4. Offshore Development and Production

Natural gas production in the Federal offshore has increased substantially in recent years, gaining more than 400 billion cubic feet between 1993 and 1997 to a level of 5.14 trillion cubic feet. Virtually all U.S. offshore production flows from the Outer Continental Shelf (OCS) of the Gulf of Mexico, which accounted for 27 percent of dry natural gas production from the Lower 48 States in 1997 and 18 percent of proved reserves. This trend is expected to continue, particularly as innovative technologies have improved the economics of offshore investment and opened up development in the deeper waters of the Gulf.

- Recoverable gas resources in the Gulf of Mexico (as of 1995) are estimated to be 96 trillion cubic feet (Tcf) in undiscovered fields with an additional 37 Tcf to be proven in already known fields. The ultimate volume and timing of recovery from these target volumes will depend on future economics and the evolving infrastructure.

- Industry success in the offshore, given the relatively low natural gas prices of the past 10 years, is due to achievements in cost management, reductions in project cycle time, and increases in well productivity.

- Fields in the deep water supplied only 3 percent of natural gas production from the Federal offshore in the Gulf of Mexico in 1997, but the average annual growth in deep-water gas production was 46 percent between 1990 and 1996.

- In 1989, the deep-water record for production was the Jolliet platform in 1,760 feet of water. This mark has been eclipsed by the Mensa project in more than 5,300 feet of water, which initiated production in July 1997. Mensa shattered the then-record for the Gulf of 3,214 feet held by the Ram-Powell tension leg platform.

- The Deep Water Royalty Relief Act (DWRRA), signed into law by President Clinton in November 1995, improved the economics of deep-water production. The fraction of blocks in water deeper than 800 meters (2,526 feet) receiving bids in 1994 was less than 10 percent of all bids for blocks in the Western and Central Gulf of Mexico, but by 1997, blocks at this water depth received more than half the bids. Bids for the deepest tracts offered in sale #169 for the Central Gulf of Mexico in 1998 remained stable, while bids for shallow-water tracts plummeted by more than 50 percent.

- Overall, offshore gas production from the Gulf of Mexico is expected to be between 3.7 and 7.2 trillion cubic feet by 2002. The key element in any outlook is the production trend for shallow-water fields, which is consistent with the relatively large volumes flowing from that region compared with the deep-water fields.

The near-term outlook for natural gas production from the offshore regions of the Lower 48 States depends on a number of factors, but primarily the prevailing economics. The relatively low oil and gas prices for much of 1998 have resulted in reduced drilling in the shallow waters of the Gulf. While this is of concern in the near term, gas supplies from the Gulf over the long term undoubtedly will be very large given the extremely large estimates of recoverable resource volumes.

The offshore regions of the Lower 48 States are an important source of domestic energy supplies. Production from Federal and State waters provided about 29 percent of total dry gas production in the Lower 48 States in 1997, with 95 percent of this total from the Outer Continental Shelf (OCS) of the Gulf of Mexico alone.[1] This situation stands in impressive contrast to expectations just two decades ago when the Gulf of Mexico was considered to be a mature oil and gas region with limited potential for further discovery and development. In fact, the region was

[1]Figures derived from *U.S. Crude Oil, Natural Gas, Natural Gas Liquids Reserves, 1997 Annual Report*, Energy Information Administration, DOE/EIA-0216(97) (Washington, DC, September 1998).

considered so lacking in promise that it was then called the "Dead Sea." A December 1973 report by the U.S. Department of the Interior stated that all potentially productive blocks in water depths up to 600 feet in the Federal Offshore Louisiana would be leased by 1978 and all exploration and development would be completed by 1985.[2] However, development of shallow prospects continued, and by the late 1980s and early 1990s improvement in existing technologies and the introduction of new technologies enabled the industry to access prospects in the deep-water areas[3] and the subsalt plays.[4]

The economics of deep-water activities has improved to the point that operators have continued with project development despite the recent downturn in prices for crude oil and natural gas, reflecting a very healthy and improving environment for oil and gas production and development. Deep-water fields require relatively long lead times for development and substantial capital investment even at an early stage, and they have relatively low operating costs. All of these factors encourage continued development and operation even though the prevailing economics may seem inadequate.

Although this chapter does not include an economic analysis of the impact of recent price declines, it appears the recent drop in oil and gas prices may have only a minimal impact on the long-term outlook for offshore production unless the low prices persist for an extended period. There has been some reduction in shallow-water drilling activity recently, but development of deep-water projects proceeds. The expected expansion of deep-water field production can help to offset declines in shallow-water operations, but shallow-water fields yield the vast portion of the gas total so some falloff may be expected.

This chapter analyzes recent production trends in the offshore Gulf of Mexico to provide an indicator of expected production levels from the shallow-water regions and from known deep-water fields. The economics of offshore projects is examined by reviewing and assessing trends in costs and productivity. The chapter also discusses the effect of environmental laws and regulations on offshore activities, especially as they pertain to deep-water operations.

The oil and gas industry has been active in the offshore regions of the United States throughout much of this century (see box, p. 93). During that time, the industry often found itself as a critical element in the ongoing debate regarding the best policy for managing offshore resources. Sometimes the goals of supplying energy and preserving water and air resources have been perceived as conflicting. In fact, over time, certain laws and Congressional or Presidential actions have limited activities in offshore areas or explicitly blocked them at least temporarily. At present, oil and gas drilling is prohibited along the entire U.S. East Coast, the west coast of Florida, and the U.S. West Coast except for some areas off the coast of southern California. Thus, today virtually all offshore activity is confined to the Gulf of Mexico, and offshore development can be considered almost synonymous with that of the Gulf.

Production from the Gulf of Mexico

The Federal offshore region of the Gulf of Mexico has become an increasingly important source of natural gas, accounting for nearly 27 percent of dry natural gas production in 1997. This is in sharp contrast to earlier years. Gas production in the mid-1950s from the Federal waters of the Gulf of Mexico was relatively small, with only 81 billion cubic feet (Bcf) produced in 1955, or less than 2 percent of the volume produced in the mid-1990s. Production surged dramatically after the mid-1950s, exceeding 1 trillion cubic feet in 1966 and achieving a then-record 4.99 trillion cubic feet in 1981 (Figure 30). After the surge in the early 1980s, offshore gas production declined until 1986, after which it gradually has grown to a record level of 5.14 trillion cubic feet in 1997.

The success in offshore production is expected to continue, but the recent downturn in economic conditions may hinder realization of production. Overall, offshore gas production

[2]U.S. Department of the Interior, Bureau of Mines, *Offshore Petroleum Studies Estimated Availability of Hydrocarbons to a Water Depth of 600 Feet from the Federal Offshore Louisiana and Texas Through 1985* (December 1973).

[3]For this report, *deep waters* pertain to water depths of greater than 1,000 feet (approximately 305 meters), which establishes the effective economic barrier between the use of fixed platforms and the new technology of the deep-water production systems. There are different regulatory requirements by the Minerals Management Service (MMS) for deep-water projects in depths of 1,000 feet or more. For example, operators have to file Deep Water Operating Plans with MMS for projects beyond 1,000 feet of water depth and for all subsea completions.

[4]About 85 percent of the continental shelf in the Gulf of Mexico is covered by salt deposits, comprising an extensive area for potential hydrocarbon development. The salt layers pose great difficulty in geophysical analysis and drilling through and below salt columns presents unique challenges.

Offshore Milestones

The oil and gas industry in 1997 celebrated the golden anniversary of a major milestone for activities in offshore waters. In 1947, Kerr-Mcgee, Stanolind, and Phillips Petroleum Company drilled the Kermac 16 in 20 feet of water in the Ship Shoal Block 32 field. This field is located 43 miles southwest of Morgan City, Louisiana. Other wells were drilled in water as early as 1905 in Southern California, but the Kermac 16 was the first well drilled out of the sight of land. Sixteen 24-inch piles supported the platform, which produced 1.4 million barrels of oil and 37 million cubic feet of gas. This platform produced until 1984.

Another milestone event for the Gulf of Mexico took place in 1953 when the first movable offshore drilling rig, called "Mr. Charlie," was built, which was a major advancement. That was also the year the State and Federal boundaries were defined according to the U.S. Submerged Land Act. The first offshore sale of oil and gas leases also was held in 1953. Other notable events after 1953 are as follows.

- The first semi-submersible drilling rig was launched by Shell in 1962.
- The first subsea production system was installed for Shell in 1972 in Main Pass Block 290.
- The Cognac Platform was installed for Shell in a record 1,025 feet of water in Mississippi Canyon block in 1979.
- In 1988, Shell installed the Bullwinkle platform, the world's tallest standing structure, to produce in 1,353 feet of water, and Placid Oil first used a floating production system in Green Canyon Block 29.
- In 1989, Conoco and Texaco established production at their Jolliet tension leg platform (TLP), located in 1,760 feet of water.
- The Deep Water Royalty Relief Act (DWRRA) was passed in 1995, which mandates royalty relief for certain leases in the Gulf of Mexico (the DWRRA is described in more detail later in the chapter).
- Production began in June 1998 from Shell's Mensa field in 5,376 feet of water, which established the then water-depth record for production. This project included a world record 68-mile subsea tieback to transport production to an existing platform in shallower water.

from the Gulf of Mexico is expected to range between 9 and 20 Bcf per day by the end of 2002, reflecting the considerable uncertainties involved. The near-term production outlook is affected greatly by recent development and the expected development of the inventory of waiting prospects. The expected volumes of recoverable natural gas resources are significant for the longer term. The Minerals Management Service published an estimate for total natural gas resources in the Federal waters of the Gulf of Mexico of 275 trillion cubic feet (Tcf), of which 95.7 Tcf remain as conventionally recoverable volumes in undiscovered fields as of January 1, 1995.[5] This bountiful endowment provides opportunities for sizeable gas supplies from this area in the longer term.

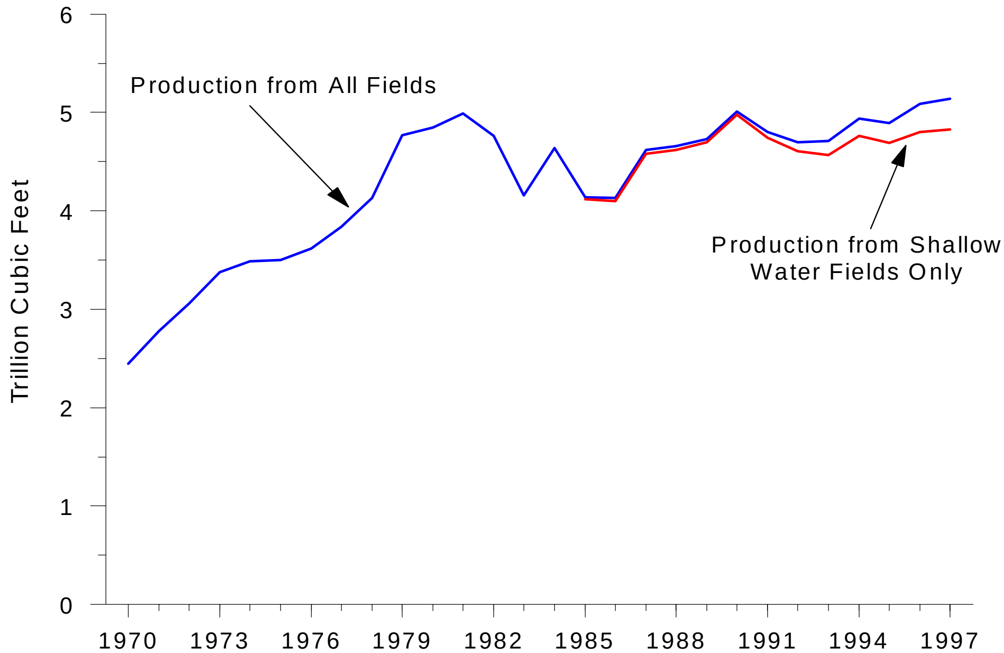
Factors Affecting Production

An important factor contributing to the recent production growth has been impressive technological advances, which over time have extended the industry's reach into areas previously inaccessible because of major technical and operational obstacles, such as deposits in waters greater than 1,000 feet in depth and subsalt deposits.[6] Despite these opportunities in more challenging locations, the major share of gas production to date has flowed from those deposits in shallow waters. Thus, the most fruitful application of new technologies, in terms of gas production, has been in maintaining or increasing flow from areas that already were subjected to considerable exploration and developmental

[5]Minerals Management Service, *Summary of the 1995 Assessment of Conventionally Recoverable Hydrocarbon Resources of the Gulf of Mexico and the Atlantic Outer Continental Shelf*, OCS Report MMS 96-0047 (January 1997).

[6]Subsalt accumulations can be found in structural traps below salt sheets or sills, which comprise an impermeable barrier that entraps the hydrocarbons in potentially commercial prospects.

Figure 30. Total Gas Production from Federal Waters of the Gulf of Mexico, 1970-1997



Sources: **1970-1992:** Minerals Management Service. **1993-1997:** Energy Information Administration, Office of Oil and Gas.

activity. Deep-water gas production, which was 143 Bcf in 1997, or 3 percent of Gulf of Mexico OCS production, remains a significant but limited fraction of the total. Subsalt prospects retain considerable promise for the future, but successes have been limited so far. While projects such as the Mahogany and Tanzanite fields are encouraging, the modest number of subsalt projects overall and the relatively slow pace of development are indicative of the obstacles that remain to be resolved.

The major factors affecting near-term offshore production include the availability and utilization of drilling rigs, trained personnel, and transportation capacity. The circumstances for these factors differ for the shallow- and deep-water areas.

Drilling Rigs

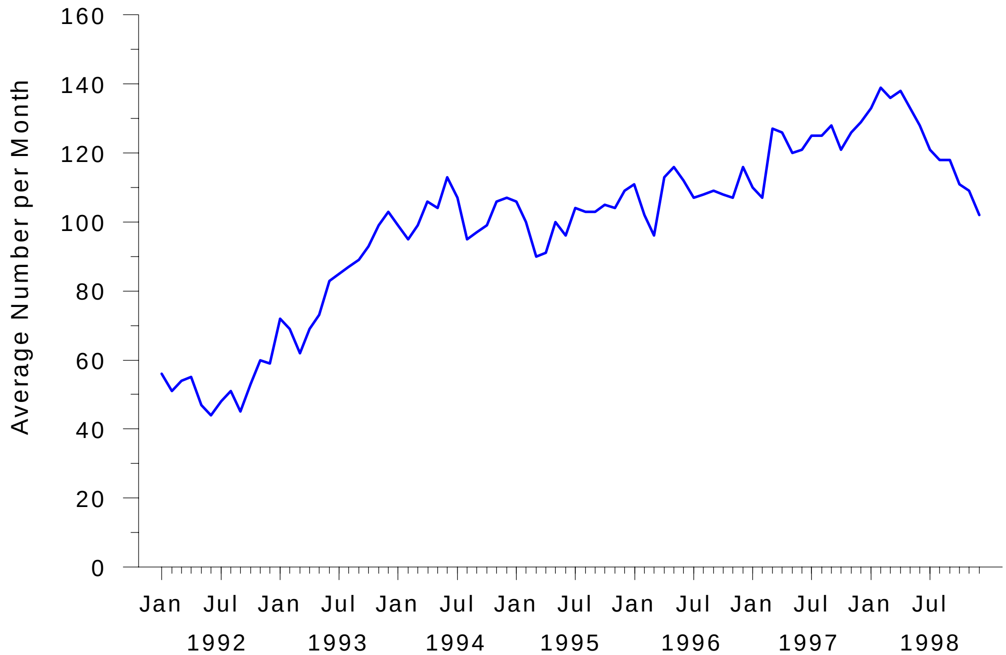
The number of drilling rigs employed in the offshore during the past few years has grown from an average of 52 in 1992 to 124 in 1998 (Figure 31). However, with the recent decline in prices for both natural gas and crude oil, the number of active rigs has declined 27 percent from the peak of 139 in February to 102 in December. The ratio of active to contracted rigs in the Gulf of Mexico (all depths) is at an all-time low.[7] One operator estimated that the cost for shallow-water rigs would decline by roughly 45 percent from mid year to the end of 1998.[8] Unfortunately these usually attractive costs are not expected to stimulate much additional industry activity given that they are being offered in an attempt to maintain activity levels. Utilization of deep-water rigs, however, remains at relatively high levels despite the decline in price for output.

Operators of deep-water projects appear to be proceeding with a longer-term planning horizon. Deep-water drilling rigs are generally under contract through 2001 or 2002, by which time prices may recover to levels comparable to those in recent years. These factors have contributed to continued development in deep waters, however, operators are not necessarily compelled to proceed aggressively. An operator with flexibility in project development may

[7]One reason for the idle contracted rigs is to avoid incurring the other variable costs associated with drilling.

[8]Karen Santos, "Less Jack for Rigs," *Houston Chronicle* (July 14, 1998).

Figure 31. Monthly Offshore Drilling Rigs, 1992-1998



Source: Energy Information Administration, *Monthly Energy Review* (various issues).

choose to extend a project's schedule, and planned projects that have not begun may be delayed until favorable economic conditions return or are expected to return. If such delays become common, the sequence of new production may not be timely enough to offset declines in regional production volumes. However, it appears likely at present that the industry is proceeding with deep-water development activity. The number of drilling rigs capable of operating in deep waters would be the constraining factor if interest in project development surged, because the inventory of available prospects is more than sufficient to utilize available equipment and personnel.

Before the recent falloff owing to low prices, the increase in drilling activities had created tight markets for rigs in the Gulf of Mexico, with signs of rig scarcity appearing regularly. Contracts for two Global Marine jack-up rigs in 1997 were secured within a week of the company announcement of their availability.[9] Deep-water rig rates had increased tremendously during the past year and rapid development of the set of pending deep-water prospects would tend to drive well drilling costs eventually to prohibitive levels. A number of new drilling rigs are being built, but unless the industry sees very high utilization rates or guaranteed contracts are offered to motivate new rig manufacture, a reluctance to build in the industry has lingered limiting the amount of new rig construction.[10]

Availability of Trained Personnel

Another important factor in production levels is the availability of personnel, with respect to both numbers and skill levels. The limited number of trained and experienced offshore workers also is likely to constrain rapid offshore development. Previous cuts in personnel have reduced the numbers of skilled workers, and also have discouraged growth in the size of the workforce. Even if higher wages were offered to entice new workers, new experts and workers require time to train. The scarcity of qualified personnel willing to take the risk in such a cyclic industry

[9]Sheila Popov, "The Tide Has Turned in the Gulf of Mexico," *Hart's Petroleum Engineer International* (October 1997), pp. 25-35.

[10]A major factor impeding the construction of new rigs is the very high cost. Upgrading an existing rig incurs costs exceeding $100 million, according to "Deepwater semi upgrade nearing completion," *Oil and Gas Journal* (November 10, 1997), p. 40.

seems to have more significance for the future than previously seen, according to anecdotal evidence.[11]

Transmission Capacity

An essential factor needed for supporting offshore gas supply operations is adequate transmission capacity to move supplies to onshore pipelines and then to market. Additional capacity of 2.6 billion cubic feet (Bcf) per day was completed in 1998 to increase flow to onshore Louisiana. This flow rate is the equivalent of 4 percent of total U.S. gas production. Although it is generally considered that the Gulf of Mexico transportation system is virtually full, claims of actual capacity constraints have not arisen to date. Further, new and expanded capacity in 1999 and 2000 is expected to total 2.0 Bcf per day at an estimated cost of more than $410 million.[12] While logistical difficulties may remain, no major bottlenecks appear likely in moving gas onshore in the near term, although requirements over the longer term are expected to be extensive. One study estimated the cost of new transportation pipelines in the offshore would exceed $7 billion during the next 15 years.[13]

Deep Water Royalty Relief Act

One sign favorable to near-term supply prospects is the resurgence in offshore blocks receiving bids in recent leasing sales. Lease bids received by the Minerals Management Service (MMS) for Gulf of Mexico tracts offered in Federal lease sales averaged about 959 per year from 1988 to 1990. From the relative high point of 1,079 tracts receiving bids in 1989, however, bidding declined to a level of 212 in 1992. Beyond 1992, bidding increased through 1997 when numbers reached their highest levels in the past 10 years. In fact, the 863 tracts receiving bids in 1995 were only slightly below the 943 bids received in the previous 2 years combined.

The upward trend in lease bidding was stimulated further by the passage of *The Outer Continental Shelf Deep Water Royalty Relief Act* (DWRRA) in November 1995. This legislation mandates royalty relief for certain oil and gas leases in at least 200 meters of water (656 feet) in the Gulf of Mexico.[14] The deep-water zone is further divided into three parts for different levels of royalty relief (Table 9). Production in excess of the stated levels is subject to standard royalty charges. An eligible lease is one that results from a sale held after November 28, 1995, of a tract 200 meters or deeper, lying wholly west of 87 degrees 30 minutes west Longitude, and is offered subject to royalty suspension volume authorized by statute. The DWRRA seems to have stimulated interest in deep-water prospects. Although the resurgence of offshore bidding began before the DWRRA took effect, even the 863 bids in 1995 were more than 20 percent below the 1,079 bids received 6 years earlier (Figure 32). There is a distinct upward shift in the trend for the number of bids received in 1996 when the DWRRA took effect.

Although progress in accelerating development schedules for deep-water projects has improved, they generally still require 2 to 4 years. New fields discovered in the next few years and developed according to a typical schedule likely would not initiate production until after 2002. Thus, future production from deep-water fields in the Gulf of Mexico over the near term depends heavily on discoveries to date.

Near-Term Production Outlook

A sense of optimism is a common element in the outlook for gas production from the Gulf of Mexico OCS, particularly in light of a number of large deep-water projects that are awaiting development. But the immediate outlook for gas production is more uncertain now than in recent years because of some decline in shallow-water activities. The gas production trends to date indicate that the bulk of production in the offshore will flow from shallow-water fields. Thus, if shallow-water fields do not maintain their level of production, the offshore Gulf of Mexico total likely will decline as reductions in the much larger shallow-water production rates would more than offset anticipated new deep-water gas production. Significantly larger volumes from the Gulf would depend heavily on new reserves from fields in both shallow and deep waters.

Overall, offshore gas production from the Gulf of Mexico is expected to range between 10 and 20 Bcf per day by

[11]Limitations of personnel and equipment are not limited to the offshore. One company claims that it is unable to "utilize its full complement of drilling rigs...due to the lack of qualified labor and certain supporting equipment not only within the company but in the industry as a whole." Further, the company expects this to continue "throughout 1998 and into 1999." Unit Corporation, a contract drilling firm, as reported in their 10-Q report, June 30, 1998.

[12]Additional detail on transmission projects can be found in Chapter 5, "Natural Gas Pipeline Network: Changing and Growing."

[13]Estimate cited in "INGAA Foundation Releases Updated Study On Gulf Of Mexico Resources And Pipeline Infrastructure," *Foster Report*, No. 2185 (June 4, 1998).

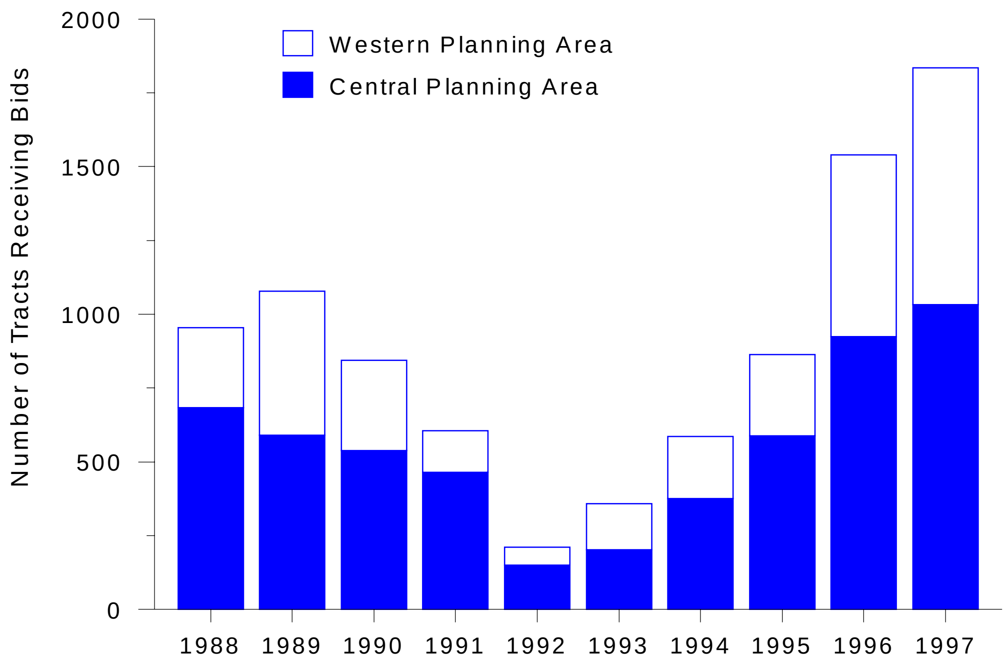
[14]The footage equivalents of metric measures throughout this report are determined on the basis of 1 meter equal to 39.37 inches. Source: *Webster's New Collegiate Dictionary*, G. & C. Merriam Company (1976).

Table 9. Offshore Oil and Gas Volumes Exempt from Royalty Charges Under the *Outer Continental Shelf Deep Water Royalty Relief Act*

	Exempt Volumes	
Depth	Barrel of Oil Equivalent (million barrels)	Equivalent Gas Volume (billion cubic feet)
200-400 meters (656-1,312 feet)	17.5	98.5
400 to 800 meters (1,312-2,625 feet)	52.5	295.6
>800 meters (2,526 feet)	87.5	492.6

Note: The barrel of oil equivalent volumes were converted into billion cubic feet based on assumed heat content of 5.8 million Btu per barrel of oil and 1,030 Btu per cubic foot of gas.
Source: Energy Information Administration, Office of Oil and Gas.

Figure 32. Gulf of Mexico Bidding Trends, 1988-1997



Note: See Appendix A for maps of the Western and Central Planning Areas of the Gulf of Mexico.
Source: Minerals Management Service, *Gulf of Mexico Projections 1998-2002*, Figure 5.

2002 (see box, p. 98). The possibility of large additional production volumes has important implications for markets in the Gulf Coast region. Realization of the high estimate (20 Bcf per day) means that roughly 2 trillion cubic feet of additional production would flow into onshore markets by 2002. Introduction of such large volumes in a relatively short period would have a significant impact on regional gas markets. This volume is equivalent to 10.6 percent of total gas produced in the United States during 1997. However, the optimistic production projections may not reflect a number of practical considerations. Any large incremental volumes from deep-water fields depend on development of both the projects themselves and the associated infrastructure, so these volumes are less certain than those from shallow-water fields.

The shorter lead times and relative availability of existing infrastructure in shallow-water areas facilitate quicker project development. Consequently, there is not a significant backlog of pending projects, and shallow-water development through 2002 will depend primarily on expected reserve additions. The pace of reserve additions is conditional on both the level of drilling and the size of expected discoveries. Annual reserve additions are unlikely

Outlook Methodology

The outlook for offshore production in this chapter was developed using a scenario approach, in which low and high cases were developed by altering selected technical assumptions to demonstrate the range in results under reasonably possible outcomes. Projections for gas and oil production were developed to account for both nonassociated (NA) gas and associated-dissolved (AD) gas. Most gas production in the deep-water regions has been as a coproduct of oil projects, so AD gas projections are particularly important for this area. The projections were determined from available data on recent production, proved reserves, and reserves additions, as well as a number of related parameters. The assumed technical parameters determine the projected production without explicitly incorporating current or expected prices into the analysis. Actual production likely will differ from the projections owing to unforeseen circumstances, such as variation in project timing, available transportation capacity, and fluctuations in market demands.

Projected production in each scenario consists of three elements: flows from currently producing fields in both shallow and deep waters, volumes from known deep-water fields undergoing or awaiting development, and production from new field discoveries, which were derived from available offshore reserves and production information.

Low-case production from currently producing fields was based on an analytical method using the proved reserves estimates, both initially and as they are expected to “grow” over time. The reserves available in each time period are produced according to the measured reserves-to-production (R/P) ratio, which is based on historical data. Reserve growth was fitted to historical data and estimated using Minerals Management Service (MMS) Gulf of Mexico ratios. The natural decline in production performance more than offsets the gains from reserves growth, resulting in a declining production profile. The high case for currently producing shallow- and deep-water fields was based on the assumption of stable production. Detailed parameter assumptions were not established for this case, but it is deemed reasonable as a continuation of the general trend for production from shallow waters during recent years.

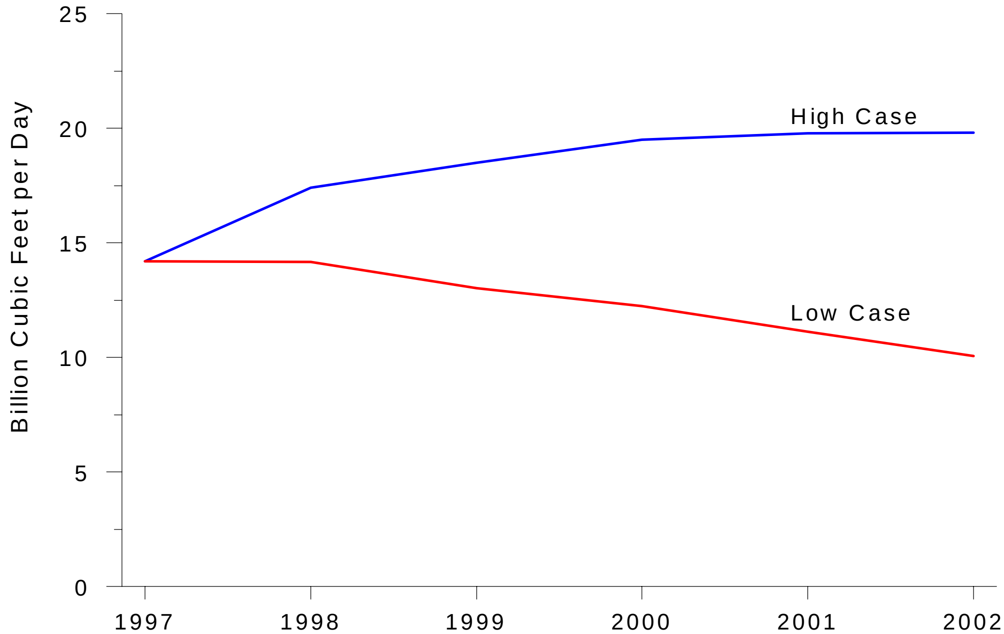
Volumes from known deep-water fields undergoing or awaiting development were incorporated into the projection according to the announced schedule. The third element, production from new field discoveries, was derived from available offshore reserves and production information. New field discovery volumes occur at the rate of 1.1 trillion cubic feet per year, which is estimated from recent trends in the data. These volumes were adjusted to account for additional recovery growth and then produced according to the decline rate indicated by recent R/P ratios.

The high-case scenario results in increased offshore natural gas production up to 20 billion cubic feet (Bcf) per day by 2002, although it also could decline significantly to 10 Bcf per day (Figure 33). The gas production outlook clearly depends upon expected shallow-water production to a great extent. This is due to the relative size of the volumes produced in shallow and deep fields. Reductions in the much larger shallow-water production rates can more than offset anticipated new deep-water gas production, as seen in the low case. Total production in the low case declines even though new deep-water projects may add more than 1.9 Bcf per day by 2002. The importance of shallow-water production is significant in light of the recent reduction of drilling efforts in these areas. The large incremental volumes from deep-water fields depend on development of both the projects themselves and the associated infrastructure, so these volumes are less certain than those from shallow-water fields.

to increase significantly from historical levels because of the expected declines in average field size and the reduced levels of drilling in shallow waters.

Development of pending deep-water projects will offset some portion of any decline in shallow-water production—deep-water projects scheduled for initial production by 2002 may add more than 1.9 billion cubic feet per day—but potential development in the deep waters cannot proceed unconstrained. The number of rigs capable of drilling in deep water is limited. In 1996 and 1997, 1,531 leases were granted in deep-water tracts with 10-year lease terms and 245 tracts with 8-year terms. As the industry has only approximately 39 semi-submersibles and ships, with a capacity to drill four wells per year for each drillship, it would require more than 11 years to drill just a single well in each lease. Given the uncertainties surrounding offshore development, any projections are subject to wide variation.

Figure 33. Projected Gas Production for the Federal Gulf of Mexico



Source: Energy Information Administration, Office of Oil and Gas.

Also, as noted earlier, factors contributing to uncertainty surrounding production outlooks for the Gulf of Mexico are not limited to geologic risk, but include the relative economics and available equipment and personnel. Perpetuation of the very high growth rates of the 1990s implies yearly increases in incremental production that would be a challenge in terms of available personnel and equipment and the required infrastructure.

The deep-water regions to date have yielded fields with very large recoverable gas volumes. Estimates for potential production have been quite optimistic regarding oil, with growth in natural gas lagging behind. As one example, the Minerals Management Service (MMS) projected, in a high case, crude oil production from the entire Gulf of Mexico in 2002 of 1,976 thousand barrels per day, which is a virtual doubling of its estimated December 1996 basis of 1,047 thousand barrels per day. Even in the low case, MMS still projected a gain of 59 percent by 2002 relative to the end-of-1996 volume.[15] MMS projected that gas production in the high case would rise by 24 percent, to 17.5 Bcf per day, during the same period. The conditions of the MMS low case would produce instead a decline to 12.4 Bcf per day by 2002.[16]

The low- and high-case scenario projections developed by the Energy Information Administration (EIA) for this report show a wider range of possible variation than the MMS low- and high-gas scenarios. These differences arise for a number of reasons. The MMS analysis was based on data through June 1997, while the EIA scenarios incorporate the latest information and data available for offshore activities. These data and a greater production decline rate in the EIA analysis result in lower projected gas production in the low-case scenario, with EIA's 10.1 Bcf per day in 2002 almost 20 percent below the MMS estimate. In contrast, the EIA high-case scenario shows an estimated 19.8 Bcf per day, which exceeds the MMS value by 12 percent. The EIA estimate reflects the impact of more optimistic assumptions regarding the impact of field development on expected reserves and the likelihood of new discoveries.

The low- and high-case scenarios provide a reference range of likely outcomes for offshore production, which can be

[15]All oil production figures in this chapter include lease condensate liquids.

[16]Minerals Management Service, *Gulf of Mexico Outer Continental Shelf Daily Oil and Gas Production Rate Projections From 1998 Through 2002,* OCS Report MMS 98-0013 (February 1998).

used to assess offshore outlooks. For example, the reference case in EIA's *Annual Energy Outlook 1999 (AEO99)* shows offshore Gulf of Mexico gas production initially declining by 13 percent from 1997 to 2000, then a reversal in trend leads to production recovering to the 1997 level by 2002. While the *AEO99* volumes in the later years are well within the expected range, production levels in 1998 and 1999 are below the low-case scenario. This discrepancy in the analyses is attributable mainly to a difference in the expected timing of changes driven by the recent severe drop in prices. The *AEO99* reference case and the low-case scenario are consistent after adjusting for this lag.

The 1998 price decline caused significant declines in certain industry activities, such as drilling and field development, however, the lag between these changes and production apparently is more extensive than previously thought. The latest information from operators indicates that, despite reductions in overall supply activities in the offshore Gulf of Mexico, industry endeavors have yielded sufficient new production volumes to offset any decline from 1997 to 1998. (Production from the offshore is expected to begin to show more dramatic declines in 1999.) The extent of the response lag was not known at the time of the AEO99, so this aspect of offshore supply was not incorporated into that analysis. The response lag between reduced industry activities in the offshore and the impact on gas supplies apparently has obscured important trends underlying present and future markets. As domestic gas supplies decrease, prices should rise, although gas supply increases expected elsewhere, including Canadian supplies,[17] should mitigate potential increases in wellhead gas prices.

The near-term outlook provides a number of insights regarding the interplay of the underlying attributes of the industry. The level of reserve additions assumed in each case serves as a limiting factor that cannot support continued production growth. Expanding production volumes require a corresponding growth in the sequence of reserve additions, otherwise reserves are not replenished and the reserve stock declines. Further gains in production might be achieved with higher extraction rates from the existing proved reserve stock, but production growth as a result of such attempts is not sustainable.

[17]A discussion of pending projects expected to increase U.S. imports of Canadian gas can be found in Chapter 1 of this report.

Economics of Offshore Investments

The success of offshore production activities has occurred despite the exceptionally large dollar amounts required for development. Deep-water projects in particular have associated investment costs that may exceed $1 billion,[18] thus requiring a favorable geology base to be successful. Initial recovery estimates for individual fields in deep waters have been in the range of hundreds of billions of cubic feet, with ultimate recovery possibly approaching 1 trillion cubic feet in some cases. Fields of such magnitude are exceptional but offshore fields in general dwarf those expected to be found elsewhere in the Lower 48 States and they are a clear enticement for operators to pursue additional offshore supplies.

The presence of hydrocarbons alone is not sufficient to promote production without both favorable economics and a means to operate in such extreme circumstances. Large volume fields allow relatively fixed costs, such as those for discovery wells or production platforms, to be spread over many more units, lowering the average fixed cost per unit. This tendency is apparent in the finding costs data for the large major U.S. energy companies.[19] The finding costs for oil and gas combined in all water depths of the offshore declined from $15 per barrel of oil equivalent (BOE) to $4 per BOE (1997 dollars) in the 10 years from 1986 to 1996. The differential in finding costs between the relatively low-cost onshore and the offshore was all but eliminated until a slight surge in offshore finding costs appeared. Despite the recent increase, offshore finding costs remain below levels in 1992 and earlier years (Figure 34).[20]

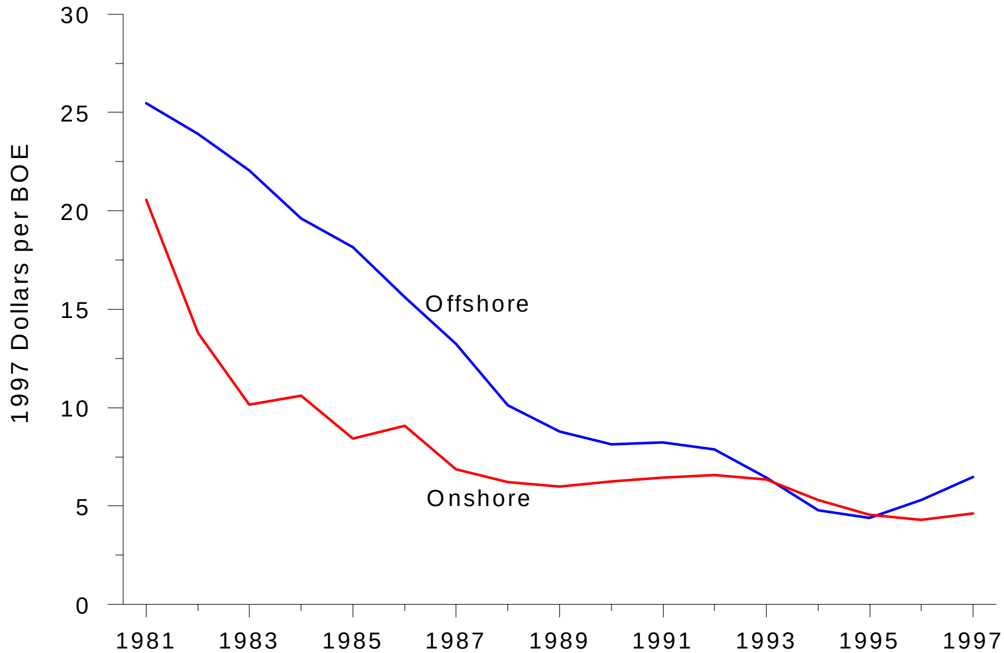
It is misleading, however, to attribute the success of the industry in offshore regions to the discovery of large fields alone. There have been tremendous strides in innovation and technology that have refined virtually all aspects of exploratory and developmental costs and productivity. Competition drives operators to push the limits of

[18]The initial development phase for Shell's Mars project is estimated to cost $1 billion, as reported in <http://www.offshore-technology.com/projects/mars>.

[19]These companies are those required to file Form EIA-28, "Financial Reporting System," pursuant to Section 205(h) of the Department of Energy Organization Act. In 1996, 24 companies filed Form EIA-28. These data are for the offshore, including both shallow- and deep-water operations. The data are used here as a representative sample for illustrative purposes.

[20]Energy Information Administration, *Performance Profiles of Major Energy Producers 1996*, DOE/EIA-0206(96) (Washington, DC, January 1998).

Figure 34. U.S. Onshore and Offshore Finding Costs for Major Energy Companies, 1981-1997



BOE = Barrel of crude oil equivalent.

Notes: Major energy companies are those required to file Energy Information Administration (EIA) Form EIA-28, "Financial Reporting System." Natural gas is converted to its oil equivalent using the conversion factor of 0.178 barrels of oil per thousand cubic feet of gas.

Source: Energy Information Administration, derived from Form EIA-28, as published in the *Performance Profiles of Major Energy Producers 1997*.

technology continually in their search for economic rewards. Within this framework, it is advantageous to seek improved technology as well as new and better ways to conduct business in order to gain possible competitive advantages. These efforts to create the necessary technologies that make offshore operations possible and manage costs have been as important as the geology base itself.

Key Factors in Economic Success

Three key elements that contribute to economic success in the offshore are cost management, reduction in project development time, and improved well performance.[21] The degree to which firms achieve gains in any or all of these areas will contribute heavily to their potential for success or failure.

Cost Management

Cost management includes both efforts to alter operations to offset increased costs and measures to reduce costs associated with given aspects of a project. An example of the first type of effort occurred when recent increased demand for offshore rigs drove drilling rates up. Companies had no control over the market-determined price but could search for ways to minimize drilling time and therefore drilling costs. The other type of cost management effort refers to the continual search for cost-reduction techniques. Technology often is a major influence on cost reduction. For example, the collection of 3-D seismic data has been enhanced through new processing techniques and new mechanical techniques, such as increasing the numbers of streamers, using longer streamers, and using remotely operated vehicles to set geophones or hydrophones on the sea floor.[22] Improved data and interpretation can lower drilling costs by reducing the number of required exploratory wells and better placement of a smaller number of developmental wells.

[21]These elements are adapted from "Three Main Factors Drive Deepwater Project Economics" by Sheila Popov, *Hart's Petroleum Engineer International* (December 1997).

[22]Additional detail on technology is available in Appendix B.

Cost reductions are achieved in a number of other ways. Outsourcing of certain services can allow for the sharing of resources to avoid the cost of being on site 24 hours per day. For example, inspection of operational equipment by qualified contractor personnel and equipment on a part-time basis allows those resources to be used for multiple projects. As costs are shared across a larger volume of service, the costs associated with any one project decline. Despite potential economic advantages, outsourcing is an area of concern for the Minerals Management Service (MMS). The MMS has issued a notice regarding possible waivers from daily inspection requirements, which may prove essential for marginally economic projects.[23] Used equipment is becoming another important factor even for deep-water operations. This approach allows for both direct cost savings and reduction in delivery time to the site. Another cost-saving option is subsea well completions and transportation tiebacks to nearby platforms for production processing. This has been a promising approach to offshore development in deep waters. This approach lowers overall project cost by avoiding the cost of a production platform at the water's surface dedicated solely to a single project.[24] The record to date for a tieback is the 68-mile transmission system connecting the Mensa subsea completions with the production platform at West Delta 143. This record is not expected to be broken anytime soon, owing to the substantial costs of the transmission system.

The Shasta and Mustique projects, in water depths between 830 and 1,040 feet of water,[25] are prime examples of the importance of cost management. These projects were released by major companies to Hardy Oil and Gas USA Inc. for development. Management of these projects focused on development of a project team with active vendor participation to allow the inclusion of their expertise in all phases of the project. The approach to develop both fields was to employ subsea completions with tiebacks to existing production platforms. Additional cost savings were achieved by the use of specialized equipment to complete the wells at Shasta, which is expected to reduce operating costs by 15 percent over the life of the wells. Successful project development can be seen in the Shasta wells, each of which can produce 30 million cubic feet (Mmcf) per day, and the single Mustique well, which produces at 25 MMcf per day.

Accelerated Project Development

The success of the Shasta and Mustique projects underscores the importance of adequate planning to ensure both optimal resource recovery and a strong economic return on investment. However, as experience in offshore operations grows, companies' need for measured caution lessens and firms emphasize timely activity in their approaches to project development. The goal is to accelerate development, which increases the expected net financial return by yielding an earlier economic return and reducing the carrying costs of early expenditures on leases, geology and geophysical work, and exploratory drilling.

Design improvements between the Auger (initial production in 1994) and Mars (initial production in 1996) projects, both at water depths of approximately 2,900 feet, allowed Shell to cut the construction period to 9 months with a saving of $120 million.[26] Accelerated development enhances economic attractiveness by reducing project uncertainty because adverse changes in market price for the commodity or factor costs become more of a possibility as development time lengthens.

One approach to achieve revenues as soon as reasonable is the use of a subsea completion and transportation of production to an existing platform. A key advantage to this approach is that it provides an early contribution to project returns while additional engineering and design work for the full project proceeds. Another approach being developed especially for deep-water project development is in the overlapping of design phases and construction. Improvements in technology and project management allowed Shell Deepwater to develop the Ursa project in about the same calendar time as its Mars and Ram-Powell projects, even though Ursa is roughly twice their size. Development for offshore projects in general had ranged up to 5 years previously, with deep projects requiring up to 10 years. Recent field development has been accelerated with the period from discovery to first production in

[23]Gregg Falgout, "Outsourcing Lowers Costs," *Hart's Oil and Gas World* (April 1998), pp. 33-34.

[24]This option is quite attractive to the operator of the production platform, who charges for the processing service. Anecdotal evidence indicates that the platform operator in some cases may profit more from the project than the production operators.

[25]The Shasta project consists of two wells, separated by 1.5 miles, in 860 and 1,040 feet of water.

[26]Minerals Management Service, *Deepwater in the Gulf of Mexico: America's New Frontier*, OCS Report MMS 97-0004 (February 1997).

shallow water ranging between 6 and 18 months.[27] Experience with deep-water construction and operations has enabled development to proceed much faster, with time from discovery to production declining from 10 years to just over 2 years by 1996 (Figure 35).

Improved Well Performance

A third major factor behind favorable offshore economics for gas production is the rather astonishing production performance characteristics of large fields. This is seen clearly in deep-water fields, which tend to have high permeability and pressure that result in rapid flow to the wellbore. Individual well flows of 100 million cubic feet (MMcf) per day have been achieved at some fields, such as Mensa. Flows of this magnitude eclipse the average daily rate of 170 thousand cubic feet for wells in the entire Lower 48 States.

Well performance is important in terms of both ultimate recovery volumes and the speed at which those volumes are produced. Ultimate recovery determines the level of project revenues, and the flow rate affects the present value of expected revenues. If the improvement in early well flow rates occurs without sacrificing recovery volumes, the present value revenue is enhanced in both ways. Greater recovery per well is a key objective to the operator because, in addition to the contribution to higher revenues, it also reduces the number of required production wells and the associated drilling and completion expenditures.

Accelerated production improves present value profit in an indirect way. Within the income tax code, the advantage of cost deductions is delayed until project revenues generate tax liabilities for which the deductions are a useful offset. Increased flow in the initial years of a project generates larger early revenues and thus provides opportunities for the use of the accrued tax deductions from cost expenditures, enhancing the present value of cost recovery for tax purposes. This attribute is particularly advantageous for projects evaluated on a standalone basis.

The importance of well performance is underscored in a sensitivity test conducted on the expected profitability of a representative gas field.[28] The initial flow rate was identified as a major influence on the estimated present value profit (PVP) based on computation of rank correlations between PVP and the stochastic input variables. The rank correlation provides a useful quantitative approach to validate the importance of project elements to the expected returns. Drilling costs, on the other hand, did not show up as important to expected profitability, even though it may constitute many millions of dollars in total project cost.

Given that production performance variables such as the initial flow rate dominate over drilling costs as a major influence on profitability, a rational strategy is for the operator to pursue well drilling and completion technology with an emphasis on increased productivity despite increased costs. As long as the cost increments are managed properly, the productivity gains may be well justified. Analysis of a representative deep-water gas project shows that possible increases in drilling costs of 50 percent could be offset by flow rate increases of only 19 percent (assuming all other project parameters remain unchanged). These estimates show the economic incentive behind research and development in drilling and completion technologies that have resulted in very high flow rates.

Other Factors

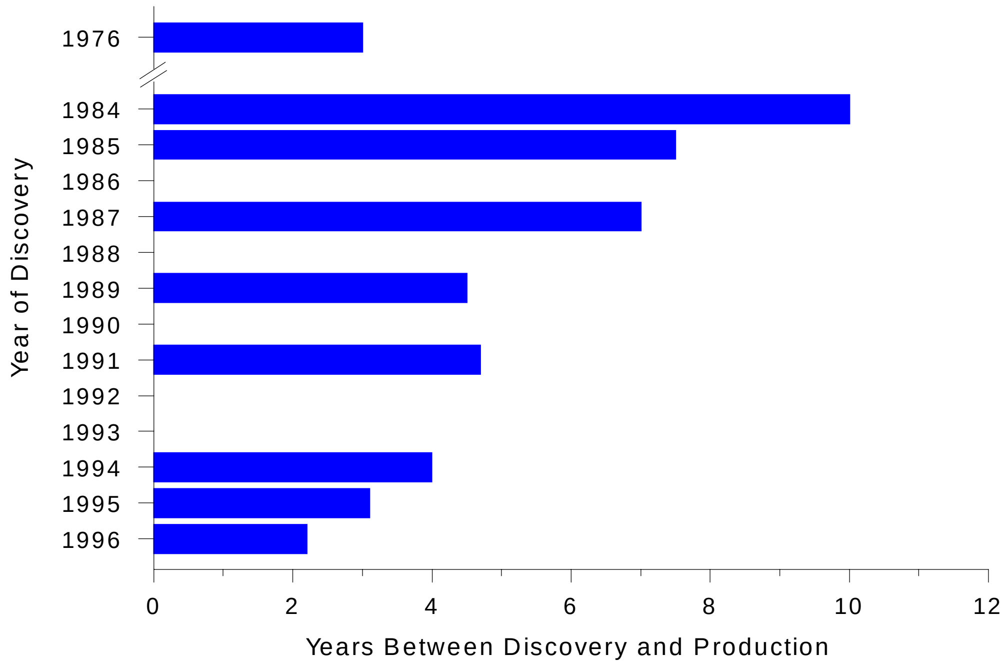
In addition to those items that are within the influence of the companies themselves, developments in the industry at large affect the economic environment for offshore operations. Growth of the industry drives infrastructure expansion, which in turn may enhance the economics of new offshore projects in a number of ways. Project costs are reduced as new projects can avoid full costs of assets dedicated to that single project, such as pipelines for transport to market. Pipeline construction and operation offer economies of scale that result in lower unit costs when output from multiple fields can be aggregated. Project costs also may be reduced by the use of subsea completions with output being "tied-back" to existing production platforms for gathering and processing. This practice will benefit from a more extensive infrastructure system, in which a larger number of platforms will offer greater numbers of opportunities to use this approach. Development of marginal fields will depend heavily on platforms in the area, not at any great distance. (The use of platforms for multiple projects also has the reciprocal advantage for the platform operator of increased overall return to those assets.)

Investors in incremental projects that rely on existing infrastructure also benefit from reduced risk in project timing, less cost uncertainty, and reliable performance of supporting assets. Reliance on existing assets avoids new construction endeavors, which could encounter delays or

[27] "New Ideas, Companies Invigorate Gulf," *The American Oil & Gas Reporter* (June 1996), p. 68.

[28] A description of the representative gas field and details of the economic analysis are provided in Appendix C.

Figure 35. Cycle Time for Deep-Water Projects



Note: Cycle times are for projects in production or under development. Prospects without a scheduled start date are excluded.
Source: Energy Information Administration, Office of Oil and Gas.

unforeseen events that cause the project to fail outright. In conducting project evaluation, such risk factors do not necessarily preclude construction, but they can raise unit costs for the associated service, thus reducing the net price or profit received by the producers. The net price received by producers is determined as the netback from the market price after accounting for transportation and other services, if any. While the markets may not yield a price sufficient to ensure a favorable return for the production project, the net price received by producers is subject to less risk if the needed infrastructure is in-place and available. Reduced risk enhances the expected profitability outlook for the project, which underscores the importance of new pipeline construction projects for improving the economic outlook for this region.[29] As economic returns for marginal fields improve, the minimum economic field size becomes smaller, resulting in ever-greater volumes of economically recoverable hydrocarbon volumes.

[29]Additional information on new pipeline construction and capacity expansion is available in Chapter 5 of this report.

Environmental Aspects of Offshore Operations

The oil and gas industry has conducted offshore activities for more than 5 decades. As a key contributor to the Nation's energy supplies, the industry has periodically found itself in the midst of a tense debate concerning the proper balance of sometimes conflicting interests in the offshore. Numerous people and companies are concerned with the offshore and its coastal regions as a resource to provide residential areas, wildlife habitat, recreation, fishing and agriculture, in addition to oil and gas operations. Government agencies have tried with various strategies and policies to reflect the will of the people in managing the offshore regions including the coastal areas. In 1953, Congress designated the Secretary of the Interior to administer mineral exploration and development of the OCS through the Outer Continental Shelf Lands Act (OCSLA). While the OCS is under Federal jurisdiction, federally approved activities must be as consistent as possible with approved State management programs.

After the OCSLA, the next major legislation affecting offshore operations was the National Environmental Policy

Act (NEPA) passed in 1969, the same year in which there was a major oil spill in the Santa Barbara channel. Additional environmental legislation was passed over the ensuing years. Targeted items under these laws included protection of the water and air, as well as the wildlife (Table 10). Most of the provisions under these laws imposed procedural steps or restrictions on operations, which generally caused higher costs for compliance, but oil and gas development itself could proceed. Over time, however, certain laws and Congressional actions either worked to block activities in offshore areas or explicitly blocked them at least temporarily. Since 1990, most portions of coastal waters have been subject to moratoria precluding any oil and gas activity.

Coastal Zone Issues

The Coastal Zone Management Act (CZMA), passed in 1972, has had far-reaching consequences and provoked extensive litigation and discussion. The CZMA aimed for the preservation, protection, and restoration of coastal areas to the extent possible,[30] and to resolve conflicts between various uses that were competing for coastal areas. The CZMA was intended to promote cooperation and coordination between the Federal government and State and local agencies in coastal States and States bordering the Great Lakes. An important element in achieving these goals is management of the offshore and coastal areas that is consistent with Federal and State plans and policies. Congress recognized that Federal decisions or actions in the OCS may have a severe impact that extends well into State waters. Thus, the CZMA requires that an applicant submitting a plan for exploration, development, or production from an OCS lease must include "a certification that each activity which is described in detail in such plan complies with such state's approved management program and will be carried out in a manner consistent with such program."[31] In effect, the CZMA provides for State review of Federal actions that affect a State's coastal zone.[32]

Prior to State review of Federal actions, the State must establish a management program that has been approved by the Secretary of Commerce. The key features in a State management plan would:

- Identify the relevant coastal area subject to management under the program
- Define permissible land and water uses
- Identify areas of particular concern
- Develop guidelines for use in particular areas
- Establish an organization and process for planning and implementation of the program.

The CZMA is rather unique in that participation by the States is on a voluntary basis. The CZMA provides mechanisms to encourage States to develop a management program, and in fact, it provides considerable incentive to do so. Advantages of participating in the program include technical assistance to local decisionmakers, funds for hiring State and local government employees to help implement the program, funds to develop special plans for areas of particular concern, funds for low-cost construction projects, such as boardwalks, to improve the public's ability to enjoy the coastal resources, and Federal consistency with the State's coastal management program. Not all qualifying States have become active participants, but all that have not, with the exception of Illinois and Indiana, currently are in the process of developing a program.

Although the intent of Congress in passing the CZMA was to promote cooperation and coordination between Federal and other agencies, disagreements arose over time that led to litigation. These cases initially led to a Supreme Court decision in 1984 that substantially weakened the act, but drove Congress to issue additional legislation that further refined its intent and actually gave the CZMA more strength. In 1990, the act was amended to clarify that all activities of Federal agencies are subject to the consistency requirements of the CZMA if the activities affect natural resources, water uses, or land uses in the coastal zone.

[30]"The Congress finds and declares that it is the national policy...to preserve, protect, develop, and where possible, to restore or enhance, the resources of the Nation's coastal zone for this and succeeding generations." 16 USC Sec. 1452, Title 16 – Conservation, Chapter 33 – Coastal Zone Management, Sec. 1452. Congressional declaration of policy. Source: <gopher://hamilton1.house.gov70/00d%3A/uscode/title16/sect38/file.011>.

[31]Source: <http://wetland.usace.mil/regs/CZMA307.html>.

[32]The *coastal zone* is defined for purposes of the CZMA as "coastal waters (including the lands therein and thereunder) and the adjacent shorelands (including the waters therein and thereunder), strongly influenced by each other and in proximity to the shorelines of the several coastal states, and includes islands, transitional and intertidal areas, salt marshes, wetlands, and beaches. The zone extends, in Great Lakes waters, to the international boundary..." *Coastal Zone Management Act of 1972*, Section 304(1).

Table 10. Major Environmental Actions Affecting Federal Offshore Gas Recovery

Year	Action	Notes
1953	Outer Continental Shelf Lands Act passed.	Provides for Federal jurisdiction over submerged lands of the OCS and authorizes the Secretary of the Interior to lease those lands for mineral development.
1969	National Environmental Policy Act passed.	Requires a detailed environmental review before any major or controversial Federal action.
1970	Clean Air Act passed.	Regulates emission of air pollution from industrial activities.
1972	Coastal Zone Management Act passed.	Requires State review of Federal action that affects the land and water use of the coastal zone.
	Marine Mammal Protection Act passed.	Provides for the protection and conservation of all marine mammals and their habitats.
1973	Endangered Species Act passed.	Requires a permit for the taking of any protected species and requires that all Federal actions not significantly impair or jeopardize protected species or their habitats.
1977	Clean Water Act passed.	Regulates discharge of toxic and nontoxic pollutants into the surface waters of the United States.
1981	First OCS leasing moratorium enacted by Congress–FY 1982.	California.
1982	Federal Oil & Gas Royalty Management Act passed.	Among other requirements, requires that oil and gas facilities be built in a way that protects the environment and conserves Federal resources.
1983	First preleasing moratorium enacted–FY 1984.	North Atlantic.
1984	National Fishing Enhancement Act passed.	Encourages using offshore oil platforms as artificial reefs.
	Focused leasing concept introduced.	Allows deletion of low-interest, environmentally sensitive acreage from sale areas early in the lease sale process.
1988	Congress enacts first OCS drilling ban–FY 1989 DOI appropriations.	Covers leases in eastern GOM, south of 26° N.
1990	Amendments to Clean Air Act passed.	Gives Environmental Protection Agency jurisdiction for OCS facilities outside Central and Western GOM.
	Oil Pollution Act of 1990 (OPA-90) passed.	Among other provisions, OPA-90 addresses areas of oil-spill prevention, contingency planning, and financial responsibility for all offshore facilities in, on, or under navigable waterways.
	Outer Banks Protection Act passed.	Includes moratorium language for areas offshore North Carolina.
	Presidential decision withdrew areas offshore California, Washington, Oregon, North Atlantic, and Eastern GOM (south of 26° N) until after the year 2000.	
1995	Deep Water Royalty Relief Act passed.	Expands MMS' discretionary authority to grant royalty relief and mandates royalty relief (under certain conditions) for GOM leases in 200 meters or greater water depth.

OCS = Outer Continental Shelf. FY = Fiscal year. GOM = Gulf of Mexico. DOI = Department of the Interior. MMS = Minerals Management Service.
Source: Adapted from "U.S. Offshore Milestones," Minerals Management Service, <http://www.mms.gov>.

Florida and North Carolina are using the CZMA consistency provisions to block exploration and development of OCS prospects, which are thought to be largely gas prone. Critics of the CZMA have characterized this law as "the 'veto' law"[33] because of the powerful role delegated to the States, and States certainly have used its provisions to impede and obstruct Federal activities within their jurisdictions, such as oil and gas leasing. However, decisions regarding offshore activities under the provisions of the CZMA are based on the States' management program that has previously been approved at the Federal level by the Secretary of Commerce. Thus, the outcome reflects coordinated planning on a Federal and State basis, and it generally cannot be circumscribed by the program objectives of a single Federal or State agency.

Artificial Reefs

Although support for offshore oil and gas development varies among the States, it has a long history of acceptance in the Gulf of Mexico. Activities have been conducted for decades off Texas and Louisiana, with industry operations extending more recently into areas off the coasts of Mississippi, Alabama, and Florida.

While problems have occurred from time to time, a number of benefits have flowed from offshore operations. The more readily apparent ones include valuable supplies of oil and gas, government revenues, and employment. An additional benefit comes in the form of artificial reefs formed by the placement of obsolete operating platforms or rigs. An artificial reef refers to the placement of a man-made object on the sea bottom, which then becomes part of the ecosystem. This is particularly beneficial in the Gulf of Mexico given that the submerged terrain generally is flat and sandy, lacking hard structures on which invertebrates and plants can attach themselves.

The success of artificial structures in providing food and shelter for a host of fish species has led to the use of various materials for this purpose. Ships, airplanes, buses, bridge rubble, old tires and other items have been installed as artificial reefs with varying degrees of success. Train boxcars have been found to deteriorate greatly within a year or two of placement. Items also may shift and move when subjected to currents. Abandoned oil and gas platforms, however, were designed for a marine environment and so are quite durable and they tend to be secure. New rigs tend to become covered within 6 months to a year, which in turn attracts other creatures to eventually form a complex food chain.

The Minerals Management Service has encouraged the "rigs to reefs" option owing to its environmental and economic advantages. In 1983, MMS announced its support for the program, and in 1985 announced a formal policy on it. Under the rigs to reefs program, companies donate structures, install the reefs, and may make financial donations to the States from any realized savings related to avoided disposal costs. In cases with high relocation costs, such as moving a rig from the Gulf to the east coast of Florida, there may be no savings to allow for a donation to the State. However, the donation of the platform and absorption of transportation costs by the company provides the State the opportunity to gain the benefits while avoiding the costs otherwise associated with the installation of an artificial reef.

The first planned rigs to reef conversion occurred in 1979 with the relocation of an Exxon experimental subsea template from offshore Louisiana to a permitted site off Florida. To date, at least 120 structures have been used for the creation of artificial reefs, with 72 off Louisiana, 39 off Texas, 3 off Alabama, and 6 off Florida. Financial contributions to the States from the companies exceed $15 million.[34] The advantages to the State from the program include the environmental benefits and funds for the management of marine habitat, enhanced recreational areas, and the companies benefit from lower dismantling costs.

Outlook

Relatively low gas and oil prices during 1998 have made the outlook for offshore supply activities in the next year or two rather uncertain. However, a recovery in prices or further improvement in cost management, project cycle reduction, or well productivity can help to mitigate the impact of these price levels. Technology has contributed greatly to improved performance in the offshore. Much of the current attention is focused on technology enhancements that make the deep-water and subsalt fields increasingly attractive as investment options. However, the bulk of production historically has come from conventional fields in shallow-water regions of the Gulf of Mexico, and this trend is expected to persist for some time to come. Much of the technology that holds promise for great returns

[33] *Coastal Zone Management Act*, <http://moby.ucdavis.edu/GAWS/161/2metro/CZMA.html>.

[34] Figures provided by Villere Reggio of the Minerals Management Service, Gulf of Mexico OCS Region (October 5, 1998).

in the deep-water areas also has wide applicability in shallow depths.

Production in the longer term naturally depends on the trend in discoveries, which is itself conditional on geologic and economic factors. A key geologic factor is the field size distribution, which generally is expected to be highly skewed with few very large fields and increasing numbers as field size declines. The largest fields, being less challenging to find, tend to be discovered first, so exploration efforts yield diminishing volumes of reserve additions over time as smaller fields are discovered.[35] While even these smaller fields are likely to be large compared with those found in other regions in the Lower 48 States, this perspective on resources leads to declining returns to exploration. However, exceptions to the theoretical discovery model occur often. One recent example is the King discovery, about 70 miles southest of Louisiana in the Mars Basin, where development plans had not been completed when two additional "major" oil-bearing zones were discovered.[36] Given the Mars and Ursa fields already had been discovered in the Mars basin, this is a rather promising development. Elsewhere, after disappointments in the pursuit of subsalt prospects led to a relative lull in activity industry-wide, Anadarko announced a major subsalt discovery in shallow water that should contain at least 140 million barrels of crude oil equivalent (BOE), with reasonable potential of exceeding 200 million BOE.[37]

The frequency of these unexpected events indicates that declining offshore reserve additions with no relief is not an inevitable outcome. Additionally, annual reserve additions also relate to the number of wells drilled, which is influenced by economic factors. The timing of the exploitation of the resource base will depend on costs, productivity, and the evolving infrastructure. Production over a sustained period cannot expand unless reserve additions increase.

The optimistic consensus regarding the long-term supply potential of the offshore Gulf region is heavily influenced by the prodigious estimates of remaining recoverable natural gas resources. Recoverable gas resources in undiscovered fields in the Federal waters of the Gulf of Mexico are estimated by the Minerals Management Service (MMS) to be 96 trillion cubic feet (Tcf), with an additional 37 Tcf to be proven in already known fields. Combined with the 29 Tcf already in proved reserves for this area, this is equivalent to the 1997 estimate of 165 Tcf in proved reserves for the entire United States.

The estimated 96 Tcf in undiscovered fields represents the volumes of gas that are expected to be recoverable by conventional techniques, but without regard to the economic merit of recovery. As the economics for the offshore Gulf of Mexico improves, the portion of the technically recoverable resource base that is expected to be recovered expands considerably. Industry success in its efforts to manage costs, reduce cycle time, and increase productivity enhances the expected economic return for marginal fields, allowing the minimum economic field size at each water depth to become smaller. The apparent success of offshore operators in improving costs and productivity has increased the set of economically viable fields beyond the numbers previously anticipated for the offshore and, in particular, the deep-water regions. Because of the highly skewed distribution of field sizes, the inclusion of ever smaller fields multiplies the number of economically viable fields, which expands the economically recoverable portion of the total, although by less than a proportionate amount.

In conclusion, the supply outlook for the Gulf of Mexico shows considerable potential for growth. Although the relatively low oil and gas prices for much of 1998 have led to reduced drilling in the shallow waters of the Gulf, over the long term, gas supplies from the Gulf of Mexico undoubtedly are going to be very large in light of the estimated recoverable resource volumes. The timing of the resource development is subject to both market and technical influences. The expected flow volumes from both shallow- and deep-water regions potentially are so large that the supply outlook has important implications for both regional markets and the Lower 48 States as a whole.

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[35] Declining volumetric returns to exploratory drilling over time do not require that successive discovered fields are strictly smaller. The search process is not perfect and the outcome for any year represents the aggregation of fields of different sizes. The yearly average volume per discovery will decline as the set of yearly discoveries shifts from larger to smaller sizes.

[36] "Vastar hits deep zones at Gulf prospect," *Oilgram News* (July 23, 1998), p. 3.

[37] "Anadarko announces big subsalt discovery," *Oilgram News* (July 30, 1998), p. 1.