
A REVIEW OF THE GEOLOGY AND PETROLEUM RESOURCES OF GULF OF MEXICO (GOM)

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ABSTRACT

This paper provides a comprehensive review of the geology and petroleum resources of the Gulf of Mexico (GOM), emphasizing its significance as one of the world's largest petroleum basins. The GOM's geological formation began during the Mesozoic Era with the breakup of Pangea, which led to the creation of the basin through processes like rifting and seafloor spreading. The basin is characterized by thick sedimentary deposits and complex salt tectonics, which have contributed to the region's hydrocarbon potential. Hydrocarbon production in the GOM has evolved from shallow waters to deepwater and ultra-deepwater drilling, driven by advances in technology and increased demand. Miocene-age reservoirs have been the most productive, while future potential lies in the Lower Tertiary formations. Despite its economic significance, the GOM faces significant challenges, including environmental hazards like hurricanes and oil spills, such as the Deepwater Horizon disaster. Mitigation efforts focus on improving subsurface data analysis, advanced seismic imaging, regulatory frameworks, and technological advancements to manage environmental risks while optimizing hydrocarbon recovery. The paper underscores the need for sustainable practices in hydrocarbon extraction while exploring the potential for renewable offshore energy and carbon storage as future energy solutions for the GOM.

Keywords: Gulf of Mexico, Petroleum Resources, Reservoirs, Salt Tectonics, Oil Spill.

1.0 INTRODUCTION

The Gulf of Mexico (GOM) basin is a petroleum province of global and domestic economic importance. The United States' Bureau of Ocean Energy Management (BOEM) estimates that in the federal offshore GOM, undiscovered technically recoverable resources total 87.5 billion barrels of oil equivalent, and hydrocarbon companies are moving into deeper water and riskier plays in search of the profitable prospects needed to supply global demand that is projected to grow to 27 million incremental barrels per day by 2020. Uncertain subsurface conditions in exploratory wells, already one of the riskiest phases of hydrocarbon development, are exacerbated by extreme environments that include water depths of up to 10,000 feet, total well depths nearly 30,000 feet below the mudline, pressures of almost 30,000 psia (pounds per square inch, absolute), and temperatures over 300 degrees Fahrenheit. In addition, recent events, including impacts from natural events (e.g. Hurricanes Katrina and Rita) and anthropogenic events (e.g. Deepwater Horizon oil spill), have highlighted gaps in our ability to predict risks and effectively prevent deleterious outcomes throughout the lifecycle of hydrocarbon development in extreme offshore settings. To reduce uncertainty, identify knowledge and technology gaps, support risk assessments, and improve flow rate estimates in the GOM region, a sufficient understanding of the subsurface is required for a variety of stakeholders. While proprietary data and information are available to specific entities, they are typically associated with restrictions for use and access. However, information from published literature and publicly available data sources can be integrated to support good comprehension of the petroleum system across the GOM, and when appropriate, offer insights into field- or site-specific areas, as well. Information from published literature includes site-specific reservoir descriptions and basin wide syntheses, studies of basin structure and salt, analyses of the petroleum system, and reservoir fluids found within hundreds of references. Publicly available databases containing information such as subsurface attributes are less abundant and typically focus on field or well specific scale information. However, BOEM does release a well-populated GOM-wide public database of reservoir sands characteristics that contains field-specific information and production statistics. While information about the subsurface GOM petroleum system ranges in quantity, accessibility, and resolution, there is a foundation from existing studies that can be utilized to reduce uncertainty and evaluate for spatial and temporal trends at the field to regional scale. These can be used by a range of stakeholders (e.g. industry, regulators, and scientists) to support science-based decision-making, while also serving to identify knowledge and technology gaps. In support of ongoing and future science-based studies pertinent to the GOM, this paper reviews aspects of the GOM petroleum system that are relevant basin-wide and presents references and resources to access for more information. Many sources referenced also contain in-depth field- or site-specific analyses detailing the reservoirs, structures, and petroleum systems in the GOM.

2.0 GEOLOGY OF GULF OF MEXICO

2.1 Basin Development and Geologic Overview

The Geological Society of America's 1991 volume *The Gulf of Mexico Basin* is a thorough synthesis of information on every aspect of the GOM basin's geology. In 2008, Galloway published a chapter in *The Sedimentary Basins of the United States and Canada* to provide an updated description of the current knowledge of the northern Gulf's stratigraphy and depositional history. These discuss in detail the origin of the GOM basin, its structural evolution and stratigraphic framework, and its resources. The structural framework for the GOM is well laid out in a widely cited 1995 paper by Diegel et al., and is augmented by more recent studies of basement structure and salt tectonics. Basin evolution, as it pertains to the

petroleum system of the GOM, is summarized here. During the Mesozoic Era, breakup of Pangea initiated the formation of the GOM basin. Intermittent connections to the Pacific Ocean, concurrent with rifting in the Jurassic Era, led to periodic inundation of the forming basin by shallow seawater that laid down a thick layer of evaporites now known as the Louann Salt. Continued rifting, followed by seafloor spreading, separated the salt into northern and southern basins and permanently connected the basin to the ocean in the east. Late Mesozoic deposition is marked by interbedded deposition of terrestrial clastic sediments, marine shales, and carbonates associated with prograding continental margins and the development of carbonate platforms around the basin. River systems, including the proto-Mississippi River, deposited terrigenous sediments to the Basin starting in the Late Jurassic to the present. During the late Cretaceous and into the Cenozoic Era, continental uplift due to the Laramide Orogeny and later crustal movements in North and Central America increased the sediment supply to the Gulf dramatically. Thick, sandy strata prograded onto the continental shelf and spilled onto the continental slope and basin floor, resulting in interbedded sands and shales within the basin itself. In some places, Cenozoic basin deposits accumulated to more than 10,000 meters thick. Deposition in the Pliocene and Pleistocene is also characterized by thick, interbedded terrigenous deposits, which themselves are more than 3000 meters thick in some areas. The result of this large and rapid deposition of sediment was destabilization and gravitational detachment of the sediment fill on the underlying shale and salt layers, in addition to mobilization of the autochthonous Louann salt. Large detachment fault systems parallel the current basin shoreline in Texas and Louisiana, including Paleocene and Eocene fault systems under the Texas coastal plain and Oligocene and Miocene detachments on the offshore Texas-Louisiana shelf. Periods of extension caused coeval compression at the toe of the continental slope, creating provinces of compressional salt-cored anticlines in the western and central basin (the Perdido and Mississippi Fan fold belts). Differential loading on the Louann salt displaced it towards the centre of the basin and up through the overlying sediment, creating a complex system of salt welds and allochthonous diapirs, sheets, and canopies. The Louisiana Texas continental slope is characterized by many minibasins, where ponded sediment and salt withdrawal have created advantageous environments for hydrocarbon accumulation.

2.2 Petroleum System

Classic elements of a petroleum system include the geologic and hydrologic components and processes necessary to generate and store hydrocarbons, including a hydrocarbon source, migration pathway, reservoir rock, trap and seal, and appropriate timing. For the GOM, information about the basin's petroleum system and sub-systems can be found in many published articles and volumes, including the Atlas of Northern Gulf of Mexico Gas and Oil Reservoirs and the AAPG Bulletin theme issue Gulf of Mexico Petroleum Systems. Updated literature with descriptions of recent plays are presented in publications such as a 2012 study of traps and reservoirs in the central northern Gulf of Mexico by Weimer and Bouroullec and a review of the properties of the deep water Wilcox formation by Oletu et al. Reports from BOEM update the estimated hydrocarbon reserves annually, and their 2012 Outer Continental Shelf Assessment summarizes the current knowledge of the northern Gulf's plays, including their geology and estimated hydrocarbon resources and reserves. For publicly available information pertinent to reservoir properties and hydrocarbon properties, one of the most extensive available resources is BOEM's Atlas of Gulf of Mexico Gas and Oil Sands Data, which is publicly downloadable and updated annually. This expansive data set presents data aggregated and averaged to the sand level from non-releasable, reservoir-specific data sources. This includes production statistics, estimated reserves, age, physical and reservoir properties of the sands, and properties of the hydrocarbons produced.

2.3 Reservoir Geology

Deepwater and ultra-deepwater reservoirs are dominantly associated with turbidite deposits, particularly with the channel and levee systems and fan/lobe sheet sand mass-transport deposit components of these turbidite systems. The GOM is a notably prolific basin in that hydrocarbon plays span the vertical and lateral extent of the system. Plays occur vertically throughout the stratigraphic column, and laterally across the basin, the multitude of established large and small fields illustrate the breadth of the system as well. Miocene-age reservoirs, many of which are associated with deepwater and ultra-deepwater plays, have been the most productive reservoir system, producing more than 23 billion barrels of oil equivalent as of 2009. In addition, notable deepwater and ultra-deepwater hydrocarbon plays in the GOM are also found within Pliocene and Pleistocene sediments. In the future, the Paleocene, Eocene, and Oligocene sediments that comprise Lower Tertiary plays on the continental slope are expected to contain the most undiscovered, technically recoverable resources, estimated at nearly 18 billion barrels of oil equivalent. The Lower Tertiary Wilcox trend has produced at least a dozen discoveries in the last decade.

Reservoir quality and type varies largely as a function of depositional and structural environment but can also be a function of secondary alteration and diagenetic processes. Turbidite sands associated with Miocene to Pleistocene reservoirs generally have high porosities and good to excellent reservoir quality but can be compartmentalized by faults or interbedded low permeability strata. In comparison, older Lower Tertiary sands are generally deeply buried with good lateral extent, but in comparison to the Miocene reservoirs have much lower porosities and permeabilities. Reservoir properties associated with GOM plays can vary widely across the basin, thus analysis of field- to reservoir-specific attributes, when available, is key to improving understanding of different scale differences in reservoir attributes.

Hydrocarbons are produced from almost 1,300 fields in the federal offshore GOM, 209 of which are in the deepwater and ultra-deepwater. According to BOEM, more than half of the hydrocarbon reserves remaining in the GOM are in the deepwater and ultra-deepwater reservoirs. As of 2011, 21.91 billion barrels of oil and 192.4 trillion cubic feet of gas have been produced. The northern GOM is more prone to gas than oil, though many fields produce both. Oil and gas compositions, as well as associated fluids and gases (e.g. CO₂ or H₂S) are important as indicators for reservoir connectivity, age, source, and timing of fluid migration. Average gas-oil ratios, oil and gas gravities, and production estimates are available in public data from BOEM. Hydrocarbon sources in the GOM have been heavily influenced by the timing of sediment deposition. Lower sediment influx to the basin in the Mesozoic Era, followed by the rapid, voluminous deposition in the Cenozoic Era, has left much of the modern continental slope over-pressured and with a depressed temperature gradient, leaving Mesozoic rocks on the slope within the necessary temperature regimes to generate hydrocarbons. Analyses of regional hydrocarbon sources can be found in. The primary sources throughout the GOM basin are the carbonates and shales deposited in the Upper Jurassic, Upper Cretaceous, and early Cenozoic Eras. Hood et al.'s analysis of GOM hydrocarbon systems interprets the source rocks supplying the most of the deepwater GOM reservoirs to be Upper Jurassic sediments of Tithonian age, and links sea-floor seeps in the ultra-deepwater to Oxfordian sources. Reservoirs in the western offshore basin and the Texas-Louisiana continental shelf are charged with hydrocarbons from Paleocene and Eocene source rocks. Hood et al. subdivide these systems further by original composition. Data from both wells and seeps were used in Hood et al.'s analysis to map the locations and maturity of the sources and hydrocarbons. GOM deepwater and ultra-deepwater reservoirs tend to be less

mature than reservoirs with similar sources closer to the basin rim. Detailed chemical analyses of seeps and reservoir fluids can be used to provide insights into hydrocarbon sources and migration pathways. Research and data on the presence and indications of seeps throughout the Gulf of Mexico is also available from BOEM.

2.4 Salt and Structure

Subsurface faults and fractures are important as migration pathways, traps, and seals throughout the GOM, but the publicly available data related to these structural elements, when available, are scattered and difficult to assemble. Basin-wide studies of structural elements for the GOM include Diegel et al.'s description of the larger framework of structural trends and features across the GOM, along with Hood et al.'s analysis of hydrocarbon systems and migration pathways.

Detailed subsurface structural information is often interpreted from 2D and 3D geophysical surveys that are commonly commercial or proprietary. However, publicly available geophysical data sets for some areas of the GOM are accessible from several sources, including the National Geophysical Data Centre and BOEM. In addition, interpreted seismic lines are often published in field-specific studies as they are heavily relied upon for field assessments such as those by Weimer et al. for fields in the Green Canyon and Ewing Bank region. Salt is a distinctive element of the GOM petroleum system. Salt deformation, injection, and withdrawal are responsible for many of today's existing traps and seals. Sediment loading and salt withdrawal have produced numerous minibasins, creating accommodation space for sediment accumulation, and the evacuated salt pierces and overhangs younger sediments as diapirs and canopies.

The salt and sediment movement creates faults, salt welds, and turtle structures, and compressional folding at the base of the continental slope has formed series of salt-cored anticlines. All these structures are common hydrocarbon traps, but also often serve as fluid migration pathways. Recent studies by Hudec et al. and Hudec et al. connect structural styles and trap types in the deep water to salt provinces influenced by the original emplacement and movement of the salt related to rifting in the Jurassic Era. Hydrocarbon reservoir placement, size, and thickness in the GOM can be strongly influenced by salt and structural complexity. Weimer and Bouroullec describe the control structure and salt have on the size and location of reservoirs in the region around the Mississippi Fan and detail trap styles and patterns throughout the area. Deepwater reservoirs in this area produce primarily from Miocene or younger sediments, and traps are typically combinations of structural and stratigraphic elements. Structural traps are formed by anticlines or faults, including turtle structures, caused by extension and structural inversion during salt evacuation. Thunder Horse, the largest field in the GOM, produces from a turtle structure. The salt-bounded minibasins prevalent on the continental slope often have combination traps due to stratigraphic pinchout, confining or overhanging salt, or turtle structures and have produced discoveries such as the Mars, Ursa, and Devils Tower fields. On the ultra deep-water Louisiana-Texas slope, the Paleocene and Eocene Wilcox reservoirs are often buried below the Sigsbee salt canopy. Anticlinal, faulted structures dominate the traps here, including the salt-cored folds of the Perdido and Mississippi Fan fold belts. The Great White field produces from the Perdido Fold Belt, while Cascade and Chinook fields produce from pillow folds near the toe of the Sigsbee salt.

2.5 Geological Background

The Gulf of Mexico's geological framework plays a crucial role in its status as a major petroleum reservoir. The region's sedimentary basins, formed over millions of years, contain

vast quantities of hydrocarbons. The Gulf's subsurface is characterized by complex formations of salt domes, shale layers, and sedimentary rock that have historically trapped oil and natural gas. This geological setting is conducive to the formation and accumulation of fossil fuels, making the Gulf a prime target for exploration.

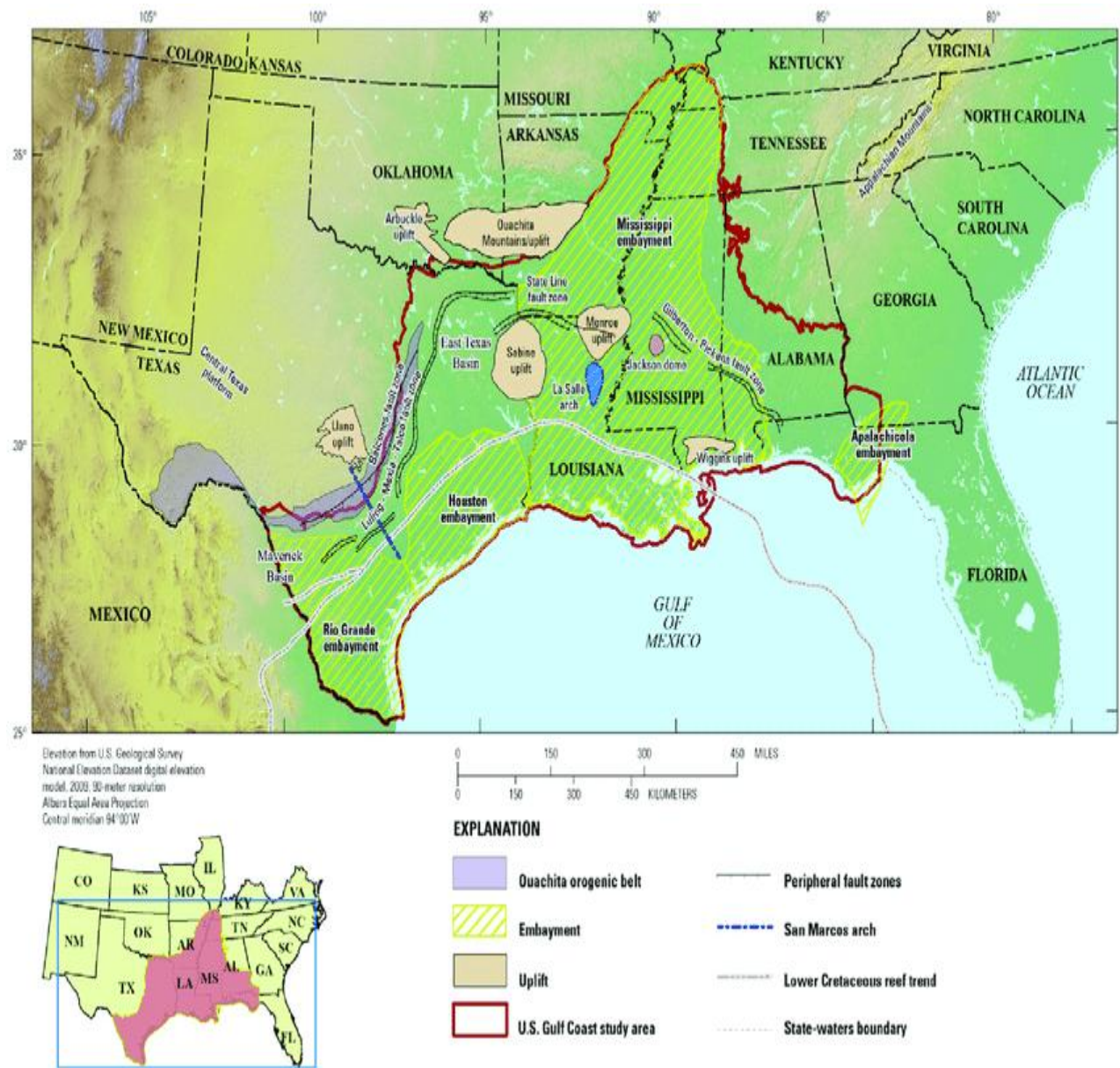


Figure 1: Geologic map of the U.S. Gulf Coast study area within the southern U.S. Major structural features adapted from Ewing and Lopez (1991) and Galloway (2011). In the inset on the lower left, area in red is the U.S. Gulf Coast study area.



Figure 2: The Sun lights up the Texas and Louisiana coast. According to researchers at the University of Texas Institute for Geophysics, the unique geology of the Gulf of Mexico has helped contribute to its success as an oil and gas producing ‘super basin’. Source: NASA

The Gulf of Mexico holds huge untapped offshore oil deposits that could help power the U.S. for decades.

The energy super basin’s longevity, whose giant offshore fields have reliably supplied consumers with oil and gas since the 1960s, is the result of a remarkable geologic past – a story that began 200 million years ago among the fragments of Pangea, when a narrow, shallow seaway grew into an ocean basin, while around it mountains rose then eroded away.

The processes that shaped the basin also deposited and preserved vast reserves of oil and gas, of which only a fraction has been extracted. Much of the remaining oil lies buried beneath ancient salt layers, just recently illuminated by modern seismic imaging. That’s the assessment of researchers at The University of Texas at Austin, who reviewed decades of geological research and current production figures in an effort to understand the secret behind the basin’s success. Because of its geological history, the Gulf of Mexico remains one of the richest petroleum basins in the world. Despite 60 years of continuous exploration and development, the basin’s ability to continue delivering new hydrocarbon reserves means it will remain a significant energy and economic resource for Texas and the nation for years to come, said lead author John Snedden, a senior research scientist at the University of Texas Institute for Geophysics (UTIG). “When we looked at the geologic elements that power a super basin – its reservoirs, source rocks, seals and traps – it turns out that in the Gulf of Mexico, many of those are pretty unique,” he said. The geologic elements that have made the Gulf of Mexico such a formidable petroleum resource include a steady supply of fine- and coarse-grained sediments, and salt: thick layers of it buried in the Earth, marking a time long ago when much of the ancient sea in the basin evaporated. Geologically, salt is important because it can radically alter how petroleum basins evolve. Compared to other sedimentary rocks, it migrates easily through the Earth, creating space for oil and gas to collect. It helps

moderate heat and keeps hydrocarbon sources viable longer and deeper. And it is a tightly packed mineral that seals oil and gas in large columns, setting up giant fields. “The Gulf of Mexico has a thick salt canopy that blankets large portions of the basin and prevented us for many years from actually seeing what lies beneath,” Snedden said. “What has kept things progressing is industry’s improved ability to see below the salt.”

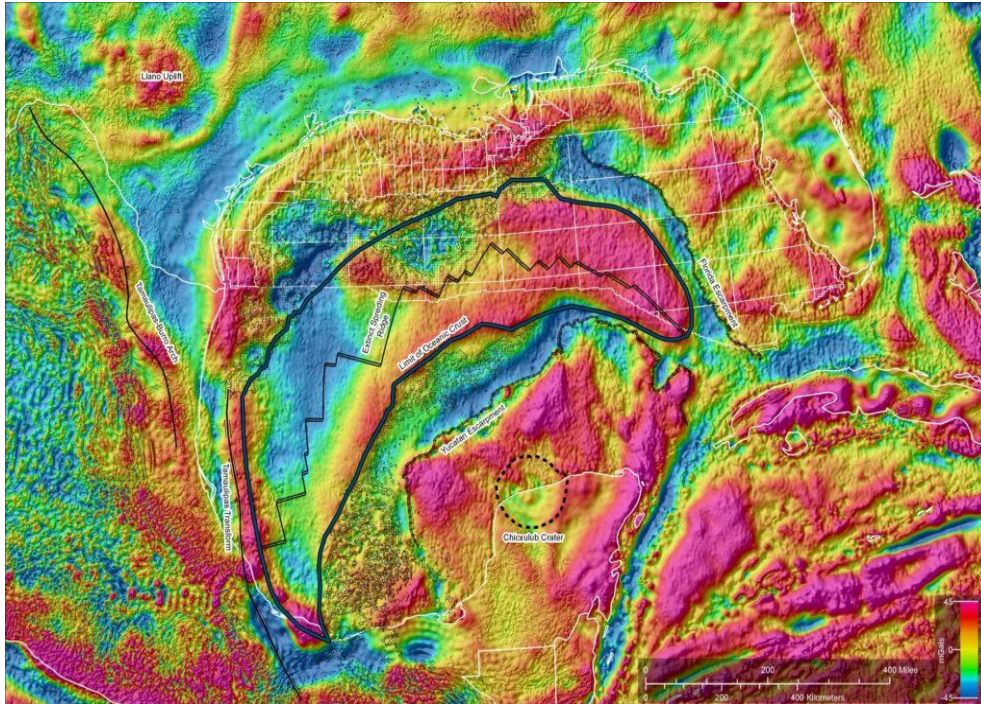


Figure 3: A map of the Gulf of Mexico region colored to show minute changes in gravity caused by different rock types — areas of strongest gravity are in purple, and weakest in blue. Knowing where rock types are clustered can tell geologists about the structure and evolution of the Earth. The map was compiled using published, publicly available data by researchers at The University of Texas at Austin, whose research has helped trace the geology behind the success of the Gulf of Mexico’s oil and gas reserves. Source: Ian Norton/UTIG

The Gulf of Mexico is one of the most significant regions for petroleum resources in the world. The Gulf of Mexico’s geological structure is favorable for oil and gas formation. It has large sedimentary basins that have trapped hydrocarbons over millions of years. The region contains a vast amount of oil and natural gas reserves, with significant reserves located in both shallow and deep-water areas. Historically, most of the oil and gas production has come from shallow waters, typically less than 200 meters deep. In recent decades, exploration and production have increasingly moved into deep and ultra-deep waters. The region’s deepwater reserves have been a major focus due to their vast potential.

3.0 PETROLEUM EXPLORATION AND PRODUCTION

3.1 Major Players

Countries: The Gulf of Mexico is bordered by several countries, including the United States, Mexico, and Cuba. Each country manages its own portion of the Gulf and has its own regulatory framework.

Companies: Major international oil companies, such as ExxonMobil, Chevron, BP, and Shell, as well as national oil companies like Pemex (Mexico's state-owned oil company), are heavily involved in exploration and production.

3.2 Exploration and Production

Petroleum exploration in the Gulf of Mexico began in the early 20th century, with significant advancements occurring over the decades. Initially, exploration focused on shallow waters, typically less than 200 meters deep. These areas were relatively accessible and yielded substantial quantities of oil and gas. However, as shallow-water reserves began to deplete, the industry turned its attention to deeper waters.

The latter part of the 20th century and the early 21st century saw a dramatic shift towards deepwater and ultra-deepwater drilling. Advances in drilling technology, such as semi-submersible rigs and dynamic positioning systems, enabled the extraction of oil and gas from depths exceeding 1,500 meters. This shift has opened up new reserves and significantly increased production capabilities. Major international oil companies, including Exxon Mobil, Chevron, BP, and Shell, along with national oil companies like Mexico's Pemex, have invested heavily in the Gulf's deepwater fields.

3.3 Economic Impact

The economic impact of petroleum resources in the Gulf of Mexico is profound and multifaceted. For the United States and Mexico, the Gulf represents a critical component of their energy security and economic stability. In the U.S., offshore oil and gas production contributes billions of dollars to the national economy, supporting thousands of jobs in drilling, refining, and related industries. Similarly, Mexico's state-owned oil company, Pemex, relies heavily on Gulf production for revenue, which supports the country's economy.

The petroleum industry in the Gulf also has a significant impact on local economies, particularly in coastal states such as Texas and Louisiana. The industry supports a wide range of services, from offshore supply vessels to specialized engineering firms. This economic activity extends beyond direct employment, influencing local businesses and communities that cater to the industry's needs.

3.4 Environmental Impact and Mitigation

The Gulf of Mexico has experienced significant oil spills, including the Deepwater Horizon spill in 2010. These events have had substantial environmental impacts and highlighted the need for effective management and response strategies. The Gulf Coast is frequently impacted by hurricanes, which can cause coastal erosion, sediment redistribution, and other geological changes. While the Gulf of Mexico's petroleum resources offer substantial economic benefits, they also pose significant environmental risks. The region has faced several major environmental challenges, most notably the Deepwater Horizon oil spill in 2010. This disaster had devastating effects on marine and coastal ecosystems, highlighting the risks associated with deepwater drilling.

In response to such incidents, regulatory frameworks have evolved to enhance safety and minimize environmental impact. The U.S. government, through agencies like the Bureau of Ocean Energy Management (BOEM) and the Environmental Protection Agency (EPA), enforces stringent regulations on offshore drilling practices. These regulations aim to prevent spills, manage waste, and protect marine habitats.

Fourteen million people live, work and play along the Gulf Coast — an area particularly vulnerable to two major coastal hazards: tropical cyclones and sea-level rise coupled with land subsidence, which takes place when large amounts of groundwater (and oil and gas) are withdrawn from certain types of rocks and the land compacts and “sinks.” In Louisiana, subsidence is also occurring as the Delta compacts and because of the lack of sedimentation caused by anthropogenic changes to the flow of the Mississippi River. Subsidence enhances the relative sea-level rise and increases flooding risks — especially for coastal communities. And, with its 25,000 miles of oil and gas pipelines and more than 4,000 oil and gas platforms, the Gulf Coast is also vulnerable to contaminant spills — as evidenced by the blowout of the Deepwater Horizon, the largest man-made disaster in the nation’s history that released an estimated 4.9 million barrels of oil into the Gulf. The solution to mitigating the effects of storm events, sea-level rise and contaminant spills is to create more resilient communities, with easy access to current, reliable information, and to provide better models and tools that help track spills. To create more resilient communities, we need to:

- i. Improve hurricane intensity and other storm estimates and tracking for improved evacuation warnings
- ii. Develop better maps for storm surge, inundation flooding and runoff
- iii. Increase knowledge of rip currents, surf-zone dynamics and shoreline currents
- iv. Monitor shoreline changes over time
- v. Increase knowledge of ocean currents, both at the surface and at depth.

3.5 Future Prospects

Technological Advances: Advances in drilling technology, such as deepwater drilling and hydraulic fracturing (fracking), continue to enhance the ability to extract resources from challenging environments.

Renewable Energy Transition: As global energy markets evolve and there is a shift towards renewable energy sources, the role of petroleum resources in the Gulf of Mexico may face changes, though it remains a vital resource in the near term.

Overall, the Gulf of Mexico remains a crucial area for petroleum resources, balancing economic benefits with environmental considerations.

The Gulf of Mexico, an expansive and ecologically rich body of water bordered by the United States, Mexico, and Cuba, stands as one of the world's most vital sources of petroleum. The region's significance is underscored by its substantial oil and gas reserves, advanced extraction technologies, and the economic and environmental implications of its exploitation. This essay explores the geological background, exploration and production practices, economic impact, environmental considerations, and future prospects of the Gulf of Mexico's petroleum resources.

4.0 CASE HISTORY

The Gulf of Mexico Deepwater Mission (Tyler et al., 2022)

4.1 Reconnaissance

The deepwater oil and gas business was born in the Gulf of Mexico (Gulf), largely as result of pioneering efforts by Shell Oil Company. In the late 1940s, Shell Oil made many of the early moves offshore and continued to lead the way into deeper waters and new geologic trends. For decades, the company dominated the Gulf, discovering and producing more oil and gas than any other firm. In 1977–1979, Shell installed the Cognac steel jacket in 1,025 feet of water (300 meters), the first platform in deepwater by one of the modern definitions of the term. Other operators followed with platforms along the “Flex Trend,” an area in the Gulf that reaches just beyond the edge of the continental shelf, where there is a flexure in the seafloor (Cossey 2004). Many discoveries leading up to and along the Flex Trend were made using “direct hydrocarbon indicators” (DHIs) or, as Shell referred to them at the time, “bright spots.” This method of interpreting seismic attributes emerged in the late 1960s from dramatic advances in digital capabilities. Binary-gain digital recording systems enabled geophysicists to measure and quantify the “relative wave amplitudes” between seismic traces for the first time. This measurement was sometimes referred to as “true amplitude recovery” (Forrest 1999; Forrest 2000a). Before then, seismic techniques were used mainly to map subsurface structures and identify possible oil traps. Operators still had to take the substantial risks of drilling to determine if oil and gas existed in those structures and traps. But the new digital seismic data offered the enticing possibility of “directly detecting” hydrocarbons on the seismic record by the identification of “amplitude anomalies” or “high amplitude reflections” produced by slight changes in the acoustic velocities of sound signals as they passed through oil or gas (Forrest 1999; Forrest 2000a). Shell Oil and Mobil Oil were the first companies to identify and quantify such anomalies, and to factor them into their bids for offshore leases in the early 1970s. Mobil referred to them as “hydrocarbon indicators.” Shell called them bright spots, because they seemed to light up on the seismic record. Being able literally to “see” hydrocarbons on the seismic record before ever drilling a well could solve questions about whether hydrocarbons existed in a certain location or what the drilling targets were. The method was not foolproof. It did not work in all kinds of geology, and it sometimes produced false indicators of oil and gas. But, in general, bright spots became a valuable exploration tool in the Gulf (Offshore Energy Center, 2006). Although Shell Oil had pioneered bright spot seismic and made an important amplitude discovery at Cognac, it largely missed out on the Flex Trend. During 1975–1977, Shell had deemphasized this play in favor of exploration elsewhere, such as Alaska, and on geopressed natural gas prospects in the ultra deep Texas Miocene. Although the company achieved success in discovering natural gas, it became clear, as a 1987 “lookback study” by Shell exploration and production (E&P) concluded, that Shell had “lost a good opportunity to add volumes mostly by Bright Spot discoveries,” and “a lot of smaller companies did well on the 78 percent of the volumes SOI [Shell Offshore, Inc.] did not bid” (Holmes 1987). In the late 1970s, Shell exploration refocused on the Gulf frontier, looking beyond the Flex Trend into the deepwaters off the edge of the continental shelf. The industry in general shied away from going any further into deepwater, and development had stalled out in the late 1970s along the shelf edge. Discoveries in the Flex Trend were significant, but they were relatively small, with discontinuous sands and fairly low flow rates. Experts in many companies had looked at the field size distribution in the Gulf and the available and evolving production technologies and concluded that there would never be an economic development more than 60 miles from shore. Existing geological data also suggested the unlikelihood of major oil finds in

deepwater. More than 100 wells had drilled into the bathyal zone and found very few commercial hydrocarbon-bearing sands. These were wells on the shelf drilled deeper than existing productive zones to test older sediments lying beneath 3. For background on Shell Oil and its offshore history, see Priest 2007. The conventional wisdom was that deepwater contained “no sands, no source rock, no nothing” (Yeilding 2013). Combining information from deepwater cores with a regional seismic survey acquired and processed by Petty-Ray Geophysical in 1977, scientists from industry and academia had begun to piece together a regional picture of deepwater geology in the Gulf. This picture showed that massive salt pillars, or diapirs, had squeezed up from the mother layer of salt called the Louann sheet. The Mayan (Yucatan) continental block had been displaced from the Gulf Coast margin of the US by rifting beginning 165 million years ago (mya) during the Jurassic period (201–143 mya). Cycles of seawater rushed into and evaporated from a slowly forming Gulf, leaving behind layers of salt that grew as thick as 30,000 feet in some places. During the late-Jurassic period, several major river systems draining the continental interior of North America piled enormous quantities of coarse, clastic sediments on top of fine-grained, organic-rich carbonates and shales that had been deposited by marine sequences over the salt: Upper Jurassic limestone and marl, Lower Cretaceous marl, lower Upper Cretaceous marland mudstone, and lower Tertiary mudstone (Galloway 2009). These carbonates and shales, subjected to just the right amount of heat and pressure, became excellent sources for hydrocarbon generation in the shallower parts of the Gulf continental shelf. One early concern about deepwater was the availability and maturity of source rocks off the edge of the continental shelf, but “modeling successfully demonstrated that probable source rocks, predominantly Cenomanian to Turonian [Cretaceous Period, 143–67 mya] in age, have entered the oil window throughout most of the deep and ultra-deep water province” (Whaley, 2006: 20). During the Paleogene period (66–23 mya), which followed the Cretaceous, siliciclastic sediment poured in from the ancestral Rocky Mountains, followed by Appalachian-derived sediment from the proto Mississippi River during the Miocene and Pliocene epochs (23–3 mya). These formed the major reservoirs to which hydrocarbons from the source rocks migrated. Buried under mounting layers of sediment deposited over tens of millions of years, and so subjected to tremendous heat and pressure, the salt turned from brittle to ductile and began to pinch up (Voosen 2010). The tilting of the continental margin caused the salt to flow into broad canopies down the slope. Salt movement forced sandstones overlaying the salt in deepwater to subside slowly, forming cup-shaped minibasins featuring many different kinds of arrangements for trapping oil. These mini-basins also overflowed and allowed sand to be transported to unconfined areas down dip (Steffens and Braunsdorf 1997). Although minibasins contain loads of reworked sediment, they get progressively younger, from 6.2 to 4 million years old, as one moves southwest across the slope from the Mississippi Canyon to the Keathley Canyon (Yeilding 2013). These sandstones were named “turbidites” because they had been deposited when ancient underwater rivers systems driven by turbidity currents channeled huge volumes of sediment off the edge of the continental margin. In the 1940s and 1950s, pioneering geologic work to piece together the Gulf at the basin and regional levels had discovered that the Mississippi River had created a broad alluvial valley, repeatedly entrenched and filled since at least the Pleistocene epoch (3–1 mya), and that troughs with bottom-hugging currents had transported denser-than-seawater sediment onto the continental slope and abyssal plain (Kolla and Perlmutter 1993). The structural anomalies in these basin settings suggested by the 1977 Petty-Ray regional seismic survey looked similar to productive features on the shelf. “These big structures popped up out there,” remembered John Bookout, president of Shell Oil at the time and a dedicated petroleum geologist himself. “Everybody was just astonished. ‘Look at all the different kinds of possible

traps and variety of configurations.’” Still, the spotty seismic coverage made these anomalies speculative at best.

Shell Oil, always the leader in frontier exploration in the Gulf, was willing to entertain the speculation. Top officials in the company believed that Shell Oil’s future lay offshore. Over the years, they had placed larger and larger bets on offshore development. Now, John Bookout and other E&P leaders were prepared to stake the company on it. There was no alternative for an enterprise whose core business was in the US Exploration vice president, Bob Nanz, estimated that 60 percent of the oil yet to be found in the nation was located offshore, most of it on the federal outer continental shelf (OCS) (Nanz 1975). Shell was eager to lease and drill off the entire extent of the U.S. coastline, from the Atlantic to the Pacific to the Arctic. But all these frontier areas posed daunting environmental as well as political challenges. The Gulf of Mexico, by contrast, was familiar. It had established infrastructure and service industries. The population that lived there was accepting of the industry. The Gulf basin had been giving to the industry for decades, going all the way back to the Spindletop discovery of 1901. Could it give any more? Peering into deepwater from the edge of the Gulf’s continental shelf, Shell’s geologists were itching to find out. The company had drilled a few oil discoveries, such as Cougar and Peccary, along the shelf margin in turbidite sands. But deltaic and turbidite reservoirs on the shelf were highly faulted and required many wells to develop. Turbidites in deepwater, by contrast, were potentially larger and less faulted, thus requiring fewer wells. Theory held that they could be unusually porous, due to the sifting of the sands carried by turbidity currents over long distances, and that they might be more tightly sealed and under higher pressure (Steffens and Braunsdorf 1997; Voosen 2010). Evidence also existed that oil had been generated in deepwater. During 1964–1967, Shell Oil’s research lab had sent the drillship Eureka, equipped with the first automatic dynamic positioning system, on a core-drilling program in 600–4,000 feet of water in Gulf. Some of those cores, taken from the tops of shallow salt domes, had oil shows. How much might exist further down was still a big question (Steward 2004). Hoping to test its theories about the Gulf’s regional geology, during 1978–1980, Shell nominated deepwater tracts at federal auctions. But no other companies seconded their nominations, and the US Bureau of Land Management (BLM) did not select the tracts for lease (Flowers 1999; Otteman 2001). Even if the tracts had been offered, the price of lease bonuses had soared so high, in lockstep with oil price increases in the late 1970s, that the costs of exploring in deepwater would have been prohibitive. Some of Shell’s top exploration officials began lobbying the Department of Interior, the BLM, and the US Geological Survey (USGS) to open up the deepwater to leasing and to relax the terms of access (West 2002). The lobbyists got their wish after the election of Ronald Reagan as the 40th US president and his appointment of the Colorado conservative, James Watt, as Secretary of the Interior. In 1981, Watt honored his pledge to lease a billion acres of the OCS by announcing a new system of “area-wide” leasing (AWL) offshore. This policy put into play entire planning areas (e.g., the central Gulf) up to 50 million acres, rather than rationed tracts through a restrictive nomination and selection process as in the past. Oil companies could bid on any tract they wanted in a lease sale for a given planning area, rather than having to choose from a limited number of carefully selected ones. This would reduce competition for leases and bring down bonus bids. AWL gave the industry access to far greater offshore acreage at much cheaper prices (Boué and Luyando 2002). At the time, there were compelling reasons to proceed this way in the Gulf. Oil companies had long operated in this region, there was established infrastructure, and there was abundant geological information that could be put to more flexible use under a more open system. The introduction of AWL also coincided in 1982 with the merging of the BLM OCS program and the USGS Conservation Division into a new agency, the Minerals

Management Service (MMS). After Watt's 1981 announcement, Shell geared up for the deepwater play. The first objective was to demonstrate the feasibility and safety of drilling in deepwater. The capabilities of floating drilling in ever deeper waters had evolved steadily since Shell Oil's pioneering work in the early 1960s with Bluewater 1, the first semi-submersible drilling vessel. During the 1970s, a series of major technological achievements in exploratory drilling technology extended capabilities to a 6,000-foot design limitation for the latest deepwater rigs. In the early 1970s, Shell and the drilling contractor Sedco introduced computer-controlled dynamic positioning, guideline less-re-entry, and electro-hydraulic blowout preventer (BOP) controls on Sedco 445, a new class of drillship designed to break the 2,000-foot water-depth barrier. But, in 1981, this was still frontier territory. No well had been drilled deeper than 1,500 feet of water in the Gulf; there had been only a handful of wells drilled deeper than 3,000 feet around the world, and none of them were in the US. Concerns remained about the hydrodynamic response of very long marine risers and the reliability of dynamic positioning systems (Wickizer 1988). Shell's first opportunity to upgrade and demonstrate deepwater drilling technology happened not in the Gulf, but off the Atlantic Coast. In preparation for a December 1981 lease sale there, in which Shell obtained leases in water ranging out to 7,500-foot depths in the Baltimore and Wilmington Canyon areas, Shell's Head Office assigned Carl Wickizer, manager of Production Operations Research, to conduct a feasibility study of "ultra-deepwater" drilling and development beyond 6,000 feet, where many critics believed a technology barrier existed. In 1982, Shell contracted with Sonat Offshore Drilling to lease the drillship, Discoverer Seven Seas, one of the few vessels in the world 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 remotely operated vehicle (ROV) to enable sophisticated work where human divers could not venture. Shell also used a proprietary side-scan sonar technology to demonstrate the stability of seafloor topography. In late 1983, with the concerns of regulators allayed, Seven Seas drilled an exploratory well in a world record water depth of 6,448 feet in the Wilmington Canyon. Although the drilling program in the Atlantic, which included two other deepwater wells, did not discover oil, the successful demonstration of drilling at such extreme depths established the industry's capability to work safely beyond 6,000 feet and inspired confidence in Shell's management for moving forward into deepwater in the Gulf (Wickizer 1988).



Figure 4: Discoverer Seven Seas drillship that drilled the Mars discovery (2009). Source: Shipspotting.com.

The achievements in deepwater drilling came with a loud caveat: cost. “Simply extending the equipment and practices of our shallow water past,” warned Carl Wickizer in a May 1984 luncheon talk to the Offshore Technology Conference (OTC), “is not likely to be cost effective in deepwater. Inefficiencies and equipment failures can inflate the cost of a well so as to negate the impact of technological advances” (Wickizer 1984). In Shell’s deepwater feasibility program, Discoverer Seven Seas spent one day out of seven simply testing the BOP system. Lost time from equipment malfunctions was inordinately expensive. Day rates for leasing a deepwater vessel would be pricey. “If we are to achieve the cost effectiveness needed,” explained Wickizer, “we must reach new levels of reliability, quality assurance, preventative maintenance, and operational efficiency” (Wickizer 1984). Even then, he suggested, these things might not be enough. Two other conditions had to be met. Well productivity had to be high and the fields had to be giant. “In the face of such experience, we must ask ourselves about field development,” said Wickizer. “Is it feasible?” He answered the question in the affirmative, but with some hesitation. “We think so, and in a reasonable time frame—provided that the proverbial deepwater elephant has finally been discovered, and that we can achieve acceptable costs” (Wickizer 1984). By this time, Shell’s exploration teams were actively hunting for deepwater elephants. Because of the tremendous costs of deepwater development, their guiding principle was “high rates and high ultimates.” In other words, they were looking for fields with high flow rates and high ultimate reserves. Nothing less would work. But Shell officials were buoyed by their advancing geophysical capabilities, their reinforced confidence in deepwater drilling, and the expectation of cheaper leases with area-wide sales. They bid aggressively at the first area-wide sale for the Gulf, held in New Orleans on May 25, 1983. It was a momentous occasion. “While rigs stood idle in the inshore shallows of the Gulf of Mexico,” reported Newsweek on the first sale under the new system, “more than 1,200 oilmen gathered last week in New Orleans’ Superdome to testify to their faith in the health of their industry” (Newsweek 1983: 77). The sale brought a record \$3.47 billion in high bonus bids. But with so much acreage put up for sale, the average price per acre was only about \$1,000, three to four times lower than the average in the 1979–1980 sales. Shell spent \$270 million for sixty blocks (Oil and Gas Journal 1983: 48). Three of the prospects it bought—Bullwinkle, Tahoe, Popeye—were in 1,300–3,000-foot water depths. In

October 1983, Discoverer Seven Seas made a major discovery at Shell's Bullwinkle prospect on the shallow end of that depth range. After this discovery, Shell briefly lost its deepwater nerve. Fixed platform technology could not be enlarged much beyond the depth of the monster steel jacket planned for Bullwinkle in 1,300 feet of water. The costs of alternative concepts, such as tension-leg platforms, compliant towers, and subsea completions, presented serious questions. Subsea wells were still expensive and not yet completely reliable. Conoco's Hutton TLP, installed in the North Sea in 1984, had experienced serious cost overruns. One of the leading methods Shell's production department considered for depths beyond 1,500 feet was subsea wellheads linked by pipeline back to a fixed platform in shallower water. But offshore pipelining faced distance limitations and economic constraints. Shell's production managers had an ironclad rule: the company could explore no farther than fifteen miles past 600 feet of water, the practical depth limit and distance for installing marine pipelines at the time. Due to this policy, Shell Offshore's exploration managers made only a few bids in the April 1984 sale, the second major area-wide sale in the Gulf. They were caught off guard, however, when other companies, notably Exxon and Placid Oil, acquired acreage in water deeper than Shell had been prepared to go (Forrest 1999; Oil and Gas Journal 1984: 36). The results from the April sale prompted a flurry of meetings and discussions in Shell about what its deepwater strategy should be. Billy Flowers, then offshore vice president, met with Shell's top E&P officials Jack Threet, vice president for exploration, Charlie Blackburn, executive vice president for E&P, and John Bookout to make the case for pushing farther into the Gulf. All three appreciated the urgency, given the competition, and they resolved that Shell would drop the fifteen-mile rule and begin to gather seismic data from ultra-deepwater, using a \$45 million, state-of-the-art seismic vessel, Shell America, which had just been launched and outfitted (see Figure 2.8). Time was short before the next Gulf area wide lease sale in July 1984. On the auction block, the government placed large tracts in the western Gulf. Shell America immediately set out to gather as much proprietary seismic data as possible. Because of the time constraint, however, the vessel had to focus on specific locations. Tom Velleca, general manager of geophysics in Houston, urged the Offshore Division to organize a team to search quickly for prospects in the Garden Banks area. Located in waters ranging from 1,000 feet to 4,000 feet, the prospects they worked on were considered very speculative. The geophysicists did not have as much seismic coverage as they would have liked. Shell America had time to shoot only one seismic line across some of them. Shell bid on 10 prospects in the sale and won seven of them, including a potential field in the Garden Banks area called Auger, which would become Shell's first deepwater development (Abbott 1984; Flowers 1999).

4.2 Field Appraisal

In January 1988, a year before Discoverer Seven Seas began drilling Mars but after the discovery at Auger, Shell Offshore, Inc. formed a task force to address pressing questions about deepwater turbidite reservoirs. This "Turbidite Task Force" formed the nucleus of an emerging deepwater organization within Shell. Deepwater had been simply part of Shell's Gulf exploration and production organization and fully contained within operations on the shelf. There were three different streams of effort going on in the deepwater. The first was the evaluation of the Powell, Tahoe, and Popeye discoveries. The second involved advancing deepwater exploratory drilling. The third had to do with the general geophysical and geological exploration approach to this new frontier. As the company struggled to manage the deepwater challenge in the mid-1980s, people working in these effort streams endured constant organizational change. Carl Wickizer, who led the deepwater drilling feasibility tests in the Atlantic, was a constant overseeing presence, continually responsible for the technical management of deepwater activity until he retired in 1993. Wickizer and other managers

assembled the Turbidite Task Force in early 1989 and charged it with integrating these efforts to study how turbidite reservoirs might behave and determine how Shell could reach its objective of achieving “high-rate, high-ultimate” wells (Wickizer 2001). The first exchange at the inaugural meeting of the group, which included about a dozen people, captured the problem. Representatives from exploration, Gary Steffens and John Howell, walked into the room and put the production engineers on the spot: “Why won’t production mature our prospects?” Production leader, Mark Shannon, who came from petrophysical research, met the question with his own rejoinder: “Why can’t you find something that’s clearly commercial?” (Montague and Shannon 2009). The difference in opinion was friendly, for the most part, and a meeting of the minds was the whole point of the group, which included geophysicists, petrophysicists, reservoir engineers, specialists in aquifer modeling, and different kinds of geologists. This “brain trust” did not focus on discrete projects or prospects. Rather, as co-leader Dave Montague put it, they had free reign “to systematically go through the available data, to gather new data, to look at interpretations of existing fields, to come up with out-of-the-box ways to answer the questions we had” (Montague and Shannon 2009). There were few direct analogs on which to draw to answer those questions. Bullwinkle’s wells were producing at a high rate, more than 3,500 barrels per day. Deepwater economics, however, required much higher rates than that. Only a few wells in the history of the Gulf could match Bullwinkle’s. The same could be said for per-well ultimate reserves. The average Gulf well produced one or two million barrels at the most. Shell was banking on ten times that amount. “But we did have some knowledge and encouragement from some of the fields we had worked on and also some of the foundation work that had gone into the lease sales themselves,” said Shannon (Montague and Shannon 2009). They needed more than encouragement. The Turbidite Task Force collected data from everywhere they could find. They scoured the world for turbidite outcrops, from Spain, to Norway, to Newfoundland, to California. They studied the academic literature on turbidites. They mined MMS data for production on every well in the Gulf, how the wells were arrayed, and what this information said about drainage areas. They studied competitor’s fields, paying special attention to Conoco’s Joliet development in Green Canyon as it had pays in multiple depositional sequences. They traded data with companies, such as Exxon and Mobil. They carried out studies of their own fields on the continental shelf that might serve as analogs for Shell’s deepwater finds. Peccary, a small gas field located 25 miles northeast of Popeye and 50 miles from Bullwinkle in the Green Canyon, had pay zones and geological characteristics similar to some of the fields they were considering in deeper water. “We did a lot of work on Peccary to unravel it and then put it back together,” said Mark Shannon. “Sort of upscale it and see what it might do had it been a deepwater field developed in the way we were thinking about doing at places like Auger” (Montague and Shannon 2009).

In its studies, the Turbidite Task Force attacked a long list of problems. They needed to understand how to interpret the “seismic facies.” In other words, how could they get more than structural information from seismic data? How could they find out the geological causes responsible for the seismic signature of the rocks, which was the driving force behind the development of seismic facies analysis? What did this say about the reservoir properties and the production systems? What was the reflection coefficient of deepwater sands if they were, in fact, over-pressured and compactable? How could you distinguish between “amalgamated channels” of sands and sands “sheets”? This was very important, because amalgamated channels were likely to be more compartmentalized than sheets, and thus would make a difference in decisions about where to drill. None of these kinds of analyses had really been performed before with turbidites. “We were basically trying to link from seismic to the storage tank to understand how things worked, how the plumbing worked,” said Dave

Montague. The task force also looked at potential disaster scenarios with these young reservoirs that had been buried extremely rapidly and were therefore highly compactable. With the draw down in reservoir pressure from production, they would compact and possibly damage the well tubulars. “In fact, they were highly compressible,” explained Mark Shannon. “But we got more support from aquifers than we had expected. The reservoirs, in fact, stood up better over time than had been predicted” (Montague and Shannon 2009). The primary conclusions of the task force, which ran through 1992, were very encouraging. The first and most important one was that, barring structural complications, turbidites could be amazingly continuous over a distance of miles. To think that these very thin beds would be that continuous was a surprising and counterintuitive conclusion for some geologists. Second, turbidites did have the capacity for high-rate production with the proper completion systems. Deepwater turbidites were more tightly sealed below layers of dense mud and therefore highly pressurized. “It’s like putting a brick on a balloon full of water,” explained Shell exploration geologist Alan Kornacki. “The water wants to burst upwards. If you put a straw into that balloon, the weight of brick will push the water out at a tremendous rate” (Thorpe 1996,144). Third, they found some confirmation, as indicated at Mars, that sands deposited in the middle of the basins, down off the structural highs, would be more prospective than sediments at the top of salt relief. This was due to the nature of structural deposition when the salt had preceded sedimentation of the source rock or reservoir, but also because of structural complications near the top of salt features. The time-honoured tactic in the Gulf Coast region was to drill the bumps at the top of salt domes. But the task force compiled a lot of evidence to show that this might not be the best place to target drilling. “We had a geologist in the team who used to sarcastically refer to the ‘bump drillers,’” remembered Shannon (Montague and Shannon 2009). Alongside the work of Shell’s Turbidite Task Force, the initial exuberance over the Mars discovery quickly turned to sober determination to understand the character and extent of the reservoirs. In July 1989, Shell began drilling its first appraisal well in block MC 807. On August 9, as the drill bit was penetrating the shallow layers of the seabed, 20th Century Fox released *The Abyss*, a film directed by James Cameron, in which an experimental oil drilling vessel, *Deep Core*, owned by a company called Benthic Petroleum, discovers an alien race inhabiting a spacecraft sitting eight kilometres deep in the Cayman Trench. No telling what crossed the imaginations of those in charge of the drilling operation as they approached the targets at Mars. No doubt some of them had seen the blockbuster film and felt at least a small sense of other worldliness in the work they were doing. The appraisal drilling lasted until August 1991, totalling six wells, including one sidetrack. Five were drilled in MC 807, one block south of MC763, and all penetrated pay sands in numerous Pliocene and Miocene intervals. A sixth drilled in MC 806 was a dry hole, delimiting the southwest extent of the field. All were successfully plugged and abandoned, except for MC 807 #4, which was suspended and completed later as a subsea producer. Together the appraisal wells established the presence of 24 individual pay sands within 14 significant hydrocarbon-bearing turbidite reservoir layers ranging from 10,000 feet to 19,000 feet below seafloor level. The heart of the field lay in MC 807, which became its official marker (Mahaffie 1994:234; US Department of the Interior 2014). The drilling appraisal produced exhilarating results. However, there was still a lot of work left to do for the geologists to comprehend the character of the field they had discovered. “It’s a big field, so to get your mind around the reservoir and its extent necessitated a rather lengthy appraisal program,” said Bill Henry, Mars development engineering team leader (Duey 1999). Mars was in a new geological frontier beneath unprecedented water depths. The configurations for oil traps had been profoundly influenced by the interaction between sedimentary processes and salt movements. Early interpretations of “repeat formation tester” (RFT) pressure measurements and geochemical samples indicated that the reservoirs were compartmentalized in complex

ways. The problem, as Shell Offshore geologist, Mike Mahaffie, explained, was that “details regarding the spatial arrangements of individual sands within the reservoir interval is often lacking, due to the inability to accurately predict internal reservoir architecture between existing well control or within the seismic loop itself” (Mahaffie 1994, 233). Not just Shell, but the industry as a whole was inexperienced with deepwater turbidites. In April 1990, Placid Oil pulled the plug on a small floating platform in the Green Canyon (GC) 29 area because of poor results from wells in turbidite sands. Before any decisions could be made about developing Mars, which would require giant capital outlays, geologists needed to understand the depositional history, shape, and behaviour of the reservoirs. This meant constructing a new and reliable model to provide certainty about the characteristics of the reservoir sands. This was essential to informing a billion-dollar investment. By 1990, such understanding was ever more vital. Oil prices had continued to slide, while Shell’s costs had soared. Shell E&P’s long-range plan forecast persistently low prices. Thus, the Mars field appraisal took place during a period when management was not keen to move forward aggressively on costly projects. “It was a big investment at a time when there wasn’t a lot of money available, and we were really stepping out in terms of the rock,” noted Bob Markway, the Mars asset leader. “That probably led to a little more caution than usual” (Duey 1999, 8). Nevertheless, the work continued. Mars was too promising to postpone. In August 1989, immediately after the drilling began, Jim Funk, division exploration manager, assigned Patricia Santogrossi to be the team lead for the Mars appraisal. Santogrossi was one of the few women to have established herself as a senior professional in the male world of exploration. She had joined Shell in 1975, one of seven women in a class of 43 geoscientists. Seven years later, she was the only woman left. She survived layoffs in the mid-1980s, when a disproportionate number of women and people of color who had newly joined the industry lost their jobs. Santogrossi spent ten years in the 1980s gaining valuable experience working in the Santos Basin for Shell Pecten in Brazil learning how to interpret turbidite sandstones with seismic data. In 1979, Pecten Brazil had made the first discovery under Brazil’s risk-contract drilling system, agas field called Merluza (Santogrossi 2014). As data from the wells came in, Santogrossi’s appraisal team undertook a stratigraphic study to model the architecture of the reservoirs. The key to this was the use of high-resolution 3D seismic data acquired over the area by the seismic vessel Shell America after the discovery well had been drilled. The 1970s revolution in digital, 3D seismic imaging, pioneered by Geophysical Services, Inc. (GSI), had dramatically enhanced the resolution of subsurface data. In the 1980s, the move to computer workstations enabled much faster processing, giving geophysicists the ability to handle the massive amount of data generated in a 3D survey from increasingly tighter grid spacing. By the late 1980s, 3D seismic could bring into focus subtle details about fault geometries, depositional features, petroleum traps, and reservoir continuities. A 3D survey, at that point in time, was very expensive. It cost approximately \$3 million to acquire a 3D data set covering a 20-by-20-kilometer area and another \$1 million for the hardware to process it (Boreham et al 1991, 41). The total exploration and well appraisal costs for the Mars field are estimated to have totaled \$110 million. The 3D survey was a significant item, but clearly justifiable for Shell’s exploration leaders. The general attitude at Mars, according to Bill Henry, was “let’s make sure we optimize the heck out of it before we move forward” (Duey 1999, 8). Like other deepwater decisions at Shell Oil in the late 1980s, it took a hard sales pitch to upper management to get approval. In 1989, Jack Little, president of Shell Exploration & Production Company, wanted to save money by parking Shell America in port. To preserve the deepwater opportunity, Shell Offshore exploration general manager, Bill Broman, traveled from New Orleans to Shell’s Houston headquarters to make a presentation to Little. Broman showed quite clearly it would cost more to keep Shell America in the Port of Galveston, Texas, doing nothing than to have it

working in the Gulf acquiring seismic data. Little had to concede the case. He wanted to cut costs, so Shell America continued to shoot seismic. Shell Oil exploration vice president, Tom Hart, who often forcefully expressed his views about exploration to Little, was deeply impressed with this masterful presentation by Broman. “I wouldn’t have had the nerve to make that claim to Little,” he said. From then on, Hart referred to Shell America as Flying Dutchman, the mythic ghost ship unable to make port and destined to sail the oceans forever (Sears 2010b). In May 1990, Shell America finally did return to port in Galveston to receive major equipment upgrades. The vessel previously had acquired 3D seismic surveys, but with only one digital streamer cable—the device equipped with hydrophones that recorded acoustic echoes bounced off the subsurface layers. It often had to work in conjunction with other seismic vessels to gather enough data, making many passes over the target area to acquire the needed information. This is what made a 3D survey so expensive. To help bring down costs and allow for single-ship data acquisition, crews added new digital streamer cables and rebuilt floats—the sound sources arrayed on both sides of the boat that released compressed air into the water and acoustic vibrations into the earth. Before the upgrade, the ship had a single reel that stored a maximum of 18,000 feet of streamer cable. The refurbished ship had a total of 48,000 feet of cable, 24,000 feet on each of two massive storage reels, 18-feet in diameter. The upgrades also included a remodeled main deck to accommodate the weight and bulk of the new cables and reels and a more powerful computer system that allowed for onboard seismic data processing. The upgrades enabled Shell America to tow two or even three streamers at a time, instead of just one, and thus collect two to three times as much data for each survey-pass. “As you move into the world of 3D, you can speed up the acquisition of data by getting as many subsurface lines as possible each time the vessel makes a pass,” explained Yoram Shoham, manager of Applied Geophysics Research at Shell’s Bellaire Research Center. “The main difference between a two-dimensional line and three-dimensional areal coverage is in aperture; if you close one eye you lose depth perception. You see things better with both eyes open, and you could see even better if you had an array of 20 or 200 eyes. With 3D surveys, we’re looking at the same object, but from many directions, and that gives us a much better view of it” (Abbott 1991, 29). After crews worked around the clock to complete the upgrades, Shell America departed in late 1990. It increased the speed and extent of proprietary 3D surveying not only for Mars, one of its first major targets, but also for much of the company’s deepwater leasehold and prospects for upcoming sales. The ambitious 3D data collection taken at Mars was a turning point in the history of exploration in the Gulf. Because of the extraordinary expenditure, 3D surveys before Mars were small, “postage stamp” in size (Yielding, 2013). At Mars, Shell began gathering blanket coverage of complex structural areas, shooting up to 500 parallel lines across a target area, spaced between 50 and 200 feet from each other. In 1989, only 5 percent of the wells drilled in the Gulf relied on 3D seismic; in 1996, nearly 80 percent did. Companies acquired the majority of that data between 1990 and 1993 (Oil & Gas Journal 1997). During this time, operators began to rely on 3D seismic not only for field development, but for wildcat exploration as well. Wider swaths of equipment, including multiple vessels and streamers, and the advent of onboard processing significantly reduced the unit costs of 3D acquisition. Group shoots and large speculative surveys by geophysical contractors brought forth a torrent of high-quality 3D seismic data in the Gulf. By many accounts, 3D seismic boosted wildcat finding success from less than 30 percent to 60 or 70 percent. In 1992, Woody Nestvold, chief geophysicist for the Royal Dutch Shell Group in The Hague, announced that the Group would no longer acquire 2D data. It would use 3-D exclusively for both exploration and production (Nestvold 1996). In the Gulf, Mars was the field that marked the dramatic transition from 2D to 3D seismic acquisition. The Mars geologists integrated the outcrop studies from the Turbidite Task Force and data from wireline well logs with the 3D seismic package. Using “seismic

inversion,” a method of correlating seismic profiles with values measured in the borehole, they were able to extend well information throughout the 3D seismic architecture and produce a “reservoir rock property distribution that incorporated all available data” (Chapin, Tiller, and Mahaffie 1996, 178). This gave them a framework with which to develop depositional models for the 14 pay-bearing sands. They then used these models to predict the aerial distribution of “lithofacies,” or stratigraphic units, and to aid in the extrapolation of reservoir attributes needed to guide the placement of development wells. The outcrop studies helped the geological evaluators develop a classification scheme that subdivided the stratigraphic units into “three major categories: 1) thin-bedded channel levee and overbank sediments, 2) channel-fill complexes, and 3) sheet sands” (Mahaffie 1994, 233). In short, the depositional models and classification schemes gave Shell a much better idea of where the big pay sands would be. The few wells that had been drilled out in deepwater, such as those by Getty and Arco, had been drilled on the tops of structural crests, where the sands were poor. Explorationists raised on the wisdom of “bump drilling” had difficulty accepting that reservoirs would be out in the flats in the middle of the basin. But Shell reservoir analysis, combined with the work of the task force, showed that the best pays would be down off the crests in the basin. “It was initially hard to grasp that this was as big as the seismic (data) suggest,” recalled Jim Funk. “It looked like it could be a one-of-a-kind field” (Davis 1997, 2E). By the spring of 1991, with the appraisal drilling nearly completed and the geological analysis progressing, Shell E&P had grown confident enough to go public with Mars. On May 4, after two years of secrecy, Shell Oil and its partner, BP, announced the discovery with initial reserve estimates that suggested it was the largest and most important US oil find of the late 20th century. The final resource appraisal for Mars placed the oil reserves at 1 billion barrels, nearly four times the size of Auger. This is the amount of oil Shell internally booked when exploration transferred the asset to production (Santogrossi, 2014). In an early statement to the press, however, BP had mistakenly estimated the reserves at 700 million barrels, which is what was widely reported and never corrected at the time. Even the smaller field-size estimate was major news. Shell’s string of previously announced deepwater discoveries had caught the industry’s attention, but Mars made people sit up and listen. The announcement suggested that the potential of the deepwater Gulf was far greater than anyone outside of Shell had suspected. Oil analyst Daniel Yergin called Mars “the most significant discovery since the North Slope” of Alaska in 1968 (Lee 1991). Although the oil industry took notice of the Mars discovery, the general public and most journalists did not. The Los Angeles Times and the Christian Science Monitor were the lone US newspapers to carry the story. The only reporting that the New York Times did on Shell Oil during mid-1991 was on the company’s July announcement of a 15 percent reduction in its US workforce of 31,000 (Hayes 1991). The biggest stories on “Mars” in 1991 were the suggestion by astronomers that the planet had once contained oceans, the National Aeronautics and Space Administration (NASA)’s announcement of a plan to send a single-spacecraft mission to the planet, and the call by a US National Space Council study for a manned mission to Mars by 2014 (Hayes 1991; McKay, Toon, and Kasting 1991). This would be only the first instance in which Shell’s Mars project would be overshadowed by public and official fascination with the planet Mars. One person at Shell Oil was certainly not distracted by news about the celestial Mars: Rich Pattarozzi. Promoted to general manager of E&P for deepwater in 1991, Pattarozzi faced a troubling problem. Oil prices had crashed again after a brief rise during the Iraq crisis and war. At the same time, E&P managers learned that Shell had the highest cost per barrel of oil and gas produced among its competitors, and the company had just registered its first quarterly loss since the Great Depression, which led to the voluntary layoffs announced in July. By the end of the year, Shell Oil would register a miniscule net income of \$20million on more than \$20 billion in revenue and assets, a \$1 billion decrease in net

income from the previous year. With construction beginning on the Auger TLP, Pattarozzi was deeply worried about the profitability of this and other deepwater projects. Auger's wells were planned to produce around 4,000 barrels per day, similar to what Bullwinkle's were then producing. "This isn't going to work," Pattarozzi told his staff. "The economics aren't there. We've got to do better than that." It was conceivable that Auger might be Shell's first and last deepwater project (Pattarozzi 2000). By this time, however, Shell's reservoir engineers and geologists, supported by the Turbidite Task Force studies, grew increasingly optimistic about the quality of turbidite reservoirs and the potential for high rate, high-ultimate wells in deepwater. In the spring 1991, based on the recommendation of the task force, the deepwater division began a production test at Tahoe (Viosca Knoll Block 783), one of the company's early deepwater discoveries. It was a relatively small gas field that did not merit a production facility, but was on the drawing board as a subsea tieback. "We didn't want a production test in the Gulf of Mexico," recalled Dave Montague. "That was the last thing Shell wanted to do. But we made a very strong case that a large part of our reservoirs were thin-bedded, Tahoe-like reservoirs, and we just really needed to know about the productivity and lateral extent of those reservoirs" (Montague and Shannon 2009). The test was carried out safely and successfully. Flow rates from beds at Tahoe as thin as a centimeter were encouraging, achieving 29 million cubic feet per day (MMcfd) of natural gas and 974 barrels per day (bbl/d) of condensate (Abbott 1994a; Lawrence and Anderson 1993).

Based on the information coming in, his engineers believed that deepwater wells should behave differently than other wells, and that they could produce at higher rates than initially thought. Auger's wells could possibly produce something close to 8,000 barrels per day, twice the rate planned for the facility and twice as good as any well ever produced in the Gulf. "But we had no way of knowing whether that was really true or not," said Pattarozzi. In the spring of 1992, after extended deliberation, he and his engineers approached the production superintendent at Bullwinkle, on the outer-continental slope, just off the shelf edge, to see if he would test a producing well at higher rates. Bullwinkle had Pliocene turbidite reservoirs similar to those examined in deepwater. Its wells were producing at about 3,500 barrels per day, which was considered highly productive. On the shelf, a good well produced 1,000 bbl/d and an excellent well flowed at 2,000 bbl/d. Understandably, the Bullwinkle superintendent was not thrilled about increasing the choke on one of his wells and possibly damaging it. But Pattarozzi's engineers, with upper management support, convinced him that the draw-down pressure in the well would not increase enough to do any damage. Fortunately, Bullwinkle's wells had been installed with downhole pressure gauges, so that pressure changes in reservoirs at 12,000 to 15,000 feet subsurface depths could be observed and measured (Pattarozzi 2000). The engineers were right. The first well they tested at Bullwinkle increased its production from 3,500 bbl/d to 7,000 bbl/d with hardly any change in bottom-hole, draw-down pressure (Pattarozzi 2000). The test was a divine breakthrough. If this was any indication of the general productivity of the wells at Auger and other prospects Shell had under lease, it not only radically changed the cost structure of Auger but gave the company a whole new economic model with which to approach deepwater projects. "We went from believing wells could only produce 3,500 barrels a day to saying wells could produce 20,000 barrels a day," remembered Pattarozzi. By increasing the productivity of the wells, deepwater platforms could be designed with fewer of them, thus reducing overall costs significantly. The results were so encouraging that Shell Offshore managers, in August 1993, were able to obtain relatively swift approval from Shell Oil's board of directors to move ahead with development of another tension-leg platform (TLP) at Mars, even though Auger had not yet been installed. After the production test at Bullwinkle, said Bob Howard, president of Shell Offshore, Mars was a "pretty easy sell" (Howard 2000). Shell took four

years, 1989–1993, between the discovery of Mars and the “authorization for expenditure” (AFE) to go ahead with development. By 1993, the pieces seemed to be in place. Shell E&P had a new reservoir model for the deepwater basin province, backed by high resolution 3D seismic, borehole data, and outcrop analog studies. And it had a new economic model, supported by analog field production tests. The annual convention of the American Association of Petroleum Geologists (AAPG) in New Orleans that year was a coming out party for deepwater petroleum geology. Papers presented by representatives from oil companies, academic institutions, and government organizations studying the Gulf amounted to nothing less than a “paradigm shift” in the integrated understanding of the “geology, geophysics, biostratigraphy, and hydrocarbon habitat of the deepwater Gulf of Mexico [sic],” according to Dave Lawrence of Shell Offshore and Roger Anderson of the Lamont-Doherty Earth Observatory. Speakers commonly cited the high porosities and permeabilities of deepwater reservoirs, excellent connectivity in the sands, and high recovery efficiencies. Lawrence and Anderson said, “Well data from 160 rank wildcat wells, more than 110 appraisal and field wells, and seismic data acquired through more than 1,000 proprietary seismic crew months portray the deepwater as a diamond in the rough” (Lawrence and Anderson 1993).

4.3 Drilling

In early 1990, after the Mars discovery, Shell engineers formulated a two-phase plan for development. Phase 1 called for drilling 24 wells through the TLP, plus two nearby subsea wells. Depending on the results of Phase 1, Phase 2 would drill another 15 wells from either a second TLP or some other facility. Even with the expert geological and geophysical work Shell was doing at Mars, there were still many unknowns about the field’s multiple reservoir horizons. The overriding imperative was keeping the number of expensive wells drilled to a minimum. In order to do that, engineers needed as much reservoir information as possible. Given the enormous investment required to develop the field, managers wanted to gather samples about early production performance and pre-drill several wells before the TLP arrived on site (Kunkel 1999). Shell took an unconventional and untried approach to the pre-drilling program. The drilling team, led by development engineering head Bill Henry and drilling superintendent Joe Leimkuhler, set out to drill ten wells. But instead of drilling down to the deepest reservoirs in a traditional “bottoms-up” approach, Shell decided to drill to intersect as many of the stacked and offset reservoirs as possible. “There was some risk associated with the sampling approach, but it was offset by tremendous reservoir performance knowledge in all of these major reservoirs that we could then take advantage of in the subsequent drilling development program,” said Henry. “It helped us define how we could optimize the development as we went down the road” (Duey 1999, 8). One of the biggest risks was dealing with the presence of “shallow water flows” (SWF) at the targeted drilling locations. A confusing name for a problem encountered in deep water, SWF are geohazards that occur not in shallow water, but at shallow formation depths usually less than 5,000 feet below the mudline. The Mississippi River has long dumped massive sediments into Mississippi Canyon at a rate too rapid for them to consolidate. As more sediment piled up, water and pressure became trapped. Here, in what are known as shallow water zones, sands are highly pressured and unconsolidated. When a well drills through one of these zones, over pressured water and sand escape. In extreme cases, a cavern is excavated around the well. With no support for the casing string, the well buckles. Overpressures can even “communicate through the fractures to shallower zones, adjacent wells, or the seafloor,” causing “large craters, mounds, or cracks and potentially the loss of the well and the site” (Sparkman 2002, 661).

At the very least, SWF zones cause circulation problems because of the narrow window between pore pressures and fracture gradients. In other words, if the weight of the drilling mud is not heavy enough, the pore pressure of the formation will push sand and water into the well and cause it to fail. If the mud is too heavy, or “overbalanced,” the sands may fracture, resulting in the loss of drilling mud, or “lost returns,” and thus the loss of well control. In a SWF zone the difference between a mud weight that is too high and one that is too low is precariously small, less than 100 pounds per square inch (psi), or a mud weight of 0.3 pounds per gallon (ppg). “A more technically appropriate term might be ‘deepwater, near-surface, narrow-margin drilling,’” writes Greg Myers, manager of engineering and operations for the Integrated Ocean Drilling Program (IODP) (Myers et al 2007, 88). Mississippi Canyon was an area prone to shallow water flows. Paleontological age determinations found that SWF risks are associated with regions that had high rates of sediment accumulation during the past 70,000 years, especially near the centre of deltaic deposition by the Mississippi River (Ostermeier et al., 2002). Before development drilling at the Mars, Shell had lost three wells in the area. One had been a Mars appraisal well, which suffered serious flow back to the seabed. In 1990–1991, two other exploration wells at the Ursa prospect, seven and one-half miles east of Mars, had experienced buckled and worn casing due to SWF and had to be abandoned. “I was worried about that flow based on some of things we had seen at Ursa,” admitted Joe Leimkuhler. “One of the flows seen at Ursa was severe enough to ruin a potential TLP tendon pattern” (Silverman 1999, 32). Exploration drilling at Mars also had experienced the problem of poor penetration rates at deeper depths—a snail’s pace of 18 feet-per-hour below 12,000 feet. This was approximately the same drilling rate as for the Auger development wells. With the high rig cost of the Sonat semi-submersible, George Richardson, hired to perform the pre-drilling, this rate of penetration (ROP) threatened to inflate drilling costs intolerably. One way to increase the ROP in taking the pre-drilled wells to depth was to use synthetic drilling muds, as opposed to water-based muds, which were just being introduced into the Gulf. Synthetic-based muds (SBM) formulated with linear alphaolefins and isomerized olefins had lower kinematic viscosities, which is measured as the time it takes oil to travel through the orifice of a capillary under the force of gravity, than water-based fluids. Their use provided for faster penetration, less mud related nonproductive time, and they were more environmentally friendly than oil-based muds (OBM), which were another alternative for achieving faster penetration. In 1993, the US Environmental Protection Agency (EPA) prohibited the on-site discharge of drill cuttings from OBMs, which had to be hauled onshore for disposal. At the time, the EPA allowed the discharge of SBM cuttings on the basis that they met the discharge limitations for water-based muds. Synthetic fluids were expensive, priced at around \$300 per barrel, but the higher cost was offset by not having to ship the cuttings to shore. Still, with the potential for lost returns in the SWF zones, the gain from increased ROP came at the risk of losing precious drilling fluids (Silverman 1999; Friedheim and Candler 2008). Weighing the benefits of a smoother ride for the drillbit versus the costly chance of lost circulation in the three deeper wells, the drilling team chose to use conventional muds to drill through the SWF zone and try SBMs in the 9 7/8-inch hole section further down below it. Positive results led to continued improvement. “When we started using the SBM at Mars, we averaged only 32 ft/hr, and used it on 26 percent of the well,” said Leimkuhler. “We worked our way up to 60 ft/hr in 80 percent of the well depth. We elected not to use SBM in the first interval below the SWF, because if you lost the returns in the flow zone, you would have a paved interstate highway to the mud line and we did not want that to happen.” Returns lost with water-based muds tended to swell and heal the fractured rock, whereas the SBM coated and sealed the shales, keeping them from healing as fast (Silverman 1999, 34). The Macondo well, drilled by the Deepwater Horizon in 2010, encountered narrow pore pressure/fracture gradient differentials throughout the well, one of

the complications that led to the catastrophic blowout. Mars appraisal leader Patricia Santogrossi helped the drillers precisely identify and account for the SWF zones at the drilling site. She demonstrated to them and her management that the subsurface contained a feature that “soled” at approximately 5,100 feet. Swift currents during sediment deposition often caused a “sole marking,” such a flute or groove on the bottom or sole of a sandstone bed. Soles are common in turbidites. The particular sole in question consisted of a large concentric region of extensional fault blocks that had detached at that level. At least one Shell geoscientist at the research lab believed the feature to be a channel. But its true nature was revealed by a “complex tracing analysis” display of instantaneous phase, or a different kind of seismic representation. According to Santogrossi, her management suggested that she not confuse the drillers with alternate seismic displays they might not understand. However, it was too late. Her production colleagues already had taken the seismic section and proceeded to change the casing-riser design to address the problem (Santogrossi 2014). The key to conquering the SWF zones was the use of a “two riser system,” first developed at Auger. A drilling riser is a low-pressure tube that provides a conduit for the drill stem and drilling fluids from the vessel to the blowout preventer at the seafloor. For conventional subsea drilling systems, the dimensions of the wellhead and subsea blowout preventer restricted the size of casings, the metal pipes inserted into a recently drilled section of a borehole and held in place with cement. At Auger and Mars, five to six casing strings were required to get down to depth, each getting smaller as they were sleeved through the larger diameter casings on the way down the well hole, like an old-fashioned maritime telescope from the end lens to the eyeglass. The production casing in the pay zones at Mars was designed to be 7 inches in diameter, to handle the anticipated higher-than-normal flow rates. A conventional system could not support production casing of this weight. The two-riser system allowed for larger casing as it employed a 26-inch marine riser and subsea diverter, a device that diverts gas or other fluids from shallow zones away from the rig, in combination with a conventional 21-inch riser and subsea blowout preventer (Gonzalez et al 1992). A less costly and complicated alternative was “riserless drilling,” which uses seawater pumped down the drill pipe as the primary drilling fluid. This avoids the challenge of filling the marine riser with fluid to offset the well pressure, thus making it easier to balance subsea well pressures and re-enter the drilling hole. But riserless drilling often required a shallower placement of the casing shoe and shorter casing intervals, leading to slimmer-than-desired production casing. “We elected to set 26-inch casing above the SWF, grout it in place for pile integrity, then drill through the SWF zone with the 26-inch riser and subsea diverter employed,” explained Leimkuhler. In order to gather as much information about the SWF zone, George Richardson drilled four wells to total depth near the corners of the well pattern. Data from these wells helped define casing points, drilling procedures, and cementing strategies such as casing running speeds, cement slurry density, and cement volumes that eventually guided the success in isolating the SWF on all of Mars 24 wells (Silverman 1999, 33). Cementing wells in the SWF zone posed another set of hurdles. The drilling team could tell what the pressures in the sands were while drilling through them, but they could not tell what the pressures were on the backside while cementing. The industry later employed devices to monitor pressure on the annulus, which is the void between the drill string and the formation, but this was not available at Mars. “It turned out that on the initial wells we did a lot of damage to the zones from that mud that was forced in during drilling and cementing operations,” Leimkuhler said. They began drilling under the impression that the formation was stronger than it really was, using mud and cement that were too heavy, and found that not enough cement was returning up the annulus between the casing and the formation. “As we drilled and cemented each subsequent well, we did increasing damage to the surrounding area. We had flowback to the seafloor after a lot of the cementing jobs at Mars” (Silverman 1999, 34-35). In hindsight, it turned out to be a

normal flowback of well fluids, not shallow water flows, a result of drilling too fast and generating too much pressure behind the drill from the flow and cuttings. The pre-drilling program lasted three years, October 1993 to January 1996. The team and George Richardson successfully drilled and cased a total of 10 wells to reservoir depth prior to the installation of the TLP and also completed a subsea well to be tied back to the facility. Difficulties notwithstanding, they completed the casing and cementing of the 10 wells with success. Still other struggles had to be overcome in the process. Mars drilling locations exposed Shell to deepwater Loop Currents for the first time at a permanent site in the Gulf. These currents, traveling as deep as 2,500 feet below the water surface, arrive through the straits of Yucatan, loop around into the northern Gulf, and then exit through the Florida Keys. They placed substantial stress and created vortex-induced vibrations (VIV) on the risers and the auxiliary choke and kill lines used for circulating fluids to the subsea blow-out preventer (BOP) at Mars. In 1994 and 1995, George Richardson lost a total of 60 days of rig time due to two separate Loop Current events. A workable solution was found to attach a system of fin-like fairings to the risers and auxiliary lines to streamline the current flow, similar to an airplane wing, to reduce VIV. The first system of fairings worked well until Hurricane Opal passed over the Mississippi Canyon area in September 1995. Afterward, engineers built a second set that was easier to run and pull and used it to finish the pre-drilling program at Mars and also at Ursa (Silverman 1999). Another dilemma for the Mars pre-drilling program involved the selection of a desirable well completion system. Reservoirs consisting of relatively young sediments, like Mars's, tended to be so poorly consolidated that sand was often produced along with the hydrocarbons. Sand intrusion created numerous complications. It could fill up the well bore, clog surface processing equipment, and erode well tubulars, valves, fittings, and flowlines. Conventional techniques for controlling sand production typically employed a "gravel pack," which involved placing a steel screen in the wellbore along the production zone, and then packing surrounding annulus with gravel to prevent the passage of formation sand into the well (Van Domelen et al 2000; Economides et al 2013). Some of Mars' deepwater turbidites presented a further complication. Their sands were very large-grained, and thus characterized by high porosity. They had significant space between sand grains. The ratio of void space to total rock was more than 25 percent, very high. They also had high permeability. The connectivity or ease of movement of fluids through pore spaces ranged from 500 mD (millidarcies) to 4 darcies, again very high. The Mars field had an average porosity of 24–32 percent and permeability averaging 190 mD, but which ranged up to 2 darcies (Oil and Gas Journal 1993). In such reservoirs the gravel often had to be injected at pressures at or near the formation fracture pressure to pack it into all the well perforations. Shell used this approach, called a "high-rate water pack," to complete the wells at Auger. Mars, however, was a good candidate for a relatively new type of completion called a "frac pack" (Silverman 1999). A frac pack is a method of hydraulically fracturing a high permeability well. A propping agent, such as silica sand, resin-coated sand, or high-strength ceramic materials like sintered bauxite, is injected into the formation to create and prop open fractures. Frac packs were initially used in the early 1990s to bypass near-well bore damage inflicted during drilling or well perforation to generate higher flow rates from the well than what was generally seen in gravel packed wells (Ellis 1998). For various reasons, not all reservoirs or wells at the time were considered for frac packing. But the Mars wells were. Working with Halliburton Production Enhancement services, the drilling team applied frac packs to six of the first 10 pre-drilled wells. Not only did this completion method give the wells additional flow capacity, it also provided for greater sand control reliability. The average per-well production rate with frac pack completion was 13,000 bbl/d, ranging from 8,000 bbl/d to 20,000 bbl/d (Silverman 1999). Based on the success of frac packing, Shell obtained approval of the MMS to commence production from some of the smaller, stacked

reservoirs in the same well. That way, both could be produced at a lower rate for greater ultimate recovery than if completed separately in different wells, thereby increasing reserves and reducing the number of wells needed (Kunkel 1999). A darcy and millidarcy are units of permeability, named after Henry Darcy. The unit is a coefficient calculated by factoring together viscosity, pressure, and thickness of the medium. Optimized well design from the reservoir sampling, the plan for multiple completions, and the higher than-expected flow rates from the pre-drilled wells (13,000 bbl/d compared to 11,000 bbl/d) forced a redesign of the Mars TLP as it was under construction. The Mars project was initially approved to include a second TLP or facility to drill additional wells. But managers determined that the reserves for both phases could be developed by the single TLP if its capacity was expanded from 100,000 bbl/d of oil and 110 MMcfd of gas to 140,000 bbl/d of oil and 170 MMcfd of gas. The Mars team scrambled to perform a debottlenecking study and introduced several innovative technologies to increase design production rates. The flexibility of a new contracting alliance system helped pull off this crucial modification with little delay. The pre-drilling program at Mars was a technical success and readied the site for the installation of the TLP in 1996. The average drilling performance of spudding each well and reaching total depth was 2.4 days per 1,000 feet, compared to 3.8 days per 1,000 feet at Auger. The quality of the crude oil assayed through the drilling program was average, with the better quality crude found in the deeper, Lower Miocene intervals. The reservoirs had low gas-to-oil ratios of 1,100–1,200 standard cubic feet per barrel (scf/bbl). The API gravity rating for the younger Pliocene (Pink and Orange) sands was 22–26, and 31–34 for the Miocene sands, which classified Mars crude as medium grade. The crude was also high sulfur, or “sour,” 2.3–2.6 percent for the Pliocene and 1.8–2.2 percent for the Miocene. It also tended to have high metals content and wax and hydrate potential. All this meant that Mars crude would have to be discounted due to extra processing required. But this only slightly tempered the enthusiasm over the size and productivity of the field that Shell was about to put into production. The API gravity rating measures how heavy or light a petroleum liquid is compared to water. The higher the number, the lighter the crude. A gravity of greater than 10 means the oil is lighter and floats on water. If less than 10, the oil is heavier and sinks. Medium oil is defined as having an API gravity between 22.3 and 31.1, and light crude has a gravity above 31.1.

5.0 CONCLUSION

The Gulf of Mexico remains one of the world’s most prolific petroleum basins, having contributed significantly to energy security and economic growth. Its vast hydrocarbon reserves, particularly in deepwater and ultra-deepwater plays, have ensured continued interest from major oil companies. However, as drilling moves into more challenging environments, the risks associated with hydrocarbon development escalate. Recent environmental disasters, such as the Deepwater Horizon oil spill, have highlighted the importance of better understanding the geological systems and subsurface dynamics of the GOM. Looking forward, while petroleum resources will continue to dominate the Gulf’s energy landscape, emerging renewable energy sources present new opportunities for sustainable energy development. Enhanced geologic and seismic data will be critical in reducing risks and improving decision-making processes for future energy extraction and environmental protection efforts in the GOM.

Below are some recommendations that aim to balance the economic benefits of petroleum production with the need for environmental protection and sustainable practices. As the industry evolves, continuous adaptation and innovation will be essential to address both opportunities and challenges in the Gulf of Mexico.

i. Enhanced Environmental Protections

Stricter Regulations: Implement more rigorous environmental regulations to minimize the risk of oil spills and other ecological impacts. This includes stricter safety standards for offshore drilling operations and improved response strategies for spill contingencies.

Monitoring and Compliance: Increase monitoring of environmental conditions and ensure robust compliance with environmental standards. Utilize advanced technologies like satellite imagery and remote sensors to track and respond to potential environmental hazards.

ii. Sustainable Practices

Transition to Cleaner Energy: Encourage investment in renewable energy sources and technologies to reduce dependency on fossil fuels. This could involve exploring offshore wind farms or other alternative energy projects in the Gulf region.

Carbon Capture and Storage (CCS): Promote research and development in carbon capture and storage technologies to mitigate greenhouse gas emissions from petroleum activities.

iii. Technological Innovation

Advancements in Drilling Technology: Support the development of new drilling technologies that improve efficiency and reduce environmental impact. This includes enhanced seismic imaging for better resource estimation and advanced well control technologies.

Data Integration: Leverage big data and machine learning to improve exploration and production processes. Integrate geological data with real-time operational data to optimize resource extraction and reduce costs.

iv. Risk Management

Improved Risk Assessment: Conduct comprehensive risk assessments for offshore drilling operations, including geological hazards such as salt dome stability and subsurface pressure variations.

Emergency Preparedness: Strengthen emergency preparedness and response plans to handle potential accidents or natural disasters, ensuring that all stakeholders are well-coordinated and prepared.

v. Collaboration and Research

Industry-Academic Partnerships: Foster partnerships between industry and academic institutions to advance geological research and improve understanding of the Gulf's complex geology and petroleum systems.

Public and Stakeholder Engagement: Increase transparency and engage with local communities, stakeholders, and the public to address concerns and build trust regarding petroleum operations and their impacts.

vi. Policy and Regulation

Updated Policy Frameworks: Adapt policy frameworks to reflect new scientific knowledge, technological advancements, and environmental considerations. Ensure that regulations support both economic development and environmental sustainability.

Incentives for Innovation: Provide incentives for companies to adopt best practices and invest in cutting-edge technologies that enhance safety and reduce environmental footprints.

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