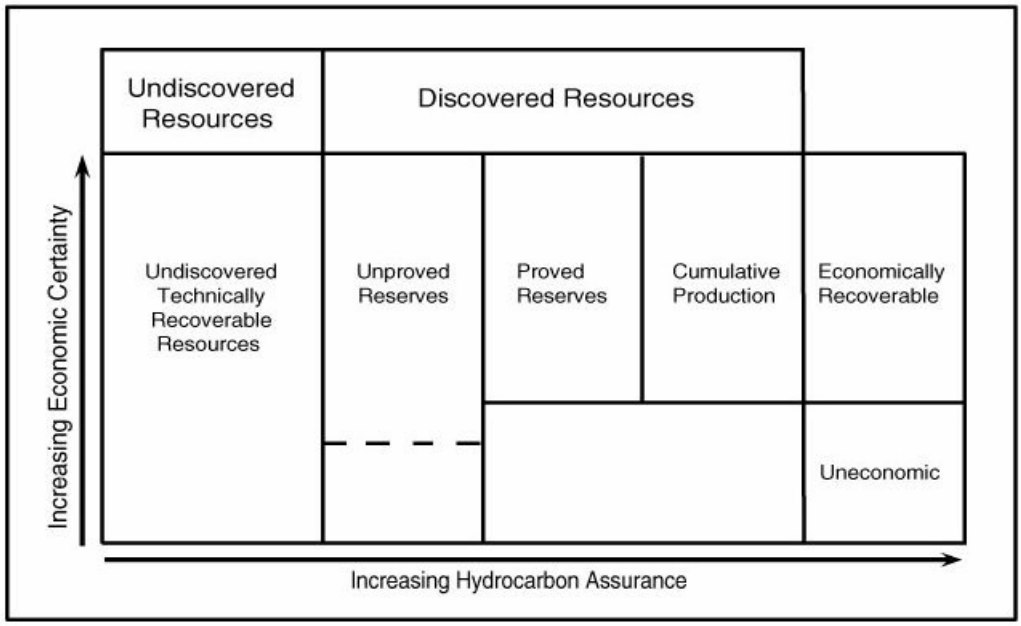

Figure 3: MMS Resource Classification Schema

Reserves can be classified as proved when sufficient economic and geologic knowledge exists to confirm the likely commercial production of a specific volume of hydrocarbons. Proved reserves must at the time of the estimate either have facilities that are operational to process and transport those reserves to market, or a commitment or reasonable expectation to install such facilities in the future (Society of Petroleum Engineers, 1997).

The overall movement of petroleum resources within the schema is upward as development and production ensue. The degree of uncertainty as to the existence of resources decreases to the right in the diagram. The degree of economic viability decreases downward and also implies a decreasing certainty of technologic recoverability.

Another key concept to grasp is that of "technically recoverable resources." Resource assessments that are intended to be of more than scientific interest are generally limited to accumulations that are believed to be amenable to discovery and production employing conventional techniques under reasonably foreseeable technological and economic conditions. The assessments discussed in this report excluded oil and natural gas that are producible only through the use of more exotic and expensive "unconventional technologies." This distinction eliminates from consideration significant portions of the resource base, some portion of which may be developable in the future.

3. Commodities Assessed: The petroleum commodities assessed in this inventory are crude oil, natural gas liquids (condensate), and natural gas that exist in conventional reservoirs and are producible with conventional recovery techniques. Crude oil exists in a liquid state in the subsurface and at the surface; it may be described on the basis of its American Petroleum Industry (API) gravity as "light" (i.e., approximately 20° to 50° API) or "heavy" (i.e., generally less than 20° API). Condensate is a very high-gravity (i.e., generally greater than 50° API) liquid; it may exist in a dissolved gaseous state in the subsurface but liquefy at the surface. Crude oil with a gravity greater than 10° API and condensate can be removed from the subsurface with conventional extraction techniques and have been assessed for this effort. Natural gas is a gaseous hydrocarbon resource, which may consist of associated and/or nonassociated gas; the terms natural gas and gas are used interchangeably in this report. Associated gas exists in spatial association with crude oil; it may exist in the subsurface as undissolved gas within a gas cap or as gas that is dissolved in crude oil (solution gas). Nonassociated gas does not exist in association with crude oil. Gas resources that can be removed from the subsurface with conventional extraction techniques have been assessed for this inventory. Crude oil and condensate are reported jointly as oil; associated and nonassociated gas are reported as gas. Oil volumes are reported as stock tank barrels and gas as standard cubic feet. Oil-equivalent gas is a volume of gas (associated and/or nonassociated) expressed in terms of its energy equivalence to oil (i.e., 5,620 cubic feet of gas per barrel of oil) and is reported in barrels. The combined volume of oil and oil-equivalent gas resources is referred to as BOE and is reported in barrels.

This report encompasses only a portion of all the oil and natural gas resources believed to exist on the U.S. continental margin. This assessment does not include potentially large quantities of hydrocarbon resources that could be recovered from known and future fields by enhanced recovery techniques, gas in geopressured brines, natural gas hydrates, or oil and natural gas that may be present in insufficient quantities or quality (low permeability "tight" reservoirs) to be produced by conventional recovery techniques. In some instances the boundary between these resources is somewhat indistinct; however, not included in this assessment is any significant volume of unconventional resources. These unconventional resources have yet to be produced from the OCS; still, with improved extraction technologies and economic conditions, they may become important future sources of domestic oil and gas production.

Estimates of the quantities of historical production, reserves, and future reserves appreciation are presented to provide a frame of reference for analyzing the estimates of the UTRR. Furthermore, reserves appreciation and the UTRR comprise the resource base from which the midterm future oil and gas supplies will emerge.

4. Data Sources: This assessment of the hydrocarbon potential of the OCS required the compilation and analysis of published information and vast amounts of proprietary geologic, geophysical, and engineering data obtained by industry from operations performed under permits or mineral leases and furnished to the MMS. Prior to January 1, 2003, the effective date of this assessment, more than 11,500 permits to conduct prelease geologic or geophysical exploration had been issued on the OCS. In addition, more than 22,000 leases were awarded to industry for the exploration, development, and production of oil and natural gas. As a condition of these permits and leases, the MMS acquired approximately 1.75 million line-miles of 2-D CDP seismic data and nearly 300,000 square miles of 3-D CDP seismic data. Moreover, the MMS has accumulated geologic and reservoir engineering information from over 42,400 wells drilled on the U.S. continental margin. These exploration activities have resulted in the discovery of 1,151 fields. Additionally, the Canadian and Nova Scotian Governments released significant volumes of seismic and well data acquired from industry exploration activities on the Scotian Shelf. Also, the MMS has acquired and analyzed seismic and well data offshore the Canadian Arctic, Bahamas, and Cuba. It evaluated and considered publicly available information from the onshore portions of the OCS basins, as well as international geologic analogs from the South China Sea, Vietnam, North Sea, North Africa, Angola, Australia, Brazil, Norway, Canada and Mexico among others. This database, in its entirety, was the information source for the play delineation process, as well as the basis for determining key parameters of geologic variables and pool size distributions for the OCS.

5. Limitations of Resource Assessments: It is important to recognize that estimates of undiscovered oil and natural gas resources are just that: *estimates*. Resource assessments are an attempt to quantify something that cannot be accurately known until the resource has been essentially depleted. In spite of this inherent uncertainty, resource assessments are valuable input to developing energy policy and for corporate planning—e.g., for ranking exploration opportunities, as a basis for economic analyses, and assessments of technology and capital needs. The assessment results do not imply a rate of discovery or a likelihood of discovery and production within a specific time frame. In other words, resource assessments cannot be used directly to draw conclusions concerning the rate of conversion of these undiscovered resources to reserves and ultimately production. However, all else being equal, to the extent that industry relies on its own assessment results for a given area, or, less likely, those of the Federal Government, increases in resource estimates could change their perceptions of expected returns on capital and ultimately result in increased exploration activity.

Imperfect knowledge is associated with almost every facet of the assessment process. Dreyfus and Ashby (1989) noted that resource assessments are performed at widely varying levels of detail and precision. At one end of the spectrum lie estimates of proved reserves. These assessments rely primarily upon detailed investigations incorporating relatively abundant subsurface G&G data, as well as actual reservoir performance information associated with the particular reservoir. At the other end of the spectrum is the appraisal of undiscovered resources that might exist in areas of regional, national or even global scope. While dealing with the same

type of data as reserve estimates the scope is extended to a generalized inference of the probable quantities of undiscovered hydrocarbon resources that may exist in broad areas. All resource estimates are subject to continuing revision as undiscovered resources are converted to reserves and reserves to production and as improvements in data and assessment methods occur. Uncertainty surrounding the estimates also decreases as the asset progresses through this cycle.

The various estimates presented in this report should be considered general indicators and not predictors of the absolute volumes of petroleum potential of the areas. It is also important to realize that the UTRR volumes estimated may not be found or, in fact, produced. It is, however, implied that these resources have some chance of existing, being discovered, and possibly produced. Finally, serendipitous plays, those found as complete surprises, are not considered in this assessment. These unknown plays do not have a geologic model that can be logically assessed at this time. In sum, resource estimates should be viewed from the perspective of the point in time the assessment was performed—based on the data, information, and methodology available at that time.

6. Role of Risk and Uncertainty in Resource Assessments:

"… the greatest error in forecasting is not realizing how important the probabilities of events other than those everyone is agreeing upon are."
— Paul Samuelson, economist

Exploration for hydrocarbons is a high risk proposition. Risk and uncertainty are integral parts of every resource assessment, with nearly every component of the assessment process incorporating a consideration of risk and uncertainty. The accumulation of petroleum in significant quantities requires the juxtaposition of many complex geologic events: the accumulation of organic matter in a source rock; the maturation of this organic matter into petroleum; the presence of a reservoir rock with sufficient thickness, porosity, and permeability; the migration of the petroleum into a trap with adequate size and seals; and the preservation of the petroleum in the trap. Prior to drilling, the actual existence of these geologic conditions is unknown. Not only must all of these conditions coexist they must also converge at a particular location, an unlikely event that results in a high probability of failure often described as dry hole or geologic risk. Even if all of these conditions coexist at a particular location, there remains considerable uncertainty regarding the effectiveness of a seal, the size of a trap, the quality and thickness of the reservoir, and the volume and type of hydrocarbons that not only migrated into the trap, but were preserved and still remain to be recovered.

In general, risk and uncertainty in estimates of undiscovered oil and natural gas are greatest for frontier areas that have had little or no past exploratory effort. For areas that have been extensively explored and are in a mature development stage, many of the risks have been reduced or eliminated and the degree of uncertainty in possible outcomes narrowed considerably. As a result, resource potential can be evaluated with much more confidence. However, even in some mature producing areas, such as the GOM shelf, considerable uncertainty remains about the petroleum potential at greater drilling depths. Uncertainty also pervades projections of whether potential reservoirs have been unrecognized or bypassed in past drilling. Similarly, in frontier areas where resource estimates are largely based on analog comparisons between maturely explored areas and unexplored areas, uncertainty is introduced because each area or basin has unique characteristics.

Scientists can estimate the quantity of the UTRR based on the present state of geological and engineering knowledge, modified by a consideration of future technological advancement. However, the percentage of that quantity that may actually be discovered and produced is ultimately an economic question. Uncertainties about future crude oil and natural gas prices and the costs of exploration and development (including the impacts of technology advances on costs) adversely affect all economic resource estimates. In terms of the commercial viability of an accumulation there is substantial uncertainty concerning total costs and future market prices, resulting in additional economic risk and uncertainty for a project. In short, uncertainties embodied in economic assumptions lead to significant uncertainties in estimates of the UERR and account for some of the large differences among published estimates.

Finally, there are no foolproof, completely mechanical methods for estimating potential quantities of undiscovered hydrocarbon resources. Because all methods contain elements of subjective judgment or expert opinion, the risk analysis and degree of uncertainty reflected in an estimate is affected by the knowledge, experience and assessment expertise of the personnel performing the assessment. This expertise is continually refined as new information tests the validity of previous assumptions.

The MMS stochastic resource assessment methodology incorporates geologic risk and uncertainty at the prospect, play and basin level. The level of uncertainty is reflected in the frequency distributions for uncertain variables affecting the volume of hydrocarbons that may exist in a prospect and the number of accumulations that may exist in a play if technically recoverable hydrocarbons are present. Resource volumes are estimated conditional on recoverable hydrocarbons being present in a prospect and play. These conditional assessments are then weighted by the appropriate risk analysis which considers the probability that hydrocarbons may in fact not be present in a prospect, play or basin. Key factors in this analysis include the potential for the existence of reservoir quality rock, adequate trapping mechanisms, mature source rock, and the presence of effective migration pathways for moving the hydrocarbons from the source rock to the trap.

The question of how much oil and gas remains to be discovered and produced cannot be answered with certainty. The answer can only be estimated with a significant degree of uncertainty, so the assessment results are expressed as probability distributions showing the full range of possible outcomes. Despite all of this inherent risk and uncertainty a common problem surrounding resource assessments is that the way that they are frequently used and reported often underemphasizes the uncertainty inherent in the final estimates. Users of petroleum assessments tend to focus on only one number, the mean value, as providing a definitive answer to the question of how much undiscovered petroleum may exist on the OCS. The focus on the mean value is misleading. In reality, what an assessment offers is a broad range of possible values—like the 66.6 to 115.1 Bbo and 326.4 to 565.9 Tcfg range from the current MMS assessment—based on the best knowledge available at the time.

The following example illustrates some of the problems inherent in reporting and interpreting resource estimates. In some cases when a discovery is made in a frontier area and a casual observer examines published resource estimates developed prior to the discovery with post discovery assessments for the prospect or play, the conclusion is made that the resource potential was seriously underestimated. This may, in fact, be true, but frequently it represents a failure to

properly understand the role of geologic risk in the reporting of estimates of undiscovered recoverable resources.

At the play level (for a definition of the term "play" refer to the appendix B), geologic risk analysis is the process of subjectively estimating the chance that at least a single hydrocarbon accumulation exists somewhere in the play. This is referred to as the marginal probability of hydrocarbons for the play (MP_{hc}). Once a conceptual or frontier play has been geologically defined it is necessary to address the question of its probable existence. As part of the play description it is assumed that critical geologic factors, such as the existence of adequate hydrocarbon source rocks, thermal maturation, migration pathways and timing, and reservoir facies exist. However, in conceptual plays and at the earliest stages of exploration in immature plays, the assessment team cannot state with absolute confidence that all of these critical factors occur anywhere within the extent of the delineated play.

The play-level assessment of MP_{hc} is comprised of a subjective analysis performed on each of the critical components necessary for the existence of a productive play— the hydrocarbon source, reservoir, and trap components. The MP_{hc} or play chance (White, 1980) analysis assesses individually the probability of existence for each of the critical geologic factors. If a play contains more than a minimal show of hydrocarbons as in an established play, all critical geological factors are known to be present. If any of these essential factors are not present or favorable the play will not exist. The probability of the presence of each factor is subjectively estimated by the assessment team. Each component is considered to be geologically and thus statistically independent from the others. Therefore, the product of the marginal probabilities for each individual component represents the chance that all factors simultaneously exist within the play—that the play is, in fact, successful.

This play-level MP_{hc} is in addition to the prospect-level MP_{hc}, which relates the chance of all critical geologic factors being simultaneously present in an individual prospect given the play, in fact, exists. The play-level MP_{hc} reflects the regional play-level controls affecting all prospects within the play. The prospect-level MP_{hc} incorporates prospect-specific considerations. The realization that an individual prospect may be devoid of hydrocarbons does not mean that the play is nonproductive, nor does the existence of hydrocarbons in a play assure their existence in a particular prospect. However, if the play is devoid of hydrocarbons so are all of the prospects contained within that play.

The DOI reported volumes of oil and natural gas, unless stated otherwise, are discounted by the probability that the area assessed is devoid of technically recoverable hydrocarbons. Figure 4 illustrates the effect of this risking process on reported resource estimates.

Risked estimates reflect the long term expected outcome from repeated exploration in areas identical to the one being assessed. An MP_{hc} of 0.5 means that 50 percent of the time the basin will be dry and the other 50 percent of the time technically recoverable hydrocarbons will be present. In the 50 percent of the cases when exploration is successful, the volume discovered is represented by the solid curve labeled "conditional." The assessment shows that there is a 95 percent chance that at least 1.5 Bbo will be found and a 5 percent chance that the amount found will be at least 6.5 Bbo. The average amount is assessed at 3.75 Bbo. The basin, however, is a frontier basin without a discovery, therefore if the basin is dry, the volume of resource expected

to be discovered is zero. The resource assessment results reported would reflect this risk of failure. This is shown in the dashed curve labeled "Risked." Note on this curve there is a 50 percent chance that the volume of resources discovered will be greater than zero. The corresponding F_{95} and F_5 estimates are zero and 5.5 Bbo, respectively. The reported mean estimate is 1.88 Bbo.

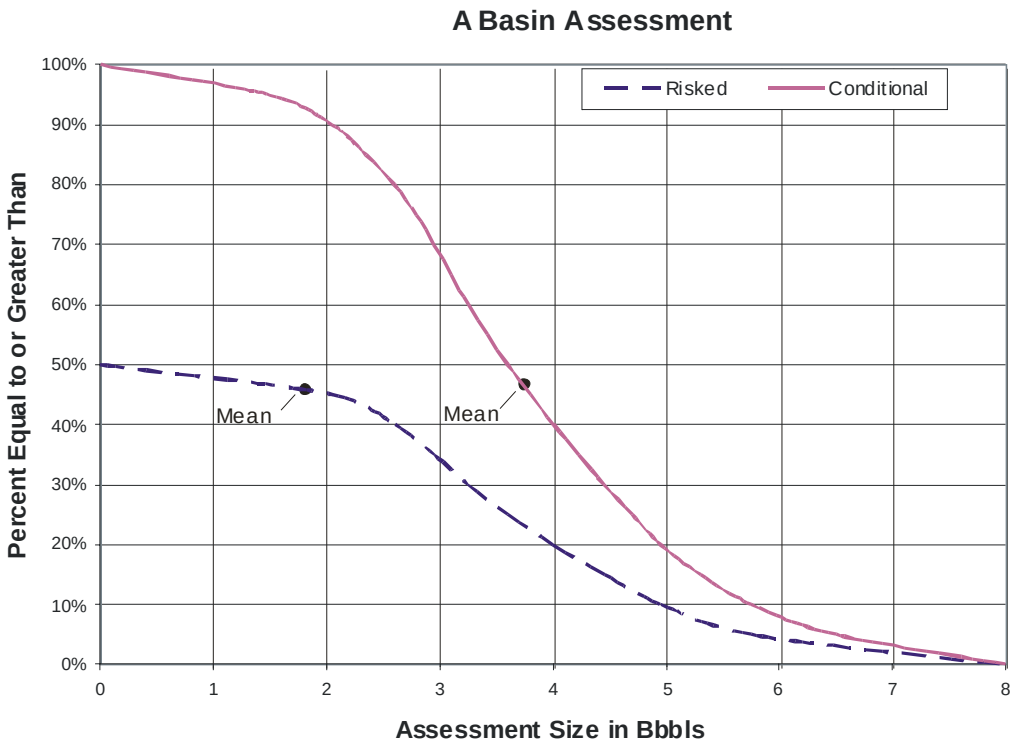

Figure 4: Sample Cumulative Probability Distribution for a Basin Showing Risked and Conditional (unrisked) Results
Note: MP_{hc} at the basin level is 0.5

In the above example, if the drilling results indicate that the basin is dry, does the reported pre-drill assessment represent an over-estimate? The assessor forecast that this result would occur half of the time. In fact, this represents the single most likely outcome of the assessment. On the other hand, if the published pre-drill estimate was 1.88 Bbo and 4.0 Bbo was reported as the volume discovered after exploration was completed, does the assessment represent an underestimate? Post drilling, after the MP_{hc} has in this case been resolved and shown to be 1.0, the reviewer should use the conditional assessment curve to form a judgment concerning the quality of the assessment. In the case of an exploration failure a subjective assessment can be made as to the reasonableness of the forecast probability of failure. Was failure assessed as a likely or probable outcome?

The merits of the risk assessment can only realistically be judged by a comparison of the results from numerous ventures. In cases where details of the assessment are available, the judgment can be strengthened on the basis of a thorough review of individual details. For example, assume

that the basin was dry because of the absence of a thermally mature source rock. Adequate traps and reservoir rocks were found to be present. Did the risk analysis correctly identify source as the major component of risk and the presence of trap and reservoir as highly probable? In the case of success, were the actual hydrocarbon type encountered, pay thickness, reservoir porosity, etc. within the assessed distributions? This information, if available, is rarely reviewed by assessment critics. It is, however, a part of the "look-back" self assessment performed by most resource assessment teams.

Resource assessments are complex. Presentation of the results in a readily meaningful format that adequately portrays this complexity and uncertainty has proven to be an elusive goal. At the risk of appearing to be constantly changing perceptions regarding the hydrocarbon potential of the OCS, the DOI performs periodic assessments that incorporate significant new data and information. In a forward looking sense these periodic reassessments somewhat mitigate this overstatement/understatement issue.

7. Role of Technology and Economics in Resource Assessment:

> *"While research adds to our proved reserves by developing new ways to find and produce oil, it is a field of activity whose advances are impossible to predict. This is because they depend to a large degree on such important, intangible human resources as initiative and ingenuity."*
>
> *—Lewis G. Weeks, petroleum geologist*

This inventory assesses only technically recoverable hydrocarbon resources, both discovered and undiscovered. In developing these estimates it is necessary to make fundamental assumptions regarding future technology and economics. The inability to accurately predict the magnitude and effect of these factors introduces additional uncertainty to the resource assessment.

Scientists can estimate the quantity of technically recoverable resources (both discovered and undiscovered) on the basis of the present state of geologic and engineering knowledge, modified by a subjective consideration of future technologic advancement. However, the quantity of resources that may ever actually be produced is dependent in large part upon economics. Actual cost/price relationships are critical determinants. New capital intensive exploration and development technologies require higher product prices for implementation. Typically, as these high-cost technologies are more widely employed, costs decrease, resulting in even more widespread use of these techniques. On the other hand, new modest-cost exploitation technologies that increase recoveries or decrease finding, development, or operating costs can markedly increase estimates of technically recoverable resources without requiring an increase in product prices. A decrease in price as experienced in the late 1980's can be moderated or offset by the implementation of a technology that reduces unit costs or vice versa. Rogner (1997) concluded that "over the last century technology has probably had a more profound and lasting impact on prices than prices have had on technology." Generally, the effects of price and technology can be considered interchangeable within the context of a resource assessment. There is a technologic and economic limit to the amount of in-place oil and natural gas resources that can be physically recovered from a reservoir. Within conventional reservoirs, approximately 30 to 40 percent of the in-place oil and 65 to 80 percent of the in-place natural gas resources are typically recovered through primary and secondary recovery mechanisms. Three principal

factors affect the amount of oil or gas that can be recovered from a known reservoir— rock properties, technology, and economics. While industry cannot change the properties of the rock it can develop new techniques to recover more oil from the rock, thus adding to the resource base. For example, recent technology advances, such as horizontal wells and multi-lateral completions, enable the recovery of a higher percentage of the in-place resources from a field.

Additional technologic and economic constraints are applicable to the circumstances under which exploration and development activities can occur (e.g., ultra-deepwater or ultra-deep drilling). Advanced technology now provides for the exploitation of resources in these hostile operating environments that were not previously economically viable. New technologies also reduce the cost of exploring for and developing resources that are otherwise still technically recoverable, e.g. long-distance subsea tie-backs to host production facilities, extended reach drilling, or the introduction of SPAR platforms (for a definition of the term "SPAR" see appendix B). A reduction in exploration or development costs lowers the minimum threshold volume that must be discovered for commercial development, thus increasing the number of opportunities for production. In each of these ways the introduction of new technologies serves to expand the resource base that is identifiable and "technically or economically recoverable."

Another important aspect of the role of technology in a resource assessment is the ability through the deployment of new technology to rethink fundamental approaches to developing exploration play concepts. Scientific advances aided by new technologies have affected the ability to identify previously unknown potential exploration plays. An example of this was the introduction of new seismic data acquisition techniques, which when combined with high end computing technology and new data processing algorithms resulted in the ability for the first time for geoscientists to "see" below massive salt bodies underlying a large portion of the GOM OCS, opening up the "subsalt play."

Understanding the natural evolution in technological progress is critical to fully comprehending resource assessments. Continued expansion of the technologic frontiers can be reasonably assumed to partially mitigate the impacts of a lower quality resource base and less favorable economic conditions. Because it has a significant impact on the cost/price relationship, many forecasters choose to model the impacts of technological advancements primarily as a reduction in the future cost of fining and producing domestic oil and natural gas resources. Recently, the MMS resource assessments captured this effect in the price (cost) supply curves, which present estimates of the volumes of economically recoverable resources at various product prices.

The National Research Council (1991) in its examination of the 1989 national resource assessment summarized the complex problems intrinsic to the conventional-unconventional and recoverable-unrecoverable boundaries and resource assessments. Both of these boundaries are in flux due to changing economic viability over time and are dependent upon a multifaceted set of economic and technologic variables. Significant changes in the cost/price relationship or fundamental changes in technologic capabilities can shift these boundaries, causing modifications in perceptions and the practical meaning of the definitions. Thus, uncertainties in economic and technologic conditions contribute to the substantial uncertainties in the resource assessment.

B. Inventory Results

Essential in performing the resource management mission responsibilities of the DOI is developing and maintaining a thorough knowledge of the mineral resource base. This knowledge provides an understanding of the characteristics and distribution of the resource, providing a sound basis for decisions related to resource management issues. With this as the primary objective, the MMS completed an assessment of the technically recoverable oil and natural gas resources of the OCS, which reflects data and information available on January 1, 2003. This assessment was the culmination of a multi-year effort that included data and information not available at the time of the previous assessment (MMS, 2001a), incorporated advances in petroleum exploration and development technologies, and employed new methods of resource assessment.

This assessment of the U.S. continental margin incorporated a comprehensive play-based approach toward the analysis of hydrocarbon potential. A major strength of this method is that it has a strong relationship between information derived from oil and gas exploration activities and the geologic model developed by the assessment team. An extensive effort was involved in developing play models, delineating the geographic limits of each play, and compiling data on critical geologic and reservoir engineering parameters. These parameters were crucial input in the determination of the total quantities of recoverable resources in each play.

1. Cumulative Production: Cumulative production is a measured quantity that can be accurately determined. The uncertainty associated with these estimates is less than with comparable estimates of volumes of reserves and considerably less than estimates of undiscovered resources.

Through 2002, 14.1 Bbo and 153.6 Tcfg (41.4 BBOE) were produced from the Federal OCS (see figure 5 and table 1(b)). Almost 97 percent of this production has occurred within the GOM.

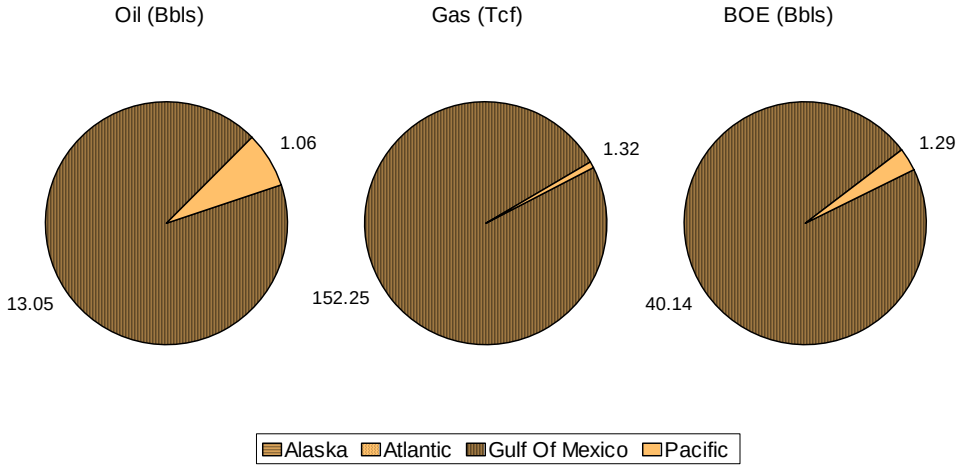

Figure 5: Distribution of Cumulative Production by Type and Region
Note: Alaska OCS cumulative production is 10 MMbo (10 MMBOE)

2. Reserves: Reserves are frequently estimated at different stages during the exploration and development cycle of a hydrocarbon accumulation, i.e., after exploration and delineation drilling, during development drilling, after some production and, finally, after production has been well established. Different methods of estimating the volume of reserves are appropriate at each stage. Reserve estimating procedures generally progress from volumetric to performance-based techniques as the field matures. The relative uncertainty associated with these estimates decreases as more subsurface information and production history become available. Estimates of reserves are uncertain; however, traditional industry practice has been to calculate reserves through a deterministic process and present the results as single point estimates. Table 1(b) shows that the total proved and unproved reserves remaining in the 1,151 fields beneath the OCS are estimated to be 8.6 Bbo and 29.3 Tcfg (13.8 BBOE). Nearly 94 percent of the reserves are present within the GOM (see figure 6). There are no reserves identified on the Atlantic OCS.

Table 1(b): Total Endowment of Technically Recoverable Oil and Gas on the OCS, 2006

Regions	Cumulative Production		Reserves		Reserves Appreciation		Undiscovered Technically Recoverable Resources						Total Endowment (Mean)	
							Oil (Bbbl)			Gas (Tcf)				
	Oil (Bbbl)	Gas (Tcf)	Oil (Bbbl)	Gas (Tcf)	Oil (Bbbl)	Gas (Tcf)	F_5	F_{95}	Mean	F_5	F_{95}	Mean	Oil (Bbbl)	Gas (Tcf)
Alaska OCS	0.01	0.00	0.03	0.00	0.00	0.00	55.14	8.66	26.61	279.62	48.28	132.06	26.65	132.06
Atlantic OCS	0.00	0.00	0.00	0.00	0.00	0.00	7.57	1.12	3.82	66.46	14.30	36.99	3.82	36.99
Gulf of Mexico OCS	13.05	152.25	7.06	27.70	6.88	30.91	49.11	41.21	44.92	249.08	218.83	232.54	71.91	443.40
Pacific OCS	1.06	1.32	1.46	1.56	0.00	0.00	13.94	7.55	10.53	24.12	13.29	18.29	13.05	21.17
Total OCS	**14.12**	**153.57**	**8.55**	**29.26**	**6.88**	**30.91**	**115.13**	**66.60**	**85.88**	**565.87**	**326.40**	**419.88**	**115.43**	**633.62**

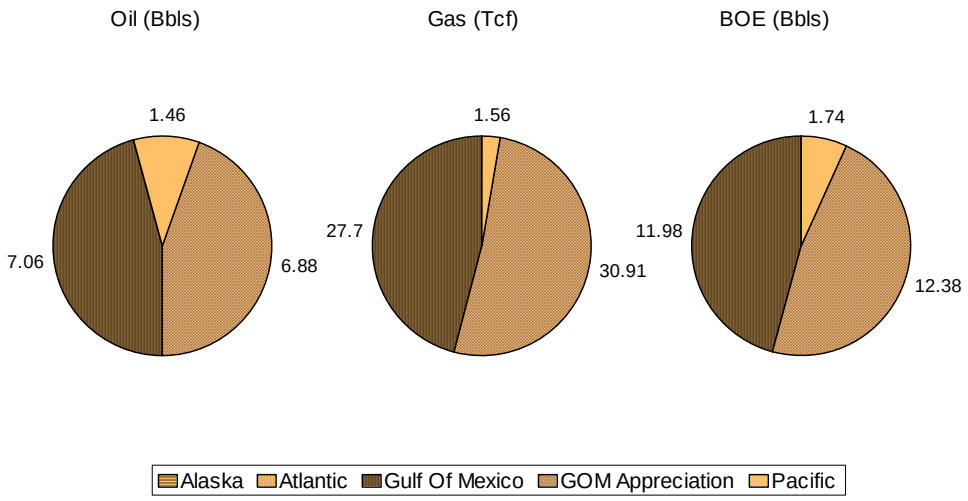

Figure 6: Distribution of Reserves by Type and Region
Note: Alaska OCS reserves are 30 MMbo (30 MMBOE)

3. Reserves Appreciation: Cumulative production plus total estimated future production (from reserves) equals the estimate of the ultimate recovery (EUR) from a field. Predicting a field's true EUR requires an estimate of its future reserves growth or appreciation. The reserves appreciation phenomenon has been observed in onshore and offshore basins for years. During the initial years after discovery reserve estimates typically increase rapidly. The rate of growth then tends to level off at a much smaller annual rate of increase. Appreciation is the result of numerous factors which occur as a field is developed and produced. Most importantly:

standard industry practices for reporting proved reserves are consistently conservative;
an increased understanding of the petroleum reservoir;
physical expansion of the field through the discovery of new reservoirs or the extension of existing reservoirs; and
improved recoveries due to experience with actual field performance, the implementation of new technology, and/or changes in the cost-price relationships.

Growth functions are modeled from empirical historical trends derived from the set of existing OCS fields having proved reserves at the end of 2002 were used to develop an estimate of an existing field's size at a future date. Growth factors represent the ratio of the size of a field several years after discovery to the initial estimate of its size in the year of discovery. The assumptions central to this analysis are that:

the amount of growth in any year is proportional to the size of the field;
this proportionality varies inversely with the age of the field;
the age of the field is a reasonable proxy for the degree to which the factors causing appreciation have operated; and
the factors causing future appreciation will result in patterns and magnitudes of growth similar to that observed in the past.

The appreciation model used in this assessment projects no growth for fields more than 53 years of age. This appears to be a reasonable conclusion since it fits well with the observed data and does not entail extending projections considerably beyond the time frame of the observations. On balance, however, the model used in this assessment of reserves appreciation is apt to be conservative. The oldest fields are generally the largest, contribute the bulk of the original proved reserves, and also are most likely to experience growth beyond 53 years of age. Although the total volume of hydrocarbons presumed to be available through future reserves growth is substantial, the resources associated with this phenomenon are attainable only in relatively small increments.

Reserves appreciation in the GOM routinely exceeds new field discoveries and contributes the bulk of annual additions to proved reserves. It is an important consideration in any analysis of future oil and natural gas supplies. Future reserves appreciation within the existing active fields in the GOM OCS is estimated at 6.9 Bbo and 30.9 Tcfg (12.3 BBOE)(see figure 6 and table 1(b)). This anticipated volume of growth approaches the yearend 2002 estimate of proved and unproved reserves in the GOM.

Reserves appreciation has not been estimated for the existing fields on the California and Alaska OCS. The fields off California have not exhibited any meaningful pattern in the growth of the estimates of ultimate recovery (EUR) that could be used to project future appreciation. The single producing field on the Alaska OCS is primarily in state waters and does not have a significant production history (10 MMbo, Federal share).

4. Undiscovered Technically Recoverable Resources (UTRR): Estimates of UTRR (refer to table 1(b)) for the entire OCS range from 66.6 Bbo at the F_{95} fractile to 115.1 Bbo at the F_5 fractile with a mean of 85.9 Bbo. Similarly, natural gas estimates range from 326.4 to 565.9 Tcf with a mean of 419.9 Tcf. On a barrel of oil-equivalence basis 54 percent of the potential is located within the GOM (see figure 7). The Alaska OCS ranks second with 31 percent. The Pacific is third among the regions in terms of oil potential and fourth with respect to gas. The Atlantic region, on the other hand, ranks third when considering gas potential and fourth in terms of oil.

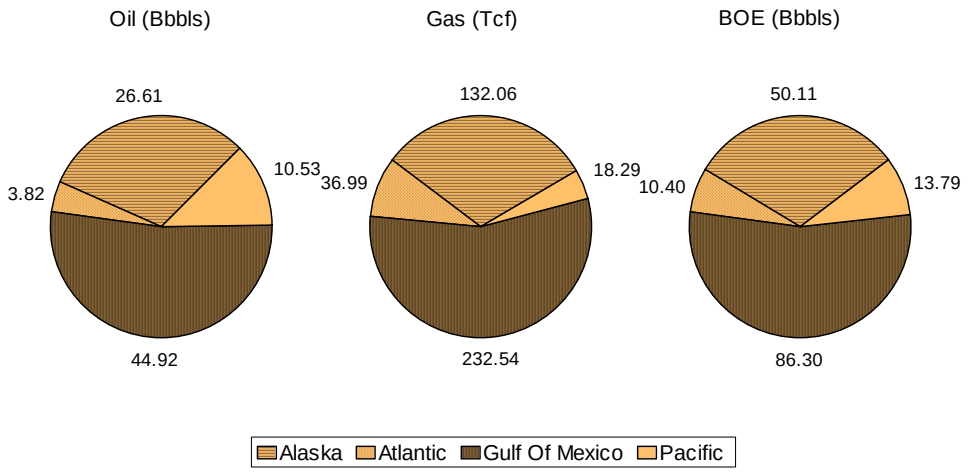

Figure 7: Distribution of UTRR by Type and Region

5. ***Total Endowment***: Mean estimates of the OCS total hydrocarbon endowment are 115.4 Bbo and 633.7 Tcfg (228.2 BBOE). The total endowment distribution by resource category can be seen in table 1(b) and figure 8(a) and (b). More than 18 percent of the total endowment in terms of the mean estimate of the BOE has already been produced. An additional 11 percent is contained within the various reserves categories, the source of near and midterm production.

After more than 50 years of exploration and development, 70 percent of the mean BOE total endowment is represented by undiscovered resources.

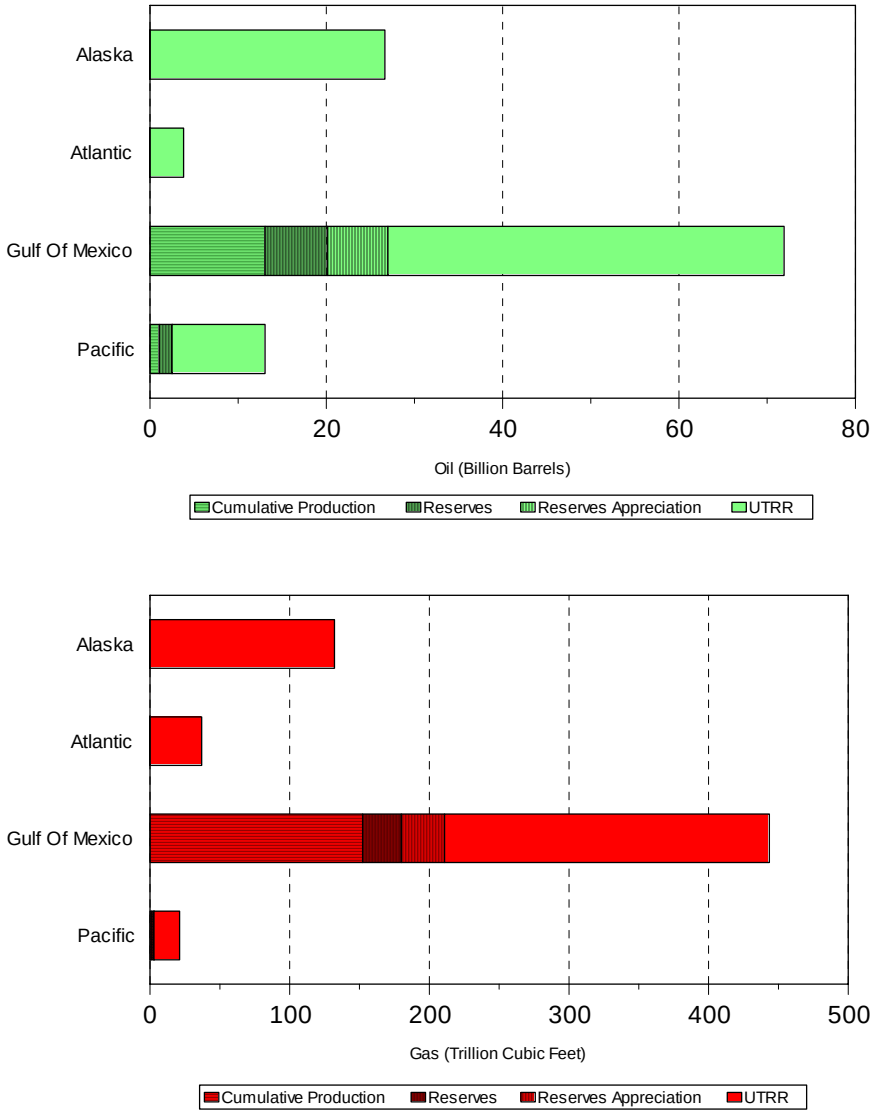

Figure 8(a): Distribution of Total Hydrocarbon Endowment by Type, Region and Resource Category

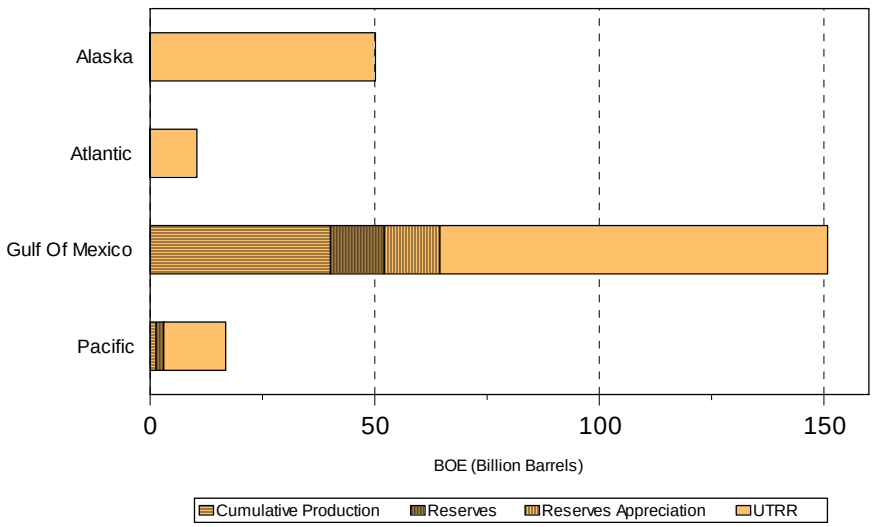

Figure 8(b): Distribution of Total Hydrocarbon Endowment by Type, Region and Resource Category

Note: Alaska OCS cumulative production is 10 MMbo (10 MMBOE) and reserves are 30 MMbo (30 MMBOE)

More than half of this potential exists in areas of the OCS outside of the central and western GOM. During the 50 year history of OCS production more than 14 Bbo and 153 Tcfg have been produced, providing employment opportunities, energy security for the Nation and revenue to the treasury. The vast majority of the remaining reserves, 7.1 Bbo and 27.7 Tcfg, are located within fields in the central and western GOM. Equally important as a source of future domestic production is the 6.9 Bbo and 30.9 Tcfg projected as future volumes of reserves appreciation within the existing GOM fields.

6. Comparison of the MMS 2006 Assessment with the MMS 2001 Assessment: Figure 9 shows that in the four year period between the effective dates of this assessment (January 1, 2003) and the prior assessment (MMS 2001, January 1, 1999), 2.3 Bbo and nearly 20 Tcfg were produced from the OCS, 96 percent from the GOM. This production came from the volume of reserves and reserves appreciation reported in the 2001 resource assessment.

The sum of reserves and reserves appreciation reported in this assessment is 15.4 Bbo and 60.2 Tcfg compared to 13.7 Bbo and 105.1 Tcfg in the 2001 assessment. Despite producing more than 2 Bbo, the estimate of GOM oil reserves increased by 2.7 Bbo and the appreciation estimate decreased by 860 MMbo, a net increase of 1.8 Bbo. Industry was successful in replacing all of the oil reserves produced in the Gulf during this period (see figure 10). The story for natural gas is not as encouraging. Estimates of natural gas reserves decreased by 7.4 Tcf during the period between the assessments. At first glance, this is not too disconcerting since approximately 20 Tcfg were produced. Comparing only estimates of natural gas reserves, the conclusion could be made that industry managed to replace two of every three cubic feet produced. This is not good news, but there was plenty of opportunity to have done worse. The natural gas picture is gloomier when the forecast volumes of reserves appreciation are also considered. These projections decreased by more than 37 Tcf between assessments. In the 2001 assessment the total estimate of gas reserves and projected appreciation was 105.1 Tcf. In this assessment the total was 60.2 Tcf, a decrease of 45 Tcf—despite only 20 Tcf of production.

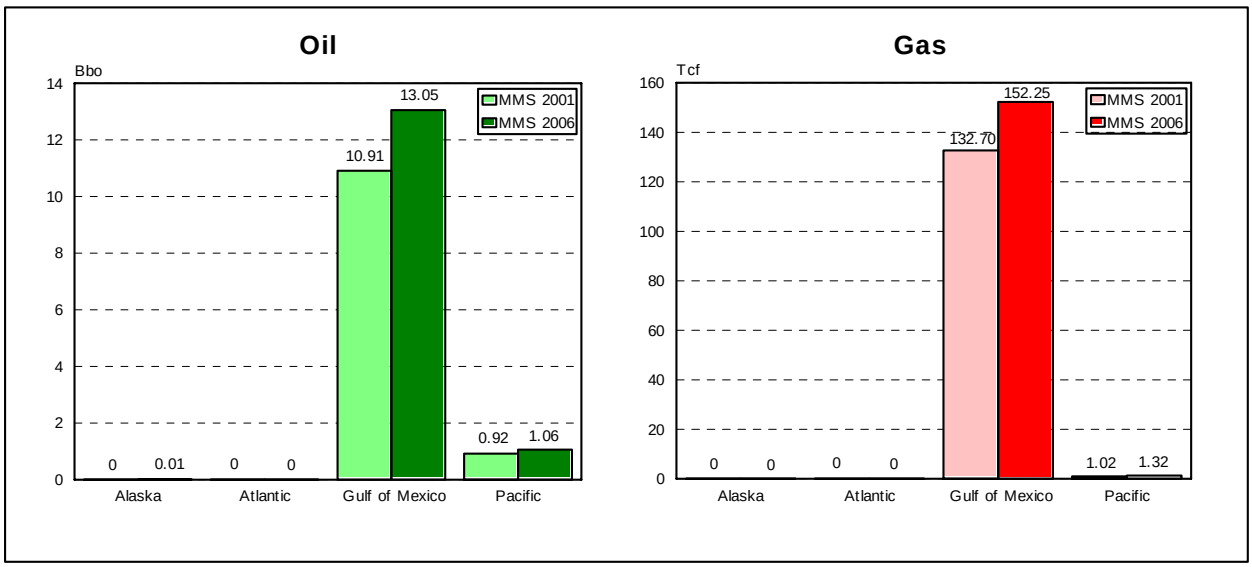

Figure 9: Comparison of Cumulative Production - 2001 and 2006 Assessments (January 1, 1999 versus January 1, 2003)

Note: Alaska OCS cumulative production was zero at the time of the MMS 2001 assessment and 10 MMbo for this assessment.

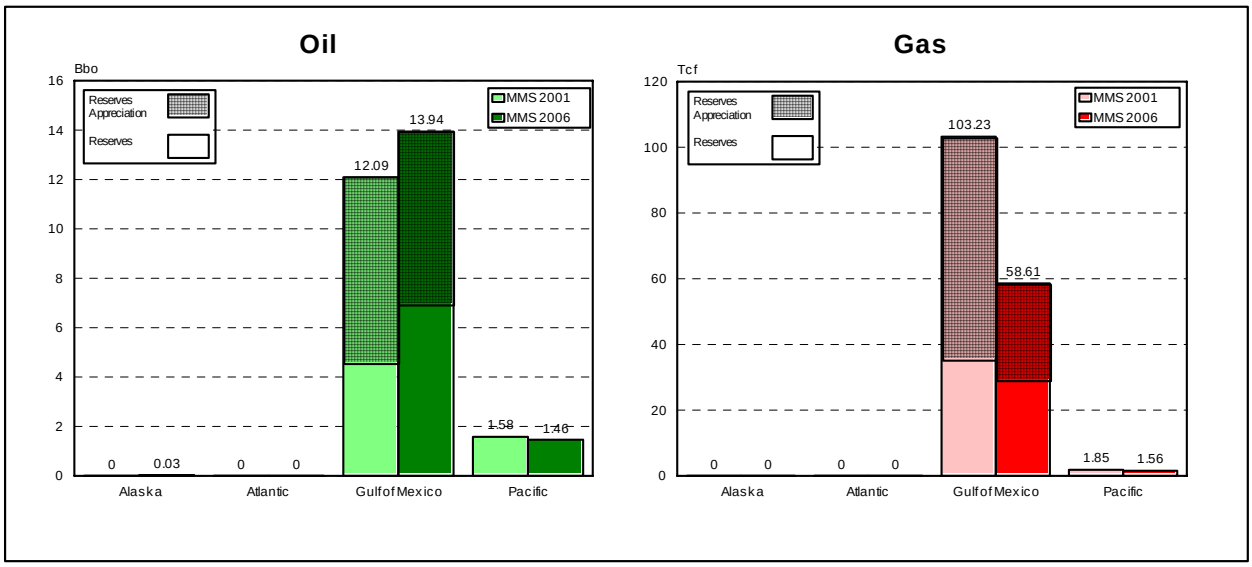

Figure 10: Comparison of Estimates of Reserves and Reserves Appreciation – 2001 and 2006 Assessments

Note: Alaska OCS reserves were zero at the time of the MMS 2001 assessment and 30 MMbo for this assessment.

A portion of the decrease in the estimates of future oil and gas reserves appreciation represents volumes converted to reserves and/or production. This, however, does not explain all of the decrease. Other causes are that newer discoveries, particularly the larger deepwater fields where most of this reserves growth would be expected to occur are much more oil prone and also

experience lower growth rates than previously observed in older offshore fields. This could be due to better initial appraisals prior to development resulting from improved data quality and analytical capabilities. Better initial assessments in these discoveries are essential due to the large capital investments and cutting edge technologies required for these risky projects.

Figure 11 compares the mean estimates of UTRR from the two resource assessments. For the entire OCS, estimates for oil increased 15 percent and for gas, 16 percent. The vast majority of this increase occurred in the GOM where estimates of UTRR range from 41.2 to 49.1 Bbo and 218.8 to 249.1 Tcfg with a mean of 44.9 Bbo and 232.5 Tcfg. The mean estimates of UTRR in the Gulf increased by 12.8 Bbo and more than 40 Tcfg. This represents a 21 percent increase in oil resources and a slightly greater percent increase in natural gas resources since the previous assessment. This increase in UTRR occurred during the same period as approximately 4.5 Bbo and 14 Tcfg were being discovered in fields, such as Thunder Horse and Holstein. The resources associated with these discoveries moved from the UTRR category in the previous assessment to the reserve category for this assessment.

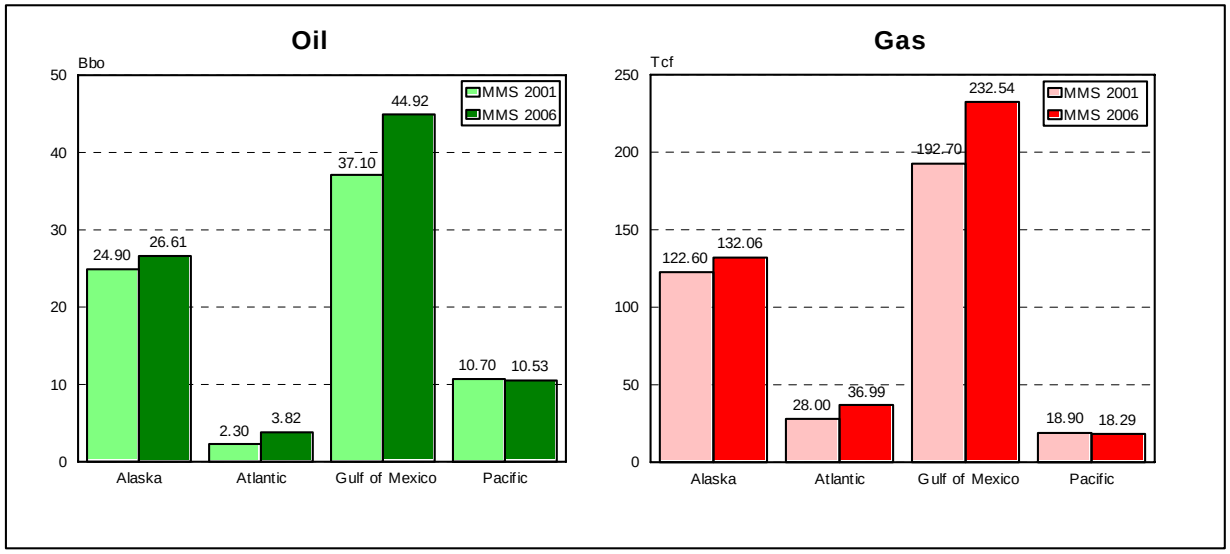

Figure 11: Comparison of Mean Estimates of Undiscovered Technically Recoverable Resources –2001 and 2006 Assessments

Not surprisingly, the increase in the oil estimate for the GOM was nearly all in deepwater (water depths greater than 800 meters) plays. Figure 12 compares the mean estimates of UTRR in the deepwater GOM from the last two assessments. The mean estimates of UTRR in the deepwater were 38.8 Bbo and 125.2 Tcfg (61.1 BBOE), which represents an increase over the previous assessment of 10.8 Bbo and 10.0 Tcfg (12.6 BBOE). The increase in the deepwater oil estimates accounts for nearly 85 percent of the overall 12.8 Bbbls increase. The increase in the deepwater gas mean estimates represents about a quarter of the overall 40 Tcf increase. The major portion of this increase is associated with deep and ultra-deep gas plays beneath the shallow water shelf.

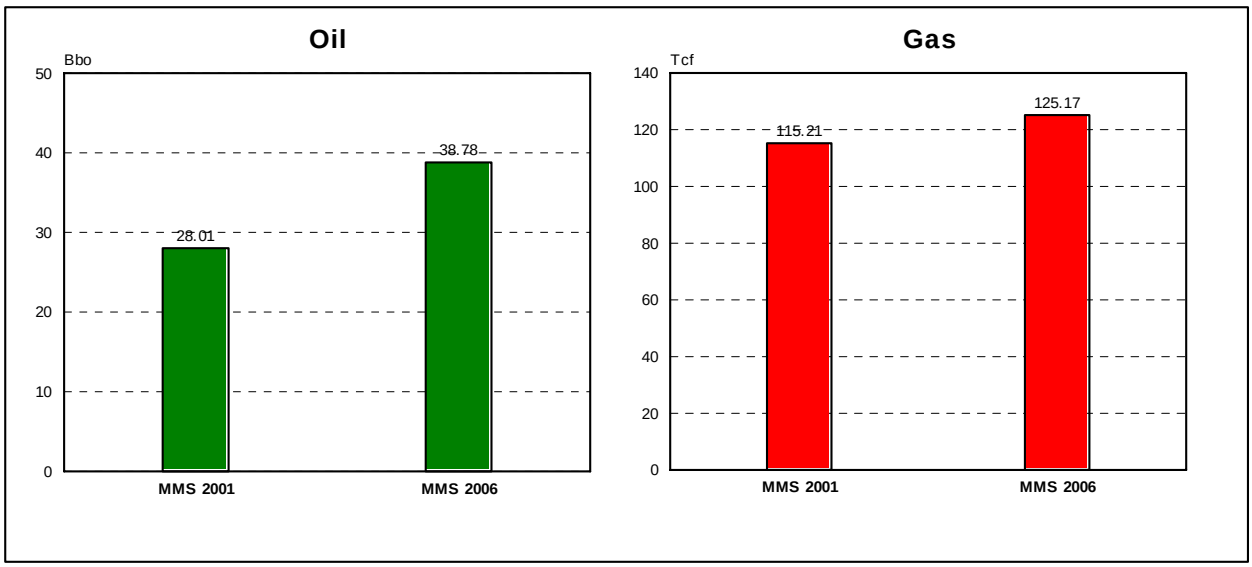

Figure 12: Comparison of Mean Estimates of Undiscovered Technically Recoverable Resources in the Deepwater GOM – 2001 and 2006 Assessments

The increases in the mean UTRR estimates in the Atlantic and Alaska OCS were modest, totaling 3.2 Bbo and 18.5 Tcfg. Estimates in the Pacific region decreased slightly.

IV. Historical Changes to Resource Estimates

"Even when all the experts agree, they may well be mistaken."
—Bertrand Russell, philosopher and mathematician

"Trying to predict the future is a mug's game. But ... we need to have some sort of idea of what the future's actually going to be like because we are going to have to live there, probably next week."
—Douglas Adams, author

As mentioned previously, in making judgments about what is essentially unknowable, uncertainty abounds! There is little in the way of scientific laws and hard-and-fast rules to guide an assessment. The art of resource assessment employs a multi-faceted analytical procedure. Results are not generally repeatable by different assessors, each using different methodologies, within what most observers would view as reasonable margins of error. There is plenty of room for differences of opinion and error. No single definitive assessment procedure appropriate to all situations exists that has been demonstrated to be "correct."

Assessment comparisons are easy to make, but difficult to do correctly in a meaningful manner. Assessments are comparable if each assessment's resource estimates attempt to measure the same commodities under similar conditions. For example, technically recoverable estimates should reflect the effect of reasonably foreseeable changes in technology and not reflect changing economic conditions not caused by technology advances or political paradigms.

If a reviewer is determined to compare petroleum estimates, especially a series of estimates developed over time, he should be prepared to tread carefully. To do so properly, it is first necessary to ascertain that the assessments cover the same things. The assessments should be identical in terms of:

commodities assessed,
categories of resources assessed,
areas assessed,
reporting of statistical data, e.g., ranges and probabilities, and
technological and economic conditions incorporated.

As discussed earlier, the last item may be the most troublesome to deal with since these conditions are rarely explicitly stated or easily measured. They are also precisely the conditions most apt to change between assessments. Irrespective of modifications in methodology, changes in basic geologic knowledge, economic conditions, and exploitation technologies make it difficult to compare estimates developed over time or to draw in-depth conclusions regarding the impact of these factors on individual assessments.

Since 1975, the DOI has completed eight comprehensive, large-scale assessments of the undiscovered petroleum potential of the OCS. These estimates have been prepared by different bureaus, each using different assessment methods that in turn continued to evolve over time. The techniques used vary from simple Delphi and volumetric yield approaches to geologic

analogy, to statistical techniques, such as finding rates and discovery process models, to summation of prospects and play assessment approaches employing sophisticated discounted cash flow analysis. The estimates presented all appear to have no time limit regarding realization, although they assume discovery and recovery under the economic and technologic trends prevailing at the time of the assessment. The assessments also have covered different areas, measured different resources, e.g. UTRR versus UERR, and employed different assumptions developed from the perspective of different knowledge bases available at a particular point in time.

To effectively compare these estimates, one must develop an understanding of how they were prepared; the extent and reliability of the data upon which they were based; the expertise of the assessors; the implications and limitations of the methodology used; and the nature of any geographic, economic, technologic, or time limitations and assumptions that may apply. This analysis would be an exhaustive, time consuming effort. However, an attempt to compare the changes in the estimates can be made in light of the geologic knowledge base available to each assessment team, the state of exploration and production technology, choice of assessment methodologies, and the portion of the resource base assessed between successive the DOI assessments.

The degree to which variations among the reported assessments are attributable to different perceptions of the magnitude and distribution of the resource base is impossible to determine. For certain the estimates have a time dimension that impacted the degree of basic geologic knowledge available to the assessors, as well as their technologic and economic perceptions. In the case of the GOM region, an example of the changing information base available to the assessor is the 28,671 wells drilled and additional 920 fields discovered during the period covered by the assessments (1975 to 2002). The number of wells drilled on the OCS outside of the GOM increased from 362 to 1427 during this period. All but one of the 362 wells at the time of the first assessment was located in the Pacific OCS. Millions of line-miles of 2-D seismic and more than 350,000 square miles of 3-D seismic were acquired on the OCS.

The first two assessments were performed by the USGS and the remainder by the MMS. Table 2 summarizes the results from each assessment. The comments column highlights some of the key high level characteristics of each assessment in terms of area covered (defined primarily by water depth), key economic assumptions if applicable, assessment methodology, etc. Note that the principal estimates reported originally were of UERR. More recently the focus has shifted to estimates of UTRR. The MMS has in recent assessments supplemented the primary UTRR estimates with price-supply curves that demonstrate the sensitivity of resources to changes in the cost-price relationship.

1. USGS 1975 Assessment (Miller et al., 1975): This assessment utilized a Delphi technique incorporating subjective judgment by a group of appraisers to directly estimate probabilities of occurrence and the undiscovered resource potential of an area. The assessors relied on various analyses to guide their judgments. These estimates were primarily analog based; e.g., volumetric yields, finding rates, etc., comparing more mature, geologically similar basins to the frontier OCS basins being assessed. The USGS relied on publicly available data to perform this assessment. Outside of the shelf portion of the central and western GOM and the Santa Barbara Channel there was little in the way of hard geological data available on the OCS for use in this assessment.

Table 2: Summary of the Department of the Interior OCS Resource Assessments

Organization	Effective Date	Region	Risked Estimates of Undiscovered Resources									Reserves[2]			Cumulative Production			Total Endowment (Mean)			Comments
				Oil (Bbbl)[1]		Gas (Tcf)			BOE (Bbbl)			Oil	Gas	BOE	Oil	Gas	BOE	Oil	Gas	BOE	
			F_5	F_{95}	Mean	F_5	F_{95}	Mean	F_5	F_{95}	Mean	(Bbbl)	(Tcf)	(Bbbl)	(Bbbl)	(Tcf)	(Bbbl)	(Bbbl)	(Tcf)	(Bbbl)	
USGS (Miller et al. 1975)	1/1/1975 UERR	Alaska OCS	33.00	3.20	16.10	80.00	8.00	44.00			23.93	0.16	0.15	0.19	0.46	0.42	0.53	16.72	44.57	24.65	1. 0-200m WD
		Atlantic OCS	6.55	0.00	3.25	22.00	0.00	10.00			5.03	0.00	0.00	0.00	0.00	0.00	0.00	3.25	10.00	5.03	2. Includes state waters
		Gulf of Mexico OCS	10.23	3.45	6.25	91.00	18.00	50.00			15.15	4.66	102.35	22.87	4.14	32.14	9.85	15.05	184.49	47.87	3. Florida Straits included in Atlantic OCS
		Pacific OCS	5.00	2.00	3.00	6.00	2.00	3.00			3.53	1.31	0.86	1.47	1.50	1.42	1.75	5.81	5.28	6.75	4. Prevailing pre-1974 prices: $4.17/bbl and $0.22/mcf
		Total OCS[3]	**53.53**	**11.05**	**28.60**	**181.00**	**42.00**	**107.00**			**47.64**	**6.13**	**103.36**	**24.52**	**6.09**	**33.98**	**12.14**	**40.82**	**244.33**	**84.30**	5. Delphi subjective judgment
USGS (Dolton et al. 1981)	mid 1980 UERR	Alaska OCS	27.60	5.67	14.33	109.65	33.32	64.61			25.83	0.30	3.20	0.87	0.70	0.60	0.81	15.33	68.41	27.50	1. 0-2500m WD
		Atlantic OCS	14.17	1.37	5.51	42.82	9.17	23.66			9.72	0.00	0.00	0.00	0.00	0.00	0.00	5.51	23.66	9.72	2. Includes state waters
		Gulf of Mexico OCS	16.20	5.01	8.09	114.15	41.66	71.84			20.87	2.70	73.90	15.85	5.60	55.30	15.44	16.39	201.04	52.16	3. Florida Straits included in Atlantic OCS
		Pacific OCS	8.33	1.83	4.04	13.55	3.73	6.89			5.27	1.70	2.30	2.11	1.90	1.50	2.17	7.64	10.69	9.54	4. Prevailing 1980 prices: $28.07/bbl and $1.59/mcf
		Total OCS[3]	**51.68**	**21.03**	**31.97**	**230.65**	**117.42**	**167.00**			**61.69**	**4.70**	**79.40**	**18.83**	**8.20**	**57.40**	**18.41**	**44.87**	**303.80**	**98.93**	5. Delphi subjective judgment
MMS (Cooke, 1985)	7/1/1984 UERR	Alaska OCS			3.33			13.85			5.79	0.00	0.00	0.00	0.00	0.00	0.00	3.33	13.85	5.79	1. 0-2500m WD
		Atlantic OCS			0.68			12.31			2.87	0.00	0.00	0.00	0.00	0.00	0.00	0.68	12.31	2.87	2. Includes Federal OCS only
		Gulf of Mexico OCS			6.03			59.64			16.64	3.41	43.70	11.19	5.90	62.50	17.02	15.34	165.84	44.85	3. Florida Straits included in Atlantic OCS
		Pacific OCS			2.19			4.70			3.03	1.15	2.14	1.53	0.28	0.16	0.31	3.62	7.00	4.87	4. Starting: $29/bbl and $2.90/mcf escalated
		Total OCS[3]			**12.23**			**90.50**			**28.33**	**4.56**	**45.84**	**12.72**	**6.18**	**62.66**	**17.33**	**22.97**	**199.00**	**58.38**	5. PRESTO I prospect summation
MMS (Cooke et al, 1990)	1/1/1987 UTRR	Alaska OCS	11.21	0.59	3.84	39.42	4.67	16.75			6.82	0.00	0.00	0.00	0.00	0.00	0.00	3.84	16.75	6.82	1. 0-2500m WD
		Atlantic OCS	3.15	0.09	0.96	33.71	6.78	17.03			3.99	0.00	0.00	0.00	0.00	0.00	0.00	0.96	17.03	3.99	2. Includes Federal OCS only
		Gulf of Mexico OCS	15.12	5.52	9.57	156.92	63.02	103.34			27.96	3.95	47.00	12.31	6.93	75.20	20.31	20.45	225.54	60.58	3. Florida Straits included in Atlantic OCS
		Pacific OCS	8.92	0.81	3.51	15.07	3.50	8.01			4.94	1.30	2.14	1.68	0.37	0.33	0.43	5.18	10.48	7.04	
		Total OCS[3]	**25.60**	**9.20**	**17.88**	**204.80**	**97.80**	**145.13**			**43.70**	**5.25**	**49.14**	**13.99**	**7.30**	**75.53**	**20.74**	**30.43**	**269.80**	**78.44**	
	1/1/1987 UERR Primary Case	Alaska OCS	4.76	0.00	0.92	0.00	0.00	0.00			0.92	0.00	0.00	0.00	0.00	0.00	0.00	0.92	0.00	0.92	4. Starting: $18/bbl and $1.80/mcf escalated
		Atlantic OCS	1.01	0.00	0.25	9.77	0.00	4.51			1.05	0.00	0.00	0.00	0.00	0.00	0.00	0.25	4.51	1.05	5. PRESTO III & DIST
		Gulf of Mexico OCS	9.88	2.77	5.64	103.65	36.01	64.33			17.09	3.95	47.00	12.31	6.93	75.20	20.31	16.52	186.53	49.71	
		Pacific OCS	6.02	1.78	2.10	11.04	1.78	5.17			3.02	1.30	2.14	1.68	0.37	0.33	0.43	3.77	7.64	5.13	
		Total OCS[3]	**14.30**	**4.00**	**8.91**	**113.84**	**44.30**	**74.01**			**22.08**	**5.25**	**49.14**	**13.99**	**7.30**	**75.53**	**20.74**	**21.46**	**198.68**	**56.81**	
MMS (Cooke, 1991)	1/1/1990 UERR	Alaska OCS	7.16	0.00	1.87	0.00	0.00	0.00			1.87	0.00	0.00	0.00	0.00	0.00	0.00	1.87	0.00	1.87	1. 0-2500m WD
		Atlantic OCS	1.01	0.00	0.25	9.77	0.00	4.51			1.05	0.00	0.00	0.00	0.00	0.00	0.00	0.25	4.51	1.05	2. Includes Federal OCS only
		Gulf of Mexico OCS	17.16	1.24	6.34	122.68	27.90	64.74			17.86	3.03	40.20	10.18	7.84	88.90	23.66	17.21	193.84	51.70	3. Florida Straits included in Atlantic OCS
		Pacific OCS	6.12	0.63	2.49	12.14	2.46	6.15			3.58	1.48	2.20	1.87	0.46	0.48	0.55	4.43	8.83	6.00	4. $18/bbl and $1.80/mcf flat
		Total OCS[3]	**23.93**	**3.56**	**10.95**	**133.68**	**46.44**	**75.40**			**24.36**	**4.51**	**42.40**	**12.05**	**8.30**	**89.38**	**24.21**	**23.76**	**207.18**	**60.62**	5. PRESTO III
MMS (MMS, 1996)	1/1/1995 UTRR	Alaska OCS	33.57	16.85	24.31	229.53	58.01	125.93	70.61	28.68	46.72	0.04	0.70	0.16	0.00	0.00	0.00	24.35	126.63	46.88	1. No WD limit
		Atlantic OCS	3.70	1.30	2.30	43.40	15.90	27.50	10.70	4.50	7.20	0.00	0.00	0.00	0.00	0.00	0.00	2.30	27.50	7.20	2. Includes Federal OCS only
		Gulf of Mexico OCS	11.10	6.00	8.30	110.30	82.30	95.70	30.00	21.20	25.40	8.60	65.60	20.27	9.34	112.60	29.38	26.24	273.90	75.05	3. Florida Straits included in Gulf of Mexico OCS
		Pacific OCS	12.60	9.00	10.70	23.20	15.20	18.90	16.60	11.80	14.10	1.23	2.03	1.59	0.68	0.65	0.79	12.61	21.58	16.48	
		Total OCS[3]	**55.30**	**37.10**	**45.61**	**369.20**	**186.30**	**268.03**	**117.00**	**72.90**	**93.42**	**9.87**	**68.33**	**22.03**	**10.02**	**113.25**	**30.17**	**65.50**	**449.61**	**145.62**	
	1/1/1995 UERR	Alaska OCS	7.65	1.41	3.75	4.33	0.02	1.11	8.20	1.43	3.95	0.04	0.70	0.16	0.00	0.00	0.00	3.79	1.81	4.11	4. $18/bbl and $2.11/mcf flat
		Atlantic OCS			0.40			5.20			1.33	0.00	0.00	0.00	0.00	0.00	0.00	0.40	5.20	1.33	5. GRASP & PRESTO V
		Gulf of Mexico OCS			4.90			57.90			15.20	8.60	65.60	20.27	9.34	112.60	29.38	22.84	236.10	64.85	
		Pacific OCS			5.30			8.30			6.78	1.23	2.03	1.59	0.68	0.65	0.79	7.21	10.98	9.16	
		Total OCS[3]			**14.35**			**72.51**			**27.25**	**9.87**	**68.33**	**22.03**	**10.02**	**113.25**	**30.17**	**34.24**	**254.09**	**79.45**	
MMS (MMS, 2001)	1/1/1999 UTRR	Alaska OCS	35.40	16.50	24.90	226.80	55.00	122.60	71.90	28.00	46.70	0.00	0.00	0.00	0.00	0.00	0.00	24.90	122.60	46.70	1. No WD limit
		Atlantic OCS	2.80	1.90	2.30	34.10	23.90	28.00	8.90	6.20	7.30	0.00	0.00	0.00	0.00	0.00	0.00	2.30	28.00	7.30	2. Includes Federal OCS only
		Gulf of Mexico OCS	44.90	33.40	37.10	207.20	180.40	192.70	81.80	65.50	71.40	12.09	103.23	30.46	10.91	132.70	34.52	60.10	428.63	136.38	3. Florida Straits included in Gulf of Mexico OCS
		Pacific OCS	12.60	9.00	10.70	23.20	15.20	18.90	16.60	11.80	14.10	1.58	1.85	1.91	0.92	1.02	1.10	13.20	21.77	17.11	4. GRASP & PRESTO V
		Total OCS[3]	**88.30**	**63.70**	**75.00**	**468.60**	**292.10**	**362.20**	**166.90**	**117.80**	**139.50**	**13.67**	**105.08**	**32.37**	**11.83**	**133.72**	**35.62**	**100.50**	**601.00**	**207.49**	
MMS (MMS, 2006)	1/1/2003 UTRR	Alaska OCS	55.14	8.66	26.61	279.62	48.28	132.06	104.89	17.25	50.11	0.03	0.00	0.03	0.01	0.00	0.01	26.65	132.06	50.15	1. No WD limit
		Atlantic OCS	7.57	1.12	3.82	66.46	14.30	36.99	19.39	3.67	10.40	0.00	0.00	0.00	0.00	0.00	0.00	3.82	36.99	10.40	2. Includes Federal OCS only
		Gulf of Mexico OCS	49.11	41.21	44.92	249.08	218.83	232.54	93.43	80.15	86.30	13.94	58.61	24.37	13.05	152.25	40.14	71.91	443.40	150.81	3. Florida Straits included in Gulf of Mexico OCS
		Pacific OCS	13.94	7.55	10.53	24.12	13.29	18.29	18.24	9.91	13.79	1.46	1.56	1.74	1.06	1.32	1.29	13.05	21.17	16.82	4. GRASP II
		Total OCS[3]	**115.13**	**66.60**	**85.88**	**565.87**	**326.40**	**419.88**	**215.82**	**124.68**	**160.60**	**15.43**	**60.17**	**26.14**	**14.12**	**153.57**	**41.45**	**115.43**	**633.62**	**228.18**	

[1]Includes oil and condensate (natural gas liquids)
[2]Includes reserves appreciation if assessed
[3]Only mean values additive

No wells had yet been drilled on the Atlantic OCS and only a single deep stratigraphic test well had been drilled on the Alaska OCS in the Gulf of Alaska. Twenty exploratory wells had been drilled off central and northern California and 12 off Oregon-Washington during the period 1963 through 1969. Three wells had been drilled in the current Florida Straits Planning Area, off the Marquessa Keys during 1960 and 1961. At least 17 other wells were drilled in state waters or onshore adjacent to this area. All of these wells were considered at the time to be dry holes. Elsewhere in the eastern GOM the initial four dry holes had recently been drilled on the eastern crest of the Destin Dome structure and two other dry holes were drilled on other prospects located within the planning area.

In the central and western GOM industry was proceeding with its steady seaward march into deeper waters on the continental shelf (less than 200m water depths). Discoveries were primarily off Louisiana, but industry activity along the shelf edge was beginning to move westward off Texas. Eleven of the 12 discovered Pacific OCS oil and gas fields, including both producing fields, were in the Santa Barbara Channel. The other discovery was located to the south in the Los Angeles basin.

Industry proven technology capabilities were just beginning to expand beyond the shallow waters of the OCS. The first pipeline in water depths exceeding 1,000 feet had recently been laid. The Hondo platform soon to be installed in 850 feet of water in the Santa Barbara Channel was being fabricated at the time of the assessment. The introduction of dynamic positioning systems, used on drill ships and semi-submersible drilling rigs, was opening up deepwater exploration.

The assessment included only those portions of the OCS located in water depths of less than 200 meters. The offshore portion of the assessment also included state waters. Estimates of UERR were reported. The UERR were defined as "economically recoverable under price-cost relationships and technological trends prevailing at the time of the assessment." The assessment assumed that prevailing pre-1974 costs and prices relationships would continue. The 1973 average refiner's acquisition cost for crude oil was $4.17 per barrel and the average wellhead price for gas was $0.22 per million cubic feet (Mcf). The price, cost and technology considerations were not a quantitative part of the assessment procedure, but rather considered subjectively by each assessor in formulating their judgments.

Estimates of UERR (see table 2) ranged from 11.05 to 53.53 Bbo and 42.0 to 181.0 Tcfg, with a mean estimate of 28.6 Bbo and 107.0 Tcfg. The GOM was forecast to contain 22 percent of the oil and offshore Alaska 45 percent, with the remainder nearly evenly split between the east and West Coasts (see figure 13). The assessment forecast that 47 percent of the undiscovered economically recoverable gas was located in the GOM. Offshore Alaska followed with 41 percent of the total. The mean estimate of total endowment was projected at 40.8 Bbo and 244.3 Tcfg (84.3 BBOE).

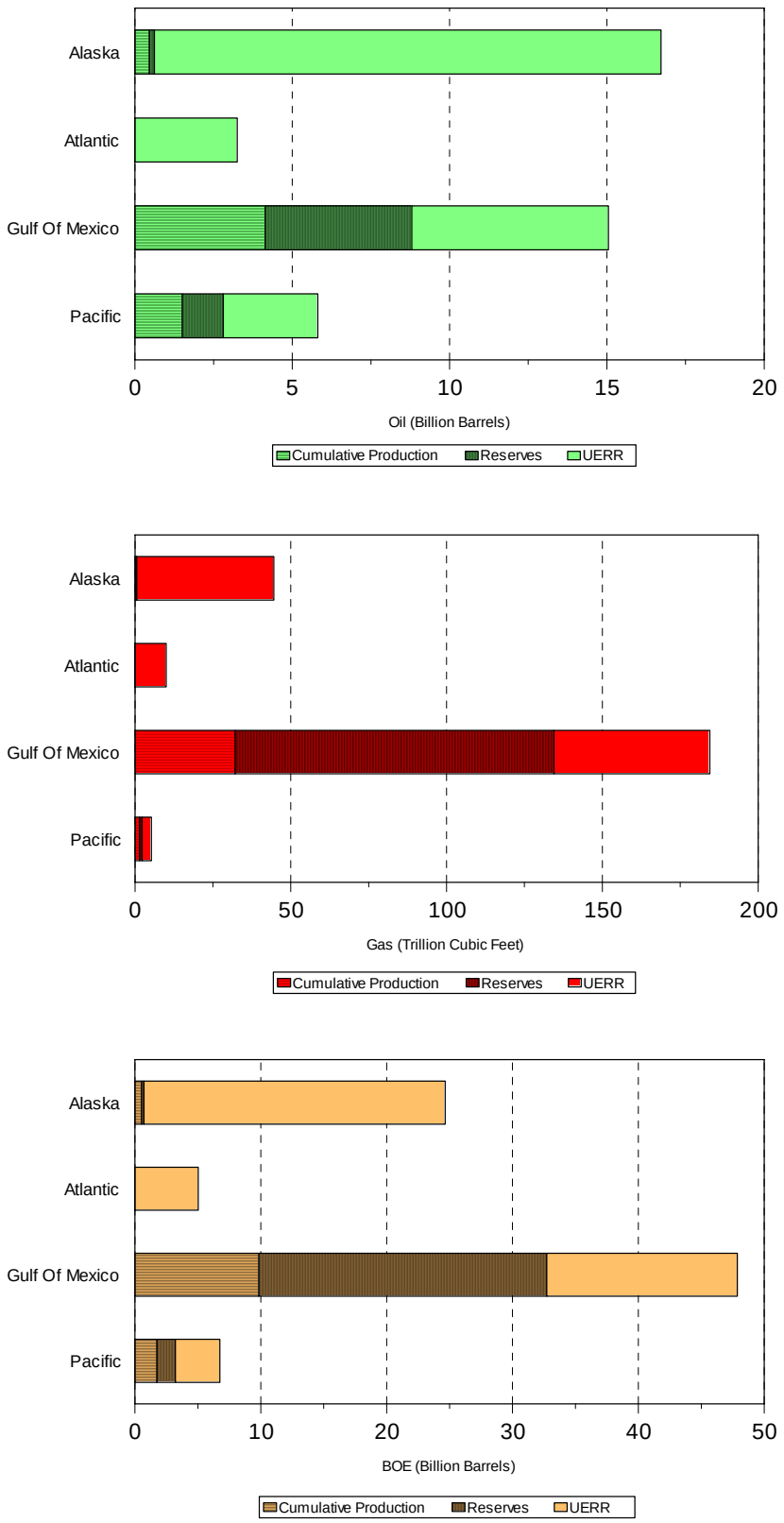

Figure 13: Distribution of Total Hydrocarbon Endowment by Type, Region and Resource Category, USGS (1975)

2. USGS 1981 Assessment (Dolton et al., 1981): The USGS completed its second national resource assessment in 1981 again employing an updated version of its Delphi assessment technique. This time there was information available in many frontier basins from industry's early seismic and exploratory drilling campaigns. During the period since the previous assessment eight additional deep stratigraphic test wells (one in St. George, six in Kodiak, and one in the lower Cook Inlet) were drilled in frontier Alaska basins. The results from follow-on industry exploration drilling in each of these basins were discouraging. The initial industry interest was in the Gulf of Alaska where 11 dry exploratory wells were drilled between 1976 and 1978. Industry next moved on to the lower Cook Inlet where an additional nine dry holes were drilled in the first cycle of exploration for this basin. The results were only slightly more encouraging in the Atlantic OCS. In the south Atlantic one deep stratigraphic test well was followed up by six dry holes within the southeast Georgia embayment. Two deep stratigraphic tests were drilled in the North Atlantic providing direct geologic control for this assessment. During this period, industry's primary interest was in the Baltimore Canyon trough offshore New Jersey where two deep stratigraphic tests (one with an announced hydrocarbon show) and 23 exploratory wells were drilled. Tests on the "Great Stone Dome" structure were huge disappointments. Five wells, drilled on a single structure by Tenneco and Texaco flowed significant quantities of natural gas and some oil on tests. This was enough to sustain some industry interest in the area.

In the Santa Barbara Channel industry was in the midst of a string of new field discoveries. Four of the five producing OCS fields were in the Santa Barbara Channel. Exxon installed Platform Hondo in 1976 in 842 feet of water, a world record water depth at the time. Two deep stratigraphic tests were drilled off southern California, one on the Cortes Bank about 90 miles southwest of Los Angeles, and the other in the Point Conception area of the Santa Maria Basin. A hydrocarbon show was encountered in the Point Conception test. Based on favorable stratigraphy in the Cortes Bank test a series of nine exploratory wells were drilled on the southern California borderland. All of these wells were dry holes. The first OCS discovery in the Santa Maria Basin, the Point Arguello Field, was made in late 1980. The northernmost block of this field was leased after the field discovery in 1981 for a bonus bid of $333,596,200. This is the all time OCS record high bid.

Industry continued to drill additional dry holes on and around the Destin Dome structure and elsewhere in the eastern GOM. By October 1975, drilling in the area had halted after a total of 15 dry holes. One encouraging note, however, was the penetration of the Norphlet Formation which revealed the presence of massive reservoir quality sandstone. This dry hole became even more important with the 1979 discovery of the Mary Ann Field in state waters offshore Alabama which generated interest in the probable extension of the prolific Norphlet trend into adjacent Federal waters. In the central and western GOM industry interest was focused on the Flexure trend, located at the outer edge of the continental shelf offshore Louisiana and Texas and the Corsair trend on the Texas shelf.

The offshore portion of the assessment again included state waters. Industry exploration and production activity in the Flexure trend in the GOM, the Santa Barbara Channel, and elsewhere had exceeded the 200 meter water depth technology limit used in the previous assessment.

The first OCS deepwater production facility, Shell's Cognac fixed leg platform, was installed in the GOM in 1979 in 1,023 feet of water. Acknowledging this advancement in deepwater exploration and production technology, the USGS expanded the extent of the offshore area included in this assessment to include all areas in water depths less than 2,500 meters. The water depth limit of 2,500 meters in conjunction with a consideration of only those sediments shallower than 30,000 feet represented two high level technology limits imposed in this assessment. Estimates of UERR were again reported. The assessment assumed that prevailing 1980 costs and prices relationships would continue. During 1980 prices averaged $28/bbl and $1.60/Mcf, more than seven times the 1974 averages assumed in the prior report. The concept of a "minimum economic field size" (MEFS) was introduced for the various OCS regions. This MEFS incorporated quantitatively a consideration of local costs, prevailing prices and foreseeable technologies. The USGS applied individual threshold sizes across a broad range of locations, geologic conditions and water depths. Resources in accumulations below the appropriate MEFS were excluded from consideration in the assessment. The MEFS were subjectively considered by each individual assessor.

Estimates of UERR ranged from 21.0 to 51.7 Bbo and 117.4 to 230.7 Tcfg, with a mean estimate of 32.0 Bbo and 167.0 Tcfg (table 2). Despite the dismal exploration results from drilling in the frontier basins in the Gulf of Alaska, southern California borderland and the southeast Georgia embayment, mean estimates of overall UERR increased by 14 percent for oil and 56 percent for gas. Table 3 shows a more detailed breakdown of the two assessments by offshore region and the shelf and slope areas.

Table 3: Comparison of the Department of the Interior 1975 and 1981 OCS Resource Assessments by Water Depth

Organization	Effective Date	Region	Risked Estimates of Undiscovered Resources									Reserves 2			Cumulative Production			Total Endowment (Mean)		
			Oil (Bbbl)1			Gas (Tcf)			BOE (Bbbl)			Oil	Gas	BOE	Oil	Gas	BOE	Oil	Gas	BOE
			F_5	F_{95}	Mean	F_5	F_{95}	Mean	F_5	F_{95}	Mean	(Bbbl)	(Tcf)	(Bbbl)	(Bbbl)	(Tcf)	(Bbbl)	(Bbbl)	(Tcf)	(Bbbl)
USGS (Miller et al., 1975)	1/1/1975 UERR	Alaska shelf	33.00	3.20	16.10	80.00	8.00	44.00			23.93	0.16	0.15	0.19	0.46	0.42	0.53	16.72	44.57	24.65
		Atlantic shelf	6.55	0.00	3.25	22.00	0.00	10.00			5.03	0.00	0.00	0.00	0.00	0.00	0.00	3.25	10.00	5.03
		Gulf of Mexico shelf	10.23	3.45	6.25	91.00	18.00	50.00			15.15	4.66	102.35	22.87	4.14	32.14	9.85	15.05	184.49	47.87
		Pacific shelf	5.00	2.00	3.00	6.00	2.00	3.00			3.53	1.31	0.86	1.47	1.50	1.42	1.75	5.81	5.28	6.75
		Total shelf	**53.53**	**11.05**	**28.60**	**181.00**	**42.00**	**107.00**			**47.64**	**6.13**	**103.36**	**24.52**	**6.09**	**33.98**	**12.14**	**40.82**	**244.33**	**84.30**
		Alaska slope																		
		Atlantic slope																		
		Gulf of Mexico slope																		
		Pacific slope																		
		Total slope																		
		Total OCS	**53.53**	**11.05**	**28.60**	**181.00**	**42.00**	**107.00**			**47.64**	**6.13**	**103.36**	**24.52**	**6.09**	**33.98**	**12.14**	**40.82**	**244.33**	**84.30**
USGS (Dolton et al.,1981)	mid 1980 UERR	Alaska shelf	25.22	4.73	12.67	99.00	28.50	57.40			22.88	0.30	3.20	0.87	0.70	0.60	0.81	13.67	61.20	24.56
		Atlantic shelf	4.51	0.07	1.58	17.90	2.20	8.20			3.04	0.00	0.00	0.00	0.00	0.00	0.00	1.58	8.20	3.04
		Gulf of Mexico shelf	9.67	1.79	5.01	79.20	22.00	45.10			13.03	2.70	73.90	15.85	5.60	55.30	15.44	13.31	174.30	44.32
		Pacific shelf	3.15	0.63	1.57	5.20	0.90	2.50			2.02	1.70	2.30	2.11	1.90	1.50	2.17	5.17	6.30	6.29
		Total shelf	**30.20**	**9.20**	**17.60**	**166.80**	**72.00**	**113.40**			**40.96**	**4.70**	**79.40**	**18.83**	**8.20**	**57.40**	**18.41**	**33.72**	**250.00**	**78.20**
		Alaska slope	5.86	0.00	1.63	20.20	0.00	7.20			2.92	0.00	0.00	0.00	0.00	0.00	0.00	1.63	7.20	2.92
		Atlantic slope	11.87	0.17	4.62	34.50	5.10	15.40			7.36	0.00	0.00	0.00	0.00	0.00	0.00	4.62	15.40	7.36
		Gulf of Mexico slope	6.36	1.15	3.09	51.80	11.10	26.50			7.81	0.00	0.00	0.00	0.00	0.00	0.00	3.09	26.50	7.81
		Pacific slope	6.30	0.66	2.53	10.20	1.90	4.40			3.31	0.00	0.00	0.00	0.00	0.00	0.00	2.53	4.40	3.31
		Total slope	**19.20**	**4.20**	**11.87**	**87.10**	**28.60**	**53.60**			**21.39**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**11.87**	**53.50**	**21.39**
		Alaska OCS	27.60	5.67	14.33	109.65	33.32	64.61			25.83	0.30	3.20	0.87	0.70	0.60	0.81	15.33	68.41	27.50
		Atlantic OCS	14.17	1.37	5.51	42.82	9.17	23.66			9.72	0.00	0.00	0.00	0.00	0.00	0.00	5.51	23.66	9.72
		Gulf of Mexico OCS	16.20	5.01	8.09	114.15	41.66	71.84			20.87	2.70	73.90	15.85	5.60	55.30	15.44	16.39	201.04	52.16
		Pacific OCS	8.33	1.83	4.04	13.55	3.73	6.89			5.27	1.70	2.30	2.11	1.90	1.50	2.17	7.64	10.69	9.54
		Total OCS	**51.68**	**21.03**	**31.97**	**230.65**	**117.42**	**167.00**			**61.69**	**4.70**	**79.40**	**18.83**	**8.20**	**57.40**	**18.41**	**44.87**	**303.80**	**98.93**

[1] Includes oil and condensate (natural gas liquids)
[2] Includes reserves appreciation if assessed

The mean oil and gas estimates for UERR located on the shelf (0 – 200 meters water depth) in this assessment were 17.6 Bbo and 113.4 Tcfg (41.0 BBOE) versus 28.6 Bbo and 107.0 Tcfg (47.6 BBOE) in the prior assessment, a decrease of 38 and 14 percent for oil and BOE, respectively. The total mean estimate for gas increased slightly in this assessment. A closer look shows that UERR estimates for oil were down in every region, as was gas with the exception of offshore Alaska where the estimates increased by 13 Tcf or almost 30 percent. The increase in the estimate of potential quantities of gas in the shallow waters offshore Alaska is probably the result of a combination of factors. The drilling results off Alaska, while generally disappointing, indicated that the Bering Sea basins were probably more gas prone than previously assumed. The considerably higher gas prices incorporated in this assessment and the lower economic risk and MEFS thresholds associated with gas discoveries more than offset any increase in geologic risk imposed. The remainder of the increase in UERR is attributable to the inclusion of the continental slope in this assessment. Approximately one third of the total UERR estimate was for the deeper water portion of the OCS. Of particular note at the time of this assessment was the announcement by the USGS scientists of the existence of a buried Mesozoic shelf-edge reef complex that extended intermittently along much of the Atlantic continental margin. Comparisons were made with similar features in prolific producing trends in Mexico and the onshore U.S. gulf coast.

Mean estimates of the total hydrocarbon endowment of the OCS developed from this assessment were 44.9 Bbo and 303.8 Tcfg (98.9 BBOE), corresponding to an increase of 11 percent for oil and 24 percent for gas (18 percent for BOE) since the 1975 assessment. The mean value for oil UERR was 71 percent of the mean estimate for the total oil endowment. Corresponding estimates for gas and BOE are 55 and 63 percent.

The GOM was forecast to contain nearly one quarter of the UERR oil and offshore Alaska 44 percent (see figure 14). The assessment forecast that 43 percent of the UERR gas was located in the GOM. Offshore Alaska followed with 39 percent of the total.

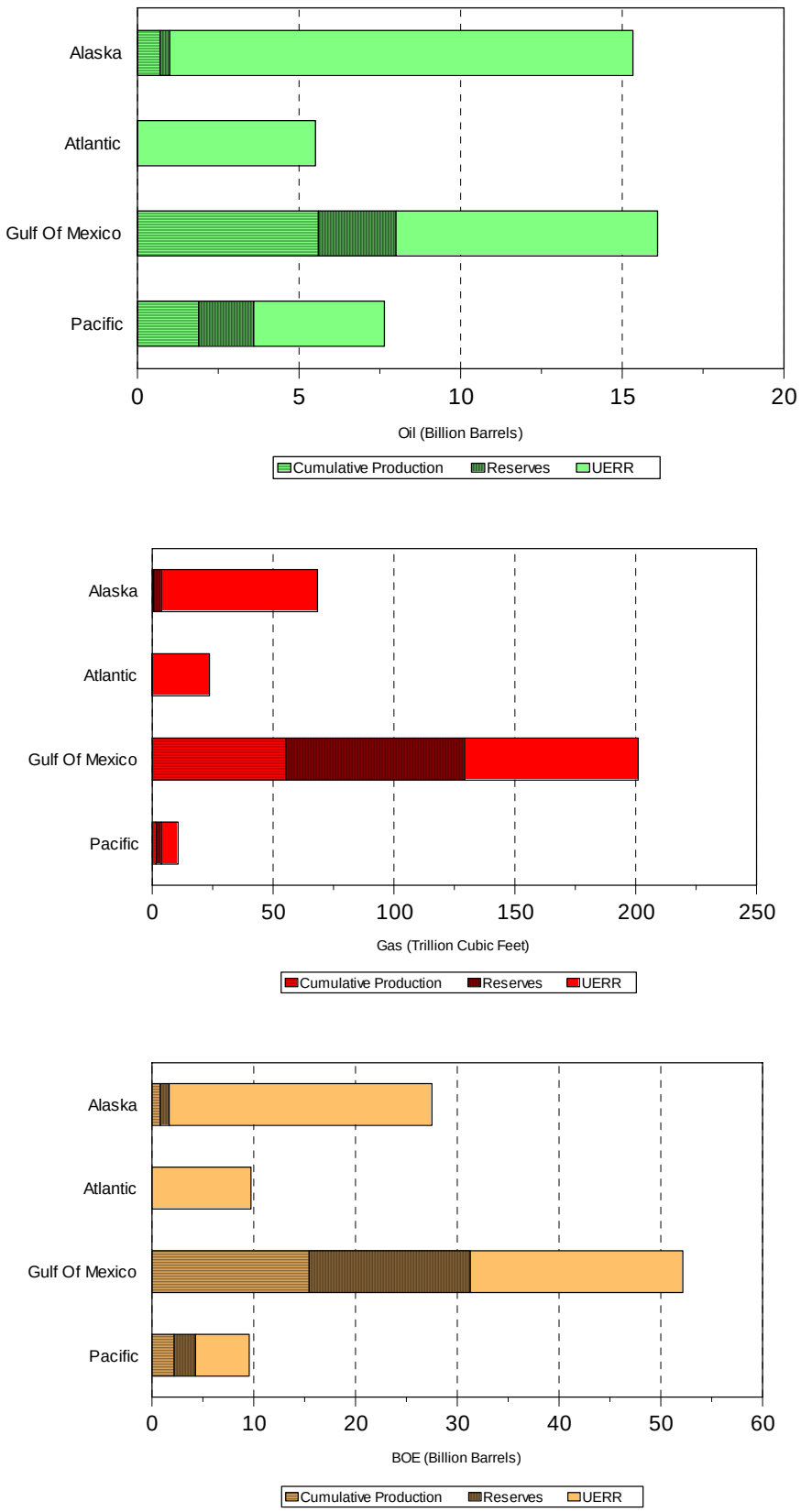

Figure 14: Distribution of Total Hydrocarbon Endowment by Type, Region and Resource Category, USGS, (1981).

3. MMS 1985 Assessment (Cooke, 1985): This assessment was performed as the initial phase in the development of a new proposed 5-year oil and gas leasing program. It was the first systematic assessment of the entire OCS performed by the newly created MMS. The resource assessment was completed primarily by a portion of the organization that was within the former Conservation Division of the USGS. Prior to this effort, staff assessment experience was confined to assessing the potential of smaller portions of the OCS for the analysis of environmental and policy concerns related to individual lease sales and for determining the adequacy of industry bids for leases. Not surprisingly, the MMS assessment methodologies at the time were, in comparison to the broad regional analysis employed by the USGS, very data intensive, requiring extensive site-specific G&G information. Its assessments relied almost exclusively on data and information within the public domain. The MMS assessment relied extensively on proprietary G&G data acquired on the OCS by the oil and gas industry. The analysis also incorporated as part of the methodology a more quantitative consideration of economic and cost information.

The MMS initially considered continuing the use of the classic Delphi approach to regional resource assessment that was employed by the USGS. Because of its leasing responsibilities and a desire to employ an internally consistent and repeatable assessment technique for all analyses that supported leasing decisions, the MMS ultimately chose to pursue another direction. Previous resource assessments presented risked resource estimates which incorporate the probability that the area under consideration may be devoid of hydrocarbons. The MMS program analyses typically require the use of conditional resource estimates in association with their corresponding marginal probability. To support these analyses the assessment focused on developing and presenting conditional resource estimates. Because of this focus a complete risked resource distribution was not included as part of the assessment products, only the mean values were reported. A more complete discussion of the differences between conditional and risked estimates is presented in section V of this report.

The assessment technique employed by the MMS was a summation of prospects approach incorporated in a Monte Carlo simulation model called PRESTO (Probabilistic Resource estimates Offshore). This mathematical model enabled assessors to make judgments concerning each of the variables affecting the assessment. These individual judgments were then subjected to the model simulation to derive a resource estimates. Unlike the Delphi subjective assessment approach, this model allowed for the incorporation of new information in a quantifiable and repeatable way. This assessment approach as implemented did, however, require that individual exploration targets be identified by existing G&G information.

Instead of a consideration of flat prevailing product prices, the MMS incorporated in its economic analyses long term price forecasts that incorporated inflation and real price changes. Starting prices used in this assessment were $29/barrel and $2.90/Mcf. Project economics and technology were largely considered through the use of the MEFS (see appendix B) cut-offs that were rigorously applied within the simulation model. In this assessment the use of the MEFS was fine tuned to much smaller portions of planning areas than previous assessments. These areas and the MEFS were defined primarily in terms of production characteristics, water depths, and distance from shore. For the first time, only the portion of the offshore under Federal jurisdiction was included in the assessment. The area assessed in both the Chukchi and Beaufort Seas was limited to water depths of less than 200 meters, which was considered to be the

foreseeable limit on exploitation technology. The assessed area in the Atlantic OCS was also reduced from that considered in the prior assessment by the World Court decision establishing the U.S. – Canada maritime boundary. Estimates of UERR were again reported.

The effective date of this assessment in terms of G&G data and information considered was July 1, 1984. Since the previous assessment, five additional deep stratigraphic test wells had been drilled in three Alaskan frontier basins (two wells in the Norton Basin, one well in the St. George Basin and one well in the Navarin Basin). An additional six exploratory wells were drilled in the Beaufort Sea and a final dry hole in the Gulf of Alaska. During 1983, industry drilled a single unsuccessful $140 million exploratory well on the "Mukluk" prospect in the Beaufort Sea where it had previously invested $1.5 billion to acquire leases. With the exception of the Beaufort and Chukchi Seas and a final well in the lower Cook Inlet this period marked the end of exploration interest in these frontier basins.

All eight exploratory wells drilled in the north Atlantic were dry holes. In the mid-Atlantic an additional 15 exploratory wells were drilled since the previous assessment was completed. Three of these wells were drilled on the "Tenneco-Texaco" discovery. The last, drilled on the structural crest was a dry hole. A 3-D seismic survey was acquired over the structure in an attempt to resolve structural and stratigraphic complexities and determine if additional effort was merited. The leases were subsequently relinquished in April 1984. During this period Shell undertook an ambitious, multi-well, deepwater drilling program that set several world water depth records. The target was the buried Mesozoic shelf-edge reef complex and associated features. Unfortunately all of these wells were also deemed dry holes. Industry acquisition of seismic data in the Atlantic virtually ceased after the 1984 acquisition season.

The Santa Maria Basin underwent extensive exploration from 1980 through 1986. More than 40 exploration and delineation wells were drilled in the Santa Maria Basin during this time. By mid 1984 seven oil and gas fields had been discovered.

Exploration in the eastern GOM continued to yield generally disappointing results. Eleven exploratory wells were drilled (six within the Charlotte Harbor area) without a commercial discovery. A positive note, however, was the discovery in 1983 of the Mobile 823 Field which extended the Norphlet trend eastward into the eastern GOM.

On the technology front, the first artificial drilling island was constructed in Alaska in 1981 and used to successfully drill two exploratory wells in 18 feet of water. During 1983 the Lena platform, a compliant tower, was installed in the GOM in 1,017 feet water. While this structure did not set a water depth record it did successfully prove a technology that could be extended to water depths of as much as 3,000 feet, well beyond the capabilities of bottom founded fixed leg platforms which had approached their water depth limit. On the drilling front, Tenneco had recently drilled the first exploration well in the GOM to exceed 25,000 feet, subsea in depth. The Bullwinkle Field was discovered in 1983 in 1,331 feet of water. The Bullwinkle platform was designed as one of the first deepwater production hubs. The Amberjack Field was also discovered in 1983 in 1,049 feet of water.

As explained previously, in this assessment region-level estimates of UERR were reported only at the mean value. The GOM was forecast to contain nearly 50 percent of the UERR oil and

offshore Alaska 27 percent (see figure 15(a) and 15(b)). The assessment forecast that two-thirds of the UERR natural gas was located in the Gulf. Offshore Alaska and Atlantic followed with about 15 percent each of the total. Estimates of the undiscovered resource potential of the OCS decreased dramatically to 12.2 Bbo and 90.5 Tcfg (28.3 BBOE).

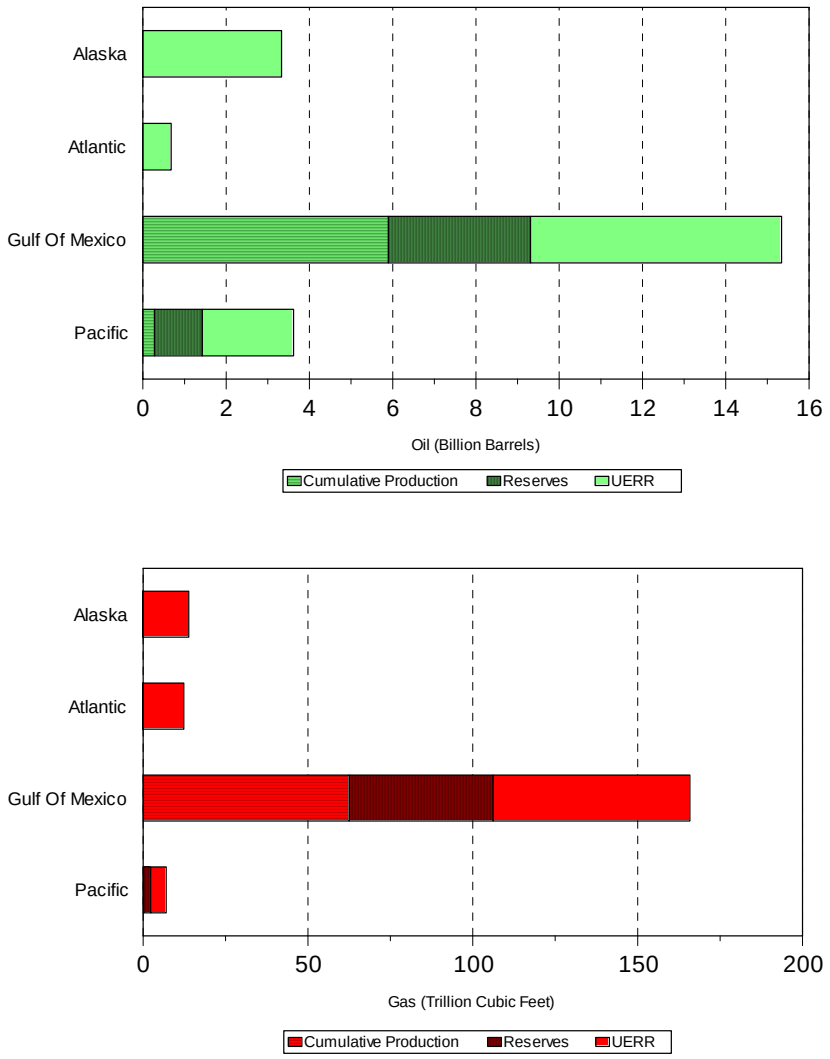

Figure 15(a): Distribution of Total Hydrocarbon Endowment by Type, Region and Resource Category, (MMS, 1985)

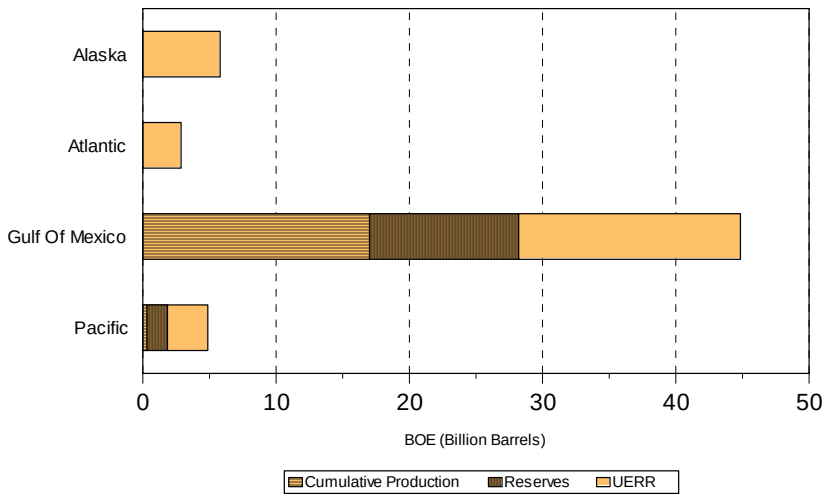

Figure 15(b): Distribution of Total Hydrocarbon Endowment by Type, Region and Resource Category, (MMS, 1985)

Direct comparisons with the previous assessment are especially tenuous in this case. There were major differences in the methodologies employed, information base available, technology and economic assumptions, and areas assessed. Estimates of the undiscovered resource potential of the OCS represented a decrease of 62 percent for oil and 46 percent for natural gas (55 percent for BOE) from the earlier assessment. Cooke (1985) adjusted the previous assessment results in the lower 48 to remove the effect of excluding state waters. After this adjustment the overall differences are slightly smaller, 55 percent for oil and 44 percent for natural gas. The decreases were the greatest in the Alaska (about 75 percent for both oil and gas) and the Atlantic (87 percent for oil and 48 percent for natural gas) OCS. Decreases in the Pacific estimates were more modest at 31 percent for oil and 24 percent for gas. The GOM estimates of UERR decreased slightly for oil and gas, 3 and 13 percent respectively.

Certainly a significant portion of the difference can be attributable to different methodologies and objectives. The MMS was highly dependent upon the existing proprietary information base and near term decision-making considerations related to the OCS leasing program that must reflect current market realities. In hindsight, this assessment displayed a conservative, short term view of potential exploration opportunities. The large decreases in the estimates for Alaska reflected the very disappointing drilling results on the OCS. The only exploration successes offshore at the time of the assessment were in state waters in the upper Cook Inlet and Beaufort Sea. The MMS risk analysis reflected low probabilities of encountering commercial quantities of hydrocarbons outside the Beaufort Sea. Even in the Beaufort Sea the estimated probability for commercial success was only 0.70. The area with the next highest probability, 0.27, was the Navarin Basin, which had yet to have an exploratory well drilled. As discussed earlier, an increase in risk greatly lowers the reported estimates.

The story for the Atlantic is similar—disappointing exploration results reflected in increases in the perceived levels of risk dramatically lower reported resource expectations. In both the Pacific and GOM regions estimates of the total hydrocarbon endowment, which consider the volumes of hydrocarbons discovered and produced during the period between assessments, also decreased, though less markedly. These decreases probably reflect primarily the removal of state

waters from consideration. Secondary factors contributing to the reduction were the heavy focus on prospects in combination with a more rigorous consideration of economic factors.

Mean estimates of total hydrocarbon endowment of the OCS developed from this assessment were 23 Bbo and 199 Tcfg (58.4 BBOE), corresponding to a decrease of 50 percent for oil and 35 percent for natural gas (42 percent for BOE) from the prior assessment. The impact of considering or excluding areas within state waters on this assessment is apparent in table 2. Despite the discoveries made in the intervening years estimates for oil reserves were down slightly; reported gas reserves decreased by a whopping 34 Tcfg. Cumulative production reported was significantly lower for oil, but higher for gas.

4. MMS 1990 Assessment (Cooke et al., 1990): After the MMS completed its first OCS-wide resource assessment, it requested that the National Research Council of the National Academy of Sciences (NAS) review the methodology that was employed. The NAS review (National Research Council, 1986) was generally favorable, but it did offer a number of suggestions for improving future assessments. These included: (1) pursuing a grouped-prospect play assessment methodology compatible with existing MMS models; (2) reporting the undiscovered resource base in addition to the economically attainable potential; and (3) developing a systematic process for including the resource potential from unmapped or unidentified prospects. The MMS incorporated each of these recommendations in this assessment.

This assessment was the first attempt by the DOI to assess the underlying conventionally recoverable resource base instead of just that portion that was perceived to be economically recoverable given a certain set of assumptions regarding future economic conditions. This assessment continued to rely on the MMS prospect oriented analyses and databases, but was supplemented by an additional consideration of unmapped prospects that could be anticipated to exist. This methodology used an updated version of the PRESTO model and an additional model to account for the resource potential of any unmapped prospects. Cooke and Dellagiarino, 1990, and Lore and Peccora, 1988, further describe this technique. The PRESTO model was modified to incorporate economic considerations beyond the field level. In frontier areas, in particular, discoveries may be large enough to cover prospect-specific costs, but because of a lack of existing infrastructure be abandoned as uneconomic. Additional economic screens were incorporated to more rigorously test to assure that resources discovered could support the necessary costs to bring the product to market. This additional consideration tended to raise the economic risk associated with frontier portions of the OCS.

The effective date for the information base used in this assessment was January 1, 1987. There was a dramatic decrease in oil and gas prices during 1986 which served to heighten interest in price volatility and its effects on resource assessments. In this assessment, the MMS reported three different categories of resource estimates: (1) the undiscovered “resource base,” synonymous with undiscovered conventionally recoverable resources (and UTRR), (2) a primary economic case based on prevailing conditions, and (3) an alternative economic case based on significantly higher oil and gas prices. The primary economic case again incorporated a price forecast. The starting prices for this assessment were $18/barrel and $1.80/Mcf. The first two cases are presented in table 2.

Exploration activity peaked on the Alaska OCS during the mid-1980s. Industry interest was now focused on the Arctic areas. Eleven exploratory wells were drilled in the Beaufort Sea since the previous assessment. Industry had by now made several noncommercial discoveries in this area. Since the prior assessment, three basins in the Bering Sea experienced an initial round of exploration. The most promising prospects were drilled first and the results were extremely disappointing. Twenty-four exploratory wells were drilled during the period between assessments in the Norton Sound (six wells), Navarin basin (eight wells), and the St. George Basin (ten wells). None encountered commercial quantities of hydrocarbons. The final two dry holes were drilled in the lower Cook Inlet as part of the second industry exploration campaign in the area.

Industry interest in much of the Alaska OCS was waning. This lower level of interest was reflected in the sharp drop in 1986 in the annual number of geophysical exploration permits issued. The results of the initial Alaska exploration rounds condemned many very large prospects and some play concepts. For other plays and prospects geologic risk was significantly increased. In some plays previously thought to be oil-prone, analysis of the drilling results indicated that if hydrocarbons were present they were more likely to be gas-prone. The limited activity in the Cook Inlet primarily confirmed previous the MMS geologic models.

A final deep water dry hole was drilled in the mid-Atlantic. Since subsequent efforts to drill the large “Manteo” structure located in the Carolina trough off North Carolina were unsuccessful, this period essentially marked the end of all industry exploration activity on the U.S. Atlantic continental margin.

The exploration drilling program in the Santa Maria Basin concluded in 1986, resulting in the discovery of 14 oil and gas fields with reserves of over 1 Bbbls of mostly heavy oil. The Point Pedernales Field was the first of these discoveries to produce, beginning in the first quarter of 1987.

In the GOM industry was actively extending the deepwater Flexure trend westward into the western GOM and aggressively pursuing additional opportunities associated with the Corsair trend off the Texas coast. The Ram-Powell Field was discovered in 1985 in 3,239 feet of water and the Allegheny Field was discovered in 3,254 feet of water. It took ten years to achieve first production from Ram Powell. Mensa, one of the largest natural gas accumulations in the deepwater Gulf, was discovered in December 1986 in 5,280 feet of water.

Estimates of UERR for oil ranged between 4.0 and 14.3 Bbo with a mean value of 8.9 Bbo. Natural gas estimates ranged from 44.3 to 113.8 Tcfg, with a mean of 74.0 Tcfg. Approximately 63 percent of the UERR was projected to be present in the GOM. Nearly a quarter of the estimate was in the Pacific region. Nearly 87 percent of the undiscovered gas estimated to be economically recoverable was in the GOM. Nowhere in the Alaskan OCS was natural gas considered to be economic under the imposed economic conditions. The re-evaluation of many areas as being gas-prone when considered in conjunction with lower prices and the large volume of stranded gas on the North Slope condemned Alaska’s OCS gas prospects. Poor exploration results coupled with the economics of gas led to another round of increases in risk assessments associated with Alaskan basins.

At the mean level, the estimates of UERR represent a decrease compared to the previous assessment of 27 percent for oil and 18 percent for gas. Despite the significant decrease in price expectations oil estimates decreased only slightly for those areas outside of Alaska. The decreases in the Pacific and GOM estimates were offset by new discoveries during the intervening period. Dismal exploration results in the frontier areas of Alaska and the Atlantic combined with the recent oil price collapse resulted in a lowered assessment of UERR potential. Notwithstanding the decrease in the estimates of UERR for oil and natural gas in this assessment, mean estimates of the total hydrocarbon endowment remained virtually unchanged between assessments.

Estimates of UTRR ("undiscovered resource base" in this assessment) were presented for the first time. Estimates ranged from 9.2 to 25.6 Bbo, with a mean of 17.9 Bbo and 97.8 to 204.8 Tcfg, with a mean value of 145.1 Tcfg. More than half of the undiscovered oil and two-thirds of the gas estimate were in the GOM. Alaska was next with 21 percent of the oil and 11 percent of the gas.

In the mean primary case economic analysis 50 percent of the OCS total UTRR is economic (see figure 16(a)(b)). In the GOM 60 percent of the oil and gas UTRR was economically recoverable. In Alaska less than a quarter of the 3.8 Bbo and none of the 16.8 Tcfg were considered to be economically recoverable. The Pacific and Atlantic OCS fell in between.

5. ***MMS 1991 Assessment (Cooke, 1991):*** In response to industry concerns expressed about the prior assessment, the Association of American State Geologists (AASG) was asked to review the geologic information that formed the foundation for the assessment. The review concluded that "The assessment of undiscovered, conventionally recoverable oil and gas resources on the OCS is supported by an adequate data base, personnel with suitable expertise and training, and a disciplined, structured process that produces results that inspire confidence." (AASG, 1988, p. 2). The DOI also requested that the NAS review the assumptions and procedures employed by both the MMS and USGS in recent assessments. The findings from this review were not available at the time this assessment was being performed.

In preparation for the 1992 to 1997 five year oil and gas leasing program, the MMS reviewed the existing resource estimates to determine if they were still adequate. It was determined that the estimates should be updated in five planning areas where significant new data had become available since 1987. The planning areas updated were the Beaufort Sea, Chukchi Sea, Hope Basin, northern California and eastern GOM. The amount of seismic data available in the Chukchi Sea more than doubled since the previous assessment was completed. As a result, not only were more prospects identified, but the existence of some of the larger prospects was confirmed by the new data. There were also three new exploratory wells drilled in the basin since the prior assessment. In the Beaufort Sea three additional wells had been drilled and a number of changes were incorporated in the geologic model, the most significant of which was an increase in the probability of success.

Activities from this time onward in the Pacific OCS consisted mainly of establishing and maximizing production of previously discovered oil and gas fields. Due primarily to environmental objections the last Pacific OCS lease sale was held in 1984. Also, the last exploration well in the Pacific OCS was drilled in 1990. By 1995 there were 11 producing fields in Pacific region, located in the Santa Barbara Channel, Santa Maria Basin and Los Angeles Basin.

In preparation for an upcoming lease sale in the eastern GOM a significant amount of new seismic data were acquired and interpreted by the MMS. In 1987 Amoco drilled the first discovery (noncommercial) well in the Norphlet formation in the eastern GOM. In 1987 and 1989 Chevron U.S.A. drilled two discovery wells in the eastern GOM in Destin Dome Block 56 located approximately 25 miles south of Pensacola. Both wells found significant quantities of natural gas in the Norphlet Formation below 22,000 feet. This discovery was part of the same play that was found productive in the Mobile Bay and adjacent state and Federal waters. Several discoveries were also made in the eastern extension of the shallow Miocene “bright spot” play. These discoveries increased the marginal probability of success for the eastern GOM area to 1.00.

Only estimates of UERR were reported. The largest change in estimates occurred in the Chukchi Sea portion of the Alaskan OCS. Resource estimates for the Beaufort Sea increased modestly, while Hope Basin estimates decreased by about 25 percent. Overall, mean estimates of the UERR for Alaska more than doubled compared to the earlier assessment (see figures 16 and 17).

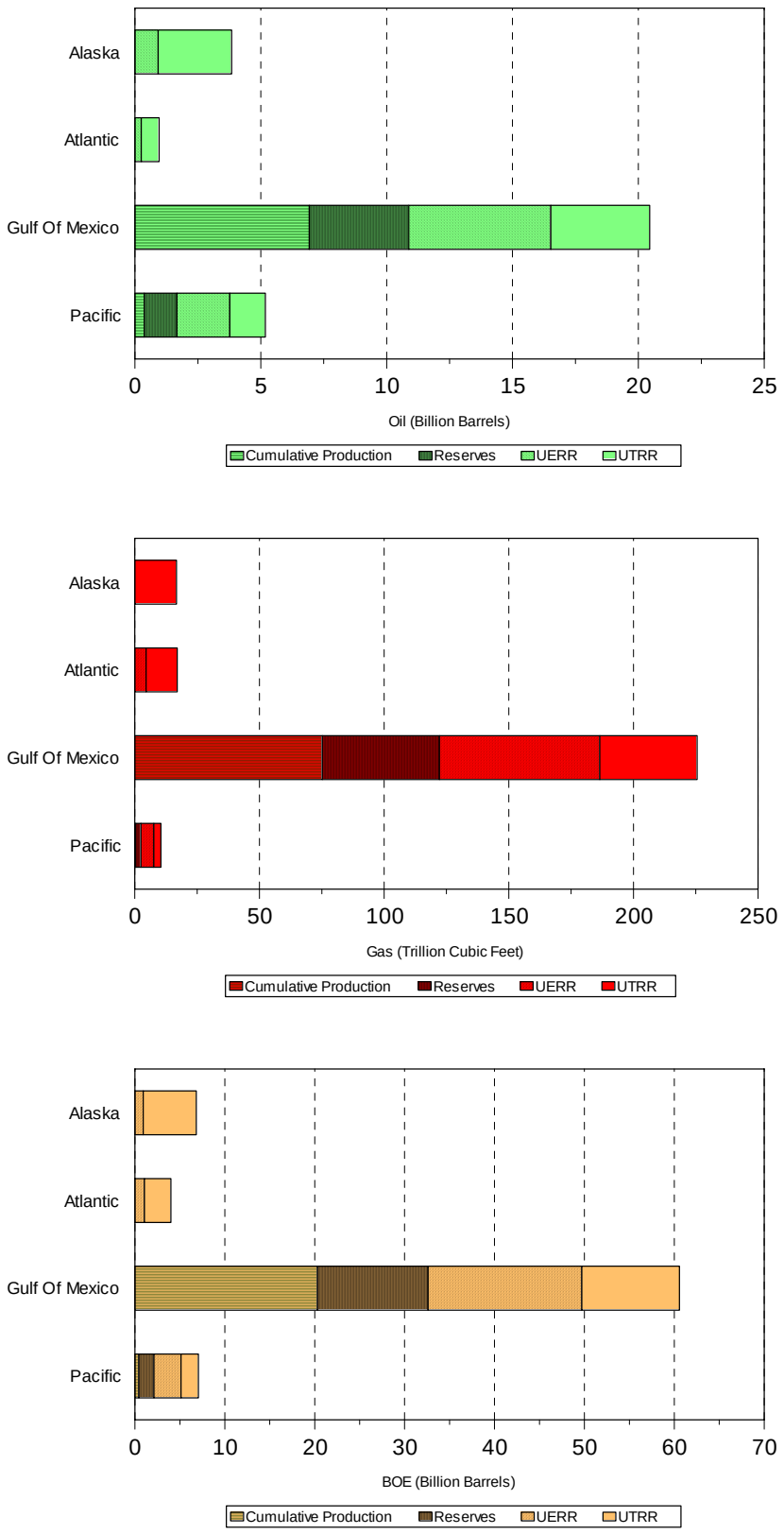

Figure 16: Distribution of Total Hydrocarbon Endowment by Type, Region and Resource Category, (MMS, 1990)

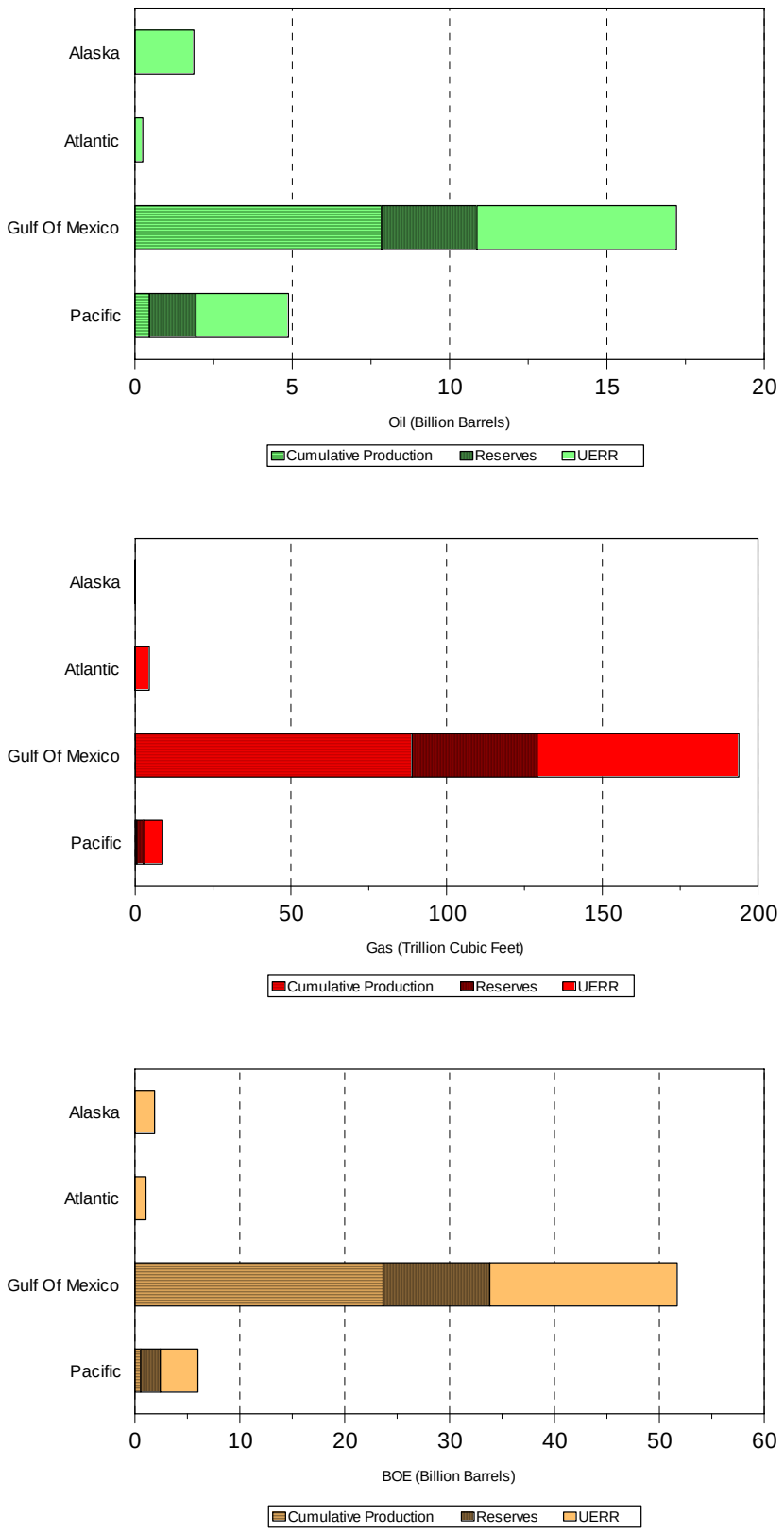

Figure 17: Distribution of Total Hydrocarbon Endowment by Type, Region and Resource Category, (MMS, 1991)

Mean estimates of UERR for the eastern GOM more than tripled to 1.25 BBOE. In the entire GOM the oil estimate increased 12 percent and gas estimate remained unchanged. The northern California estimates of UERR also increased substantially primarily due to changes in the geologic model for the Point Arena Basin. Mean estimates for both oil and gas UERR in the Pacific estimate increased by about 18 percent.

For the OCS as a whole, mean estimates of UERR increased modestly from 8.9 to 10.9 Bbo, 74.0 to 75.4 Tcfg and 22.1 to 24.4 BBOE.

6. MMS 1996 Assessment (MMS, 1996): This assessment represented a watershed event in the MMS resource assessments. It incorporated major changes in the basic underlying approach to resource assessment and shifted the principal focus from assessing UERR to undiscovered conventionally (or technically) recoverable resources. The recommendations from the earlier NAS review were available for consideration in this assessment. In stark contrast to the AASG, the NAS stated "…that there may have been a systematic bias toward overly conservative estimates. Eliminating the probable sources of this bias will improve the accuracy and credibility of future assessments." (National Research Council, 1991, p. 4). The primary concerns identified by the NAS included (1) concerns regarding play definition, (2) use of conceptual plays, (3) treatment of dependencies among variables, and (4) unintended imposition of economic constraints on estimates of UTRR.

The recommendations of the NAS study were fully incorporated in this assessment. Previous MMS resource assessments employed play concepts, but the focus was on groupings of prospects within the context of a play. The analysis was still prospect-oriented. The modeling emphasis for this assessment was reversed. It was the first time the MMS geoscientists applied an assessment method called "play analysis" on a national scale. This method evaluates the resource potential of "plays"—families of prospective and/or discovered petroleum accumulations that share a common history of oil or gas generation, migration, reservoir development, and trap configuration (White, 1980). In play analysis, statistical methods are used to translate the judgments of geologists into a set of probabilities that given petroleum volumes will exist within the plays. Databases were constructed and subsequent analyses were performed from this viewpoint. A new play-based computer model, Geologic Resource Assessment Program (GRASP), derived from the Canadian Geological Survey's Petroleum Resources Information Management and Evaluation System suite of programs (PETRIMES) was used for the first time.

The NAS recommendations adopted by the MMS generally provided for a more expansive interpretation of the UTRR potential of the OCS, resulting in significant increases in the estimates. For example, comparing this assessment with the 1990 UTRR, in Alaska the mean estimates for oil increased from 3.8 Bbo to 24.3 Bbo. Similarly, the mean gas estimates increased from 16.8 to 125.9 Tcf. The majority of this increase occurred in the estimates for the Beaufort and Chukchi Seas. All exploratory drilling on the Alaskan OCS since the previous assessment occurred in these two areas, seven new wells were drilled in the Beaufort and four wells in the Chukchi Sea. Although none of the wells were deemed to be commercial successes, the results confirmed play concepts and reduced geologic risks. A detailed discussion of the impacts of these methodological changes on MMS estimates is contained in MMS (1996) and Sherwood *et al.* (1998).

Despite the oil and gas industry's overall pessimism concerning the potential of the GOM, some individual companies continued to expand their deepwater portfolios and invest in the development of technology. In 1987 Shell made a world deep water record field discovery at the Coulomb Field in 7,558 feet of water. They were further rewarded for their deepwater efforts with the discovery of Auger, a field with reserves of approximately 220 million BOE. The discovery of Auger Field and other promising finds gave rise to the view that the deepwater GOM had unrealized resource potential. What was particularly striking was not only the size of the fields, but also the high flow rates of individual wells.

Several new production technologies were introduced in the GOM since the effective date of the last assessment. A floating production system was installed in 2,172 feet of water and a semi-submersible in 1,554 feet of water. The first U.S. tension leg platform (TLP) was installed at the Joliet Field in 1,722 feet of water. Shell pushed the limit of fixed leg platforms with the massive Bullwinkle platform which was installed in 1,330 feet of water. Subsea production technology continued to evolve during this period. Prior to 1988 the deepest subsea completion was in 350 feet of water. This jumped to 2,243 feet of water with Oryx' GC 75 Field development.

Elsewhere, the level of drilling in the GOM had dropped to levels not seen in thirty years. This was not the case with geophysical exploration. The impact on this assessment of 3-D seismic imaging technology and new computerized mapping, modeling, and interpretation programs was significant. Marine 3-D seismic data had been in use since the early 1980's, primarily as an exploitation tool— acquired as an exclusive proprietary survey by an operator to improve field development after a discovery was made. The high cost of these proprietary 3-D surveys necessitated that they be written-off against a commercial discovery. By the mid-1980's there was a noticeable industry-wide trend in increased success rates for field development wells drilled on the basis of 3-D seismic data. This realization, coupled with the initial availability of low cost speculative 3-D seismic data and the emerging workstation technologies combined to fuel an explosion in speculative 3-D data acquisition. The technology was viewed by industry as a primary weapon in controlling costs and risks in an era of price uncertainty and quickly became a standard tool for exploration.

The continued evolution of the computational and graphical power of workstation technology coupled with decreasing CPU costs placed a powerful interpretation tool that could handle the vast amounts of data necessary to build 3-D models within the grasp of most geoscientists. This capability in turn created additional demands for 3-D seismic data as both an exploitation and exploration tool. Sophisticated workstations allowed geologists, geophysicists, and petroleum engineers for the first time to fully integrate data previously exclusive to their individual disciplines into a composite 3-D geologic and petrophysical model of a prospect or field. This new capability created opportunities to more fully exploit existing discoveries, identify new targets in old fields, and re-evaluate prospects that were previously drilled unsuccessfully on the basis of 2-D seismic data and less than full integration of available geologic data. This focus was clearly in evidence in terms of actual drilling activity.

Industry, as a whole, was retrenching and backing off risky investments during this period, but a few companies continued to pursue high-risk, high-cost exploration opportunities. Following closely on the heels of advances in 3-D seismic data acquisition, interpretation tools and computational power of computers was the emergence of the "subsalt play" as the next hot

exploration play in the GOM. The play extended across the outer portion of the central GOM shelf and onto the upper slope encompassing an area of approximately 36,000 square miles. This area is characterized by relatively shallow water depths (300 to 2,000 feet) within areas of extensive existing infrastructure related to the Flexure trend activity, as well as recent deepwater discoveries. This proximity made for attractive project economics. In spite of the extensive publicity, this play was not a totally new phenomenon in terms of geologic targets.

The subsalt play is actually a technology-driven play. It is defined principally by the presence of tabular salt bodies, commonly referred to as salt sheets, sills, lenses, canopies, or tongues. Unlike traditional salt domes, which had been exploration targets since the earliest OCS wells were drilled, these salt bodies do not appear to be deep rooted to a mother salt layer. Typical mid-1980's vintage 2-D time-migrated seismic geophysical processing techniques frustrated explorationists for years. It could not properly image the base of the salt body, strata below the salt or correctly portray salt and sediment geometries. It also created problems in the conversion to depth from seismic travel time. As a result, wells could not be precisely located, greatly increasing operator risk. It was only through the use of advanced 3-D seismic acquisition and the raw processing power of massively parallel processor (MPP) supercomputers that explorationists were able to reprocess seismic to accurately see through these salt bodies.

At least 20 wells were drilled to subsalt objectives between 1979 and the first discovery in 1990 at Exxon and Conoco's Mickey (since renamed Mica) prospect. Despite a modest number of wells drilled every year, it was not until 1986, that the first substantial reservoir quality sands were encountered by Diamond Shamrock after drilling through 1,000 feet of salt. Unfortunately no hydrocarbons were present, but the discovery of thick reservoir quality sands was enough to encourage additional drilling. At Mickey, Exxon drilled through nearly 3,300 feet of salt before encountering hydrocarbons. This was seen as a significant breakthrough in the history of exploration and exploitation of the GOM since it opened a huge volume of sediment to prudent, reasonable risk exploration for the first time. The discovery, however, was in 4,350 feet of water making commercial exploitation uncertain.

The major technological breakthrough that put this play within reach of larger independents occurred during 1992 and 1993 when the first MPP supercomputers became available outside of the government and defense industries. These computers made practical for the first time, pre-stack depth migration processing of 3-D data sets on a non-proprietary basis. An indication of the raw computing power of the new supercomputers was the ability to process in about three weeks what a 1980 vintage mainframe would take about 5 years to accomplish.

In 1993, Phillips, Anadarko and Amoco drilled the Mahogany prospect. They drilled through 3,500 feet of salt before encountering significant oil and natural gas pays. This discovery touched off a frenzy of subsalt leasing and drilling activity. Despite the high levels of risk and uncertainty associated with prospect definition, high exploratory well costs, use of cutting edge drilling and processing technologies, and the larger than usual upfront data processing costs, the play was of significant interest. It offered the potential for huge world class reserves in a mature producing area located in proximity to existing infrastructure. The relatively shallow water depths greatly reduced the MEFS and increased the profitability of otherwise commercial finds.

Following this initial euphoria, subsequent subsalt exploration yielded mixed results. The immediate follow-up drilling at the Mattaponi, Mesquite and Ship Shoal 250 prospects were announced as dry holes. The only announced discovery in the immediate flurry of drilling was the Teak prospect. The disappointing results from the first round of drilling activity led to a re-evaluation of the geologic complexities, seismic uncertainties, and drilling difficulties associated with subsalt exploration.

On other technology fronts, industry continued to push the envelope on deepwater production technology. The Auger TLP was installed in 2,864 feet of water. The use of subsea production systems in deepwater was becoming more common including remote wells with tie-backs to host systems. A subsea completion was installed at Mars in 2,956 feet of water, in 1996 and at Mensa in 1997, in 5,295 feet of water. The distance from subsea completion to host facility was increasing during this period, achieving a record of 68 miles with the Mensa development.

The first horizontal well had been drilled in the GOM offshore. This technology initially allowed the exploitation of marginal accumulations on the shelf, but soon became an integral part of many deepwater developments.

For the entire OCS, estimates of UTRR for oil ranged between 37.1 and 55.3 Bbo with a mean value of 45.6 Bbo. Gas estimates ranged from 186.3 to 369.2 Tcfg, with a mean of 268 Tcfg. Comparable estimates for BOE were 72.9 to 117.0 BBOE with a mean of 93.4 BBOE. Fifty percent of the mean estimate of UTRR on a BOE basis was projected to be present in the Alaska OCS (see figure 18(a) and (b). The GOM, Pacific and Atlantic OCS comprise 27, 15 and 8 percent, respectively of the total UTRR.

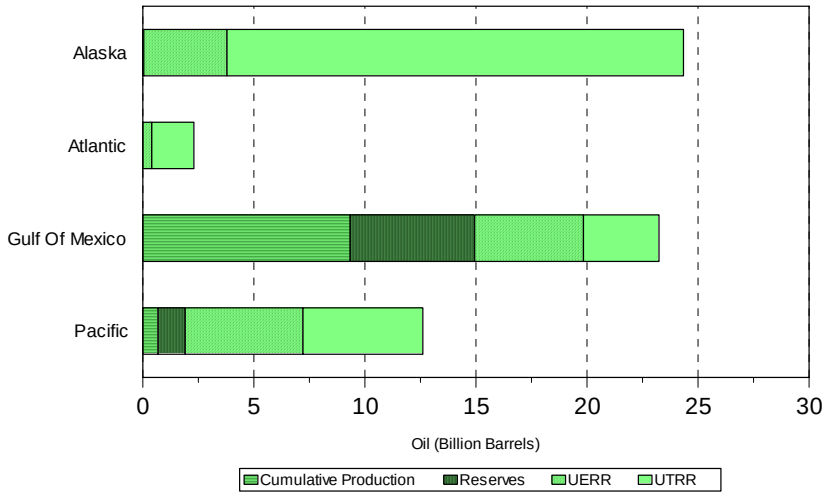

Figure 18(a): Distribution of Total Hydrocarbon Endowment by Type, Region and Resource Category, (MMS, 1996)

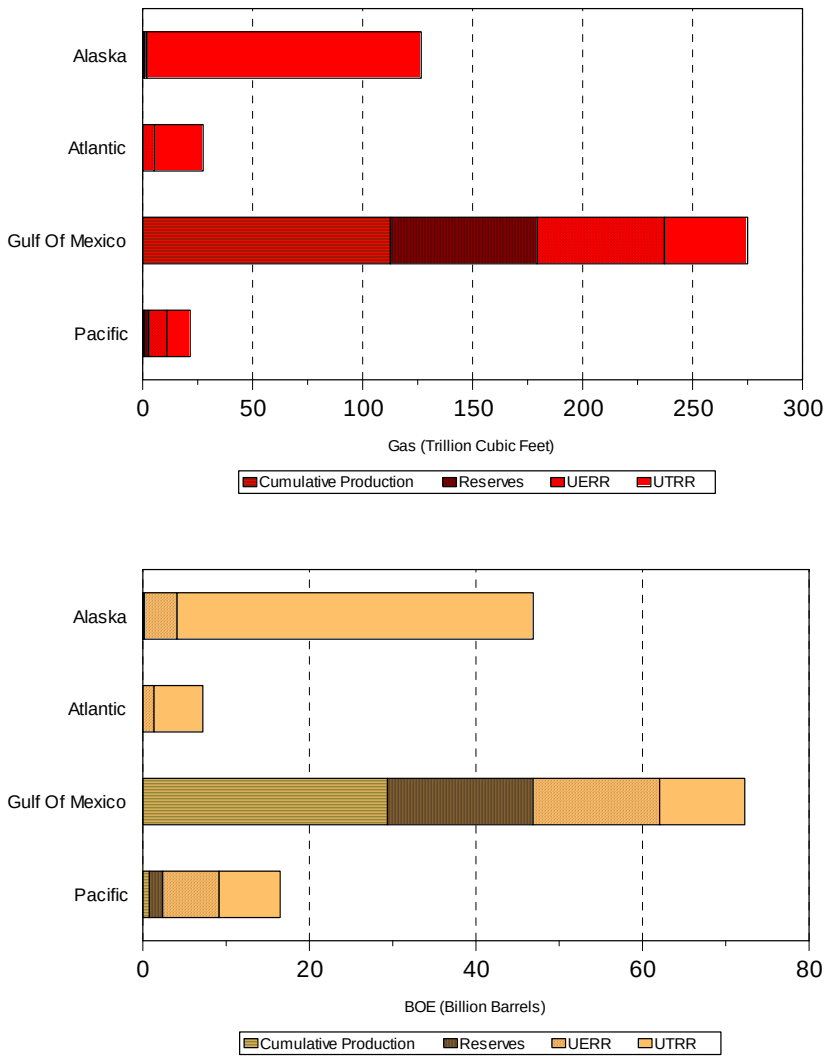

Figure 18(b): Distribution of Total Hydrocarbon Endowment by Type, Region and Resource Category, (MMS, 1996)

At the mean level, the estimates of UTRR for the OCS represent an increase compared to the previous assessment of 155 percent for oil and 85 percent for gas. The vast majority of this increase occurred in the Alaska estimates where oil increased by 20.5 Bbo and natural gas by 109.2 Tcfg. The increase in the estimates for the Alaska OCS was primarily the result of a concerted effort in response to the NAS recommendations to further remove any consideration of economic constraints from the estimates. Ninety percent of the Alaska endowment was located in the Beaufort and Chukchi Seas. Mean estimates of UTRR in the Atlantic OCS increased by 1.4 Bbo and 10.8 Tcfg (3.32 BBOE), a 158 and 65 percent increase respectively, for oil and gas. There were no new G&G data acquired in the area. The increase was primarily the result of a fundamental re-assessment of the area's prospectiveness and the use of the new assessment approach. The re-assessment included acquiring G&G data and information from Canada's Scotian shelf and from a consideration of additional analog basins for the Atlantic margin.

The mean estimate for UTRR in the Pacific region increased by 7.1 Bbo, an approximate tripling from the prior assessment, and 8.08 Tcf, almost double the prior estimate. A portion of this increase was attributable to a new analysis of the Monterey formation that indicated a potentially much larger volume of reservoir rock than previously considered. The major cause of the increase, however, was probably due to the new assessment approach and philosophy employed by the MMS for this assessment.

In the GOM region the mean estimates of UTRR decreased by 1.3 Bbo and 8.1 Tcfg (2.7 BBOE) when compared to the 1990 assessment. If the intervening discoveries and production are considered, as in the estimates of total endowment, the assessment of the GOM resource potential actually increased by 9 Bbo and 80 Tcfg (23.4 BBOE)

7. MMS 2001 Assessment (MMS, 2001): The cut-off date for data and information used in this assessment was January 1, 1999. At the time of the previous assessment the deeper water portions of the GOM were still relatively unexplored and non-major companies wanted a piece of the action. Over the previous decade the deepwater areas of the GOM increasingly became the focus on the OCS for leasing, seismic acquisition, drilling and production activity. The major oil companies forged the way until 1996 when independents joined the fray. This interest was spurred by a number of large deepwater field discoveries and technological advances in drilling and development systems. Many of these discoveries were among the largest in the GOM in decades. The total number of deepwater discoveries with an estimated ultimate recovery (EUR) of more than 100 million BOE (e.g. Neptune, Nansen, Holstein, Mad Dog, Medusa, and Thunder Horse) more than doubled in the period since January 1, 1995. During the nine year period between 1989 and 1997, 175 fields containing total resources of 1.2 BBOE were discovered in the shallower waters of the GOM. The mean size of these discoveries was 6.9 million BOE. During this same period 44 fields containing resources of over 2.4 BBOE, a mean field size of 55.5 million BOE, were discovered in deepwater— double the total resource volume discovered in the shallow water fields in only 25 percent of the number of fields.

Estimates of UTRR ranged from 63.7 to 88.3 Bbo and 292.1 to 468.6 Tcfg, with a mean estimate of 75.0 Bbo and 362.2 Tcfg (see table 2). The GOM OCS was forecast to contain one-half of the mean estimate of oil UTRR and offshore Alaska one-third (see figure 19). The assessment forecast that 53 percent of the mean UTRR gas was located in the GOM. Offshore Alaska followed with 34 percent of the total. This assessment resulted in an increase of the mean values by 29.4 Bbo and 94.2 Tcfg over the earlier 1996 assessment.

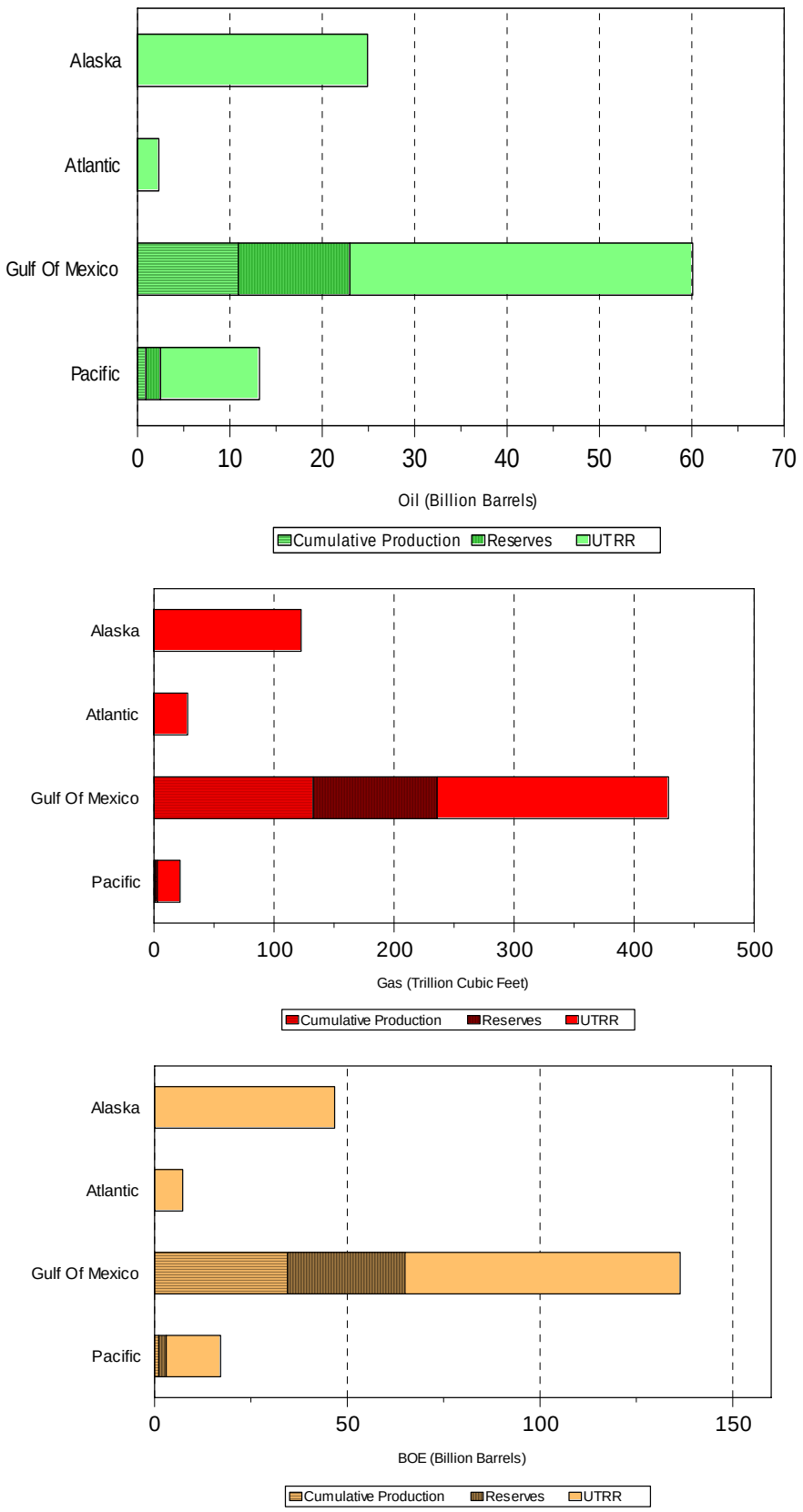

Figure 19: Distribution of Total Hydrocarbon Endowment by Type, Region and Resource Category, (MMS, 2001)

The increase occurs almost entirely in the deepwater GOM. In the 1996 assessment the mean estimates of UTRR for the deepwater portions of the Gulf (water depths greater than 900m) were 3.6 Bbo and 36.5 Tcfg (10.1 BBOE). In this assessment the comparable deepwater (water depths greater than 800m) estimates increased to 28.0 Bbo and 115.2 Tcfg (48.5 BBOE).

Mean estimates of total hydrocarbon endowment of the OCS developed from this assessment were 100.5 Bbo and 600.1 Tcfg (207.5 BBOE), corresponding to an increase of 53 percent for oil and 34 percent for natural gas (42 percent for BOE) since the prior assessment. The mean value for oil UTRR represented 75 percent of the mean estimate for the total oil endowment. Corresponding estimates for the increases in gas and BOE are 60 and 67 percent. More than 65 percent of the total endowment is projected in the GOM. Only 38 percent of the total oil endowment and 55 of the natural gas endowment in the GOM were represented by discovered resources.

8. MMS 2006 Assessment (MMS, 2006): The first Alaskan OCS production occurred in 2001 from the joint state/Federal Northstar unit in the Beaufort Sea. Several new play concepts were introduced in the GOM since the previous assessment and others continued to evolve. Play concepts were being refined in the ultra-deep sediments on the shelf (>20,000 feet) where discoveries such as JB Mountain and Mounds Point have recently been announced (MMS, 2001(b), 2003). In the deepwater areas there were several exciting new discoveries. Drilling for the first time encountered Paleogene reservoirs at several locations. In the western GOM several discoveries were made in the Perdido foldbelt. These discoveries included Trident and Great White. Discoveries such as St. Malo and Cascade also continued to be made in the Mississippi fan foldbelt.

Deepwater exploratory drilling capabilities continued to increase. A new short-lived water depth record of 7,718 feet for an exploratory well was set by Chevron in August 1998, eclipsing the previous record of 7,620 feet set in 1996 at the BAHA prospect. A new water depth record was then established by Kerr McGee in 2001 at their Merganser discovery in 7,950 of water. This record would also be quickly surpassed as the first well to be drilled in water depths exceeding 10,000 feet was permitted.

The limits of deepwater production technology also continued to expand. Since the previous assessment numerous water depth production records were surpassed. Shell/British Petroleum (BP) established the water depth record for production from a platform at 2,940 feet with its Mars TLP in 1996. This was soon surpassed in 1997 by the Ram-Powell TLP, which was installed in 3,214 feet of water. This in turn was quickly surpassed by Shell's Mensa subsea development in MC Block 731, which set two world records in July 1997— a world water depth record for production at 5,300 feet and a world record of 68 miles for tieback distance to its host platform. This water depth record was also soon surpassed in 2002 at Camden Hills when a subsea tree was installed in 7,209 feet of water.

In March 1999, Shell (and partners Exxon, BP, and Conoco) began production from another TLP for the Ursa project in 3,885 feet of water. New production concepts were also introduced since the previous assessment. The world's first production SPAR, Oryx/CNG's "Neptune" platform, was installed in 1997 in 1,930 feet of water. A second SPAR system, Genesis, was brought on production in 1998 in 2,597 feet of water. Diana-Hoover, a drilling and production SPAR, was

installed in 4,800 feet of water in 2000. The SPAR technology has the potential for use in water depths up to 10,000 feet. British-Borneo Exploration installed Morpeth, the world's first mini-TLP, in 1,700 feet of water in 1998. This effort was followed in 1999 with another mini-TLP at its Allegheny project in 3,186 feet of water. This technology has potential applications in water depths approaching 3,500 feet. Another new development technology was introduced to the Gulf when Amerada Hess installed a compliant tower in 1998 on its Baldpate project in 1,619 feet of water. This was quickly followed by Petronius in 1,754 feet of water.

The advances in 3-D seismic data acquisition and processing technologies driven by the special requirements in the subsalt play and in areas proximal to steeply dipping salt bodies fueled a resurgence in the acquisition of modern data in areas previously shot with older data acquisition techniques. As a result, whole new families of previously unidentified or poorly defined exploration prospects were being targeted. The new data and interpretation techniques reduced risk and uncertainty to levels that permitted companies to pursue these prospects.

On the information technology front, impacts were felt throughout the industry. The speed, volume, and scale of access to geotechnical data and information continued to explode within the exploration and production (E&P) industry with the enormous advances in computational power. Geoscientists and engineers experienced a fundamental revolution in the applied earth sciences that radically altered their ability to integrate, adapt, and analyze a broad spectrum of G&G data. The value of these new technologies was seen by the petroleum industry as a tool to drive down cost, risk, and uncertainty, as well as increase productivity. The technology was focused on data acquisition and manipulation, analysis applications, visualization, and integration.

For the entire OCS, estimates of UTRR for oil ranged from 66.6 to 115.3 Bbo with a mean value of 85.9 Bbo (refer to table 3). Natural gas estimates ranged from 326.4 to 565.9 Tcfg, with a mean of 419.9 Tcfg. Comparable estimates for BOE were 125.7 to 215.9 BBOE with a mean of 160.6 BBOE. Fifty-four percent of the mean estimate of UTRR on a BOE basis was projected to be present in the GOM OCS. The Alaska, Pacific and Atlantic OCS comprise 31, 9 and 6 percent respectively of the total UTRR.

At the mean level, the estimates of UTRR for the OCS represent an increase compared to the previous assessment of 10.9 Bbo and 57.7 Tcfg or about 15 percent for oil and 16 percent for gas. The vast majority of this increase occurred in the GOM where estimates of UTRR range from 41.2 to 49.1 Bbo and 218.8 to 249.1 Tcfg with a mean of 44.9 Bbo and 232.5 Tcfg. This represents a 21 percent increase in oil resources and a slightly greater percent increase in natural gas resources since the previous assessment. Again significant increases in the estimates for the deepwater areas were the major contributor to the overall growth in the estimates of UTRR. The mean estimates of UTRR in the deepwater were 38.8 Bbo and 125.2 Tcfg (61.1 BBOE), which represents an increase over the previous assessment of 10.8 Bbo and 10.0 Tcfg (12.6 BBOE). This increase in UTRR was also accompanied by approximately 4.5 Bbo and 14 Tcfg that were discovered in fields, such as Thunder Horse and Holstein whose resources were moved to the reserve category during this time period.

In the Pacific Region, the mean estimate for UTRR of 10.5 Bbo and 18.3 Tcfg represented a slight decrease for both oil and natural gas. The Atlantic estimate of UTRR ranges from 1.1 to 7.6 Bbo and 14.3 to 66.5 Tcfg with a mean of 3.8 Bbo and 37.0 Tcfg. The estimates represent a 66 percent increase in oil resources and a 33 percent increase in gas resources in the Atlantic OCS, when compared with the MMS 2001 assessment. The last remaining leases in the Atlantic OCS, on the Manteo prospect, expired in 2002 without a well being drilled. However, significant new analog information was available as the result of recent exploration in the Scotian shelf offshore Canada and the west African continental slope offshore Mauritania. Applying these new exploration ideas to the older Atlantic play models led to adjustments to risks in previously defined plays and the identification of additional new plays.

Estimates of UTRR on the Alaska OCS changed only slightly compared to the previous assessment. The mean oil estimates increased at mean level by 1.7 Bbo, while the natural gas estimate declined by 6.7 Tcf.

Mean estimates of total hydrocarbon endowment of the OCS developed from this assessment were 115.4 Bbo and 633.7 Tcfg (228.2 BBOE), corresponding to an increase of 15 percent for oil and 5 percent for gas (10 percent for BOE) since the prior assessment. The mean value for oil UTRR represented 74 percent of the mean estimate for the total oil endowment (see figure 20(a) and 20(b)). Corresponding estimates for gas and BOE are 66 and 70 percent. More than two-thirds of the total endowment is projected in the GOM. Only 37 percent of the total oil endowment and 48 percent of the natural gas endowment in the GOM is represented by discovered resources.

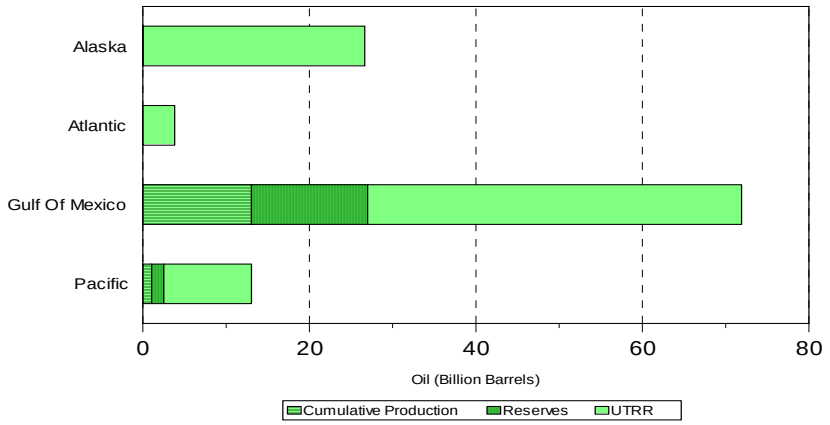

Figure 20(a): Distribution of Total Hydrocarbon Endowment by Type, Region and Resource Category, (MMS, 2006)

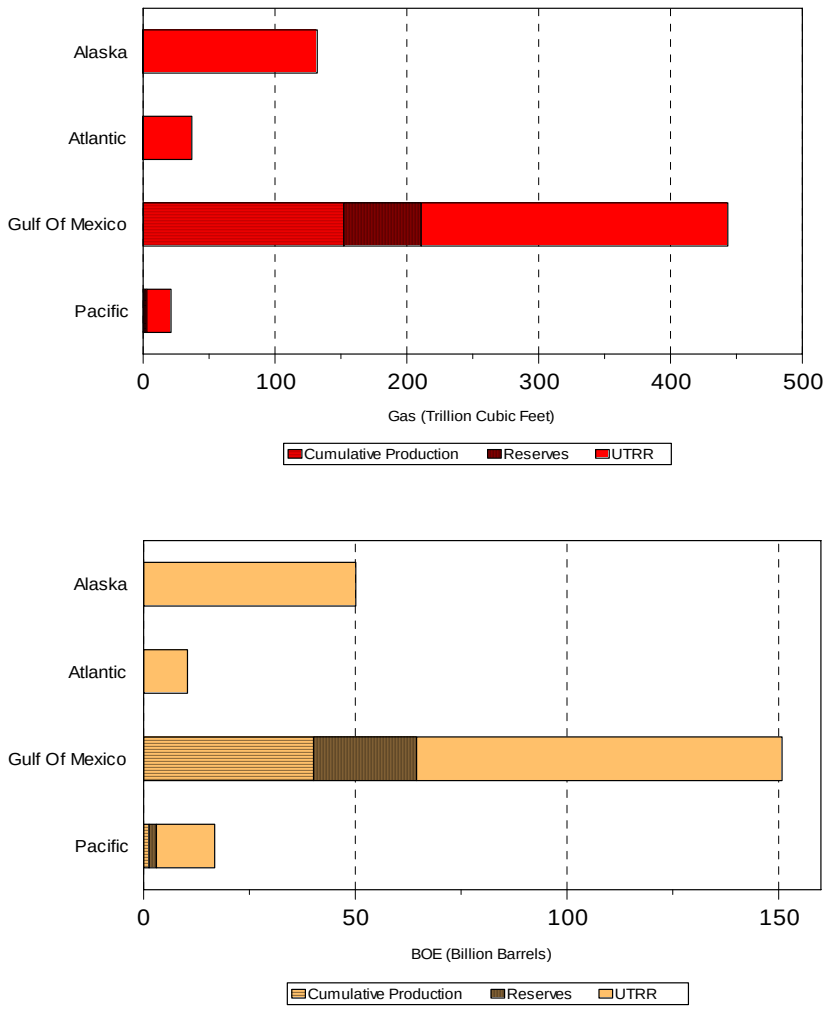

Figure 20(b): Distribution of Total Hydrocarbon Endowment by Type, Region and Resource Category, (MMS, 2006)

9. Summary:

Samuelson's Law: "Always look back. You may learn something from your residuals. Usually one's forecasts are not so good as one remembers them; the difference may be instructive."
—Paul Samuelson, economist

The DOI has completed eight comprehensive resource assessments since 1976. Resource estimates are very much a product of the knowledge base existing at the point in time during which they are developed. As such, they reflect the results from a complex interaction of many factors—available G&G data and information, working geologic models and play concepts, exploration and production technology and activities, cost-price relationships, and assessment techniques—which make clear attribution of a change in estimates to a single factor difficult.

It is difficult to draw broad general conclusions concerning the impact of new G&G data and information on the DOI resource assessments. The additional G&G data and information that become available to assessors between assessments is frequently mixed in terms of having a positive or negative effect on the perception of the overall hydrocarbon potential of the OCS. During this period, the G&G information available to assessors changed dramatically. For example, industry drilled nearly 30,000 wells and collected several million line-miles of 2-D and nearly 350,000 square miles of 3-D seismic data. At the time of the initial assessment there was only a single deep stratigraphic test well drilled anywhere on the Atlantic and Alaska OCS. More than 900 fields have been discovered in the interim. These data have increased knowledge considerably regarding the resource potential of the OCS. However, much of these data exist in the central and western GOM and southern California. The information that was acquired in most of the other areas is now 20 to 40 years old. There remains today, considerable uncertainty concerning the resource potential of many of these frontier areas. The availability of additional modern G&G data could reduce this uncertainty.

Oil and natural gas prices have experienced considerable volatility since the initial assessment. Assessments reporting UERR utilized different prices and sets of economic conditions. Technological advances have expanded exploratory drilling capabilities from a little over 1,000 feet of water to 10,000 feet. The oil and gas industry's ability to exploit discoveries has advanced from about 650 feet of water to over 7,500 feet. The ability to drill horizontal and extended reach wells or use multi-lateral completions was nonexistent 30 years ago and subsea completion technology was in its infancy. Marine 2-D seismic data were primitive by today's standards and there were no 3-D seismic data available. In 1975 the information technology revolution had not yet occurred, but by the 1990's information technology had exploded, which served as the catalyst to transform the geosciences and the petroleum industry.

Not only did each successive oil and natural gas resource assessment strive to incorporate the rapidly changing resource base, economic climate and advances in industry's exploration and production capabilities, it also advanced the science of resource assessment by continuously updating and revising assessment techniques, models, and approaches.

Figure 21 compares the results from each of the DOI assessments. Early DOI resource assessments focused on reporting estimates of UERR. The period covered by these assessments (1975-1995) was characterized by volatile oil and gas prices. It was also a period during which the oil and gas industry's technology capabilities expanded immensely. Exploration in frontier OCS basins in the Atlantic, the Bering Sea, southern Alaska and portions of the southern California borderland was disappointing. At the same time, production in the central and western GOM and the Santa Barbara Channel expanded greatly and production was established in the Santa Maria Basin off California. Assessment techniques became more sophisticated during this period, evolving from Delphi subjective judgment approaches to detailed stochastic hydrocarbon play evaluations.

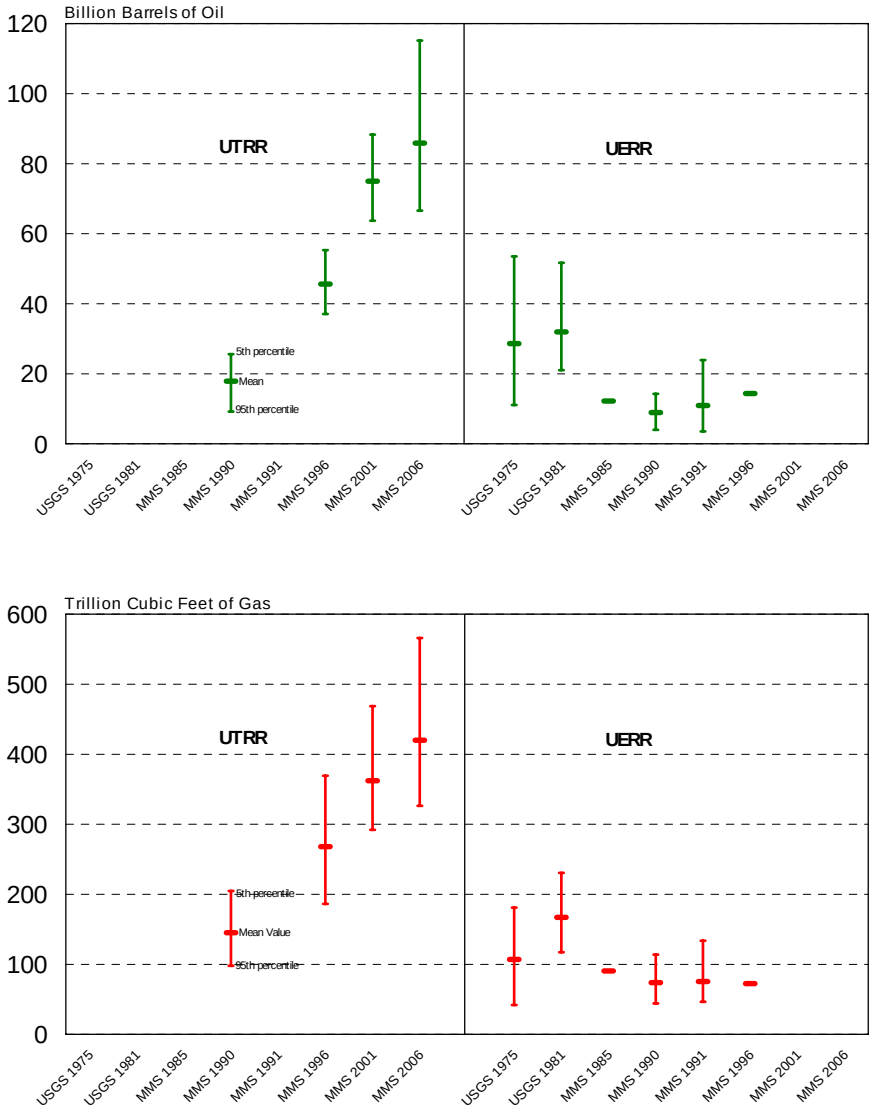

Figure 21: Comparison of the Results of OCS Resource Assessments, 1975-2005

Mean estimates for both oil and natural gas increased between the 1975 and 1981 assessments. The increases reflect the much higher prevailing product prices in 1980 and the inclusion of the deepwater portions of the OCS (a reflection of industry's increased technological capabilities) in the later assessment. In the 1985 assessment, estimates of the oil and natural gas UERR decreased dramatically and remained near that level through the 1996 assessment. The initial decrease was due to a combination of factors; exclusion of state waters from the assessment, utilization of a new assessment methodology, and disappointing exploration results in the Atlantic, eastern GOM, southern California borderland and south Alaska. During the period between the 1985 and 1996 assessments 3.8 Bbo and 50.6 Tcfg were produced (refer to table 2). At the same time reserve estimates increased by 5.3 Bbo and 22.5 Tcfg. While the reported estimates of UERR were relatively stable, the actual perception of the magnitude of the hydrocarbon endowment that was economic to produce grew dramatically.

The 1990 assessment included the initial attempt at assessing the larger conventionally recoverable resource base. This assessment realized that this should represent a more stable estimate of the OCS hydrocarbon potential that was less influenced by possibly short term considerations of technology capabilities or prevailing cost/price relationships. The concept had merit and is still being followed today, but the first attempt was probably conservative due to modeling limitations and a failure, particularly in Alaska, to completely remove economic considerations from the assessment. The estimates of oil and natural gas UTRR have increased steadily, primarily due to increases in the GOM deepwater and the arctic areas of Alaska.

Given the phenomenal changes that have occurred over the past 30 years, it is impossible to determine to what degree the changes in the assessments are attributable to different perceptions concerning the resource base. There have clearly been major disappointments on the OCS that are reflected in the assessments, but it has been 20 years or more since any significant exploration activity has occurred in these areas. In other areas such as central and northern California, offshore Oregon and Washington and the South Florida Basin, there has been no meaningful exploration activity since the 1960's. The introduction of new geologic models and play concepts coupled with modern technology could make some of these areas worth considering for another look. Perceptions concerning the resource potential of the central, western and portions of the eastern GOM, areas experiencing robust levels of exploration and production effort, have continued to evolve for the better over the years.

V. Interpreting Resource Estimates and Possible Effects of Understated Inventories on Domestic Investment

The dictum "If you must forecast, forecast often," is neither a joke nor a confession of impotence. It is a recognition of the primacy of brute fact over pretty theory. That part of the future that cannot be related to the present's past is precisely what science cannot hope to capture.

—Paul Samuelson, economist

A. Background

The Energy Policy Act 2005, section 357(a)(4) directed the Secretary of the Interior to, "...estimate the effect that understated oil and gas resource inventories have on domestic energy investments."

Some confusion may surround terms like "inventories" when describing oil and natural gas. For example, the general public might think of inventories of oil and natural gas as physical stockpiles of the resources or to the investment community, these inventories might represent estimated quantities of already discovered reserves reflected on the books of individual oil and gas companies. In an effort to estimate the effects of understated inventories—the use of the term, "inventories" is meant to describe the quantities of oil and natural gas yet to be discovered.

The premise of this request—to estimate the effects of "understated" resource inventories—suggests that government assessments are too conservative, when viewed over time and in hindsight following actual discoveries in some OCS areas. However, note too that each assessment reflects a snapshot in time that should not be viewed as either understated or overstated when compared to later assessments, which reflect changed circumstances and knowledge. True knowledge of the extent of oil and natural gas resources can only come through the actual drilling of wells. Estimating undiscovered resources, no matter how sophisticated the models and statistical techniques employed, is an inherently uncertain exercise that is based on hypotheses and assumptions, with the results limited by the quality of the underlying geologic data. Results incorporate perceived levels of risk and are expressed in ranges of estimates to reflect the uncertainty. Nevertheless, resource assessments are a critical component of energy policy analysis, and provide the industry and public with important information about the relative potential of U.S. offshore areas as sources of oil and natural gas to supply the Nation's future energy needs.

The main objective of the government's assessment of undiscovered resources is to develop a set of scientifically-based hypotheses concerning the potential quantities of oil and natural gas that may exist on the OCS. The estimates are used primarily for internal planning and policy purposes. The MMS assessments of OCS resources typically provide aggregate oil and gas resource estimates for all of the OCS planning areas in the GOM, and offshore the Atlantic, Pacific, and Alaska coasts. These assessments represent the government scientists' best estimate of what quantities of oil and natural gas remain undiscovered given the current state of geologic knowledge and reasonably foreseeable technology. Both the MMS and the DOE use these

assessments for planning, forecasting, and policy analyses. The oil and gas companies and private investors will use this information generally to guide investment decisions and their search for new resources.

The MMS resource assessments also provide detailed information about specific plays associated with the aggregate estimates for OCS planning areas. Although this play information can provide industry with some new perspectives on an area, it is unlikely that this information alone or the aggregate resource assessments for OCS planning areas, have any direct material effect on the oil and gas industry's domestic investment in exploration and development as a whole. The MMS resource assessment is one of a number of sources of information used by industry and the public, when making investment decisions. Industry and private investors, when considering alternative investment opportunities, often conduct independent assessments, employing their own models and techniques for evaluating and interpreting the data. The same factors that serve to moderate the government's assessment of certain areas (e.g., lack of data, uncertainty) may also tend to influence industry's own assessments and conclusions, and ultimately their willingness or ability to invest in those areas.

The OCSLA requires the Secretary of the Interior to develop OCS oil and gas leasing programs that set out the schedule and location of lease sales based on consideration and balancing of a number of factors, including the geologic characteristics of the oil- and natural gas-bearing physiographic regions of the OCS. The MMS conducts comprehensive national assessments of the undiscovered oil and gas resources on the OCS at least every five years. The potential quantities of oil and gas resources are evaluated on the basis of the interpretation of the geology of the petroleum provinces within all OCS planning areas. For the development of a 5-year oil and gas leasing program, the assessments serve to indicate the relative potential of various petroleum provinces and planning areas, and provide the MMS with the basis for considering possible effects of future oil and gas related activities from the OCS. The MMS resource assessments are also used by Congress and other agencies to support energy policy analyses and decision making.

The MMS considers the rankings of planning areas based on aggregate resource estimates as well as the in-situ values of those resources as factors for establishing the size, timing and location of lease sales when developing the 5-year OCS oil and gas leasing programs. Industry can only acquire the OCS leases during sales scheduled on the program, so if planning areas or portions of areas are not offered during that 5-year timeframe due to low resource potential (or due to congressional or executive withdrawals, state and local opposition, or lack of industry interest), companies would not be able to invest in those areas. The MMS estimate of resource potential would not, by itself, preclude an area from being offered. Industry and others are afforded a number of opportunities to provide input on those areas of interest to them, and to comment on the proposed schedule.

The current assessment considers the most recent geophysical, geological, technological, and economic information available to the MMS. The MMS does not sponsor or perform any G&G exploration. It instead relies on data that is either published or available to it, as a condition, of permits or leases issued to the oil and gas industry.

B. Can We Expect Inventories of Undiscovered Resources to Decline Over Time?

Each assessment is at best a snapshot in time that reflects the most timely data, current exploration and development technologies, and existing knowledge about the resource potential for each OCS area. The analytical search process continually adds prospects to the inventory as they are identified, drops them as they are leased or eliminated by further seismic evaluation or drilling, and re-characterizes their resource potential and costs. Thus, the actual knowledge of oil and natural gas resources on which leasing and planning decisions are based is never final or definitive. Changes occur with time in technology, the G&G data base available to assessors, and geologic interpretations and models which can lead to higher or lower estimates when the assessments are updated in later years. For this reason, specific assessments of undiscovered oil and gas resources need not decline systematically over relatively short time periods.

The MMS routinely updates and revises its resource estimates to reflect changing conditions and knowledge. For the 2006 assessment, mean estimates have increased 15 percent from the 2001 assessment for oil and 16 percent for natural gas. The GOM, once characterized as a "Dead Sea" in terms of a good location for oil and gas investment, has re-emerged as a world class petroleum province. Advances in seismic and drilling technology have enabled industry to drill exploration wells more efficiently and with a higher commercial rate of success than could reasonably have been anticipated. New drilling technology for exploration and development enabled industry to step out into deeper waters resulting in the discovery of significant new trends and plays. The more recent assessments reflect this new information.

C. Utility of Resource Assessments

The importance of having credible estimates of potential volumes of undiscovered oil and natural gas resources will differ from the perspective of the government as resource owner versus private industry as business investors, oil and gas producers, and portfolio managers. Government resource assessments are used for programmatic planning, like development of the 5-year OCS oil and gas leasing program, analyses of proposed legislation, or estimating effects on investment and revenues from various leasing and regulatory policies, like proposals for royalty relief. Clearly, the government cannot rely solely on known reserves of oil and gas for planning purposes as these assessments would grossly underestimate resource potential for many areas and give misleading or unreliable analytical results. Therefore, to ensure meaningful policy analyses, government decision makers need to consider projections of potential undiscovered accumulations of oil and natural gas from comprehensive assessments of resource potential.

The government's resource assessments typically focus on large areas, examining the interplay of prospective geologic plays to estimate the potential sizes of yet-to-be discovered accumulations of oil and gas. These assessments do not attempt to locate, identify or delineate specific potential fields or prospects.

Industry's investment decisions include a variety of considerations and are based largely on comparative evaluations of the profitability of specific investment alternatives, including overseas opportunities. Their decisions on where to drill for oil and natural gas rely on a number of factors related to expected financial returns, market position, and perceived risk. These investment decisions occur in a staged manner over time. On the OCS, exploration and

development costs are relatively high—seismic surveys, drilling, platform, and decommissioning costs can be substantial, especially in frontier areas. Based on their assessments, many companies will acquire (by competitive bidding) an inventory of promising acreage before undertaking very costly seismic acquisition or exploratory drilling programs. The expected profitability of specific projects will be affected by a company's perception of risk—geologic, economic, and political—which will be lower in areas with proven resource potential and where oil and gas development is more-broadly accepted. Industry will only invest in domestic oil and gas exploration and development when they have reasonable certainty of realizing a sufficient return on that investment—e.g., on the OCS, in those areas with open access and predictable lease sale schedules, where there's a reasonable certainty that lease rights will be honored, appropriate plans would be approved on a timely basis, and that any discovered resources could ultimately be produced. In those OCS areas that are off-limits to leasing, companies will not expend capital or time attempting to evaluate the hydrocarbon potential of those areas. In the face of uncertain rights to lease and develop, industry will tend to invest elsewhere in exploration.

D. Effects of Risk on Resource Assessments

Oil and natural gas deposits on the OCS are hidden from view under hundreds or thousands of feet of water and thousands of feet of the earth's crust. Seismic surveying to reveal possible accumulations and exploratory drilling are the basic investments that are made in the search for oil and gas. Actual deposits can only be discovered through drilling costly exploratory wells. Exploration investment more often than not fails to yield discoveries of oil and gas, and when prospects are identified, on closer evaluation, some do not warrant further investment with exploratory drilling. Many prospects that are drilled turn out to contain no oil and gas; others are found to contain oil or gas, but are not economically producible because of the size and character of the deposit. Estimating resource potential is not an exact science, and different technical experts and companies could have widely different views on appropriate methodologies and the interpretation of data. While the government has much of the same basic G&G data on unleased OCS oil and natural gas prospects, as do private companies, interpretations of those data and perceptions of an area's hydrocarbon potential will vary. Both groups, however, will evaluate the resource potential by explicitly incorporating risk and uncertainty into the resource assessments to account for the absence of a strong relationship between the geologic variables and the presence of specific amounts of hydrocarbon resources, as well as the lack of geologic information for many of the OCS areas.`

The government assessments of oil and gas resource potential rely on risk-based methodologies to statistically reflect different chances for drilling success for different areas. Frontier areas such as parts of the eastern GOM and other offshore areas under congressional or executive withdrawal offer the potential of larger field-size discoveries. Yet, both risk and uncertainty are greater with investments in these areas. As described previously in section III, the resource assessment models explicitly account for differences in geologic risk among oil and gas provinces and planning areas. As a result, the risk-based estimates in frontier areas ordinarily will have been seen as far too conservative if later exploration demonstrates that the area is hydrocarbon-prone (and will have overstated resources in those areas that ultimately prove unsuccessful). To the extent the government relies upon understated, or overstated, resource estimates in determining programmatic "balancing" decisions pursuant to OCSLA requirements, this could introduce some bias into program decisions. The MMS attempts to mitigate this

problem by conducting periodic assessments that incorporate new data from drilling and new seismic surveys.

E. Improving Resource Estimates with More Data

The Nation and the energy debate would benefit from a better understanding of the resource potential, including the gas or oil "proneness" of areas, and the ability of the OCS to contribute significantly toward meeting future domestic demand. There is much uncertainty in the resource estimates due to a lack of adequate data, especially in those OCS areas which have been unavailable for exploration and development for many years. For example, outside of the active OCS producing areas, significant quantities of oil and gas resources are known to exist in part of the eastern GOM and the California OCS, but in other areas, less is known about resource potential due to the availability of scarce or older data. In Alaska, there has not been any commercial exploration activity for many of the areas outside the Beaufort and Chukchi Seas for the past two decades.

> There is more uncertainty in resource estimates for those areas of the OCS subject to long-standing moratoria or presidential withdrawal. In areas like the north, mid-, and south Atlantic, most of the west coast, and portions of the eastern Gulf of Mexico, the last acquisition of geophysical data and drilling of exploration wells occurred more than 25 years ago and in some cases nearly 40 years ago. At that time, there were a few prospective discoveries and numerous indications of potential for the occurrence of oil and gas. For these areas, only currently available information (existing, older well and seismic data) and information from onshore activities, neighboring countries (e.g., Canada and Mexico), or appropriate international analogs have been used for recent resource assessments.

Due to subsequent access restrictions, there has been little or no opportunity to follow-up on the initial round(s) of exploration activity in many of these frontier areas. Yet, in the interim, there have been enormous advances in exploration, formation evaluation and exploitation technologies that could be utilized in these frontier areas today. Industry has made huge advancements in the technology of seismic data acquisition and processing, which allows for use of these data to create high resolution images of the subsurface to great depths. With this and other technical advances, the industry has become increasingly successful in finding oil and natural gas resources. Additionally, worldwide, there has been an enormous amount of exploration and production activity in frontier offshore basins that can provide new geologic analogs and exploration and production insights to exploring within frontier U.S. offshore basins. Canada has maintained a significant level of offshore exploration and production activity along their eastern coast, and now the U.S. is importing Canadian offshore production.

Although our fundamental knowledge of the origin, migration, and entrapment of oil and gas has advanced markedly during the past 40 years, the fact that incremental scientific advances are still being made leads to additional uncertainty in resource estimation. In other words, new knowledge may lead to increases or decreases in estimates of undiscovered resources, but generally leads to a reduction of uncertainty.

To support policy decisions that rely on these resource estimates, it is important to obtain sufficient G&G data for all areas in order to make appropriate comparisons and to reduce uncertainty about resource potential, especially in frontier areas. The lack of new exploration activity (seismic surveys or drilling exploratory wells) in areas of the OCS under long-standing congressional moratoria or executive withdrawal affects both the reliability of the Government's

assessment of the oil and gas potential of these areas as well as industry's interest in any future investment in these areas. New G&G information from exploration, especially in frontier areas, could substantially reduce the risk and uncertainty surrounding the existence of commercial quantities of oil and gas and spur industry investment. If, on the other hand, exploration results condemn an area, that information also can benefit the public debate and decision making.

F. Constituent Positions

The MMS received a number of responses on the subject of an OCS inventory in response to the August 24, 2005, Request for Comments and Information on the 5-Year OCS Oil and Gas Leasing Program for 2007-2012. Industry comments stated that the OCS inventory will provide a current and long overdue assessment of the true potential of the entire OCS and that 2-D and 3-D seismic surveys should be used by the DOI to gather needed information so that decisions can be based on factual data. They pointed out that present assessments reflect outdated information and that using modern seismic surveys would provide the government and industry with accurate multi-dimensional images that would help predict where resources lie and help inform the American public as to the scope of these resources. Again, the MMS did not acquire new seismic data in frontier areas of the OCS for this assessment. The industry noted too that the true resource potential in most of the OCS is unknown and that large, prospective areas remain under-explored due to access restrictions. As a result, many in the industry believe that resources may be larger than reflected by present evaluations, and the more an area is explored, the more its resource estimates tend to grow. Moreover, the industry stated that access restrictions decrease industry's domestic investment and increase investment in international ventures. Industry comments strongly recommended that all OCS areas be open to exploration and development. They noted that even if areas currently off limits were made available today, it will take decades to evaluate, and if commercial quantities of hydrocarbons are discovered, to develop any resources found.

A number of coastal states—in areas where OCS activities are currently prohibited by a current presidential withdrawal or annual congressional moratoria—are concerned that such an inventory could ultimately lead to oil and gas development off their coasts. Earlier, during debate on the Energy Bill, some congressional members indicated that they might seek to block appropriations of any funds for such an inventory.

In their comments on the 5-Year Program, a few state agencies on the Atlantic coast noted the importance of OCS resource assessment efforts for making informed decisions about OCS leasing. Maine raised concerns about the effects of seismic activity on marine life and expressed support for using existing data to complete the inventory. Florida opposed the inventory. The Gulf coast states, with the exception of Florida, generally supported the inventory, with Louisiana expressing strong support and recommending use of 2-and 3-D seismic technology. On the Pacific coast, California cited environmental concerns in opposing the inventory. State and local government commenters in Alaska did not specifically address the OCS inventory. Comments from environmental organizations generally opposed the OCS inventory. A number of commenters from environmental and recreation interest groups and the congressional members from California expressed concern about the effects of seismic activities on marine mammals and fisheries, and some commented that seismic airgun inventories should be prohibited from any inventory activities (some with a caveat, at least until studies of potential impacts are completed).

VI. Impediments and Restrictions Affecting OCS Oil and Gas Activities

"Americans must have an energy policy that plans for the future, but meets the needs of today. I believe we can develop our natural resources and protect our environment."
—President George W. Bush

A. How Legislative, Regulatory, and Administrative Programs or Processes Restrict or Impede OCS Oil and Gas Development

Producing more of the Nation's energy domestically will protect economic and national security and help close the growing gap between the amount of energy used and produced. Despite expected increases in OCS oil and natural gas production over the next ten years, the Nation likely will not be able to mitigate the growing long-term expected shortfall between projected domestic supply of and demand for oil and natural gas without continued and timely access to high potential areas on Federal lands, including the OCS. Yet, impediments on leasing and development from outright restrictions on access to certain Federal lands by the legislative and executive branches, or from legal, regulatory and administrative requirements on leasing and development can restrict or delay development activities. Unnecessary restrictions on exploration and development, or unreasonable delays in governmental review and approval processes, can raise project costs and risks, affecting if and when resources can be developed relative to alternative industry investment opportunities.

For the OCS to continue its significant contribution to meeting the Nation's energy needs, certain impediments will need to be addressed soon, so that governmental planning and industry investment decisions can proceed in a timely and systematic manner. There are long lead times needed for exploration and development of OCS oil and gas resources, especially in frontier areas where risks and costs are especially high. Preparing to offer oil and gas leases entails years of planning and consultation under sections 18 and 19 of the OCSLA. Once a lease sale is held, it could take five to ten years for drilling to commence. Production could take another five years or more after a discovery.

The OCS acreage is made available to the oil and gas industry for competitive bidding through a lease sale process governed by section 18 of the OCSLA. Subsections 18(c) and (d) prescribe a detailed process of consultation and analysis for preparing a 5-year program. As administered by the MMS, the process has taken at least 18 months—and has taken up to 36 months—to complete in order to comply with NEPA requirements and to adhere to the OCSLA section 18 process, which includes 8½ months of comment and waiting periods. Even if conditions change, the schedule cannot be significantly revised without undertaking the full preparation process again. Many believe that the current procedures for preparing and revising a 5-Year Program under the OCSLA are overly cumbersome and take more time than should be necessary (see appendix A, item 6).

The current 5-year OCS Oil and Gas Leasing Program for 2002-2007 includes 20 sales in eight OCS planning areas—annual sales in the central and western GOM and periodic sales in part of the eastern GOM, Beaufort Sea and Cook Inlet, Alaska. Three other planning areas in Alaska—Norton basin, Chukchi Sea, and Hope basin—also have sales scheduled if there is any interest

expressed by industry at the beginning of the sale process. The current 5-Year Program does not schedule lease sales in any areas restricted by either the congressional moratoria or the presidential withdrawal. Only a small portion of the eastern GOM not subject to the moratoria

or withdrawal is being offered in this 5-year program. Part or all of nine OCS planning areas have been subject to long-running leasing moratoria enacted annually as part of the Interior and Related Agencies appropriations legislation, as well as the presidential withdrawal until after June 30, 2012. The first congressional moratorium was enacted for one planning area in 1982, and moratoria expanded to other areas during the remainder of that decade. The first long-term presidential withdrawal of areas of the OCS occurred in 1990 (and was amended in 1992) under the administration of George H.W. Bush. In 1998, the Clinton Administration extended the withdrawal to all OCS areas then subject to moratorium under existing appropriations legislation until June 30, 2012, and withdrew all National Marine Sanctuaries indefinitely. At the time of the withdrawal order, all of the nine planning areas affected had been subject to annual congressional moratoria since 1990. The withdrawal had the effect of removing all of the areas from leasing consideration for the next two 5-year leasing programs (2002-2007 and 2007-2012).

The congressional moratoria and presidential withdrawal prohibit new oil and gas leasing, but do not apply to existing leases. Existing leases in areas subject to the moratoria and withdrawal are located off California (about 79 leases) and northwest Florida (about 95 leases). Local opposition to the OCS activities has been an impediment to development of these leases.

A total of about 611 million acres of the OCS, some of which contain large amounts of recoverable oil and gas resources are off-limits to leasing and development. The moratoria and presidential withdrawal cover about 85 percent of OCS acreage offshore the lower 48 states and 3 percent of the OCS offshore Alaska. The acreage and resource potential associated with the planning areas withdrawn from leasing is shown table 4. The MMS estimates that the resources in OCS areas currently off limits to leasing and development total 18.9 Bbo and 85.8 Tcfg (mean estimates).

Table 4: Oil and Gas Resources in OCS Areas Unavailable for Leasing and Development

OCS Areas Withdrawn from Leasing	**Area (million acres)**	**Undiscovered Technically Recoverable Resources (mean estimate)**	
		Oil (Bbbls)	**Natural Gas (Tcf)**
North Aleutian Basin*	33.43	0.75	8.62
Washington-Oregon	71.00	0.40	2.28
Northern California	44.79	2.08	3.58
Central California	43.68	2.31	2.41
Southern California**	88.99	5.58	9.75
Eastern Gulf of Mexico**	69.70	3.98	22.16
North, Mid and South Atlantic	259.53	3.82	36.99
Total:	**611.11**	**18.92**	**85.79**

* Starting in 2004, Congress discontinued the moratorium for the North Aleutian Basin, but the area remains subject to the existing presidential withdrawal.
** Does not include resources in areas already under lease.

The presidential withdrawal also placed off limits indefinitely all ten national marine sanctuaries, which are relatively small areas located in the Atlantic, GOM, and Pacific regions of the OCS (as well as off Hawaii and American Samoa). Existing regulations and individual management plans governing sanctuaries can affect local oil and gas activities in and around these areas (see also the appendix A, item 10).

> Under the authority of section 12 of the OCSLA, President Clinton withdrew from leasing indefinitely all National Marine Sanctuaries. Sanctuaries are located in the following OCS planning areas:
>
> - Washington-Oregon (Olympic Coast)
> - Central California (Cordell Bank, Gulf of the Farallones, and Monterey Bay)
> - Southern California (Channel Islands)
> - Western Gulf of Mexico (Flower Garden Banks)
> - Straits of Florida (Florida Keys)
> - South Atlantic (Gray's Reef)
> - Mid-Atlantic (Monitor)
> - North Atlantic (Stellwagen Bank)

The OCS leasing program is currently confined geographically to the central and western GOM, a small portion of the eastern GOM, existing leases offshore California, and certain areas offshore Alaska. The central and western portions of the GOM account for almost all current domestic offshore oil and natural gas production.

With the increasing activity in the deep and ultra-deep waters of the GOM, it is clear that the relative contribution to domestic energy production from Federal offshore areas will increase substantially in the upcoming years. The potential contribution from other frontier OCS areas is highly uncertain. There has been no recent exploration activity in most of these areas because of the congressional moratoria and presidential withdrawal. In the majority of the eastern GOM, the West Coast and the Atlantic OCS, the last acquisition of geophysical data and drilling of exploration wells occurred more than 25 years ago. Yet, in the interim there have been enormous advances in exploration and production technologies and a myriad of new drilling, completion, and production technologies that could be used to ascertain the oil and natural gas potential in these frontier areas today. Additionally, worldwide, there has been an enormous amount of exploration and production activity in frontier offshore basins that would provide new geologic analogs and exploration and production insights to use in exploring frontier U.S. offshore basins. Opponents of continued moratoria contend that increasing access to Federal OCS lands could not only help open up new areas for exploration and development of oil and gas resources, but will help avoid potential supply disruptions (e.g., from hurricane damage) from concentrating so much of the OCS energy infrastructure in a small, weather-sensitive geographic area. Opponents of OCS leasing generally contend that leasing moratoria and other restrictions on access protects local and regional environmental and economic interests, especially for areas where coastal tourism and recreation are of paramount importance.

Despite the critical importance of the OCS oil and gas program to the Nation's energy future, and notwithstanding important technological advancements in exploration and development that have resulted in significant improvements in its safety and environmental record, opposition to offshore development still exists in many coastal communities, particularly offshore California, Florida, and parts of the Atlantic coast. Such opposition stems from longstanding concerns about potential environmental and economic damage from development in environmentally sensitive marine and coastal areas, and on the socioeconomics of coastal areas.

A variety of laws and regulations have been put in place to govern oil and gas operations in offshore areas, but opposition to OCS drilling continues in these areas. Yet, the environmental record of the OCS program has been outstanding—there has not been a significant platform spill in the last 35 years. The OCSLA mandates that the MMS ensure safe and environmentally sound operations on the OCS through its regulations which govern all offshore oil and gas leasing, exploration, development, and production activities. The MMS regulatory requirements and monitoring of operations are specific and stringent concerning the performance of offshore oil and gas operations. The program requires specific training for offshore workers, safety systems, submission for approval of exploration and development/production plans that include comprehensive environmental reports and oil spill contingency plans, and use of best and safest technology available. The MMS also has a comprehensive accident investigation program followed by safety alerts to all companies to prevent recurrence of similar incidents, and an effective and vigorous civil and criminal penalties program. It conducts about 25,000 inspections of offshore facilities a year. This comprehensive regulatory program ensures that offshore production is one of the safest ways to provide for our nation's oil and natural gas energy needs. Natural gas production offshore represents one of the most environmentally sound energy investments this country could make. A decision to not produce OCS resources can also have consequences. Most likely, it will mean more imported oil and LNG. Compared to imported sources, the OCS production is an economically and environmentally preferred source of energy.

The ongoing legislative and executive withdrawals mean that large portions of the OCS are off-limits to oil and natural gas exploration and development. But access can also be restricted to otherwise available areas for a variety of reasons, including administrative withdrawals for other uses, such as for national defense or for protection of archaeological, cultural or environmentally-sensitive marine resources. New uses of the OCS, for example for deepwater ports to import LNG, could also affect the oil and gas industry's use of the seabed for exploration and development on existing leases, as well as restricting potential development on areas offered for lease. Deepwater port applicants seek locations in close proximity to pipeline infrastructure, which is incidentally near fixed oil and gas facilities. They also look for unobstructed access to designated shipping fairways. To accommodate these needs, both domestic laws and international maritime conventions are being used by the U.S. Coast Guard (USCG) to create enforceable safety zones and unenforceable precautionary notice areas and anchorage areas, all of which, unless decidedly precise, can potentially encroach on oil and gas leases (see appendix A, item 11).

The oil and gas development can also be affected by delays in the leasing and permitting process, or from various stipulations in the terms of the lease or permit that affect (permanently or seasonally) surface occupancy, use, and timing of development for safety reasons or to protect sensitive environmental resources. All the OCS leases contain various terms, conditions, and stipulations that govern development of the oil and natural gas resources on the lease. These conditions are meant to protect the environment and ensure safety of operations, and ensure that resources are properly developed and provide a fair return to the public. The MMS does not consider existing lease stipulations and approval conditions to be an undue impediment to OCS oil and gas development. Many of the requirements are derived from implementing laws or from the consultation process, and so have facilitated development because they were critical to obtaining Federal, state and local approvals. None are considered so onerous that they would constitute an impediment to development.

OCS oil and gas activity must comply with a variety of Federal and state statutes, regulations, and administrative orders under various laws like NEPA, CZMA, ESA, MMPA, CAA, and CWA, which are designed to provide for safe and responsible resource development with appropriate environmental protection. Many of the ocean's energy resources are in environmentally sensitive areas and the development of those resources must be balanced against potential environmental impacts.

The MMS is the primary regulatory and permitting agency for OCS activities. However, other agencies, such as the USCG, EPA, Department of Transportation (Office of Pipeline Safety), U.S. Army Corps of Engineers, U.S. Fish and Wildlife Service, and the National Marine Fisheries Service, have independent regulatory authority and processes for certain aspects of these activities. Additionally, coastal states potentially affected by any proposed OCS leasing or development activity are afforded numerous opportunities to have their concerns addressed through the consultative processes outlined in both the OCSLA and NEPA. Any unnecessary delays and uncertainties associated with approval processes can impede proper energy exploration and development.

The MMS prepares thorough environmental analyses, including environmental impact statements and environmental assessments to address every proposed leasing action and exploration and development activity on the OCS. The MMS requires all operator plans for exploration and development have associated environmental documentation under NEPA and they are also subject to CZMA provisions that allow review by coastal states.

Under the CZMA, affected states review certain proposed OCS activities for consistency with their coastal zone management plans. If a state finds the activity to be inconsistent, the activity cannot proceed unless the Secretary of Commerce overrules the state after a company appeal. This process can stop or delay OCS activities. The effectiveness of some of the governmental review processes can become problematic if there are conflicting or unclear requirements and uncertain deadlines. The MMS has taken a number of actions to help streamline and improve coordination among government agencies for permitting and administrative processes to avoid unnecessary delays to OCS activities.

B. Summary of Public Comments on the Question Posed in the Request for Comments on the 5-Year Oil and Gas Leasing Program 2007-2012 (see also comments in appendix A)

Throughout the two to three year multi-step process of developing new 5-year OCS oil and gas leasing programs, the MMS consults with its constituents, ensuring that the program takes into account the concerns of all parties. The MMS requests comments from states, local and tribal governments, American Indian and Native Alaskan organizations, the oil and gas industry, Federal Agencies, environmental and other interest organizations, as well as the general public. Consultation with affected parties also occurs at the local level through the MMS regional offices.

On August 24, 2005, the MMS issued a request for comments and information on the preparation of a new 5-Year OCS Oil and Gas Leasing Program for 2007-2012. That request cited section 357 of the Energy Policy Act of 2005 and solicited relevant information, and specifically asked for comment on, "How legislative, regulatory, and administrative programs or processes of the Federal Government or coastal states, as well as local zoning restrictions on onshore processing facilities and pipeline landings, restrict domestic energy production from the OCS." The MMS

asked for comments and information concerning the following topics that relate to the OCS inventory provision:

1) leasing moratoria and withdrawals;
2) measures to increase flexibility in the 5-Year Program and expedite OCS resource assessment;
3) legislative, regulatory, and administrative impediments;
4) gas-only leasing as an alternative approach to promote increased production of natural gas from the OCS; and
5) removing the joint bidding restrictions on larger companies to encourage increased interest in certain high cost, high risk areas offshore Alaska.

Numerous comments were received from a variety of interested and affected parties, including the oil and gas industry and supporting associations, environmental and other interest organizations, and Federal, state, and local government agencies. The draft Proposed 5-Year OCS Oil and Gas Leasing Program will summarize and consider all comments received on the notice. A summary of the comments received on the OCS inventory topics follows:

1. *Leasing Moratoria and Withdrawals*: Industry comments favored consideration of all areas of the OCS for inclusion on the lease sale schedule, regardless of their status in terms of congressional moratoria or executive withdrawals, and for expanding leasing access to those areas. Most companies noted that the industry has proven that OCS exploration and production of oil and natural gas can be done in a safe and environmentally responsible manner while meeting the energy needs of the country.

Environmental organizations and state and local governments on the Atlantic and Pacific coasts generally favored continued exclusion of moratoria and withdrawal areas, but a number of commenters (including the State of Virginia, and 2 state legislators from North Carolina) noted the importance of having more geographically-dispersed domestic energy production. Some have suggested more research on the feasibility of producing natural gas off their coasts in an environmentally responsible manner. The States of California, Oregon and Washington all expressed support for moratoria. The GOM states that commented, with the exception of Florida, supported OCS leasing in the GOM and elsewhere, including moratoria and withdrawal areas. Florida expressed opposition to leasing anywhere within at least 100 miles of its coast. The State of Alaska and some local stakeholders are supporting oil and gas activities onshore and in state waters, and support continued analysis of the North Aleutian Basin OCS planning area to develop sufficient information on which to base future decisions concerning OCS leasing. Other local government commenters and environmental organizations favored continued exclusion of the area.

2. *Flexibility and Expedited Assessment*: Many of the comments from industry and associations called for increased flexibility in 5-year leasing program planning and endorsed the section 357 inventory provision. Several industry commenters recommended reducing the existing 5-step program preparation process by one step. Concerning the OCS inventory, most of the industry commenters addressing this topic recommended the use of state-of-the-art technology, including 2- and 3-D seismic data. Environmental organizations generally opposed the OCS inventory, and state comments were mixed. On the Atlantic coast, state agencies in

Delaware, Virginia, and Georgia expressed some support for OCS resource assessment efforts. Maine raised concerns about the effects of seismic activity on marine life and expressed support for using existing data to complete the inventory. Florida opposed the inventory. The Gulf coast states, with the exception of Florida, generally supported the inventory, with Louisiana expressing strong support and recommending use of 2- and 3-D seismic technology. On the Pacific coast, California cited environmental concerns in opposing the inventory. State and local commenters in Alaska did not specifically address the OCS inventory.

3. ***Legislative, Regulatory and Administrative Impediments***: Many industry commenters referred to impediments, but they were not very specific in either identifying obstacles or recommending solutions. Several expressed the opinion that the permitting processes are too diverse and complicated, generally recommending that the processes be unified and coordinated to the greatest extent possible. Environmental organizations and state and local government agencies generally expressed support for existing processes, and several state commenters identified their relevant laws, goals, and policies. The State of Connecticut indicated that it disagrees with the supposition that existing Federal, state, and local programs and processes restrict onshore energy-related development.

4. ***Gas-Only Leasing***: Only a few of the industry commenters viewed gas-only or gas-preference leasing to be a viable alternative worth further consideration; most opposed it, citing investment risks and resource conservation issues as the main reasons. Environmental organizations generally opposed gas-only leasing, and most state and local government agencies did not address the issue. One exception is the State of Virginia, whose Division of Mines, Minerals, and Energy commented favorably and noted that gas-prone areas of the mid-Atlantic could, subject to safety and environmental safeguards, serve as a possible testing ground for such an approach.

5. ***Joint Bidding Restrictions***: Many industry respondents offered comments on existing joint bidding restrictions, and the majority of those who addressed the issue recommended discontinuing those restrictions for certain high-cost, high-risk areas of the OCS. Most agreed that dropping the restrictions for Alaska areas should be considered, and some suggested that altering the restrictions in other regions of the OCS (e.g., deepwater GOM) should be considered as well. A few of the smaller companies expressed support for the existing restrictions. The State of Alaska recommended that further consideration be given to dropping joint bidding restrictions, particularly for the Cook Inlet planning area. No other state or local government agencies addressed this issue.

C. Ongoing DOI Initiatives to Increase Domestic Supplies of OCS Oil and Natural Gas

In order to provide for the Nation's growing energy needs, President Bush's NEP established a comprehensive, long-term energy strategy, which recognizes that conservation and more efficient use of energy, diversification of energy supply, and increased production of all domestic energy resources—renewable and nonrenewable—are critical to the Nation's energy future. The NEP promotes increased domestic oil and natural gas production to bridge the transition to renewable sources of energy. To address energy supply issues, the NEP emphasized the importance of identifying where resources are located on Federally-managed lands and the extent and nature of any impediments to accessing them. The MMS's goal is to provide optimal access to the resources from OCS lands consistent with sound stewardship principles to determine the

appropriate balance between resource protection and resource development and with appropriate terms and conditions to mitigate undue degradation, and with full public involvement. New provisions in the Energy Policy Act of 2005 and directives from the NEP to identify and resolve impediments and restrictions on development will play an important role in advancing these goals.

Since 2001, DOI has implemented a variety of initiatives in response to NEP directives by ensuring continued access to Federal lands for domestic energy development, and by expediting permits and other Federal actions necessary for energy-related project approvals. A number of DOI initiatives have improved efficiency and interagency coordination to help streamline governmental regulatory and environmental reviews, and it has put in place a suite of incentives to encourage leasing and development in frontier areas of the OCS where higher costs and risks can be a barrier to investment. The DOI is now responding to new provisions of the Energy Policy Act of 2005, which also are designed to encourage domestic energy investment in new offshore leasing and development.

The MMS supports the NEP by providing royalty-in-kind oil to fill the SPR and by implementing the offshore 5-year oil and gas leasing program which provides a predictable schedule of lease sales for industry to acquire promising OCS oil and gas acreage. By holding lease sales on schedule, the MMS ensures that the OCS remains a solid contributor to the Nation's energy and economic security. Since May 2001, the DOI has held 15 OCS oil and natural gas lease sales on schedule, leasing about 21 million acres for $2.7 billion of bonus bids, while going through a comprehensive consultation process with other Federal Agencies, state and local governments, and the public. Production from leases issued as a result of these sales will contribute substantially to future domestic oil and natural gas production. The MMS is on schedule for completing the next 5-year oil and gas leasing program by July 2007, which will establish the schedule for future OCS lease sales during the 2007-2012 timeframe.

The continued success of the offshore program is due in part to the judicious use of leasing, financial, and other incentives to promote continued industry interest in acquiring and exploring OCS leases, and investment in new technologies for exploration and development in frontier areas. Because of limitations on access to many areas of the OCS, the MMS has been investigating and adopting incentives that will help foster new development in the remaining areas available in the GOM and offshore Alaska in order to supply the nation with oil and gas resources to help offset the expected growing shortfall in domestic supplies. Based on existing information and access, the two most promising areas offshore to find new sources of oil and natural gas will be in the GOM—from newly-explored areas as industry steps out into deeper water, and from potentially large natural gas reservoirs expected to be found in deep horizons of the mature shallow water GOM shelf.

The NEP recommended that the DOI consider economic incentives for environmentally sound offshore oil and gas development where warranted by specific circumstances. The DOI has established a suite of economic incentives to promote discovery of new sources of energy and stimulate domestic oil and natural gas production. To sustain or increase the levels of OCS production, the MMS has employed various royalty relief and other incentives for both new leasing and existing leases. Financial incentives, which generally take the form of royalty relief subject to price thresholds reduce financial risks for lessees willing to invest in technologically

challenging, high risk areas such as offshore Alaska, the deep and ultra-deep waters of the GOM, and the drilling of deep wells in shallow waters areas of the GOM.

The MMS has also developed policies for extending lease terms to aid in planning wells to be drilled to sub-salt and ultra-deep prospects, accounting for the additional complexity and cost of planning and drilling such wells. Additional incentives will be provided as the MMS implements provisions of the Energy Policy Act of 2005. The Act authorizes the DOI to design a program of royalty relief for marginal properties, methane hydrates, and enhanced production through carbon dioxide injection. It also authorizes the DOI to provide royalty relief for existing non-producing OCS leases off Alaska, and specifies new tiers of royalty relief for deep water and deep depth drilling for natural gas in the GOM. The DOI expects the incentives to boost domestic production of oil and natural gas significantly over the next decade.

The NEP also directs the DOI to regulate energy production in an environmentally sound manner by expediting permits and other Federal actions necessary for energy-related project approvals. To help streamline our procedures, the MMS's ongoing e-government transformation project is re-engineering OCS business processes, using technology to receive and process data and information, to improve the quality of the information exchange between the MMS and the private sector, thus helping ensure timely approvals of plans and permits. The MMS has developed an online public commenting system and is implementing an online well permitting system that will streamline the permitting and approval process for OCS oil and gas well drilling operations. The online system will soon be extended to cover plan and permit approvals as well.

As directed in the NEP, the MMS also ensures timely response to proposed actions by reviewing and approving oil and gas exploration and development plans on predictable schedules. By MMS regulation, exploration plans must be processed and final action taken within 30 days; development and production plans within 120 days, and rights of way pipeline applications within 140 days. In the last three years, the MMS has processed 100 percent of these types of plans and applications within the specified time frames.

As the primary regulatory and permitting agency for OCS activities, the MMS has been working closely with other agencies to ensure timely and efficient reviews of proposed OCS oil and gas activities and to develop a more efficient means of issuing permits. It has been working closely with the National Oceanic and Atmospheric Administration (NOAA) to achieve prompt and efficient consultations under the ESA and rulemakings under the Marine Mammal Protection Act (MMPA). The DOI and MMS also worked closely with NOAA on an interdepartmental working group to address the NEP directive to re-examine the current federal legal and policy regime to determine if changes are needed regarding energy-related activities and the siting of energy facilities in the coastal zone and on the OCS.

The MMS also is working in partnership with the USCG to improve regulatory oversight of oil and gas operations where there is overlapping jurisdiction. Under a new Memorandum of Understanding (MOU), the MMS and the USCG have streamlined the process for inspections of offshore facilities, improving government efficiency and reducing a reporting burden on industry. The MMS also has been assisting the USCG and the Maritime Administration in the processing of applications to approve the first offshore ports for LNG on the OCS. A new interagency MOU on deepwater ports clarifies agency roles and serves as a vehicle for

expediting the permitting process. Licenses have now been issued for three new ports in the GOM, one of which started taking LNG deliveries in March of 2005.

Although the vast majority of OCS leasing activity is in the GOM, the MMS is also working with other Federal, state and local government agencies to streamline the permitting process for exploration and development projects offshore Alaska. The MMS is streamlining the permitting process by resolving conflicting regulatory authorities and requirements, improving regulatory reviews, and developing timelines and schedules for specific project reviews.

Through such initiatives, the MMS has been successful in promoting increased leasing, exploration, and development in many areas of the OCS, and has been improving coordination among government agencies and streamlining many of the administrative processes. However, a number of legal, regulatory, and administrative constraints affect OCS exploration and development activities in many areas of the OCS (see appendix A). The MMS continues to investigate ways to manage safe and environmentally-acceptable OCS oil and gas development and avoid unnecessary delays on OCS program activities.

Appendices

Appendix A: Impediments and Restrictions Affecting OCS Oil and Natural Gas Exploration and Development
Appendix B: Glossary
Appendix C: Abbreviations, Acronyms, and Symbols
Appendix D: References

Appendix A: Impediments and Restrictions Affecting OCS Oil and Gas Exploration and Development

Type of Impediment or Restriction	Description (including effects on domestic supply)	Comments
Legislative and Regulatory		
1. Restrictions on Access to the OCS for Oil and Gas Exploration and Development: Congressional Moratoria (and Presidential Withdrawal) see also item #7 below)	Due to annual congressional moratoria and presidential withdrawals, OCS oil and gas leasing may proceed only in the central and western Gulf of Mexico (GOM), a small portion of the eastern GOM, and areas offshore Alaska. Annual congressional moratoria affect all or parts of 8 OCS planning areas (three in the Atlantic Region, 4 in the Pacific Region, and one in the GOM Region). The presidential withdrawal applies to the same 8 areas plus the North Aleutian Basin Planning Area off Alaska and is in effect through June 30, 2012. Altogether, about 611 million acres of the OCS which contain large amounts of recoverable oil and gas resources are off limits to leasing and development due to the moratoria and withdrawals. The moratoria and Presidential withdrawal covers about 85 percent of OCS acreage offshore the lower-48 states and 3 percent of the OCS offshore Alaska. The areas subject to moratoria and withdrawal are listed and discussed below. The Minerals Management Service (MMS) estimates that the mean amount of undiscovered resources in the OCS areas under moratoria is about 19 billion barrels of oil and 84 trillion cubic feet of natural gas.	Due to increasing energy supply concerns, there is growing support to open some moratoria areas to exploration and production in order to increase domestic production. The Administration gives great weight to states' views concerning activities that affect their coasts and economies. Opponents of moratoria argue that Congress should change appropriations language and provide funds to support OCS leasing and development activities in some or all OCS moratoria areas to increase domestic energy supplies and provide more geographically-dispersed energy development. Various types of new legislative proposals address the status of areas of longstanding moratoria. Some provide for exploration in moratoria areas to identify resource potential. Other proposals would open certain areas, but limit access to gas-only leasing, give the states the ability to decide whether or not activities could occur off their coasts, or transfer authority for administering and regulating oil and gas leasing, exploration, and development activities in portions of the OCS to coastal states. Many congressional delegations, state and local government officials, and environmental and other interest organizations of states adjacent to areas currently off-limits generally support the moratoria and presidential withdrawal. Over the next 18 months, during development of the new 5-Year Program for 2007-2012, the MMS expects to receive public comment both for and against opening certain OCS areas for exploration and development. In comments on the 5-Year Program RFI, environmental organizations and state and local governments on the Atlantic and Pacific coasts generally favored continued exclusion of moratoria/withdrawal areas. The GOM states that commented, with the exception of Florida, supported OCS leasing in the Gulf and elsewhere, including moratoria/ withdrawal areas. The State of Florida opposes leasing anywhere within at least 100 miles of its coast. The oil and gas industry and industry

In an August 24, 2005, Federal Register Notice, the MMS asked for public comment on all areas of the OCS, initiating the first step for developing the 5-Year OCS Oil and Gas Leasing Program for 2007-2012. This request for information (RFI) provides the Secretary of the Interior an opportunity to gather the current views of all interested parties in considering the future direction of the Program. The MMS received more than 11,000 comments. Some of the comments are referenced in this table; the Draft Proposed Program will summarize and consider the full range of comments received.

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Legislative and Regulatory		
		associations support expanded offshore leasing particularly in the eastern Gulf, offshore Alaska, and certain areas of the Atlantic. Many industry commenters asked that the 5-Year Program be designed with maximum flexibility, some suggesting that all areas of the OCS be analyzed, should current prohibitions change. Should the moratoria be lifted for any of these OCS areas, before any leasing activity could occur, the MMS would need to update resource assessments and conduct numerous environmental studies to address information needs identified by the National Academy of Sciences.
East Coast	The North, South, and Mid-Atlantic planning areas (259.5 million acres) are subject to congressional moratorium and presidential withdrawal, and no leasing has occurred since 1983. There has been no development or production of OCS oil and gas along the U.S. East Coast. The MMS conducted 10 OCS lease sales between 1976 and 1983, but no active leases remain. Forty-six exploratory wells and 5 stratigraphic test (COST) wells were drilled in the Atlantic OCS between 1978 and 1984, with no commercial finds. Natural gas and oil was discovered during drilling in the mid-Atlantic, but it was uneconomic at the time. No exploratory wells have been drilled anywhere on the Atlantic OCS since 1984. Recently, off the coast of Canada, some major gas fields have been discovered and developed. The same gas play(s) may extend south into the North Atlantic and other Atlantic planning areas. Based on existing information to date, the geology of the Atlantic OCS implies that if hydrocarbons occur, they will most likely be natural gas prone. In addition, recent exploration successes offshore Mauritania (Northwest Africa), are encouraging for basins formed under similar geologic conditions on the Atlantic OCS. The MMS estimates (2006) that the undiscovered technically recoverable resources in these East Coast areas could range from 1.12 to 7.57 billion barrels of oil and condensate, and from 14.3 to 66.46 trillion cubic feet of natural gas.	There has been increased industry interest in leasing off the Atlantic coast due in part to recent development off the coast of Nova Scotia and due to increased prices for natural gas. In comments on the 5-Year Program RFI,* a number of commenters (including the State of Virginia, and 2 state legislators from North Carolina) noted the importance of having more geographically-dispersed domestic energy production. Some are encouraging more research on the feasibility of producing natural gas off their coasts in an environmentally responsible manner. It's possible that proposals to modify the moratoria and withdrawals affecting areas adjacent to one or more of these states could be received as consultation on preparing a new 5-Year Program for 2007-2012 begins. Legislation to allow states an increased role in OCS leasing was proposed, but not passed. In comments on the 5-Year Program RFI,* a number of commenters from East Coast states, the congressional delegation from New Jersey and Florida, and environmental and recreation interest groups supported continued moratoria and exclusion of the Atlantic coast from leasing consideration. The State of Florida commented in support of codifying into law a buffer from leasing of at least 100 miles around the Florida coastline.
Eastern Gulf of Mexico	The portion of the eastern GOM Planning Area that is not under congressional moratoria or presidential withdrawal is a 5.95 million acre area (located more than 15 miles directly south of Alabama and more than 100 miles directly south of the Florida panhandle) that was originally	As it begins preparation of a new 5-Year leasing program for 2007-2012, the MMS is consulting with affected states and other interested parties, requesting comments concerning the area that will be available for lease. Industry voiced strong interest in opening all, or larger portions, of the

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Legislative and Regulatory		
	proposed for Lease Sale 181. Of this area, about 1.48 million acres is available for oil and gas leasing under the current 5-Year Program. The rest of the planning area (69.7 million acres) is under moratorium and withdrawal. There have been 13 OCS lease sales in the eastern GOM since 1959 and there are about 248 active leases in this area. To date, more than 64 exploratory wells have been drilled in the eastern GOM, with 20 having commercially producible hydrocarbon discoveries. The MMS estimates (2006) that between 26.58 and 39.02 trillion cubic feet of natural gas and 4.47 and 8.97 billion barrels of oil and condensate are contained in the Eastern GOM Planning Area. Of this total, about 66% of the undiscovered technically recoverable resources (mean estimates) in the area are currently off limits to leasing. In 2001, during pre-sale planning for Sale 181, the Secretary of the Interior reduced the available area in the eastern GOM to 1.48 million acres. This modified area is at least 100 miles from any portion of the Florida and Alabama coasts. In the "modified Sale 181" area, there are about 142 active leases. The MMS estimates (2006) that 3.9 trillion cubic feet of natural gas and 1.0 billion barrels of oil and condensate are contained in the modified area. About 18 exploratory wells have been drilled there, with 8 discoveries. Industry interest in the eastern GOM is very high. Five independent exploration and production companies and one energy company have come together to develop multiple ultra-deepwater natural gas discoveries located in the central and eastern GOM. First production from the Independence Hub is expected in 2007.	eastern Gulf for exploration and development. They noted that areas withdrawn from the program have significant resource potential. They recommend that Congress open access to this area and that the MMS at a minimum offer the entire Sale 181 area. Some industry commenters were opposed to restrictions within 100 miles of Florida, and some asked the MMS to explore the possibility of modifying the portion of the eastern Gulf that is withdrawn to make more of the planning area and its resources available for leasing in a way that would be attractive to industry and acceptable to the Governors of Florida and Alabama and others. Twenty-one members of the Florida congressional delegation commented in support of continuing moratoria, and the State of Florida commented in support of codifying into law a buffer from leasing of at least 100 miles around the Florida coastline.
West Coast	All 4 of the OCS planning areas on the West Coast (covering 248.5 million acres) are subject to congressional moratorium and Presidential withdrawal, and no leasing has occurred since 1984. The geologic potential within the 4 planning areas encompasses one of the greatest concentrations of hydrocarbon deposits in the world. The Southern California Planning Area alone is estimated to contain almost 6 billion barrels of oil and 10 trillion cubic feet of gas in undiscovered fields. OCS oil and gas production on the West Coast is confined to 43 leases offshore southern California. The Region has been an important contributor to the Nation's energy supply, with more than 1.1 billion barrels of oil and 1.4 trillion cubic feet of gas produced over the past 38 years.	As it begins preparation of a new 5-year program for 2007-2012, the MMS is consulting with all interested and affected parties, including the Governors of California, Oregon, and Washington and other stakeholders from those states. In comments on the 5-Year Program RFI,* the State of California reiterated its strong opposition to any new leasing in the California OCS and its support for continued moratoria. The Governor of Oregon supports the continuation of the existing moratorium and opposes any OCS oil or gas development in or outside of its territorial sea. The State does not oppose non-invasive, ecologically benign inventorying activities.

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	The MMS estimates (2006) that the undiscovered technically recoverable resources in these West Coast areas could range from 7.55 to 13.94 billion barrels of oil and condensate, and from 13.28 to 24.12 trillion cubic feet of natural gas.	The Governor of Washington continues to support the moratorium on oil and gas leasing off its coast, and notes that the State is now conducting a review of its ocean policy. Four oil and gas companies indicated interest in the Pacific OCS without identifying a specific planning area. In 2003, the MMS received 2 industry requests for geotechnical information related to previous drilling activities conducted offshore Oregon and Washington. These inquiries may be indicative of some interest in the oil and gas potential of the Oregon and Washington Planning Areas. In areas subject to continuing moratoria (such as the Pacific OCS), many leases have been relinquished, terminated or expired over the years, yet they still contain significant accumulations of oil and gas but cannot be re-leased due to the moratoria. The MMS estimates that offshore the West Coast, almost 150 million barrels of oil and 360 billion cubic feet of gas are trapped in discovered fields on terminated or expired leases that have undergone full environmental analyses and review years ago but were never developed. Economic changes and/or technological innovations such as extended reach drilling and 3-D seismic data acquisition may now make these properties more attractive targets. In many cases, properties that have been turned over or sold to new, smaller operators have demonstrated that they can operate more efficiently and continue production operations for many years (e.g., Pt. Arguello field, Carpinteria, and Pt. Pedernales, whose remaining reserves exceed 180 million barrels of oil and 200 billion cubic feet of gas).
Offshore Alaska	For the OCS offshore Alaska, only the North Aleutian Basin (33.4 million acres) has been subject to longstanding congressional moratoria and Presidential withdrawals. Since February 2003, some local officials in Alaska have dropped their opposition to leasing in the North Aleutian Basin and have expressed support for environmentally responsible oil and gas activity. In 2004, Congress removed the North Aleutian Basin from the moratoria in response to comments and resolutions submitted by some local stakeholders requesting that the leasing restrictions be discontinued. However, it is still subject to the section 12 presidential withdrawal that extends through June 30, 2012, and therefore is unavailable for leasing at this time. Twenty-three tracts in the North Aleutian Basin were leased in 1988. All leases were repurchased by the Government after the Exxon Valdez oil spill, responding to concerns over the potential effects of a spill	During development of the new 5-Year Program for 2007-2012, the MMS will work with the Governor of Alaska and other interested and affected parties to determine if the North Aleutian Basin should be included in the 5-Year Program Draft Environmental Impact Statement (EIS) and if we should request the Presidential withdrawal to be modified. The Governor and some local stakeholders are supporting oil and gas activities onshore and in state waters, and support continued analysis of the North Aleutian Basin planning area to develop sufficient information on which to base future decisions concerning OCS leasing. There are indications that some local stakeholders are interested in reviewing the economic benefits of a possible North Aleutian Basin sale. The Bristol Bay fishery may be declining. Recent years have witnessed

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Legislative and Regulatory		
	on the Bristol Bay fishery. The North Aleutian Basin has high resource potential because it contains high quality reservoir formations and large, simple structures that may form petroleum traps. Geologic potential is viewed to be better offshore than on adjacent onshore state lands. The MMS assesses the North Aleutian Basin as gas prone. The MMS estimates (2006) that the undiscovered technically recoverable resources in the North Aleutian Basin Planning Area could range from 0.02 to 2.50 billion barrels of oil and condensate, and from 0.04 to 23.28 trillion cubic feet of natural gas.	depressed salmon prices and record low salmon returns. Coastal impact assistance under the Energy Policy Act of 2005 or from new legislation could be provided directly to the local community which could enhance the acceptance of exploration activities, particularly related to gas. Gas development infrastructure associated with a successful North Aleutian Basin exploration program could support exploration and development of other OCS gas prone basins (e.g., other Bering Sea basins, Shumagin, Kodiak). In comments on the 5-Year Program RFI,* 11 companies expressed interest in a North Aleutian Basin OCS lease sale. A number of comments from local government organizations also support leasing in the North Aleutian Basin subject to completion of appropriate studies and provided maximum protections for fisheries, the environment, and the local economy. A few local government comments and some environmental and recreation interest groups support continued moratoria/withdrawal for the North Aleutian Basin.
2. Restrictions on Access to the OCS for Oil and Gas Exploration and Development: International Boundary Issues	The United States needs international boundary agreements with neighboring countries—with Cuba and Mexico for the Eastern Gap, or with Canada for portions of the eastern Beaufort Sea and Southern Gulf of Alaska— before any oil and gas leasing and development can occur in these areas.	In order to gain access to any disputed areas, the United States would have to enter into discussions with Mexico and Cuba, or Canada, to forge a continental shelf boundary agreement similar to what was done by Mexico and the United States for the Western Gap area in the GOM. The process would involve the Department of the Interior (DOI) and the Department of State (DOS), and the U.S. Congress would have to ratify any agreement.
	Eastern Gap: The Eastern Gap is an area of the GOM OCS that is bordered by, but beyond, the Exclusive Economic Zones of Mexico, Cuba and the United States. The northern portion of the Eastern Gap is included in the Central and Eastern GOM OCS Planning Areas. Unlike the situation with the Western Gap between Mexico and the United States, the three nations adjacent to the Eastern Gap have not agreed on a continental shelf boundary in this area. In the absence of such a boundary agreement, the MMS has not offered any blocks in the northern portion of the Eastern Gap, not even those located in the Central GOM Planning Area, which is offered for areawide leasing annually. In fact, this area was excluded from the multi-sale Call for Information and Nominations for Gulf sales in the 5-Year Program for 2002-2007, making it unavailable for any sales in the current program. Industry interest in this area is expressed through their bidding	In comments on the 5-Year Program RFI,* companies indicated interest in the central and eastern GOM; however, none of the comments specifically addressed leasing in the disputed area.

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	activity on blocks within ten miles of the Eastern Gap. Resources in the Eastern Gap are expected to reflect the geologic plays that extend into this area. Data for the Eastern Gap is minimal and additional information is needed to evaluate the potential.	
	U.S./Canadian Disputed Areas: The international boundaries between the United States and Canada in the Eastern Beaufort Sea and Southern Gulf of Alaska have yet to be resolved. To date, industry has never indicated any interest in the southern portion of the Gulf of Alaska, but companies did bid on tracts in the disputed area in the eastern Beaufort Sea in past sales. The bids were held in escrow unopened, but eventually returned to the companies several years after the lease sales. For the most recent 5-Year Programs, the area available for leasing in the disputed area in the eastern Beaufort Sea was minimal or the disputed area was deferred in total from the lease sales. The MMS has seismic data and has mapped oil and gas prospects in the disputed areas north of the current Beaufort Sea Planning Area. Currently, the nearest oil and gas infrastructure are the facilities at Prudhoe Bay, hundreds of miles away. The value of prospects in the disputed area depends largely on whether oil and gas prices remain high and whether nearby prospects (either in Canada or the U.S.) are developed.	In comments on the 5-Year Program RFI,* nine companies indicated interest in the eastern Beaufort Sea; however, none of the comments specifically addressed leasing in the disputed area.
3. Inability to Enter Into Transboundary Agreements	In areas of the OCS where oil and gas activity takes place along an international boundary (i.e., deepwater GOM), production is currently governed by the "rule of capture" which allows various holders of rights (lessees) atop a common reservoir to produce all the hydrocarbons they are able to and as fast as they can, even if the production disproportionately drains the reservoir, reduces the output of other rights holders (lessees), or damages the reservoir. Competing oil and gas lease holders operate under this rule on adjacent blocks on the OCS – the MMS monitors rates of production to avoid damage to the reservoirs. Under this present situation, bidders in U.S. lease sales cannot be certain of the viability of transboundary oil and gas prospects. In the case of GOM deepwater leases, the rule of capture could pit U.S. oil and gas rights holders against those of Mexico.	The DOI and the DOS are willing to enter into discussions with Mexico, but it is not clear if and when Mexico will be willing to meet. The OCS Lands Act (OCSLA) would need to be amended to give the MMS the authority to enter into agreements on the joint development of transboundary reservoirs. Doing so would provide certainty for resource estimation, enhance viability of transboundary prospects, and provide for orderly and reasonable development of oil and gas resources.
4. Need for Additional Incentives for Industry Investment in Frontier OCS Areas	The DOI is actively facilitating industry's search for new domestic deposits of oil and natural gas in the GOM and offshore Alaska. Under the Deep Water Royalty Relief Act of 1995 and implementing regulations, the MMS is	In comments on the 5-Year Program RFI,* a number of companies recommended discontinuing restrictions on joint bidding for certain high-cost, high-risk areas of the OCS. [Restrictions against joint bidding by

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Legislative and Regulatory		
	providing appropriate financial and other incentives when needed to encourage industry to acquire and explore leases in frontier areas like deep and ultra-deep waters, and from deep-depth natural gas reservoirs in shallow waters of the GOM that may otherwise be too costly to explore for and produce. Additional incentives are to be provided as the MMS implements provisions of the Energy Policy Act of 2005. The MMS expects the incentives to boost domestic production of oil and natural gas significantly over the next decade.	major oil and gas companies are meant to ensure against unfair competition.] Most agreed that dropping the restrictions for Alaska areas should be considered, and some suggested that altering the restrictions in other regions of the OCS (e.g., the deepwater GOM) should be considered as well. A few of the smaller companies expressed support for the existing restrictions. The State of Alaska recommended that further consideration be given to dropping joint bidding restrictions, particularly for the Cook Inlet Planning Area. Some industry commenters favored use of royalty relief to provide incentive for exploring harsh areas. One commenter suggested incentives to explore for the smaller reserves remaining in the GOM and for platform owners processing or transporting 3rd party production. A joint letter from environmental groups commented that royalty relief in Alaskan waters should not proceed.
5. Revenue Sharing with State and Local Governments	With OCS leasing, the benefits (energy and revenues) flow to the nation as a whole, but any associated environmental or social costs are borne largely by the adjacent coastal states and local communities. Proponents of revenue sharing believe that some of the conflict over OCS development could be ameliorated if the Federal Government shared more of the lease revenues with affected states. This could mean access to additional OCS acreage and reduced delays and costs with leasing and permitting OCS activities. Generally, there is broad support for revenue sharing from states, local communities and industry; but costs to the Federal Treasury would be substantial. Under existing law, 27 percent of the lease revenues from the OCS 8(g) zone (a 3-mile band seaward of state waters) are shared with adjacent coastal states to help offset the impacts from OCS oil and gas development off their coasts. From 1982 to 2004, about $3.2 billion was distributed to these states. Some states transfer funds to the coastal communities. There has been a number of impact assistance programs put in place over the years that shared OCS revenues with affected states, but these limited programs failed to make any inroads in building new support from state's that historically oppose OCS development off their coasts.	Proponents of revenue sharing for coastal impact assistance contend that expanding the program (dollars or timeframe) would make coastal states and local communities more supportive of oil and gas development off their coasts, and help improve oil and gas infrastructure in some coastal areas. Opponents of revenue sharing strongly oppose efforts to use fiscal incentives in an attempt to encourage coastal states to accept more offshore drilling. Under the Energy Policy Act of 2005, the Congress approved coastal impact assistance of $1 billion over FY 2007- 2010 for 6 producing states (Alaska, California, Texas, Louisiana, Mississippi and Alabama) and their political subdivisions. Recent legislative proposals would include revenue sharing arrangements for all coastal states and local governments to provide them a larger share of revenues from any future OCS production off their coasts. In comments on the 5-Year Program RFI,* most state and many local government comments included support for direct revenue sharing. A number of companies expressed support for revenue sharing to benefit state or local communities in close proximity to oil and gas development.

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Legislative and Regulatory		
6. Complex and Time-consuming Lease Sale Planning Process The 5-Year OCS Oil and Gas Leasing program	The OCSLA provides for development of comprehensive 5-Year Programs and supporting environmental documents that are used to establish the size, timing and location of OCS leasing over a 5-year timeframe. Resulting sales offer industry access to OCS acreage for leasing by competitive bid for potential future exploration and development of oil and gas resources. Only areas included in the 5-Year schedule can be offered for sale. The OCSLA subsections 18(c) and (d) prescribe a detailed process of consultation and analysis for preparing a 5-year program. As administered by the MMS, the process takes at least 18 months, and has taken up to 36 months, to complete in order to comply with NEPA requirements and to adhere to the OCSLA section 18 process, which includes 8½ months of comment and waiting periods. Subsection 18(e) calls for an annual review of the approved program and provides that it may be revised and re-approved at any time. Even if conditions change, the schedule cannot be significantly revised without undertaking the full preparation process again.	Many believe that the current procedures for preparing and revising a 5-Year Program under the OCSLA are cumbersome and take more time than should be necessary. To improve the planning process, the Secretary's OCS Policy Committee is looking at options to improve the planning process. Possible ways to improve efficiency include: (1) reduce the number of steps and time intervals required to prepare a new program, and (2) permissible additions and accelerations to an approved 5-Year Program without having to repeat the entire preparation process [e.g., revise the OCSLA to provide for the addition of an area for lease if the Governor(s) of affected state(s) agree]. In comments on the 5-Year Program RFI,* many industry letters noted that they would like to see a flexible, timely process for amending the 5-Year Program should current prohibitions change. Several commenters recommended that the program include leasing in areas currently off limits and completion of studies for these areas should restrictions change during the 2007-2012 period. Another commenter suggested eliminating the EIS for the 5-Year Program and only completing EISs for each lease sale, and allowing the Secretary discretion to add or delete sales when the need arises. One company suggested the schedule could include one or more non-designated sales to be named by the Secretary.

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Regulatory and Administrative Programs and Processes		
7. Restrictions on Access to the OCS for Oil and Gas Exploration and Development: **Presidential Withdrawals** (see also #1 above)	The first long-term withdrawal of areas of the OCS under the authority of section 12 of the OCSLA occurred in 1990 (and was amended in 1992) under the Administration of George H.W. Bush. The decision to withdraw areas from leasing followed over a year of consultation and analysis by a cabinet-level task force established by the President. The full withdrawal (as amended) applied to the following areas, all of which were under congressional moratorium at the time: all West Coast planning areas, the southeastern portion of the eastern GOM (referred to as Sale 116, Part II), and the North Atlantic Planning Area. The areas were withdrawn through 2000. Although the first withdrawal was intended to remove the controversial areas of the OCS from leasing consideration and allow the program to proceed elsewhere, controversy and conflict remained in several areas that were not withdrawn and came under congressional moratorium (i.e., Mid-Atlantic off New Jersey and North Carolina, Gulf off Florida Panhandle, North Aleutian Basin off Alaska). Moratoria on these areas and others continued throughout the 1990's, along with increasing demands that moratorium areas be excluded permanently from leasing. In 1998, the Clinton Administration acted by directing that all of the areas then subject to moratorium under existing appropriations legislation (P.L. 105-83) be withdrawn from disposition for leasing until June 30, 2012, and withdrew all National Marine Sanctuaries indefinitely.	The current presidential withdrawal places certain areas of the OCS off-limits for leasing until June 30, 2012. Annually enacted moratoria do not prevent inclusion of an area in the 5-year program, but long-term withdrawals do. President Clinton reserved the right to lift the withdrawal. Many states and other stakeholders continue to oppose offshore oil and gas activity off their coasts, and the Administration gives great weight to the views of adjacent states, as does the law. In comments on the 5-Year Program RFI,* the State of Alaska and some local governments expressed support for continued analysis of the option for future leasing in the North Aleutian Basin; 11 companies expressed interest in a North Aleutian Basin OCS lease sale; other local government commenters and environmental organizations favored continued exclusion of the area. Some environmental organizations, and state and local governments on the Atlantic and Pacific coasts, generally favored continued exclusion of moratoria/withdrawal areas. However, other commenters, including the State of Virginia, indicated an interest in evaluating gas potential off their coasts.
8. State, local Government and/or Other Opposition		In comments on the 5-Year Program RFI,* a number of government and industry commenters noted the importance of consulting with local stakeholders during the leasing and development process.
East Coast	There has been widespread opposition to OCS oil and gas activity on the Atlantic Coast for many years. Although 10 OCS lease sales were held in the 1970's and early 1980's, and nearly 50 exploration wells were drilled, there were no commercial hydrocarbon discoveries, and subsequent increasing opposition led to long-running congressional moratoria and presidential withdrawals. Opposition has been most intense in the North Atlantic, which has been under annual moratoria since 1984 and has been withdrawn since 1990. In the Mid-Atlantic and South Atlantic Planning Areas, opposition is heaviest in North Carolina and Florida. Congressional moratoria have been in effect in both areas since 1990, and they have been subject to presidential withdrawal since 1998. North Carolina's opposition	As reflected in comments on the 5-Year Program RFI,* the State of Virginia has commented in favor of evaluating gas resources off its coast, and Delaware supports the offshore inventory. However, elsewhere on the coast, opposition remains constant, with Massachusetts, North Carolina, Florida, and others continuing to support banning of leasing.

Type of Impediment or Restriction	Description (including effects on domestic supply)	Comments
Regulatory and Administrative Programs and Processes		
	to proposed OCS activity in the Manteo Unit located 40 miles off its coast led to litigation and eventual settlements resulting in the termination of all the leases in the unit. There are no existing OCS oil and gas leases off the Atlantic Coast.	
Eastern Gulf of Mexico	The State of Florida is opposed to oil and gas leasing off its coast. For recent sales in the eastern GOM, the DOI modified the "Sale 181" area (the only portion of the eastern Gulf not under a leasing moratorium or withdrawal), reducing the area available for lease by 75%, from 5.95 million acres to 1.48 million acres. This modification removes all acreage from new leasing within 100 miles of Florida as requested by the Governor. The MMS estimates that the resources in the adjusted area are 3.9 trillion cubic feet of natural gas and 1.0 billion barrels of oil and condensate. Industry interest in leasing in the eastern GOM area is high. In the original Sale 181 area, there are about 156 active leases (142 leases in the "modified Sale 181 area"). Additionally, there are about 95 leases in the eastern GOM located outside of the original Sale 181 area.	As the MMS prepares a new 5-Year Program for 2007-2012, the Secretary of the Interior will make a determination whether to include for leasing any area within the 5.95 million acres that is not subject to moratoria and withdrawals. In comments on the 5-Year Program RFI,* the State of Alabama requested that the MMS continue to exclude from leasing OCS blocks within 15 miles of Baldwin County. The State of Florida was pleased with the Secretary's intention not to offer areas for lease within 100 miles off their coast in the eastern GOM planning area and it supports a permanent buffer of at least 100 miles around the entire coastline of Florida. Without additional legal assurances for permanent protections, Florida states that it will continue to oppose drilling in the eastern Gulf, including the area outside the revised Sale 181 area. Florida also requested that the DOI address existing leases in the withdrawal areas in the eastern GOM.
West Coast	Significant opposition to OCS oil and gas leasing and development can be found in California, Oregon, and Washington. The Governor of California, the State Legislature, the Counties of Santa Barbara and San Luis Obispo, the Cities of Los Angeles and Malibu and a host of environmental groups have all voiced opposition to any offshore oil and gas leasing and development. Since the 1970's, the state, environmental groups, California Coastal Commission, and other parties have filed legal challenges concerning OCS activities. Opposition to OCS activities offshore California is not limited to proposed new leasing. The State of California and others have filed legal challenges concerning existing undeveloped OCS leases offshore southern California. The lease owners have also filed lawsuits alleging breach of contract on those undeveloped leases. These undeveloped leases contain unproven reserves estimated to be 1 billion barrels of oil and more than 500 billion cubic feet of natural gas. The California Ocean Protection Council, established under the California Ocean Protection Act and charged with guiding ocean policy and coastal	In comments on the 5-Year Program RFI,* the States of California, Oregon and Washington all expressed support for moratoria. Additionally, 32 representatives, and both Senators from the State of California expressed strong opposition to any proposal to lift the moratorium or to allow states to "opt-out" of existing moratoria. They also oppose any effort to meet the inventory requirements of the Energy Policy Act of 2005.

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Regulatory and Administrative Programs and Processes		
	protection, "opposes any effort to lift the congressional moratorium on offshore oil and gas leasing activities" and as an action item indicates it plans to "pursue extinction of OCS leases." The California State Legislature has also been active on the offshore oil and gas issue. On March 29, 2005, the Assembly and Senate passed a joint resolution "requesting that Congress continue the federal offshore oil and gas leasing moratorium for fiscal year 2006 and beyond." Local government interest in offshore oil and gas leasing and development is largely confined to coastal communities. The Counties of Santa Barbara and San Luis Obispo have been most vocal on the issue of oil and gas leasing, with both counties adamantly opposed to lifting the existing moratoria.	
Offshore Alaska	As part of the consultative process in Alaska, stakeholders have raised objections and concerns to specific proposals for development of existing Federal OCS leases offshore Alaska. Impediments also include the extensive whale migration corridor withdrawn from leasing. In the Beaufort Sea, conflict with subsistence hunting of bowhead whales is a primary concern, whereas in the Cook Inlet area commercial fishing and recreation are significant. In Alaska, severe climate, weather and ice conditions provide significant technological challenges for oil and gas exploration, development, and transportation. Industry's capital and operating costs are much greater offshore Alaska than in other parts of the OCS and onshore.	BP Exploration (Alaska) Inc. has 2 development projects in the Beaufort Sea, near Prudhoe Bay. The Northstar Project began production in November 2001 from both state and Federal waters. The Liberty Project is again being considered by BP, but they have yet to provide a new development plan. Several other companies are considering seismic surveys in the Beaufort and Chukchi Seas. Additional exploratory drilling could lead to additional development in the Beaufort Sea and Cook Inlet areas. The DOI is working with all stakeholders to resolve their issues pursuant to pertinent laws and regulations. The DOI in Alaska has made a concerted effort to ensure cooperation among DOI agencies on projects, and that management in other agencies are aware of the need for timely evaluations. Royalty incentives could help offset the high cost of operating in Alaska and contribute to OCS development. In comments on the 5-Year Program RFI,* a number of environmental and recreation interest groups expressed concern about effects of offshore exploration and development on mammals, fisheries, subsistence activities, recreation activities, and ecological resources. Some of these commenters opposed leasing in some or all Alaskan OCS areas, some opposed lifting the moratoria for the North Aleutian Basin, while others supported analyses of areas to assess potential impacts and determine if leasing would be appropriate. One congressional comment and a number of local government organizations ask for continued protections for Native whaling.

Type of Impediment or Restriction	Description (including effects on domestic supply)	Comments
Regulatory and Administrative Programs and Processes		
9. Complex Regulatory Process	**West Coast:** There are numerous Federal, State, and local regulations, administered by agencies at different government levels, that are applicable to the offshore and onshore facilities used to develop, produce, process, and transport offshore-produced oil, gas, and related products. OCS development projects often involve related onshore facilities or operational modifications in state and local jurisdictional areas. The project applicant must therefore obtain numerous permits from Federal, state and local regulatory agencies. Federal agencies having regulatory jurisdiction over offshore oil and gas projects include the MMS, U.S. Army Corps of Engineers, the Environmental Protection Agency, U.S. Fish and Wildlife Service, and National Marine Fisheries Service. The state and local agencies having regulatory jurisdiction over the project include the California State Lands Commission, the California Department of Fish and Game, California Coastal Commission, County Planning and Development Departments, and County Air Pollution Control Districts.	The MMS is the lead Federal Agency for the OCS portion of projects and the County or the California State Lands Commission is typically the lead state agency for the near shore and onshore components of projects. To manage this effort and integrate any concerns of other regulatory agencies, a Joint Review Panel (JRP) is commonly formed to manage the environmental reviews and coordinate the permitting process. During the 1980's the JRP process was used successfully to coordinate environmental reviews and permitting of several large OCS oil and gas development projects. Because of strong opposition to offshore oil and gas development, it does not appear likely the JRP process would be a viable option for any proposed development projects that would involve construction of new oil and gas platforms and infrastructure on undeveloped OCS leases. The JRP process, however, may be a viable option to address any proposed new development projects that involve drilling extended reach wells from existing platforms into adjacent undeveloped OCS or state tidelands leases. There have been two recent proposals to develop oil and gas deposits located on state tidelands leases by drilling extended reach wells from existing OCS platforms. The MMS has discussed the possibility of forming JRPs with the California State Lands Commission and the Santa Barbara County Planning and Development Department to manage the environmental review and permitting process for these projects. The discussions are currently on hold due to proposed changes in the scope of the projects and requests for additional information from the project applicants.
	Offshore Alaska: Permitting offshore oil and gas activities in Alaska involves multiple authorizations from different Federal, state and local authorities with overlapping or conflicting requirements, unclear jurisdictional authorities and different review schedules and application formats. A single exploration well can take 2 years to permit. This has stifled industry investment in new exploration and development projects in the State of Alaska, both onshore and offshore.	Several efforts are underway to clarify and streamline the regulatory process within existing administrative and regulatory controls. These efforts include amendments to the State of Alaska's Coastal Zone Management Program which NOAA approved in December 2005 (and local plans are now being revised to reflect the new state standards), development and implementation of memorandums of agreements among regulatory authorities and applicants to clarify regulatory processes, preparation of programmatic NEPA documents to facilitate individual permit actions, and formation of cooperative working groups to develop guidelines and protocols for processing applications. The DOI agencies have been trying to clarify regulatory responsibilities up front on projects to eliminate any confusion. Cooperative agreements define each agency's duties and prevent duplication of efforts and requirements on operators and lessees. In the absence of such agreements, duplicate reporting requirements, conflicting regulations, and different agency regulations may place undue burdens on operators and lessees when different agencies regulate the same entities.

Type of Impediment or Restriction	Description (including effects on domestic supply)	Comments
Regulatory and Administrative Programs and Processes		
10. Effects of Implementing Other Laws and Programs on OCS Oil and Gas Activities; Lack of Clear Legal or Regulatory Requirements	Oil and gas activities can be affected by delays in the leasing and permitting processes. Such delays can raise project costs and risks, affecting if and when OCS resources can be developed. A number of laws other than the OCSLA also can affect OCS oil and gas development. Reviews of proposed activities required under laws like the National Environmental Policy Act (NEPA), the Coastal Zone Management Act (CZMA), the Endangered Species Act (ESA), the Marine Mammal Protection Act (MMPA), the Clean Air Act, and the Clean Water Act can cause significant delays in OCS pre-leasing activities and permit or plan approvals (examples of how impediments can occur under these other laws are discussed below). Some coastal states, environmental groups, and other parties have filed litigation against certain OCS activities under these laws.	Congress attempted to reduce the potential for litigation by amending the OCSLA and the Coastal Zone Management Act in 1978 to provide the coastal states and other parties with expanded opportunities for participation in the decision making process and a greater voice in the process. However, instead of reducing litigation, there actually has been increased litigation due to differing interpretations of the extent and scope of these laws, which has been an impediment to the OCS leasing program.
	Increased complexity/costs; Spamming in electronic public comments: For example, some NEPA documents, especially environmental impact statements, continue to grow in size and complexity. These extensive documents (multi-volumes) are extremely time consuming and costly to produce. Delays in governmental reviews and analyses can cause projects to be delayed and increase costs, possibly leading to withdrawal of applications. Agencies also are experiencing growing numbers of "spam" comments via e-mail, websites, and fax, which cannot always be processed within a reasonable NEPA process timeframe, and thus have the potential to delay or increase energy project costs.	"Modernizing NEPA Implementation," the NEPA Task Force Report to the Council on Environmental Policy, was published in September 2003. The report provides recommendations to promote consistent, clear, cost-effective NEPA documents that meet agency and stakeholder needs. The U.S. Congress and the Administration could assist and support agencies in implementing appropriate recommendations from the report, and by ensuring that the law and implementing regulations promote completion of environmental documents in a timely and cost-effective manner while meeting the goals of NEPA. In commenting on the 5-Year Program RFI,* one industry letter suggested eliminating the EIS for the 5-Year Program and only completing EISs for each lease sale.
	Uncertain requirements and conflicting timelines in review processes: For example, under the CZMA, states review certain proposed OCS activities for consistency with their coastal zone management plans. If a state finds the activity to be inconsistent, the activity cannot proceed unless the Secretary of Commerce overrules the state after a company appeal. This process can stop or delay OCS activities.	One of the recommendations of the President's National Energy Policy (NEP) was to re-examine the current federal legal and policy regime to determine if changes are needed regarding energy-related activities and the siting of energy facilities in the coastal zone and on the OCS. A DOI and Department of Commerce (DOC) interdepartmental working group identified possible amendments to the regulations where changes were needed to provide greater clarity and predictability. The DOC published a final rule on January 5, 2006. The DOI will continue to work in partnership with NOAA and coastal states to further streamline and improve coordination on CZMA and other statutory matters.

Type of Impediment or Restriction	Description (including effects on domestic supply)	Comments
Regulatory and Administrative Programs and Processes		
	Incompatible timeframes between complementary statutory requirements: For example, under the ESA, the DOI consults with NOAA-Fisheries and the U.S. Fish and Wildlife Service to ensure that OCS activities will not cause any protected species to be jeopardized by activities associated with the exploration for and development and production of oil or gas. The DOI requires stipulations as part of lease terms and conditions for Alaska and the GOM to avoid potential adverse impacts to protected species. For example, stipulations address aircraft overflight restrictions, vessel collision avoidance, trash and debris avoidance and awareness and lighting protocols. If ESA consultations include marine mammals and the biological opinion indicates anticipated incidental take of marine mammals, then the action agency and OCS lessees and operators are not exempt from the prohibitions of ESA until an MMPA incidental take authorization is obtained (which could take 6 months to several years). In the meantime, OCS lessees and operators must decide to weigh the risk of conducting activities with the risk for a potential take. Many operators and lessees are not willing to risk the potential for incidental take with the potential for violating the ESA. This impedes OCS activities even if the MMS requires protective measures to avoid or minimize the potential for incidental take.	To facilitate compliance with the integrated nature of the ESA and MMPA, some have suggested that Congress could amend the MMPA or the ESA or both to reduce the conflict between timelines associated with the Acts.
	Social conflicts over the extent and use of best available science: For example, the potential for acoustic impacts on marine mammals is a new issue affecting OCS activities. Oil and gas resource inventories and exploration activities, specifically seismic survey activities, are now controversial because that activity generates loud, low-frequency sound in the water column. There is not yet sufficient scientific data to document impacts on marine mammals or other marine organisms. Recent concerns on the impact of these operations on marine life, and marine mammals in particular, have led to increasing numbers of lawsuits and restrictions on seismic exploration. Under the MMPA, Federal agencies must err on the side of caution, which has impacted how and whether seismic surveys are conducted. The purpose of the MMPA is to protect marine mammals and the primary goal is optimal sustainable population levels. However, the focus of the implementing regulations is at the level of protecting the individual (from taking/harassment).	Regulatory requirements for protection of marine species should be based on the best available science, and balance the need for protection with the need for maintaining a domestic energy program. Lease stipulations and operational measures should be practical, cost effective, and aimed to achieve minimal delays in ongoing operations. Adaptive management practices can be used to modify or adjust restrictions while ensuring adequate resource protection. To clarify legal requirements and help facilitate oil and gas exploration (and seismic surveys in particular), Congress could amend the MMPA to give industry activities the same language for "takes" as suggested by the National Research Council (NRC 2000). The MMS is working closely with NOAA to achieve prompt and efficient consultations under the ESA and rulemakings under the MMPA in order to achieve consistent operating conditions for OCS activities. To help streamline reviews, the MMS will work with NOAA on a process for activity-based consultations for OCS activities in the GOM.

Type of Impediment or Restriction	Description (including effects on domestic supply)	Comments
Regulatory and Administrative Programs and Processes		
	Extent of Restrictions In or Near Protected Areas: The presidential withdrawal by President Clinton in 1998 withdrew from new leasing all National Marine Sanctuaries indefinitely. Existing activities within sanctuaries are governed by individual management plans and regulations that can severely restrict oil and gas operations. Any updates of the management plans or regulations, or decisions to expand sanctuary boundaries can affect nearby OCS leases and oil and gas development. Pipeline laying and any new platform construction could be severely restricted or not permitted within expanded sanctuary boundaries. Routine oil and gas operational discharges could also be potentially prohibited within or adjacent to the sanctuaries.	
11. OCS Lease Terms and Conditions	OCS leases contain various terms, conditions, and stipulations that govern development of the oil and gas resources on the lease. These conditions are meant to protect the environment and ensure safety of operations, and ensure that resources are properly developed and provide a fair return to the public.	The MMS does not consider existing lease stipulations and approval conditions to be an impediment to OCS oil and gas development because many of the requirements are derived from implementing laws or from the consultation process, and so have facilitated development because they were critical to obtaining Federal, state and local approvals. None are considered so onerous that they would constitute an impediment to development. Such requirements are generally understood by industry and the public to be legitimate operational conditions. The MMS continues to consult with stakeholders to assess opportunities to improve lease terms and its regulations.
Military Stipulations	**Offshore California:** The coastal waters offshore southern California are used intensively for military-related operations. The majority of these operations are conducted in the Point Mugu Sea Range which is a 36,000 square mile area of ocean and controlled air space that extends from 3 to 180 nautical miles offshore San Luis Obispo County, Santa Barbara County, Ventura County and Los Angeles County. There are a total of 23 OCS platforms located offshore these counties. To minimize the potential for conflict between military and oil and gas operations, the MMS has attached military stipulations to OCS leases. The stipulations: (1) require that all vessel and aircraft traffic within designated Military Warning Areas be coordinated with the U.S. Air Force and the U. S. Navy; (2) authorize the U.S. Government to temporarily suspend offshore oil and gas operations and require evacuation of personnel in the interests of national security; (3) require lessees to control electromagnetic emissions so as not to interfere with military operations, and; (4) limit the liability and hold the U.S. Government harmless from any damage or injury resulting from the programs and operations of the military.	Military and oil and gas operations have co-existed in the Point Mugu Sea Range for more than 40 years. During that time, no military operations have been delayed, disrupted, or cancelled due to conflicts with oil and gas operations. In addition, there have been no accidents (vessel or aircraft collisions, deaths, or serious injuries) involving oil and gas operations on the Sea Range. Several OCS platforms located offshore Vandenberg Air Force Base have been occasionally directed to follow sheltering and evacuating procedures during missile launches. These procedures have not caused major disruptions in platform operations.

Type of Impediment or Restriction	Description (including effects on domestic supply)	Comments
Regulatory and Administrative Programs and Processes		
	Gulf of Mexico: For lease sales in all planning areas of the GOM, the "Military Areas" stipulation has long been used to implement "Hold and Save Harmless," "Electromagnetic Emissions" and "Operational" requirements designed to protect lessees and operators from military activities in established military warning and test areas. In addition to that stipulation, specific other military requirements are developed and implemented on a case-specific basis. For example, in the Western GOM, the "Operations in the Naval Mine Warfare Area" stipulation is currently used to prevent oil and gas lessees and operators from interfering with scheduled mine warfare testing activity. In the eastern GOM, special discussions between the MMS and Eglin Air Force Base officials have occurred and related stipulations have been developed for the purpose of insuring no conflicts arise between military activities in that area and potential oil and gas lessees and operators. In the eastern GOM, such stipulations either adopted or considered for adoption range from additional coordination requirements to exploration drilling window requirements to sub-seafloor development requirements. Also, deferral of blocks east of the 86 degree 41 minute north longitude line from future oil and gas leasing is a standing Department of Defense position at this time. In all cases to date, coordination and consultation between the GOM Region and military counterparts in the GOM Region have been successful in developing deferrals or stipulations which address both the MMS and DOD needs.	Military access historically has been an issue in the GOM. The MMS and the Department of Defense (DOD) regularly communicate on access and operational restrictions on leases in areas also used by DOD. MMS has a Memorandum of Agreement with DOD to address joint use issues on the OCS. The MMS will continue to work with DOD as needed to address future issues on a sale-by-sale basis. The MMS and DOD have successfully resolved any program conflicts that have arisen to date. In comments on the 5-Year Program RFI,* one company asked that more work be done to find a way for multiple uses to co-exist on the OCS—it opposes overly restrictive stipulations, such as subsea-only requirements or drilling windows for Naval operations in the Gulf.
Oil Transportation Stipulations	**Offshore California:** The MMS has placed oil transportation stipulations on OCS leases that require hydrocarbon products to be shipped by pipeline if: (1) pipeline right-of-ways can be obtained; (2) pipeline installation is technologically feasible and environmentally preferable, and; (3) in the opinion of the lessor, pipelines can be installed without net social loss, taking into account any incremental costs of pipelines over alternative methods of transportation and any incremental benefits in the form of increased environmental protection or reduced multiple-use conflicts. In addition, following the development of sufficient pipeline capacity, no crude oil production will be transported by surface vessels from offshore production sites, except in case of emergency. The MMS lease stipulations were developed, in part, to address state and local concerns that large oil spills could result if oil tankers or barges were to collide with other vessels or be lost at sea.	The MMS oil transportation stipulations have not posed an impediment to OCS oil and gas development. Since the lease stipulations were imposed in the early to mid-1980's, two major common carrier pipelines, the All American and Pacific Pipelines, have been constructed with capacity to transport large volumes of heavy crude oil to refineries in Los Angeles. The All American Pipeline now also connects, via the Sisquoc Pipeline, into northbound pipelines to refineries in the San Francisco Bay area. Consequently, the existing pipeline capacity is more than adequate to carry current and anticipated offshore production.

Type of Impediment or Restriction	Description (including effects on domestic supply)	Comments
Regulatory and Administrative Programs and Processes		
LNG stipulations (to address safety fairways and surface occupancy)	With increasing demand for natural gas, the Nation is turning to importation of liquefied natural gas (LNG) from the Middle East, Africa and elsewhere, which can now be done competitively by tankering. LNG terminals, both onshore and offshore, will continue to be built to handle these ships. To support the increased need for LNG imports, and for safety and efficiency reasons, many LNG terminals are proposed to be located on the OCS with some terminals using existing OCS infrastructure such as pipelines and platforms. Proposals also call for the creation of caverns in salt domes to store regasified LNG. There are some potential conflicts with OCS oil and gas development associated with the siting of deepwater port terminals on the OCS. The OCS is currently home to about 8,400 leases (covering about 46 million acres), more than 4,000 fixed and floating oil and gas production facilities and more than 37,000 miles of pipeline infrastructure. Deepwater port applicants seek locations in close proximity to pipeline infrastructure, which is incidentally near fixed oil and gas facilities. They also look for unobstructed access to designated shipping fairways. Such locations place deepwater port terminals in locations where proposed tanker routes will be required through non-traditional shipping lanes. With tanker volumes expected to increase from the current standard of 138,000 cubic meters to over 250,000 cubic meters, vessels will require more maneuvering room. To accommodate these needs, both domestic laws and international maritime conventions are being used by the U.S. Coast Guard to create enforceable safety zones and unenforceable precautionary notice areas and anchorage areas, all of which, unless decidedly precise, can encroach on existing OCS oil and gas leases.	The MMS establishes appropriate rentals for use of the seabed for deepwater port LNG facilities and has been assisting the U.S. Coast Guard and the Maritime Administration in reviewing LNG port applications, ensuring that information on the ocean environment, multiple use, safety, and, OCS oil and gas exploration, development, and production activities are fully integrated into the plan approval process. The Coast Guard and MARAD have received 12 applications for LNG licenses, 3 of which have already been approved. Any restrictions on OCS activities that may result from deepwater port placement and/or the perception of increased risks from LNG import activities can potentially impact OCS oil and gas investment decisions and development. For recent lease sales in the GOM, MMS has included a lease stipulation that advises potential lessees about limitations on oil and gas use of the seabed and water column in the vicinity of an approved offshore LNG deepwater port receiving terminal on Vermilion Area Blocks 139 and/or 140. This stipulation specifically addressed the Port Pelican LNG project needs as they are known at this time. Since this project is still in development, the stipulation includes an 800-meter oil and gas exclusion area around the proposed project location as currently described. Once the project is installed, the stipulation calls for the exclusion zone to be reduced to a 500 meter area around the outermost points of the actually emplaced facility. The two LNG projects, BHP Billiton's Cabrillo Point Deepwater Port Project and Crystal Energy LLC's Clearwater Deepwater Port Project, that have been proposed offshore Los Angeles County and Ventura County are not expected to pose an impediment to OCS oil and gas development. The safety fairways for the proposed projects do not overlap development prospects on existing OCS leases. The Federal agencies must continue to work together on the development of projects in Federal offshore waters to ensure compliance with the respective regulatory authorities, that rights of lease holders are not violated, that domestic energy exploration and production activities are not impeded, and that the highest levels of safety and environmental protection are maintained. In comments on the 5-Year Program RFI,* a number of industry commenters noted that OCS activities have coexisted with many other ocean based industries for decades and they believe this co-

Type of Impediment or Restriction	Description (including effects on domestic supply)	Comments
Regulatory and Administrative Programs and Processes		
		existing relationship can continue. One company asked that more work be done to find a way for multiple uses to co-exist on the OCS—it opposes overly restrictive stipulations, such as subsea-only requirements or drilling windows for Naval operations in the Gulf. The State of Florida suggested that any activities that would interfere with military defense or NASA activities be prohibited in the Program.
12. Local Zoning and Other Restrictions on Onshore Processing Facilities and Pipeline Landings [Local Government Land Use Restrictions/Policies]	OCS activities cannot occur without onshore support facilities, such as ports and processing plants. Potential impediments include: Siting of onshore support facilities, which must meet all Federal, state, and local permitting requirements. This is of particular concern in California and Florida. States that support OCS activities have sought long-term coastal impact assistance to help address infrastructure issues that arise with increased OCS activities, including impacts on port facilities, highways, and water systems along the Gulf coast.	The Energy Policy Act of 2005 provides for $1 billion over 4 years (2007-2010) to be used to fund coastal impact assistance programs in 6 states and local communities directly affected by OCS-related activity. The states could use the funds to address infrastructure and environmental issues associated with OCS development.
	Gulf of Mexico: There are no specific local ordinance issues identified that block OCS development. Lack of sufficient infrastructure in some OCS areas may impede development (possible revenue sharing issue).	
	Offshore California: Beginning in 1985, numerous California cities and counties enacted ordinances that either bar the construction of onshore support facilities for offshore oil and gas development or subject the approval of such facilities to a vote by local citizens. By the end of 1988, 15 cities and 9 counties had passed such onshore support facility ordinances. The majority of OCS production offshore California is produced from OCS leases located offshore Santa Barbara County, Ventura County, and San Luis Obispo County. In 1996, voters in Santa Barbara County approved Measure A76 which prohibits the development, construction, installation or expansion of any onshore support facility to support offshore development along the south coast of the county unless approved by a majority vote of local citizens. In 1998, the voters of Ventura County approved a county initiative to protect open-space and agricultural resources from commercial development and other uses, including oil and gas development facilities. The initiative known as SOAR requires that until 2020, changes in land use designations be subject to a vote of the people. San Luis Obispo County and the City of San Luis Obispo have also passed County measures	Some have suggested that Congress could enact legislation that would encourage or direct military bases to authorize construction of oil and gas infrastructure (processing facilities, pipelines, refineries, etc.) that can support development of OCS oil and gas resources (e.g. Vandenberg Air Force Base and Camp Pendleton on the West Coast). Other proposals have suggested that closed military bases could become potential sites for refinery development.

Type of Impediment or Restriction	Description (including effects on domestic supply)	Comments
Regulatory and Administrative Programs and Processes		
	(Measure A) and municipal codes which prohibit the authorization or permitting of any onshore support facility for offshore oil and gas unless such authorization is approved by a vote of the people.	
	Offshore Alaska: The North Slope Borough (NSB) is proposing amendments to its Title 19 land use regulations. Although the draft regulations do not apply directly to OCS activities, they will affect any OCS development that requires onshore support facilities. As currently proposed, the draft regulations could cause problems for OCS oil and gas activity unless technical standards and requirements are clarified and duplication with existing regulatory authorities is eliminated.	The DOI supports the NSB's desire to develop land use regulations that will protect the long-term interests of borough residents while serving the resource development needs of Alaska and the country. The NSB has postponed consideration of its Title 19 land use regulations pending new appointments.

Appendix B: Glossary

The glossary defines relevant terms in a general rather than in a strictly technical way.

API gravity: An arbitrary scale expressing the gravity or density of liquid petroleum products. The measuring scale is calibrated in terms of degrees API. The higher the API gravity, the lighter the fluid.

Appreciation: Analogous to reserves appreciation. See "reserves."

Assessment: The estimation of potential amounts of technically recoverable hydrocarbon resources.

Associated gas: See "gas, natural."

Barrel: A volumetric unit of measure for crude oil equivalent to 42 U.S. gallons.

Barrel of oil-equivalent (BOE): The sum of gas resources, expressed in terms of their energy equivalence to oil, plus the oil volume. The conversion factor of 5,620 standard cubic feet of gas equals 1 BOE is based on the average heating values of domestic hydrocarbons.

Chance: See "probability" or "risk."

Condensate: Hydrocarbons, associated with saturated gas that are present in the gaseous state at reservoir conditions, but produced as liquid hydrocarbons at the surface.

Conditional estimates: Sizes, numbers, or volumes of oil or natural gas accumulations that are estimated to exist in an area, assuming that they are present. Conditional estimates, therefore, do not incorporate the risk that the area may be devoid of oil or natural gas.

Continental margin: The composite continental rise, continental slope, and continental shelf as a single entity. The term, as used in this report, applies only to the portion of the margin whose mineral estate is under Federal jurisdiction; geographically synonymous with Outer Continental Shelf (OCS).

Continental shelf: The shallow, gradually sloping zone extending from the shoreline to a depth at which there is a marked steep descent to the ocean bottom.

Continental slope: The portion of the continental margin extending seaward from the continental shelf to the continental rise or ocean floor.

Conventionally recoverable: Producible by natural pressure, pumping, or secondary recovery methods, such as gas or water injection.

Cumulative probability distributions: A distribution showing the probability of a given amount or more occurring. These distributions include the values for the resource estimates presented throughout this report: a low estimate having a 95-percent probability (19 in 20 chance) of at least that amount (F_{95}), a high estimate having a 5-percent probability (1 in 20 chance) of at least that amount (F_5), and a mean estimate representing the average of all possible values. These distributions are often referred to as S-curves.

Cumulative production: The sum of all produced volumes of hydrocarbons prior to a specified point in time.

Deterministic: A process in which future states can be forecast exactly from knowledge of the present state and rules governing the process. It contains no random or uncertain components.

Development: Activities following exploration, including the installation of production facilities and the drilling and completion of wells for production.

Development systems: Basic options used in constructing OCS permanent production facilities.

Compliant tower: An offshore facility consisting of a narrow, flexible tower and a piled foundation that can support a conventional deck for drilling and production operations. Unlike the fixed platform, the compliant tower withstands large lateral forces by sustaining significant lateral deflections and is usually used in water depths between 1,500 and 3,000 feet.

Fixed platform: An offshore facility consisting of a jacket (a tall vertical section made of tubular steel members supported by piles driven into the seabed) with a deck placed on top, providing space for crew quarters, drilling rigs, and production facilities. The fixed platform is economically feasible for installation in water depths up to about 1,650 feet.

Floating production system (FPS): An offshore facility consisting of a semi-submersible which is equipped with drilling and production equipment. It is anchored in place with wire rope and chain or can be dynamically positioned using rotating thrusters. Wellheads are located on the ocean floor and are connected to the surface deck with production risers designed to accommodate platform motion. Floating production systems can be used in water depths ranging from 600 to 6,000 feet.

Mini-tension leg platform (mini-TLP): An offshore facility consisting of a floating mini-tension leg platform of relatively low cost developed for production of smaller deepwater reserves which would be uneconomic to produce using more conventional deepwater production systems. It can also be used as a utility, satellite, or early production platform for larger deepwater discoveries. Mini-TLPs can be used in water depths ranging from 600 to 3,500 feet.

SPAR: An offshore facility consisting of a large diameter vertical cylinder supporting a deck. It has a typical fixed platform topside (surface deck with drilling and production equipment), three types of risers (drilling, production, and export), and a hull which is moored using a taut catenary system of 6 to 20 lines anchored into the sea floor. SPAR's are presently used in water depths up to 3,000 feet, although existing technology can extend this to about 10,000 feet.

Subsea system (SS): An offshore facility ranging from single subsea wells producing to a nearby platform, floating production system, or tension leg platform to multiple wells producing through a manifold and pipeline system to a distant production facility. These systems are now used in water depths up to 7,000 feet, although existing technology can extend this to about 10,000 feet.

Tension leg platform (TLP): An offshore facility consisting of a floating structure held in place by vertical, tensioned tendons connected to the sea floor by pile-secured templates. Tensioned tendons provide for use of the tension leg platform in a broad water depth range and for limited vertical motion. Tension leg platforms can be used in water depths up to about 6,000 feet.

Dissolved gas: See "gas, natural."

Economic analysis: An assessment performed in order to estimate the portion of the undiscovered conventionally recoverable resources in an area that is expected to be commercially viable in the long term under a specific set of economic conditions.

Economic risk: See "risk."

Economically recoverable resources: See "resources."

Exploration: The process of searching for minerals prior to development. Exploration activities include geophysical surveys, drilling to locate hydrocarbon reservoirs, and the drilling of delineation wells to determine the extent and quality of an existing discovery prior to a development decision.

Field: A producible accumulation of hydrocarbons consisting of a single pool or multiple pools related to the same geologic structure and/or stratigraphic condition. In general usage this term refers to a commercial accumulation.

Fixed platform: See "development systems."

Floating production system: See "development systems."

Frequency: The number of times an indicated event occurs within a specified interval.

Gas, natural: A mixture of gaseous hydrocarbons (typically methane with lesser amounts of ethane, propane, butane, pentane, and possibly some nonhydrocarbon gases).
Associated gas: Natural gas that occurs in crude oil reservoirs as free gas (gas cap).

Dissolved gas: Natural gas that occurs as gas in solution within crude oil reservoirs.
Nonassociated gas: Natural gas that occurs in reservoirs not in contact with significant quantities of crude oil.

Geologic risk: See "risk."

Growth factor: A function used to calculate an estimate of a field's size at a future date. Growth factors reflect technology, market, and economic conditions existing over the period spanned by the estimates.

Annual growth factor: The function representing the ratio of the size of a field of a specific age as estimated in a subsequent year.

Cumulative growth factor: The function representing the ratio of the size of a field a specific number of years after discovery to the initial estimate of its size in the year of discovery.

Hydrocarbon maturation: The process by which organic material trapped in source rocks is transformed naturally by heat and pressure through time and depth of burial into oil and/or gas.

Hydrocarbons: Any of a large class of organic compounds containing primarily carbon and hydrogen. Hydrocarbons include crude oil and natural gas. As used in this report the term is synonymous with petroleum.

Marginal probability of hydrocarbons (MPhc): An estimate, expressed as a decimal fraction, of the chance that an oil or natural gas accumulation containing technically recoverable quantities of hydrocarbons exists in the area under consideration. The area under consideration is typically a geologic entity, such as a reservoir, prospect, play, basin, or province; or a large geographic area such as a planning area or region. All estimates presented in this report reflect the probability that an area may be devoid of technically recoverable hydrocarbons.

Mean: A statistical measure of central tendency; the arithmetic average or expected value, calculated by summing all values and dividing by the number of values

Model: A geologic hypothesis expressed in mathematical form.

Minimum economic field size (MEFS): The smallest field size that will generate income sufficient to cover expenses and yield a prescribed minimum rate-of-return.

Monte Carlo simulation: A method of approximating solutions of problems by iterative sampling from simulated random or pseudo-random processes.

Nonassociated gas: See "gas, natural."

Oil, crude: A mixture of hydrocarbons that exists naturally in the liquid phase in subsurface reservoirs.

Outer Continental Shelf (OCS): The continental margin, including the shelf, slope, and rise, beyond the line that marks the boundary of state ownership; that part of the seabed under Federal jurisdiction.

Petroleum: A collective term for oil, gas, and condensate.

Planning area: A subdivision of an offshore area used as the initial basis for considering blocks to be offered for lease in the Department of the Interior's OCS oil and gas leasing program.

Play: A group of known and/or postulated pools that share common geologic, geographic, and temporal properties, such as history of hydrocarbon generation, migration, reservoir development, and entrapment.

Probability: A means of expressing an outcome on a numerical scale that ranges from impossibility to absolute certainty; the chance that a specified event will occur.

Prospect: A geologic feature having the potential for trapping and accumulating hydrocarbons; a pool or potential field.

Proved reserves: See "reserves."

Recoverable resources: See "resources."

Region: A very large expanse of acreage usually characterized or set apart by some aspect such as a political division or area of similar geography. In this report, the regions are groupings of planning areas.

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.

Proved reserves: The quantities of hydrocarbons estimated with reasonable certainty to be commercially recoverable from known accumulations and 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 appreciation: The observed incremental increase through time in the estimates of reserves of an oil and/or gas field. It is that part of the known resources over and above proved and unproved reserves that will be added to existing fields through extension, revision, improved recovery, and the addition of new reservoirs. Also referred to as reserves growth or field growth.

Unproved reserves: Quantities of hydrocarbon reserves 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 being classified as proved.

Estimated ultimate recovery (EUR): All hydrocarbon resources within known fields that can be profitably produced using current technology under existing economic conditions. Estimates of ultimate recovery equal the sum of cumulative production, proved reserves, unproved reserves and reserves appreciation.

Reservoir: A subsurface, porous, permeable rock body in which an isolated accumulation of oil and/or gas is stored.

Resource assessment: The estimation of potential amounts of recoverable resources. The focus is normally on conventionally or technically recoverable hydrocarbons.

Resources: Concentrations in the earth's crust of naturally occurring liquid or gaseous hydrocarbons that can conceivably be discovered and recovered. Normal use encompasses both discovered and undiscovered resources.

Recoverable resources: The volume of hydrocarbons that is potentially recoverable, regardless of the size, accessibility, recovery technique, or economics of the postulated accumulations.

Technically recoverable resources: The volume of hydrocarbons that may be produced from a wellbore as a consequence of natural pressure, artificial lift, pressure maintenance (gas or water injection), or other secondary recovery methods. They do not include quantities of hydrocarbon resources that could be recovered by enhanced recovery techniques, gas in geopressured brines, natural gas hydrates, or oil and gas that may be present in insufficient quantities or quality (low permeability "tight" reservoirs) to be produced via conventional recovery techniques.

Economically recoverable resources: The volume of technically recoverable resources that is potentially recoverable at a profit after considering the costs of production and the product prices.

Undiscovered resources: Resources postulated, on the basis of geologic knowledge and theory, to exist outside of known fields or accumulations. Included also are resources from undiscovered pools within known fields to the extent that they occur within separate plays.

Undiscovered technically recoverable resources (UTRR): Resources in undiscovered accumulations analogous to those in existing fields producible with current recovery technology and efficiency, but without any consideration of economic viability. These accumulations are of sufficient size and quality to be amenable to conventional primary and secondary recovery techniques. Undiscovered conventionally recoverable resources are primarily located outside of known fields.

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

Risk: The chance or probability that a particular event will not occur; the complement (1.00 - MP_{hc}) of marginal probability or success.

Economic risk: The chance that no commercial accumulation of hydrocarbons will exist in the area under consideration (e.g., prospect, play, or area). The chance that an area may not contain hydrocarbons or the volume present may be noncommercial is incorporated in the economic risk.

Geologic risk: The chance that technically recoverable volumes of hydrocarbons will not exist in the area under consideration (e.g., prospect, play, basin or area). The commercial viability of an accumulation is not a consideration.

Risked (unconditional) estimates: Resource volumes that are estimated to exist, incorporating the possibility that the area may be devoid of technically recoverable volumes of oil or natural gas. Statistically, the risked mean value may be determined through multiplication of the mean of a conditional distribution by the related marginal probability of occurrence.

Seal: Impervious rocks that form a barrier to migrating hydrocarbons above, below, and/or lateral to the reservoir rock.

Source rock: A sedimentary rock, commonly a shale or carbonate, whose organic matter has been transformed naturally by heat and pressure through time and depth of burial into oil and/or gas. This transformation is referred to as generation or maturation.

SPAR: See “development systems.”

Stochastic: A process in which each observation possesses a random variable.

Subjective judgment: A technique utilized to assign probabilities of occurrence to possible events when all of the possible outcomes of an event are not known and when the frequency of recognized outcomes cannot be estimated with certainty; often referred to as expert opinion.

Subsea system: See “development systems.”

Tension leg platform: See “development systems.”

Total endowment: All conventionally recoverable hydrocarbon resources of an area. Estimates of total endowment equal the sum of undiscovered technically recoverable resources, cumulative production, proved reserves, unproved reserves and reserves appreciation.

Trap: A barrier to hydrocarbon migration that allows oil and gas to accumulate in a reservoir.

Stratigraphic trap: A trap that results from changes in the lithologic character of a rock.

Structural trap: A trap that results from folding, faulting, or other deformation of a rock.

Uncertainty: Imprecision in estimating the value (or range of values) for a variable.

Undiscovered economically recoverable resources (UERR): See “resources.”

Undiscovered resources: See “resources.”

Undiscovered technically recoverable resources (UTRR): See “resources.”

Unproved reserves: See “reserves.”

Appendix C: Abbreviations, Acronyms, and Symbols

AAPG	American Association of Petroleum Geologists
AASG	Association of American State Geologists
AGA	American Gas Association
API	American Petroleum Institute
Bbls	billion barrels
Bbo	billion barrels of oil
Bcfgpd	billion cubic feet per day
BBOE	billion barrels of oil-equivalent
BOE	barrels of oil-equivalent
CAA	Clean Air Act
CDP	common depth point
CWA	Clean Water Act
CZMA	Coastal Zone Management Act
DOE	Department of Energy
DOI	Department of the Interior
E&P	exploration and production
EIA	Energy Information Administration
ESA	Endangered Species Act
F_5	5th percentile, a 5-percent probability (a 1 in 20 chance) of there being more than that amount
F_{95}	95th percentile, a 95-percent probability (a 19 in 20 chance) of there being more than that amount
FY	Fiscal Year
G&G	geological and geophysical
GOM	Gulf of Mexico
GRASP	Geologic Resource Assessment Program
HPF	Historic Preservation Fund
LNG	liquefied natural gas
LWCF	Land and Water Conservation Fund

Mcf	thousand cubic feet
MEFS	minimum economic field size
MMbo	million barrels of oil
MMBOE	million barrels of oil-equivalent
MMbopd	million barrels of oil per day
MMPA	Marine Mammal Protection Act
MMS	Minerals Management Service
MP_{hc}	marginal probability of hydrocarbons
MPP	massively parallel processor
NAS	National Academy of Sciences
NEP	National Energy Plan
NEPA	National Environmental Policy Act
NOAA	National Oceanic and Atmospheric Administration
OCS	Outer Continental Shelf
OCSLA	Outer Continental Shelf Lands Act
PETRIMES	Petroleum Exploration and Resource Evaluation System
PRESTO	Probabilistic Resource Estimates Offshore
RFI	Request for Information
SPE	Society of Petroleum Engineers
SPR	Strategic Petroleum Reserve
Tcf	trillion cubic feet
Tcfg	trillion cubic feet of gas
UERR	undiscovered economically recoverable resources
UTRR	undiscovered technically recoverable resources
U.S.	United States
USCG	U.S. Coast Guard
USGS	U.S. Geological Survey

Appendix D: References

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