

Chapter Two

“Each oil well has its own personality”

The History of Offshore Oil and Gas in the United States

March 1938 was an eventful month in the history of oil. Mexico nationalized its oil industry, establishing a precedent. Standard Oil of California (which later became Chevron) completed the first discovery well in Saudi Arabia—still the greatest oil find on record today. And during that same month, the first production of offshore oil took place in the Gulf of Mexico.

Beginning in the 1890s, oil companies had drilled wells in the ocean, but from wooden piers connected to shore. In the 1930s, Texaco and Shell Oil deployed moveable barges to drill in the south Louisiana marshes, protected from extreme conditions in the ocean. In 1937, two independent firms, Pure Oil and Superior Oil, finally plunged away from the shoreline, hiring Texas construction company Brown & Root to build the first freestanding structure in the ocean. It was located on Gulf of Mexico State Lease No. 1, in 14 feet of water, a mile-and-a-half offshore and 13 miles from Cameron, Louisiana, the nearest coastal community. In March 1938, this structure brought in the first well from what was named the Creole Field.¹

Getting their feet wet for the first time, oil derricks march into the Pacific and the Summerland Oil Field near Santa Barbara, California, at the start of the 20th century. Over the next decades, innovation followed offshore innovation, propelling the industry and helping fuel the nation's remarkable economic expansion. Yet as companies drilled ever deeper and farther from shore, technological hurdles rose ever higher—and risks grew ever greater.

G.H. Eldridge/U.S. Geological Survey

The Creole platform severed oil extraction from land—and did so profitably, setting in motion the march of innovation into ever-deeper waters and new geological environments offshore. The Gulf of Mexico, where offshore drilling began, remained a vital source of oil and gas for the United States. The large, sand-rich depositional system of the Mississippi River that spilled onto the continental margin for tens of millions of years created a world-class petroleum province. The salt domes that pocked the Gulf basin provided excellent traps for hydrocarbons. Prior to 1938, oil hunters had made hundreds of discoveries on domes under the Louisiana and Texas coastal plain. There was no reason to believe that this geology would stop at the shoreline.

The Creole platform highlighted the risks as well as rewards encountered offshore. A hurricane knocked out many of the pilings during construction. The lack of crew quarters on the platform created hardship for workers commuting to and from shore on shrimp boats. Many more challenges lay ahead as the marine environment imposed unique hazards on oil companies trying to adapt land-drilling methods offshore. They would have to squeeze complex drilling and production facilities onto small standing or floating platforms in a region exposed to hurricane-force winds and waves. High costs intensified pressures to find speedy solutions to problems and get the oil flowing. The remoteness of facilities and their space constraints amplified the perils of working under adverse conditions with dangerous equipment and combustible materials. “Nobody really knew what they were doing at that time,” recalled a member of Kerr-McGee’s earliest offshore drilling crew. “It was blow-by-blow. And it wasn’t easy living out there.”²

As geologists and drillers made discoveries in deeper water, development would stall at a limiting depth, sometimes for several years, until advances were made in production technology to catch up with exploration. Blowouts, drilling-vessel disasters, and platform failures often forced engineers back to the drawing board. Steadily, the offshore industry pioneered ways to meet economic and environmental challenges offshore, first in the Gulf and then around the world. But the risks never went away.

Wading Into Shallow Water

On August 15, 1945, the day after the Japanese surrender in World War II, the U.S. government lifted gasoline and fuel-oil rations. In the first five years after the war, Americans bought an astounding 14 million automobiles, increasing the number of cars in service to 40 million. By 1954, Americans were purchasing 7 million tankfuls of gasoline per day.³ This booming demand for gasoline, coupled with growing use of home heating oil, vaulted petroleum ahead of coal as the leading source of energy in the United States.

Early Technologies

To meet soaring demand, oil firms embarked on a quest to find new reserves. The intrepid ones returned to the Gulf to drill on leases offered by Louisiana—and made use of wartime technologies and equipment. Sonar and radio positioning developed for warfare at sea proved valuable for offshore exploration. The Navy trained schools of divers in underwater

FIGURE 2.1: Timeline of Major Events



History of Offshore Oil and Gas in the United States

1896	First offshore oil production in the United States—from wooden piers off Summerland, California
1938	First Gulf of Mexico discovery well in state waters; first free-standing production platform in the ocean—Creole field offshore Louisiana
1947	First well drilled from fixed platform offshore out-of-sight-of-land in Federal waters—Kermac 16 offshore Louisiana
1953	Submerged Lands Act & Outer Continental Shelf Lands Act
1954	First federal Outer Continental Shelf lease sale & Maiden voyage of the <i>Mr. Charlie</i> submersible drilling vessel, industry's first "day rate" contract
1962	First semi-submersible drilling vessel, <i>Blue Water 1</i> , and first subsea well completion
1969	Santa Barbara blowout/oil spill (California)
1978	Shell Oil Company's Cognac production platform (first in 1,000 feet of water) & OCS Lands Act Amendments
1981	First Congressional Outer Continental Shelf leasing moratorium
1982	Creation of the Minerals Management Service (MMS)
1988	Piper Alpha disaster in the North Sea
1994	First production from Shell's Auger tension-leg platform in 2,860 feet of water
1995	Deepwater Royalty Relief Act
1996	First spar production facility in the Gulf of Mexico at the Neptune field
1999	Discovery of BP's Thunder Horse field in 6,000 feet of water; at 1 billion barrels of oil equivalent, the largest discovery in the Gulf of Mexico
2006	Successful test at the Jack 2 field, in 7,000 feet of water and more than 20,000 feet below the seafloor, establishing the viability of the deepwater Lower Tertiary play
2010	Arrival of <i>Deepwater Horizon</i> at Macondo well in January

salvage operations and introduced new diving techniques, seeding the diving business that became vital to offshore operations. Construction companies, such as Brown & Root and J. Ray McDermott, and numerous boat operators acquired war-surplus landing craft and converted them to drilling tenders, supply and crew boats, and construction and pipelaying vessels.⁴

In 1947, Kerr-McGee Oil Industries drilled the first productive well “out-of-sight-of-land,” on a platform located in 18 feet of water, 10.5 miles off the Louisiana coast in the Ship Shoal area. The Kermac 16 platform used a war-surplus tender barge to house drilling mud and other supplies, plus the workers’ quarters, thereby reducing the size and cost of a self-contained drilling and production platform—an important advantage in case of a dry hole. In 1948, Humble Oil (the Texas affiliate of Standard Oil of New Jersey, later renamed Exxon) introduced the concept of latticed steel templates, or “jackets,” which provided greater structural integrity than platforms built with individual wood piles.⁵

Drilling Revived

To explore and develop their new leases obtained from the federal government (see Chapter 3 on the origin of federal leasing), oil firms tapped into the Gulf Coast oil-service sector, but they also promoted the formation of a distinct offshore industry by contracting out for specialized services in marine geophysical surveying, offshore engineering and construction, transportation (boats and helicopters), diving, and mobile drilling.⁶

Mobility in drilling was crucial to the offshore industry’s long-term viability. The costs of drilling exploratory or “wildcat” wells from fixed platforms, most of which would not discover oil, were prohibitive. In 1954, the Offshore Drilling and Exploration Company capitalized on a novel approach to the quest for mobility, using its \$2 million *Mr. Charlie* “submersible” drilling barge. *Mr. Charlie*’s hull could rest submerged on the bottom in 30 feet of water for drilling, and then be refloated and moved to other locations, like a bee moving from flower to flower to extract nectar. Working for Shell Oil on the industry’s first “day-rate” contract (\$6,000 per day), *Mr. Charlie* drilled and developed two of the Gulf Coast’s largest oil fields, in the East Bay just off the South Pass outlet of the Mississippi River. “That’s a great rig you have there!” exclaimed Shell’s New Orleans vice president after the first well. “I can see the day when you will need several more of them.”⁷

Giant salt-dome fields discovered offshore Louisiana—Shell’s East Bay and West Delta, the California Company’s (Chevron) Bay Marchand and Main Pass, Magnolia’s (Mobil) Eugene Island, and Humble Oil’s Grand Isle, all under less than 30 feet of water—encouraged operators to move farther out in the Gulf. As Offshore Drilling and Exploration expanded its submersible fleet, other companies such as the Zapata Offshore Company (formed in 1954 by future U.S. President George H.W. Bush), experimented with “jack-up” rigs. These rigs jacked their platforms out of the water by extending a series of cylindrical or truss-type legs to the bottom, taking drilling into water depths exceeding 100 feet. By 1957, 23 mobile units were operating along the Gulf and 11 more were under construction.⁸

Drilling offshore was a relatively costly proposition in the 1950s (a Gulf oil executive described it as “a billion-dollar adventure in applied science”⁹), but it was astoundingly

successful. In 1956, 26 percent of offshore exploratory wells struck oil and gas, compared to just 11 percent onshore. Of these wells, 1 in 20 discovered fields with more than 50 million barrels of reserves—more than five times the equivalent success rate of onshore wells. By 1957, there were 446 production platforms in federal and state waters. Wells offshore Louisiana and Texas were producing 200,000 barrels a day, feeding the vast refinery complexes that already existed along the Mississippi River between New Orleans and Baton Rouge, in the “Golden Triangle” of coastal East Texas (Beaumont–Port Arthur–Orange), and along the Houston Ship Channel. Offshore wells accounted for 3 percent of total U.S. production, but the percentage was rising.¹⁰

Pushing Beyond Limits

In the late 1950s, the frantic pace of Gulf offshore exploration slowed. Costs increased significantly in water depths beyond 60 feet (then the definition of “deepwater”). A few jack-up rigs capsized in rough seas. After Glasscock Drilling Company’s *Mr. Gus* drilled a \$1 million dry hole for Shell in 100 feet of water in 1956, the vessel sank in transit a year later during Hurricane Audrey. Beyond the damage to offshore infrastructure, Audrey destroyed the support center of Cameron, Louisiana, where an estimated 500 people tragically perished. Underwater pipelines, necessary for bringing oil to shore, were expensive and tricky to place in deeper water. A national recession in 1958, an oversupply of crude oil from growing imports, and declining finds in deeper waters tempered enthusiasm for new exploration. At the same time, Louisiana’s legal challenge to the state-federal boundary offshore delayed federal lease sales for several years beginning in 1955. Some people in industry thought this did not matter: they believed offshore exploration had reached its limits.¹¹ Others were more optimistic.

Shell’s Frontier Technology and the 1960s Boom

In August 1962, after seven years of research and development, Shell announced it had successfully tested a new kind of “floating drilling platform,” redefining the marine geography of commercially exploitable hydrocarbons. The *Blue Water 1* was a converted submersible consisting of three large columns on each side that connected the drilling platform to a submerged hull. Giant mooring lines kept the vessel on position. Until then, companies had been experimenting with ship-shaped vessels called “drillships” to explore in water depths beyond 150 feet, but these could not withstand heavy wave action. Because the *Blue Water 1*’s hull could be ballasted to rest safely below wave level, the vessel was remarkably stable. Classified as the first “semisubmersible,” the *Blue Water 1* made its successful test in 300 feet of water, and it was equipped to operate in 600 feet. Complementing the new floating platform, Shell tested the first successful subsea wellhead completion using remote controls. As one Shell representative told reporters, “We’re looking now at geology first, and then water depths.”¹²

The achievement was akin to John Glenn’s space orbit the same year. Even more astonishing was Shell’s decision, in early 1963, to share its technology with other companies. At its three-week “School for Industry,” seven companies and the U.S.

Geological Survey paid \$100,000 each to learn about Shell's "deepwater" drilling program—thereby ensuring that suppliers and contractors were up to speed and that there would be at least some competition from other oil companies for deepwater leases (which otherwise would not be awarded at auction). The diffusion of Shell's technology led to the construction of semisubmersibles in Gulf Coast shipyards and enabled the industry to move into deeper water.¹³

Federal policies also helped accelerate offshore exploration and development. Oil import quotas went into effect in 1959 and were tightened in 1962. These measures protected the domestic market for higher-cost offshore oil. In 1960 and 1962, sensing pent-up demand after the hiatus in federal leasing during the late 1950s, the Bureau of Land Management auctioned large swaths of Gulf acreage. The response was overwhelming: in the historic March 1962 sale, 411 tracts, totaling nearly two million acres, were leased—more than in all previous sales combined. The sale opened up new areas off western Louisiana and Texas and extended the average depth of leases to 125 feet. Because so much land was put up for auction, the "cash bonus" price for the average lease was driven down, enabling more companies to participate in the Gulf.¹⁴

Drilling on that vast inventory of leases set off one of the greatest industrial booms the Gulf Coast had ever seen. By September 1963, nearly 90 drilling operations were in progress. Workers flocked from around the Gulf region to take high-paying jobs offshore or in the growing support centers of New Orleans, Morgan City, Lafayette, Beaumont, and Houston. Although exploratory success offshore Louisiana in the immediate years after 1962 could not match the extraordinary record of the late 1950s, the discovery rate for large fields of 100 million barrels or more was impressive: 155 for offshore Louisiana versus 3,773 for the United States as a whole. By 1968, 14 of the 62 large fields discovered in the United States were offshore Louisiana, and 11 of those 14 lay either wholly or partially within federally administered areas. Total offshore production from the Gulf of Mexico rose from 348,000 barrels per day in 1962 (4.8 percent of total U.S. production) to 915,000 barrels per day in 1968 (8.6 percent of the U.S. total), and most of this increase came from federal areas, especially acreage leased in 1962.¹⁵

The March 1962 sale had another consequential effect onshore: the \$445 million in cash bonuses earned by the government alerted many officials to the importance of outer continental shelf leases as a source of federal revenue. The next year, the Bureau of Land Management opened an office in Los Angeles and offered the first oil and gas leases off the coasts of Oregon and Washington. Three years later, the Bureau offered the first leases in California's Santa Barbara Channel. The federal outer continental shelf leasing program thus took on national scope.¹⁶

Pushing Technological Frontiers—and Physical Limits

Meanwhile, technological innovations revitalized the Gulf offshore industry and generated interest in other ocean basins. New well designs and well-logging techniques resolved deep subsurface drilling problems and reduced well costs. Drilling experiments in extreme water depths, such as Project "Mohole" funded by the National Science Foundation, set the stage for dramatic advances in future oil exploration. In 1962, Shell equipped the drillship

Eureka with the first automatic dynamic positioning system and embarked on a core-drilling program in 600 to 4,000 feet of water in the Gulf. *Eureka's* cores confirmed for the first time that oil had been generated in the sands that the Mississippi River had deposited over eons in the broad alluvial valley extending beyond the continental shelf into the deep Gulf. Then, beginning in 1968, the Joint Oceanographic Institutions for Deep Earth Sampling project launched the famous voyage of the *Glomar Challenger* drillship, whose core samples gave further evidence of oil generation in extreme ocean depths.¹⁷

Although exploratory drilling capabilities raced ahead of commercial producing depths—a recurring theme in the history of offshore oil—the industry nevertheless made great advances during the 1960s in all phases of offshore exploration and production. Among other innovations, digital sound recording and processing greatly enhanced the quality of seismic data and fortified geoscientists' ability to interpret subsurface geology. Improvements in soil-boring techniques led to greater understanding of seabed soil mechanics and foundations. Higher-strength steel yielded stronger jacket construction and the use of larger equipment to install larger rigs. Digital computers made possible the three-dimensional modeling of platform jacket designs. Together, these developments moved production operations into 350-foot water depths by 1969.¹⁸

Toward the end of the decade, however, the cost of bringing in productive leases began to outrun the price of oil, which had remained at \$2 to \$3 per barrel in the United States since the end of World War II. Many of the large, easy-to-identify structures in the Gulf had been picked over and drilled. Some companies were fooled by geology into making costly mistakes. At a federal offshore Texas sale in 1968, for example, a Humble-Texaco partnership staked \$350 million on leases that yielded nothing. Offshore Texas, it turned out, proved to be largely gas-prone, but regulated prices made natural gas less profitable than oil.¹⁹

Hurricanes wreaked havoc with production. In 1961, Hurricane Carla triggered soil movements in the Mississippi Delta that destroyed a large number of pipelines. Hilda (1964) and Betsy (1965) knocked out 20 platforms and damaged 10 others, as 70-foot wave heights, far exceeding earlier estimates, overwhelmed platform decks. Camille (1969), a Category 5 hurricane, passed directly over 300 platforms, most of which survived the waves, but the storm caused violent mud slides that wiped out three large platforms in 300 feet of water.²⁰

On top of the business failures and natural disasters, the sheer technological challenges and the necessity to complete work as quickly as possible compromised safety. Project profitability depended on how soon production could be brought online. Drilling vessels were contracted on day-rates, increasing time pressures. Production processes were highly interdependent: delay in one place could cause delays elsewhere. So there were relentless demands to drill the wells, install the platforms, and get the oil and gas flowing. "When I first started working, they didn't care whether they killed you or not!" remembered one offshore veteran. "In other words, 'we are going to get it done, regardless.' There was no suing like people are suing now. Back then, if you got hurt, they just pushed you to the side and put somebody else in."²¹

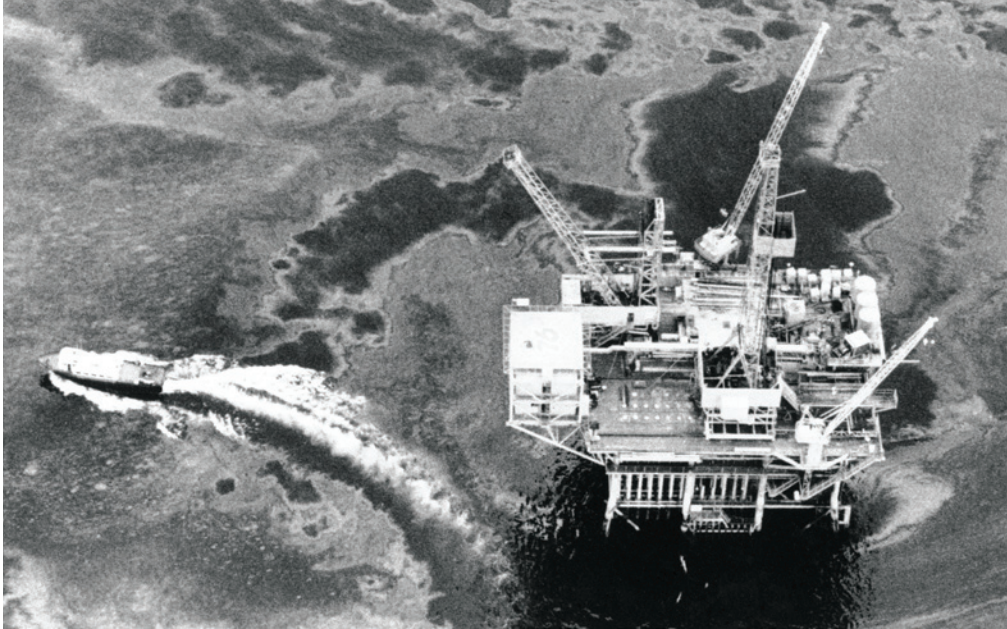
Accident rates for mobile drilling vessels remained unacceptably high, especially for jack-ups. Blowouts, helicopter crashes, diving accidents, and routine injuries on platforms were all too common. Facilities engineering on production platforms was a novel concept. Platforms often had equipment squeezed or slapped together on the deck with little concern or foresight for worker safety. Crew quarters, for example, could sometimes be found dangerously close to a compressor building.²²

Federal oversight followed the philosophy of “minimum regulation, maximum cooperation.”²³ Between 1958 and 1960, the U.S. Geological Survey Conservation Division, the regulatory agency then overseeing offshore drilling, issued outer continental shelf Orders 2 through 5, requiring procedures for drilling, plugging, and abandoning wells; determining well productivity; and the installation of subsurface safety devices, or “storm chokes.” But the Offshore Operators Committee (representing leaseholders) persuaded regulators to dilute Order 5 to permit waivers on requirements for storm chokes. Significantly, the orders neither specified design criteria or detailed technical standards, nor did they impose any test requirements. Companies had to have certain equipment, but they did not have to test it to see if it worked.²⁴ In general, as a 1973 National Science Foundation study concluded, “the closeness of government and industry and the commonality of their objectives have worked against development of a system of strict accountability.”²⁵

Lax enforcement contributed to the lack of accountability. The U.S. Geological Survey freely granted waivers from complying with orders and did not inspect installations regularly. Federal and state regulatory bodies were underfunded and understaffed. In 1969, the Gulf region’s lease management office had only 12 people overseeing more than 1,500 platforms. Even those trained inspectors and supervisors often lacked experience in the oil business and a grasp of its changing technological capabilities. “Each oil well has its own personality, is completely different than the next, and has its own problems,” observed one consultant in 1970. “It takes good experienced personnel to understand the situation and to cope with it.” Too often on drilling structures, he complained, one found inexperienced supervisors; employees who overlooked rules and regulations (the purpose of which they did not understand); and, perhaps most troubling, even orders from bosses to cut corners—all of which created conditions for an “explosive situation.”²⁶

Explosive Situations

On January 28, 1969, a blowout on Union Oil Company Platform A-21 in the Santa Barbara Channel released an 800-square-mile slick of oil that blackened an estimated 30 miles of California beaches and lethally soaked sea birds in the goopy mess. Although the well’s blowout preventer worked, an inadequate well design allowed the hydrocarbons to escape through near-surface ruptures beneath the seafloor. Union Oil had received a waiver from the U.S. Geological Survey to set casing at a shallower depth than required by Order 2, highlighting the lack of accountability that had come to characterize offshore operations.²⁷ The 11-day blowout spilled an estimated 80,000 to 100,000 barrels of oil²⁸—

SANTA BARBARA OIL SPILL

Oil from a ruptured well surrounds a platform six miles off the coast of Santa Barbara. The 1969 spill, an estimated 100,000 barrels, was the largest in U.S. waters prior to 2010. Some 30 miles of shoreline were fouled, and thousands of birds died along with fish, dolphins, and sea lions. The incident drew public outcry and triggered environmental-protection legislation. Today, Platform A-21 is still operating.

Associated Press

the largest offshore drilling accident in American waters until the Macondo blowout. It generated intense opposition to offshore oil in California, but the fallout also reverberated nationally, setting the stage for the passage of the National Environmental Policy Act (NEPA), a symbol of the growing strength of the national environmental movement, as well as a host of other increasingly demanding environmental protection laws throughout the 1970s (See Chapter 3).²⁹

Offshore operators suddenly faced a potentially hostile political and regulatory climate. Ten days after the accident, Secretary of the Interior Walter Hickel, with the support of President Richard Nixon, issued a moratorium on all drilling and production in California waters. In April, Secretary Hickel completed a preliminary assessment of the leases affected by the moratorium and allowed 5 of the 72 lessees to resume drilling or production. In August, the Interior Department issued completely revised outer continental shelf Orders 1–7—the first update since the orders were established—with more specific requirements about company plans and equipment for prevention of pollution and blowouts. It also issued new Orders 8 and 9 on the installation and operations of platforms and pipelines. These were the first rules in which the department claimed authority to prohibit leasing in areas of the continental shelf where environmental risks were too high.³⁰

The industry protested the new outer continental shelf regulations, but calamities in the Gulf undermined its case. In February 1970, Chevron's Platform C in Main Pass Block 41 blew out and caught fire. The spill forced a postponement of a federal lease sale, damaged

wildlife, and drew a \$31.5 million suit against the company by Louisiana oyster fishermen and a \$70 million suit from shrimp fishermen. Chevron was also fined \$1 million for failing to maintain storm chokes and other required safety devices—the first prosecution under the 1953 Outer Continental Shelf Lands Act. The Justice Department also obtained judgments against other major oil and gas companies for similar violations. Then, in December, Shell suffered a major blowout on its Platform B in the Bay Marchand area, killing four men and seriously burning and injuring 37 others. Investigators attributed the accident to human error resulting from several simultaneous operations being performed without clear directions about responsibility. It took 136 days to bring 11 wild wells under control, at a cost of \$30 million. The failure or leaking of subsurface-controlled storm chokes contributed to the size of the conflagration.³¹

In the wake of these disasters, the government further strengthened its regulatory program. The Interior Department again revised and expanded outer continental shelf orders to mandate new requirements: surface-controlled storm chokes; the testing of safety devices prior to and in use; more careful control of drilling and casing operations; prior approval of plans and equipment for exploration and development drilling; and updated practices and procedures for installing and operating platforms. To enforce the new regulations, the U.S. Geological Survey tripled its force of inspectors and engineers, ceased using industry-furnished transportation for inspections, and introduced a more systematic inspection program based on newly developed criteria.³²

In response, the Offshore Operators Committee and the industry's Offshore Safety and Anti-Pollution Equipment Committee worked closely with the U.S. Geological Survey both in advising changes in the outer continental shelf orders and in promptly drafting a new set of American Petroleum Institute (API) "recommended practice" guidance documents for the selection, installation, and testing of safety devices, as well as for platform design. The major offshore operators revamped personnel training for offshore operations, and they formed an organization called Clean Gulf Associates to upgrade oil-spill handling capabilities.³³ Certifying agencies issued new standards and guidelines for mobile drilling.³⁴ In addition, the industry's annual Offshore Technology Conference, first held in 1969, became an important forum for publishing and sharing technical information that led to safer designs and operations.³⁵

The industry's safety record in the Gulf improved significantly after the new regulations and practices were introduced: the reported incidence and rate of fatalities and injuries decreased, as did the rate of fires and explosions.³⁶ During the 1970s and 1980s, the frequency of blowouts did not decline significantly, but there was a sharp drop in the number of catastrophic blowouts, and fewer casualties and fatalities were associated with them.³⁷

Design and equipment problems were steadily being solved. But reducing accidents caused by human error, poor safety management, or simultaneous operations continued to be a vexing challenge.

Constrained Expansion

As new regulations brought more caution to offshore oil development, countervailing forces emerged to speed it up. Domestic oil supply could not keep up with demand. In the postwar period, Americans' consumption of petroleum—largely for operating automobiles—climbed dramatically, rising steadily from 243 gallons of motor gasoline per capita in 1950 to 463 gallons per capita in 1979.³⁸

U.S. oil production peaked, however, in 1970. Along with the OPEC oil embargo of 1973 and consequent skyrocketing price of oil products, this event spurred the quest to develop new offshore reserves. With crude oil prices tripling to \$10 per barrel, oil companies could justify more expensive offshore drilling and development. Under the mandate of "Project Independence," the Nixon Administration announced a dramatic increase in the pace of leasing in the Gulf and a resumption of sales off the Atlantic, Pacific, and Alaskan coasts. At the March 1974 federal lease sale of offshore Louisiana acreage, the industry spent a record \$2.17 billion in cash bonuses for leases covering 522,000 acres, including a few tracts ranging beyond 1,000-foot depths.³⁹

The First Deepwater Play

In June 1975, Shell made a monumental discovery on one of those new leases. Shell geophysicists had employed an innovative seismic technique called "bright spot" to lead drillers to an attractive prospect, code-named Cognac, in 1,000 feet of water in the Mississippi Canyon, not far from the mouth of the great river. The drilling uncovered an estimated 100-million-barrel reserve.⁴⁰ Cognac pioneered other discoveries in what would come to be known as the "Flex Trend," an area in the Gulf that reaches just beyond the edge of the continental shelf, where there is a flex in the seafloor. The Flex Trend would be the world's first true oil play in 1,000-foot water depths, the modern definition of "deepwater."⁴¹

When Shell purchased its leases, it did not yet have a design concept for deepwater production. Barges were not big enough to launch a 1,025-foot steel jacket in one piece. Therefore, adapting Exxon's precedent—the company installed its Hondo jacket in 850 feet of water in the Santa Barbara channel in 1976—Shell chose to build the Cognac structure in three pieces and assemble them vertically in place. The complex, nerve-wracking installation inflated total development costs to nearly \$800 million. But Cognac was both a technical and commercial success. It won the American Society of Civil Engineers 1980 award for "Outstanding Civil Engineering Achievement," the first ever received by an oil company. Production commenced in 1979, just as the supply shock caused by the Iranian Revolution drove the price of oil to nearly \$40 per barrel.⁴²

Along with Hondo and major developments in the North Sea pioneered by Phillips, Conoco, and BP, Cognac paved the way for truly enormous offshore engineering-construction projects. In 1976, Brown & Root and J. Ray McDermott opened giant new construction yards at Harbor Island, near Corpus Christi Bay, to accommodate the assembly and load-out of deepwater structures. In these yards, they built jackets lighter and cheaper

than Cognac and launched them in single pieces. In the late 1970s, Brown & Root built a 700-foot structure for Chevron's Garden Banks field, and a 650-foot jacket for Atlantic Richfield. In 1980–1981, McDermott built two platforms for Union Oil in the 1,000-foot waters of the East Breaks area, 100 miles south of Galveston. During 1979–1983, Brown & Root built and installed a novel “guyed tower” for Exxon in 1,000 feet of water just southwest of Cognac.⁴³

Even as rising oil prices and declining onshore production in the late 1970s spurred them on, Gulf oil operators encountered economic and geological constraints. Bonus bids soared beyond the estimated value of the oil that might be discovered and produced: the September 1980 sale in New Orleans, for example, brought in \$2.8 billion in cash bonuses, shattering all previous records. During the 1970s, the bonus paid per barrel of oil equivalent discovered by the largest producing companies increased four- to five-fold, undermining the economics of deepwater.⁴⁴ Furthermore, initial production rates from some of the early producing wells in the Flex Trend proved disappointing. Many industry exploration managers came to believe that after 25 years of development, only lean prospects remained in the Gulf. The best hope for increasing national reserves, they concluded, was from other parts of the U.S. outer continental shelf.⁴⁵

Beyond the Shelf

Rising lease bonuses still did not deter major companies (such as Chevron, Exxon, Mobil, and Amoco), along with some of the larger independents (such as Pennzoil, Union, and Tenneco), from drilling and developing fields in the deepwater Flex Trend. But discoveries could not offset overall production declines in the Gulf. Oil production on the shelf had peaked at just above 1 million barrels per day in 1972; by 1978, it had fallen below 800,000 barrels per day. Because discoveries in the Flex Trend play were relatively small, with fairly low flow rates, most Gulf oil and gas still came from shallow water, despite declining overall production there. In 1970, the average production-weighted depth of oil extracted from the Gulf was just 100 feet, and by 1980 it was still less than 200 feet.⁴⁶ Many managers had concluded that there would never be economic developments more than 60 miles from shore. Other experts became convinced that significant oil-bearing sands would never be found beyond the continental shelf. “But what conventional wisdom really tells you,” as one Shell geophysicist explained, “is that you just don’t know what you don’t know.”⁴⁷

At just that time, some scientists from industry and academia had begun to piece together a regional picture of the geology deep underneath the Gulf by combining information from cores with a regional seismic survey shot out into deepwater. This picture showed that massive salt pillars, or diapirs, had squeezed up from the mother layer of salt deposited beginning 165 million years ago, when the Gulf of Mexico was slowly forming. As the diapirs pinched up, sandstone overlaying the salt slowly subsided, forming cup-shaped “mini-basins” featuring different kinds of configurations for trapping oil. These sandstone formations were named “turbidites” (they had been deposited when ancient underwater

rivers, called turbidity currents, channeled huge volumes of sediment onto the continental margin). The structural anomalies in these mini-basins looked similar to productive features on the shelf, but the spotty seismic coverage allowed for only speculative knowledge of their potential, at best. Shell, always the leader in Gulf frontier exploration, had drilled a number of wells in similar rocks along the margin of the continental shelf. Turbidites in deepwater were potentially much larger, less faulted, and might have prolific flow rates. At least in theory, they would require fewer wells, making them more attractive as economically exploitable reservoirs of oil.⁴⁸

During 1978–1980, hoping to test its theories about the regional geology, Shell nominated deepwater tracts for auction. But no other companies seconded its nominations, so the government never selected the tracts for sales.⁴⁹ Then, in 1982, the Interior Department announced a new system of area-wide offshore leasing. This policy put into play entire planning areas (e.g., the central Gulf of Mexico) up to 50 million acres, rather than rationing tracts through a tedious nomination and selection process. Companies could bid on any tract they wanted in a lease sale for a given planning area, thus giving them access to far more extensive offshore acreage at significantly less cost.⁵⁰

Strong political opposition to area-wide leasing by some coastal states and environmental organizations stymied its effective use in other parts of the nation (see Chapter 3), but not in the Gulf, where oil companies had long operated. Established infrastructure and abundant geological information there could be put to more flexible use under a more open system. Oil companies responded to area-wide leasing by bidding aggressively for attractive blocks on the continental shelf, while making a number of speculative bids on acreage ranging into 3,000-foot depths beyond the edge of the shelf. The May 25, 1983 sale harvested a record \$3.47 billion in high bonus bids. All told, in seven lease sales held from 1983 to 1985, the Interior Department, through the newly formed Minerals Management Service (see Chapter 3), leased 2,653 tracts, more than had been leased in all the federal sales since 1962 combined. About 600 of these tracts lay in deepwater beyond 1,000 feet.⁵¹

Shell acquired the lion's share of deepwater tracts in the March 1983 sale and immediately started drilling. In 1982, it had leased Sonat Offshore Drilling's *Discoverer Seven Seas*, one of the few vessels rated for 6,000-foot depths. Shell then spent more than \$40 million to extend the vessel's depth capability with a larger marine riser, enhanced dynamic positioning, and a new remote-operated vehicle to enable sophisticated work where human divers could not venture. In October 1983, the *Seven Seas* made a major discovery at Shell's Bullwinkle prospect, establishing the deepwater "Mini-Basin Play," which targeted the turbidite sandstones in the basins flanking the salt structures.⁵²

In the next central Gulf area-wide sale, in April 1984, many different operators jumped in to compete for deepwater tracts. This prompted Shell to move quickly in deploying the *Shell America*, a \$45 million custom-designed, state-of-the-art seismic vessel that provided company geophysicists with high-quality, proprietary seismic data. Armed with these data and other intelligence gained from drilling its 1983 leases, Shell dominated the May 1985 sale, winning 86 of 108 tracts on which it bid, in water depths ranging to 6,000 feet. For

Shell, pushing deeper was an imperative for its operations in the United States, as onshore reserves continued to decline. “Exploration has been called a poker game,” explained one Shell official. “But there’s more to it than that. In this game, we don’t have chips or coins or dollar bills that can change hands over and over again. We’re dealing with a declining resource base, and every barrel we find is never going to be found again.”⁵³

The Era of Uncertainty

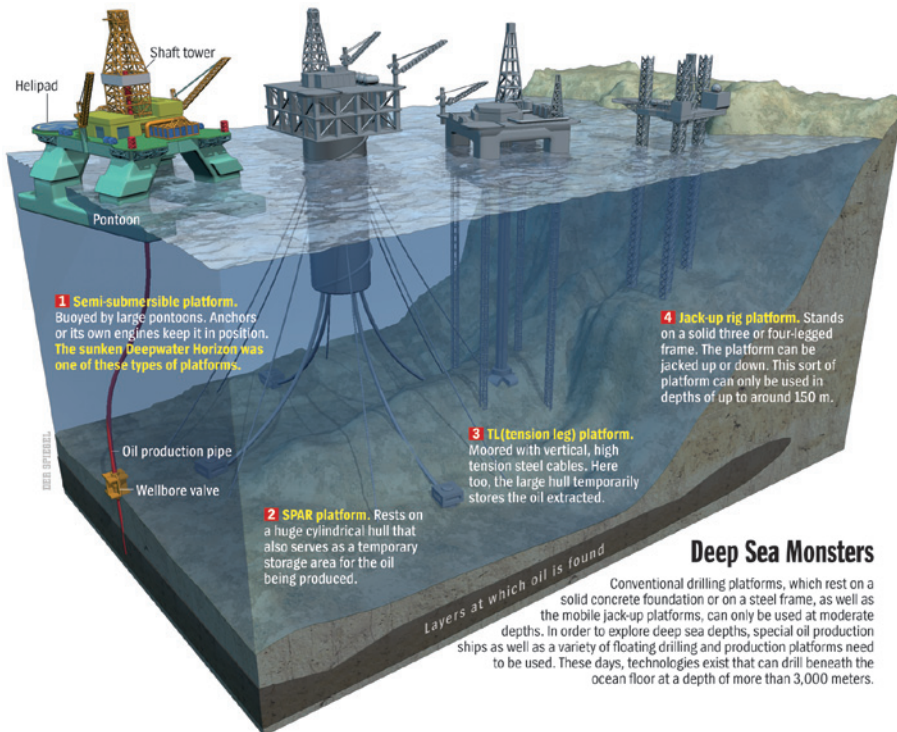
The long cycles of oil exploration and development do not always align well with the shorter cycles of the economy. Just as Shell bet heavily on deepwater, the severe recession in 1981 further depressed falling oil demand. For the first time in 34 years, U.S. oil consumption hit a plateau and began declining.⁵⁴ The now “forgotten victory” of energy conservation and efficiency measures passed in the mid-1970s, in response to historically high oil prices, reversed the long trend of an increasingly petroleum-intense U.S. economy. During 1985–1986, oil prices collapsed to \$10 per barrel, as international producers saturated the global market with crude.⁵⁵

Expensive Gulf development projects were canceled or shelved. Construction of mobile drilling vessels and other kinds of offshore-servicing equipment fell sharply. Unemployed oilfield workers transitioned into new trades, or migrated from southern Louisiana in search of better opportunities. This human and capital flight marked the beginning of what one scholar called “the inevitable disassembly of the offshore system and its onshore support network for the Gulf of Mexico.”⁵⁶

The offshore projects that went forward faced intimidating challenges. Shell drilled some dry holes costing more than \$10 million apiece. Development stretched the limits of technological and financial resources. To produce oil from the Bullwinkle field, the company installed in 1988 a \$500 million fixed platform, 162 stories high—taller than Chicago’s Sears Tower (now the Willis Tower), the tallest building in the world at the time. The Bullwinkle platform was the largest and last conventional jacket of its kind. The scale and costs of constructing anything bigger were simply prohibitive.⁵⁷

Moving deeper would require alternative production methods: subsea wells, tension-leg platforms, or floating systems. Operators had put subsea wells to use in the North Sea, but they were still extremely expensive. The tension-leg platform was an innovative concept consisting of a production facility situated on a floating hull held in place by long tendons that kept the hull from bobbing like a cork but allowed some degree of side-to-side motion. In 1984, Conoco installed the first full-scale design of this type in the North Sea, in 485 feet of water, and in 1989 the company placed its Jolliet mini-tension-leg platform in 1,760 feet of water in the Gulf.⁵⁸ But tension-leg platforms would have to be scaled up for major projects in deepwater. In 1987–1988, Placid Oil developed a field in 1,500 feet of water with a floating production facility converted from a semisubmersible drilling vessel. But Placid soon abandoned the development, sold the semisubmersible, and sought bankruptcy protection.⁵⁹

Deep Sea Monsters



DER SPIEGEL 19/2010

The deepwater costs were matched by the safety and environmental risks. In 1985, an Office of Technology Assessment study of Arctic and deepwater oil drilling highlighted the “special safety risks” of “harsh environments and remote locations.” It identified “a need for new approaches to preventing work-related injuries and fatalities in coping with new hazards in the hostile Arctic and deepwater frontiers.” It also presciently warned of the glaring deficiencies in safety oversight offshore, observing that “there is no regulatory requirement for the submission of integrated safety plans which address technical, managerial, and other aspects of offshore safety operations.”⁶⁰

Setbacks in the Arctic

As the study indicated, deepwater was not the only frontier that captured the industry’s interest. In the 1980s, companies also had their sights set on the Arctic region, then thought to have the highest resource potential in the United States. Since the 1960s, major firms had produced oil from Alaska’s Kenai Peninsula and Cook Inlet. In 1977, the massive onshore Prudhoe Bay field on the North Slope started pumping oil through the Trans-Alaska Pipeline. Many explorers expected to find the next great oil frontier to the north of Prudhoe Bay, in the Bering, Beaufort, and Chukchi Seas. Although the industry lost a contentious struggle to gain access to the Bering Sea’s Bristol Bay, home to the world’s largest commercial salmon fishery, they did win the right to lease and drill in the Beaufort and Chukchi Seas.⁶¹

Everywhere operators drilled offshore Alaska, however, they came up empty. Either they found no source rocks or the deposits they did find were not large enough at that time to turn a profit in the Arctic's forbidding environment. After a costly dry hole at a prospect called Mukluk in the Beaufort Sea and some futile efforts to explore in the Chukchi Sea, the industry temporarily lost its craving for the Arctic. The public-relations fallout from the *Exxon Valdez* oil spill in 1989, which resulted in congressional and presidential moratoriums on leasing in Bristol Bay, contributed to the industry's suspended interest in offshore Alaska.⁶²

Renewed Focus on the Gulf of Mexico

The mid-1980s collapse in oil prices also ruined many companies' appetite for further leasing in the deepwater Gulf of Mexico. But Shell and others chose to take a longer-term view—a decision reinforced by the failures in Alaska. Additional reinforcement came in 1987, when the Minerals Management Service reduced the minimum bid for deepwater tracts from \$900,000 to \$150,000—enabling companies to lock up entire basins for 10 years for only a couple million dollars.⁶³ During the next five years, despite flat oil and gas prices, the industry acquired 1,500 tracts in deepwater.⁶⁴

Shell's December 1989 announcement of a major discovery at a prospect called Auger, located in the Garden Banks area 136 miles off the Louisiana coast, spurred further interest. Two years earlier, Global Marine's new, giant semisubmersible, the *Zane Barnes*, struck oil for Shell after drilling through 2,860 feet of water and another 16,500 feet beneath the seafloor. Shell kept the discovery quiet as it delineated the extent of the field, which turned out to contain an estimated 220 million barrels of oil equivalent, the company's third-largest offshore discovery in the Gulf. Underpinning Shell's decision to go forward with Auger was the discovery of relatively high flow rates from the turbidite sands at Bullwinkle, where engineers found they could open the wells to 3,500 barrels per day (three times the rate considered good for a well on shallower parts of the Gulf continental shelf). If Auger had similar flow rates, the field could be profitably developed, even in water more than twice as deep as Bullwinkle's. Few people knew that Auger was only one of a number of Shell deepwater discoveries.⁶⁵

As the company formulated an ambitious strategy to launch a series of major platforms, a gloomy economic outlook tempered Shell's euphoria over the Auger discovery and production breakthrough at Bullwinkle. The projected cost of developing Auger exceeded \$1 billion. In appraising the next prospect, code-named Mars, Shell's exploration managers looked for ways to save money and offload some of the financial risk; accordingly, in 1988, they brought in British Petroleum (BP) as a partner with a 28.5 percent interest in the project.⁶⁶

At the time, Mars seemed like a risky endeavor, with low probability for a major discovery. Furthermore, BP posed little threat. The company had been kicked out of Iran and Nigeria in 1979 and was struggling with a bloated management structure, poorly performing global assets, and uninspired leadership. Shell viewed BP as merely a banker.⁶⁷

All that changed in 1989, when Sonat's *Discoverer Seven Seas* drilled into Mars. The field, located due south of the mouth of the Mississippi, lay in nearly 3,000 feet of water. The discovery well encountered multiple oil- and gas-bearing layers stacked on top of each other over several hundred meters. Mars was more than twice the size of Auger—the largest field discovered in the Gulf in 25 years. For Shell, Mars promised a big payoff for large bets on deepwater leases. For the industry, Mars confirmed the Mini-Basin trend in the Gulf as a bona fide play. For BP, Mars allowed the company's managers, engineers, and scientists to go to school on Shell's deepwater technology. Perhaps just as importantly, according to BP's chief in the United States, "Mars saved BP from bankruptcy."⁶⁸

During the next several years, major oil companies—and even more significantly, contractors in the offshore service industry—propelled the evolution of technology in innovative new directions. The 1970s revolution in digital, three-dimensional (3-D) seismic imaging, pioneered by Geophysical Services Inc. (GSI), and the 1980s move to computer workstations, which enabled faster processing of the data generated in such surveys, combined to enhance dramatically the industry's accuracy in locating wells for field development—a critical factor when drilling a single well in deepwater could cost as much as \$50 million. Beyond development drilling, 3-D seismic imaging boosted the success of wildcat discovery wells from less than 30 percent to 60 or 70 percent. As the major companies began to divest from older producing properties in favor of new deepwater prospects, smaller firms purchased older properties and redeveloped them with significant reserve additions using 3-D seismic imaging. In all, 3-D seismic imaging effectively tripled or even quadrupled the estimated amount of oil and gas reserves in the Gulf of Mexico.⁶⁹

Drilling and subsea engineering advanced in similar fashion. Drilling contractors developed a new generation of vessels that took drilling from 5,000 to 10,000 feet of water, and from 20,000 to 30,000 feet of sub-seafloor depth. New directional drilling techniques, made possible by "downhole steerable motors," allowed engineers to maneuver a well from vertical to horizontal to achieve greater accuracy and more fully exploit reservoirs. Drillers also found ways to obtain information from deep inside wells, using "measurements-while-drilling" tools and sensors that provided position, temperature, pressure, and porosity data while the borehole was being drilled. Improvements in marine risers using lightweight composite materials and tensioners, along with new methods for preventing oil from cooling and clogging in deepwater pipelines, enabled the industry to make long tiebacks between subsea wells and production facilities. To support subsea installation and operations, the industry turned to sophisticated remote-operated vehicles mounted with TV cameras and umbilical tethers containing fiber-optic wire for the transmission of vivid images.⁷⁰

Even as the major operators pushed into deepwater, they outsourced more of the research and development (R&D) of new technologies. The bust of the 1980s had driven the exploration and production companies to decrease internal R&D and adopt policies of buying expertise as needed, rather than cultivating it from within. R&D investments in oil exploration and production by the major companies declined from nearly \$1.3 billion in 1982 to \$600 million by 1996. According to a National Petroleum Council study, "This 'buy versus build' strategy resulted in a significant reduction in the number of

skilled people within operating companies who understood technology development and deployment.”⁷¹ Service companies (Schlumberger, Halliburton, Baker Hughes, and Oceaneering) became the major source of technology development. An illustration of this trend was the Texaco-initiated “Deep Star” consortium, established in 1992, through which offshore operators funded contractor-generated R&D.⁷²

Rapid technological advances in the early 1990s did not immediately translate into more economically feasible practices. Cost overruns, delays, and strained relationships with contractors plagued the fabrication and installation of Shell’s giant tension-leg platform for Auger, the industry’s bellwether deepwater project. Further, Shell discovered that crude oil from the Auger field was sour (containing sulfur, which had to be separated out at the refinery) and thus had to be discounted. The company’s only salvation on the project depended on Auger’s wells flowing at a higher rate than Bullwinkle’s.⁷³

Auger Pays Off

Fortunately for Shell and the offshore industry, the wells did not disappoint. In the spring of 1994, Shell began to bring in wells at Auger that flowed at more than 10,000 barrels per day. Even with oil prices at \$20 per barrel or less, deepwater now promised handsome profits. The Auger wells confirmed the reservoir model for turbidites in deepwater and even exceeded Shell’s most optimistic estimates. Engineers designed Auger to handle 42,000 barrels of oil (and 100 million cubic feet of gas) per day from 24 wells, but by July the first three wells were already producing 30,000 barrels per day. “Debottlenecking” efforts eventually raised Auger’s capacity to 105,000 barrels of oil and 420 million cubic feet of gas per day by the late 1990s.⁷⁴

Auger’s prodigious output also made subsea completions (with the wellhead located on the ocean floor rather than on a surface production platform) economic in the Gulf, as they had been in the North Sea. With tension-leg platforms like Auger, subsea completions became important as a component of an early production system or as a remote subsea development. Large fields or clusters of smaller fields, which otherwise would not justify the expense of multiple or larger platforms, could thus be profitably developed.⁷⁵

Auger’s many blessings came at a cost to Shell and the environment. Expanding production at Auger was extremely challenging. At the start of production in April 1994, Shell continuously flared or vented between one and six million cubic feet of natural gas per day, without the required federal permission. The flaring and venting continued for more than four years until the Minerals Management Service announced it had discovered this violation as well as Shell’s failure to record and report the releases. In a 2003 civil settlement, Shell agreed to pay \$49 million, an amount equivalent to the value of about two weeks of production from Auger. If the company was chastened after having to admit to these serious violations, Shell management also must have been tempted to look at this charge as an incidental cost of doing business in the deepwater Gulf.⁷⁶

AUGER TENSION-LEG PLATFORM



Like a giant alien creature, a scale rendering of a tension-leg drilling platform is superimposed over New Orleans. Built by Shell to tap its Auger deepwater field some 200 miles southwest of the city, the huge platform uses steel mooring cables to stabilize its 3,000-foot legs and can drill 20,000 feet below the seafloor. The platform augured well for Shell in the late 1990s, delivering 100,000 barrels of oil a day.

Courtesy of Shell

Deepwater Treasures

The productivity of the Auger wells made the Gulf of Mexico the hottest oil play in the world. And it was mostly about oil. Deepwater proved to be largely oil-prone. The source rocks for most of the deepwater region are an Upper Jurassic kerogen that generates natural gas only when subjected to very high temperatures. But subterranean thermal gradients and source-rock temperatures in the deep Gulf are quite modest, despite the enormous pressures exerted several miles below the seabed. The massive amounts of salt (see below) has acted like a heat sink, keeping hydrocarbons from getting too hot and thus cooking up large amounts of natural gas.⁷⁷

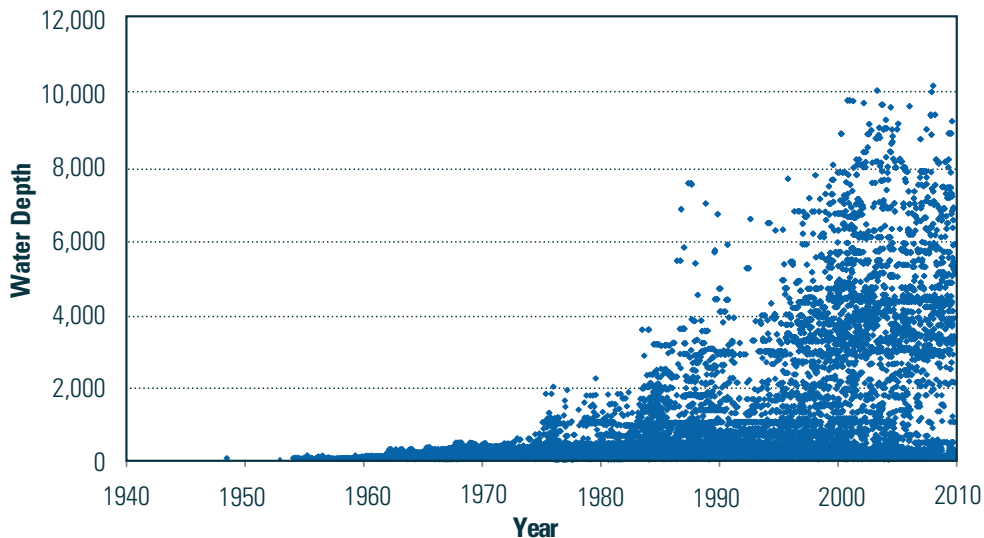
Despite downward pressure on oil prices in the late 1990s, the promise of prolific production from deepwater was too much to resist. Exploration and production firms with deepwater leases consolidated their positions. Companies that had sat on the sidelines during the 1980s stampeded into unclaimed areas. Newly developing or commercialized exploration and production technologies found vibrant new markets. Contractors all along the Gulf Coast and, indeed, around the world, geared up for a surge of activity. Port Fourchon, Louisiana's southernmost port on the tip of Lafourche Parish, came to life as the jumping-off point for supplying and servicing deepwater operations in the Gulf.⁷⁸

The next landmark on the horizon for deepwater drilling was Mars. In July 1996, Shell began producing from its Mars platform, six months before NASA launched its Pathfinder probe to the planet Mars. At a total cost of \$1 billion, Shell's Mars was more than three times as expensive as the Mars Pathfinder, and its remote technologies and engineering systems were arguably more sophisticated. The investment of money and technology paid dividends: the Mars platform tapped into the largest field discovered in the United States since Alaska's Prudhoe Bay. Creating a system to produce the field also established a new paradigm for large projects and revealed how exploration and production strategy was being reshaped in the Gulf.⁷⁹

To reduce costs and avoid the headaches experienced at Auger, Shell introduced a different contracting model at Mars based on "alliances," including the sharing of technology and patents. Shell ended up giving away more than BP, which had little deepwater experience. But the costs and risks were too large to go it alone, as Shell had usually preferred to do. The partners carried the alliance concept over to their relationship with contractors, who built the tension-leg platform hull, fabricated the topsides, and integrated the two. The project team brought in contractors early on to collaborate on developments and share risks and rewards. The key advantage of this approach was that it reduced the so-called "cycle time" of design, bidding, and contracting by an estimated six to nine months.⁸⁰ On a platform such as Mars, where the first well came in at 15,000 barrels per day, the time-value of money made at the beginning rather than at the end of the platform's life was quite significant. Shell's contracting model at Mars, replicated on its subsequent tension-leg platforms, established the growing importance of alliance networks for global oil and gas developments in technologically complex frontier regions characterized by high costs and risks.⁸¹

In the late 1990s, having control of one-third of all Gulf leases in depths greater than 1,500 feet, Shell rolled out one tension-leg platform after the other.⁸² In 1997, a Mars "clone" called Ram-Powell, developed in a joint venture with Exxon and Amoco, went on-stream in 3,200 feet of water 80 miles southeast of Mobile, Alabama. In March 1999, Shell and its minority partners, BP, Conoco, and Exxon, started up the massive Ursa, on a lease two blocks to the east of Mars. Nearly double the weight of Mars, Ursa was designed to accommodate astounding initial well-production rates of 30,000 barrels per day; in September 1999, a well at Ursa broke all records with a production rate of nearly 50,000 barrels of oil equivalent per day. Finally, in 2001, Shell brought in production from the Brutus platform, which tapped into a 200-million-barrel field in 3,000 feet of water in the Green Canyon.⁸³

Shell's new technologies solidified the company's position as the leader in the Gulf. Its tension-leg platforms, as well as major fixed platforms such as Bullwinkle and West Delta 143, not only produced hydrocarbons from the fields beneath them, but also served as hubs used to take and process oil and gas production from satellite subsea wells, thus extending the life of those platforms once their own production declined. Deepwater output from Shell's platforms and subsea wells, and eventually from other companies in the vicinity, fed into network of Shell-owned or operated crude-oil trunk pipelines, gathering systems, and natural-gas pipelines. Shell also made special arrangements to

FIGURE 2.4: Wells Drilled in the Gulf of Mexico by Water Depth, 1940-2010

Source: Commission staff, adapted from Bureau of Ocean Energy Management, Regulation and Enforcement

transport crude oil production from its growing deepwater properties into the Clovelly storage facilities owned by the Louisiana Offshore Oil Port in South Louisiana. By 2001, Shell operated 11 of the 16 key oil trunk pipelines servicing deepwater.⁸⁴

Shell's lead in the deepwater Gulf was substantial but not unassailable. During the latter half of the 1990s, many companies gained ground, including a rising percentage of small and midsized independents. But the only company that chased down and eventually overtook Shell was BP.

Deeper Still

In the 1990s, technological breakthroughs in imaging and drilling through massive salt sheets opened a new “subsalt” play, first on the shelf and then ranging into deepwater. Discoveries in at least four different “fold belts” across the Gulf of Mexico extended the search for oil into “ultra-deepwater” and led to another wave of innovation in floating production. In 1990, most oil and gas from the Gulf had still come from shallow water; average production-weighted depth had barely reached 250 feet. By 1998, the weighted average passed the 1,000-foot milestone, at which point deepwater production (at about 700,000 barrels per day of oil and 2 billion cubic feet per day of gas) surpassed that from shallow water for the first time.⁸⁵

As the industry moved deeper, the abandonment and decommissioning of older platforms on the shelf became a thriving business. During the 1990s, 1,264 platforms were removed, more than twice the total prior to 1990; after 2000, removals continued at a rate of 150

per year.⁸⁶ Some obsolete platforms found use as “artificial reefs” through a creative program, coordinated by the Minerals Management Service and the states of Texas and Louisiana, to place old platforms in specially designated locations on the sea bottom, where they attracted marine life much like natural reefs.⁸⁷

Meanwhile, another relaxation in the terms of access to Gulf of Mexico leases, in the form of the Deepwater Royalty Relief Act (see Chapter 3), helped sustain the oil industry in deepwater. Deepwater royalty relief no doubt enticed some oil companies, especially non-majors, into deepwater. But judging from the huge upswell in bidding at the May 1995 Central Gulf of Mexico sale, before royalty relief was enacted, the race appeared to be already under way.⁸⁸ Oil explorers were clearly gunning for fields like Auger with high flow rates and high ultimate reserves. Many of them were also on the hunt for petroleum in a new geological location: beneath the Gulf’s massive sheets of salt.

Subsalt Discoveries

Salt is the dominant structural element in the Gulf of Mexico petroleum system. Oil explorers had long ago discovered oil trapped against the flanks of salt domes or between the salt diapirs in the deepwater mini-basins. But geologists had typically assumed that there could be no oil reservoirs lying beneath any salt they encountered. By the 1970s, advancing knowledge about the basin’s regional geology suggested that oil *could* be found under the salt. In many places, the salt pillars that extruded upward into sandstone and shale flowed horizontally in elastic plumes over vast expanses of younger, potentially oil-bearing sediment that extend more than 35,000 square miles across the Gulf. Geologists invented new terminology to describe different kinds of salt formations in the picture they pieced together—canopies, tongues, nappes, egg crates, and turtle domes—and established a special subfield of geology to explain how the salt moves. What they were really interested in, however, was what lay beneath the salt.⁸⁹

The subsalt play began in 1990, when Exxon (with partner Conoco) made the first discovery at a prospect called Mickey. Located in 4,352 feet of water on the Mississippi Canyon 211 lease (about 10 miles northeast of where BP would later drill Macondo), Mickey was not then large enough to put into production.* Two years later, Chevron drilled a well in Garden Banks 165 through almost 7,000 feet of salt and another 5,000 feet of subsalt sediment. The well found no oil, but was a milestone because it demonstrated that the technology existed to drill through an enormous body of salt.⁹⁰

Finally, in 1993, Phillips Petroleum announced the first commercial subsalt oil discovery. Years earlier, Phillips had begun to look systematically for places where salt sheets might be obscuring oil reservoirs. In 1989, the firm acquired 15 leases including one at a location called Mahogany. It was a speculative move. Salt plays tricks with seismic sound waves, which travel through salt at a much higher velocity than through the surrounding sediments and also get refracted, much as the image of a pencil is bent when it is stuck in a glass of water. Obtaining clear images of rocks in their proper location under the salt seemed almost impossible. To get a better focus, Phillips shot a 3-D seismic survey over

* Ten years later, Exxon developed the prospect as a subsea natural gas development called Mica.

the prospect. And to share the substantial expenses of conducting the survey and drilling through the salt—twice the cost of a normal well—the company took on Anadarko and Amoco as partners. Phillips’s geophysicists then processed the seismic data with a newly developed computing algorithm, yielding a picture sufficiently improved to make an informed stab at the target. The first well, drilled by a Diamond Offshore semisubmersible, passed through 3,800 feet of salt, at one point encountering unstable rock that threatened to collapse the well. Eventually, the drill hit a 100-million-barrel field. In 1996, Phillips’s Mahogany platform began producing at 20,000 barrels per day.⁹¹

The subsalt play progressed, haltingly, from Mahogany. Drilling through salt involved myriad technical complications. Under high temperature and pressure, salt masses flow, creep, and deform like plastic; this movement can shift the well casing and production tubing. These wells also had to be drilled to great depths, escalating costs. And limitations on computer power made it difficult to obtain reliable seismic images from beneath the salt, adding risk to exploration. Subsalt wells missed hydrocarbons a lot more often than they hit them.⁹²

As operators drilled a string of dry holes, the post-Mahogany euphoria ebbed. In the 1995–1997 lease sales, companies began to turn from shallow subsalt prospects, pursuing instead ultra-deepwater (greater than 5,000 feet) prospects, looking for easier-to-image drilling targets in foldbelts formed by the lateral movement of salt and sediment. In 1995, Oryx Energy made a discovery at Neptune, opening a new play in the Western Atwater Foldbelt. The next year Shell announced a strike at its Baha prospect in the far western Gulf. This discovery initiated the Perdido Foldbelt play in more than 8,000 feet of water.⁹³ A deeper ocean frontier, once again, beckoned the industry.

An Industry Restructured—and Globalized

As geologists and geophysicists in Houston dedicated themselves to solving the riddles presented by depths of the Gulf of Mexico, the world oil industry began a radical restructuring. Oil and gas companies had not yet recovered from the 1980s bust when oil prices swooned again in the late 1990s, driven in large part by the drop in global demand precipitated by the Asian financial crisis. Increased shareholder pressure on oil firms to improve short-term financial results and longer-term profitability spurred one of the greatest merger movements in history. In 1998, BP acquired Amoco. The next year, Exxon merged with Mobil in an \$80 billion deal to create the world’s largest company. BP-Amoco countered by acquiring ARCO; Total merged with Fina and Elf (renamed Total in 2003); Chevron combined with Texaco; and, finally, Conoco and Phillips joined to create the sixth “super major” (along with Royal Dutch Shell). During these consolidations, many companies relocated staff from New Orleans and elsewhere to Houston, reinforcing that city’s claim as the international oil capital.⁹⁴

Mergers boosted results as management pared away overlapping functions and laid off employees, reinforcing the trend toward outsourcing R&D and reducing internal technological expertise. Mergers benefitted the oil industry, on the other hand, by equipping firms with new capital reserves needed to finance long-term growth strategies—some of them dependent on riskier, but potentially higher-return, ventures. The deepwater Gulf figured significantly in the growth strategies of all the “super major” oil companies—albeit as only one among several frontier provinces worldwide. They took renewed interest in Arctic and sub-Arctic regions and began to invest in other deepwater basins from the northeast Atlantic west of the Shetland Islands, to the Campos Basin off Brazil, to West Africa’s Gulf of Guinea and offshore Angola, to northwest Australia. By the early 2000s, analysts regarded the three provinces rimming the central Atlantic Ocean—the Gulf of Mexico, Brazil, and West Africa—as the “New Golden Triangle,” the place where the largest future reserves were likely to be found.⁹⁵

Echoing the oil companies, consolidation also swept through offshore contractors. After half of the world’s seismic crews were idled in 1999 due to a price collapse early in the year, the ensuing shakeout left only handful of seismic contractors, led by Western-Geco, owned by Schlumberger and Baker-Hughes; Petroleum Geo-Services; and CGG and Veritas (which merged in 2007). The major oil-service companies, which provided a variety of drilling, evaluation, well-completion, and production services, began to combine at the same time (notable was the 1998 merger between the oilfield giants, Halliburton and Dresser Industries). Most significantly, the drilling-contractor industry—continuously in the process of mergers, acquisitions, and bankruptcies—consolidated further. In 1999, Sedco-Forex and Transocean, themselves the products of earlier mergers, became Transocean Sedco Forex, later simplified as Transocean. In 2000, it acquired R&B Falcon, whose assets included a semisubmersible under construction in Korea by Hyundai Heavy Industries called the *Deepwater Horizon*. In 2001, Global Marine merged with Santa Fe, and six years later this firm became part of the modern Transocean, by far the largest offshore drilling firm in the world.

During this era, offshore oil exploration and production became an increasingly global enterprise. U.S. operators searched for oil in deepwater basins outside the Gulf of Mexico, and more than ever, companies such as Norway’s Statoil, Brazil’s Petrobras, and France’s Total were drilling in the Gulf. Shipyards along the Gulf Coast—the pioneers in design and construction of mobile offshore drilling units—had by the 1990s almost totally surrendered this work to competitors in Korea and Singapore. Many of the largest offshore engineering, construction, and pipelaying firms (Heerema Marine Contractors, Technip, Worley Parsons, and others) were globally oriented companies based outside the United States.⁹⁶

Offshore contractors headquartered in the Gulf survived by expanding internationally. Morgan City’s J. Ray McDermott branched out around the world more aggressively after the 1980s industry depression and eventually moved its headquarters to Houston. Louisiana-based Gulf Island Fabricators, Chet Morrison Contractors, Global Industries, and even Frank’s Casing Crew and Rental Tools grew from small, family-owned firms servicing operations in the Gulf to become major offshore contractors active worldwide.

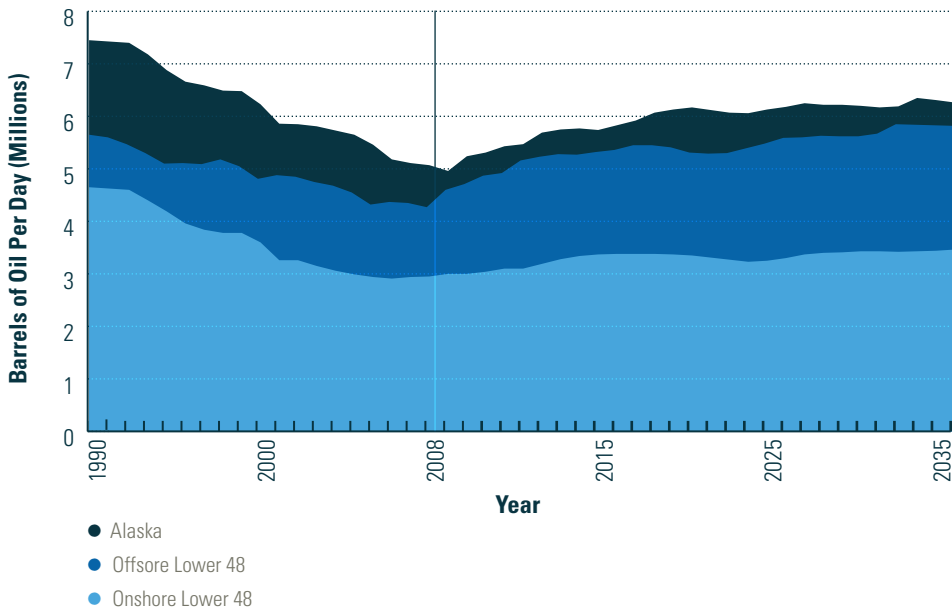
BP's Moment

In the late 1990s, the global company making the biggest news in the Gulf of Mexico was BP. Founded in 1908 and since 1954 named British Petroleum, it had for decades built its business around access to crude oil from Iran and neighboring Middle Eastern countries. In the 1960s and 1970s, BP achieved great success in discovering and developing oil reserves in the North Sea and in Alaska's Prudhoe Bay. By the early 1990s, however, BP had been exiled from the Middle East and Nigeria. Production from Prudhoe and the North Sea were in decline. Billions of dollars had been invested in unprofitable nonpetroleum ventures. And an ambitious exploration program had yet to bear fruit. The company tottered on the brink of bankruptcy.⁹⁷

Sir John Browne, a forceful exploration manager whose father had also worked for BP, orchestrated its stunning turnaround. In the 1980s, as executive vice president of Sohio, BP's American subsidiary, he reined in spending and cut staff in order to place the company on better footing. Returning to London in 1989, he reorganized BP's exploration arm; Browne slashed expenditures, established a rigid—if not ruthless—performance ethic, and refocused on high-risk but potentially high-reward opportunities. Upon becoming chief executive in 1995, he directed a major part of BP's upstream focus to the deepwater Gulf. In the deals he negotiated to acquire Amoco and ARCO, BP emerged with a greatly expanded portfolio of Gulf leases and assets.⁹⁸

In the late 1990s, BP's Gulf exploration team made a series of remarkable deepwater discoveries. Once the fields came online, they vaulted BP ahead of Shell as the Gulf's largest oil producer. BP prided itself as a "fast follower," rather than an "early adopter," in exploiting technological innovations. BP had closely followed Shell at Mars and quickly applied what it had learned to develop the Marlin field with a tension-leg platform in 3,400 feet of water. BP also joined with Exxon in developing deepwater discoveries at the Hoover and Diana fields in the western Gulf. After the string of subsalt dry holes in the mid-1990s, some of BP's competitors began looking for other kinds of plays the Gulf might still present. Shell shifted to managing production from its large number of deepwater developments. But BP sprang faster than anyone to confront the Gulf's nagging exploration challenge—the salt.⁹⁹

In a costly and complex undertaking, BP combined new advances in computer processing for 3-D seismic imaging with new methods of acquiring seismic data from multiple directions to gather a better understanding of the salt history, stratigraphy, and the sources and migration pathways of oil in deepwater. BP's scientists and engineers found geographically promising areas just as large as those discovered and profitably exploited on the shallower continental shelf. Based on their analyses, they began to believe that the deepwater frontier could ultimately hold 40 billion barrels of commercially exploitable oil—four times the prevailing estimates. Said Dave Rainey, BP's deepwater exploration manager, "One of the lessons we have learned about the Gulf of Mexico is never to take it for granted."¹⁰⁰

FIGURE 2.5: U.S. Crude Oil Production, 1990-2035 (projected)

Source: Commission Staff, Adapted from U.S. Energy Information Administration

As this chart makes clear, overall production of crude oil in the U.S. has been declining for decades. However, production from deepwater wells in the Gulf of Mexico (Offshore Lower 48) is on the rise.

A new generation of drilling vessels coming onto the market, along with advances in drilling, encouraged BP to take the risk to explore those prospects. Outpacing most of the industry by a year, the company shifted its sights to prospects in much deeper waters. Rich rewards followed with a historic string of giant oil finds in subsalt formations ranging out to 7,000 feet of water. In 1998, BP struck oil in the deepwater subsalt of the Green Canyon's Mississippi Fan Foldbelt at Atlantis (minority partner BHP Billiton) and Mad Dog (minority partners BHP Billiton and Chevron), two of the largest fields ever discovered in the Gulf of Mexico. Atlantis's original reserves estimates were 400–800 million barrels of oil equivalent and Mad Dog's were placed at 200–450 million barrels. In 1999, working for BP (and minority partner Exxon) in 6,000 feet of water in the Mississippi Canyon, Transocean's *Discoverer Enterprise* drilled the largest Gulf field of all time, a subsalt prospect called Crazy Horse (subsequently renamed Thunder Horse), containing more than 1 billion barrels of recoverable reserves. That find alone catalyzed yet another rebirth of offshore oil in the Gulf of Mexico.¹⁰¹

The discoveries kept coming. A month later, BP made another oil and gas hit at Horn Mountain (150 million barrels of original reserves) in the Mississippi Canyon. In 2000, BP and Shell discovered a major above-the-salt deposit at Holstein (more than 200 million barrels) near the Mad Dog and Atlantis fields in the Green Canyon. The same year, those two partners announced their Na Kika project, a joint subsea development of five independent fields tied back to a central semi-submersible floating production facility, an industry first for the Gulf of Mexico. In 2001, BP found another giant oilfield, containing

500 million barrels, called Thunder Horse North.¹⁰² Also that year, BP and yet another partner, Chevron, discovered a 100 million barrel field in 7,000 feet of water at their Blind Faith prospect in the Mississippi Canyon. (In the harsh glare of hindsight following the Macondo blowout, the executive director of the Natural Resources Defense Council commented that, in the name Blind Faith, “It would be hard to find a more fitting symbol of the oil industry’s steady and assertive advance into the Gulf’s deep waters, or the corporate thinking behind it.”¹⁰³)

In August 2002, BP’s Browne boldly announced that the company would spend \$15 billion during the next decade on drilling and developing these discoveries. BP had become the largest-acreage holder in the deepwater Gulf, with more than 650 tracts in water depths greater than 1,500 feet, and in possession of one-third of all deepwater reserves then discovered. The deepwater Gulf of Mexico, Browne asserted, would be the “central element” of BP’s growth strategy.¹⁰⁴ “The question is how they will manage the embarrassment of riches they have,” said one analyst at the time. “They have a bunch of projects and they need to coordinate people and contractors. There is the sheer scale of the facilities and the size of the investment required—all this before a drop of oil ever comes out of the ground.”¹⁰⁵

Clouds on the Horizon

After BP’s impressive discoveries, the industry dove into deeper waters across the Gulf. From 2001 to 2004, operators found 11 major fields beneath water 7,000 feet deep or more. Most deepwater discoveries were made in relatively young sandstones of the lower Miocene era. But companies increasingly explored down into the deeper and older Paleogene or “Lower Tertiary” strata found in the foldbelts near the edge of the Sigsbee Escarpment, a salt sheet that resembles a near-surface moonscape extending to the base of the continental slope. In 2006, Chevron and its partners Devon Energy and Statoil disclosed promising test results from a two-year-old discovery at its Jack prospect, proving that Lower Tertiary reservoirs could produce oil at pressures encountered at great depths, creating excitement that the Lower Tertiary play might ultimately yield between 3 billion and 15 billion barrels of hydrocarbons—collectively rivaling the size of the great Prudhoe Bay discovery. This implied a future for ultra-deep drilling, ranging out to 10,000-foot water depths and 25,000 feet beneath the seafloor. Reported the *Oil & Gas Journal*, “The Jack-2 test results boost confidence in that potential and highlight the central role technology plays in future supply.”¹⁰⁶

The industry was in need of a confidence booster after the previous three years of development challenges that had sorely tested BP’s and the industry’s confidence and conviction about deepwater.

BP’s decision to develop multiple deepwater fields at once was an incredibly ambitious undertaking. Its program focused on the major fields at Holstein (a discovery above the salt), Mad Dog, Atlantis in the Green Canyon, and Thunder Horse in the Mississippi

BP Thunder Horse Platform

BP's mighty Thunder Horse platform was out-muscled by Hurricane Dennis in 2005 as it was being readied for service. Evacuated crews returned to find the semi-submersible production facility listing badly. After repairs and thorough analysis, additional problems were discovered that put the platform further behind schedule. For BP it was worth the wait: By 2009 Thunder Horse was producing a whopping quarter-million barrels a day.

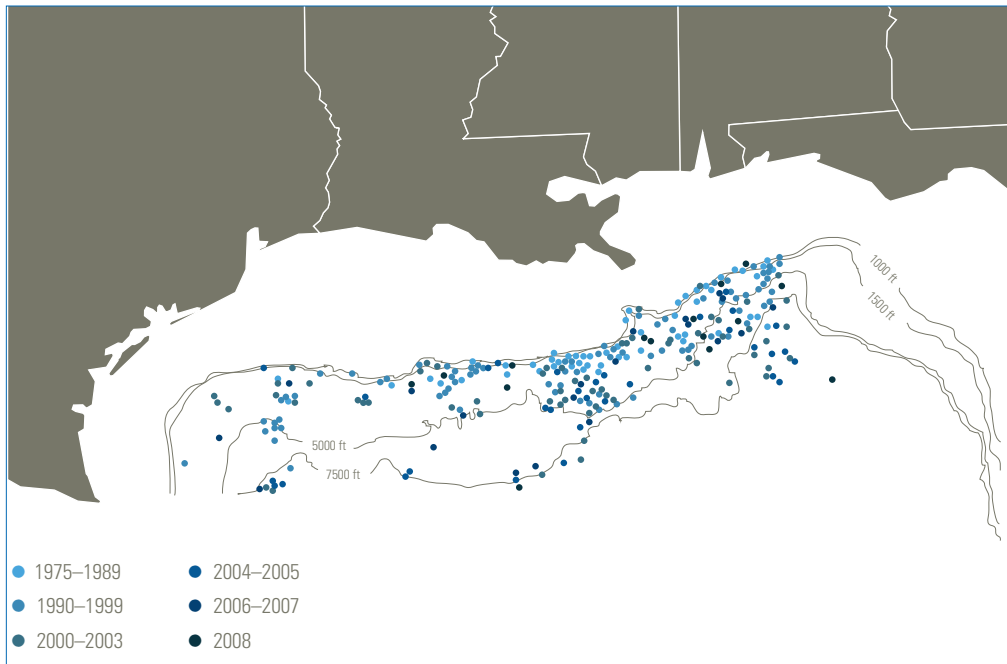
Getty Images/U.S. Coast Guard photo/PA3 Robert M. Reed/digital version by Science Faction

Canyon—with total potential reserves of 2.5 billion barrels of oil, in water ranging from 4,000 to 7,000 feet deep, requiring wells reaching 30,000 feet in total depth. To produce oil at these places, BP selected “truss spars” for Holstein and Mad Dog, and semisubmersibles (such as the one BP and Shell had introduced at Na Kika), for Thunder Horse and Atlantis.¹⁰⁷

Beyond about 4,000-foot depths, the weight of tension cables was too great, so BP could not employ tension-leg platforms, the workhorses at Shell's first deepwater projects. The spar, successfully demonstrated in 1996, is a giant buoy consisting of a large-diameter, vertical cylinder supporting a deck for drilling and processing. Its deep-draft floating caisson keeps about 90 percent of the structure underwater, giving the structure favorable motion characteristics. During 2000–2005, Kerr-McGee (acquired by Anadarko in 2006) went on to pioneer several innovations in spar designs.¹⁰⁸

BP's choice between spars and semisubmersible production facilities depended upon different economic, functional, and safety factors at each field. All four projects would be linked by pipeline to a platform hub, where crude oil would be transferred into a 390-mile pipeline, the Cameron Highway, and transported to refineries at Texas City and Port Arthur. All four projects, as well as Na Kika, also would connect to the BP-operated Mardi Gras transportation system, itself a billion-dollar project that integrated five different

FIGURE 2.6: Deep Discoveries



pipelines covering a total of 450 miles, with capacity to transport 1 million barrels of crude and 1.5 billion cubic feet of natural gas per day. The selection and development of technology on all these projects was a major challenge at every step, given the extreme water depths, reservoir conditions, and associated environmental issues. Thunder Horse had an unusually high pressure/high temperature reservoir. Atlantis was located under complex seafloor topography near the steep Sigsbee escarpment, and a large portion of the field was subsalt. Mad Dog lay under a massive salt canopy, causing large uncertainties in describing the actual reservoir. The Holstein geology forced BP to use a spar with wells housed on the platform. As BP production managers admitted in 2004, “None of the projects can be categorized as ‘business as usual.’”¹⁰⁹

The \$5 billion Thunder Horse project was especially challenging. A major incident in drilling occurred even before the semisubmersible facility was put in place. In May 2003, the top of the drilling riser on the *Discoverer Enterprise* broke loose from the vessel, ripped apart again 3,000 feet under the surface, and left the lower marine riser package to collapse on and around the top of the blowout preventer, where the riser and drill pipe snapped off. The blowout preventer’s blind shear rams were activated and worked as designed, averting any spill. “No one was hurt, and the well was secure,” BP reported, “but the initial scene was daunting.”¹¹⁰

An even bigger scare awaited the Thunder Horse semisubmersible production facility, which was towed to the field and moored on location in April 2005. As work proceeded to connect the predrilled subsea wells and commission all the facilities above and below the

water, Hurricane Dennis neared in July, forcing the evacuation of all personnel and leaving the production facility unmanned. “No one could have anticipated the major shock that awaited the first helicopter flights after the storm had passed,” according to one official BP account. The columns and other areas of the hull had filled with water, causing the facility to list to one side. Investigations later revealed that a valve in the bilge and ballast system had been installed backward, allowing seawater to move into the hull, a failure exacerbated by electrical pathways that were not watertight. Had BP not arrived when it did, the structure might have been lost. Crisis management crews were able to right the facility within a week, but reworking Thunder Horse’s hull systems delayed commissioning for a year. Similar work on the Atlantis semisubmersible production platform pushed its installation back several months, too, until July 2006.¹¹¹

Nor was that the end of BP’s major shocks—it discovered that a weld had cracked open on one of the Thunder Horse manifolds that collected oil from the network of satellite subsea wells. The company made the difficult decision to pull out all the manifolds and subsea equipment that had a similar weld configuration—adding hundreds of millions of dollars to the cost of the project. After a lengthy investigation, engineers found that minute cracks had formed in the thermal insulation on the manifold pipe work, leading to reactions that embrittled the weld interface. BP and contractors developed new weld techniques, created more rigorous inspection and assurance procedures, and refurbished all the affected subsea equipment on Thunder Horse and at Atlantis. Thunder Horse finally delivered its first oil on June 2008, three years behind schedule.¹¹² By March 2009, production ramped up to 250,000 barrels per day, 4.5 percent of total U.S. daily production. (Atlantis went online a year before Thunder Horse, in 2007, but BP has been dogged by accusations that Atlantis has not been in compliance with safety and environmental regulations.¹¹³)

Damaging Hurricanes

BP was not alone confronting environmental challenges. During 2002 and 2004–2005, hurricanes ravaged the Gulf Coast, with major impacts on offshore infrastructure and operations. In September 2002, Hurricane Lili blew into the heart of the Ship Shoal, Eugene Island, and South Marsh Island areas, damaging platforms and pipelines. Two years later, Ivan—a Category 4 storm—swept through the alley east of the Mississippi River delta, causing mudflows and anchor-dragging by mobile drilling units that tore up undersea pipelines. The following year, Hurricane Katrina flooded New Orleans and points east, with horrible effects. Offshore, Katrina destroyed 47 platforms and extensively damaged another 20. The 1,000-ton drilling rig on Shell’s Mars platform collapsed, prompting an around-the-clock onsite recovery effort.

A month later, Hurricane Rita, storming farther west, wiped out 66 platforms and broke up another 32. Rita capsized Chevron’s Typhoon, an unfortunately named mini-tension-leg platform. The majority of the platforms obliterated in these two storms were from an early generation of Gulf facilities, more than 30 years old. The two hurricanes also damaged more than 70 vessels and nearly 130 oil and natural gas pipelines, as they hit more prolific and sensitive areas than previous storms and, accordingly, caused much more extensive damages. Ominously, the short interval between the two storms exhausted the resources available for normal recovery and overwhelmed support bases.¹¹⁴

The Oil Industry and Deepwater Technology at Decade's End

As the end of the decade approached, the offshore industry in the Gulf had recovered from hurricane devastation and pressed on with deepwater and ultra-deepwater developments. Although many independent companies (such as Anadarko, Hess, BHP, Newfield, Marathon, and Mariner) had substantial deepwater leases and were actively exploring and developing them, the edge of the frontier was mainly the playground of the super-majors and firms with partial government ownership, such as Norway's Statoil and Brazil's Petrobras.¹¹⁵

In September 2009, Transocean's *Deepwater Horizon* semisubmersible made a historic discovery for BP at the company's Tiber prospect in the Keathley Canyon. Drilling in 4,000 feet of water and to a world-record total depth of 35,055 feet, *Deepwater Horizon* tapped in a pool of crude estimated to contain 4 to 6 billion barrels of oil equivalent, one of the largest U.S. discoveries. Six months later, in March 2010, Shell (with partners Chevron and BP) started production at its Perdido spar in 8,000 feet of water in the Alaminos Canyon. A hub for the development of three fields, Perdido was the world's deepest offshore platform, and the first project to pump oil and gas from the Lower Tertiary. Other Lower Tertiary developments were coming onto the horizon. Later in the year, Petrobras planned to develop the Gulf's first floating production, offloading, and storage facility to produce from Lower Tertiary reservoirs at its Cascade and Chinook prospects. By 2010, the industry had announced 19 discoveries in the Lower Tertiary trend, 14 of them containing more than 100 million barrels of oil equivalent.¹¹⁶

Technical Tests

The fanfare around these discoveries and developments could not disguise the fact that the technical challenges of ultra-deepwater drilling and production and the subsalt geology remained unique and formidable. Water depths are extreme, down to 10,000 feet. Total well depths, as Tiber demonstrated, can go beyond 30,000 feet. Well shut-in pressures can surpass 10,000 pounds per square inch. Bottom-hole temperatures can exceed 350 degrees Fahrenheit. Salt- and tar-zone formations can be problematic. The sandstone reservoirs are tightly packed, and ensuring hydrocarbon flow through risers and pipelines can be difficult. According to a 2008 report from Chevron engineers for the Society of Petroleum Engineers, all these factors "separate many [Gulf of Mexico] deepwater and ultra-deepwater wells from deepwater and ultra-deepwater wells in other parts of the world."¹¹⁷

Drilling in extreme water depths poses special challenges. Risers connecting a drilling vessel to the blowout preventer on the seafloor have to be greatly lengthened, and they are exposed to strong ocean currents encountered in the central Gulf. Managing higher volumes of mud and drilling fluid in these long risers makes drillers' jobs more demanding. Connecting and maintaining blowout preventers thousands of feet beneath the surface can only be performed by remote-operating vehicles. A 2007 article in *Drilling Contractor* described how blowout preventer requirements got tougher as drilling went deeper, because of low temperatures and high pressures at the ocean bottom. The author discussed taking

advantage of advances in metallurgy to use higher-strength materials in the blowout preventers' ram connecting rods or ram-shafts. More generally, he suggested "some fundamental paradigm shifts" were needed across a broad range of blowout-preventer technologies to deal with deepwater conditions.¹¹⁸

Under such conditions, methane hydrates raised a host of serious problems. Methane gas locked in ice ("fire ice") forms at low temperature and high pressure, and can often be found in sea-floor sediments. Temperature and pressure changes caused by drilling, or even by natural conditions, can activate the release of 160 cubic feet of gas from one cubic foot of methane, collapsing surrounding sediment, and thus destabilizing the drilling foundation. Hydrates can also present well-control problems. As hydrocarbons are produced and transported in cold temperatures and high pressures, hydrates can form and block the flow through deep pipelines and other conduits. Government, academic, and industry research programs on hydrates and associated flow problems begun in the 1990s are continuing.¹¹⁹

More broadly, knowledge about localized geology, types of hydrocarbons, and pressure profiles in ultra-deepwater wells is still not thoroughly developed. Geological conditions are complicated and vary from prospect to prospect, and from well to well. Each well, indeed, has its own "personality" that requires maintaining an extremely delicate balance between the counteracting pressures of the subsurface formation and drilling operation. Beneath the salt, pressures in the pores of the sediment are exceedingly hard to predict. Reservoirs in the Lower Tertiary are thicker and with higher viscosity than the fluids found in younger rock. Finally, ultra-deepwater developments are far removed from shore and thus from established infrastructure. As a BP technical paper prepared for the May 2010 Offshore Technology Conference noted, "the trend of deepwater discoveries in the [Gulf of Mexico] is shifting toward one with greater challenges across many disciplines represented by the conditions of Lower Tertiary discoveries."¹²⁰

Nevertheless, the challenges seemed manageable and the rewards appeared worth the perceived risk. The offshore industry had enjoyed a long run in the Gulf without an environmental catastrophe. The hurricanes of mid-decade had caused widespread damage, but not a major offshore spill. In recent years, the industry had touted its relatively clean record in the Gulf as a justification to allow exploration elsewhere. As oil prices climbed from 2003 to 2008, peaking at over \$140 per barrel, so did the industry's interest in exploring other frontier areas, especially offshore Alaska. In 2007, Shell and Total bid aggressively for federal leases offered in the Beaufort Sea, and in 2008, Shell spent \$2.1 billion for leases in the Chukchi Sea. The following year, however, a lawsuit in a federal appeals court challenging the Minerals Management Service's environmental studies preceding the sale held up applications for permits to drill on these leases.¹²¹

Still, from 2008 through early 2010, both government and industry were largely bullish about the potential of offshore drilling for the nation's future. Not incidentally, both were earning even greater revenues from ever-more ambitious exploration. In 2008, President George W. Bush and Congress ended the leasing moratoriums on vast stretches of the U.S. outer continental shelf, and Bush proposed opening new areas for exploration. In a March

31, 2010 announcement, President Barack Obama scaled back Bush's plan, but he left open the possibility of expanding offshore leasing beyond the Gulf of Mexico and Alaska. The President defended his position by observing, "oil rigs today generally don't cause spills."¹²²

As President Obama spoke, Transocean's *Deepwater Horizon*—fresh from completing BP's spectacular find at Tiber a few months earlier—was busy drilling on BP's Mississippi Canyon 252 lease, in approximately 5,000 feet of water. BP had named the prospect Macondo, after the fictional town in Gabriel Garcia Marquez's novel, *One Hundred Years of Solitude*. The fate of the town of the Macondo, as described in a memorable passage by Marquez, presaged the fate of the Macondo well and summed up the challenges facing the industry as a whole as it plumbed the depths of the Gulf:

*It was as if God had decided to put to the test every capacity for surprise and was keeping the inhabitants of Macondo in a permanent alternation between excitement and disappointment, doubt and revelation, to such an extreme that no one knew for certain where the limits of reality lay.*¹²³