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History of the Gulf of Mexico Offshore Oil and Gas Industry during the Deepwater Era

Volume 1: The Shape of These Monsters: From Fixed to Floating Offshore Oil and Gas Production, 1976–2006

US Department of the Interior
Bureau of Ocean Energy Management
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A History of the Gulf of Mexico Offshore Oil and Gas Industry during the Deepwater Era

Volume 1: The Shape of the Monsters: From Fixed to Floating Offshore Oil and Gas Production, 1976–2006

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COVER IMAGE

The hull and topsides of Conoco's Jolliet deepwater tension-leg well platform proceeds under dry-tow from its fabrication yard in Singapore to a shipyard in Mississippi in the spring of 1989. Source: US Coast Guard, Proceedings of the Marine Safety Council 49, no. 6 (November–December 1992): 55.

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List of Volumes and Authors

Volume	Authors and affiliation	Volume title
Volume 1	Joel Hewett University of Houston	History of the Gulf of Mexico offshore oil and gas industry during the deepwater era: Volume I: the shape of these monsters: from fixed to floating offshore oil and gas production, 1976–2006.
Volume 2	Tyler Priest University of Houston	History of the Gulf of Mexico offshore oil and gas industry during the deepwater era: Volume II: Shell Oil’s deepwater mission to Mars
Volume 3	Joel Hewett University of Houston	History of the Gulf of Mexico offshore oil and gas industry during the deepwater era: Volume III: the secret of the sea: offshore oil and gas revenue collection, valuation, and royalty relief, 1973–2010
Volume 4	Morgan Lundy University of Arizona Diane E. Austin University of Arizona Editors	History of the Gulf of Mexico offshore oil and gas industry during the deepwater era: Volume IV: a guide to the interviews

Overview of This Four-Volume Study (History III)

Offshore oil is the subject of one of the most important energy stories of the last 75 years, and the move into deepwater (usually defined as 1,300 feet or 400 meters) is its crowning achievement. From negligible production after World War II, offshore oil has grown to account for 30 percent of total global conventional oil production. Deepwater makes up only seven percent of the total, but this percentage is growing (U.S. Energy Information Administration, 2016). By 2006, the industry had discovered 60 billion barrels (bbl) of oil in deepwater, production from which is still coming online (Williams, 2006). During 2007–2012, 50 percent of the 170 billion bbl of global conventional oil (and natural gas equivalent) discovered by the industry was in deepwater. Many of those discoveries are yet to be developed (Nelson et al., 2013). From 6 million barrels of oil per day (b/d) in 2017, oil analysts project deepwater output to grow as high as 14 million b/d by 2030 (Seeking Alpha, 2017). The International Energy Agency (IEA) estimates that nearly half of the 2.7 trillion bbl of remaining recoverable reserves are offshore, 25 percent of which—or 340 billion bbl—will be found in deepwater (IEA, 2013). Rather than merely stemming production declines, deepwater oil has provided a substantial addition to global supply, an increase that few other sources in recent years have matched (Miller, 2014).

At current (April 2017) oil prices ($50/barrel), the present value of deepwater oil discovered in 2007–2012 is worth more than $4 trillion. Despite the sobering upfront costs of projects extending into 10,000 feet of water, the prolific per-well flow rates of 10,000–20,000 b/d (compared to 1,000–2,000 b/d for wells onshore or on the continental shelf) in many reservoirs often make them the most profitable investments for a large oil company. Royal Dutch Shell's Mars field, one of the largest in the Gulf of Mexico (Gulf) , started producing in 1996 and will earn an estimated average annual net cash flow (gross revenues minus costs, royalties, and taxes) of $1.5 billion each year until 2027.

Such economic value was by no means assured when companies began exploring in unprecedented water depths. Why did they do so? Journalists and scholars often explain the deepwater push as a response to one or more of the following: "peak oil" supply constraints, the locking up of all the "easy" oil overseas by National Oil Companies, the Deep Water Royalty Relief Act signed by President Bill Clinton in 1995, rising oil prices in the 2000s, or the reckless charge of BP into unprecedented water depths beginning in the late 1990s (Bower 2009: 18-22; Jacobsen 2011: 38-40; Klare 2012: 44-49; Lustgarten 2012: 168-172).

These interpretations all miss the mark. Deepwater oil is the result of a longer process of historical development, going back at least to the early 1970s, when leading offshore companies began to peer beyond the edge of the continental shelf in search of new reserves. The industry's move off the shelf in the Gulf emerged from an even longer history of offshore oil exploration and development in that region that had its start in the 1930s. Although technological change and innovation in the offshore industry often took great leaps forward, it usually proceeded gradually. Each new phase built on the previous phase. In a constant search for new reserves to replace declining onshore production, explorationists and engineers adapted prevailing concepts and techniques to new demands and made incremental improvements that nudged offshore operations into deeper waters. Making sense of deepwater requires an understanding of the historical evolution of the industry.

Still, the "deepwater era" (1974–present) is different in several ways from what we might call the "formative era" (1938–1973) of the offshore sector. Leasing policies and exploration strategies evolved to meet new geologic, economic, and technological challenges. Fabrication and installation practices had to be modified to address new water depths, metocean conditions, and the increasing scale of deepwater projects. Over time, more of the infrastructure installed in the Gulf was built overseas, marking the internationalization of the Gulf offshore business. The nature of work changed with increasing automation on both platforms and drilling rigs, and with the geographic dispersal of workers. Finally, the oil price collapse of the mid-1980s forced the radical restructuring of the offshore business and uniquely affected communities all along the Gulf Coast and every in aspect of the industry. New deepwater discoveries beginning in the mid-1990s revived the business and set off a new rush for leasing and development, but in a way that differed markedly from earlier periods of expansion.

The Gulf remains the primary laboratory for offshore technological innovation and regulatory practices worldwide. As offshore oil assumes a high profile in national development strategies around the globe, any effort to analyze the political, social, and economic aspects of offshore exploration and development must recognize and use the Gulf as a historical precedent or basis of comparison. This study, History III, of the history of the deepwater era in the Gulf both builds on histories of the earlier period and provides the first in-depth historical investigation of important new trends over the last thirty years. It will be valuable to those who are responsible for planning and managing the development of offshore oil and gas reserves and for more broadly understanding the impacts of such development on the Gulf Coast region.

Background of History III

The cooperative agreement for this study was awarded on June 1, 2008. Researchers from the University of Houston C.T. Bauer College of Business (UH) and the University of Arizona Bureau of Applied Research in Anthropology (BARA) organized and carried out the study. Principal investigator Dr. Tyler Priest led the research and writing for the UH team. UH History Ph.D. student Jason Theriot (who earned his degree in 2011), assisted in managing the study, conducting oral histories, and drafting preliminary reports. Consultant Joel Hewett, who had served with Dr. Priest as an analyst on the President's National Oil Spill Commission (2010–2011), contributed intensive research, edited oral histories and volumes, and authored two of the three final technical reports. Other UH History graduate students, Juan Galván Rodríguez and Natalie Schuster, assisted with research and oral history edits. John Holt and Pedro Paulo Gedda provided research and insights on the North Sea and Brazil, respectively, that helped place the deepwater Gulf in global and comparative context. Anthropologists Dr. Diane E. Austin and Dr. Thomas McGuire led the BARA team in carrying out fieldwork and oral histories in Louisiana and Mississippi.

Two previous history studies, funded by the Minerals Management Service (now the Bureau of Ocean Energy Management), laid the foundation for this research study.

- History I: Assessment of historical, social, and economic impacts of OCS development on Gulf Coast communities (MMS 2001-026, MMS 2001-027)
- History II: History of the offshore oil and gas industry in Southern Louisiana (MMS 2004-049)

These studies produced substantial documents, and they generated more data than could be analyzed in the study period. History II, the second study, for example, produced audio recordings and transcripts of more than 450 oral history interviews by the time of its conclusion. History I, the first study, looked across the Gulf with comparisons among east Texas, south Louisiana, and south Alabama, but provided only a general overview of historical patterns and periods. History II provided a deeper look, but was focused on southern Louisiana and the period from the 1930s through the 1960s, although a significant amount of data was also collected on later decades, as well.

History III, the current four-volume study, broadens the inquiry both spatially and temporally by mining the rich oral histories and documents collected in the previous study and expanding the oral history interviews into Mississippi and to cover recent decades. It rounds out and deepens research on the 1970s–1990s, when exploration and development of oil and gas continually moved into deeper waters (now routinely exploring in 10,000 feet and producing in 5,000 feet) and into new offshore environments (from the Gulf and the North Sea to Brazil, West Africa, and elsewhere).

In 1974 in the Gulf, oil companies acquired the first leases in 1,000 feet of water, extending from the upper continental slope to the abyssal plain. Reaching the symbolic water depth of 1,000 feet marked the beginning of what we might call the "deepwater era." To operate in these depths and beyond, the industry had to develop fundamentally different development concepts and commercial strategies.

The ground for History II was also prepared by several other MMS and BOEM studies.

- MMS 2002-071, Effect of the oil and gas industry on commuting and migration patterns in Louisiana, 1960–1990, establishes some of the basic effects over time of the offshore petroleum industry on the communities and region within which it operates.
- MMS 2002-022, Social and economic impacts of OCS activities on individuals and families, Vol. I, highlights differences in offshore oil's effects on various Gulf of Mexico region subareas.
- Three study reports provide essential data and preliminary historical analysis of the deepwater era: Labor migration and the deepwater oil industry (MMS 2004-057), The economic impact in the US of deepwater projects: a survey of five projects (MMS 2004-041), and Deepwater Gulf of Mexico 2004: America's expanding frontier (MMS 2004-021).
- BOEM 2014-609 through BOEM 2014-612, The study report Gulf Coast communities and the fabrication and shipbuilding industry: a comparative community study, volumes I through IV, offer important information on demographic and labor market shifts in recent years relating to two key onshore support sectors.
- Two volumes–BOEM 2014-617, Offshore oil and Deepwater Horizon: social effects on Gulf Coast communities, vol. I: methodology, timeline, context, and communities, and BOEM 2014-618, volume II: key economic sectors, NGOs, and ethnic groups–were the culmination of emergency fieldwork carried out by anthropologists from BARA in the afternath of the 2010 *Deepwater Horizon* blowout and oil spill. The findings from this study are an important adjunct to History III.

Objectives and Methods

History III was launched with objectives similar to those of the previous history studies:

- to document the strategies and objectives of the companies involved
- to ascertain the cumulative effects of offshore development on the coastal landscape, and community and family relationships
- to describe how technology and managerial innovations enabled the development of reservoirs in deeper and deeper water depths
- to study how the policies and regulations of the government agencies with responsibilities in state and the federal jurisdictions were developed
- to explore how these aspects of the story were related and effected each other
- to make the data collected and the findings from the study widely available to the public and easily accessible to those who have worked in the industry and live in the region

There were three primary tasks for the History III project:

1) further process and analyze research data collected in the Histories I and II projects;

2) conduct, transcribe, process, and archive targeted interviews on the deepwater era to fill historical gaps; and

3) extend historical analysis from the formative era.

The emphasis of History II was on gathering and archiving the stories of the people, mostly from Louisiana during the formative era, who participated in the industry. The History III study aimed to continue gathering stories and information, but concentrated on industry-involved people who were from outside Louisiana, and on key individuals who could speak about the deepwater era. Greater emphasis was placed on providing historical analysis of the research data collected in Histories I and II and in other MMS-funded studies and on providing historical interpretations of the deepwater era.

The research for this study was wide-ranging. It first involved processing and analyzing abundant materials collected in the Histories I and II projects and consulting other government studies and scholarship on the deepwater offshore oil industry. Researchers undertook a comparative review of historical literature on other regions of offshore development around the world, especially the North Sea, Gulf of Guinea, and offshore Brazil. New research was collected in government archives, trade journals, technical papers, newspapers, periodicals, and videos. The study participants engaged in extensive informal discussions and correspondence with industry veterans and experts. They also conducted 253 formal oral history interviews; 48 by the UH team and 205 by the UA BARA team. This brings the total number of transcribed oral histories collected in History II and History III to 739. All are coded, compiled in a database, and include biographical and/or ethnographic prefaces. The audio and transcripts will be provided to BOEM and archived at UH, with copies deposited with six other archives and universities in Louisiana (see list below).

As they had done in History II, the UH team focused on the corporate and governmental side of the history, interviewing managers, entrepreneurs, engineers, scientists, and government officials. They targeted individuals involved in deepwater production (especially tension-leg platforms, floating platforms, and subsea wellhead systems), along with government officials active during changes in the federal leasing and regulatory regime. The BARA team gathered community-focused oral histories, concentrating on those in Alabama, Mississippi, and Lafayette, Louisiana, which had not been the subject of previous studies. They interviewed local entrepreneurs, workers, family members, community leaders, and others who can share information about how this industry developed and evolved. Locating this history within the context of the specific social, political, economic, and environmental changes occurring during the era, the BARA team focused its analysis on changes in the offshore petroleum workforce, the impacts of the evolving industry on local landscapes, and community-level responses to the industry.

Technical Reports

This study produced four technical reports, each published in a separate volume.

I) The shape of these monsters: from fixed to floating offshore oil and gas production, 1976–2006

II) Shell Oil's deepwater mission to Mars

III) The secret of the sea: offshore oil and gas revenue collection, valuation, and royalty relief, 1973–2010

IV) Guide to the interviews

Volume I, The shape of these monsters, traces how the semi-submersible platform design went from being the deepwater development concept of choice during the mid-1980s to being a pariah among Gulf operators during the boom years of the 1990s. The November 1988 start-up of the world's first floating offshore oil and gas production platform in deepwater, Placid Oil's *Green Canyon 29* semi-submersible, seemed to herald a "new era" in petroleum development in the US Gulf of Mexico. Instead, the project folded in just 18 months and was decommissioned over 1990 at a huge loss. Thirteen years would pass before a successful semi-submersible production facility would return to the deepwater Gulf. By resurrecting the all-but-forgotten story of the Green Canyon 29 debacle, and by re-assessing the hopes expressed by many industry soothsayers during the 1980s that the semi-submersible production vessel was the technological marvel of the future, Volume I comments on the ways in which non-technical, un-economic factors—like the specter of failure—can haunt the minds of firms and managers enough to influence technological outcomes. Specifically, the dominance across the 1990s of the tension-leg platform (TLP) in deepwater is shown to be as much a consequence of the dramatic failure of Placid's Green Canyon 29 semi-submersible as the natural result of the tension-leg platform's ostensibly "superior" technology.

Volume II, "Shell Oil's deepwater mission to Mars," is a case study of Shell Oil's greater Mars project in the 3,000-foot waters of the Mississippi Canyon. Mars was the second deepwater TLP installed in the Gulf. The volume provides a detailed, step-by-step historical reconstruction of the greater Mars project, from the acquisition of the original leases in 1985 to the installation of the Mars B, or *Olympus*, TLP in 2014. The report draws on oral history interviews, technical papers, and Shell publications, both internal and external, to provide a unique perspective on the unprecedented challenges to managing a frontier project of this magnitude and duration. The aim is an in-depth understanding of the interrelated investment, operational, and technical decision-making that went into the development of one of the largest and most valuable assets in the Gulf. A lifecycle narrative of a deepwater oil project like Mars demonstrates how a technically and commercially successful organization learns and innovates in one of the most challenging physical and commercial environments in the world. A close examination of such a project through time provides insight into the evolution of corporate exploration and production strategy and the development of technical competencies.

Volume III, The secret of the sea, lays out a comprehensive history of the federal offshore oil and gas program in the US since the late 1960s. Focusing on the ways in which the desire to boost federal revenue receipts resulted in major policy changes as the industry moved into the deepwater Gulf, the report details how disagreements over the seemingly mundane particulars of Outer Continental Shelf revenue policy served as a proxy for wider partisan wars over the wisdom of government administration of publicly-owned resources in the "fair" or open marketplace. The oil shocks of the 1970s, combined with the ever-improving ability of offshore firms to drill and produce petroleum deposits in water depths beyond 1,000 feet, only reaffirmed the program's importance to the country's security and well-being during the Nixon, Ford, and Carter administrations. However, the economic imperative to expand deepwater drilling soon collided with the desire of many coastal states in the 1980s to see their shores and coastal zones adequately protected from the threat of offshore oil spills and onshore industrial development alike. Part and parcel of achieving that aim was the demand from the coastal states that they receive an ample cut from the sale of the nation's offshore resources—funds that would ultimately tally in the many hundreds of billions of dollars.

Volume IV, Guide to the interviews, provides summaries of oral histories conducted between 2007 and 2015 with men and women who lived and/or worked in southern Louisiana, Texas, or Mississippi in the decades that mark the deepwater era of the offshore petroleum industry in the Gulf (from the 1970s to the end of the 20th century). These summaries have been combined with interviews conducted in 2001–2006 for the History II study, MMS 2004-049, History of the offshore oil and gas industry in Southern. The summaries are arranged in alphabetical order by last name of the interviewee. Section 4.1 of Volume IV lists the interviews conducted for History III, and section 4.5 lists the interviews conducted for both History II and History III.

Study Depositories

The materials produced from History III, "History of the Gulf of Mexico Offshore Oil and Gas Industry during the Deepwater Era," are archived at the locations listed below. Each depository has the four volumes produced in the study, digital copies of all audio files and transcripts, and digital copies of all consent forms.

University of Houston Houston History Archives Repository Suite 261, Special Collections Department MD Anderson Library-2000 Houston, TX 77204-2000 http://archon.lib.uh.edu/index.php?p=collections/controlcard&id=231	Nicholls State University Allen J. Ellender Archives Ellender Memorial Library PO Box 2028 Thibodaux, LA 70310 http://www.nicholls.edu/library
University of Louisiana Lafayette Special Collections and Archives Edith Garland Dupré Library PO Box 40199 Lafayette, LA 70504 http://library.louisiana.edu/collections	Louisiana State University Center for Energy Studies Energy, Coast and Environment Building Nicholson Drive Extension Baton Rouge, Louisiana 70803 http://www.enrg.lsu.edu/

Morgan City Archives 501 Federal Ave. Morgan City, LA 70380	South Lafourche Library 16241 East Main St. Cut Off, LA 70345 www.lafourche.org
Terrebonne Parish Library 151 Library Drive Houma, LA 70360	

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List of Abbreviations and Acronyms

Short form	Long form
BBL	barrel of oil
BBL/D	barrel of oil per day
BCF	billion cubic feet of gas
BOE	barrel of oil equivalent
CPP	Centralized Production Platform (Conoco)
CT	compliant tower
DOT	Deep Oil Technology, Inc.
DST	drill-stem test
DTSS	dry tree semi-submersible
DWPF	Deep Water Process Facility (Placid Oil)
DWRRA	Deep Water Royalty Relief Act of 1995
EB	East Breaks (US Gulf of Mexico)
EI	Eugene Island (US Gulf of Mexico)
EPR	Exxon Production Research, Inc.
EPS	early production system
EWT	extended well test
FPSO	floating production, storage, and offloading vessel
FPU	floating production unit
G&G	geological and geophysical
GB	Garden Banks (US Gulf of Mexico)
GI	Grand Isle (US Gulf of Mexico)
GC	Green Canyon (US Gulf of Mexico)
GOM	US Gulf of Mexico Region
JIP	joint industry project
MC	Mississippi Canyon (US Gulf of Mexico)
MMbbl	million barrels of oil
MMBOE	million barrels of oil equivalent
MMcfd	million cubic feet (of natural gas) per day
MMS	Minerals Management Service, US Department of the Interior
NEPA	National Environmental Policy Act of 1969
NOC	National Oil Company
OCS	Outer Continental Shelf
OCSLA	Outer Continental Shelf Lands Act of 1953
OCSLAA	Outer Continental Shelf Lands Act Amendments of 1978
OPEC	Organization of Petroleum Exporting Countries
SS	Ship Shoal (US Gulf of Mexico)
SWF	Shallow Water Facility (Enserch Exploration)
TCF	trillion cubic feet of gas
TLP	tension-leg platform
TLWP	tension-leg well platform
TTR	top-tensioned riser
VK	Viosca Knoll (US Gulf of Mexico)
WR	Walker Ridge (US Gulf of Mexico)
WTI	West Texas Intermediate

> If the Gulf could be drained of water, one would behold on the Louisiana-Texas continental shelf a sprawling, futuristic landscape of steel that would dwarf in height and extent the skylines of all the major American cities combined . . . . To produce oil from these new depths, the industry has moved beyond the towering steel-jacket platforms ranging over a thousand feet in height to develop mammoth tension-leg platforms, tethered to the bottom, and floating “spars” that resemble monstrous buoys in the water.
>
> —Priest, A perpetual extractive frontier? the history of offshore petroleum in the Gulf of Mexico (2005: 214)

> I do not think [business historians] can fail to address the topic of business failure . . . historians . . . might even place failure on a common scale with success.
>
> —Fridenson, Business failure and the agenda of business history (2004: 563, 567)

1. Introduction: Each Unproductive Well is Unproductive in its Own Way

1.1. Prologue: Placid Oil in Troubled Waters

“Well, it’s not *all* bad news,” Phil Clarke said, trying as best he could to strike an optimistic note in his voice. Talking into the handset of his office telephone while gazing down thirty-eight stories to the asphalt of Elm Street below, he paused for a moment while the reporter on the other end of the line caught up with scribbling down his words. It was the morning of April 24, 1990, and the view from atop Thanksgiving Tower in downtown Dallas was bright and clear, conditions typical for north Texas in the late spring. Unusual, however, was the task that faced Phil Clarke that Tuesday. In his capacity as vice president of operations for the Placid Oil Company, part of Clarke’s job was to field any calls or inquiries that might come in from the press—a responsibility he rarely had to exercise. But that morning, his phone seemed to be ringing off the hook. A flurry of calls was coming in from a flock of reporters, each dialing to ask about something called the Green Canyon 29. Clarke explained to each that the GC 29 was the company’s flagship offshore oil development in the deepwater Gulf of Mexico (Gulf)—and that Placid had just pulled the plug on it (Victoria Advocate 1990).

Named after the nine-mile-square block of federal waters in which it was set off the coast of Louisiana, the Green Canyon 29 facility was not, strictly speaking, exactly an offshore oil platform. Though some crude oil did flow out of its deepwater wellbores, the underground reservoirs that Placid had drilled into were predominantly filled with petroleum gas. The platform extracted this natural bounty from deposits located 15,000 feet below the seafloor, a vertical distance so great that the Washington Monument would have to be stacked upon itself more than twenty-seven times to measure up to it (US Department of the Interior 2014). Petroleum began flowing at Green Canyon 29 to great fanfare in November 1988, and Placid executives marked the occasion back on dry land with such verve and glee they risked belying the letter of their company’s name. Placid had good reason to celebrate, though. Through several years, almost $400 million spent, and after persevering through many months of delays, the firm’s crown jewel in its offshore business was finally underway. One loose-lipped Placid executive let slip to a local news outlet that he expected the venture to return his company’s investment many, many times over (Oklahoman 1987).

His excitement would prove short-lived. Almost immediately after the first cubic foot of natural gas was brought to the surface, the project hit a major snag. Its development wells were producing both types of hydrocarbons at a rate far below what Placid expected. Then, adding technical insult to geological injury, several of the wells—which Placid had drilled at a cost of $7 million each—suffered mechanical failures that put them permanently out of service (Hagar 1990). Built with the expectation that it would remain on location for as many as fifteen years, generating petroleum and revenue all the while, the Green Canyon 29 platform was shut down after just 18 months online (Filson et al. 1988, 345). As Phil Clarke had to explain to the reporters who called his office on that sunny morning in April 1990, the Green Canyon 29 rig and all its production equipment were now headed for the mothballs.

The next day, the Associated Press ran a report on the wires detailing the reasons behind Placid's scrapping of its deepwater project. (The AP reporter, skilled in journalism but understandably unversed in the impenetrable lingo of the petroleum industry, awkwardly if not incorrectly referred to the effort as a "deep-well drilling operation.") The decision to shutter a failing oil and gas development in the deepwater Gulf was a noteworthy one during 1990, to be sure, but it was unusual for that kind of news to garner much consideration beyond the usual trade organs like the Oil & Gas Journal or Offshore magazine (Victoria Advocate 1990). Placid Oil's announcement of Green Canyon 29's demise elicited an interview request from the venerable Associated Press because, just two years prior, the platform had been hailed as a veritable technological marvel (Hagar 1990). In fact, Placid's platform was not a platform at all, at least not in any conventional sense of the word. Instead, Green Canyon 29 was a massive "semi-submersible" drilling rig that floated atop the salty swells of the Gulf, resting half-submerged below the waves (Filson et al. 1988, 343).

Set in 1,522 feet of water, the Green Canyon 29 hull was kept in place by a series of mooring lines attached to anchors of enormous size, plowed deep into the muck of the seafloor. By virtue of its extreme water depth, GC 29 set a new world record for petroleum extraction offshore. The facility also received natural gas from a remote or "satellite" well located several miles away and in 2,243 feet of water—nearly half a mile below the surface of the sea (Hagar 1990). Both a world-record breaker and a major industry "first" for the Gulf, Placid's platform was also an ambitious application of subsea, or "wet-tree," production technology. The ability of the rig's hull to support the heavy weight of marine production risers (the conduits through which oil and gas flow from the seafloor to the surface) in nearly any water depth made Green Canyon 29 a sight for sore commercial eyes along the Gulf Coast in 1988. As soon as the news broke in 1986 that Placid had green-lighted the project, offshore soothsayers and deepwater wise men declared with gusto and certitude that Green Canyon 29 would bring with it a "new era" of oil and gas production in the deepwater Gulf (ibid.).

And a new era it was indeed. During the first forty years of drilling for oil underneath the Gulf, the equipment, wellheads, and personnel needed to produce offshore deposits were kept safely propped up above the waves by steel-jacketed "fixed" platforms that were pounded and cemented deep into the seabed. The size of these structures would grow over the 1970s and 1980s to reach ridiculous proportions—enough to rival New York City's grandest skyscrapers—but they found their first shape as the humble yet reliable workhorses of the shallow-water offshore oil fraternity in the Gulf (see Priest 2007b; Schempf 2007; Pratt 2009). Offshore drilling inched beyond the sight-of-land for the first time in 1947, and by the 1950s, operators were routinely sinking wells in 100 feet of water. The advent of mobile, and then floating, drilling rigs and drillships in the 1960s empowered the early pioneers of the offshore to explore nearly at will. Although it lay in the eye of the beholder as to whether the personal gumption needed to work offshore was "bold" or "foolhardy" in nature—or both, in truth—those who labored offshore in the early years of the basin's history were handsomely rewarded with good discoveries and even better paychecks (Pratt 2009).

Offshore production pushed further and further away from shore as more and more fields were discovered. By 1973, operators had installed as many as 2,800 production platforms in the Gulf of Mexico (Geer 1973, 5). Their reach increased only gradually during the 1960s and the 1970s; by 1975, the deepest oil structure in the Gulf had been placed in a water depth just shy of 400 feet (US Department of the Interior 2014). The commercial outlook for both exploration and production growth in the basin remained undimmed as the decade wore on. A full quarter of the world's fleet of offshore drilling rigs called the Gulf home in the late 1970s (Ili and Stilwell 1978). By dint of improved technology, skyrocketing oil prices, and increased confidence on the part of drillers that they would uncover high-quality reservoirs in *deepwater*,[1] in 1975 three different firms spudded the first set of exploration wells beyond the 1,000-foot isobath. One of those operators, Placid Oil, sunk a well through an amazingly deep 1,790-foot water column in the Mississippi Canyon; unfortunately, it turned out to be a dry hole (US Department of the Interior 2014). Shell Oil had better success in July 1975 at its nearby Cognac prospect, in 1,023 feet of water, which yielded the Dutch major a significant discovery. Four years and hundreds of millions of dollars later, in September 1979 Shell drew forth the first barrel of deepwater petroleum produced anywhere in the world. Perched at the outer edge of the continental shelf, Cognac's titanic size (and high cost) signaled to all watching that if offshore petroleum was to advance much further down the continental slope in the 1980s, a new type of production facility would be needed. The future, so to speak, would have to float.

Into this environment charged Placid like a bolt from the blue. In collaboration with its partner in the project, Enserch Exploration, Placid acquired fistfuls of leases over tracts located in the Green Canyon area in the Gulf. The bulk of Placid's deepwater lease portfolio sat about 115 miles southwest of the Mississippi Canyon, not far from where Cognac had been installed. In 1984 the Placid-Enserch joint venture began drilling its best prospects in the area, soon discovering what would turn out to be the largest of GC 29's natural gas reservoirs. Close scrutiny of the marine seismic reflection data used to identify the prospects and the results of the exploration wells drilled into them led Placid's geologists to appraise the size of the field and its immediate environs at 90 to 100 million barrels of oil equivalent (mmboe) in recoverable reserves. It was a significant sum. Even so, Placid's high hopes that the Green Canyon trend would be a promising petroleum play seemed realized after two additional natural gas deposits were discovered nearby in Green Canyon Block 31 and Ewing Bank 999 (Gautreaux 1987, 126).

Figure 1.1. The Penrod 72 semi-submersible drilling rig, circa 1988, after conversion to a production unit for use at Green Canyon 29

Source: US Coast Guard 1992, 13; Filson et al. 1988.

[1] Definitions of deepwater vary widely among firms, government organizations, and third-party analysts of the offshore oil and natural gas industry. For both qualitative and quantitative purposes, this paper defines deepwater as those water depths beyond 1,000 feet of water (305 meters), with a few exceptions, noted where applicable.

Originally delivered in 1975 at a cost of $20 million in nominal figures, Penrod was one of the first semi-submersible rigs built to sport a two-deck configuration. Each of the rig's six columns measured 33 feet in diameter; the hull ran 172 feet from the bottom of the rig's horizontal pontoons to the level of the drill floor.

Figure 1.2. After nearly thirty years in service, the rusting hull of the former Penrod 72 sits in an Indonesian bay, stripped of its equipment and awaiting demolition

Visible in Figure 1.2 and in Figure 1.1. are the four rectangular sponsons that Placid added to the outside of each corner column over 1987 and 1988. In addition to providing extra buoyancy, the sponsons also housed the mooring equipment added to the rig to allow it to function in a production capacity in deepwater. Source: CaptainsVoyage Forum.

With three discoveries in hand, Placid formally approved its development project in June 1986 and committed to spend several hundred million dollars to build a deepwater platform for the site (LeBlanc 1986). To serve as the core of its "new era" floating facility, Placid's engineers turned towards a decades-old and well understood technology. Placid and Enserch acquired a weathered, 1970s-era semi-submersible drilling rig—previously named the *Penrod 72*—and overhauled its hull and topsides to make it capable of receiving oil and natural gas production in addition to drilling for it (see Figures 1.1. and 1.2.). Placid recalled the *Penrod* from where it was drilling (in the Green Canyon, incidentally) and sent it to a Gulf Coast shipyard for its date with a team of journeymen and welders (Filson et al. 1988, 343). After beefing up its substructure and payload capacity to the tune of an additional 2,150 tons, Placid moved the vessel to its production site offshore in November 1987 for final hookup and commissioning. Altogether, the *Penrod*'s conversion into a production platform set Placid back a mere $75 million—an incredibly low and attractive sum given the high costs typically seen in the risky world of deepwater development (ibid., 346). Just as importantly, the *Penrod*'s conversion had flown by like a warm Gulf breeze: the rig went from drilling to production-ready in less than six months. To Placid's delight, the entire process from rig acquisition to topsides equipment installation was "not difficult" to pull off on schedule and under budget, as one Placid offshore manager put it in 1987 (Gautreaux 1987, 127).

At the heart of Green Canyon 29's processing system stood a remarkably innovative marine riser that conveyed natural gas and liquids production vertically from the seafloor wells to the deck of the *Penrod*. This riser, developed by a consortium of equipment manufacturers that included notable firms like Hughes Offshore, was one of the world's first examples of a "hybrid" riser design. Able to remain vertically suspended on its own accord, the riser consisted of one very long section of stiff, rigid pipe, that terminated about 150 feet below the rig, and one short section of flexible "jumper" lines that allowed for a compliant connection between the top of the riser's rigid section and the pitching and yawing hull of the *Penrod*. At the bottom of the rigid riser sat a 1,200-ton jungle gym of steel beams and twisted piping known as a well template. Built to encompass "slots" or holes for twenty-four production wells, the template also served double duty as a foundation for the riser itself, which was truly titanic in size—its rigid portion was nearly eight feet in diameter, wider than a person is tall (Cober, Filson, and Teers 1987, 349–350). One jumper line tentacled out of the top of the rigid riser for each of the well slots located below the *Penrod* (Gautreaux 1987, 127).

Because the riser connected to the *Penrod* vessel off of center (see Figure 1.3.), the rig was able to produce hydrocarbons at the same time that it was drilling through the derrick located in the middle of its deck. Placid maintained that the combination of the stabilizing force of the vessel's mooring lines and the latent tension embodied in the rig-to-riser connection would allow Green Canyon 29 to remain so stable that it could continue to produce even if struck by one of the Gulf's fabled hundred-year storms (Cober, Filson, and Teers 1987, 351). As impressive factoids like the above began to spread among members of the offshore community, the premature accolades for Placid Oil began to stack up. Although the use of subsea production technology was "more or less routine" by the mid-1980s, Placid's application of it in such deep waters was greeted as a key technical achievement in and of itself (Curtis and Mercier 1985, 1). Placid was not immune to the hype that surrounded Green Canyon 29's launch; members of its management team touted their platform as a "significant" and historic "milestone" in the history of deepwater oil and gas—long before it produced a single drop of oil or generated even one dollar of revenue (Cober, Filson, and Teers 1987, 347; Gautreaux 1987, 128).

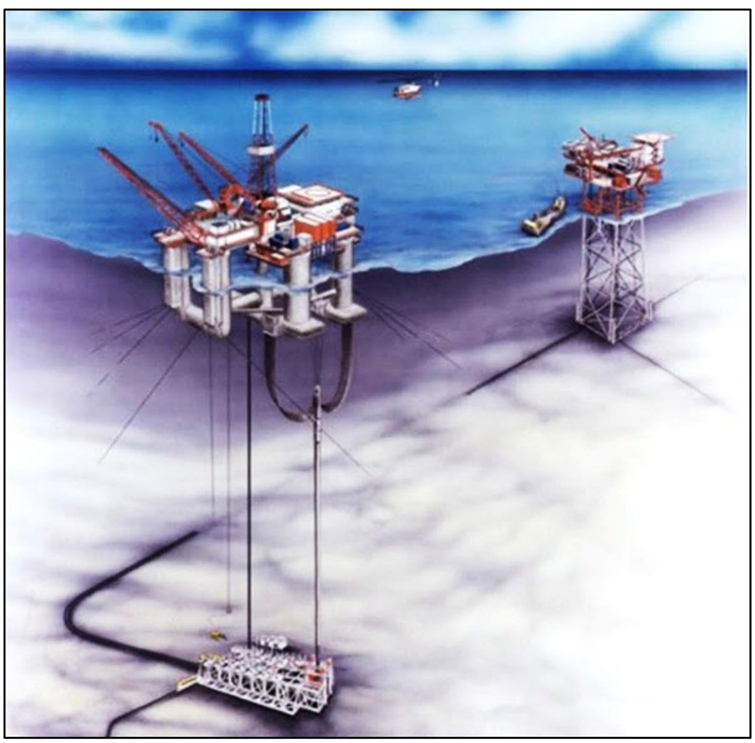

Figure 1.3. Artist's depiction of the Placid Green Canyon 29 semi-submersible FPU and its freestanding riser, as replicated by Enserch in the mid-1990s

With the exception of Enserch's use of the Glomar Biscay I instead of Penrod 72 as the core of its Garden Banks 388 system, the architectures of the two deepwater Gulf developments were virtually identical. Source: Kaskus Online Education Forum.

Breathless anticipation along the Gulf Coast oil patch for the project's start soon deteriorated into a cacophony of anxious sighs. The bad economic news that had been looming on the horizon since the start of the 1980s began to crest in 1985, threatening to capsize Placid's deepwater plans. After peaking in 1981 at over $37 per barrel, the annualized price of crude oil softened for several years before plummeting in 1985 and 1986 to hit a low of less than $15 per barrel (US Department of Energy 2014). The sustained presence of high oil prices had been the grease lubricating the skids of deepwater's growth from the very start, and so their sudden disappearance hit the region like a Sunday punch. After only five years in existence, in 1984 the deepwater Gulf saw the volume of oil and gas it produced every year stall, and then begin to decline (see Figure 1.4.).

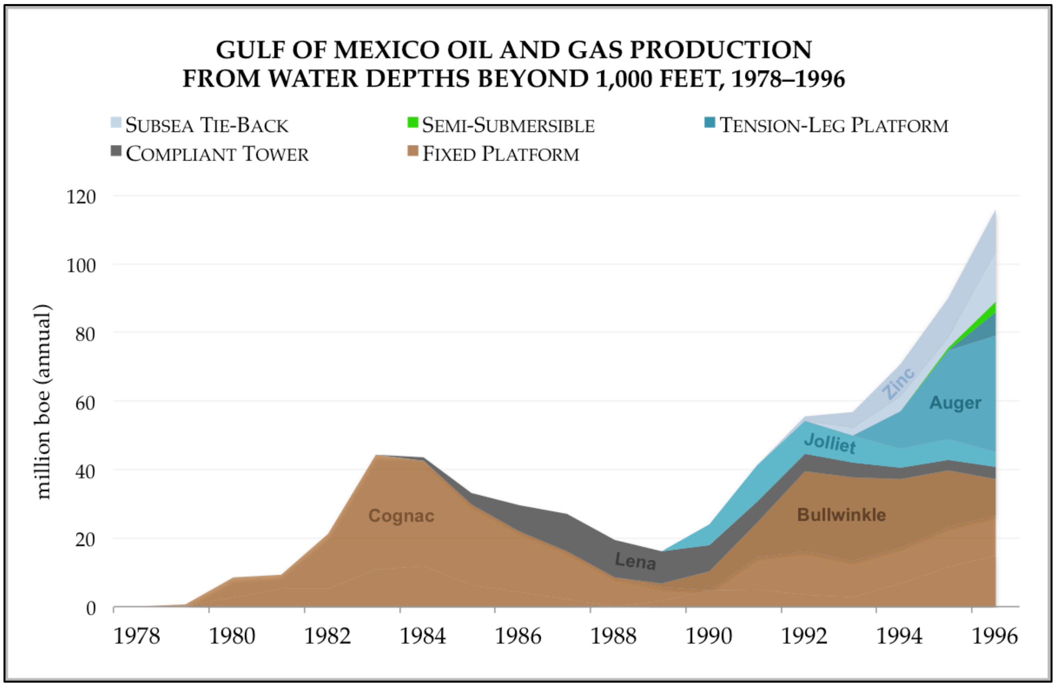

Figure 1.4. Gulf of Mexico oil and gas production from water depths beyond 1,000 feet, 1978–1996, by development concept type

Driven in large part by oil from the Jolliet TLWP and the Auger tension-leg platform, deepwater production began to surge after 1989. Starting production in 1996 was the landmark Mars field (dark teal wedge), also via tension-leg platform. Compare each color and concept type to the platform time series in Figure 1.5.; the production profile extended to 2001 in Figure 1.6.; the deepwater basin facility map in Figure 1.18.; and the development decision time-series chart in Figure 1.24.

Source: US Department of the Interior 2014. Note that production volumes from a few fixed platforms set in less than 1,000 feet of water (like Cerveza and Cerveza Ligera) are included, per their historical classification as deepwater structures. See fn. 1.

Placid forged confidently ahead. Its business partner Enserch told the media in March 1986 that GC 29 would remain economically solvent even if the price of crude remained at just $15 per barrel—a level so low that most industry experts regarded it as the price's likely floor[2] (Oil & Gas Journal 1986). The price of a barrel of West Texas Intermediate crude averaged just pennies above $15 for the remainder of 1986, giving the Placid-Enserch concern just enough running room for Green Canyon 29 to remain profitable—

[2] Although Green Canyon 29 was a natural gas development, offshore firms routinely pegged their economic projections to the crude oil benchmark during this period, for both simplicity and analytical uniformity.

in theory (US Department of Energy 2014). Not all offshore operators were as optimistic about the economic climate as Placid appeared to have been. Conoco, for one, adopted a $20-per-barrel oil price as its minimum threshold for justifying going forward with a final investment decision offshore (LeBlanc 1985). Luckily for Placid, the oil price rebounded somewhat between 1988 and 1990, giving the company a small price cushion upon which to achieve positive cash flow.

But even a high oil price cannot bail out a project that produces only a pittance of petroleum. Placid ended up drilling just 4 of its planned 20 development wells at Green Canyon 29 before calling it quits (Hagar 1990). Spring may be the time of plans and projects, but the only plans Placid had come April 1990 was to wrap up the decommissioning of its first and only deepwater project.

Why did the wells at Green Canyon 29 fail so spectacularly? In the mind of the offshore production manager, all productive wells are alike—namely, that their flow of oil or natural gas is vigorous enough to be profitable. But each unproductive well is unproductive—or fails—in its own way. The first well to come online at Green Canyon 29 filled up with fine granules of silt and sand after just two months onstream, due to the failure of a downhole "gravel pack" screen intended to prevent just such clogging due to unconsolidated rock formations common to the Gulf (ibid.). After undergoing repairs, that wellbore returned to production several months later, but it continued to falter, and its flow never reached a level close to what Placid had forecasted for it to attain (US Department of the Interior 2014). Another well suffered from gravel pack problems on its very first day online, its flow rarely rising above a relative trickle. Even the best-performing well of the bunch, one of the satellite completions located in deeper water, soon sputtered and entered a period of rapid decline; it then suffered a mechanical failure that doomed it for good (Hagar 1990). Dishearteningly, the well drilled through the template directly below the platform flowed worst of all.

And yet, there was perhaps a small glimmer of sunshine amidst all the bad news of April 24, as Phil Clarke stressed to his reportorial raconteurs on the phone in Dallas. In the process of decommissioning the *Penrod* rig and its production system, Placid would retrieve the semi-submersible, and bring GC 29's subsea wellhead components and most of its pipeline infrastructure to shore before mothballing them in a nearby warehouse. The equipment would next go to the auction block, to be sold off to the highest bidder. Equipment showing such little wear and tear, offered at such a deep discount, was likely to sell quickly. Clarke felt confident that his company would recoup at least a fair chunk of change from the auction. It was not all bad news, indeed.

Placid had refurbished the *Penrod* to make it capable of handling up to 40,000 barrels of liquids and 120 million cubic feet of natural gas per day (Filson et al. 1988, 343). That capacity proved overoptimistic by a very long shot. Green Canyon 29's peak flow rate topped out at just 1,900 barrels and 17.9 mmcf per day—an amount approximately 15% of what the facility was built to receive (US Department of the Interior 2014). In total, Placid's deepwater reservoirs produced just over 5.4 billion cubic feet (bcf) of natural gas, half a million barrels of liquid natural gas condensate, and about 50,000 barrels of crude oil (ibid.). Together, those figures summed up to a total of 1.5 million barrels of oil equivalent produced, a tiny fraction of Placid's initial recoverable reserves estimate of 73 mmboe (Lane 1987; Oklahoman 1988). The volume of hydrocarbons produced by Green Canyon 29 is an amount so negligible that it is virtually invisible when displayed as a time-series graph of the deepwater Gulf's production profile during the 1980s and 1990s (see Figure 1.4).

It is unknown just how much money Placid recouped from its deepwater equipment auctions. We can, however, make a rough estimate of how much value was created over the life of the Green Canyon 29 development. In all, an estimated $17,622,000 in gross revenues was brought to shore by the new-era semi-submersible platform—minus a $2,203,000 royalty payment owed to the owner of the resource, the federal government. In addition to the estimated $400 million in development costs that Placid incurred between 1984 and 1989, the company had already paid out a cool $18.5 million in signature bonus bids to acquire the offshore leases overlaying the GC 29 reservoirs. The economic failure at Green Canyon 29 was so high-profile and costly that implicit in Placid's decision to shutter the project was an admission that the company was no longer suited to operate in the deepwater Gulf. "We bailed out [of the basin] completely" after deciding to pull the plug on *Penrod*, a Placid manager recalled afterwards (Pendleton 1991). By the end of 1990, Placid's hopes for a toehold in deepwater were as dead as Marley's door-nails. It was a massive financial blow.

2.2. All for Lena

To extract offshore oil and gas from depths beyond the conventional platform's reach, operators needed a new development tactic. One of the first such projects looked to a symbol of the Gulf Coast for inspiration. Comparing the function of their new platform type to the bending resilience of a palm tree, the engineers behind an early design for a compliant tower explained that it would stand in the wind "like a palm tree instead of an oak" (Offshore 1983; Cornitius 1983). For those native to the Gulf Coast, it was an inspired choice indeed; nearly everyone in Houston or along the Louisiana bayous has seen television footage of the aftermath of a hurricane in which palm trees stand proudly in the wind, intact, beside the concrete foundation slab of a house destroyed by the storm.

By the mid-1970s, compliant structures of differing types had been used offshore for many years, but only in very shallow water. Pratt, Priest, and Castaneda (1997, 83) explain how offshore engineers grew interested in the concept of compliancy for a deepwater oil or natural gas platform:

> [E]ngineeers initially thought about limiting the dynamic response of jackets in deeper water mainly in terms of reducing the natural period of the structures. In the mid-1970s, they started asking if the same effect could be achieved by making the fundamental period of the structure *larger* than the wave energy period . . . . Was it possible, in other words, to design a structure that oscillated so slowly that waves moved past it before it had time to respond and reach its maximum condition?

It *was* possible; and it could apply to both bottom-founded and floating facilities alike. The first manifestation of this principle became known as the "guyed" tower.

Exxon's ever-innovative Exxon Production Research group began looking seriously into compliant tower designs as far back as 1968, when it focused its efforts on a "buoyant" tower design for 1,350 feet of water (Chuck 1976, 1). With no leg "batter" at all, the tower had a profile straight and slender, save for the addition of several hollow metal air tanks pinned near the top of the jacket, descending 20% of the structure's height to grant it additional buoyancy. The concept was something like a palm tree, if it were somehow rooted firmly into the ground, flexible in its length, and sat underneath 10 feet of water with balloons attached to the top of its branches—the buoyant tower could flex in all directions, but the restoring upward force of the air tanks would keep it almost always vertical. Exxon management soon concluded that the buoyant tower suffered from major conceptual problems, namely a too-heavy reliance on the functioning of a complicated "flexjoint" (ibid.). These problems did not damn the idea fully in EPR's estimation, but rather redirected their research attention towards other sources of compliancy.

EPR next turned its attention to the "guyed" tower, named for the series of taut mooring guy lines radiating around the structure, from the top of the jacket to anchor points on the seafloor. Exxon's initial interest in the design was for use in the North Sea, not the deepwater Gulf, and the first round of drafting and scale-model tests that EPR performed was premised on a 1,500-foot water depth in the stormy conditions common between the Scottish and Norwegian coasts (ibid., 2). Early test results were promising, and the design that emerged from EPR called for a four-legged, square jacket frame, with each leg set 100 feet apart and measuring between 5 and 8 feet in diameter. It also called for 20 guy lines, each between 3 and 4 inches in diameter, noting that the combination of the jacket's piling system and the lines would keep stresses on the dry-tree production risers within acceptable limits (ibid.).

Results in hand, Exxon wanted to test its design at a more realistic scale than the 1/60 indoor wave tank test. Over the course of 1975 and 1976, Exxon convened a consortium of companies to build and deploy a pilot test of the guyed tower at 1/5 scale. Rival operators like Marathon and Pennzoil were involved, as were firms like Brown & Root and Mitsubishi Heavy Industries (ibid., 4). The group decided to place their test tower in 300 feet of water at Grand Isle Block 86 in the Gulf, reasoning that a 20-foot-high Gulf wave would simulate the 100-foot waves common to the North Sea (ibid.). Installed in late 1975, the diminutive guyed tower would remain in place for 42 months, generating crucial data along the way, similar to the instrumentation Shell had placed on its South Pass 62 structure in advance of Cognac's final investment decision (Burleson 1999, 80). The tower was armed to the hilt with instruments for measuring wave heights, wind and wave forces, the offset distance of the platform from center, its acceleration and incline, and the bending stresses imposed on the production well conductors (see Figure 1.9.).

Figure 1.9. Exxon's 1/50 scale guyed tower test model, pictured December 1975 in Grand Isle 86

Visible on the 440-ton tower is the 100-foot wave height measurement staff; current meters dangling in the water. Wind speed-and-direction aerovanes are yet to be installed on the steel beam jutting out from the top deck. In the center sits an air-conditioned shack for housing recording equipment, inclinometers and accelerometers. Source: "Deep Driller," Forum Public Mind, December 10, 1975; Chuck 1976.

The results of the pilot test as well as studies conducted by Exxon and Brown & Root confirmed that the guyed tower would be economic and competitive with other platform types between 1,000 and 2,000 feet of water (Pratt, Priest, and Castaneda 1997, 83). The guyed tower began to come to life in 1978, when Exxon decided to adopt the EPR design to develop its Lena oil field in the deepwater Gulf. It is unclear why the guyed tower design, intended for the North Sea, was built first for the Gulf. While the 1/5 pilot test was conducted in the Gulf's Grand Isle, that was only because Exxon had an operations center nearby, and the partners agreed that the location would minimize the cost of building and maintaining the pilot structure (Chuck 1976, 4). One possible motivation behind Exxon's decision was a series of changes made to the United Kingdom's offshore oil and gas fiscal regime in the early 1980s that reduced the amount of revenue an operator could make by producing the Queen's oil, rankling drillers and redirecting at least some investment back over the pond to the US (Oil & Gas Journal 1982; Pratt 2013, 144–145).

In 1,017 feet of water in the Mississippi Canyon, Lena was placed in a water depth just shy of Cognac's record, but still to great acclaim. True to the concept's name, most of the innovation performed in advance of Lena centered on its distinguishing feature, the guy lines (Pratt, Priest, and Castaneda 1997, 88). With 20 lines in all—just as EPR's design had called for—the Lena lines attached to the jacket not far below the waterline and radiated out a lateral distance of 3,000 feet from the tower base (Abbott et al. 1995, 317; Pratt 2013, 159). This angle meant that far from resembling the steep anchoring angle pictured in EPR's 1981 patent submission for "A Compliant Pile System For Supporting A Guyed Tower" and often replicated in representations of Lena, the guy lines had a rather large footprint. If the Lena guyed tower were made the size of the Washington Monument (at 555 feet tall), its lines would run far enough to the north to touch Constitution Avenue.

Exxon was especially proud of one key part of the guyline system. The bulk of Lena's stability came from the extremely long piles driven deep into the seafloor through its base. These were attached to the jacket structure in a novel configuration, which Exxon Production Research highlighted in its patent filing for the guyed tower concept (see Figure 1.10.). It was one component of the lines, however, that Exxon singled out in several magazine advertisements depicting the Lena tower, as its "Exxon-designed" feature (Exxon 1978). Exxon attributed the source of this invention to "serendipity" (Chuck 1976, 1). EPR attached the end of each guy line to a 30,000-pound drag anchor (aptly named a "BOSS" anchor) designed to bury deeply into the muck and resist removal when tugged on vertically. Inward from the anchor on each guy line was a series of heavy but loose "clump" weights, which Exxon attached in order to minimize vertical "uplift" on the drag anchors—seemingly certain to provide an extremely strong and stiff response to all wave forces (ibid.). Experimental results showed, to the delight of Exxon Production Research engineers, that the two weights worked nicely in sync with each other, generating a "stiff" response against normal wave heights, and a "compliant" response for those "few giant waves" which would lift the clump weights but not disturb the BOSS anchors (Pratt, Priest, and Castaneda 1997, 88). This system was vastly different from the method used in mooring semi-submersible drilling rigs ever since the first semi-submersible appeared in the 1960s, which called for each mooring line to extend at a shallow angle and attach to a submerged "spring" buoy at an appreciable distance away from the rig, before descending more rapidly to the seafloor, increasing its areal reach and thus its stability (Kobus, Meyers, and Bounds 1977, 170; Filson et al. 1988, 347).

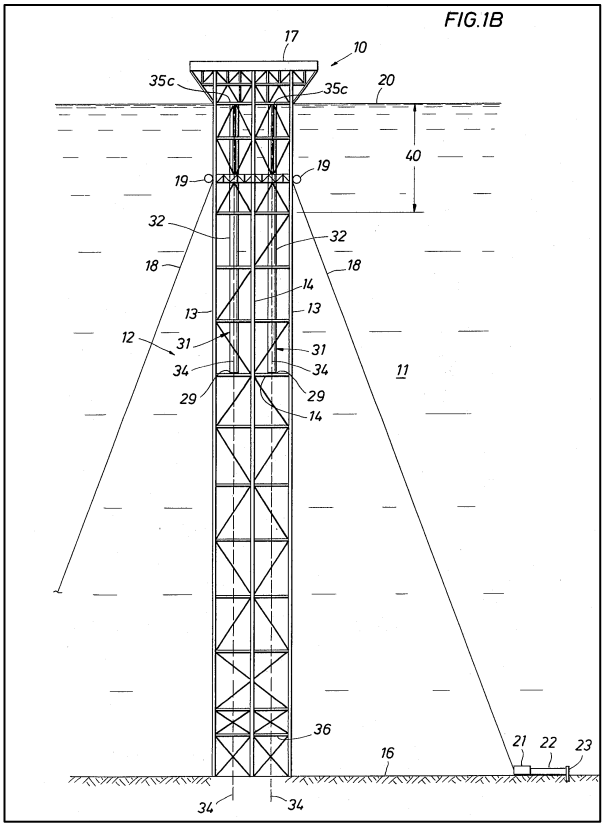

Figure 1.10. Patent drawing for “A Compliant Pile System For Supporting A Guyed Tower,” filed by Exxon Production Research in 1981 and granted in 1983.

The patent text details how the piles that are hammered into the seafloor extend vertically into a “pile jacket” that is affixed to the platform itself; but the pile connects to it only at the lower end of the pile jacket. As a result, the pile jacket (and the platform) can flex axially. Source: Exxon Production Research Co., Houston, Texas. 1983, 2.

Construction on Lena began in 1981 and its slender jacket—although still a 27,000-ton beast—was launched in May 1983 (Burleson 1999, 81). The difficulties in launching Lena and setting it into place rivaled that of Cognac in terms of cost, engineering, and the nervous nail-biting of offshore managers. Brown & Root had to expend more than 200,000 man-hours of engineering labor on just the seconds-long launch (Pratt, Priest, and Castaneda 1997, 84). Once assembled, Lena stood higher than the iconic Empire State Building, a fact that Exxon often trotted out (it was certainly more impressive than being as tall as the lesser-known Transamerica building). Lena’s cost was impressively high as well: an estimated $800 million, an amount that Exxon admitted was excessive but mostly attributed to the path-breaking nature of the project’s innovative status (Pratt 2013, 157–160). To date, Lena has produced approximately 105 mmboe, mainly as crude oil (US Department of the Interior 2014). Despite its ability to marry characteristics of conventional fixed platforms and floating facilities in a single deepwater package, the guyed tower never caught on after Lena. Offshore opined in 1985, one year after production began on the field, that the guyed concept was a laudable technical feat but one likely “destined” to go the way of conventional steel structures like Hondo and Cognac (LeBlanc 1985). Even after a decade of time to refine the design, as an influential Texaco executive parsed things in 1992, “guyed towers . . . have raised as many questions as they have answered” (Offshore 1992). The guyed tower also never caught on in its original target market, the North Sea (Lyle 2007, 45). Further refinement of the compliant tower design over the 1990s, however, did lead to the creation of two near-cousins of Exxon’s guyed design, only minus the eponymous guy lines: both Texaco’s Petronius and Amerada Hess’s Baldplate compliant towers found their way to the deepwater Gulf’s bottom in 1998 in depths beyond 1,600 feet of water.

Still, Exxon seemed to hint that it agreed with the editors of Offshore magazine not long after production began at Lena. Individual-well production rates rarely exceeded 1,500 barrels of oil equivalent per day on average (US Department of the Interior 2014). Exxon was publicly circumspect about Lena's disappointing performance for many years, officially demurring when asked whether it was preparing to build another for the deepwater Gulf, noting simply that it was looking to "match" each offshore discovery to "the best-suited production system" available (LeBlanc 1984). By 1993, Lena had produced a cumulative 65 million barrels of oil equivalent—a healthy sum—but Exxon officials admitted that same year that, given the chance to develop the field again, they would have passed on the opportunity. The Lena reservoirs "were much more complex than expected," explained Michael Flynn in September 1993 to a Congressional panel inquiring into a slowdown in deepwater activity (US Congress 1993, 14). In retrospect, Exxon's Flynn explained, the Lena field merited either abandonment or to have been developed with a "smaller platform" that would have resulted in Exxon "recovering fewer reserves" (ibid.).

Lena is deserving of historical consideration in part due to its status as the first successful unconventional development concept deployed in deepwater. The innovative practices that went into the creation of the guy lines have been likened to "training wheels" necessary to start with, but able to be removed on future versions of the compliant tower (Pratt 2013, 160). Lena's outcome also informed the path of floating facilities in deepwater. Lena's marine risers were the first in deepwater to survive in a non-conventional, compliant-design environment—a critical precursor to future deepwater compliant structures like the tension-leg platform. Even though Lena's flow was less robust than what the famously capital-disciplined Exxon would have liked, the field's production still amounted for a large percentage of deepwater cash flow during the 1980s (see Figure 1.4.), generating around $800 million in gross revenues through the end of 1989. Though any profit from Lena went to Exxon's coffers, its benefits accrued in some measure to all operators engaged in deepwater; they all benefitted from the general experience gained at Lena, and Exxon's spending on oilfield services preserved a market for deepwater supply service companies during lean times.

The progression of fixed-jacket technology from Hondo to Lena was more than the perfection of a mature production system. By the point at which Union Oil began putting together plans to develop its Cervezas fields, firms looking towards deepwater began reviewing competing production strategies as a de rigueur step in their business practices. Union nearly commissioned twin compliant towers for Cerveza and Cerveza Ligera in February 1979, but backed away in part because they were more than willing to see a major like Exxon foot the bill for a first-prototype innovation (Tannahill, Eisenhower, and Engle 1982, 235).

Despite the wide differences between the protracted installation processes of Hondo and Cognac, and the swift setting down of the Lena platform, the deepwater projects of this era shared the common plight of having to suffer through long delays before production started (see Figure 1.24.). Though much of Hondo's delay can be attributed to its unique extra-technical political situation, it, too, had to wait while its development wells were drilled from the platform deck. No operator seriously considered the alternative, which was to "pre-drill" and temporarily plug a series of production wells on the seafloor in advance, using a separate drilling rig—and pray that the monstrous towers could be lowered precisely above them so that all the equipment would fit together. Not until the start-up in the deepwater Gulf of the Pompano fixed platform in 1,290 feet of water in 1994 were production wells drilled in advance of setting a steel jacket in place; BP-Amoco completed 10 wells of a 40-well template before Pompano's installation (Oil & Gas Journal 1994; Koen 1995).

Aiming these massive structures at an invisible point on the bottom of the Gulf was a preposterous task, but the progression from Hondo to Lena showed great improvement in doing so. Cognac's base was set down in 1977 within 20 feet of its target placement (Priest 2007b, 199). By 1983, Lena landed within just five feet of its goal (Burleson 1999, 81). This improving trend notwithstanding, as the 1980s began to wear on into the second half of the decade, the combination of Lena's poor reservoir results and the drooping oil price made the sanctioning of *any* kind of deepwater project seem unlikely. Many offshore managers felt as early as 1982 that the deepwater oil and gas business was on the cusp of entering "a sustained period of crisis mode" (Pike and Duey 2007, 51).

1.2. What the Placid Story Tells Us

The "new era" in deepwater oil and natural gas development that Placid Oil seemed to promise never materialized in the Gulf, but not because Green Canyon 29 was a harbinger of project failures to come. Quite the opposite. Instead, just four years later, nearly every indicator of industrial health in the deepwater basin was surging upward. Drilling activity was growing; the number of firms investing in deepwater was on the rise; and the *sine qua non* of the petroleum business—raw production—was booming. This growth, however, was driven not by deepwater platforms similar to Placid's, but thanks to a revolutionary new type of production facility: the tension-leg platform, or TLP (see Figure 1.5.). Pioneered by Conoco at its Jolliet field in 1989, the first deepwater tension-leg facility was followed in short order by the addition of even larger TLPs at Shell's Auger (in 1994) and Mars (1996) fields in the deepwater Gulf. The advent of these large developments quickly breathed new life—and immense sums of money—into the region. Whereas Gulf operators had sunk a total of 198 producing wells in deepwater between 1980 and 1990, that figure more than doubled to 445 over the following decade (US Department of the Interior 2014). After six years of decline, by 1989 production volumes in deepwater began to rise again, kicking off a period of uninterrupted growth that would last for fourteen years—much of it thanks to the rapid flow rates achieved by the TLPs standing watch above the reservoirs at Auger and Mars. When the deepwater basin produced an annual volume of 500 million barrels of oil equivalent for the first time in 2001, floating platforms accounted for an impressive 55% of that total (see Figure 1.6.). Moreover, the bulk of that figure (78%) was pumped to shore by a tension-leg platform (ibid.).

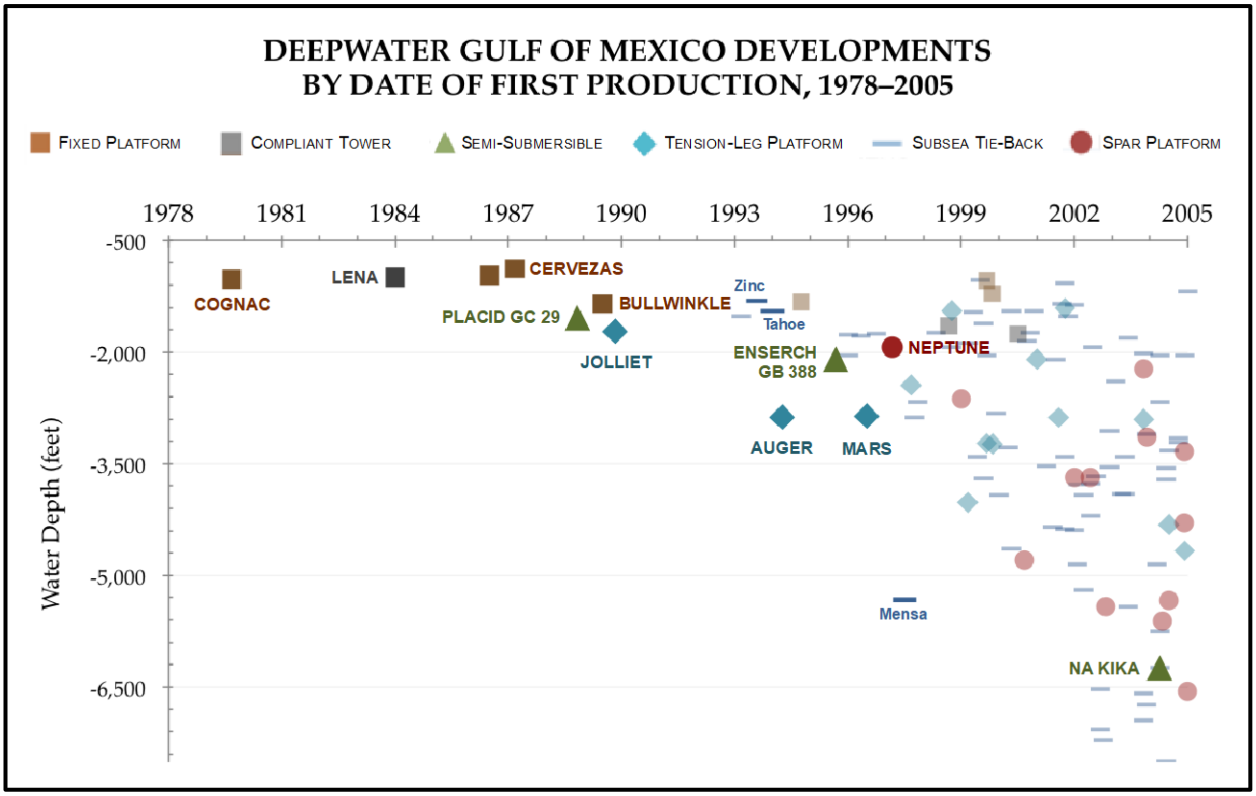

Figure 1.5. Selected deepwater Gulf developments by date of first production, 1978–2005

Key facilities like the Cognac fixed platform or the Auger TLP are highlighted and presented in bold type. Important subsea tie-back developments like Zinc and Tahoe are also highlighted, but presented in lowercase. Note the lengthy drought of semi-submersible FPU installations after 1990, while the number and types of deepwater platforms put into production expanded rapidly during the same period. Compare especially to Figure 1.24. Source: US Department of the Interior 2014.

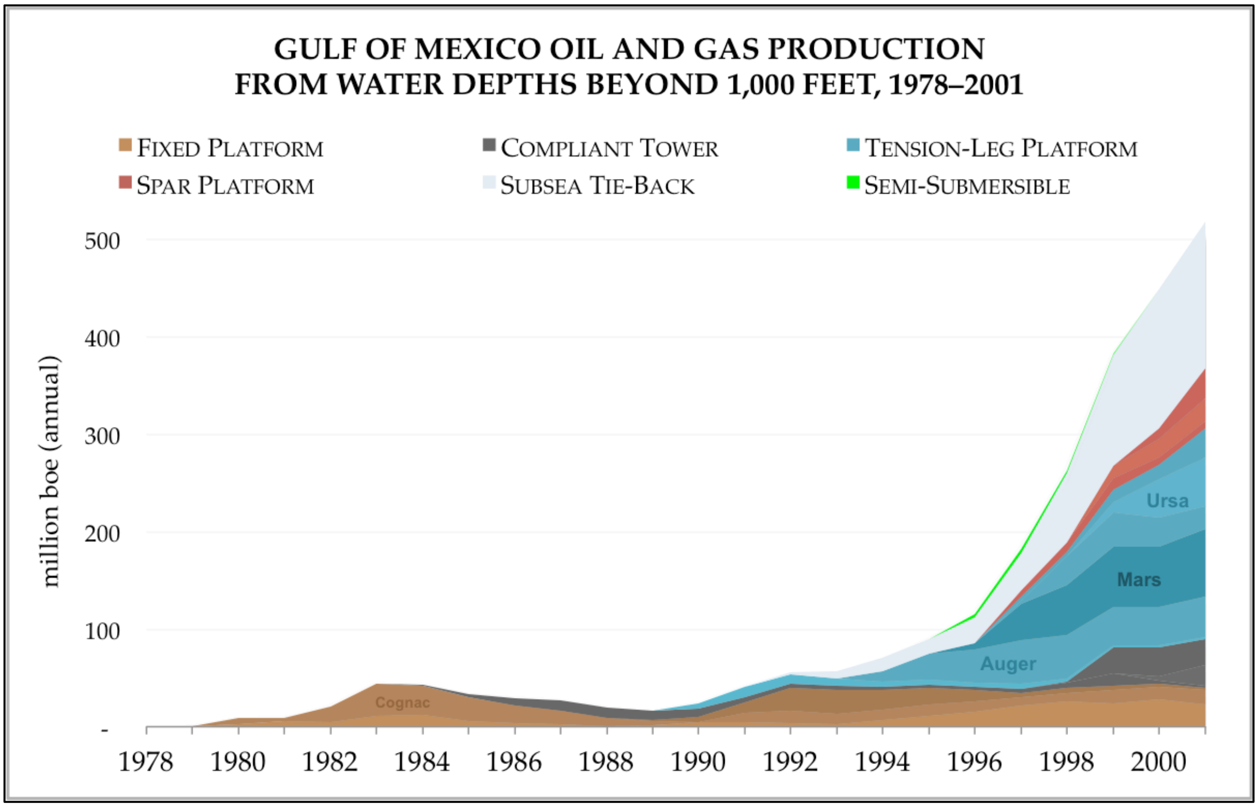

Figure 1.6. Gulf oil and gas production from water depths beyond 1,000 feet, 1978–2001, by development concept type

Both the dominance of the TLP concept in deepwater, and the sheer size of its contributions to production in the basin, become especially pronounced after first oil was achieved at Mars in 1996. Compare to Figures 1.4. and 1.5. Source: US Department of the Interior 2014.

Although deepwater activity took off like gangbusters after Placid's departure in 1990, the rising tide of success in the Gulf did not lift the fortunes of the semi-submersible floating production unit with it. The platform type was "conspicuously absent" during this period, as one observer noted as early as 1995 (Behrenbruch 1995). After production ceased at Green Canyon 29 in April 1990, no oil and gas would flow from a successful deepwater semi-submersible floating production unit (FPU) in the Gulf until November 2003, when a joint Shell-BP venture christened the Na Kika semi-submersible platform at its launch into 6,340 feet of water (see Figure 1.26.). The one departure from this lengthy absence is the proverbial exception that proves the rule: the only other semi-submersible FPU to appear in deepwater during this thirteen-year drought was the *Enserch Garden Banks* rig, installed in 1995 by Placid's former partner, Enserch Exploration. In nearly every respect an almost exact clone of the Green Canyon 29 system—Enserch had been the dominant bidder at Placid's GC 29 equipment auction—the Garden Banks 388 project, like its forebear, was a failure. Also costing about $400 million in total, the GB 388 facility was dismantled in 1999 having produced less than 10 mmboe, about three-quarters as crude oil. Like Placid's project before it, GB 388 generated far less revenue than Enserch expended on the project, bringing in an estimated $150 million after paying out royalties and leasing costs—a figure well below the total amount sunk into the project (US Department of the Interior 2014).

By the time the semi-submersible production platform did return to the deepwater Gulf in 2003, it was in the shape of a new, titanic species, a vessel more than twice the size of the *Penrod* and accompanied by a hefty price tag of $500 million for the facility alone (Dorgant et al. 2001, 3). Commissioned to yoke together production flows from multiple deepwater fields, the Na Kika platform drew its name from a mythical Polynesian deity prone to taking the form of a deep-sea Octopus, grasping and consuming everything within reach of its powerful tentacles. (Some may recognize the Anglicized name of this monster more readily: the *Kraken*.) Shell and BP's selection of the semi-submersible production concept for Na Kika was the first commission in the facility type's dawning renaissance. BP soon sanctioned similar vessels to develop its colossal and record-setting Thunder Horse and Atlantis fields, which achieved first oil in 2008 and 2007, respectively. The "classic" semi-submersible platform, built around a retired and converted old drilling rig like the *Penrod*, did not reappear in the deepwater Gulf of Mexico until ATP Oil & Gas turned on the taps at its Gomez field in March 2006 at a water depth of 3,281 feet. Haunted perhaps by the ghosts of both Green Canyon 29 and Garden Banks 388, Gomez also failed, abandoned by ATP in 2013 amidst less-than-stellar well results and the company's bankruptcy proceedings (Paganie 2006).

What can explain the prolonged absence of the semi-submersible FPU from the deepwater Gulf during the basin's greatest and most significant spurt of economic expansion? This paper addresses that question by tracing the sequence of innovation in deepwater production platform design that emerged between 1976 and 2006, and the changes in production strategies that came with it. An especial focus is paid to the late 1980s, which were supremely consequential in this regard. Particular attention is paid to the ways in which engineers housed in outside research firms, and corporate managers from inside the oil and gas companies, went about determining when the discovery of a new deepwater prospect merited the creation of new platform technology—and why. Opening with the installation of Exxon's Hondo fixed platform in 850 feet of water off California in 1976, and concluding with a brief look at how the ultra-deepwater Atlantis and Thunder Horse semi-submersible vessels came into being, this paper details the ways in which economic forces combined with the unique culture of the offshore oil business in the Gulf to determine the course of the basin's growth and mold the shapes taken by its deepwater Leviathans.

This narrative begins with steps taken by offshore operators like Exxon, Shell, and Union Oil to adapt the jacket structure of the conventional fixed platform for use in great depths. Following the spike in crude oil and natural gas prices brought on by the OPEC (Organization of the Petroleum Exporting Countries) oil embargo in 1973, these firms were able to easily justify spending hundreds of millions of dollars to erect massive steel towers to tap oil reservoirs on the seaward edge of the geologic continental shelf. However, simply extending conventional fixed platform technology was an impractical option for going much deeper than about 1,300 or 1,500 feet of water. Exploration efforts beyond the shelf did not flag in the face of this limitation, however, and the first viable alternative deepwater production concept finally emerged at the end of the 1970s. Brought to life by Exxon after its internal research and development arm, Exxon Production Research, Inc., pioneered its creation, the Lena guyed tower was piled into the Gulf's seafloor like its predecessors had been, but relied on the concept of compliance to remain upright. Instead of resisting wind and wave forces by brute strength, Lena remained stable after its installation in 1983 by flexing in tandem with its marine environment.

By greatly reducing the amount of steel needed for its jacket, the compliant tower promised to be economically competitive with rival concepts to about 3,000 feet of water. But the design never really caught on. Operators grew tired of spending nearly as much money on *launching* a structure like Lena (and accurately guiding its descent to the seafloor) as they did in building the thing in the first place. In water depths not far beyond Lena's 1,017 feet, installation costs for bottom-founded platforms swelled to become prohibitively large. Moreover, the old way of producing an offshore reservoir—waiting until a platform was launched and fully installed before starting to drill its development wells—became a luxury no longer affordable in the low price environment of the mid-1980s (see Figure 1.24.). Every day that a firm had to wait to begin flowing oil or natural gas was another downward tug on an offshore development's total value. Although the deepwater fixed platform evolved very rapidly from its starring role as a path-breaking technology to an obsolescent has-been, its advancement was a critically necessary step in the progression from shallow-water work to the near-universal use of floating facilities in deepwater areas around the world. Efforts like Shell's Cognac, Union's Cerveza and Cerveza Ligera platforms, and Exxon's Lena generated critical knowledge about the physical mechanics of operating in great depths offshore, and improved how geologists and geophysicists understood the "petroleum systems" that underlay the outer reaches of the continental shelf.

Varying prototype designs for floating production platforms had spent years floating in the ether amid the marine engineering community, but serious engineering work on them did not collect steam until the late 1960s. The first self-contained floating production platform of any type appeared in 1975 in the North Sea, where the SEDCO-Hamilton group deployed a converted semi-submersible rig to produce its Argyll field in shallow water. Ship-shaped production vessels first appeared in 1977, around the same time that an independent engineering firm named Deep Oil Technology, Inc., was running sea trials on a scale model of its first iteration on the tension-leg design principle. Like the Argyll semi-submersible before it, the first TLP made its worldwide debut in the North Sea, where Conoco spearheaded the particulars of TLP engineering and design work to exploit its 485-foot-deep Hutton field in 1984. Whereas converting an aging semi-submersible or retired oil tanker to serve as a floating platform was a relatively cheap and simple task, the tension-leg platform that emerged at Hutton was heavy on engineering intensity and capital requirements alike. Conoco spent an estimated $1.8 billion to build the Hutton TLP.

The high cost of its first-of-a-kind prototype aside, the rise of the tension-leg platform's fortunes as a potential rival to the semi-submersible FPU piqued the interest of Gulf Coast operators. The central technological benefit that the TLP offers to producers is its ability to support the heavy wellheads and vertically-tensioned risers required to host a surface or "dry-tree" completion. Petroleum reservoirs in the deepwater Gulf are often characterized by the loose or "unconsolidated" nature of their pay sands, which have a frustrating tendency to disintegrate as oil and gas flow through a rock formation and into a wellbore (National Commission on the BP *Deepwater Horizon* Oil Spill and Offshore Drilling 2011). This can cause a well to "sand up" and produce at lower rates, or to simply stop—the phenomenon that plagued Placid's wells at Green Canyon 29 (Hagar 1990). Though unconsolidated formations can be produced profitably through subsea or "wet-tree" wells, one of the primary benefits to an operator of a surface completion is the ability to readily and cheaply access the wellbore. This provides the company with convenient access for performing maintenance tasks, well stimulation, and other kinds of remedial work necessary to maintain production at efficient rates (Chitwood, Rothberg, and Miller 1993). Though operators can perform the same remedial actions on subsea wells, doing so can be extremely expensive—as much as 10 times the cost of equivalent work done on a surface completion (Quinlan 2003). A further strike against subsea wells is that, due to complex pressure and mechanical reasons, dry-tree wells simply produce far better than wet-tree completions do. Even under the same operating conditions, a subsea well is likely to produce just 33% of what an identical surface completion will (von Flatern 2014).

By 1984, after the debut of Cognac and Lena, if offshore oil and gas production was to expand in deepwater, two important conditions needed to be met. First, simply put, there would have to be commercial quantities of oil and natural gas present in the rocks beyond the edge of the continental shelf. Historical production profiles of the deepwater Gulf, like the one shown in Figure 1.6., give the impression that the existence of large pockets of hydrocarbons in deepwater was a foregone conclusion by that point. This is far from the truth. Although Cognac's wells had been draining a commercial deepwater field since 1979, production from Lena starting in 1984—while good enough to repay Exxon's investment, eventually—was weaker and less geologically promising than hoped. There was no guarantee at all that drilling in deepwater would pay off. Sure, wells sunk in the 1960s by a scientific expedition in 11,700 feet of water had confirmed the presence of "oil shows" in the Gulf's Sigsbee Escarpment, but the mere indication of oil traces was a far cry from confirming the presence of commercial fields (National Petroleum Council 1969, 7; US Commission on Marine Science 1969, 123). As one geologist who specialized in the deepwater region for Shell Oil later said: "It was generally thought by the industry as late as the early 1980s," Richard Sears explained, "that beyond the [continental] shelf edge...there was likely not going to be commercial accumulations of oil and gas" (Shell 2014). By drilling offshore in shallow waters but to an extreme total vertical depth, a wellbore sunk on the shelf could pierce the same deep horizons as those encountered in deepwater; but the results of test wells drilled in this manner provided little reason to celebrate (Sears 2010, 3; Godec, Kuuskraa, and Kuck 2002). Those optimistic enough to believe that deepwater contained untold treasures conceded that its gems were likely to be small, probably containing less than 100 million barrels of oil each. Those kinds of discoveries could be commercially produced only if the economic times were extremely favorable, or under very efficient operating conditions.

The second condition to be met was strategic, not stratigraphic, in nature. Because uncertainty was the watchword of deepwater geology in the mid-1980s, it was not at all clear to offshore companies which technological platform design would be their best bet for stepping off the edge of the continental shelf. Both the dry-tree capability of the TLP and the wet-tree systems of the semi-submersible FPU brought to the drafting table significant upsides and drawbacks. Not only did operators disagree about which technical system was superior; they were of differing minds on how those technologies should best be deployed. One of the primary downsides of a large-scale or "full-field" development like Hondo, Hutton, or even Green Canyon 29, was the immense economic risk it entailed. Just as Exxon had experienced at Lena in 1984 and Placid would at GC 29 in 1990, sinking a half-billion dollars into a deepwater facility only to find the reservoirs beneath it to be sub-par seemed almost by definition a gamble not worth taking. The alternative was to produce a field across a series of smaller and cheaper steps. Known variously as Early Production, Staged Production, or more commonly as Phased Development, the technical fix proposed for this challenge was premised on the mobility and flexibility that seemed inherent in the function of both semi-submersible and ship-shaped FPUs. Instead of commissioning a monstrously large platform to produce a proved field, as Shell would later do for Auger and Mars, a phased approach would dispatch an FPU to a discovery to produce it for a short period of time from just a handful of wells. Not only would such "early production" bring with it an immediate shot in the arm of cash proceeds from sales, it provided the operator with invaluable information about the size, shape, and quality of the field. Good results from an initial phase would allow the company to perfectly match the design type and processing capacity of a permanent facility to the reservoir, which yielded valuable cost efficiencies. Conversely, in the case of poor well results, Phased Development would allow the company to abandon the project with only minor losses on the books. The phased development approach caught on with some firms in the North Sea, but most readily with Brazil's state-owned national oil company, Petrobras—the most prolific user of semi-submersible FPUs around the globe. Notably, as seen in Figure 1.14., the idea of phased development or the strategy behind it was by no means limited to subsea well systems. There was no reason why a large field in the deepwater Gulf could not be produced with surface completions by sanctioning more than one tension-leg facility in a phased manner.

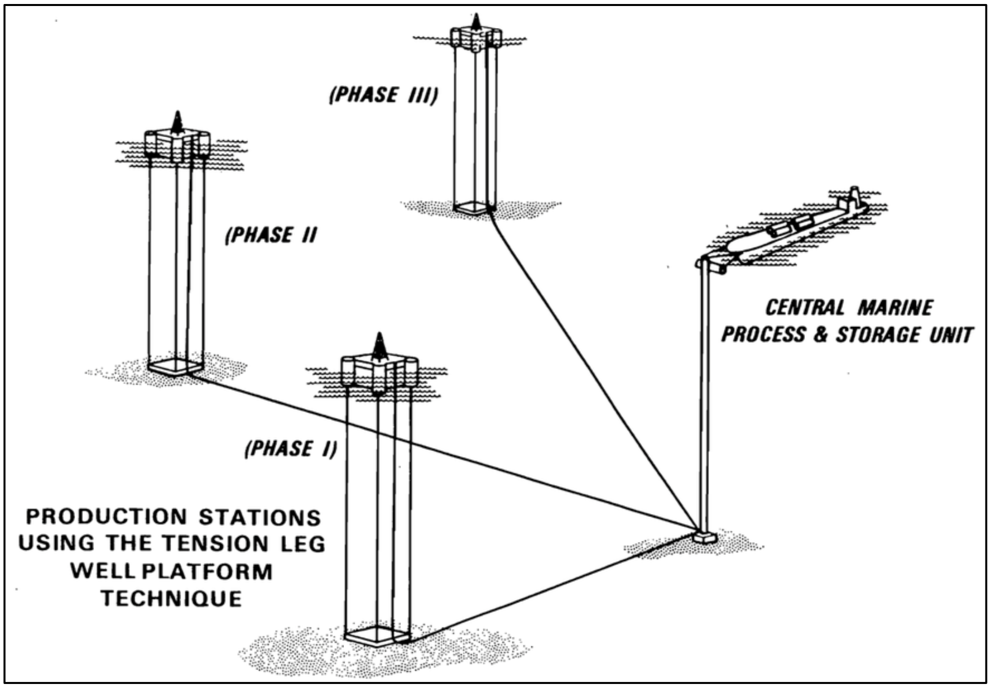

Figure 1.14. Proposal for a phased development strategy for deepwater and ultra-deepwater fields, using multiple dry-tree-capable TLWPs producing to either an export pipeline or floating FPSO vessel for shuttle export, 1985

With each TLWP serving as a "gathering station" for production from a large number of wells—both dry completions directly below the platform and local subsea tie-backs—this unique combination of production technologies allowed an especially economical system for remote or marginal fields. Compare to the relationship between the Jolliet TLWP and its shallow-water Centralized Production Platform in Figure 1.21. Source: Curtis and Mercier 1985, D-20. Reproduced courtesy of the American Petroleum Institute.

Uncertain geology and an unclear path of technical progress kept the deepwater industry sidelined at a "confusing crossroads" during the mid-1980s (Britton 1992, 82). There was, as the editors of Offshore magazine opined in 1984, "no clear solution in sight" as to whether one platform concept or another would end up dominating in deepwater (LeBlanc 1984). Instead, as Offshore explained, it seemed far more likely that a "great variety of systems" would be deployed there in competition for the foreseeable future (ibid.). By a perverse or perhaps sardonic twist of history, at the precise moment that the industry developed the technical skills to make great advances in FPU technology and dot the deepwater Gulf with floating platforms, the economics of offshore oil were thrown into upheaval. The collapse of the crude oil price in 1986 severely restricted the amount of capital available for new projects. In addition to Placid Oil's ongoing preliminary work for Green Canyon 29, at least four other Gulf firms in 1986 were considering sanctioning a semi-submersible FPU to produce deepwater finds. Each abandoned those plans after the price collapse (Offshore 1986). None returned to resurrect them, even after the boom time of the 1990s was underway.

Thus, come 1987, the path of deepwater development in the Gulf faced an important and extremely complicated juncture. Unlike some critical events that are only understood as turning points in retrospect, those involved in this period of deepwater's history acknowledged then its pivotal nature. In December 1987, more than 400 representatives from offshore oil companies, marine engineering concerns, and the US Minerals Management Service gathered at the Doubletree Hotel on Canal Street in downtown New Orleans. There, in the balmy weather of a Louisianan winter, they shared technical papers on the status of offshore oil and the murky outlook for deepwater (US Department of the Interior 1987). The conference focused on the only three deepwater development projects that had survived the devastation of the previous year's price collapse (see Figure 1.24.): Bullwinkle, Jolliet, and GC 29.

The first in this trio was Shell Oil's $500 million Bullwinkle fixed platform. Built on a conventional steel jacket for a site in 1,353 feet of water, Bullwinkle was almost treacherously big, a manifestation of the shallow-water workhorse platform writ to the very largest letter imaginable (see Figure 1.22.). Shell formally approved the 150-mmboe Bullwinkle development in June 1985, one year before Placid would do the same for Green Canyon 29. Fabrication of the monster continued apace into 1988. Bullwinkle would achieve many per-unit cost savings over Shell's Cognac platform, but the particulars of the jacket's engineering were only of modest interest to those in attendance in the conference at the Doubletree. That was old news. They were there to hear about the "floaters."

The second of the three was Conoco's Jolliet tension-leg well platform, or TLWP. Built to exploit a smaller oil deposit than Bullwinkle's, the facility was located about 85 miles west of the steel titan, in 1,722 feet of water. Conoco opted to build its first tension-leg platform for deepwater as a scaled-down variation on the original Hutton TLP design, creating a system architecture that placed the wellheads atop the TLWP hull while relegating the bulk of the platform's heavy processing equipment to a nearby conventional fixed jacket erected in shallow water (see Figure 1.21.). This arrangement was a necessary component in the economic calculus that Conoco relied on in deciding to invest in Jolliet. With recoverable reserves estimated at 60 mmboe, the major upside of producing Jolliet to a TLWP—in fact, possibly its best selling point—was the expectation among Conoco's executives that before long, they would be towing the platform to produce a nearby field once Jolliet was fully drained. This would spread part of the project's $450 million capital outlay over multiple revenue sources. In a significant departure from past practice in the Gulf (but following a precedent set at Hutton), Conoco sent a separate drilling rig to the Jolliet site in advance of the platform's arrival to "pre-drill" or "batch set" a series of production wells. This allowed Conoco to begin producing from Jolliet less than one month after its installation, a vast improvement over the long waits for first oil seen at fixed platforms like Hondo or Union's Cerveza and Cerveza Ligera towers.

The third deepwater project reviewed in New Orleans was Green Canyon 29. Placid's Antoine Gautreaux basked in the received glow of the Doubletree conference hall's energetic applause, generously paid in advance of the firm's historic technical achievement-to-be. Gautreaux explained that the conversion of the *Penrod* rig was predicated on a strategy similar to Conoco's at Jolliet. Like the tension-leg well platform, Gautreaux said, Placid's semi-submersible vessel hosted most of its processing equipment on a nearby shallow-water structure. Doing so minimized the payload that the already-beefed-up *Penrod* would have to hold above the waves, keeping down conversion costs (see Figure 1.3.). Curiously, even though Green Canyon 29 superficially resembled a phased development—namely by its association with the semi-submersible platforms used by Petrobras in its phased developments off Brazil—it was built as a full-field development. Placid's wasted work in setting a giant well template for 24 wells underneath the *Penrod 72* evinces as much. The failure of GC 29 was so financially detrimental to Placid precisely because the company had *not* taken steps to limit its risk exposure by testing the quality of the area's natural gas reservoirs in advance or through a phased strategy.

All three of these deepwater developments—Bullwinkle, Jolliet, and Green Canyon 29—were worthy of consideration at the New Orleans conference in 1987, considering how little business outside of the three had survived the economic doldrums. However, it was clear to all in attendance that the pending results from Jolliet and GC 29 would have a significance felt far beyond the balance sheets of Conoco and Placid. It seemed at least somewhat plausible that the future of floating production would go the way of the winner of this welterweight match between TLWP and semi-submersible FPU. As the two projects drew closer to their start dates, the evenhanded forecasts made in 1984 and 1985 that deepwater would be filled with a "great variety of systems" began to wane. Bets were called in on the ultimate outcome of the match. The dry-tree advantages of the TLP aside, the high capital costs of deploying that type of system in deepwater seemed ill-fitted to the post-crash mindset offshore. The semi-submersible FPU was battle-tested, and the flexibility provided by its low costs and high mobility seemed almost perfectly tailored to the growing geological consensus that only poor reserves remained in deepwater. Late in 1987, the editors of *Offshore* magazine revisited their own forecast from 1984 for growth in the deepwater market. Acknowledging that some measure of continued competition between dry-tree and wet-tree facilities was inevitable, they wrote that if Placid's Green Canyon 29 indeed turned out to be a "successful deployment" of an all-subsea well system, that news would "force a re-evaluation" of their conclusion that no single platform type would be crowned the superior solution for deepwater oil and gas in the Gulf (LeBlanc and Cornitius 1987).

Once Green Canyon 29 began to pump natural gas in November 1988, things moved quickly in the deepwater Gulf. Word began to slip out that Placid's wells were underperforming. Soon after Jolliet began production in November 1989, Shell Oil made a major announcement that truly electrified the industry. Stunningly, in December 1989, Shell made it known that it would spend perhaps $1 billion to develop its deepwater Auger field, discovered two years earlier in 2,860 feet of water in the Garden Banks area of the Gulf (Enze et al. 1994, 1). Appraised to contain recoverable reserves of 300 mmboe or more, it was now apparent that Shell believed Auger to be large enough to support the cost of a single, full-field TLP facility, massive in size and able to support the heavy dry-tree risers for 32 surface completions (Schempf 2001, 5). Although the first few years of the 1990s were lean ones in the deepwater basin, Shell's letting of major multi-million-dollar contracts buoyed hopes that the project was the advance guard of a coming boom. Then, in May 1991, Shell outdid itself again when it made public its discovery of an even larger, 700 mmboe field at its Mars prospect in the Mississippi Canyon. With Green Canyon 29 already off the scene, keeping mothballs company on dry land, all eyes turned to its rival, Jolliet. With many months of production history under its belt by 1991, it was clear that the Jolliet TLWP would turn a profit even though its geology was similar to that encountered at the Placid field. Conoco's ability to cheaply perform well interventions and "workover" through the platform's surface wells was the life preserver that kept the development's balance sheet above water.

However, continued stagnation in the price of crude oil between 1990 and 1993 dimmed the bright future for deepwater hinted at by the sanction of Auger and the announcement of the Mars discovery. In a variation on the "classic" style of the Phased Development approach, one influential industry research consortium named DeepStar lobbied during this period for the use of long, "extended-reach" subsea tie-backs to produce deepwater fields located as far as 60 miles away from the edge of the Gulf's continental shelf. Accepting that low oil prices might be there to stay, DeepStar argued that the main thing was to stop worrying about prices, and learn to reduce lifting costs as much as possible. The group envisioned the widespread use of semi-submersible FPUs in deepwater, to take in early production from subsea fields while maintaining the deepwater flowlines that DeepStar posited would connect a whopping 85% of all deepwater reserves to shallow-water platforms and their pipelines to shore. First formed under the auspices of Texaco, DeepStar (for DEEPwater STAged Recovery) lamented that Green Canyon 29 had been saddled with a permanent well template, as it contravened the inherent flexibility of the semi-submersible FPU that gave it an economic edge.

The low oil price made Shell anxious about the viability of even its massive Auger field. Many forecasts of the future oil price made in the late 1980s and first few years of the 1990s for the decade ahead proved to be grossly incorrect. For example, the US Energy Information Administration's 1990 forecast of the per-barrel price of crude oil for 1995 was $24.45; the actual price averaged $17.41 over the course of the year (US Department of Energy 1999. 83). For the Auger and Mars developments to be profitable, key Shell executives worried, the TLPs would either need to be graced by much higher oil prices, or exert better rates of flow than those witnessed at past deepwater projects like Cognac, Lena, Jolliet, and even Bullwinkle. As detailed extensively in a chapter of Volume II of this study, Shell Oil's deepwater mission to Mars, Shell convened a single-purpose task force to investigate whether the types of deepwater sands the company was encountering on the far edge of the continental shelf could be induced to flow at higher rates. The Turbidite Task Force was named after the turbidity currents that deposited the source rock that Shell's drills were targeting, a process best likened to the image of prehistoric underwater "snow avalanches" rushing large amounts of organic matter out to sea and down the slope to settle in broad swaths that would later turn into massive hydrocarbon deposits (Imbert, Pittion, and Yeats 1996). After an exhaustive review of global reservoir quality data, and after conducting a key production test at its Tahoe natural gas field in the deepwater Gulf, Shell was confident that they were on the cusp of a major revelation.

The site of Shell's first commercial application of the turbidite task force's hypothesis was the lumbering dinosaur of the trio of deepwater developments discussed at the Doubletree Hotel in December 1987: Bullwinkle. By relaxing the pressure "choke" on several of Bullwinkle's wells, in a flash they went from producing at rates between 2,000 and 3,000 barrels of oil per day, to surpassing 8,000 barrels per day with no attendant loss of back pressure, a side effect that could reduce ultimate recovery (US Department of the Interior 2014). Shell was elated with the results, in part because it meant that the Auger TLP would now need only 14 to 17 high-capacity wells drilled instead of 24 or 32, saving many millions of dollars—and recouping the TLP's high capital costs much sooner than expected (Priest 2007b, 250; Boué 2006, 120). This outcome was so definitive and revolutionary that even before Auger could produce a single drop of oil, Shell boldly chose in October 1993 to commit an additional $1.2 billion to develop Mars with a second massive TLP (Oil & Gas Journal 1993) —a decision that seems almost to tempt fate in light of Placid's prematurely lauded success at Green Canyon 29. Yet the combination of extremely large field sizes and excellent producibility when tapped by dry-tree wells was more than enough to justify the higher capital costs needed to deploy a full-sized, truly giant tension-leg platform.

The news that deepwater turbidite sands promised to be spectacularly profitable in the Gulf undercut the main selling point of the semi-submersible FPU platform and the production strategy of phased development. The new geological consensus that deepwater had many more Auger-sized fields left to be discovered rendered moot the raison d'être for deploying a platform with only subsea completions. Jolliet's continued positive cash flow, in light of Green Canyon 29's demise, only seconded the apparent technological superiority of the deepwater TLP's surface completions. Interestingly, though the success of the downsized and theoretically-mobile TLWP at Jolliet might have seemed an early victory for a phased approach in the Gulf, Jolliet's reservoirs had other plans. Conoco's intention to re-float the TLWP after the field was depleted (estimated to be no later than 2005) was shelved because Jolliet's reservoirs kept flowing far longer than anticipating, continuing to produce well into 2014 before finally ceasing later that year (US Department of the Interior 2014). Despite DeepStar's best efforts, the crux of their technical plan (dramatically advancing multi-phase pipeline flow and pumping equipment) remained beyond the reach of 1990s and even 2000s-era technology. Perhaps most significantly, the rise in deepwater drilling that trailed the good news from Bullwinkle and Auger—which had the potential to spark a rash of discoveries of new, smaller fields, and a rush of semi-submersible FPUs to tap them—instead sapped the long-standing oversupply of aging semi-submersible rigs offshore. Higher day rates sent older rigs to the scrapyard, put idle ones back to work, and prompted drilling contractors to finally place orders again for new drilling vessels.

With a much more confident note in their voices than when they had declared Green Canyon 29 to be the start of a "new era" offshore in 1990, industry soothsayers were correct in 1992 when they heralded the cutting of first steel for the Auger tension-leg platform as the dawning of a "new day" over deepwater (George 1992). By mid-decade, the TLP was clearly the "shape of things to come" (Abbott and Arya 1994b).

It is a causal bridge too far to claim that Green Canyon 29's failure somehow "caused" the semi-submersible FPU to fall out of favor for over a decade in deepwater. But it would be equally unwise to discount the profound effect that a fiasco like Placid's can have on an industry's mindset and the trajectory of its technological change. As business historian Patrick Fridenson writes in the second epigraph above, narratives that investigate the nature of economic enterprises like offshore petroleum production would be well served to give serious scholarly attention to failure. Just as a successful innovation can point the way *toward* additional fruitful outcomes, so can a failed effort guide engineers and financial investors *away* from an ill-fated vein of inquiry.

However, this paper does not rehabilitate and expand the story of failure at GC 29 so that it can serve as a cautionary tale of innovation gone awry. What Placid was attempting to achieve in deepwater is not analogous to Ford's pushing the Edsel in the 1950s or Coca-Cola's infamous attempt to market "New Coke" in 1985. Highlighting the effect that the GC 29 failure had on deepwater technology is important because, unlike the blunders of Ford and Coke, the Placid story has been neatly excised from almost all popular tales of its industry's history. The standard narrative told about the rise of deepwater oil and gas, often repeated by even well-informed observers of the deepwater Gulf, puts forth a clean transition from the fixed platforms of Cognac and Bullwinkle to the monstrously large TLPs that Shell deployed at Auger, Mars, Ram-Powell, Brutus and Ursa (Slaughter and Shattuck 2017). By projecting a past of untrammeled success, this narrative makes it appear as if it was obvious to those involved that the tension-leg platform was the superior technical solution for producing the deepwater Gulf.

Fridenson's exhortation for business historians to place failures like Green Canyon 29 on a common scale with successes like Mars forces us to grapple with the many nontechnical and decidedly cultural reasons why the history of deepwater production related below unfolded as it did. "Past failures," Fridenson writes, "are a specter that haunts the minds of consumers and citizens, managers and board members. They may shape the future of business through the lessons they teach to managers" (Fridenson 2004, 580). Fridenson's choice of the word *haunt* is an apt one. It reflects the way in which GC 29's unexpected demise rippled through the technical community in deepwater. In a history of offshore petroleum published in 1997, Hans Veldman and George Lagers (1997, 185) explain how deepwater firms typically "followed certain patterns in their thinking" during this period. "[O]nce [platform] concepts had been proven successful," Veldman and Lagers point out, "regardless whether or not the concepts as such were the key to the success, they became a standard and a basis for further development." Placid's lack of success in delivering the "new era" promised by the semi-submersible FPU had the opposite result, effectively removing it from serious consideration for a decade. It helped convince other firms—even Enserch, at its Allegheny field in 1995—to abandon plans for using a semi-submersible and subsea wells to produce their deepwater discoveries. The stigma of failure redirected—albeit temporarily—both investment and innovative efforts away from subsea production technology in the 1990s and towards improving the function of the TLP (and later, the dry-tree production Spar). It is debatable whether GC 29 was a "failure of geology" alone, as several have described it; an outright "economic failure," as Exxon has said; or simply a "technical" shortcoming. What matters most is that after April 1990, most deepwater producers in the Gulf did not much care to try and make such a distinction.

2. Close to the Borderline: Fixed Platforms Edge toward the Continental Slope

By the time wildcatters were starting to eye tracts in the Gulf of Mexico (Gulf) beyond the 1,000-foot isobath, the offshore basin already had several decades of brisk business under its belt. Proximity to the prolific onshore oil fields of Texas and Louisiana and the network of pipelines and refineries that dotted the Gulf Coast made drilling for offshore petroleum very attractive. Drilling out-of-sight of land started with Kerr-McGee's Ship Shoal 32 platform in 20 feet of water in 1947, and a constellation of steel platforms soon dotted the curve of the western Mississippi Delta's wetlands. The enactment in 1953 of the federal Outer Continental Shelf Lands Act (OCSLA) created a stable and favorable regulatory regime that offered fair and guaranteed access to offshore acreage through the administration of routine lease sale auctions. Although the offshore petroleum industry, like any business, was subject to the vicissitudes of the macroeconomic business cycle, as well as shifts in commodity prices, the offshore oil patch in the Gulf proved amazingly resilient to the downward tug of both. Periodically, veterans of exploration in the Gulf would declare the region to be on the brink of exhaustion, only to (rather happily, one can assume) eat crow once a major find breathed new life into the wildcatters' drill bits. Asked to comment in 1988 on the Gulf's outlook during one of its darkest economic times, one colorful CEO of a small independent operator said, "If I were thrown naked into the world and told to go find oil and gas, I'd still go to the Gulf of Mexico. It's easier to find it there" (Bennett 1988, 31). His attitude was not an uncommon one.

Behind this success lay both good geology and grand technology in the hands of offshore drillers. Improvements in the acquisition and interpretation of seismic data achieved in the 1960s and early 1970s made it easier for offshore hunters to detect pools of oil and gas deep below the seafloor (Priest 2007b, 135). Firms drilled fewer dry holes as a result, saving millions in the process. Although a recurring theme of the history of oil and gas in the Gulf is the ability of new technology to unlock the discovery of new reserves, the causal flow of these forces pointed in the other direction as often as not. In other words, it was the discovery of large fields early in the basin's history that brought to life the revenue and rationale needed to invest in more technology and more drilling (Priest 2007a, 233).

But the unique underwater geography (or bathymetry) of the northern Gulf also helped matters. "History was kind to the pioneers of the offshore industry in the Gulf of Mexico," explains business historian Joseph Pratt. Because the shallow-water area of the *continental shelf* recedes at a very gentle incline away from the Gulf shore, firms were able to push their drilling and production technology "step-by-step" into slightly deeper water whenever they saw fit (Pratt 2009, 192). With a downward slope of less than 1º, the shelf was so close to level in many places that one would have to travel about 70 miles southward away from the edge of Texas to reach an average water depth of just 100 feet (Campbell 1990, 106; Fitch 1956, 13).

Exploration and production drilling took these small steps in tandem for the first decade of drilling in the open Gulf until 1958, when mobile rigs began sinking exploration wells in 135 feet of water, beyond the deepest producing platform (Offshore 1997). Somewhere around the 600-foot isobath, the deltaic plain of the continental shelf begins to break into a slender but steeply-declining strip of land known as the continental slope (see Figure 1.7.). Dropping at an average inclination between 3º and 5º, but dipping at an angle as high as 15º in some stretches, this transition zone was dubbed the flexure trend or flextrend after the natural "flex" in the seafloor (Campbell 1990, 106; Ball 1983; US Congress 1992, 25). No longer resembling the flat plain of the shallow-water seafloor, the slope and much of the continental rise beyond was often varied and mountainous in profile. Beyond about 1,000 or 1,500 feet of water, as one offshore executive put it, the bottom "looks like you took the Hill Country [of central Texas] and submerged it" (Shook 1985).

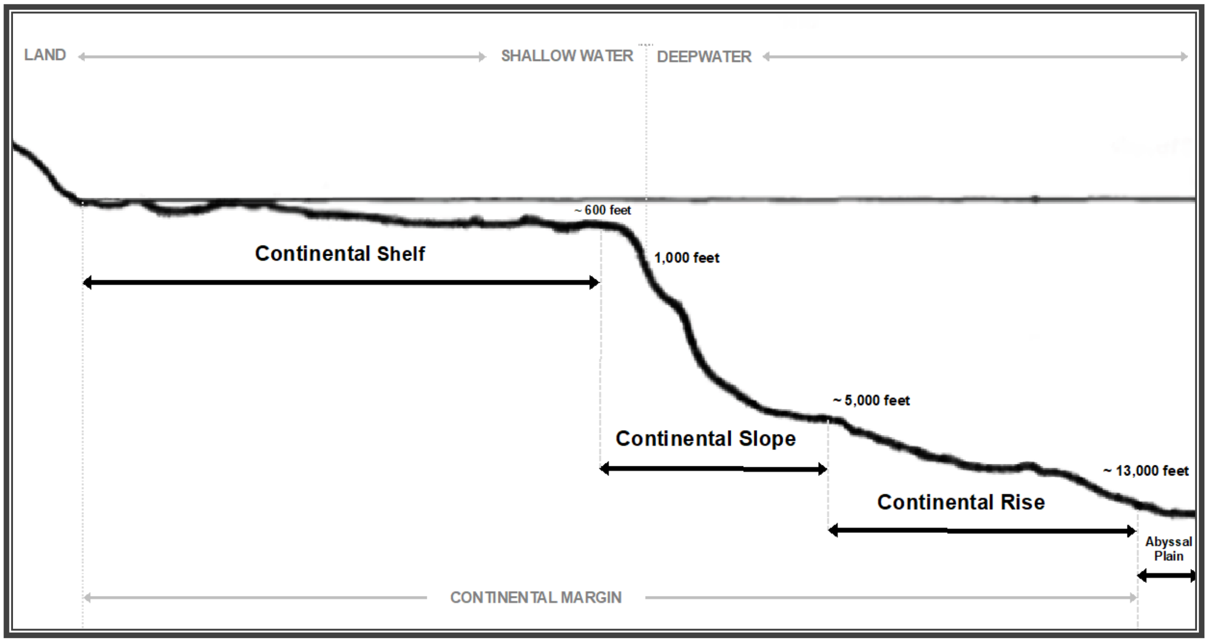

Figure 1.7. Bathymetric profile of the continental margin in the US Gulf of Mexico

All figures are approximate. Because of the gentle slope of the continental shelf in the central Gulf region, 33% of the continental margin's surface area rests underneath just 600 feet of water or less. Only 13% of the margin's surface area sits underneath 600 to 3,000 feet of water on the continental slope. Globally, the continental margin accounts for roughly 20% of the surface area of the ocean floor. Compare with the deepwater facility map shown in Figure 1.18. Source: Adapted from multiple sources. Surface area figures for the Central Gulf of Mexico region are from Boué 2006, 16–17; global continental shelf and continental margin surface area figures are from Birrell 1994, 943.

It was not just good geology (and the federal government's generous terms of access) that drove oil and gas companies increasingly offshore in the 1970s, however. In 1970, Libya and several other petroleum-producing nations began the process of nationalizing their oil and gas reserves, and the threat of a severe energy crisis loomed over the horizon (Gramling 1996, 92). Crude oil production in the US peaked the same year, spurring firms to explore more in order to replenish their ever-declining reserves (Priest 2007a, 228). The rise of what became known as "producer power" severely restricted the amount of global petroleum provinces still accessible to a western-based international oil company like Exxon or Shell, or even a domestic independent like Placid Oil (Pratt 2013, 72). An estimate made in 2009 by energy consulting firm PFC Energy determined that only 6% of the world's petroleum resources are today fully accessible to non-state controlled firms (ibid.). Crude oil prices skyrocketed after the Arab members of OPEC imposed an oil embargo on the United States in 1973. Newsweek magazine, for one, fretted about the "doomsday implications" of the oil supply crunch (Perlstein 2014, 111). Seeking reserves offshore in deeper waters was no longer a strategic choice for many oil companies, but instead nothing less than a do-or-die economic imperative (Priest 2007b). Locked out of some of the best petroleum basins worldwide, Shell Oil in particular turned to the Gulf's deeper waters to hunt, staking its future firmly in the basin (Priest 2014, 1903). Shell was not alone in this vision. "If we don't go into deep water," read one Texaco magazine advertisement published in the middle of the 1970s, "We'll all be in hot water."

The oil issue hit hard in Washington, DC's corridors of political power. Seeking to keep the political temperature from boiling over during the energy crisis, President Richard Nixon twice—in 1971 and again in 1974—directed his Secretary of the Interior to rapidly expand the industry's access to domestic offshore lands for petroleum exploration. Dismayed that the nation's reliance on foreign imports of crude oil had surged to reach 35% of its annual domestic oil consumption over the previous year (US Federal Energy Administration 1974, 2), the Nixon administration set a clear goal in 1974: that 10 million offshore acres on the Outer Continental Shelf were to be leased to oil and gas companies by 1975 to accelerate exploration for new reserves (see the chapter in Volume III of this study, The secret of the sea: offshore oil and gas revenue collection, valuation, and royalty relief in the deepwater Gulf of Mexico, 1973–2010). The "acceleration" in the pace of leasing promised to increase the frequency of lease sales, boost the annual acreage totals offered up at each lease sale auction, and drive down offshore acreage prices to the benefit of all.

Come 1974, the US Geological Survey (USGS) estimated that since drilling for oil began in the nineteenth century, more than 172 billion barrels of oil and 168 trillion cubic feet of natural gas had been discovered offshore—a sum totaling 26% of all petroleum resources ever discovered (Berryhill 1974, 1). Offshore drilling had clearly established itself as a paying proposition, and as the 1970s advanced, deepwater regions were increasingly cited as the best and most exciting opportunity for reserves growth. A decade after the USGS made its calculation, Shell Oil had grown bullish enough on the outcome of its heavy investments in the deepwater Gulf that it declared in 1983 that for every single barrel of oil remaining to be found on land worldwide, two would be discovered offshore—one of those from deepwater (Cornitius 1983). The first step taken towards achieving deepwater production came not along the Gulf Coast, however, but off the beaches of California, at a field named Hondo.

2.1. Last of the Big-Time Structures

Long a petroleum hotspot in its own right, the oil fields of Southern California were known to extend underneath the scenic beaches and their sunbathers and out below the nearby azure waters of the Pacific Ocean. As early as the 1890s, producers hammered together creaky wooden piers to support derricks and wells, and extended them just a few hundred feet beyond the beach to tap those oil reservoirs. With demand for domestic oil production rising steadily after the conclusion of the Second World War, drilling beyond the surf began in earnest in 1965 (Snyder 1977, E-1). Among the pack hunting in the Pacific was Exxon, and in January 1969 it discovered a particularly large oil accumulation not far from the Santa Barbara coast, in 850 feet of water; Exxon dubbed it Hondo (Scherer 1981). Spanish for "deep," the prospect's name was an apt one, because its depth was nearly 500 feet greater than the tallest Gulf production platform installed by 1969. The technical challenges facing Exxon's decision to go forward with developing the field were prodigious, but so was the potential payoff: Hondo appeared likely to contain as much as 500 million barrels of oil (Pratt 2013, 104).

To extend conventional steel-jacketed platform technology to that depth, an operator like Exxon had several engineering tactics at its disposal. Early extensions of shallow-water steel platforms out to the considerable water depths of 400 or 500 feet (see Figure 1.8.) were generally accomplished by strengthening the individual steel beams used in constructing the jacket's lattice frame (Pratt, Priest, and Castaneda 1997, 78). Beyond the 500-foot isobath, the presence of stronger wind and wave forces, and the larger surface area of the jacket's steel exposed to those forces, required a re-design of the overall structure. Pratt, Priest, and Castaneda (1997, 78–79) enumerate the options available to offshore engineers to strengthen such a design:

> One way of adding stiffness [to a platform] was increasing the leg batter, or slope, which was one of the main determinants of its overall stiffness. Increasing the stiffness, therefore, meant increasing the batter and thus the base area of the structure. Other ways of imparting stiffness included adding steel to the legs and piles, increasing the area of brace pipe, and lowering the mass of the structure.

Once built, these steel goliaths then had to be carefully and safely transported to their launch sites in the open water. The previous method of lowering a jacket onto its target via crane-lift was infeasible in a depth like Hondo's (Pratt, Priest, and Castaneda 1997, 71). Deeper fields would require stronger launch barges and cranes, the use of more saturation divers than normal to assist in underwater actions—and, increasingly so after 1977—the use of pricey remotely operated vehicles, or ROVs (US Department of the Interior 1979, 21).

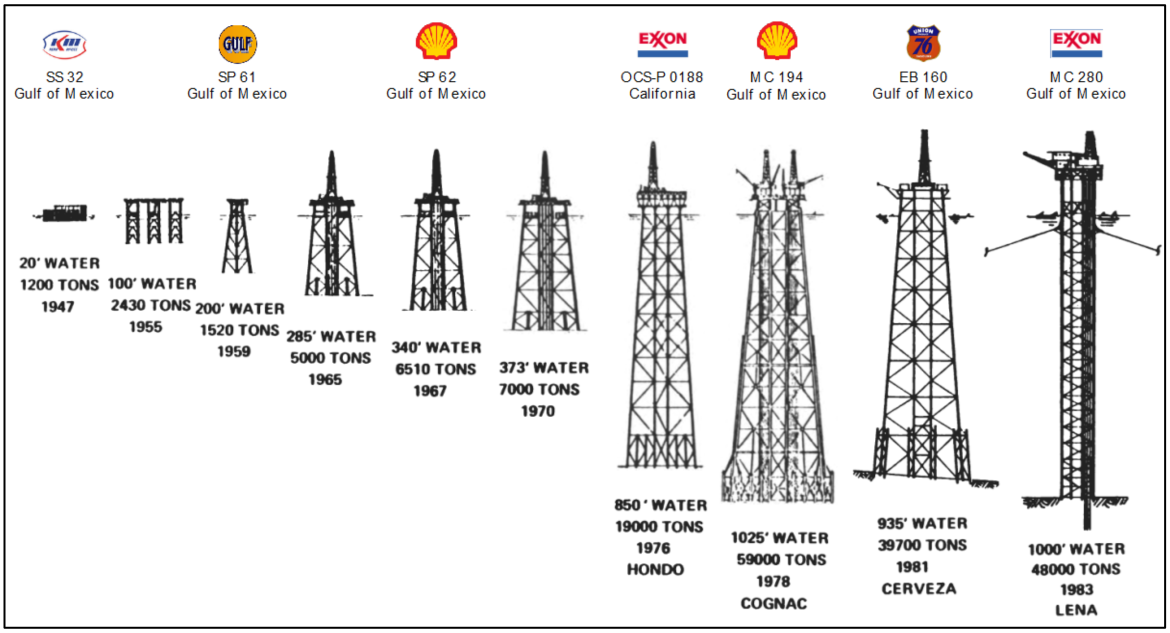

Figure 1.8. Progression of selected fixed production platforms on the US Outer Continental Shelf, 1947–1983

Missing from the depiction of Hondo (fourth figure from right) is the 50,000-deadweight-ton offshore storage and transportation tanker (OS&T) that ended up functioning as the final stage in Hondo's production train. Moored a few miles away from the platform in shallow water, the tanker would fill its hold with 200,000 barrels of petroleum liquids before shuttling it to shore. That capacity required about 35 such trips per year early on in Hondo's life. Note also that starting with the Cerveza platform in 1981, technological progress in platform design did not always result in an ever-deeper water depth. Source: Adapted from US Department of the Interior 1983, 217; US Department of the Interior 2000, 39. All rights remain reserved regarding fair use of corporate logos.

While Exxon weighed its options for producing Hondo, pollution and politics intervened. The same month Hondo was discovered, a well on a Union Oil platform just a few miles east of Exxon's prospect violently blew out, soaking the beaches at Santa Barbara with an estimated 4.2 million gallons of crude oil. The public's environmental outcry over the oil spill was swift and harsh. The Santa Barbara spill is widely credited with shepherding the sweeping federal National Environmental Policy Act (NEPA) to swift passage one year later in January 1970, and Richard Nixon chartered his own independent White House commission to investigate what policy responses would be most appropriate in the wake of the blowout and the public's mounting outrage. Nine months later, the President's Panel on Oil Spills concluded that one option for reducing public opposition to offshore drilling was to increase the use of subsea wells for production, their equipment placed out of sight on the seafloor. "We do not suggest that all the [wellhead] structures can or should be beneath the water," the panel reported back to the White House in October 1969, "but that many [of them] can" (US Executive Office of the President 1969, iv). Appealing though the all-subsea option may have been, it was an impractical option for Hondo on technological as well as economic grounds. Subsea technology at the start of the 1970s was still in its early infancy, its use generally limited to draining marginal accumulations of oil or gas that were discovered in close proximity to an already-standing fixed platform.

To produce the Hondo field in 850 feet of water required building a platform that would ultimately stand 945 feet in height, when measured from the mudline to the drilling deck. It was a truly massive structure. Once built, the weight of the Hondo jacket punched in at 12,000 tons, large and heavy enough to resist storm forces as well as support the weight of 28 heavy steel well conductors, one for each producing surface completion (Snyder 1977, E-2; National Research Council 1979, 25, 167). There was but one not-so-minor problem standing in the way: no offshore transport barge existed that was capable of floating out a jacket that was so long and so massive as Hondo's would have to be (Snyder 1977, E-3). Further adding to the Hondo project manager's mounting woes was the fact that between the Kaiser Shipbuilding fabrication yard in Oakland (where Hondo was being assembled) and the oil field itself stood the San Francisco-Oakland Bay Bridge. Its seagoing clearance was just 226 feet between sea and steel.

Exxon's solution to the water depth challenge was to carve the Hondo jacket in two. After fabricating it as a single piece over 1975 and 1976, Exxon disconnected the structure laterally into two pieces, and sent it down the coast on two separate barges (Pratt, Priest, and Castaneda 1997, 81; Snyder 1977, E-3). With the platform's bottom footprint measuring 170 by 232 feet, the second barge and its cargo squeezed under the West Bay portion of the bridge with little room to spare. Pushed off the barges in a protected area of water near the drilling site, the two pieces were joined together while floating tenuously just below the surface of the Pacific Ocean; Exxon dispatched welders inside each of the jacket's six legs to permanently join the two pieces together (Snyder 1977, E-3). Next uprighted, slowly ballasted into place, and then piled and grouted into the seafloor, the Hondo platform was finally ready for business in June 1976—but only for the business of drilling the twenty-plus production wells that Exxon needed before any oil was to flow. Regulatory, legal, and political concerns about the possibility for pollution at Hondo significantly delayed the project and altered the path that its oil and gas followed for export, relying on a shuttle tanker rather than via subsea pipeline. The saga was a protracted struggle not-so affectionately dubbed the "Battle of Hondo" in some quarters (Pratt 2013, 106; Oil & Gas Journal 1978; National Research Council 1979, 167).

All told, the need to squeeze the Hondo jacket underneath the Bay Bridge turned out to be a public relations boon of sorts for Exxon. Stunning images taken during the tow-out show Hondo's bottom piece sitting on top of its barge, underway, with the bridge and the San Francisco skyline nicely framing the shot. Exxon made hay with this image, running a series of two-page advertisements in the following years that showed a color photo of the event on one page, juxtaposed against a visual comparison of the height of the completed Hondo platform against the city's iconic Transamerica building. "Exxon Heads to Sea—To Open a New Frontier of Energy," the caption read, and its sidebar of text explained that the Hondo platform would "fit over the tallest skyscraper in our photograph," referring to the Transamerica's 853-foot elevation. Hondo nearly doubled the tallest fixed production platform to date, the ad rightly pointed out. "These facts," it went on, "may help you appreciate why finding new supplies of energy today is a challenging, costly, and risky venture" (Exxon 1976).

Exxon might well have added "lengthy" or "protracted" to that litany of risks facing the Hondo project, because a series of lawsuits filed under the new NEPA provisions slowed its progress to a trickle. Both the Santa Barbara oil spill disaster that catalyzed the new law and the regulatory hoops that Exxon was forced to jump through have been described as "nightmares" (Veldman and Lagers 1997, 76; Pratt 2013, 104–106). Despite those delays, however, Hondo was such an impressive technical achievement that many praised it as likely to remain the tallest such conventional production platform for years to come. In a major qualitative assessment conducted on the state of offshore petroleum technology and policy published in 1973, a group of government and industry experts predicted that fixed platforms were unlikely to extend beyond 900 feet of water, or not much deeper than where Hondo sat (Kash et al. 1973, 50–52). While the technical limits of going deeper were surmountable, the Kash group noted, the "ultimate upper limit" to the fixed platform's reach "is really economic" (Kash et al. 1973: 52).

Hondo did not come cheap. The fabrication of the jacket alone set Exxon back an estimated $77 million in nominal figures, but the platform's topsides, overall design work, and especially its launch and installation procedures all together totaled more than $600 million (Snyder 1977, E-3; Scherer 1981). One of the largest components of that cost was drilling the platform's production wells, which were spudded from the drilling rig installed near the center of the deck soon after installation. Development drilling did not begin until September 1977, and it lasted no less than two years, as Exxon's drillers sunk 24 producing wells, two wellbores to be used for water injection, and two more for natural gas injection, a process employed to improve overall recovery (McCollum 1979, 1). Because of this lengthy drilling process (exacerbated in part by Exxon's continuing regulatory battles), first oil at Hondo did not come until April 1981 (US Department of the Interior 2015). Though reducing the time from discovery to first production in an offshore project has a significant positive effect on its total value, Exxon actually benefited in this instance from the fact that crude oil prices increased steadily between 1976 and 1981, from a per-barrel price of $12 to $36 in nominal figures. When those high prices began to disappear in the mid-1980s, however, the long delay between a platform's installation and its first barrel of oil would become a luxury that even the biggest oil companies could ill-afford (see Figure 1.24.).

While Exxon was busy piecing together the Hondo project, another segment of the company was working to determine where exactly that "ultimate upper limit" of conventional platform technology might lie. Exxon Production Research, Inc. (EPR) designed a mock platform during 1975 and 1976 for theoretical use in 1,300 feet of water in the Bass Strait, south of the Australian mainland (Loftin 1976, 832). Apposite to the hypothetical nature of the study, EPR set out to review the feasibility of engineering a platform that was both 60% taller than Hondo and to be built and launched in a single piece. EPR's engineers concluded that such a task was possible with current technology, even though the resulting jacket design would be massive: 60,000 tons in weight, built around 12 legs with 56 securing piles and with a foundation base of 346 by 396 feet (ibid., 831). "Obviously," EPR concluded, "the design of a 1,300-foot fixed platform is not simply an extension of present-day technology, but will require many innovative techniques" (ibid.). The more acute challenge was indeed truly an economic one. Managing such a massive project would be difficult to accomplish well, EPR pointed out, even for a firm with such esteemed organizational capabilities and access to capital as Exxon. By way of example, the study report noted, to proceed with the Bass Strait platform project, the first step needed would be the construction of a new shipyard somewhere on the Australian coast, as the entire continent did not contain one capable of handling a structure of that size in 1976 (ibid.).

After Hondo, the center of innovation in offshore oil and gas production technology quickly shifted back to the Gulf. In concert with the acceleration in the number and size of offshore lease sales spearheaded by President Nixon's Department of the Interior, Shell Oil turned heavily towards the largely unexplored deepwater areas in the Gulf, eager to establish a first-mover advantage by scooping the opposition. The first leases sold beyond the 1,000-foot isobath were auctioned off in May 1974, and Shell was the first to hit pay dirt (US Department of the Interior 2014). Rumors of a large discovery in the Mississippi Canyon soon emerged after Shell's drilling program proved successful during the second half of 1975 (Priest 2014, 2062). Prospect Cognac was identified through the help of the improved seismic data technology known as "bright spot" interpretation, which Shell deployed in advance of the lease sales. The good news of Cognac's discovery was greeted by popped champagne corks and celebration within Shell's production division, and preliminary reserves estimates pegged the field as containing 100 million barrels of oil and 500 billion cubic feet of natural gas (Nations and Speice 1982, 1), a combined total of nearly 190 mmboe. Such a find was much larger than the average discovery on the continental shelf, which was the source of much of the celebration within Shell—as well as a few sinking stomachs. As historian Tyler Priest (2007a, 195) recounts, upon hearing the results of the Cognac discovery well, one Shell manager in charge of offshore production blurted out, "That's great news!" while his internal monologue immediately turned to thinking, "now we've got to produce! We've got to build a platform" (Priest 2007b, 195).

Sitting below 1,023 feet of water, Cognac was an order of magnitude deeper than Hondo, and given the nature of the Gulf's reservoirs, would need nearly twice as many production wells drilled into it as its Californian cousin. Shell faced numerous other obstacles in the deepwater Gulf environment that came with the territory of Cognac's extreme water depth. The uneven and wrinkled granite hieroglyphics of the seafloor's bathymetry posed a risk of unsteady soil underneath a platform. Shell ran six different studies on soil stability in the immediate region in response to those concerns (Sterling, Cox, and Warrington 1979, 1188). Since 1969, Shell had been collecting wave and current data from instruments installed on its South Pass 62 platform, located 30 miles away from the Cognac site. Despite its presence in shallow water, the platform's proximity to Shell's deepwater discovery meant that much of its metocean data would be applicable to the Cognac structure. In 1972, Shell added additional equipment to the platform to capture better data about currents (ibid., 1186). Another Shell effort involved mooring a drilling rig over the Cognac site over the summer of 1975, and hiring two university students to keep a meter dangling 20 feet below the rig and writing down recordings from it by hand every few hours (ibid.). These efforts were far from overkill, because the uncharted nature of the entire Cognac effort meant that unknowns lurked at every corner. When divers descended with the bottom of the platform in July 1977 to assist with piling it into the bedrock, diver Doc Helvey of Taylor Diving & Salvage took a surprise when he stepped foot on the seafloor and sank up to his knees in silty sediment (Hellwarth 2012, 4484). Like Professor Arronax or Ned Land stepping out of Captain Nemo's *Nautilus* and into the forests of the Island of Crespo, Helvey and his crew were the first to enter a truly alien environment.

Taking a page from Exxon's deepwater playbook, Shell sliced its Cognac jacket into three pieces. However, Shell would have to follow a different approach for mating the sections together. Without a placid stretch of water nearby in which the pieces could be joined while floating, what Exxon had done at Hondo was out of the question (Pratt, Priest, and Castaneda 1997, 81). Although J. Ray McDermott, Shell's primary contractor, considered building the Cognac jacket as a single piece, all involved feared that the steel tower would be susceptible to the strike of a hurricane during the months-long period it would take dive crews like Doc Helvey's to get all twenty-four of Cognac's 500-ton securing piles hammered and cemented into the seafloor rock (Sterling, Cox, and Warrington 1979, 1185). By installing the three pieces on top of each other piecemeal, the bottom section could be securely set and grouted free from the threat of a major storm destroying it. Shell's concerns proved wise; two storms rolled through the Mississippi Canyon in the late summer of 1977 (Priest 2007b, 198).

Cognac's first design, drawn in 1974, went through six major drafts before Shell landed on a final version. This process saw the platform's well count upped from 40 to 56 development wells, before increasing again to a total of 62 (Sterling, Cox, and Warrington 1979, 1186). The surface area of the topsides deck nearly doubled as well, and an additional drilling rig was added to the suite of equipment (ibid.). First steel was cut even before all the particulars of the installation process were figured out (Marshall 2007, 9), and by July 1977, the bottom piece was on its way to the floor of the Gulf, its base measuring an incredible 380 by 400 feet in dimension (Sterling, Cox, and Warrington 1979, 1191). That made Cognac's footprint larger than the estimate made by Exxon Production Research for the Bass Strait platform, and nearly as large as three football fields. EPR was correct when they noted that the process of building tall structures for the deep was no mere scaling-up of standard platform technology. The technical and managerial achievements that Shell realized with Cognac constituted a veritable "quantum leap" beyond the then-current state of offshore engineering (Priest 2014, 1895). Shell had to account for even the minute changes in size that steel would undergo when transferred from the sweltering heat of the fabrication yard to the cold of the deep seafloor (Priest 2007b, 197). After $800 million spent—a full $275 million of which was earmarked for the installation alone—Shell finally had all three pieces of Cognac assembled by 1979 (Priest 2007b, 201; Pratt, Priest, and Castaneda 1997, 81). Rather than waiting to start up production until every well was drilled, Shell produced the world's first barrel from deepwater in September 1979, from just two flowing wells (US Department of the Interior 2014). With two platform drilling rigs working full-time to complete the task, the full suite of 61 producers was complete before long, taking in oil and gas from 72 drainage points across 7 reservoirs (Nations and Speice 1982, 3).

As they had prognosticated regarding Hondo before it, some observers now predicted that it was Cognac that was certain to stand as the ultimate limit of the fixed platform's water depth (Snyder 1977, E-3). Much of Shell Oil likely stood solidly in this camp of believers. The mating of Cognac's three pieces offshore was the culprit behind the chewing to the bone of hundreds of fingernails, as the operation was an anxiety-inducing task bar none. The engineering achievements of the jacket aside, Cognac's development made Shell and its service contractors come to grips with the myriad complications and challenges of deepwater. The technological processes trail blazed at Cognac were themselves worthy of high praise. Parts of the platform's base were coated in Teflon. And by sending divers 1,000 feet below sea level, the development of Cognac caused a man to descend to the deepest a human had ever been (Hellwarth 2012, 4574). As Exxon had with Hondo's tow-out under the Bay Bridge, Shell made hay of the otherwise-mundane process of installing the pieces of its deepwater platform. Shell proudly compared the joining of Cognac's pieces to the 1975 mating of the Apollo–Soyuz test spacecraft while in orbit (ibid.). The message was clear: this was truly space-age stuff.

To date, Cognac has produced over 315 mmboe, most of it as crude oil (US Department of the Interior 2014). Technologically speaking—Shell's comparisons to the Space Age aside—after Cognac there appeared to be little left to achieve in engineering a conventional fixed platform. The panic attack-inducing installation of a jacket in three pieces was unlikely to be repeated. Single-piece fabrication and installation would be a must for future projects. Before long, firms other than Shell began to capitalize on the lessons learned at Cognac. In 1979, Chevron completed the launch of a single-piece 708-foot platform at Garden Banks Block 236 (Pratt, Priest, and Castaneda 1997, 80). ARCO did the same in the following year, for a field located in 651 feet of water in the Mississippi Canyon; and the small independent operator Zapata Offshore installed a platform in 658 feet of water near the Texas coast at East Breaks 110 in 1984, far to the west of where Cognac stood near the mouth of the Mississippi River. The proliferation of these moderate-depth, not-quite-deepwater platforms between 1980 and 1985 pushed up prices at the fabrication yards. Not only were the builders responding to the increase in demand, but with each passing year, it seemed that fewer and fewer yards even remained in the oil jacket business, due to the price slump. By 1984, only four Gulf Coast fabricators were still capable of constructing a jacket for water depths beyond 1,000 feet (Brooks 1984, 258). Due to the slump in its own particular niche of the offshore oil and gas market, drilling rig manufacturer Marathon LeTourneau in 1987 diversified its business by starting to build housing modules not for production rigs, but for US prisons (Crown 1987). For those yards left standing, the rise in fabrication orders after Cognac came with a nice premium: per-unit platform fabrication costs jumped 85% between 1980 and 1982 (LeBlanc 1994).

The most notable of the single-piece copies of Cognac were two similar steel towers built by the Union Oil Company of California, and installed in the western part of the Gulf of Mexico over oil fields perched on the edge of the Texas side of the continental shelf. Over 1981 and 1982, Union installed nearly identical platforms named Cerveza and Cerveza Ligera in 935 and 925 feet of water, respectively. Bearing names meant to invoke the low, low prices of cheap beer, the Cervezas were a "none too subtle dig at Shell's perceived extravagance" in the foreign firm's drink of choice, Cognac (Boué 2006, 116). By alighting upon a simpler design for the platforms' legs and foundations, Union was able to significantly reduce the cost of building both facilities and to compress the time needed to install them offshore. By also putting to use a new launch barge capable of handling 42,000 tons, fabrication costs for the Cerveza tower amounted to just \$90 million, and its aptly-named "lite" cousin cost just \$60 million (Boué 2006, 116; Pratt, Priest, and Castaneda 1997). Clearly, the repetition of the process was bringing increasing returns to platform builders and operators both. Still, even the "beer-budget" Cervezas did not come cheap: Union estimated that total development costs for Cerveza, including some \$128 million spent to acquire the leases, topped \$500 million (Tannahill, Isenhower, and Engle 1982, 235). With recoverable reserves of around 40 mmboe at Cerveza and 35 mmboe at Cerveza Ligera, both fields were dangerously close to sinking into the red.

When asked, Union was quick to tout how quickly they had brought the Cerveza and Cerveza Ligera platforms to fruition after their discoveries. The projects were "fast-tracked" by Union, which committed capital funds as rapidly as possible to minimize the time to first oil. Indeed, both projects proceeded quickly from start to finish in under two years (Cornitius 1981). The drilling of the production wells on both platforms after installation, however, was a slow-going process (Grecco 1987, 520). Only after every well was drilled did any begin to produce, meaning that Cerveza Ligera did not start up until 1986, nor Cerveza until 1987 (US Department of the Interior 2014). Though both of Union's platforms returned a decent profit, such delays in production would prove unimaginably wasteful to those deepwater firms still operating in the Gulf come 1985.

2.3. Have Platform, Will Travel

The high costs of the steel towers that pioneered deepwater would soon price them out of contention for further use. Those prohibitive price tags also sparked the first serious investigations into the next step needed to unlock deepwater treasures: floating production concepts (Brooks 1984, 259). The importance of that need was no surprise to anyone in the Gulf oil patch, however. If anything, offshore drillers have displayed from the very beginning a preternatural and almost universal confidence—which has proven correct—that it was only a matter of time before they would be producing oil to floating platforms in water deeper than 10,000 feet (US Department of the Interior 1979, 22).

Shell's Cognac platform was not even a month old in December 1979 when industry members at a National Research Council meeting expressed just such a sentiment. At the conference, Shell luminary F.P. Dunn rose to speak on the status of deepwater technology. Echoing a statement made earlier in the day by another speaker, Dunn noted that the "gap" between exploration and production technology had widened to eight years. In other words, it would likely be 1987 until a production platform could reach the site of the deepest exploration well drilled in 1979. Dunn's response to that gap, which had been steadily widening since 1958, was bold in its simplicity. "Well," Dunn said, "we will catch up with them" (National Research Council 1979, 39). Affirming the point made above that it was often the *discovery* of large reserves that spurred the invention of new production equipment, rather than the other way around, was the way in which Pennzoil executive R.J. Howe echoed Dunn several years later: "if the explorers find a giant oilfield in water deeper than 3,000 feet [of water]," Howe said, "one can rest assured that the engineers will devise a way to produce it" (Howe 1986, 6). Both men from Shell and Pennzoil were correct about the future of the technology gap: it began to close in the early 1990s and today has been virtually eliminated (Barton 2014, 5).

Designs and daydreams for the shape of an ultra-deepwater platform equipped for any depth had a long pedigree by the time deepwater production began in 1979. Some were more fanciful than others. As early as 1894, inventor Alfred William Palmer received a patent on a smart but all-too-impractical buoyant tower equipped with "means for making borings at bottom of deep waters and in tideways" while connected to a docked ship (Palmer 1894). Visions of the application of advanced marine technology to offshore drilling took off in earnest during the 1960s, oftentimes as an attempt to siphon off some of the public's fervor for the Space Age and redirect it towards the underwater "Inner Space" or "Hydrospace." The scientific programs of the C.USS. group pushed the limits of offshore drilling prowess to such advanced limits that it truly seemed more like fiction than science. The celebrity of Jacques Cousteau and the deep dive of Jacque Piccard and Donald Walsh's *Trieste* down 36,000 feet into the Challenger Deep crevasse in the Pacific Ocean inspired a generation of oceanographers. The US Navy's three SEALAB expeditions aimed at a future that not even the deep ocean drillers contemplated, of sustained underwater human habitats (see Hellwarth 2012). Colorful visions of subsea cities bustling enough to need traffic lanes for submersibles often cropped up in books and magazines (Cox and Woodson 1968; Armagnac 1970). When offshore engineers did turn their sights on advancing subsea production technology, many like the Lockheed and Comex-SEAL groups pursued a vision of wellsites populated with one-atmosphere, literally "dry" wellhead chambers that would allow personnel to work in a "shirtsleeves" environment (see Duey 2007; Pratt, Priest, and Castaneda 1997, 120–157). The world of inner space on the world's continental shelves offered an unexplored frontier with a surface area the size of Africa, said boosters for the increase of ocean science research funding, if only technology was developed to embrace that promise (Hellwarth 2012, 372).

Visions for ocean drilling in particular varied widely. One such proposal imagined a surface vessel that would steam to an offshore prospect before intentionally flooding its hull space to turn vertically before beginning to drill, similar in function to the US Navy's FLIP research vessel (US Commission on Marine Science, Engineering and Resources 1969, 52; Glanville et al. 1997, 1). Another Navy offshoot called for a submarine to perform the same aquatic gymnastics, only that its drill would descend into the seafloor through the middle of its propeller. Many concept sketches of ultra-deepwater drilling barges, which came in nearly any shape imaginable, were replete with images of "jet-powered helicopters" for personnel and equipment transport (Duey 2007, 25). E&P magazine was host in 1963 to a proposal for a "Triton Marine Platform," supposedly unrestricted by a maximum water depth limit, that appeared to be a cross between a semi-submersible drilling rig and a tension-leg platform, with a buoyancy chamber that could descend up and down the tendons like an elevator weight hung to offset its variable load (ibid., 25).

Other concepts hewed closer to the design of the conventional production platform, as Exxon's guyed tower had done. Ocean Systems, Inc., pushed for a design that mounted a standard jack-up rig on the top of a subsea drilling capsule that was designed to contain the wellheads and personnel in a one-atmosphere environment while also having a diameter large enough to extend the jack-up's depth capabilities significantly. This idea was creatively named the "Underwater Drilling System" (Lyle 2007, 37). A French firm tested an early form of a buoyant tower in 325 feet of water in the Bay of Biscay in the early 1970s, declaring it feasible in depths up to 2,000 feet while hosting up to 60 dry-tree wells (National Research Council 1979, 27–29). Steel jacket designs with six legs set in a hexagonal shape (instead of the standard four) were proposed, while others assumed the existence of a highly-engineered articulation point, the same that warned EPR off of the buoyant tower in the early 1970s (Offshore 1985; Chakrabarti, Halkyard, and Capanoglu 2005, 24). Gravity-based concrete structures found use in the North Sea, where they were particularly well-suited to resist the unforgiving harshness of the stormy and cold environment. Others looked to build a similar vertically-moored vessel with a low-slung concrete base, called the tension-raft jacket (Koen 1996a; Srinivasan 1995). With a barrel-like cylinder that tapered down from the platform's deck level to 250 feet below the water line, another concept would use massive air cans to keep the tower vertical, giving it a strong restoring force that would end up in another landmark innovation shepherded to fruition in part by Deep Oil Technology: the deepwater production Spar (Britton 1992, 83).

Reality finally began to catch up with imagination in the 1970s (Armando and Cvijak 1987). Naturally, the earliest forms of floating platforms for offshore petroleum work were basic derivatives of the common semi-submersible rig, drillship, and oil tanker. Even these vessels had their own predecessors of sorts.[3] Early on, the semi-submersible in particular garnered the bulk of the industry's interest. The USNavy had been long intrigued by its possible use in military forward operations (Chakrabarti, Halkyard, and Capanoglu 2005, 422). An influential national panel on marine and oceans policy known as the Stratton Commission (see Figure 1.11.) proposed in 1969 that the federal government cooperate with the private sector to build "large stable ocean platform[s]" for use in both scientific research and petroleum exploration (US Commission on Marine Science, Engineering and Resources 1969, VI-247). Variations on the design of the semi-submersible called for hulls built out of poured concrete instead of cut steel, a change that promised to grant the vessel a deeper draft in the water—as well as dramatically reduced

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[3] Only a handful of platforms in the Gulf have been equipped with a floating storage vessel arrangement similar to the configuration at Hondo. In 1967, Kerr-McGee used a surplus oil tanker to ship 110,000 barrels of produced liquids per trip from its Ship Shoal 214 platform to shore to avoid the higher costs of laying a pipeline (Duey 2007, 34). The adoption of this practice beyond a very small number of instances is limited by federal law and regulations, which restrict the flaring or venting of associated natural gas produced alongside petroleum liquids. See the Volume X in this study, "The Secret of the Sea: Offshore Oil and Gas Revenue Collection, Valuation, and Royalty Relief, 1973–2010."

labor costs (Offshore 1989a). Others envisioned semi-submersible FPUs that would float freely while relying on the tension present in the platform's well conductors (instead of mooring lines) to maintain stable in the waves (Oil & Gas Journal 1978). But the basic design of the standard semi-submersible drilling rig was difficult to improve upon for its application to floating production. It was already proven successful, and because semi-submersible hulls had been in use since the 1960s, operators of all sizes found them familiar and welcoming to use (Johnston 1985, 198; LeBlanc 1985).

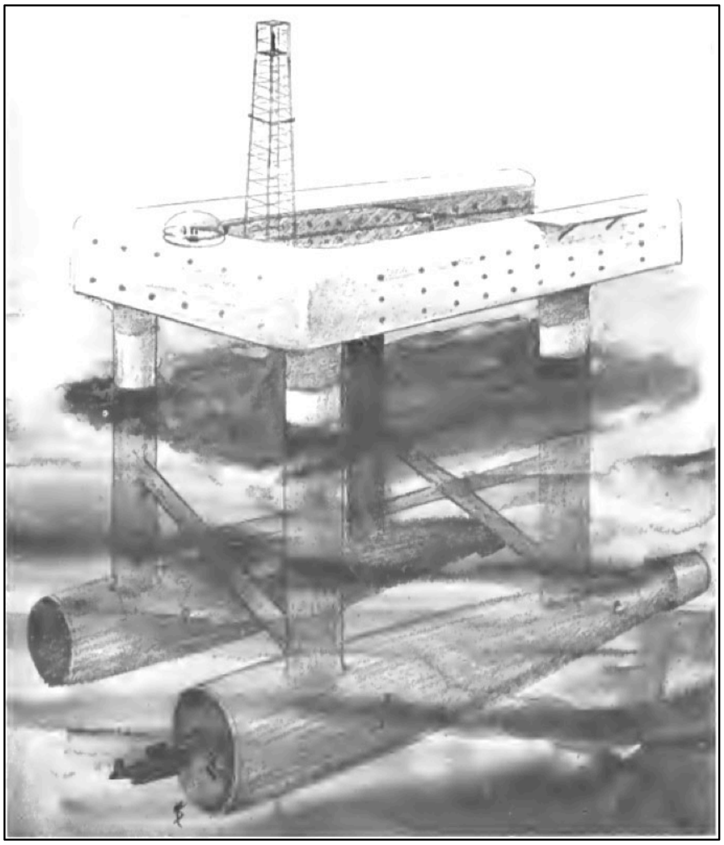

Figure 1.11. Concept sketch made by the Stratton Commission for a "Large Stable Ocean Platform" with a 20,000-foot water depth capability

"Many military, scientific, and industrial programs," the report noted in 1969, "could benefit from an ability to do useful work for long periods in the deep ocean." Source: US Commission on Marine Science, Engineering and Resources 1969, VI-247.

Thus it was only a small step to take when offshore oil and gas companies first looked to host hydrocarbon processing equipment on a floating platform. The world's first FPU came online in the North Sea at the Argyll field in 1975, an asset of SEDCO-Hamilton, in 250 feet of water in the UK sector. Setting the example for Placid Oil a decade later, with spare rigs in abundance, SEDCO-Hamilton acquired an older semi-submersible drilling rig, the *Transworld 58*, and altered its processing equipment to handle up to 70,000 barrels per day of production (Curtis and Wolfe 1982, 2525). The *Transworld* was centered over a well template on the seafloor, and also accepted production from satellite wells as far as 1.5 miles away. Produced oil and gas then flowed back down to the seafloor and laterally through a pipeline before rising into a single-point buoy, where a 400,000-barrel tanker shuttled it to shore (ibid.). The system earned widespread praise for SEDCO-Hamilton not only for its landmark achievement in floating processing, but for Argyll's additional status as the world's first exclusive use of subsea wells in a commercial offshore development (National Research Council 1979, 109).

Only by coincidence was Argyll's platform built from a floating rig. Although it was the first field on the UK continental shelf to produce in the North Sea, Argyll was a relatively small find. SEDCO-Hamilton's estimate of its recoverable reserves was decidedly too small to support the cost of a fixed-jacket platform, as the harsh North Sea conditions made such structures much more expensive to deploy than in the Gulf (such a platform for Argyll was estimated at $150 million). Argyll's petroleum was also believed to be of only moderate quality; the geology surrounding the reservoir was deemed too variable and complex in nature to cost-effectively image with seismic data, making the chance for steady production unlikely (Busby Associates 1985, 17). Taking inspiration from the nearby Ekofisk field in Norwegian waters, which Phillips had begun producing in 1971 using a temporary installation of a jack-up rig and four subsea wells (Hansen and Rickey 1994, 3), SEDCO-Hamilton searched the market but could find no suitable jack-up available to use. Only then did the group turn to semi-submersibles as a viable option (Busby Associates 1985, 19). Even though the *Transworld 58* rig and its conversion would cost a bit more than using a jack-up, the floating production system turned a previously marginal prospect into a real money-maker. Additional North Sea semi-submersible FPUs soon appeared, like the Buchan platform in 390 feet of water in 1981, and the Balmoral field in 1986 in 470 feet, both in the North Sea and the latter earning an accolade as the first FPU newly built expressly for that purpose (Hansen and Rickey 1994, 4; Praught and Liu 2012, 34). The semi-submersible concept seemed to catch on especially quickly in Brazil, where Petrobras converted the *Sedco-135D* rig to produce its Enchova field in 400 feet of water (Veldman and Lagers 1997, 176). The *Sedco-135D* was just the first of three semi-submersible rigs that Petrobras sent to the Campos Basin in the 1970s to produce offshore oil and gas there. The third, set over the East Enchova field in 1979, would end up having a notable career in the United States—as the *Penrod 72* (Lim and Ronalds 2000, 9).

The first use of a ship-shaped floating platform tanker, or an FPSO, soon followed the launch of Argyll. In 1977, Shell España dispatched an FPSO to its one-well Castellon field in the Mediterranean Sea. Situated about 40 miles off the Spanish coast, Castellon's reservoir contained virtually no associated natural gas in its crude oil, allowing it to produce directly to the tanker without the need for natural gas-handling equipment on board (National Research Council 1979, 165). For its first fifteen years, the FPSO concept was constrained by limitations in its key technical salient, the swivel-and-turret system that allowed oil and gas to flow through a single point while the vessel "weathervaned" around it according to the push of the sea (Lim and Ronalds 2000, 8). Also during this early period, nearly all FPSO vessels were conversions of surplus oil tankers (Veldman and Lagers 1997, 174); but after the oil price collapse, the use of FPSOs snowballed around the globe, and new units were increasingly built. Before long, the worldwide count of FPSOs in service would stand at more than double that of all semi-submersible production units across the globe (Lim and Ronalds 2000; Barton 2014, 16).

Still, the use of all-subsea wells tied to floating production platforms, whether in Brazil, the North Sea, or elsewhere, was no panacea to deepwater challenges. Subsea or wet-tree well completions had been in use for decades, ever since Shell Oil produced oil from the first truly offshore subsea well in 55 feet of water in West Cameron Block 192 in the Gulf (Hansen and Rickey 1994, 2). Lots of work done by engineering firms, and operators like Exxon and Shell, advanced the technology of subsea wellheads, and created methods for access and maintenance like through-flow-line (or TFL) systems. Early efforts at keeping subsea completions "dry" through the use of one-atmosphere wellhead chambers paid off when used at several deep fields off Brazil, like Garoupa (Curtis and Wolfe 1982, 2526), but the costs of extending such systems beyond perhaps 500 or 1,000 feet of water were far too great. By the middle of 1984, a full 292 subsea wells had been installed worldwide (Busby Associates 1985, 8). The most successful applications of subsea completions in the late 1970s and early 1980s were for tying-back small fields to existing fixed platforms, as at Cormorant in the North Sea in 1982 (Hansen and Rickey 1995, 677); as the core of a marginal North Sea field that produced to an FPU, as at Argyll; or as the backbone for a semi-submersible FPU as deployed by Petrobras in the Campos Basin. Despite these fruitful uses, subsea production equipment remained somewhat crude and underdeveloped until the late 1990s. Despite their low installation costs, subsea wells could easily frustrate producers to the point of madness. One technical estimate made in the mid-1980s pegged subsea well uptime to be as low as 51%, meaning that they only worked about half of the time (Busby Associates 1985, viii).

Especially in the context of deepwater use, the promise of all-subsea production was rife with promises that "next year" would be different, and marked by inevitable disappointment. The industry had been predicting for decades that subsea glory was just around the corner, but this only brought wave after wave of "hope and [then] disappointment" (White, Adamson, and Hadfield 1993, 2). Subsea production systems could not live up to the hype and the amount of interest that they "generated in the trade journals and at conferences/exhibitions" (Busby Associates 1985, 34). To make this point, one technical report produced for the Minerals Management Service on subsea technology in 1985 reprinted a laundry list of the kind of trade journal headlines that had been published for years on end: in 1977, subsea technology was making "Rapid Progress"...in 1979, it was heading towards a "New Horizon"...by 1981, subsea technology was "Dominating" the market...and in 1982, it was the "Infant Prodigy Com[ing] of Age" (Busby Associates 1985, 34–38) Predictably, subsea production systems would again "Come of Age" in 1984 and once more in 1985 (ibid.). Not until the widespread adoption of ROVs for maintenance in the 1990s did subsea production finally grow out of its teenage years (see Priest 2007b, 251).

With subsea well technology still in school, operators eyeing deepwater regions were eager to find smarter ways of supporting dry-tree risers in depths greater than 1,500 feet of water (US Department of the Interior 1979, 23). At least one firm in the 1980s promised what might be credibly called the offshore industry's Great White Whale: a semi-submersible production platform stable enough in deepwater to host surface completions. Starting in 1986, the veteran offshore drilling firm Ocean Drilling & Exploration Company, or ODECO (Howard 1988, 14), began marketing its design for a dry-tree semi-submersible platform named the *Ocean El Dorado* (see Figure 1.12.). The vessel as imagined by ODECO would be built on an utterly massive scale. Designed around six columns with an operating draft of 180 feet—far outpacing the *Penrod*'s relatively puny draft of just 60 feet—the *El Dorado* would have a displacement mass of 230,720 tons, equal to that of two US *Nimitz*-class nuclear-powered aircraft carriers (Chabot and Petty 1988, 542; Britton 1992, 85).

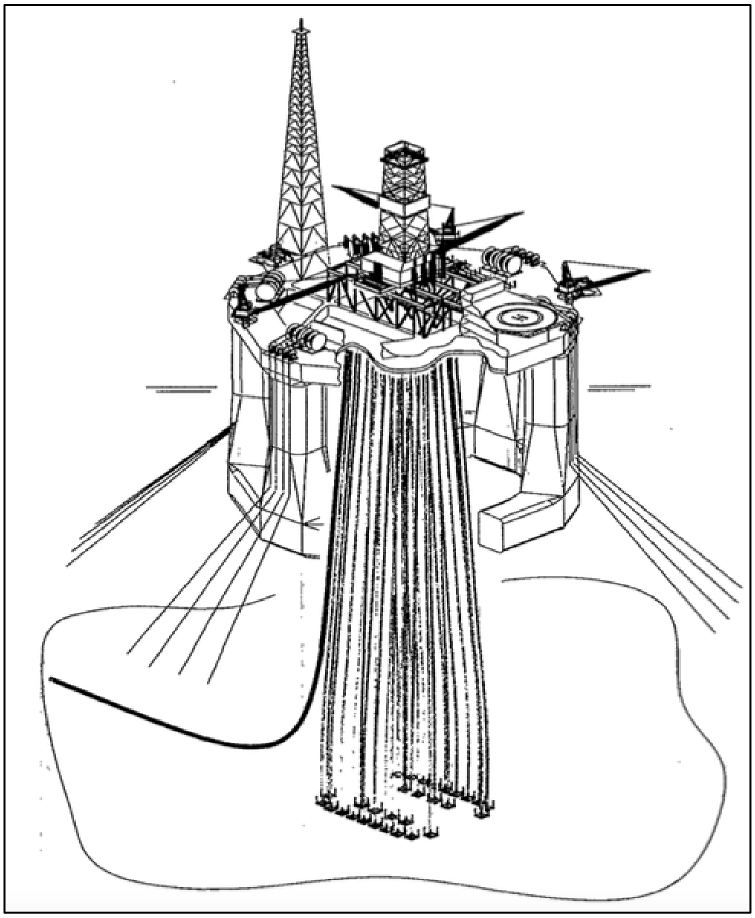

Figure 1.12. ODECO's design for its proposed Ocean El Dorado dry-tree semi-submersible oil and gas production platform, 1987

The El Dorado was marketed deep as a "purpose-built, catenary-moored semi-submersible vessel capable of simultaneous drilling and production in water depths ranging from 1,000 feet to 8,000 feet." Source: Petty 1987, 150; Chabot and Petty 1988, 537.

ODECO explained that it was the superior "hydrodynamic performance" of the *Ocean El Dorado*'s hull that would allow it to remain so stable, in effect able to "remain transparent" to wave forces (Chabot and Petty 1988, 537). This was the expected result of adding more columns to a semi-submersible, but increased columnar count was only a small source of the design's improved floating performance (Lim and Ronalds 2000, 2). Through its sheer size and symmetric design, the vessel would always "heel" on at least two columns no matter the direction in which it was battered by wind and waves, keeping the rig's attitude and pitch more stable than on a traditional four-column semi-submersible (Petty and Chabot 1988, 538). ODECO estimated that the *El Dorado* could function in water depths out to 8,000 feet, even while supporting as many as 64 marine risers (Howard 1988, 14; LeBlanc and Cornitius 1987). With a deck dimension of 336 by 353 feet, the size of the *Ocean El Dorado*'s deck would be just shy of the size of the Cognac platform's base (Britton 1992, 81).

ODECO lobbied hard for an oil company to place an order for the *Ocean El Dorado*, making several major presentations at the annual Offshore Technology Conference in Houston in both 1987 and 1988. Executives at the firm were so enamored of the *El Dorado* design and the dry-tree semi-submersible concept at large that they commissioned the making of a "handsome" and detailed scale model of the vessel rendered in black and grey plastic. ODECO proudly displayed the model prominently in the lobby of its office in One Shell Tower in downtown New Orleans (ibid.). Popular Science magazine ran a story on the *El Dorado* in 1992, its journalist trying his best to convey the sheer size of the titan:

> *Ocean El Dorado* . . . is a new breed of monster rig, designed for monster duty. A daring hybrid marriage of a steel semi[-]submersible and concrete tower, *Ocean El Dorado* could change the concept of both deep-water rigs and deep-water rig building in the [G]ulf [of Mexico]. It is truly massive. (Britton 1992, 85)

Like the mythical lost City of Gold dreamt about by sixteenth-century Spanish conquistadores—the rig's namesake—*Ocean El Dorado* never materialized. ODECO abandoned its efforts to see the concept into reality soon after Popular Science's portfolio was published, most likely due to the company's 1992 acquisition by the Diamond M. Drilling Company. While other firms would periodically propose dry-tree semi-submersible designs, none readily gained any traction (Offshore 1989a). Popular Science did not foresee ODECO's merger with Diamond, of course, but the article did make one prediction that flew straight and true. In its final lines, the article noted that *Ocean El Dorado* remained but a "hypothetical monster, dependent on the whims of the marketplace and, perhaps, the success of Auger's TLP" (Britton 1992, 96).

2.4. It Came From the North Sea

What Popular Science intimated was true: a hypothetical *Ocean El Dorado* would have to compete not only with other semi-submersible FPUs and with FPSOs for contracts, but with the sole platform type proven to date as capable of taking surface well completions out into deepwater: the tension-leg platform. With a technical pedigree of its own long enough to rival the guyed and buoyant towers, the tension-leg platform traced its ancestry back to the "seadromes" of the 1920s, an early proposition made by the US Navy to install platforms connected to the seafloor and stable enough to allow airplanes to refuel on them while winging their way over the seas. Serious study of the tension-leg principle for offshore petroleum began in the 1960s, much of it within Deep Oil Technology,[4] and investigations into the TLP's viability accelerated with the oil price jumps of the 1970s. It would soon find a champion and financial sponsor in Conoco, emerging on the scene in the North Sea at the Hutton field in 1984, and wading into deepwater in 1989 at the Jolliet field in the Gulf .

To many, the core concept behind the TLP seemed clear, even obvious, for decades in advance of its appearance in the North Sea (Mercier 1983, 198). Often described as an "evolutionary" form of the semi-submersible, it is true that the TLP is visually similar to its older cousin—at least when viewed from above the waterline. Like a floating cork pushed slightly down on the water's surface, and then tied to the bottom, the TLP returns to its central position naturally. Lateral movements also exert a downward force on the vessel, which only strengthens the restoring force of its buoyant hull to bring it back to center. Almost a veritable skunk works of innovation during this period, the California firm Deep Oil

[4] Deep Oil Technology and its project partners were not the only group working on the tension-leg concept for offshore production. Exxon, Shell, and Gulf Oil all pursued TLP designs of their own during the early 1980s (Offshore 1980). Gulf Oil's design stood out, as it called for the tendons to serve double-duty as both tensioning lines and production risers (see National Research Council 1979, 33). One author writing for British Petroleum in 1982 claimed that a "British designed version of the tension-leg concept, the first," was tested off the Lancashire coast in the early 1960s (Pennock 1982, 87).

Technology played a starring role early on in guiding and leading the development of this concept. In 1968, DOT emerged with the first version of a TLP, a three-columned hull that would remain on station through the use of "tensioned anchor cables affixed to mammoth dead-weight anchors" (Walker 1968, 2). The design promised "stability comparable to that of a fixed platform," and the ability to permit drilling from the rig at "any location" offshore (ibid.). Engineers at Deep Oil Technology long believed that the TLP would have no effective water depth limit at all. Although this would prove untrue for various technical and economic reasons—well, for now, that is—even years into the 1980s, many involved with the tension-leg concept held that it could easy be extended for production in 10,000 feet of water by the year 2000, if given just a little bit of extra engineering work (Curtis and Wolfe 1982, 2529; Cornitius 1983).

Just as Shell had done at South Pass Block 62 and Exxon at Grand Isle 86, the first step that DOT took after launching its joint industry project in 1973 was to acquire test data on a scaled-down pilot test model of its design. In late 1974, DOT launched a 1/3 scale hull of a TLP design west of Catalina island off California. Named the *X-1*, the rig remained at sea for three months, generating data. Later tests run by DOT added suspended risers to the model design, adding extra realism to their data on the vessel's stability parameters (US Department of the Interior 1979, 16). The results were heartening. Deep Oil Technology and the many industry partners collaborating with them on the joint research venture realized that if anything, their design was actually *over*-engineered for their goal of keeping the dry well conductors within a small range of movement to protect them from fatigue (Birrell 1991, 320). The DOT studies confirmed the TLP's basic capability to hold up surface wellheads and trees, as well as its viability for re-use across multiple fields (Stokes, Koon, and Thompson 1996, 2).

The first member of the joint industry project to bite on the TLP concept was Conoco. The company had been a key partner in the *X-1* test and the project overall, and were bullish on the concept. Most other participants showed little interest in the study data, but Conoco remained involved especially at the behest of two of its employees, Lawrence "Buck" Curtis and N.D. "Scotty" Birrell (Offshore Energy Center 2005). In 1973, Conoco made a discovery in the North Sea that they later believed would serve as a good candidate for testing the new concept: Hutton. In shallow waters of 485 feet, Hutton was of an appreciable but still marginal size at 250 mmboe, nearly all of which was crude oil (Pratt, Priest, and Castaneda 1997, 274). As with Argyll and SEDCO-Hamilton, Hutton was too small for a fixed platform to be economical. Preliminary design work on a TLP sized for the Hutton field began in 1977 (Stokes, Koon, and Thompson 1996, 2). As Exxon had done with Lena, Conoco recognized early on that as a first-of-its-kind project, Hutton would almost certainly end up an expensive endeavor; and indeed, cost overruns ballooned to an estimated $1.8 billion in nominal figures, 40% over budget (Priest 2014, 2510; Chakrabarti, Halkyard, and Capanoglu 2005, 31; Johnston 1985, 198). But Hutton was to serve in a path-breaking role, to become "probably one of the most talked about structures in existence," as one industry author wrote in 1991 (Birrell 1991, 320).

Drawing from the results of the Deep Oil Technology study and its own internal work, Conoco's Production Engineering Services group (PES) produced a version of the facility tailored to Hutton's characteristics. Led by Buck Curtis, often credited as the "father of the TLP," PES designed a TLP with a rectangular deck space of 243 by 256 feet, and supported by six columns—a departure both from the standard semi-submersible drilling rig configuration and the earliest TLP models (see Figure 1.13.). Sixteen thick-walled tendons would hold the hull in place, attached at the four corners of the substructure, and Hutton was equipped to support 32 wells via 9 marine risers—meaning, in other words, that it would be using wet-tree subsea wells, not dry completions (Birrell 1991, 320; US Department of the Interior 1980, 19). Hutton began to take shape at a Scottish shipyard, and after the hull was mated with the deck in shallow water, it was sent to sea in July 1984. The successful development of such a new facility type in a short period was a matter of intense interest and admiration in the offshore world. For those souls who worked on Hutton day in and day out, the stability of the TLP platform was the main buzz about Hutton: it proved stable enough for the roughnecks to play billiards. The crew hoisted a pool table on board, and found to their surprise that while it would move around a bit in the heavy weather, 99% of the time "you can shoot a good game of pool" (Freundlich 1988, 54).

Figure 1.13. Lawrence "Buck" Curtis of Conoco is pictured with unidentified vessel, likely the Hutton TLP, in the background, circa 1983

The Offshore Technology Conference honored Curtis in 1984 with its Distinguished Achievement Award for Individuals for his work on the TLP and on seafloor oil tanks built off Dubai in 1969. Hutton won the OTC award for corporate achievement in 1985. Source: Provided by L.B. Curtis.

As a result of the tension-leg design, the usefulness of a TLP facility is governed by four main physical characteristics: its sensitivity to the weight of its payload; the stability of the entire structure when towed-out to location; the magnitude or depth of its draft; and the hydrodynamics of the tensioned tendon legs (Mercier 1983, 301). Indeed, the tension-leg platform looks and functions similarly to the semi-submersible, so much so that early versions of the TLP design followed the same hull design standards as the semi-submersible (National Research Council 1979, 216). Both also shared the attraction of being easily removed and taken to another location to produce anew (Boué 2006, 119). The primary benefit of the TLP is to support both billiards tables and surface completions alike, of course, and it came with additional upsides. Unlike the conventional fixed platform, the Spar platform concept, and the compliant towers, the TLP's hull could be joined or "mated" to its topsides deck quayside—not out at sea. Not only was this convenient, it eliminated the need for an expensive and risky task, lifting an extremely heavy deepwater platform deck onto its jacket. Although failure in this work was a remote possibility, it did bedevil Texaco in 1998 when the firm was attempting to mate the Petronius compliant tower jacket with one of its two deck modules in 1,800 feet of water. A cable on a piece of J. Ray McDermott lifting equipment snapped, sending the 3,600-ton and $70-million portion of the topsides crashing into the sea and down to the bottom (Biers 2000). It was deemed unsalvageable and a total loss. Texaco had to start building the same unit anew.

Conoco alighted upon another key benefit of the TLP while it was developing Hutton, although it's unclear whether they anticipated or simply stumbled on to it. Conoco had planned to produce Hutton in the same manner as it would a conventional platform, by installing the facility first and only then begin to drill its development wells. The delivery of the platform's hull was delayed due to the complexity of its fabrication process (Stokes, Koon, and Thompson 1996, 3), and so Conoco made hay of the situation. Instead of allowing that two-year period of delay to lie fallow, Conoco hired a semi-submersible drilling rig to pre-drill or "batch set" the first 10 development wells through the seafloor template at the Hutton site (Curtis and Wolfe 1982, 2525). As a result, once the completed facility was floated over and secured to the site, Conoco was able to start up production just 22 days after installation (Burleson 1999, 82; Birrell 1991, 320). Little noted at the time, this was a significant boost to the overall value of the Hutton development; analyses show that one of the most significant parameters affecting project value is the time to first oil (Fee and O'Day 2006, 89). Very limited "pre-drilling" had occurred in the shallow waters in the Gulf of Mexico prior to Hutton, but Conoco's TLP was by far the largest instance of the practice to date (Curtis and Wolfe 1982, 2525).

Hutton was a technical success, and many of the precedents it set were applied to later versions of the concept. Even though the seafloor below Hutton's hull was well within the range of commercial divers, the use of ROVs advanced significantly at the project, where they were especially useful in landing the bottom of the tendon legs and securing them (Simpson 1984, 156). Still, it had yet to fully live up to its potential. Conoco had opted for subsea wells in order to limit the weight on the vessel (Curtis and Mercier 1985, 2), but also to focus the firm's innovative attention on the tendon legs. In a retrospective on the history of the TLP, R. D'Souza and Rajiv Aggarwhat (2013) periodize this stage of the tension-leg concept's development as the idea's "Pioneering" phase. The most critical activity during this period, they explain, was the study and real-world testing of the tendon lines themselves and the tensioning systems (ibid.). Hutton met this test with flags flying; one of the hull's 16 steel tubular tendons was removed in 1986 for inspection, and it was found to be in excellent shape (Stokes, Koon, and Thompson 1996, 4).

Experience after Hutton would lay bare the TLP's limitations (Mercier 1983, 301). Conoco and others found that deeper water depths require either stiffer tendons, the use of many more tendons, and/or a very large increase in the hull's displacement (D'Souza and Aggarwhat 2013, 2). In ultra-deepwater, the seawater's hydrostatic pressure on the tendon lines themselves becomes an issue (Muehlner and McBee 2013). Experience in the 2000s would show that the TLP has an upper depth range of perhaps around 6,000 feet. E&P magazine estimated in 2013 that though a TLP set in 5,000 feet of water needs 23,000 short tons of tendon steel, a TLP with the same payload set in 7,000 feet requires 37,000 short tons of tendon steel—a materials increase of 60% for a 40% water depth increase (ibid.). The use of synthetic materials and other technical fixes are likely to extend the TLP's water depth range in future years, however.

As with any good prototype, many parts of Hutton's precedent would not be adopted in the next iteration; later TLPs would have four columns instead of six, and most would return the drilling package to the center of the platform, in lieu of its off-center placement at Hutton (Mercier 1983, 299). But Hutton more than fulfilled its path-breaking role with distinction. In the oil industry, there is a tradition of handing out small Lucite paper-weight keepsakes that hold a drop of oil or liquefied natural gas droplets taken from the first barrel produced from a project. The oil drop memento handed out by Conoco and its partners from Hutton is clear about the project's esteemed role in the history of offshore oil and gas: it reads, "First Oil from a World First: [the] Hutton Tension Leg Platform."

Five years would pass until the world's second TLP would be installed. At Conoco's Jolliet platform in the Gulf , a tension-leg facility would go in water depths more than three times that of Hutton's. After Jolliet, nine TLPs would be installed over the 1990s, all in depths greater than 1,000 feet, and all but two of them in the deepwater Gulf. The decade of the 2000s saw similar figures: 13 TLPs installed in total, with the design expanding into Indonesia, Equatorial Guinea and Angola, but still 8 of those 13 were commissioned for the deepwater Gulf. D'Souza and Aggarwhat's description of this period as “pioneering” is a smart one. Come 1985, the TLP’s ability to remain stable enough in high seas to nick an 8-ball into the corner pocket for the win notwithstanding, it was not clear that it would be any more successful in deepwater than its rival facility types. The heavy weight of the top-tensioned risers for surface completions that would populate TLPs made buoyancy a scarce resource the deeper the platform went (Bell, Chin, and Hanrahan 2005, 9). The arrival of the production Spar in the mid-1990s offered a way to take surface completions even deeper, in part because of its less costly mooring systems. But the Spar also suffers from weight constraints, and from technical problems at the interface between the platform and the risers. The production benefits of dry-tree surface completions also came with very high capital costs (Lim 2009, 2). The semi-submersible FPU, in contrast, with a lighter hull than either a TLP or a Spar, came with the ability to support a large number of both top-tensioned and steel catenary risers attached to subsea wells, even in ultra-deepwater (Ronalds 2002, 5). It appeared that none of this slew of innovative development concepts was destined to be more universally technically superior than any other in all cases. It is “doubtful,” the editors of Offshore magazine surmised in 1984, that “any one system will dominate” in the deepwater Gulf (Offshore 1984).

3. Monkey-Ropes for Miles: The First Floating Platforms in Deepwater

The industry in the deepwater Gulf of Mexico (Gulf) entered the mid-1980s with an abiding sense of dread and uncertainty, but one tinged with a hint of hope. Industry trade articles published during this period on deepwater's prospects have an almost contradictory quality to them; they announce the imminent demise of the business on one page only to predict an oncoming boom on the next. And perhaps rightly so. Several major contradictions characterize this period. The sub-par performance of Lena's wells seemed to be a major knock against the quality of deepwater fields; but then a new round of deepwater discoveries that started in 1985 seemed to portend an uptick in the basin's fortunes. The crash in crude oil prices sent shivers through the upstream oil and gas industry at large, but drilling rates in the deepwater Gulf appeared to buck the trend. From Cognac's discovery in 1975 to the drilling of Bullwinkle in 1983, the number of deepwater exploration wells sunk on an annual basis remained steady at just under 20 per year (US Department of the Interior 2014). Once calendar year 1984 drew to a close, that figure had jumped threefold to 66 new exploration wells spudded in deepwater (US Department of the Interior 2014).

And yet, sometimes drilling goeth before the fall. Once the full brunt of the price meltdown hit in 1986, the worldwide utilization rate for offshore drilling rigs of all types fell to a historical low of 56%. The drilling editor of the Oil & Gas Journal summed up the awful situation nicely, writing plainly, "Largest rig fleet in history; Largest number of rigs without a contract" (Moore 1986). Even the deepwater rig utilization rate, usually more immune to shifts in the business cycle due to the limited number and advanced capabilities of deepwater drills, fell to a low of 70% (ibid.). By 1986, Offshore acknowledged that the flextrend had "lost some of its bloom" in light of the disappointments at Lena, as well as due to the continued lack of uncovering very large and concentrated reserves past the continental shelf break and down the continental slope (LeBlanc 1986). Offshore operators began reviewing the productivity of their investments on a global basis, and all water depth bands in the Gulf were increasingly coming up short (LeBlanc 1994). A rash of divestments swept deepwater, as firms scrambled to "farm out" their interests in lease portfolios that they now expected would go undrilled. Many who had strong incentives to believe otherwise remained convinced that no commercial deposits of oil and gas were to be found more than about 60 miles away from shore (National Commission on the BP *Deepwater Horizon* Oil Spill and Offshore Drilling 2011, 20–21). If such accumulations did exist, they were likely to be small, explorationists reasoned—with reserves well under 100 mmboe (Oil & Gas Journal 1992b).

Exploratory drilling in the deepwater Gulf dipped a bit from the record high it enjoyed in 1984, but there was at least one cause for celebration offshore. Under the leadership of President Ronald Reagan's Secretary of the Interior James Watt, the department began offering up offshore tracts on an "area-wide" basis, flooding the leasing market with an almost all-you-can-bid buffet of access. The first area-wide lease sales in 1983 and 1984 showed very high interest in the deeper or seaward regions of the flextrend, and a growing number of independent operators joined the chorus of bidders (Redden 1984). The reform would prove to be a major stimulus for offshore exploration, reducing the up-front costs of gaining access to deepwater prospects. In this new bidding environment, for example, Shell was able to acquire the leases over its Bullwinkle prospect for just $49.8 million, or nearly $250 million less than it had paid to lease the tracts over Cognac (see the companion volume in this study, [Hewett 2005]) .

To some entrepreneurs, the slump in overall drilling activity offered the perfect solution to the knotty problem of high capital costs in deepwater. With so many moderate-depth semi-submersible drilling rigs slung up along the Gulf Coast without a drilling contract, they were gems ripe for acquisition on the cheap. In February 1986, in the depths of the crisis, Offshore engineering editor Leonard LeBlanc lamented what anyone in Houston not laid off was likely thinking: "At some future point in history," LeBlanc (1984) wrote, "operators will deeply regret their present inability to take advantage of two circumstances that will probably never recur simultaneously in the Gulf of Mexico: a) Drilling costs (in real terms) are the lowest in history; b) Most of 2,600 choice Gulf tracts have not been drilled. Offshore firms now had a much larger technological toolbox to work from, but what was really lacking was a coherent strategy for producing in deepwater." What emerged married the availability of cheap semi-submersible drilling rigs with the ever-present promise of subsea production technology; and they called it Phased Development.

3.1. EWT, EPS, SDS, or PPS?

Disappointing production outcomes from the deepwater Gulf's early developments forced operators who were heavily invested in the basin to re-examine the way they measured the value of their assets. Although the handful of deepwater fields discovered to date were larger than those found on the continental shelf, they were not living up to their promise of yielding a higher return on investment. Two major resource assessments conducted on reserves data through 1989 indicated that the resource potential of the deepwater Gulf was limited, with only a handful of large fields left to be found (Godec, Kuuskraa, and Kuck 2002).

For a given deepwater field, the size of its recoverable reserves is far and away the largest factor affecting its net present value. The second most determining variable is the crude oil (or natural gas) price, followed by operating uptime. In other words, while better-than-expected positive reserve figures and flow rates can increase a project's value by perhaps 20% over early estimates, poor flow can crater that same value by as much as 75% (Vardeman et al. 2005, 10). In order to avoid such a situation—the very one that Placid Oil ran into at Green Canyon 29—operators in the Gulf had typically drilled a series of post-discovery appraisal or "delineation" wells to gauge the extent of a reservoir and its quality soon after a new find was made. Only with full appraisal results in hand would a company make its final investment decision either way (LeBlanc 1992).

The doldrums in deepwater's outlook after 1986 gave pause to some, to re-think the wisdom behind this approach. The appraisal approach to drilling struck Phil Wilbourn, manager of Central Offshore Engineering for Texaco, as an overly "regimented process" and a relic of the Gulf's long history of offshore oil and gas production in shallow water (LeBlanc 1992). Wilbourn explained: "If you give an exploration group in the North Sea $60 million to prove a discovery,"

> [T]hey will drill one well and test that well for a period of up to six months. At the end of six months, they are confident in the performance of the reservoir.
>
> If you give $60 million to an exploration group in the US Gulf of Mexico, they will drill ten delineation wells. Those ten wells will result in the same degree of confidence.
>
> That strategy of drilling ten delineation wells in the Gulf of Mexico has not been successful . . . . The failures to date are geological, not technical. (Offshore 1992)

The North Sea strategy of "testing" a single well that Wilbourn referred to was known as EWT, or Extended Well Testing. Generally speaking, two methods exist to directly measure the physical flow attributes of an offshore oil and gas well. One is to perform a drill-stem test (DST), a common procedure in use since the 1920s (Vella et al. 1992, 15). The drill-stem test allows a rig to acquire limited but very valuable data about the pore pressure at the target rock formation, what types of fluids and hydrocarbons are present, and other parameters of flow (ibid.). As the name suggests, a drill-stem test is conducted with the drilling string itself, and rarely lasts more than a few days (von Flatern 2012).

The second method is simply to lengthen the period of testing, seeking to simulate as close as possible the real-world conditions of production. An extended well test involves completing the well for production in a normal manner (i.e., casing and then perforating the well) and allowing it to produce at length under real-world conditions. As a result, it is a more direct measure of that which is most important for a deepwater well: how it will behave in a production environment. EWT could thus inform on a whole number of technical questions regarding production engineering: completion types, the number and placement of wells, and decisions on what type of facility to use (LeBlanc 1992). While EWT well(s) do not typically produce for the entire testing period, equally valuable data is acquired when flow is restricted and the reservoir re-pressurizes (US Department of the Interior 2000, 61).

> One executive detailed in 1992 precisely how Extended Well Testing could inform an operator's investment decisions. Rob Haigh of Adams Pearson Associates recounted his company's experience with one particularly frustrating well: We worked with an operating company on a wildcat well that had oil shows during drilling, so the operator went in with openhole testing tools...[and] the pipe partially filled with oil. There was some excitement. They cased the well, did cased-hole DSTs (drillstem tests), and tested the zone for about two hours. The pipe filled with oil and stopped flowing. After some analysis they concluded this was an under[-]pressured reservoir with a gas/oil ratio (GOR) so low that the well wouldn't flow to surface. (Freyss et al. 1992, 47)
>
> After deciding to test the well further after applying electric submersible well pumps to provide vertical lift for the oil, Adams Pearson Associates reassessed the situation. Based on results of this test, [the well was proven to be] capable of 50,000 barrels per day from a very short completion internal. The PVT (pressure, volume and temperature) properties are such that the well wouldn't flow to surface [without the presence of a well pump]. (Freyss et al. 1992, 47.)

Under the right circumstances, the revenue generated from an extended test could pay for the costs of performing the activity in the first place (Fee and O'Day 2006, 89). This benefit pales in comparison to the value of avoiding making a disastrous investment, or as with the above example, making good on an excellent field that would otherwise be abandoned.

Extended Well Testing, as Phil Wilbourn suggested, was already popular with North Sea companies, likely because the basin developed rapidly and without the "regimented" culture of the Gulf oil patch. Japan's Nippon Kōkan Kk corporation launched the world's first dedicated EWT vessel in September 1986, and the *Petrojarl I* found extensive use in the North Sea at some of its largest fields, like Troll and Oseberg (Wilson and Strader 1989, 2; Behrenbruch 1995). The vessel would attach to a completed well or series of wells, and receive production for several months. Why did no such vessel ever find use in the deepwater Gulf ? One culprit was the unique political economy that governed offshore oil and gas extraction on the Outer Continental Shelf. Rules in place since the 1950s and reaffirmed in 1978 limit the volume of natural gas allowed to be flared or vented. An extended well test for many deepwater fields would require onboard liquefaction or compression of natural gas—technology then still in its infancy for the offshore. Texaco's Phil Wilbourn pointed to these restrictions as an unwarranted hold on EWT in the Gulf, noting that officials in the Interior Department needed to "realize that flaring is a temporary transition step for deepwater" (Offshore 1992). Other commercial reasons limited the demand for EWT services in the Gulf. The low flow rates from flextrend wells completed in the 1980s would return too little revenue to cover the costs of conducting an extended well test in deepwater, and Gulf operators continued to believe that the data would be of only limited use to them in understanding the prospectivity of a deepwater field (Cribbs, Voss, and DeCarlo 1993, 28; Verrett 1994, 13). Even by 1993, the worldwide drilling vessel count for exploration in depths beyond 3,000 feet was but 20—and only 4 of those were in the Gulf (Wheeler, Wallace, and Wilbourn 1993, 17). There had to be another way.

The answer was a close cousin of Extended Well Testing, although it came with a wider set of varying acronyms. The strategy of Early Production, also known as Staged Development, Phased Production or Phased Development, has as its core principle the limiting of capital exposure risk by the division of major offshore projects into smaller, discrete phases.[5] Because deepwater reservoirs were still poorly understood in the 1980s and early 1990s, Phased Development aimed at establishing production from a handful of wells on a field as quickly as possible through temporary facilities (but more permanent than a ship like the *Petrojarl I*). Doing so would provide information allowing an operator to tailor its second-phase or more permanent platform to the field's characteristics, to substantial savings (Weaver 1990, 112). With the rapid establishment of "Early Production" as the first phase, the remainder of a field's exploitation could be systematically executed and optimized in a manner similar to following a go/no-go decision tree used in economic analysis (Mastrangelo et al. 2003, 2).

The first two North Sea fields developed stand as prime examples of the value of this strategic approach. Phillips' Ekofisk field is better likened to Early Production. An extremely large and significant field, the discovery of Ekofisk ushered in the oil era in the North Sea (Fee and O'Dea 2006, 87; Burton, Wheeler, and Ruthrauff 1993, 35). Fully expecting to produce the field over a period of decades, Phillips dispatched a jack-up rig in 1971 to produce from four subsea wells until 1974, when fixed platform facilities were permanently installed (Hansen and Rickey 1994, 3; Busby Associates 1985). By turning on the taps at Ekofisk just 18 months after its discovery, Phillips gained key "reservoir performance information" on the field, boosted its overall rate of return on investment, and cashed the proceeds of a full 28 million barrels of oil produced to help fund the ongoing fabrication of the permanent platform (ibid.).

SEDCO-Hamilton's Argyll may be better likened to the idea of Phased Development (Curtis and Wolfe 1982, 2525). With limited data and a high measure of risk regarding the field's geology, Argyll's development managers decided to bring the field online through just a few wells, limiting development drilling costs. Argyll ended up surprising SEDCO-Hamilton, however, as its wells flowed better than expected. By the end of the decade, it had produced more than 30 million barrels of oil (ibid.). After an additional five years of production on site, the original *Transworld 58* rig was removed from the field, but its subsea wells were not decommissioned. Instead, a larger semi-submersible FPU (*Deepsea Pioneer*) replaced the older vessel, allowing Argyll to continue producing beyond its originally estimated lifespan, while also allowing water injection to be used on the nearby Duncan field, which shared Argyll's export line (Lim and Ronalds 2000, 7). *Transworld 58* and its riser system were moved to produce the nearby Innes field (Curtis and Mercier 1985, D-2). Although the longevity of the Argyll field's production stream was an unexpected surprise to SEDCO-Hamilton, the eventual removal of *Transworld* for the express

[5] The Minerals Management Service [now BOEM] and the industry DeepStar consortium have jointly defined the difference between Extended Well Testing and Early Production as follows:

"*Extended well testing* is an engineering tool that would likely be conducted from the floating drilling unit to evaluate the reservoir's productivity (flow characteristics, etc., and would likely involve a single well. Such a test also provides an opportunity to obtain information that would be used to design the production facilities. A typical extended well test might last for two weeks to two months, of which the well would flow hydrocarbons only a few days. The well would be shut in for the remainder of the test to measure the reservoir's response to production.

Early production is the first phase of continuous production, conducted at a small scale (1–3 wells) and designed to demonstrate long-term reservoir productivity. Information from early production would be used for decisions about sizing the full development system facilities. The early production phase could also be used to generate revenues while the full-phase production equipment is readied for installation. Early production could last from two months to two years" (US Department of the Interior 2000, 94).

purpose of producing a nearby field was not. Indeed, using floating production on an ad-hoc and mobile basis was a large part of its allure: to use a vessel to produce multiple fields over its lifespan and spread out capital costs among multiple assets (Curtis and Wolfe 1982, 2525). Though SEDCO-Hamilton may not have expected to reasonably sanction a Phase II at Argyll, the flexibility that a smaller facility offered made it reasonably immune to the field's geological uncertainty and potential downsides. The result would have been equally salubrious had SEDCO-Hamilton, hoping for high flow rates from Argyll but preparing for a poor result, opted to produce its first phase with optional later expansions; but finding flow slumbering, had not been forced to commit a large amount of precious capital just to have the option of cashing in on the upside.

Floating production and Phased Development were pioneered in the shallows, but both seemed exceptionally well suited for use in deepwater. The risk of falling into a debacle like Green Canyon 29 with its massive losses was cause enough. There was only limited production experience from nearby deepwater fields available to give producers a sense of what they might encounter. Proponents of phased development for the deepwater Gulf said that Phase I in such a project, built around a semi-submersible FPU, would expose only 15% to 30% of the capital needed for a full-field development (Cribbs, Voss, and DeCarlo 1993, 29; Wheeler, Wallace, and Wilbourn 1993, 12). Those were compelling figures for a cash-constrained environment and one in which risk was high, the tolerance for taking such risks were low, and the geology divisions inside even the oil majors were information-starved regarding what deepwater horizons held.

Phased approaches proved especially popular in one particular area: offshore Brazil. Its national oil company, Petróleo Brasileiro S.A., or Petrobras, first opened up its offshore sector in 1968, when it began to explore in earnest in the Espirito Santos and Sergipe-Alagoas basins (Priest 2016, 8). Originally formed as a refining company (Randall 2013, 17), the focus of Petrobras shifted sharply with the new oil politics of the 1970s and Brazil's rising reliance on foreign oil imports. Under new leadership in 1974, the company looked increasingly to its offshore fields for reserves growth, and several commercial discoveries soon followed. The political raison d'être for Petrobras was simple: to boost oil production as much and as quickly as possible. Only adding to this charge were the fiscal policies pursued by the national government in the 1970s in the wake of the oil crisis; while the country's GNP remained relatively strong and steady during that period, the government went heavily into borrowed debt, and looked to oil revenues for relief (Randall 2013, 17–18; Dantas and Bell 2009, 831). The rush to drill quickly escalated into an "almost frantic effort" to strike black gold (Moore 1980). Bringing production online as quickly as possible, and at the lowest cost possible, was the aim (Assayag et al. 1997, 1), and onshore Brazil offered only poor hydrocarbon potential.

To develop its offshore reserves, Petrobras turned to the "unorthodox" strategy after 1974 of using phased developments for production (Priest 2016, 11). Following the conventional method of fabricating and installing fixed platforms and laying a vast infrastructure of subsea pipelines was quickly ruled out as an option: not only would those processes take too much time, all while Petrobras was under political pressure to produce, the firm did not yet have the capital resources capable of making those investments. Plus, the first discoveries made offshore were small fields at that—they were modest compared to global field discovery sizes (ibid., 11–12). Instead, Petrobras turned to phased development, seeking to capitalize on the benefits of floating production from subsea wells. By 1977, just two years after *Transworld 58* started production at Argyll in the North Sea, Petrobras began flowing 10,000 barrels of oil per day from a single-well development at its Enchova field in 360 feet of water with the converted *Sedco-135D* rig (Priest 2016, 12). That was but Phase I of a planned three phases for the Enchova area; the first two of which were considered Early Production, yielding revenue as well as significant amounts of reservoir data (Fee and O'Day 2006, 91). The first phase of the Garoupa field started up in 1979 from four wells, each encapsulated inside a one-atmosphere "shirtsleeves" subsea wellhead cellar (Mastrangelo et al. 2003, 2).

Between the start of Enchova in 1977 and 1985, Petrobras installed 15 semi-submersible FPUs and a number of FPSOs off Brazil (Mastrangelo et al. 2003, 8). To advance its capabilities, Petrobras began to seek out collaborations with foreign firms, recognizing that they possessed the bulk of the technology Petrobras needed—and that Petrobras needed to begin innovating on its own (Dantas and Bell 2009, 831). Petrobras signed a technical assistance contract with none other than SEDCO-Hamilton in 1977, and partnered with others like the American firm Vetco to acquire subsea production trees (Dantas and Bell 2009, 834). Those collaborations later extended to include Cameron Offshore Engineering, one of the firms that had helped Placid Oil design its freestanding hybrid riser for Green Canyon 29 (Sertãet al. 2001, 3). In the 1980s, Petrobras allied with a Swedish engineering firm and an institute at the Federal University of Rio de Janeiro to significantly boost its design and engineering capabilities around semi-submersible FPU platform systems in particular; enough to allow Petrobras to perform the bulk of the necessary engineering tasks in-house (Sertãet al.2001, 836).

In the late 1980s Petrobras began stacking up records offshore: deepest commercial discovery, deepest production manifold, deepest wet-tree completion, deepest FPU, and more (Mastrangelo et al. 2003, 3). The basin hit a major turning point in 1984 and 1985, when Petrobras made two major deepwater discoveries in the Campos Basin at Albacora and Marlim, both massive in size (Becker 1996) and well-suited to a phased approach due to their high costs and large areal extent (Freire 1989, 2). By the mid-1990s, the firm had become a leader in deepwater subsea technology, achieving by spring 1994 the world record for offshore production at 2,562 feet of water (Hansen and Rickey 1994, 5). This was thanks to two major internal research and development programs, known as PROCAP ("Technological Innovation Program on Deepwater Exploitation Systems"), commissioned in 1986 to investigate how to best produce from depths beyond 1,000 feet (Priest 2016, 15). PROCAP proceeded with a $20 million budget for its first five years (Barusco and Vianna 1988, 1). When Petrobras kicked off the second round of PROCAP work in 1992, they reaffirmed the success of their phased strategy for offshore production from the deepwater, dedicating many tens of millions of dollars towards the study of ultra-deepwater semi-submersible FPU hull designs, as well as alternative mooring systems and materials (Oil & Gas Journal 1992b). In 1991 the company set a target to double its offshore production by 1995 to reach 1 million barrels of oil equivalent per day (Offshore 1991). Even though Albacora and Marlim were expected to together provide 400,000 bbl/d of that total, it was an exceedingly ambitious target.

Petrobras found much to praise both in the technical specifics of semi-submersible-based production, and in phased development as an overall "flexible and versatile methodology" (Armando and Filho 1987, 47). With the first few waves of semi-submersibles approaching a necessary retirement age (in the absence of a major rehabilitation), they were cheap to acquire, and easy to convert into floating production platforms. With limited cash flow, Petrobras found this process of bringing on production as quickly as possible, reducing risk by gaining early production data before sanctioning further work, and the ability to tweak or optimize more permanent facilities to past practice, as an ideal strategy (Armando and Filho 1987). As the company acknowledged with pride at a meeting of the World Petroleum Congress in 1987, some of the floating production systems they installed as "early production" became permanent facilities because the fields suited their capabilities so nicely (Armando and Filho 1987, 49). The rigs over Enchova and Garoupa, for instance, required only minor re-arrangement into an optimal configuration for their respective flows. The semi-submersible FPU was chosen when Petrobras sanctioned its flagship deepwater developments at Marlim and Albacora, for its low investment cost and because the company still believed compliant towers and TLPs to be "experimental technologies" (Filho and Ribeiro 1988, 6). Brazilian crude was also easier to flow through subsea wells, due to its unique composition, which made it lighter than crude oil from the Gulf. This greatly diminished the importance of having surface completions off Brazil.

Although Petrobras became closely associated with the concept of Phased Development, the concept was by no means necessarily or inherently limited to subsea completions (see Figure 1.14). Influential movers in the industry, including Buck Curtis, advocated for arrangements in which multiple tension-leg facilities would be used to produce deepwater fields in a phased manner. Petrobras considered similar system arrangements, but ultimately ruled against using TLPs due to the large areal extent of Brazilian offshore fields, shallow reservoir depths (which makes draining the full extent of a reservoir difficult, as the wells drilled directly below the TLP have to deviate at an extremely high angle), and other technical reasons. Compliant towers were also ruled out due to the presence of unstable soil conditions (Freire 1989).

By producing to a single tension-leg well platform platform in an initial phase, an operator could enjoy the same risk-reducing benefits of early production to a semi-submersible, without taking on the attendant downsides that 1980s subsea completion technology posed. Phased approaches had proved so popular that by 1985, as many as 39 offshore fields worldwide had been developed via early production, 19 of those by semi-submersible and subsea wells (Fee and O'Day 2006, 86–88). As Buck Curtis and J.A. Mercier explained in 1985 before a conference of the American Petroleum Institute, if a phased approach to reducing reservoir risk was going to spread to the deepwater Gulf , it would require just such a system: one that combined floating platforms with dry-tree well completions (Curtis and Mercier 1985, D-8). It was unlikely, Curtis and Mercier said, that there would emerge one "universal" development concept, "suitable for every deepwater field" (Curtis and Mercier 1985).

3.2. Attack of the 60-Mile Flowlines

Undoing the "regimented" organizational culture of the Gulf proved hard to pull off. Phased Development concepts found little truck among deepwater operators during the 1980s, and only enjoyed a brief renaissance of support between 1991 and 1994, when crude oil prices slumped yet again. Gulf drillers began to fear that their home turf was in danger of falling irreversibly behind its competitor basins. While petitioning Congress over 1992 and 1993 for a reduction in the royalty rate for future production from deepwater fields, industry representatives warned legislators that it was Petrobras, not a US firm like Exxon or Texaco, that had the world's deepest subsea well completions. Exploratory drilling in deepwater had hit a virtual standstill (US Department of the Interior 2014; Burton, Wheeler, and Ruthrauff 1993, 35).

What the executives from Texaco stressed to lawmakers and their fellow industry leaders was that the downturn in activity was not the result of poor drilling outcomes in deepwater. Wells sunk through 1992 had instead proven up "significant reserves" in the deepwater Gulf (Burton, Wheeler, and Ruthrauff 1993, 35). The slowdown in project sanctions and investment, they said, was the result of a growing lack of "faith" in the ability to profitably produce beyond the shelf. With such a large resource base already discovered, they asked, why had development not moved aggressively forward?

> The answer would appear to lie in industry's view of the commercial viability of deepwater...[What is lacking is operator] faith in industry's ability to successfully implement innovative technology in a cost-effective manner in the hostile environment of the deepwater Gulf. (Burton, Wheeler, and Ruthraff 1993, 35)

The technology and the geology were all in place, but lacking was a faith in the ability of these organizations to deploy resources in an effective manner. *Implementation* was indeed the watchword instead of *innovation*, as the Texaco executives seemed to suggest that most if not all of the technology needed was already in existence. Texaco was not alone in this estimation; Conoco's Scotty Birrell seconded their call that the main strategic challenge facing deepwater firms was to reduce development costs through the "implementation of innovative technology" (Birrell 1994, 941) that they already possessed.

Texaco's gospel for this loss of faith in deepwater was the formation of a special sort of joint industry project, a consortium or research alliance known as DeepStar. More properly formed as D.E.E.P.S.T.A.R. at first, the group enshrined its aim in its project logo, which bore the motto, Gulf of Mexico Deepwater Staged Recovery System (see Figure 1.17.). Formed over 1992 from its germination in the Central Engineering Group in Texaco, DeepStar was to operate as an independent research and development consortium of dues-paying member companies (Burton, Wheeler, and Ruthrauff 1993, 36). Texaco provided early funding and engineering services and coordinated contracting for outside research studies (Wheeler et al. 1993). After mapping out an extensive "technology gap analysis" in 1992, DeepStar identified what innovation paths were ready for cost-effective implementation, and which were beyond the immediate scope of easy use (World Oil 2011a). DeepStar functioned as a classic strategic alliance, sharing all inventions and intellectual property (such as patents) freely among its paid members (World Oil 2011a). DeepStar played a major role in solving the potentially show-stopping problem of Shallow Water Flows in deepwater wells (Hays and Chitwood 1999, 18). It also facilitated some more mundane but important work, like bringing together asset owners to create a comprehensive and usable map of where deepwater platforms and equipment types had been deployed in the Gulf , which had not yet been done (Judice 1994). The failure rate of business alliances that focus on technology development is notoriously high, making DeepStar's success all the more significant (Winter 2007, 324).

The conceptual essence of DeepStar drew very heavily from the philosophy of Phased Development and Early Production: its goal was to reduce up-front capital expenditures on a project while simultaneously improving geological knowledge about its target reservoirs (Burton et al. 1993, 36). To achieve this, DeepStar surveyed the geography of the Gulf's deepwater fields and came to an important conclusion. Texaco's staff determined that a full 80% of all discoveries made to date were located on the landward side of the continental slope, very close to the edge of the shallow-water shelf (see Figure 1.15.). By implementing existing and near-mature subsea production technologies, DeepStar could establish production from these fields through subsea flowlines to a series of cheap conventional platforms set on the edge of the shelf in about 600 feet of water, known as Joint Processing Centers. Sixty miles was admittedly the extreme length of their target distance, but the principle was still sound when applied to shorter distances. "If one were to draw a 40–50 mile radius around each [shelf platform] facility," Texaco's Phil Wilbourn said, "it is amazing how many blocks are taken in" (Offshore 1992).

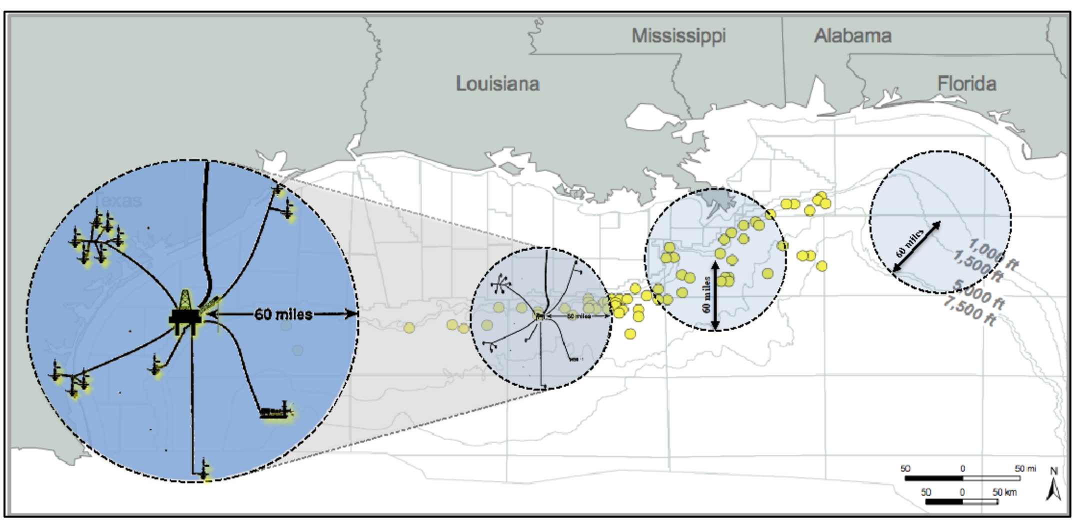

Figure 1.15. DeepStar's vision for staged recovery in the deepwater Gulf, 1993

The map details the location of all deepwater discoveries made between 1975 and 1989 (yellow dots). Superimposed along the edge of the continental shelf (left inset) is a depiction of the DeepStar system: a shallow-water fixed platform set in 600 feet of water, connected to subsea flowlines extending as much as 60 miles down the continental slope to reach deepwater reservoirs. With just 5 or 6 such processing platforms, DeepStar claimed, a 60-mile line could reach depths out to 6,000 feet and tap 80% of all fields discovered through 1993. Source: Image adapted from

US Congress 1993, 148; and US Department of the Interior 2010, 39. See also Burton, Wheeler, and Ruthrauff 1993; and Burke 1994.

The technological breakthrough most needed for DeepStar's plan to work was to achieve advancements in the effective range of those flowlines. From a subsea well completion on the continental slope, production would need to flow to a joint processing center in a "multi-phased" form: it would flow just as it came out of the ground, as a mixture of crude oil, water, and natural gas (whether "free" or dissolved in the liquids). When Texaco and then DeepStar first looked to multi-phase flow, the maximum distance possible fell between 12 and 15 miles for a crude oil stream (Offshore 1992). This was with the addition of minimum subsea seafloor pumping. And, of course, operators had gravity on their side as well, but its benefits mainly showed up in dry (dehydrated) natural gas fields, which could easily flow through lines longer than 15 miles. For oil reservoirs, DeepStar planned to use the proven method of injecting natural gas inside the production well, which lightens the mass of the crude oil stream and helps to lift it (Chitwood et al. 1993, 4). To achieve a 60-mile radius for both types of production would admittedly require the innovation of a veritable "host of technologies" not yet in place, DeepStar acknowledged, but they were understood to be but incremental advances. Innovation would focus on multi-phase subsea pumping equipment, or on subsea separation combined with single-phase pumping (ibid.). DeepStar and its members entered 1993 confident that they could achieve their goal of establishing an economic production strategy for deepwater to be fully in place by 1996 (Wheeler et al. 1993).

Reflecting its methodological similarity to Phased Development, DeepStar's vision also leaned heavily upon the widespread use of semi-submersible drilling and production rigs. Naturally, a drilling rig would be needed to drill and complete the underwater wells used to produce a given deepwater field. Other stages in the lifetime of a subsea development would also require rig presence in order to perform maintenance, downhole well recompletion, and similar work. But DeepStar's vision married its extended-reach subsea tie-back approach with an execution that would proceed in stages. Field development would come in three distinct phases (see Figure 1.16.). The discovery rig would run a drill-stem test during appraisal drilling to determine whether it should enter early production as in Phase I. With an export pipeline laid, the field would produce through between 3 and 5 wells for a short period to determine whether it merited full-field development (US Congress 1993, 140). Poor well performance at the end of Phase I would trigger project abandonment. Phase II would expand the number of wells used to produce the field for the long-term, and Phase III represented an even further expansion of the field through the use of water and/or gas injection to boost overall recovery rates. For the vast majority of the time, the subsea development would produce to the shelf platform without the presence of a semi-submersible rig on location to drill, provide gas lift or water injection, or other workover needs. The goal remained for "all production operations" to be controlled remotely from the host platform on the shelf (Wheeler, Wallace, and Wilbourn 1993, 22). Doing so would replace the nearly $20 to $30 million bill that would result from mobilizing an offshore rig to intervene in a subsea well (Velez 1997, 578).

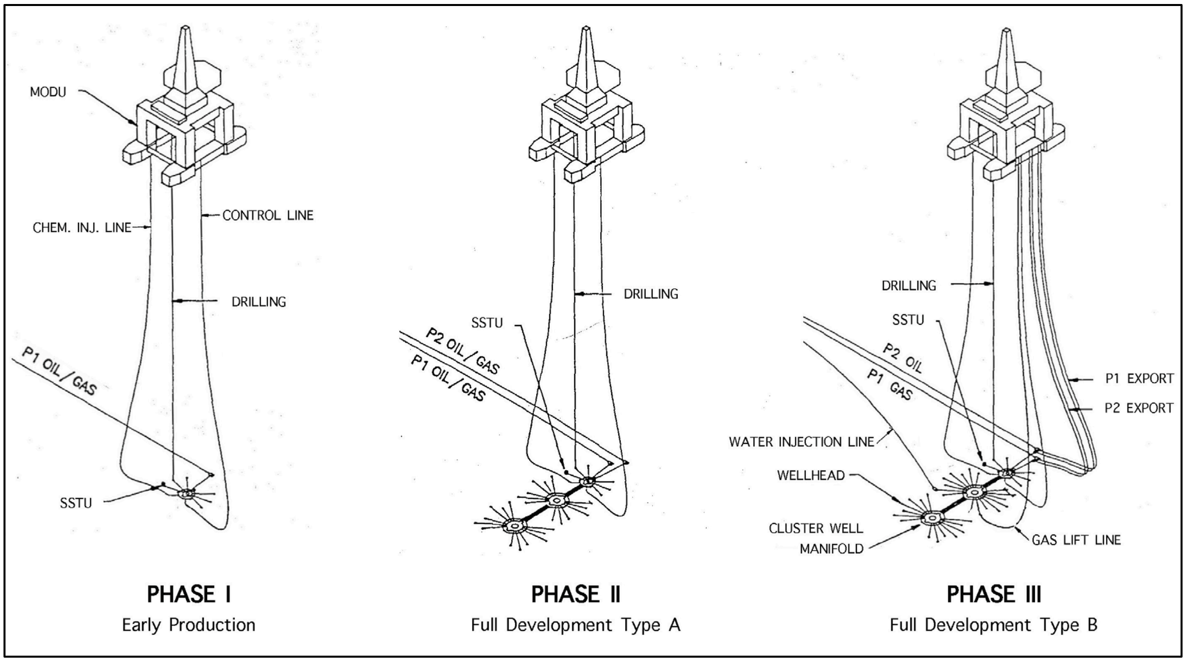

Figure 1.16. DeepStar's vision for phased development, combining its extended-reach subsea tie-back well architecture with a semi-submersible rig to provide drilling and other processing support

The use of cluster, as opposed to template well manifolds, allowed for the easier exploitation of previously-drilled and irregularly spaced appraisal wells. Up to 12 production wells might be completed for a small field, or up to 40 for a larger find (Phase III). The first phase was projected to last anywhere from 6 to 18 months, and the following phases would proceed indefinitely until reservoir exhaustion. Source: Adapted and edited from Wheeler, Wallace, and Wilbourn 1993, 22. All rights reserved.

As a result, DeepStar engaged heavily with drilling contractor companies and rig fabrication and design firms to assess the capacity of semi-submersible rigs to simultaneously drill and accommodate "limited production functions" in deepwater regions out to 6,000 feet of water (US Congress 1993, 143). Presence of a drilling rig would also likely be needed for an interim period to help boost the flowing pressure of crude oil reservoirs, in the event that multi-phase seafloor pumping did not improve as quickly as DeepStar hoped (Alexander 1993, 337). By 1993, drilling contractors Reading & Bates, Sonat, and Sedco-Forex had all joined the consortium (US Congress 1993, 144). DeepStar was interested in whether semi-submersible FPU conversions could be best targeted at a certain class or design, and in ways to reduce the cost of repeatedly mooring and un-mooring non-dynamically positioned rigs (US Congress 1993).

Despite its promising start and ample funding, DeepStar by 1997 admitted that its initial plan for a staged production system had not quite panned out. Shell concluded in 1995 that the maximum subsea tie-back length likely for several years ahead would be 60 miles for a natural gas field, but just 15 miles for an oil tie-back (Oil & Gas Journal 1995c). The technical issues involved in increasing the range of multi-phase pumping from subsea manifolds proved too difficult to quickly resolve. For instance, alongside the product export pipeline leading to a well, a control and electrical umbilical must be laid. The standard tool of direct hydraulic control only had a range out to 25 miles or so, requiring the use of far more pricey multiplexed electrohydraulic (MUX E/H) control lines for the tie-backs DeepStar envisioned (Wheeler et al. 1993; Chitwood, Rothberg, and Miller 1993, 87). That added cost often wrecked the balance sheet for a deepwater subsea project developed in the DeepStar mold. Subsea pumping technology and methods for reducing friction inside the export line also did not accelerate as quickly as the consortium had hoped. DeepStar's Paul Hays explained in 1997 that the absence of many extended-length tie-backs testified to the technical difficulty of achieving that vision:

Shell's Mensa [subsea tie-back] is the case in point...the field is essentially a dry [or de-hydrated natural] gas field. Whereas for the more general case of heavy, viscous, paraffinic crudes typically encountered in the [deepwater] Gulf [of Mexico], the near-term development solutions still appear to give primacy to surface-based completions. (Hays 1997, 24)

Even where subsea developments proved especially successful, as at Exxon's Zinc natural gas field on the western edge of Mississippi Canyon, they were rarely in the classic DeepStar design. Zinc began producing in 1993 through a large 10-well template installed in over 1,500 feet of water (see Figure 1.5.). Natural gas from Zinc only had to flow six miles to its shallow-water host, a fixed platform called Alabaster (Pearson 1992). Exxon often explained that it was only due to the "fortuitous" presence of a nearby "underwater knoll" at Alabaster that the Zinc project was able to be profitable (US Congress 1993, 14). Also driving this retrenchment from pursuing Phased Development with subsea wells and semi-submersibles in deepwater was, ironically, the growing economic outlook for the entire Gulf. The glut of idle drilling rigs that felt acute in the late 1980s and even into 1992 began to recede, as more rigs returned to service and normal attrition retired others (Cort 2001, 2). As early as 1993, it was clear that the "window of opportunity" for acquiring rigs for conversion into production platforms was "closing," as one manager from Brown & Root explained (US Congress 1993, 170). Orders for new deepwater drilling rigs were on the rise by 1994, and with them the economic advantage of converting older vessels dried up, as day rates rose with the increased demand for drilling services (Burke 1994, 38; Chakrabarti, Halkyard, and Capanoglu 2005, 27). The window was slammed shut in 1995 when both the Gulf and the North Sea enjoyed a booming rig market, instead of the bonanzas see-sawing between the two basins as it had for the past decade (Simmons 1996).

To its credit, DeepStar acknowledged the need to change direction. The consortium remained nimble and sufficiently flexible in its research objectives to thrive, and it began broadening its focus on subsea flow assurance to encompass a panoply of other thorny deepwater issues. Teams worked on pipeline laying advances (Birrell 1994, 945); production system hardware (Burke 1994, 36), and more. In 1999, DeepStar embarked on a $14 million, two-year study of "generic" deepwater technology, and it began to expand its focus to all deepwater basins and all system types. This change was reflected in a small but telling emendation to the DeepStar logo. At some point after 2002, the group redesigned its crest, replacing the previous motto aimed at the Gulf and on a system for staged recovery with the phrase, Global Deepwater Technology Development (see Figure 1.17.). More subtly, the conventional fixed-jacket platform pictured in the middle of the image was replaced by a large, multi-decked floating production vessel—a full-field development project for deepwater.

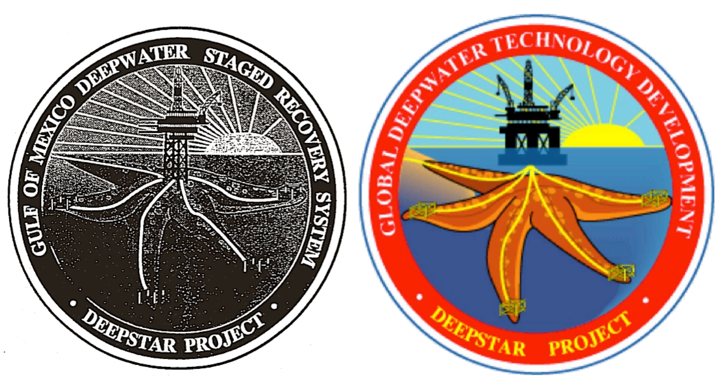

Figure 1.17. Changes made to the DeepStar logo between 1993 and the present

Source: US Congress 1993, 146.

Note the shift from a fixed to a floating production platform, and the orientation of the subsea flowlines. On the 1993 version, they run on the seafloor until reaching the bottom of the platform, before rising; now, the lines affix to the FPU through what are known as catenary risers—a key ultra-deepwater production tool. The change from "Staged Recovery System" to "Technology Development" is equally significant. The old logo remained in force until at least 2002. Compare also to Texaco's own star-shaped logo.

DeepStar was not the only collaborative research group formed during this period, but it was without question one of the most influential (Dunnahoe 2007, 62). It served a particularly important role during the 1990s as an effective mediator between offshore operators and the federal Minerals Management Service, working collaboratively with the regulator to resolve emerging technical concerns like natural gas flaring (LeBlanc 1992). DeepStar stepped in as the 1990s wore on to assume the work previously done by research and development departments housed inside operators that were being shuttered due to the downturn (World Oil 2011a). When interest in deploying an FPSO in the Gulf began to coalesce in the late 1990s, DeepStar provided the funding necessary in April 1998 to pay for the Environmental Impact Statement mandated by law before any work could proceed (Cranswick et al. 2001, 901). Since 2000, DeepStar has achieved innumerable advances in deepwater technologies across the exploration and production spectrum, and it has also retained a glimmer of the spirit of its original target: the ultimate minimization or elimination of the need for any surface-piercing facility for commercial deepwater production. The seafloor processing factory remains a key research goal for the very long term (World Oil 2011b).

In retrospect, one question lingers about why DeepStar found its genesis in Texaco and not one of the more active Gulf operators. Analysis of the firm's deepwater lease holdings at the time hints towards an answer. While the 60-mile tie-back radius envisioned by the first DeepStar mission would have incorporated 85% of all deepwater discoveries to date in the basin, it would have covered over 95% of Texaco's lease inventory (Offshore 1992; Burton, Wheeler, and Ruthrauff 1993, 36). A good deal of these leases were legacy items from Texaco's acquisition of Getty Oil in 1984. Without an operatorship in deepwater yet—the Petronius compliant tower would be its first—Texaco was a lagging player and perhaps stood the most to benefit from advancing subsea equipment. Where the firm did lead was in the pioneering of horizontal drilling offshore, as it did in 1990 at East Cameron 265 in the Gulf (Dunnahoe 2007, 67; Offshore 1990). There is evidence to suggest that firms like Texaco have often used strategic alliances such as DeepStar to gain access to other firms' technical capabilities, instead of using the collaboration to build or create new knowledge together (Mowery, Oxley, and Silverman 1996). Texaco invested heavily in Green Canyon acreage just beyond the continental shelf edge in the late 1980s, and pursued deepwater prospects elsewhere not far from the shelf, like its "Thor" and "Triton" prospects in the Viosca Knoll (Offshore 1989b). Indeed, after making major discoveries in 1995 at its Fuji and Gemini fields, Texaco opted for DeepStar-style tie-backs to develop both (Oil & Gas Journal 1995b).

That DeepStar's vision failed to catch on in the deepwater Gulf did not mean that operators had ignored one of the primary insights of Phased Development: there was a great economic advantage to be gained from the proximity of the flextrend to the edge of the continental shelf. There, by historical accident stood a vast web of production infrastructure, including existing production platforms, export pipelines, and larger gathering and trunk lines that conveyed oil and gas from multiple fields to shore. In fact, although little noted at the time, the two competing deepwater platforms of the "new era" in the late 1980s leaned heavily on shallow-water facilities for their technical function—and to stay alive. At Placid's Green Canyon 29, Conoco's Jolliet TLWP, and later, the Enserch Garden Banks 388 platform, each facility was built and designed around its ability to place the majority of its processing equipment on a conventional fixed-jacket platform, and not on the floating vessel itself (see Figure 1.18.). Without this design, it is possible that none of the projects would have seen the light of day.

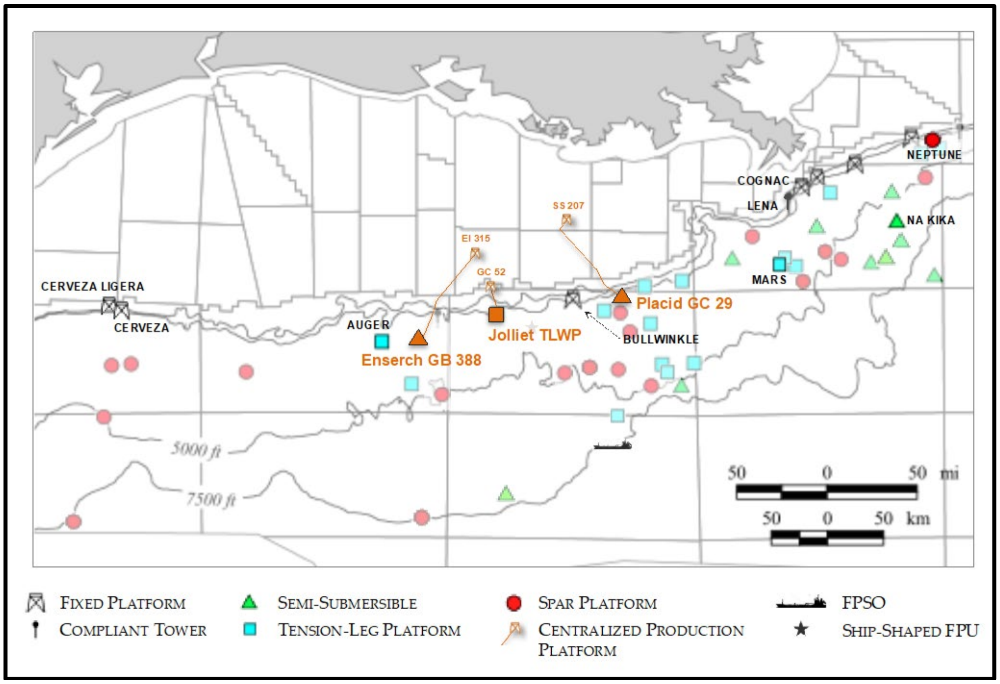

Figure 1.18. Map of deepwater facilities installed in the Gulf of Mexico, 1978–2015

Major fields, like Mars, Auger, Neptune, and Na Kika, are highlighted and named. The three deepwater facilities "tied to the shelf" and their shallow-water production facilities are shown in orange. Compare also to Figures 1.4. and 1.6. Source: US Department of the Interior 2014; map adapted from US Department of the Interior 2008, 45.

3.3. Placid Green Canyon 29 and the DWPF

Halfway through Herman Melville's 1851 magnum opus *Moby Dick* is a short chapter, "The Monkey Rope," that tells the story of the nuts and bolts of the labor needed to make the nineteenth-century whale trade work. Ishmael, the narrator, explains in vivid detail the way that the crew of the *Pequod* would, after chasing and killing a cetacean, harvest its valuable blubber for oil and convey it onto the ship. With one man standing secure on the edge of the deck, his partner would descend to stand—precariously—on top of the half-floating whale carcass. This was the slippery business known as "cutting-in," or chopping up the whale. To prevent the lower man from falling off the whale body and succumbing to the circling sharks, or from being pressed to death between whale and ship, between the two men was harnessed a "monkey-rope," a strong rope line secured around the chest of each man and connecting one to the other. Thus attached, the cutter stood half inside the whale and half submerged in the water:

> In the tumultuous business of cutting-in and attending to a whale, there is much running backwards and forwards among the crew...my particular friend Queequeg['s duty] as harpooneer [was] to descend upon the monster's back for the special purpose referred to . . . .
>
> Just so, from the ship's steep side, did I hold Queequeg down there in the sea, by what is technically called in the fishery a monkey-rope, attached to a strong strip of canvas belted round his waist. (Melville 1951, 5830)

As Ishmael explains, "both usage and honor" demanded that should Queequeg sink below the waves to rise no more, the top man on the monkey-rope was to go down with him. The fate of both was connected "so strongly and metaphysically," the narrator contemplates, that he likens the situation as having merged their individualities into a "joint stock company of two" (ibid., 5852).

Replace *Pequod* with *Penrod*, and Melville's depiction could be stretched to apply to the economic situation that Placid created between the GC 29 semi-submersible facility and its shallow water companion. The *Penrod* semi-submersible FPU sat suspended over the largest of GC 29's natural gas fields, but it was unable to actually produce that treasure alone. The rig was attached by pipeline to a conventional fixed platform set in 550 feet of water in Ship Shoal 207. Placid's name for its steel Ishmael was, prosaically, the Deep Water Process Facility, or DWPF (Cober, Filson, and Teers 1987, 353). Equipment on *Penrod* separated the liquids from natural gas, and further dehydrated the natural gas to avoid the formation of hydrates in the cold of the export pipelines (Cober, Filson, and Teers 1987, 352). Only after arriving at the DWPF did the vast bulk of the business of petroleum production processing began. After export to the shallow water platform, the liquids were heated and pushed through a three-stage separation phase, after which both streams were cooled, metered, and exported to shore (ibid.). Placid explained during a 1987 presentation on the arrangement that the presence of the Green Canyon fields to the edge of the continental shelf and the hosting of major equipment on the DWPF was essential to the GC 29 effort (had its reservoirs flowed far better, of course). The design minimized the "amount of equipment required on the rig," which saved Placid from having to boost the payload capacity of its deepwater vessel by an estimated 20% (Filson et al. 1988, 344).

The presence of the DWPF was not just a convenient way to arrange production processes, but the core of the entire project's "design philosophy," as the firm noted (Cober, Filson, and Teers 1987, 352). It kept the costs of *Penrod 72* conversion down (LeBlanc and Cornitius 1987), and as explored above, cost containment for the marginal development—already grappling with an unexpectedly low price environment—was critical to the project's success. *Penrod 72* had been selected by Placid in large part because it was one of a class of "particularly large" existing deepwater-capable semi-submersibles available (Filson et al. 1988, 343); even then, Placid's design for the FPU conversion required that the *Penrod* hull be expanded with added-on sponsons designed to give the hull the added buoyancy needed to support an already-high payload (see Figures 1.1. and 1.2.). Having to take on additional platform equipment would have scuttled the plan, if not the ship.

Even though the shallow-water DWPF platform was decidedly low-tech, Placid promoted its semi-submersible technology as a "significant advance in floating production systems" (Cober, Filson, and Teers 1987, 347). And indeed, the rig served host to a number of advanced technologies. Hughes Offshore supplied Placid with cutting-edge electrohydraulic control pods, installed on the subsea well template, that allowed for easy onboard control of both the template as well as the satellite wells (Oil & Gas Journal 1986). The star of the system, the freestanding hybrid riser, boasted components that remain impressive almost thirty years later. Developed by Hughes in collaboration with Cameron Offshore Engineering and Brown & Root, the stress joint mounted at the bottom of the riser was milled into a tapered, 3-inch thick section from titanium alloy (Wilson and Strader 1989, 4). The rigid part of the riser was assembled from 26 pieces, each fifty feet tall and over seven feet in diameter, and was built in a way that allowed the easy retrieval of riser joints and other parts for maintenance (Cober, Filson, and Teers 1987, 349). The tentacles of flexible pipe that emanated from the top of the rigid riser and connected individual well conductors to the rig was the work of a host of cutting edge firms, including Coflexip, Vetco, Lockheed, Hydril, Elf-Aquitaine, Exxon Production Research, Phillips Petroleum and Getty Oil (Panicker and Yancey 1983, 7). Placid also impressed some watchers by "bottom-towing" its pipelines to the rig, pulling them from a beach southwest of Houston on Matagorda Peninsula where they were assembled to the Green Canyon 29 site at a depth just 150 feet above the seafloor (Brown 1988, 3; Offshore 1997).

Looking past the proximate cause of the sanding up of several of the Green Canyon 29 wells and the mechanical failures in others, why, exactly, did production fall so short at Placid's platform? It is tempting to say that Placid just had back luck. After all, the petroleum business in general—and offshore drilling in particular—is not an easy avocation. Bringing hydrocarbons up from three miles below the seafloor, and through another 1,500 feet beyond that, is nothing to sneeze at, especially when performed under severe cost and time constraints. Tempting as it is, this explanation is faulty. No amount of innovation could have saved Placid from the dominant problem marking its operations in the deepwater Gulf: Placid Oil itself. From the very start of its efforts in Green Canyon, Placid and its management created as many problems as they solved. The firm largely eschewed careful planning for the project, in favor of "fast-tracking" (or less charitably, rushing) it into production as fast as possible. And it showed. Strapped for cash, Placid needed petroleum to flow "as quickly as possible" to establish a revenue stream (Gautreaux 1987, 126). Eager to move on the development, Placid did not perform enough—or enough high-quality—geological and geophysical analysis of the immediate area around its first discovery. The firm seriously misjudged the nature and quality of the fields below their platform as a result. Placid was set on not doing "any more research and development than [was] necessary," said Bruce Crager, a project manager for Hughes Offshore (Shook 1986, 14).

A lack of thorough pre-production work was not the only monkey on the back of Placid and its deepwater efforts. Heavily influencing the firm's choice of development concept was its ownership. The three Hunt brothers, heirs to the oil fortune of the iconic and colorful H.L. Hunt (rumored to be the inspiration for the character of J.R. Ewing in the hit television show Dallas), owned a majority control of Placid Oil, their flagship holding, as well as the Penrod Drilling Company. Phil Clarke, Placid Oil and Penrod alike were housed in Dallas' Thanksgiving Tower because the Hunts had built it (Jenkins 1987). The three Hunt brothers lost nearly all of their inherited wealth in the 1980s after the silver market that they had assiduously cornered fell through (Jenkins 1987). The Hunts used Placid Oil—which they directly owned through personal trusts—to cover the losses by taking out $1 billion in loans, which they restructured in 1982 with a $1.2 billion loan (Texas Monthly 1988, 90). Penrod also borrowed an additional sum—and then the oil price dropped.

With their key holdings mired in such deep debt, the inherited personal wealth of the Hunt brothers (and their thirteen children) was put in extreme jeopardy (Jenkins 1987). "The best defense is a good offense," wrote Texas Monthly magazine in explaining what happened next. In June 1986, after defaulting on $1.5 billion in bank loans, the Hunt trusts and Placid Oil together sued their 23 creditor banks for $13.8 billion "on the grounds, more or less, that the banks had tricked them into taking the money" (Texas Monthly 1988, 90; Dallas Morning News 1987a). The Hunts' trust estates, Penrod, and Placid Oil all filed for Chapter 11 bankruptcy in the fall of 1986 (Hayes 1988). The incredibly complex legal proceedings and ownership arrangements of both assets and debt all but guaranteed a drawn-out legal battle.

This delay was exactly what the Hunts were aiming at. Herbert and Bunker Hunt were banking on Placid's big project in the Green Canyon to bolster their balance sheets and lead their return to both personal and professional prosperity, by bringing in millions and breathing new life into the company's offshore operations in the Gulf (Victoria Advocate 1990). This is why Placid's selection of a semi-submersible rig to serve as its FPU was never really in question; in such dire financial straits, shifting assets internally between Placid and Penrod made good business sense. Placid's lawyers claimed that GC 29 could bring the company $150 million in profits, while the Hunts at one point cited $650 million (Oklahoman 1987). Either way, the 1,280-ton well template was installed in place at GC 29 in February 1987 while the bulk of Placid's attention was still in court. The Hunts petitioned the federal bankruptcy court to free the *Penrod 72* and the capital investment funds raised for the Green Canyon 29 project from their collateral obligations, essentially arguing that their creditors should be willing to allow them to *make* more money with which to pay them back (Dallas Morning News 1987b). The judge ruled in April 1987, granting Placid's request, and work on the rig and its equipment avoided stoppage (Lane 1987). It would take several more months and another ruling in November 1987, which put a $7.8 million lien on the "so-called Green Canyon package of property rights" before the completed *Penrod* FPU was allowed to be installed offshore (In Re Placid Oil Co., 80 B.R. 824 [Bankr. N.D. Tex. 1987]; Filson et al. 1988, 343).

But damage to the GC 29 pipelines suffered during the bottom-tow operation and other cost needs threw the project in jeopardy. The outside investors for Green Canyon 29 refused to cover those losses, the demand that finally forced Placid to the table to discuss a settlement with its creditors that the Hunts had so brazenly sued (Associated Press 1988). As the two parties neared a tentative agreement in April 1988—and as Placid sold a 10% interest in the project to two outside parties to raise cash—the platform drilling rig on *Penrod* began sinking its first development well (US Department of the Interior 2014). They reached an agreement over the summer of 1988, but the starring role that the Green Canyon 29 project was destined to play in the Hunts' personal finances had already been set.

Part of the legal and financial wrangling over Green Canyon 29 had less to do with the creative accounting practices of the Hunt family and more with the quality of the project. The attorneys for the Hunts' creditors had called the entire GC 29 project a "dry hole"—the lowest kind of insult in the oil patch—that would needlessly suck money from their clients (Oklahoman 1987). Others weren't so sure. "Placid wouldn't press on with this if it didn't look profitable," said oil analyst Derick Booth of Subsea Data Services, who was widely quoted on the matter (Oklahoman 1988). Still, the tea leaves did not look promising for Placid. Onlookers raised questions about a handful of technical problems already beleaguering the project by 1987 (Jenkins 1987), so much so that Placid's drilling manager on the project felt compelled to directly address the issue to tamp down on the buzz. "We feel we've answered all the questions and done all the [geological and geophysical] testing" needed to proceed, said Tim Stroud to the Dallas Morning News. "We're very comfortable with the test results" (1987a).

Despite its superficial appearance of similarity to the technology of Phased Development used by SEDCO-Hamilton and others in the North Sea and Petrobras in Brazil, GC 29 was by no means a small-scale Phase I of a project. Placid rushed to get production up and running as soon as possible just to get cash flowing, not as an effort to establish Early Production proper. Placid decked out *Penrod* with a full suite of processing capacity far above what the rig would achieve for several years even if flowing at full steam, and had restored the rig enough for it to be rated with a remaining lifespan of an additional 13 years (Filson et al. 1988, 345). Green Canyon 29 was do-or-die for Placid Oil and its ownership, and so the company bet big—and it lost even bigger. As a relative newcomer to deepwater, Placid had only begun pursuing deepwater Gulf acreage in earnest in 1984, and by 1987 a full 48% of its leases beyond 1,000 feet of water were in the Green Canyon area (Gautreaux 1987, 126). It designed its production system not to be temporary, but to stand as a "hub" for future discoveries. The subsea template directly below the rig was built with those fields in mind (Cober, Filson, and Teers 1987, 354). "They must have nervous stomachs," said a competitor who asked not to be identified to the Dallas Morning New*s*. "For them to win, it has to work right for the first time, and that's tough. I don't care how good you are, it's tough to put all your eggs on the first pass" (Dallas Morning News 1987a).

After April 1990, Placid and Enserch were adamant that the fault lay not in their technology stars, but in their reservoirs. Enserch senior vice president Richard Kincheloe remarked in 1992, as his firm prepared to resurrect Green Canyon 29's production system equipment for a second bite at the apple, that the project had simply been "ill-fated" from a geological perspective. "The production system worked fine," Kincheloe said (Oil & Gas Journal 1992b). Both companies continued to advocate for the semi-submersible FPU system as a whole, as the concept that was in their opinion best suited to the deepwater Gulf : it allowed a high well count, a pipeline-based export system (a virtual requirement in the basin), and the ability to simultaneously drill and produce (Filson et al. 1988, 346). Yet the failure at Green Canyon 29 actually proved the necessity of the core concept behind phased development and the benefits of using a semi-submersible FPU in the first place. "[A]ccurate reservoir analysis is a must," Offshore explained in 1985, because of the massive capital costs associated with a "mistake" in deepwater (LeBlanc 1985).

Still, Phil Clarke was correct when he remarked that Placid would recoup a fair chunk of change from auctioning off the used equipment from GC 29. The converted *Penrod* rig was an easy sale, sold in 1992 to—who else?—Petrobras, for use at its Albacora field as *Petrobras XXIV* (Oil & Gas Journal 1992a; Mastrangelo et al. 2003, 8). Shell Oil purchased one of the high-pressure 10,000-psi satellite well production trees and promptly refurbished it for use at its Tahoe deepwater natural gas subsea development. Installed three years later 180 miles away from the Placid site, the well would produce for years in 1,500 feet of water in the Viosca Knoll area of the Gulf (Oil & Gas Journal 1995c). A firm called Torchmark, Incorporated purchased a number of unidentified parts. An upstart midstream company named Leviathan acquired a majority ownership in the Green Canyon pipeline system that Placid and Enserch had laid down, paying about $15 million for their share in a system they renamed the Manta Ray (Oil Daily 1994; Haines 1993, 53). Not surprisingly, Placid's biggest auction customer proved to be its financial partner in the operation, Enserch Exploration. Not saddled with bankruptcy proceedings and eager to try again with the FPU system, Enserch acquired most of *Penrod*'s mooring system, subsea control umbilicals, one of the rig's 12-inch outer diameter catenary export pipelines, and the hybrid freestanding riser (Taylor et al. 1995, 381; Aarrestad et al. 1998, 605; Franklin et al. 2000, 1; Cober, Filson, and Teers 1987, 348). Even the humble DWPF platform in Ship Shoal 207 found a new home.

3.4. Enserch Garden Banks 388 and the SWF

Richard Kincheloe of Enserch was keen on not just the technology installed on *Penrod*, but on the entire development approach premised on the use of semi-submersible FPUs. After Placid recovered the equipment from Green Canyon 29, Enserch scooped the bulk of it up in a plan to resurrect the system at a different deepwater field. In 1989 Enserch had discovered an oil field in Garden Banks 388, in 2,096 feet of water (Blincow, Whittenburg, and Pickard 1995, 1). With the former Placid equipment in hand, Enserch formally approved its investment in the project late in 1992 (ibid.). In the same set of remarks as quoted above, Kincheloe explained why the semi-submersible FPU concept appealed to his firm. Asked why Enserch had chosen not to pre-drill production wells at the site of its deepwater platform—as Conoco had done at Hutton and Shell was then doing at Auger—Kincheloe said, "Why spend $15 million to drill a well now when we could drill it for half that cost or less from [the] floating production facility?" (Oil & Gas Journal 1992b).

Kincheloe had a point. The cost of drilling and completing deepwater development wells in during this period ate up a remarkably high percentage of a project's total capital costs, reaching as high as 60% or 70% (LeBlanc 1992; Burke 1994, 37). Enserch ended up drilling only two wells in advance (Ettle et al. 1996, 460), but the company felt assured that they had not misjudged their field's geology. Enserch's wells were targeting the same kind of reservoirs and subterranean petroleum system that Shell Oil had discovered at its large Auger find in 1987, and Kincheloe expected that Garden Banks 388 would yield very high flow rates right out of the gate (Oil & Gas Journal 1992c).

Because Placid sold the former *Penrod 72* rig back to Petrobras, Enserch had to look elsewhere for a platform candidate. After conducting a lengthy search, Enserch acquired *Glomar Biscay I*, a semi-submersible built in 1974, which made it older at its conversion into an FPU than *Penrod* had been at its overhaul in 1987 (Taylor et al. 1995, 379). After taking on new buoyancy sponsons and an updated mooring system, the vessel was re-christened *Enserch Garden Banks* (see Figure 1.3.). Enserch also added a few improvements to the thermal retention system of the freestanding hybrid riser, as well as extending its height for the additional 500 feet of water at GB 388 (Franklin et al. 2000, 2; Pickard 1994, 37). Informally named Cooper by some, the project proceeded relatively quickly after sanction. After building and installing a near-exact copy of GC 29's subsea steel template (Pickard 1994, 37), the full system was in place by August 1995 and it began production from two satellite wells the next month.

Garden Banks 388 came with its own monkey-rope, a conventional fixed platform set in 245 feet of water in Eugene Island 315 (see Figure 1.18.), 54 miles away from *Enserch Garden Banks*[6] (Taylor et al. 1995, 380). Known simply as the Shallow Water Facility in the Enserch lingo, the platform held the same suite of processing equipment that was built on the Placid DWPF. Even the production capacity of the Garden Banks 388 system was exactly the same as Placid's, built to handle 40,000 barrels of liquids per day, and 120 mmcfd of natural gas (Offshore Data Services 1995, 3).

Production began in September 1995 from the satellite wells, while the platform rig began to spud development wells through the subsea template. Although Cooper would produce for several years longer than Green Canyon 29 did, that is faint praise. As early as 1996, mechanical difficulties began to crop up in Enserch's wells, and the high flow rates that the firm was banking on never materialized (US Department of the Interior 2014). Enserch had expected the first completion to flow at 5,000 barrels per day of oil and 5 mmcfd of natural gas, but poor water drive pressure at the reservoirs kept rates low (Oil & Gas Journal 1992c; Koen 1996a). Enserch considered adding water injection to the facility to compensate, but at the start of 1996 decided to drill the full suite of template wells before making the call (Koen 1996a). The final production well count reached just seven wells (Furlow 1998). Before project start, Enserch had prudently estimated recoverable reserves to be 27 mmboe, with a likely upside totaling 50 or as high as 100 mmboe, but the field ultimately produced just 9.8 mmboe (Pickard 1994, 36; US Department of the Interior 2014). After royalty payments and the cost of its constituent leases, Enserch pulled in about $150 million in net revenue in current figures, well short of its $400 million cost (ibid.). Decommissioned in 1999, the path-breaking freestanding riser built over a decade before this time skipped the mothballs and went straight to the junkyard.

Why did production fall so short at Garden Banks 388, a semi-submersible FPU, again? Enserch was in a better financial position than Placid Oil had been in 1988, by far, but it had also fallen on tough times during the course of its deepwater development. As production problems began at Garden Banks 388, Enserch had to downgrade its recoverable reserves estimates at a different oil field, triggering a $200 million sell-off of Enserch stock (Suggs 1997). The firm suffered a $235 million net loss over the first quarter of 1997, and the company began to consolidate and streamline its operations in Houston, closing an office in Dallas (ibid.).

Enserch had more offshore experience under its belt in 1995 than Placid had when it began to develop the Green Canyon 29 reservoirs. In fact, Enserch had first identified the Cooper prospect through the use of the most cutting-edge exploration technology on the market, known as 3-D seismic acquisition and interpretation (Oil & Gas Journal 1992c). The acreage was acquired by Enserch through a lease swap trade with Exxon in 1991 (Pickard 1994, 36), two years after Exxon had drilled into the field and reportedly discovered 250 feet of net oil pay with "confirmed" productivity (ibid.). This is an indication that the major, armed with superior technical expertise and capital, had surveyed the prospect and found it wanting. For their part, though, Enserch believed the reservoirs to be commercially viable but simply too small for Exxon's taste. Richard Kincheloe said as much in 1992: "Quite frankly," he remarked, "in my opinion, [the field] wasn't big enough to Exxon to be worth the hassle" (Oil & Gas Journal 1992c). Enserch's decision to not pursue water injection—or having not anticipated a need for it in the first place—was likely driven by financial pressures external to the project, a situation not dissimilar to Placid's. Enserch reportedly considered deploying a compliant tower, TLP, or new-build semi-submersible FPU for Garden Banks 388 (Fishe and Hoolley 1995, 1), but it is questionable how serious such consideration could be given that Enserch had already acquired much of the Green Canyon 29

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[6] *Enserch Garden Banks* had a role in the 1998 film, *Armageddon*. Several scenes were filmed on the rig in January 1997. The movie renames the platform *China Sea* and presents her as drilling an exploration well, *Armageddon* "brought movie crews to the oil patch—and a degree of fame to the *Garden Banks* [sic]" (Zwicker 2006, 27).

equipment system at the time it gave the go-ahead for the Garden Banks 388 project. Either way, after Cooper, Enserch soured on the semi-submersible.

3.5. Jolliet, Marquette, and the CPP

At the same time that Placid Oil had *Penrod 72* in a Gulf Coast shipyard for its rendezvous with a new coat of paint, contractors hired by Conoco were busy overseeing the fabrication and construction of a different kind of floating production rig halfway around the world: the Jolliet tension-leg well platform was being assembled at a yard in Singapore (see Figures 1.19. and 1.20.). As one of the larger international oil and gas companies with a truly global presence, Conoco was able to easily transfer the technology and institutional knowledge it generated in its North Sea division during the design and development of the Hutton TLP to the deepwater Gulf.

Jolliet's story began when Conoco chartered a major in-house geological study of the Green Canyon area, in advance of the 1980 lease sale auction for the central Gulf. The sound of cheers and poured glasses of Cognac were still ringing in deepwater ears, but as Conoco employees intimately involved with the Jolliet project later recalled, even with that show-stopping news of Cognac's success, the geology off the shelf was still so uncertain that the decision to pursue development of Jolliet prompted a "spirited management debate" in the company about whether or not reservoir-quality sands could even exist down the continental slope (Prescott et al. 1988, 164). It was the deft application of two-dimensional, bright spot seismic technology shot over a one-mile grid that revealed a significant prospect at the Jolliet site in Green Canyon 184. Only after that point did Conoco charge its research staff with developing production technology for water depths greater than 1,000 feet—or, if at all possible, just a few feet over Cognac's record depth of 1,023 feet (Prescott et al. 1988).

Figure 1.19. Aboard Mighty Servant III in the spring of 1989, the hull and topsides of the completed Jolliet TLWP are dry-towed from the platform's fabrication site in Singapore to a shipyard in Pascagoula, Mississippi, then on to the Green Canyon

Source: US Coast Guard 1992, 25.

Figure 1.20. The Jolliet TLWP pictured in 2012, its drilling rig removed

About 1/4 of the size of the Hutton hull, Jolliet measured 140 feet from the center of each hull column to the next. The dry-tow from Singapore took roughly six weeks. Source: US Department of Commerce 2015; Hunter 1989, 345.

The discovery well that pierced Jolliet in 1981 indicated that Conoco had hit a reservoir of good quality, but one arrayed in a series of slightly separated or "stacked" horizons (Prescott et al. 1988, 164). Even so, those were promising results; the 174 total net vertical feet of oil sands allayed the fears of Conoco management that the flextrend area was absolutely free of commercial fields. Instead, they were reassured that "deepwater fan systems" had indeed been able to "carry reservoir-quality sands into the Green Canyon slope environment" (Prescott et al. 1988, 164). Moreover, this pegged Jolliet's early reserves estimate at 32 mmbbl of oil and 65 bcf of natural gas (Prescott et al. 1988, 164). Slope was in fact the operative word for Jolliet's location in the Green Canyon: within the confines of Block 184 alone, the water depth ranged from 900 feet to 2,100 feet within the nine-mile-square tract (Birrell 1991, 321; US Department of the Interior 2014).

To produce from that depth, Conoco understood that it needed more information before the company could reasonably justify making a major investment decision in a basin that was still so largely unproven, promising discovery well prospects notwithstanding. Conoco ordered a 3-D seismic shoot over a nine-block area around Jolliet in 1983, to supplement the seismic data that had led to identification of the prospect (Prescott et al. 1988, 164). With better mapping of the field's extent and data from delineation drilling that took place between 1982 and 1985, Conoco soon upped its estimate of the field's recoverable reserves to 40 mmbbl and 75 bcf, and the estimated areal extent of the reservoirs grew by about 30% ((Prescott et al. 1988). As Jolliet's boundaries, reservoir depths and reserves totals began to come into clearer shape in the minds of Conoco's drillers and managers, so too did a production concept for the field. Notably, from the start, Conoco did not view the technical challenges of producing from Jolliet's depth as insurmountable at all (Prescott et al. 1988, 165). Already at the time of discovery, the firm was assembling the parts and personnel to bring the Hutton TLP together in the North Sea, and there, in fact, Conoco had already been studying the possibility of morphing that design into a TLWP for North Sea use (Prescott et al. 1988). Conoco's initial production platform concept candidates for Jolliet set the facility water depth at 1,200 feet, and at that depth, Conoco reviewed designs for conventional fixed-jacket platforms, guyed towers, buoyant towers, semi-submersible FPUs, and of course, tension-leg well platforms.

As research and additional work continued, the center of the reservoir kept "drifting" in Conoco's mapping, pushing the preferred location for the facility from 1,200 feet of water through a series of changes up to 1,800 feet, before alighting on the final depth of 1,767 feet of water (Hunter 1985, 235).

The fact of this constant change itself eliminated all bottom-founded structures from design consideration. Notably, Conoco seriously considered using a fixed-jacket platform out to a depth of 1,500 feet, and at 1,200 feet, it was their preferred solution (ibid.). But when Jolliet's final exploitation depth was finalized at not much under 1,800 feet of water, Conoco ran the numbers and estimated that it would have taken 80,000 tons of steel to build a conventional jacket instead of the TLWP's actual tonnage of 12,000 (Offshore 1987). The constantly shifting depths had also caused the firm to consider an FPSO.

Interestingly, both the FPSO and semi-submersible production platform were eliminated from consideration because the subsea well costs were projected to be inordinately high—too high to operate, given that using subsea wells would also lower ultimate recovery from a field already presenting reservoir challenges (Birrell 1991, 321). Even more interesting was the fact that Conoco's rejection of these floaters came at the same time that other firms were busy creating new milestones in offshore production history: the first purpose-built FPSO and the first purpose-built semi-submersible FPU for offshore petroleum, both of which were deployed in the North Sea (Lim and Ronalds 2000, 7; LeBlanc 1985). Converting an existing drilling rig into a floating unit would come cheaply, Conoco reasoned, but those savings would only be eaten up by higher subsea costs (Hunter 1985, 235). Yet the operator also nixed the idea of developing the prospect with a full-field, standard-sized TLP as too expensive, given Jolliet's modest reserves—and thus was born the tension-leg well platform (see Figure 1.23.). It was precisely the "confidence" gained from pioneering Hutton that gave Conoco (and other deepwater operators) the will to move the TLP concept into deeper waters (Birrell 1991, 320). The TLWP concept for Jolliet was approved by Conoco in January 1984, and its design was refined over the following two years. The oil price collapse then effectively put all offshore projects temporarily on hold (Hunter 1985, 235).

The first proposed design for Jolliet called for the TLWP's wells to produce to a moored FPSO or VLCC (as depicted in Figure 1.14.). Eventually, though, Conoco settled on an architecture similar to what Placid and Enserch would use at their first deepwater sites. The Ishmael to Jolliet's Queequeg was a shallow-water steel platform that supported the bulk of the needed processing equipment; here named the CPP, or Centralized Production Platform. Located in 616 feet of water in Green Canyon Block 52, the CPP jacket was located much closer to its primary vessel than its analogues were at the Placid or Enserch facilities (see Figure 1.18.). Just as at those two developments, the deepwater floating platform's reliance on the shelf structure was not simply one of technical efficiency, but of economic necessity (Hunter 1985, 235). Built directly beside a pre-existing platform that produced the shallow-water Marquette oil field (and connected to it by a footbridge), the CPP received a stream of oil and water from the TLWP, as well as a line of dehydrated gas (Rench et al. 1993, 465). Processing equipment at the CPP removed gas and produced water from the oil, commingled the two gas streams for export, and discharged the cleaned water (ibid., 465). With a deck area of about 21,000 square feet, and with three levels, the CPP at its installation in September 1989 stored a significant amount of equipment, even more than Placid's DWPF or Enserch's SWF (see Figure 1.21.).

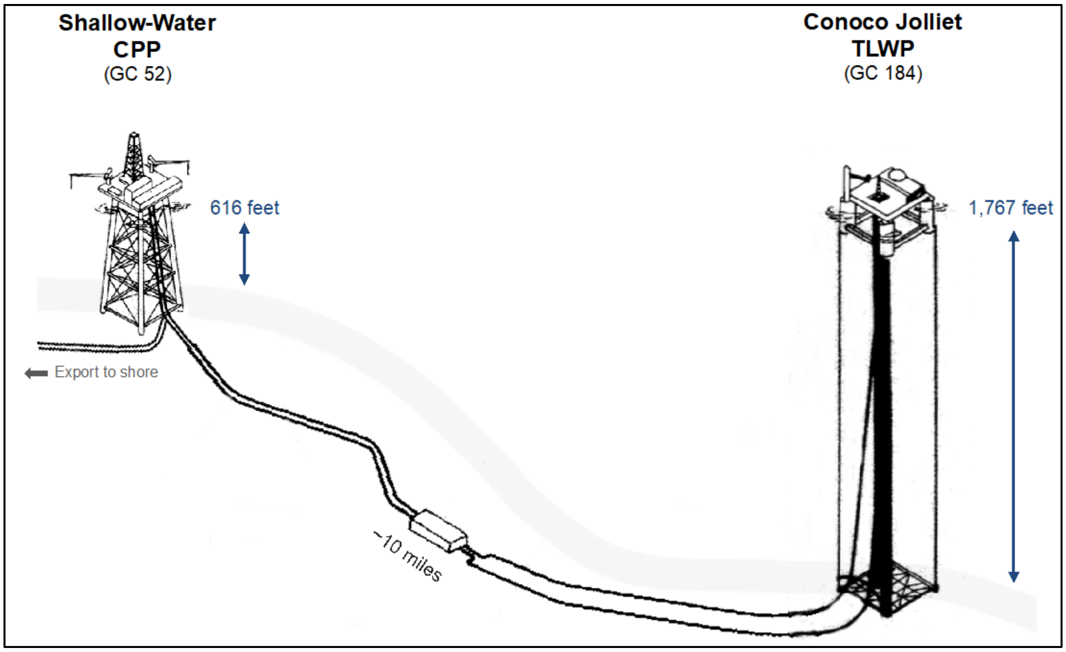

Figure 1.21. Representation of the Jolliet TLWP and its connection to Conoco's shallow-water Centralized Production Platform

The presence of an especially rocky outcropping between the two facilities at the northern edge of Green Canyon 184 required Jolliet's export pipelines to be routed carefully around the structure. The block depicted in the middle of the pipeline segment is a Unified Connection Skid, or UCS, designed to allow for easy connection of future lines. Source: US Department of the Interior 2014; Tillinghast et al. 1991; image adapted from Tillinghast et al. 1990, 61.

Conoco took great pride in the ingenuity of this novel arrangement that monkey-roped these two platforms together (Prescott et al. 1988). One Conoco executive testified to the fact that the CPP was the critical link in Jolliet's success: it allowed for the deepwater hull to be fabricated under simpler parameters, using less steel, and as a result, with cheaper tendons. The TLWP hull itself held only a basic separator, drilling completion rig, gas compression equipment and accommodations for 40 crew members (Prescott et al. 1988, 165; Offshore 1987). The idea of a wellheads-only tension-leg facility perfectly fulfilled the needs of the deepwater Gulf, offering surface completions on a floating platform, all while keeping capital costs in check. Even with its cost-effective monkey-roped arrangement, keeping the Jolliet project out of the red was an "awesome task" to meet (Stokes, Koon, and Thompson 1996, 6). Conoco would have preferred to install water injection equipment on the TWLP, but feared that doing so would render the project unprofitable (Offshore 1989b).

Because it had to support only the dry-tree surface completions, Jolliet's hull was a good deal smaller than the Hutton platform, weighing in at just 18,400 short tons of water displacement to Hutton's 65,000 (Prescott et al. 1988, 165; LeBlanc 1984). Based on its experience at Hutton, Conoco was able to reduce the over-engineered strength of the tendons, and was optimized Jolliet's buoyancy through implementing improvements inspired by Hutton's design (Stokes, Koon, and Thompson 1996, 6). Jolliet also departed from Hutton's use of four individual templates for grounding the corner tendons, by installing a single subsea structure that contained the well template slots as well as securing the tendon connections (see Figure 1.21.). The $10 million, 1,500-ton drilling template was installed in 1987 for pre-drilling to occur, and in August the *John Shaw* semi-submersible started the batch-setting, setting the conductor pipe, wellheads, and the first string of well casing for 16 producer wells at the site (Watkins and Beato 1989, 1; Birrell 1991, 324).

The water depth and pressures at Jolliet were of a magnitude greater than at Hutton, meaning that the pre-drilling process here was especially successful given the results it achieved: it maximized cost savings, as the 16 wells averaged a drilling time of 2 and 1/4 days each; Hutton's wells had taken around 5 days on average to drill, despite shallower drilling targets (Watkins and Beato 1989, 1). The batch-setting at Jolliet proved to be the opposite of what it had been at Hutton: whereas the drilling commenced at Hutton because of a delay in the hull's delivery; unexpected lack of progress at Jolliet's drilling slightly delayed the TLWP's installation (Watkins and Beato 1989). Even so, Conoco estimated that the lessons it learned from Hutton to Jolliet in how to efficiently batch-set wells saved them $6.6 million in drilling costs and 73 days of work time at Jolliet (Watkins and Beato 1989, 2). One critical cost saver was having the hull of the Jolliet TLWP fabricated at an East Asian shipyard, an early instance of an important rise in foreign shipyard fabricating major Gulf of Mexico facilities, a move soon to be replicated at Shell's Auger and Mars TLPs (Priest and Lajaunie 2014, 36).

Installation was largely seamless at Jolliet, although the vessel suffered four dropped tendons during the sea-tow of the hull from the Gulf Coast to its final location (Birrell 1991, 321), requiring four more to be built and installed prior to production starting up in November 1989. Final cost estimates for the project weighed in at $250 million for the platform, with development well drilling and completion costs for 25 producers totaling an additional $100 million (Hunter 1985, 243). The final development bill for Jolliet, including exploration and appraisal wells, came in at roughly $446 million in nominal figures (ibid.). Jolliet's installation remains notable still today as being the first for a deepwater platform to make extensive use of ROVs, launching in the minds of some the start of a "new ROV era" in deepwater drilling (Oil & Gas Journal 1990; see Westwood 1993).

As Conoco had at Hutton, Jolliet was able to achieve first oil fairly quickly due to the batch-setting of wells prior to facility arrival. The start of production showed Jolliet's "stacked" horizons of pay sands to be extremely faulted; a single Jolliet's well took in oil and gas from roughly 100 separate horizons (Hagar 1990). Producing from such a stratigraphy almost demanded the use of dry-tree well completions, to allow for easy re-entry into the well, the addition of multiple completion screens, and so on. That the crude oil price was falling during this period only underscored the need for economical access to manage the wells.

How well did Jolliet produce? Some have said that Jolliet "limped along" with decent production, but at rates below investment-grade performance (Leffler, Pattarozzi, and Sterling 2011, 37), and it is true that Jolliet's production fell below what Conoco had predicted for the short-term. In June 1989, as the project was moving rapidly towards start-up, Conoco estimated total reserves at the field at 60 mmboe, up 24% from their initial estimate (Offshore 1989b). To date, the reservoirs in Green Canyon Block 184 have produced a total of 35.5 mmbbl of petroleum liquids and 137.4 bcf of natural gas—a combined total of 60.3 mmboe (US Department of the Interior 2014). Conoco had projected annual production from the field to top 15 mmboe for each of its first three years onstream, but Jolliet flowed forth only around 10 mmboe annually during that period (Hunter 1985, 243; US Department of the Interior 2014). It took longer for Jolliet to repay its costs than Conoco had expected, but, on the opposite side of the coin, Jolliet had a longer lifespan than the firm had prepared for. Jolliet produced well into 2014 before ceasing late in the year (abandonment work was underway as of early 2015). Jolliet was a solid, if not definitive, addition to the wall of evidence that deepwater reservoirs could indeed be unquestionably economic.

The names of the shallow-water Marquette field, the CPP and its monkey-roped partner, Jolliet, came from two brave seventeenth-century souls reputed for exploring the Mississippi River and mapping virgin territory deep into the unknown. The diminutive size of the Jolliet TLWP also contributed to another key selling point in favor of the project's sanction: re-use (Birrell 1991, 321). "Flexibility" of the hull for "relocation, or duplication" was a valued issue for Conoco (Birrell 1991). From the start, the Jolliet vessel was designed to be re-floated for use at other fields after draining the Jolliet reservoirs, similar to the way that semi-submersible FPUs were intended for short-term and repeatable use in a Phased Development program. For at least a short period of time, Conoco made definite plans to either re-float the Jolliet

TLWP a few miles south to a marginal field located in Green Canyon 228; or else, to build a second TLWP and deploy it to that site (Koen 1991). Appraisal drilling began on the oil reservoir three miles southwest of Jolliet not long after the TWLP came online (Offshore 1989b; Birrell 1991). The water depth at that location, although further away from shore, was about 60 feet shallower than at the Jolliet site. Given that fact, and a smaller field size, Conoco envisioned that a suitable TLWP hull would be about 26% lighter than the Jolliet vessel (Birrell 1991, 323). Conoco went as far as making a cost estimate to assess the feasibility of moving the Jolliet platform over the GC 228 reservoir, reaching an all-inclusive price at $44 million, with a month needed to execute the operation (ibid.). Given the TLWP's inherent mobility, Conoco and others viewed it as a potential rival for the semi-submersible as the core platform for use for in any phased development (Curtis and Mercier 1985). Industry soothsayers projected—or prayed, perhaps—that Jolliet and the TWLP model was on the cusp of bringing "a new production era" to the Gulf (Offshore 1987).

And so it remained to be seen exactly what shape the tension-leg platform would take in deepwater, although Jolliet had made a strong case for the economic viability of pursuing a scaled-down approach rather than building full-field, mega-facility TLPs. Excited about their prospects, many operators nevertheless doubted that the TLP would present as an ideal solution (LeBlanc 1984). For a full-blown tension-leg facility to work, one operator explained to Offshore, there were still just too many unknown costs and risks around the design parameters and fatigue resistance of the tendons, and their anchoring and grounding systems (LeBlanc 1984). Others who were directly financially supportive of the project agreed, but thought that the vision of TLWPs as easily re-usable vessels was a superior one. Interestingly, although Texaco was a financial partner in Jolliet, their conclusions from witnessing Jolliet's experience was a heightened awareness of the weight-sensitivity of the TLP concept at large. "We see them as a wellhead platform more than a full-blown drilling and production facility," a Texaco executive remarked in 1992 (Offshore 1992), a conclusion in line with the firm's pre-disposition for using floating facilities in a phased approach, tightly connected to processing facilities on the shelf. Still, the outcome of Jolliet was as highly anticipated as Green Canyon 29: firms like Exxon watched the development, progress, and performance of the early TLPs in deepwater "closely," because the concept was such a "much-heralded innovation" that it promised indeed to open up a new era offshore (Pratt 2013, 156).

4. Release the Turbidites! Deepwater Sands Pay Off

When Jolliet came online in November 1989, the outlook for deepwater's future seemed to be optimistic. Shell Oil, which had bet heavily on the frontier in the Gulf of Mexico (Gulf) but was "running on fumes" in the eyes of many investors—its global profits in 1992 would turn out to be its lowest since 1967—announced a month later in December 1989 that they would be spending perhaps $1 billion on a full-size TLP to develop their Auger deepwater discovery (McWilliams 1995; Howarth, Jonker, Sluyterman, and van Zanden 2007, 270). Standing in 2,860 feet of water and appraised at an estimated 300 mmboe, Auger was a deepwater giant, and Shell's decision to eschew any sort of phased approach for a single, full-field tension-leg facility seemed to relegate subsea tie-back technology to a secondary role (Enze et al. 1994). A few months earlier in 1989, Shell had also discovered another deepwater elephant at a prospect named Mars. Containing a possible 700 million barrels of oil, Mars had the potential to be a veritable "basin-maker," a landmark field of monumental significance, and for that reason Shell kept the discovery under wraps until May 1991 (see Figure 1.24.). As Juan Carlos Boué explains, Shell publicly played down the significance of these finds and the basin at large, in part to hide its hand from its rival firms, as it continued to scoop up deepwater acreage in the Gulf (Boué 2006, 118).

Although Shell's investment in the Auger TLP was a major booster shot for deepwater, other economic indicators were not so palliative. As DeepStar's strategic response in the early 1990s to the state of the Gulf suggested, most drillers anticipated that the remainder of flextrend fields yet to be found would contain only about 50 mmboe, or maybe 100 mmboe on average (Oil & Gas Journal 1992b). The industry was coming to grips with the grim realization that deepwater reservoirs were destined to be overly complex, suffering from highly faulted and discontinuous geology, and, as seen at Jolliet (and later, at Garden Banks 388), would have expensive reservoir pressure maintenance requirements (Clarkston et al. 2001, 1–2). The paramount importance of surface or dry-tree completions in this environment was clear; to keep flow rates sustainably high, operators needed easy and low-cost access to wellbores for maintenance tools like acidization, coil tubing intervention, and well recompletion (Chitwood, Rothberg, and Miller 1993, 89).

Even Shell began to sweat the persistence of the doldrums in crude oil prices as they dipped below $20 per barrel. Soon after Shell let contracts for Auger's construction in 1990, its management began to lose its nerve, in light of the stubbornly low oil price. Shell convened an internal special task force to tackle the issue, and they soon turned to the third of the mid-1980s deepwater project trio, the massive but lumbering dinosaur of an outdated technology: platform Bullwinkle.

4.1. Auger: 1,700 Leagues On Top of the Seas

Poor Bullwinkle was the odd one out in the trio of projects that industry and government officials took in presentations about at the 1987 technical conference at the New Orleans Doubletree Hotel, where Green Canyon 29 and Jolliet were the clear stars. Even though the Bullwinkle jacket set a new record for the greatest height of a conventional fixed platform—and J. Ray McDermott advertised during its work that they were prepared to take the design as far as 1,600 feet of water—everyone knew that its depth of 1,353 feet would finally be the correct prediction for the fixed platform's maximum height this time around (LeBlanc 1985).

Shell discovered Bullwinkle in waters around 1,300 feet deep in October 1983, and sat on the field for a while. At that depth, the field stood on the edge of the continental shelf and at the maximum range of the conventional platform. Additional drilling took place before Shell sanctioned the development in mid-1985 (Offshore 1985b), and though Shell ultimately decided to build a fixed platform to produce Bullwinkle's estimated 72 mmboe, the choice sparked intense debate within the firm about whether it was the best way to proceed (Priest 2007b, 237–238). Recourse to pictures of the structure reveals why that decision was likely to create controversy (see Figure 1.22.). The weight of the foundation piles for the structure alone totaled 10,500 tons (Abbott et al. 1995, 316). Topping out at a final water depth of 1,353 feet and a foundation base that could contain the area of nearly three football fields, it was a true monster of the deep. Significantly, Shell considered producing Bullwinkle with a tension-leg platform, but ruled it out as too expensive (Abbott et al. 1995, 238).

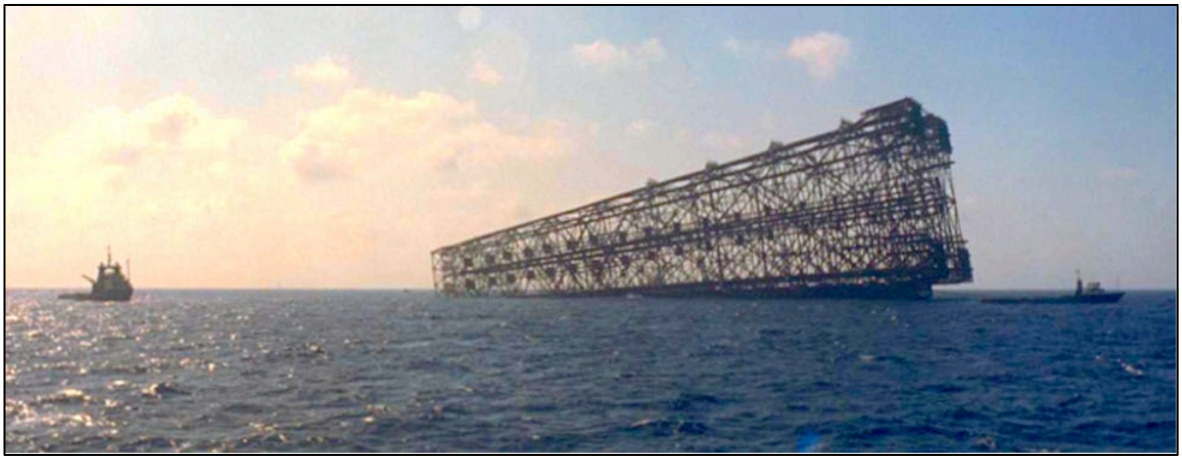

Figure 1.22. Shell's Bullwinkle jacket is towed out to its installation site in the Green Canyon right before its launch in 1988

The dimensions of its base, visible at right, measure 400 feet by 400 feet: equal to the footprint of two sets of the World Trade Center twin towers. After years of work and several days in tow, launching the jacket off the barge lasted 80 seconds. Source: Stiff and Singelmann 2004, 52; Garrison 1999, 262.

Only briefly was the option floated that Bullwinkle be built in two pieces, like its Hondo and Cognac cousins, but every fabricator involved in the contract bidding process proposed a single piece (ibid.). In its final form, the jacket weighed 77,000 tons and had 60 well slots, just 2 shy of Cognac. Its 400-by-400-foot square base is as wide as two sets of the World Trade Center twin towers, clustered together. Industry members made off-the-cuff estimates that it would take 500 welders working full time for two years to finish the jacket (Brooks 1984, 258). Total development costs reached about $500 million (Priest 2007b, 242), but even so, the use of newer computer-aided design software and technology ultimately led Bullwinkle—despite its colossal size—to tally up about 20% cheaper than Cognac, mainly due to savings on installation (Boué 2006, 117; Koen 1991). In line with the trend of improved launching practices, Bullwinkle was set down at its installation in 1988 at just 2.9 feet off from its target (Priest 2007b, 241). Development drilling began immediately, and continued through the spring of 1991, but production began to flow in early 1990. Flow rates for the field were expected to peak at 50,000 barrels of oil per day and 90 mmcfd in 1991, once the full suite of wells was completed and with reservoir pressure at its highest before depletion set in.

Bullwinkle's incredible size was taken not so much as an emblem of deepwater's ongoing productivity, but of the increasingly ridiculous lengths that operators were having to go to economically extract oil and gas there. The early 1990s gained the Gulf the moniker as the "Dead Sea," but some good news in deepwater lurked below the surface. A string of deepwater discoveries in 1991 added a jaw-dropping 1 billion boe to its reserves in one year alone (Koen 1991), enough to quell many of the more "recent doubts" circulating about the Gulf's deepwater potential (Crowden 1991, 38). Although 1991 saw a 27-year low in domestic oil and gas drilling across the US as a whole, 47% of what funds were spent went to offshore wells (Dunnahoe 2007, 64), most of that in deepwater—up 10% from the decade before.

When Shell discovered its 700 mmbboe Mars field in 1989, it began to uncover the huge potential present in the region—and it began a two-year process of adding significantly to its large portfolio of deepwater leases in the Gulf (McWilliams 1995). Shell began letting major contracts for Auger not long after the Mars discovery was made and Bullwinkle set in place. The size of the Auger discovery alone began to slowly change the economic calculus of the competition among differing deepwater development concepts and strategies. For most of the 1980s, the primary competitive advantage offered by any TLP structure was the ability to capitalize its costs over the productive life of several fields—as Conoco had planned to do with the Jolliet platform as well as with Hutton (LeBlanc 1984). But the size of Auger suggested that any TLP used to produce it would need to remain in place nearly as long as such a platform's maximum design life—possibly for several decades. Around the same time that Shell sanctioned Auger and discovered Mars, it abandoned its earlier choice of considering a series of small TLWPs or semi-submersible FPUs to produce its 1985 discovery made in the Viosca Knoll, known as Ram-Powell (Offshore 1989b).

Even with Auger's large size, the decision to go forward with the project was not easily reached (Priest 2007b, 246). Oil prices were low, and although Conoco had proven the TLP concept fairly definitively at Hutton and Jolliet, the design for Auger would be in about 1,000 feet of water more than the TLWP, a significant jump (ibid., 244). By the time Auger would be complete, two other TLPs were under way for use in the North Sea (Snorre and Heidrun), but Auger was the only tension-leg facility to support a full drilling rig on its deck, in addition to the standard suite of processing equipment (Schempf 2001, 5; D'Souza and Aggarwhat 2013). With the hull and topsides under construction in Taranto, Italy, and Morgan City, Louisiana, Shell contracted the Sonat *George Richardson* drilling rig to "pre-drill" the production wells at Auger. On site for nearly three years, the rig drilled 10 wells to their full depth (between 15,000 and 21,000 feet subsea), and batch set just the conductor casings for another 10 wells (Dupal and Flodberg 1991, 87; Enze et al. 1994, 3). With a platform deck measuring 290 by 330 feet, the Auger vessel was massive. It towered so high over the waterline that it was built with multiple elevators running between its decks (Thorpe 1996).

Even so, Shell Oil had very little company or competition in deepwater during the Auger period, striding forward while other companies abandoned their deepwater projects. With cash for new projects tight, and costs ballooning at Auger, Shell had to get creative with how to finance the development; it raised $700 million through the advance sale of up to 40 mmbbl of Auger oil to an outside "special purpose vehicle" which had separate price and interest purchase agreements with the lender, Bankers Trust (Humphries 1995, 997). Even so, with cash in hand, as the 1990s wore on and as the Auger TLP began to take shape, executives at Shell grew increasingly uneasy. Although major oil and gas companies like Shell rely on their own proprietary analyses and forecasts for the future price of oil, many other price predictions from this period proved to be overly optimistic. Forecasts made in the late 1980s and early 1990s by the US Energy Information Administration for the price of a barrel of crude oil through 1995 proved far too high. In 1990, the Energy Information Administration projected a crude oil price of $24.45 per barrel for calendar year 1995, and the projection made the following year bumped that figure up to $27.56 (US Department of Energy 1999, 83). The actual average value of West Texas Intermediate crude over 1995 was just $17.41 per barrel (US Department of Energy 1999).

At Shell, leaders like Rich Pattarozzi, general manager for deepwater E&P beginning in 1991, began to grow concerned that not even Auger's large reserves would keep the project profitable with oil prices so low. Each future well would need to produce more oil and gas—and do so quicker—than before. (Shell's response to this situation, summarized below, is laid out in greater detail in Volume II in this study, "Shell Oil's Deepwater Mission to Mars.") Shell convened a single-purpose Turbidite Task Force to investigate whether the type of reservoir sands they were increasingly encountering on the far edges of the flextrend at fields like Bullwinkle, Auger, and a natural gas find named Tahoe could be induced to produce at very high rates. After an exhaustive review of global reservoir data, the Turbidite Task Force convinced senior management at Shell to perform an offshore well test at Tahoe, a small natural gas field of around 130 mmboe in reserves located in the Viosca Knoll, east of the mouth of the Mississippi River (Oil & Gas Journal 1995c). Shell suspected that the unique geology of the deepwater Gulf's turbidite sands had the potential to sustain per-well flow rates as high as 30,000 barrels per day, far beyond the 1,500 barrels per day rate of a high-quality well on the continental shelf, or even the 3,000 to 4,000 bbl/day rates seen at some of Bullwinkle's wells (US Office of Technology Assessment 1985, 76; Priest 2007b, 248; US Department of the Interior 2014). Under the right conditions, it seemed, turbidite hydrocarbon deposits could be broad and continuous in shape, and under great enough pressure that they would flow into a well as if a brick was placed on a balloon (Thorpe 1996).

As Priest notes, Shell, proceeding in the regimented manner common to the Gulf, was reluctant at first to perform a well test at Tahoe (Priest 2007b). (Such a disposition was quickly becoming known as the "shelf mentality" of business as usual [Campbell 1999, 516].) But the "core of the design" for the Tahoe well test, explained a Shell employee, was built around the cheap acquisition of a high-pressure subsea production tree, which they purchased from Placid Oil's fire-sale from Green Canyon 29 (Abbott and Arya 1994a, 18–19). The well test was performed in the spring of 1991, and Shell returned the following year to place the single well on production in September 1992. This single-well development was but Phase I for a later expansion of Tahoe, and in August 1994 Shell approved a four-well extension of the field (Oil & Gas Journal 1995c). The well test and experience afterwards showed excellent natural gas production rates at Tahoe (Columbia University 1994, 8). These rates seemed nothing short of miraculous. In 1997, Shell's Peter Velez, who had worked as a production manager on Cognac in its early days of development, recalled the excitement that swept the platform crew when one of the wells began flowing at a rate of "just" 4,000 barrels per day. "I used to tell the lease operator," Velez recalled, "you need to sleep next to this well to make sure that it keeps flowing all the time" (Velez 1997, 572).

Pattarozzi and others still wanted more data beyond Tahoe, as well as the application of the Turbidite Task Force's theories to a crude oil field. They looked to Bullwinkle. By reducing the pressure chokes on the wells, Bullwinkle went from producing at per-well rates of 2,000 and 3,000 barrels of oil per day to over 8,000 barrels per day, with no attendant loss of back pressure (US Department of the Interior 2014; Priest 2007b). The expectations of Shell's study group proved true; the rapid and geologically-recent sedimentation of this type of deepwater sands meant that the reservoirs were large, uniformly grouped, and had not been overly compacted, giving them high levels of porosity and permeability, the two factors that determine how well hydrocarbons will flow into a well (Cossey 2004). The test at Bullwinkle confirmed that deepwater turbidites in the Gulf could contain reservoirs of truly world-class size and productivity (Boué 2006, 120). Shell's researchers soon felt assured that in similar conditions to those at Bullwinkle, a production well elsewhere in the deepwater Gulf could flow at a rate of 20,000 or perhaps 50,000 barrels per day. With this knowledge in hand, Shell opted to approve a final investment of $1.2 billion in its Mars field in October 1993, to be built from another massive TLP—even while Auger's hull was still under construction in an Italian shipyard (Oil & Gas Journal 1993).

By the time Auger flowed, results from multiple fields confirmed the exceedingly good reservoir characteristics in deepwater turbidities (Columbia University 1994, 8). Auger was installed in early 1994 and by April, had hooked up enough of its pre-drilled development wells to finally begin flowing oil. The Auger platform had been designed to handle 42,000 barrels of oil and 100 mmcf of gas per day flowing from twenty-four wells, but by July 1994 three wells alone were flowing forth over 30,000 barrels per day (National Commission on the BP *Deepwater Horizon* Oil Spill and Offshore Drilling 2011, 33). Before long, it seemed that there was no reason why an average deepwater well should not produce beyond 30,000 barrels per day, as a Shell executive told the Oil & Gas Journal (1995b) in early November 1995. The industry was "abuzz" at the renewed promise of the deepwater, renewed in fact far beyond their wildest hopes. "At a stroke," Juan Carlos Boué writes,

> The economics of deepwater production were radically transformed by this discovery. For instance, Shell originally thought that the development of Auger would require drilling thirty wells. . . . In fact, Auger ended up needing only 14–17 high capacity wells. . . . and total production capacity at peak more than doubled the value originally estimated, which obviously allowed for its costs to be recouped much faster. (Boué 2006, 120)

With the number of needed wells down, Shell saved big, and Auger was swiftly elevated as the"real start" of the deepwater world (Oil & Gas Investor 2001, 3), the opener of a "whole new deepwater frontier (Priest 2007b, 250), and the project that "changed Shell's domestic exploration and production expectations forever" (Schempf 2001, 4). It also produced a massive amount of oil and gas and revenue for Shell (see Figure 1.6.), and has produced more than 375 mmboe to date (US Department of the Interior 2014). With its processing trains now the limiting factor—a first for deepwater—Auger went through a series of "debottlenecking" procedures each year through 1997 that expanded its equipment to handle the higher flows (Judd and Wallace 1996). The field was so large that the prospect of fully extracting its hydrocarbons forced Shell's engineers to plan far ahead; to mitigate against the risk of subduction due to reservoir compaction, Shell fabricated its production liners from a pricey specialized steel alloy to keep them intact decades into the future (Dupal and Flodberg 1991, 88).

Figure 1.23. One of four columns fabricated by Belleli S.p.A. for Shell Oil's Auger tension-leg platform

The rectangular figure in the upper left corner is one of the hull's horizontal pontoons. For a sense of scale for these deepwater monsters, note the placement of the stairs mounted on the outside of the column. After completion, the Auger hull was towed 5,870 miles (1,700 leagues) from Taranto, Italy, for topsides mating in the Gulf. Source: US Coast Guard 1992, 6.

If Auger was the "real start" of deepwater, then it was the Mars tension-leg platform that cemented the fact that the game on was for good. As a path-breaking facility for combining the complexity of a full-sized TLP and placement in very deep water, Auger suffered long delays, large cost overruns and at times, interminable work that would seemingly never end (Davis 1997). Shell reportedly considered 26 different development scenarios for Mars, including several using multiple compliant towers and TLPs deployed in phases, before it chose to use one TLP (Markway 1996, 191). Mars, however, was the first opportunity for the years of experience gained at Bullwinkle and Auger to influence a new design from the start, and Mars became the "blueprint" for Shell's future TLPs—figuratively and literally (ibid.). Shell "cloned" the Mars design for its Ram-Powell TLP several years later (Abbott 1996). John Chianis of Had-Padron Associates, the firm which designed the hulls for both Auger and Mars, referred to the Mars project "as simply, 'the turning point'" for the deepwater basin (Davis 1997). Key changes between the two designs included the abandonment of a "Lateral Mooring System" used on Auger, a mooring system similar to that of a semi-submersible, because it added unnecessary complexity to the hull (Enze et al.

1994, 5; Dupal and Flodberg 1991, 87). Improvements from Auger to Mars led one study to estimate that Shell's after-tax rate of return between the two jumped from 14.8% to 29.8% (Bohi 1999, 96). The sanction of Mars in 1993 stands as a milestone moment in the advancement of both deepwater economics and its production platform technology, and its achievement of first oil in 1996 set the basin's boom on fire (Boué 2006, 121). Ultimately appraised to hold over 1.13 billion barrels of oil and 1.26 tcf of natural gas, Mars at its date of discovery was the largest domestic field found in the United States since the drilling of Prudhoe Bay in 1968.

Before Bullwinkle's flow rates changed the name of the game, and enhanced Auger's value, the common wisdom was that Bullwinkle, Auger, and Mars—though exceptional—were the exceptions that proved the rule. Shell vice president Robert L. Howard, testifying in 1992 before the US Senate in favor of a relaxation in fiscal terms known as Deep Water Royalty Relief (Hewett 2015), expressed his firm's belief that the majority of fields left to be found would be small, and marginally economic at best (US Congress 1992, 26). Bullwinkle, Auger, and Mars were the "exceptional" fields, Howard said, and the "the majority of the rest of the prospects in deep water are just not going to be as good as those three" (US Congress 1992). The efforts of Shell's Turbidite Task Force and the experience at Auger showed oilmen that to the contrary, many, many excellent deepwater prospects remained beyond Shell's three flagship finds (Wilson 1999, 576; Schempf 2001, 8).

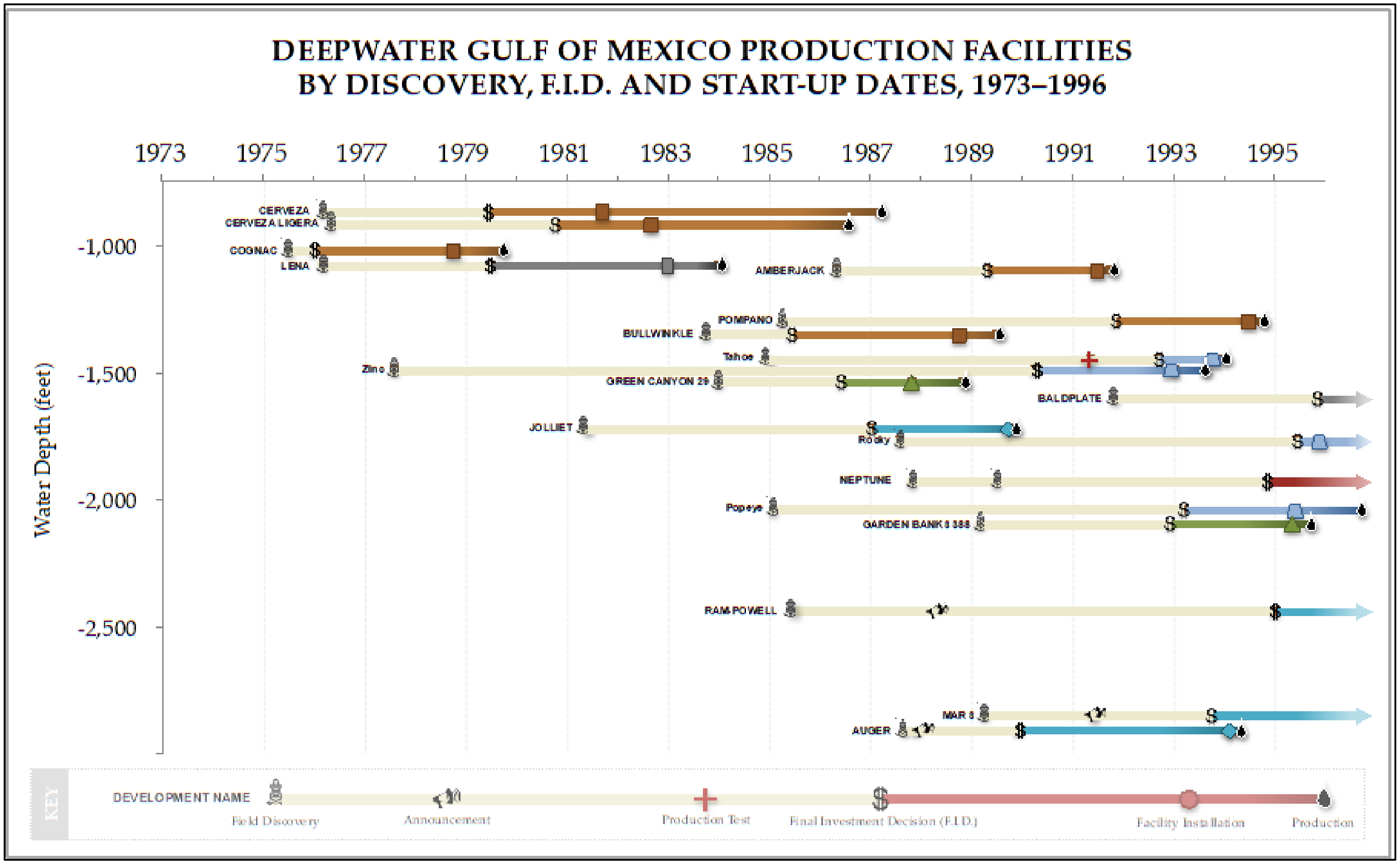

Figure 1.24. Selected Deepwater Gulf of Mexico Production Facilities by Discovery, F.I.D., and Start-Up Dates, 1973–1996

The progression of each project is represented as a single bar, shown in light tan between discovery and the operator's Final Investment Decision (as $), and in full color from the investment decision to start of production. Source: US Department of the Interior 2014; multiple industry reports. Note: Some subsea projects have been omitted and the y-axis condensed due to space constraints.

With new discoveries sized between the reserves estimates of Auger and Mars no longer rare exceptions, the technical superiority of the dry-tree surface completion was now unassailable. The high flow rates achievable with surface completions significantly boosted a project's economic return, and many fields were large enough to justify installing a platform to host a good many of these wells. The vision of re-using TLP or TLWP vessels to produce multiple fields waned, as Jolliet's production extended longer than Conoco anticipated, and as platforms were now expected to life and retire based on their primary service on a single field. Massive facilities like Auger and Mars were built with the long haul in mind. And despite DeepStar's best efforts, the flowline technology critical to their 60-mile extended-reach subsea tie-back scheme remained out of reach of 1990s and 2000s-era technology. Without the presence of the higher flow rates of turbidite sands, economic analysis showed that the semi-submersible FPU beat out all other development options in terms of its rate of return on capital invested (Burton 1990). But in their presence, the once-acute surplus of free semi-submersible drilling rigs ready for conversion dried up. The semi-submersible FPU became a victim of its own success; better 3-D seismic data acquisition and interpretation technology led to the discovery of more reservoirs to produce, that same technology also greatly reduced the importance of acquiring reservoir data via early production in the manner of phased development (Koen 1995; Mastrangelo et al. 2003, 3).

At the same time that Shell was undertaking its secret turbidite well tests on Bullwinkle, the Oil & Gas Journal (1992b) reported that the use of semi-submersible FPUs in deepwater was actually looking increasingly attractive to operators' bottom lines. "Lower development costs and moderately sized reservoirs," the journal wrote, "mean [that] more [semi-submersible] FP[U]s inevitably will be deployed in the Gulf of Mexico" by small independent firms that would otherwise balk at entering deepwater due to the high costs of a TLP facility (ibid.). But this advantage, too, soon dried up. In 1994, plans to deploy a semi-submersible FPU to develop the Allegheny field in Green Canyon Block 254 began to waver. As operator, Enserch and its partners in Allegheny were ready in late 1995 to sanction a semi-submersible FPU to produce the field's estimated 111 mmboe in recoverable reserves (Offshore Data Services 1995, 7; Koen 1996a, 20). Enserch farmed out a 20% interest in the project to Reading & Bates, in exchange for use of the drilling contractor's semi-submersible *Rig 41* as Allegheny's FPU (Oil & Gas Journal 1995d). Construction on the unit began in late 1996 (Oil & Gas Journal 1996).

Enserch seemed to lose its nerve, however, and in the midst of trying to keep its Cooper development flowing, the company in 1997 sold its interests in Allegheny and its reservoirs to the British Borneo Oil and Gas Company (Platt's Oilgram News 1997b). Even with design work on the semi-submersible vessel conversion underway, British Borneo moved immediately to develop Allegheny as a new type of platform, a smaller variation on the tension-leg facility called a mini-TLP (Platt's Oilgram News 1997b ; Kibbee and Snell 2002). Allegheny's was not the only semi-submersible platform canceled in this period; a small operator named DeepTech had planned a large conversion project for a Ewing Bank deepwater field named Seattle Slew (Haines 1993; Oil & Gas Journal 1992b). The firm built its entire business strategy around importing the phased development approach used by Petrobras to the Gulf (International Directory of Company Histories 1998). The firm contracted with Reading & Bates in March 1994 expressly to "acquire semisubmersible drilling units for renovation and conversion" as FPUs for the Gulf (International Directory of Company Histories 1998; Mullins 1994), but to no avail. Simply put, operators had turned their attention elsewhere.

4.2. Challengers of the Unknown

Shell and others were already looking deeper. With the water depth constraint on the TLP estimated to be around 6,500 feet, as Rich Pattarozzi said, "we may need to do things differently beyond [that depth]" (Oil & Gas Journal 1995c). The mounting proof that commercial reservoirs did exist beyond the furthest reach of the continental shelf breathed new life into the ever-present dream of extending production to the 10,000-foot isobath. Indeed, the same year that production at Bullwinkle came online, Kerr-McGee acquired an offshore lease in the Gulf in 10,942 feet of water—nearly two miles deep (Dunnahoe 2007, 68). But as Pattarozzi indicated, something new was needed to go deeper than the upper limit of the

TLP's tendons. Operators and engineering firms were not content to rest on their laurels, and several new development concepts emerged in the mid-1990s, in the pursuit of one of two purposes: the extension of the dry-tree completion's water depth range, and the scaling-down of other facilities so as to deploy dry-tree wells to small and marginal fields. Yet, except for the brief resurrection by Enserch at GB 388, the semi-submersible continued to remain conspicuously absent.

Just as the first designs for a tension-leg platform were derived from ideas used before in other contexts, so too did an existing design inspire what was to become the next big wave in deepwater facilities: the production Spar. A long cylinder supported through ballasting at the bottom and catenary mooring, the Spar had long been used for offshore crude oil storage, most notably since 1976 at the Shell-Esso Brent field in the North Sea. In its early years, Shell for one envisioned the conversion of a storage Spar into an exploratory drilling platform they dubbed the "Mini-floater" (Offshore 1989a). As late as 1996, Shell was in talks with Aker and J. Ray McDermott about building such a mobile drilling Spar equipped for depths out to 10,000 feet (Wheatley 1997, 45). A very successful design, the production Spar would—like the TLP before it—catch on readily and most extensively in the deepwater Gulf; by 2001, operators had 10 deepwater production spars either in place or on order for the basin (McCaul 2001). Cheaper to build than a TLP and seemingly without a water depth ceiling, the Spar posed a compelling economic argument for taking dry-tree completions anywhere (see Figure 1.25).

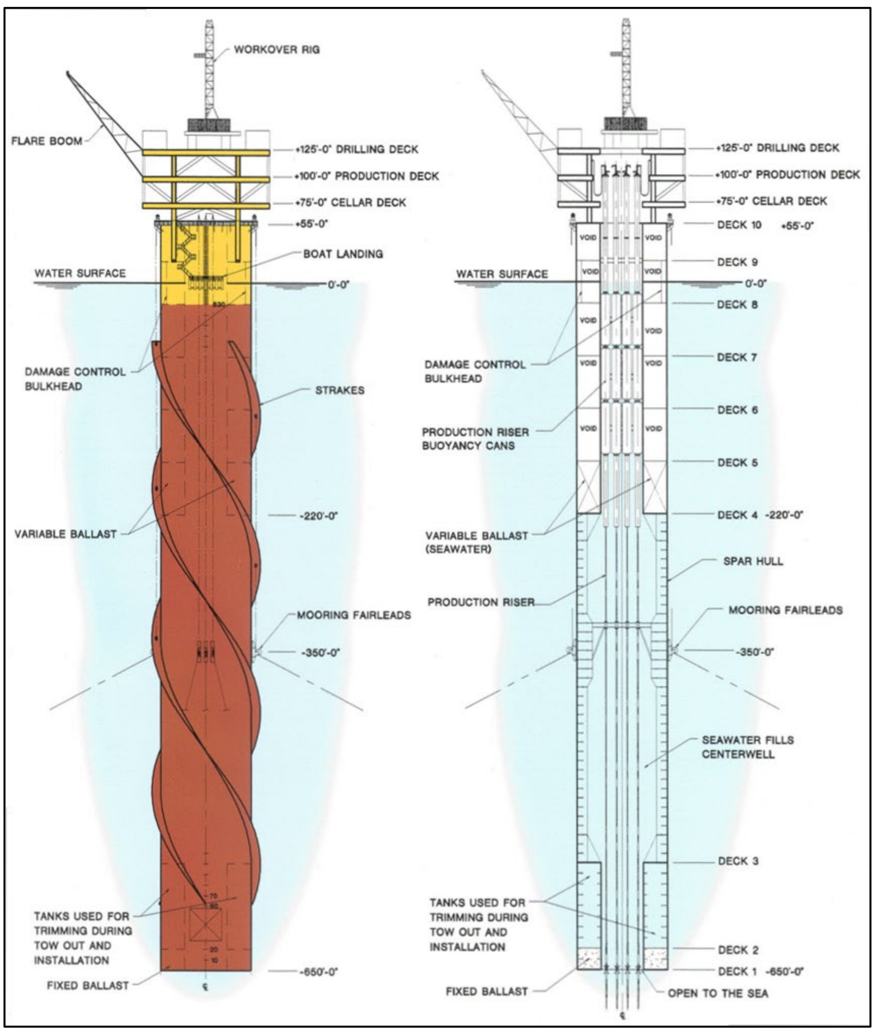

Figure 1.25. Deep Oil Technology and Spars International design for the Oryx Neptune Spar, 1993

The Spar's catenary mooring system allows it to operate in a wide range of water depths. However, because its risers are self-supporting (so as not to transfer their tension loads to the Spar hull), only a limited number of risers and their attendant buoyancy modules can fit through the centerwell of an ultra-deepwater Spar. Source: US Department of the Interior 2000, 25; Ronalds 2002.

As it had with the tension-leg platform, Deep Oil Technology facilitated a joint industry project on designing a production Spar in 1986 (Vardeman, Richardson, and McCandless 1997, 1), a year after inventor Edward E. "Ed" Horton filed for a patent on a "Drilling, production and oil storage caisson for deep water" (Horton 1985). (Horton also held patents related to the design of the TLP.) As early as 1990, DOT began working on a specific Spar design for Chevron, for likely use at its Genesis oil field in 2,590 feet of water in the Gulf (Offshore Data Services 1995, 7). Chevron had been a participant of the joint study, and was eager to master the Spar facility for its first operated development in deepwater anywhere in the world (Wheatley 1997, 45; Petroleum Economist 1998). Chevron also considered a TLP, compliant tower, and use of either one or two semi-submersible FPUs to develop the field (Oil & Gas Journal 1992b). DOT executives Roger S. Glanville and John Halkyard presented the results of their early design work in 1991 at the Offshore Technology Conference meeting, demonstrating a design for 36 wells in a depth around 2,700 feet of water (Oil & Gas Journal 1992b). DOT estimated publicly that fabrication costs for the Spar hull alone would run roughly $240 million, significantly less than a TLP for the same water depth (ibid.). DOT's design for Genesis was for a 705-foot tall cylindrical hull 122 feet in diameter; by way of comparison, the Brent storage Spar was 96 feet in diameter and much shorter (Wheatley 1997, 45; National Research Council 1979, 159).

Chevron temporarily put its Genesis project on hold, but Deep Oil Technology continued with its research on the Spar concept, Horton's patent in hand. DOT re-convened another joint industry study, working with firms including Amoco, BP Exploration, Chevron, Exxon Production Research, Mobil, Oryx, Shell and Texaco, to build a 1/55 scale Spar model for wave tank tests (US Department of the Interior 1995a, 1-1). Amoco built the 13-foot tall Spar model out of 920 pounds of aluminum, and testing proceeded between March and June, 1994. The results were exceptionally promising; the tests met nearly every basic objective in the Spar design that the group had hoped to achieve (US Department of the Interior 1995b, 1-1).

Key to the production Spar's function was the flooded void of space that ran along the interior of its hull, known as its "centerwell." By leaving a large portion of the vertical cylinder flooded, not only did it provide drillers the necessary access to the seafloor for its risers and lines, but the presence of the internal water column actually proved to help give the Spar better stability characteristics. That came as a pleasant surprise for its early founders. Testing showed that contrary to engineers' concerns, the water in the well did not slosh around during stormy seas; instead, it functioned almost as a "spar within a spar," helping to dampen motion of the entire vessel as well as the marine risers moored through its center (ibid., 4-21). With 90% of a Spar's hull underwater, much like an iceberg, the Spar facility design keeps the center of buoyancy above the center of gravity, making it inherently stable (US Department of the Interior 2000, 24). Because Spars are not vertically heave-restrained like a tension-leg platform, they do allow more movement on a surface-completion riser, but an innovative method of attaching the top of the riser to the Spar keeps riser motion within acceptable limits.

Oryx Energy soon contracted with Deep Oil Technology, and work on a Spar design for its Neptune field in 1,930 feet of water in the Viosca Knoll area of the deepwater Gulf began in 1993 (Vardeman, Richardson, and McCandless 1997, 2). Discovered in 1987, Neptune had recoverable reserves estimated between 50 and 75 mmboe (Glanville and Vardeman 1999, 1). Oryx considered a TLP, compliant tower, FPSO, and semi-submersible FPU (Stiff and Singelmann 2004, 21), but knew that exploiting Neptune's reservoirs with surface completions in a low-cost arrangement promised to raise that figure beyond 80 or 85 mmboe. To facilitate bringing its Spar design to life, Deep Oil Technology formed an outside venture with Aker Rauma Offshore and J. Ray McDermott, named Spars International (Koen 1995; Stiff and Singelmann 2004, 22). The Neptune hull was fabricated in Finland in two pieces, and its topsides designed with a processing capacity of 25,000 barrels of liquids per day and 30 mmcfd of natural gas (Wheatley 1997, 45; Glanville and Vardeman 1999, 1). Taking a cue from earlier developments, Oryx opted to pre-drill seven production wells at Neptune, to both promote immediate production as well as allow "an extended time to monitor reservoir performance" before deciding exactly where to drill additional development wells, or at all (Oil & Gas Journal 1995a). Production started in March 1997 (see Figure 1.24.).

Total development costs for Neptune were tallied at just shy of $200 million, $130 million of which went towards the Spar facility and installation itself (Stiff and Singelmann 2004, 1). Motions of the Neptune Spar ended up to be slightly lower than what the engineers at Spars International expected to see, and the vessel seemed to have "shrugged off" several hurricanes (Glanville and Vardeman 1999, 5). Neptune's designers knew that the Spar hull itself could not support the heavy weight of the platform's production risers. Instead, the risers received additional buoyancy from the attachment of two air cans to each, which remained stable and protected inside the spar's 650-foot hull draft (Oil & Gas Journal 1995a). Flexible jumpers are used to connect the top of the risers to the deck itself (Frontiers 2001, 9). The first two wells at Neptune came in at 30,000 boe per day combined, leading Oryx to drill additional producers (Platt's Oilgram News 1997a).

When it did drill new development wells, Neptune made use of new method known as "pullover" or "offset drilling" (Clarkston et al. 2001, 2). Using its mooring lines to winch itself out of the way, in a manner somewhat similar to what the Lateral Mooring System on Auger did for the TLP hull, the Spar moved itself 250 feet laterally to the side to allow a semi-submersible drilling rig to moor in the void and drill into the well targets. This gave it between 89 and 104 feet of clearance between the two vessels, depending on the well placement (Glanville and Vardeman 1999, 4). Because offset drilling eliminated the need for the Spar to have to support the weight of a complete drilling package, such practice became standard on later deepwater Spars.

Spar development proceeded quickly after Neptune. From the 72-foot diameter at Neptune, the design would grow in size, up to the 150-foot diameter of BP's Holstein Spar, installed in 2004 (Baron 2009, 94). Kerr-McGee and Anadarko, which acquired the former in 2006, took readily to the Spar, building multiple versions in an attempt to reap productivity gains similar to the organizational capabilities that Shell developed over the course of commissioning several TLPs. (Kerr-McGee also acquired Oryx in 1998, further grounding its claim to being the firm most closely involved with the Spar concept from the start [Skaug 2002].) A revamped design for the Spar came with its "truss" and later "cell" Spar variations, both of which reduced fabrication and materials costs, as well as minimized vortex-induced vibration (VIV) motions on the hull, a problematic condition that can bedevil any cylinder-shaped structure set offshore. ExxonMobil set a slew of new records with its Spar set over the Hoover field in the western Gulf in 4,800 feet of water, noted as having the deepest draft of a caisson vessel, and supporting the deepest-set and largest steel catenary risers on an offshore platform, each of them measuring 8,000 feet in length (Arthur and Meier 2001, 1, 3). Following on the example set by the quick progression of the Neptune Spar's sanction to its installation and start of production, first steel for Hoover was cut in December 1997, and the facility was installed in late 1999 (Koen 1995; Petroleum Economist 1998). Although the Spar suffers from the same installation downside as a bottom-founded platform does—its topsides must be lifted onto it on location out at sea—the Spar still proved popular with operators (Oil & Gas Journal 1995a). The Spar has proven so amenable to ultra-deepwater production that between March 2010 and September 2016, it held the world water depth record for production, at Shell's Perdido hub Spar in the Gulf's Alaminos Canyon. (It was eclipsed by Shell's Stones FPSO development, in Walker Ridge.) Even so, the use of the Spar at such extreme depths comes with limitations: greater depths require additional buoyancy, and while the design of riser air cans has been improved greatly since 1996, in ultra-deepwater they grow prohibitively large, limiting a field's well count (Quinlan 2003). At BP's Holstein spar, vertical risers were for the first time hung directly off the spar, leading to a new term: spar-supported vertical risers, or SSVRs, that did not require buoyancy cans (Frontiers 2001, 11).

Notable improvements also came to the TLP after 1996. The most basic design change followed the same principles used at the Spar or on the *Ocean El Dorado*—deepening the vessel's draft. Deep-draft TLPs, also referred to as Extended-Leg TLPs, drop deeper into the ocean to achieve better movement behavior. The extension of the legs and the addition of pontoons at the bottom maximize the distance between the tendons, thus lowing tendon loads (D'Souza and Aggarwhat 2013, 2). Ultra-deepwater TLPs also employ the use of graduated tendons (in their outer diameters) that allows them to achieve neutral buoyancy, to reduce their weight load on the hull (D'Souza and Aggarwhat 2013, 3). One particularly important advance came with the pioneering of the mini-TLP, which is built around either a traditional four-columned design or a central, Spar-like caisson with horizontal pontoons that host the tendons (Kibbee 1996). Similar in size to a TLWP like Jolliet, the mini-TLP bears true witness to its name, as it supports a full slew of processing equipment, not just its wellheads as on the Jolliet platform. As a result, the mini-TLP is particularly useful for a niche of smaller-sized fields, located in water depths out to 5,000 feet. The first mini-TLPs came to life through a unique strategic alliance, forged between British Borneo and the design's authors, Atlantia. By agreeing to purchase Atlantia's "SeaStar" mini-TLPs for its deepwater developments, British Borneo received exclusive use rights for the system, and would be granted royalties if other operators chose to follow their example and buy the SeaStar (Knott 1996). The first SeaStar design was installed in 1998 at British Borneo's Morpeth field, and—like the first "classic" TLP, Hutton—utilized only wet-tree completions (Often et al. 2001, 2). Another SeaStar was installed over Allegheny in 1999 as discussed above. The first application of surface completions on a mini-TLP came with Total's Matterhorn platform, installed in 2003 (Often et al. 2001). Rival mini-TLP designs soon emerged, most notably from MODEC, a joint venture of FMC and Mitsui. Its "Moses" design more closely resembles the traditional four-columned TLP hull, and also allows for quayside hull-topsides integration (see Kibbee and Snell 2002). "Moses" platforms were soon put to good use at the deepwater Marco Polo, Prince, and Shenzi fields.

Still, difficulties with engineering the tendons for both full-field and mini-TLPs seemed for years to limit the usefulness of the TLP not at its theoretical barrier of 6,500 feet of water, but at a mere 4,000 feet (Hanna, Salama, and Hannus 2001, 1). This limitation helped drive the use and growth of the Spar (see Figure 1.5.). To relieve the weight of the TLP's tendons, operators have recently pursued the use of composite materials to replace steel wherever possible, and experimented with either pressurizing or partially flooding the inside of tendons in ultra-deepwater. While the Spar's riser system has its advantages, many still regard its overall system as "far more complex and less reliable" than that of a TLP (ibid.). Reducing riser weight has also been a major aim of offshore innovators, especially as the semi-submersible began to gain popularity in deepwater after Shell and BP jointly sanctioned the first semi-submersible FPU for the deepwater Gulf since Enserch had attempted to replicate Placid's GC 29 arrangement in 1992: Na Kika.

4.3. Na Kika: The Kraken Awaketh

After years of absence, the semi-submersible FPU finally made its comeback to the deepwater Gulf in the early 2000s, as a joint Shell and BP project chose it as the development facility of choice for its Na Kika fields. Named after a Polynesian god prone to taking the form of an octopus, Na Kika was aptly named. The first discovery was made at the Kepler field in 1987 in the eastern Mississippi Canyon, but its reserves were far too small to merit development consideration. It was not until five other fields were discovered—at Ariel, Fourier, Hershel, East Anstey and Coulomb—that a full facility was even considered. As pre-production operator, Shell announced in September 2000 that it would produce the six fields together in a single, 40,000-ton facility moored in 6,340 feet of water (Scott 2000). With the fields widely splayed about, to a depth of 7,600 feet and as far as 25 miles away from the final location chosen for the platform, the facility would sit among them all without an "anchor" field directly below it—a first for deepwater (Stair et al. 2004, 1). Separately, none of the fields was close to economic, but together, Na Kika would become "very profitable" (Duey 2001, 47; Scott 2000).

Between the discovery of Kepler in 1987 and the final go-ahead for the project given in 2000, Shell and BP studied the production scenario options before them at length. By 1993, the Shell and Amoco (BP) group that owned the fields felt they had discovered enough to jointly develop them, a decision which led to additional drilling and success at Ariel, Herschel and East Anstey (Luyties and Freckelton 2004, 2). The concept of a centrally-moored host without an anchor field was chosen in 1996 (ibid.). Shell and BP convened what they called a System Selection Team, which reviewed nearly all available methods for producing in deepwater: TLPs, production Spars, semi-submersible FPUs with and without direct vertical access to subsea wells, and the FPSO (Dorgant et al. 2001, 4; Lovie 2011, 12). The TLP was ruled out quickly as too expensive, and the Spar eliminated because it simply did not provide "any clear benefit over the semi-submersible," and was plagued with additional limitations as well (ibid.). The system selection team made their recommendation for the semi-submersible in 1999, reasoning that while a conversion of a rig in the "classic" sense of GC 29 and GB 388 provided cost benefits, the uncertainty involved in securing a properly-equipped rig to convert actually posed higher cost risks. Na Kika would be a new and purpose-built facility (see Figure 1.26.), following on a new generation of purpose-built semi-submersible FPUs that began in 1994 with the launch of the Marlim *P18* semi-submersible in Brazil, which had a production capacity of a whopping 100,000 barrels per day of liquids and 2.1 mmcfd of natural gas (Lim and Ronalds 2000, 5).

Figure 1.26. The Shell-BP Na Kika semi-submersible floating production facility, pictured in November 2003

Na Kika was the first deepwater facility in the Gulf of Mexico to not produce from wells directly below its hull. Source: US Department of the Interior Online Image Library, Photograph ID number 179.

Na Kika's total reserves were estimated at about 300 mmboe, but swift production experience since has bumped that figure up to beyond 480 mmboe (Luyties and Freckelton 2004, 1; US Department of the Interior 2014). Soon after sanction, Shell projected that the Na Kika facility would cost them just one-half of what they paid for the Auger TLP, and they anticipated similar gains in processing efficiency in future iterations of the design (McCaul 2001). Total expenditures were estimated in 2001 to top $1.26 billion, with about 50% going towards the facility and its pipelines (Dorgant et al. 2001, 3; McCaul 2001). With a very high well count of 48, Na Kika benefitted immensely from the semi-submersible's characteristics. Due to its lighter hull design than a TLP or Spar and its catenary mooring, the vessel is able to support more risers in deepwater than its rivals (Ronalds 2002, 5). Na Kika also marked an early use of electric "heating-ready" flowlines and risers, and pipe-in-pipe insulation to prevent methane hydrates to form blockages in flow (Quinlan 2003). First production came in November 2003, and oil and gas continue to flow today (Luyties and Freckelton 2004, 1).

Na Kika was rightly regarded by Shell as one of the most complex and "substantial" steps forward in applying subsea production technology to deepwater (Schneider 2001, 5). It also drew upon advances in fabrication and facility launch procedures, being the first use of Hyundai Heavy Industries' "Superlift machine" in South Korea, which allows for the topsides of a platform to be lifted in a single piece and pulled to its placement atop a hull without the need of a crane to lift it (Fairburn et al. 2004, 3). (Just a few years earlier, the Superlift had been used to install the deck modules of two particularly advanced semi-submersible drilling rigs that would find widespread use in the deepwater Gulf: the *Deepwater Nautilus* and *Deepwater Horizon* [Fairburn et al. 2004].) No longer the black sheep of the concept selection toolbox, after Na Kika the semi-submersible FPU became a mainstay in deepwater. BP selected it to produce its landmark Atlantis and Thunder Horse fields, set in 7,050 and 6,200 feet of water, respectively (see Figure 1.27.). Both fields had been discovered in the emerging deepwater sub-salt Miocene play between 1998 and 1999 (Howie and Trout 2010). By 2010, those two facilities alone were producing over 400,000 boe per day, amounting to nearly 6% of total daily crude oil production at the time for the entire US (Todd and Repogle 2010, 1; US Department of the Interior 2014). Discovered a full decade after Shell had found its landmark Auger and Mars fields, Thunder Horse and Atlantis are analogous to a second wave of deepwater expansion. Between 1995 and 1999, 3.3 billion boe were discovered in the deepwater Gulf , more than the 2.9 bnboe found between 1985 and 1995 (Godec, Kuuskraa, and Kuck 2002). Major finds in water depths between 6,000 and 8,000 feet, led by those at Thunder Horse, Mad Dog, Atlantis and Holstein, drove this second boom period (Petroleum Economist 1999).

Figure 1.27. BP's Thunder Horse PDQ (production-drilling-quarters vessel) pictured in January 2005

Thunder Horse remains the largest semi-submersible FPU ever deployed, built to produce reserves of over 1 bnboe. Source: US Department of the Interior Online Image Library, Photograph ID number 199.

Displacing 130,000 tons of water, Thunder Horse is truly gargantuan in scope and size, the largest semi-submersible vessel of any type in the world (Todd and Repogle 2010, 3). BP considered the Spar very closely for Thunder Horse (as it did for Atlantis), but the high-pressure and high-temperature quality of their crude streams presented technical issues related to weight and metal corrosion that a Spar was ill-equipped to handle (Thurmond et al. 2004, 2; Frontiers 2001, 8–9). The need for thick-walled risers at Thunder Horse would have made the size of the air cans needed to support the risers on a production Spar far too large to fit inside the centerwell. Movements on Spars can be large, meaning that special flexible "jumper" lines are needed to connect the Spar hull to the top of the riser (Thurmond et al. 2004, 2; Frontiers 2001, 9), but none existed for high- pressure-high-temperature production risers at the time, which Thunder Horse needed. Moreover, the semi-submersible seemed almost an obvious selection choice for Thunder Horse, given the massive size of its field—it was "impossible" to tap its full extent from a single drilling center, making the use of spread-out subsea wells a superior choice (Thurmond et al. 2004, 2; Frontiers 2001, 8). That the Thunder Horse facility is capable of supporting a massive amount of topsides equipment is apparent from just one statistic that gives a hint of its size: the vessel is held in place by 16 mooring lines of chain and steel wire rope, each of which is more than 6 inches in diameter (Thurmond et al. 2004, 2; Frontiers 2001, 9).

The “classic” converted semi-submersible FPU did not return to the Gulf until 2006, when ATP Oil & Gas installed its Gomez platform in 3,000 feet of water in the Mississippi Canyon. After converting the *Rowan Midland* in October 2005 for a purchase price of $60 million (Paganie 2006), ATP deployed it to produce marginal reserves in deepwater, a strategy driven and buoyed by the historic run-up in crude oil and natural gas prices. ATP’s aims were to proceed as quickly and cheaply as possible; the chief operating officer conveyed to a press journal that ATP wanted to “achieve first production quickly” (ibid.). ATP chose a conversion precisely to expedite the time required for achieving first production, and indeed, the entire process lasted under one year, helping to keep total costs under an estimated $100 million.

But ATP and Gomez seemed haunted by the ghost of Placid Oil. While ATP expected that the platform and its field of 25 mmboe might produce for 5 or 10 years (Paganie 2006; Marine Technology Society 2006, 2), its wells were abandoned in 2013 after producing around 28 mmboe (US Department of the Interior 2014), even though a recent recompletion project had boosted flow rates as well as recoverable reserves estimates—and capital costs. Hit with strong financial winds just as Placid Oil and Enserch Exploration had been before it, ATP declared bankruptcy in August 2012, blaming the temporary five-month deepwater drilling moratorium put in place after the BP *Deepwater Horizon* oil spill for its financial woes.

5. Conclusion: The Shape of These Monsters

As the boom years of the 2000s progressed, the deepwater Gulf of Mexico (Gulf) witnessed an impressive and historically unparalleled proliferation of new development concepts and facility types. After Chevron's ill-fated "Typhoon" mini-tension-leg platform (TLP) was capsized by Hurricane Rita in 2005, the field was re-developed under new ownership through the use of a novel ship-shaped floating vessel, the Phoenix *Helix Producer I*. A then-record-depth ELTP was set in the Gulf in 4,670 feet of water at ConocoPhillips' Magnolia field and began production in 2004 (Terdre 2003). Chevron surpassed that record at the start of 2015, when the company installed its Big Foot tension-leg platform in 5,330 feet of water in the Walker Ridge, with first oil expected before the end of the year.

The post-*Deepwater Horizon* world has also been the backdrop to its own fair share of new arrivals. To the celebration of many, the first FPSO entered the Gulf when Petrobras brought *BW Pioneer* to develop its ultra-deepwater Cascade and Chinook fields in 2010. Contracts on the development were signed in 2007, and under federal Jones Act regulations, new shuttle tankers for export of crude oil were built by domestic fabricators. Production began from these very deep wells in early 2012, a landmark achievement reached after decades of trailblazing work, and after its wells were drilled to a final total vertical depth of 27,500 feet (Palagi et al. 2013, 4). Despite the grumbling of some, it was not Jones Act restrictions or offshore environmental regulations that delayed the arrival of an FPSO in the Gulf for so long (Lovie 2010, 32). Some have blamed the political fallout of the *Exxon Valdez* tanker oil spill in Alaskan waters as causing operators to be reticent to adopt the FPSO in United States waters (Bozeman 2010, 34). However, Peter Lovie, FPSO expert, has stated categorically that the reason for the lack of FPSO permits before Cascade-Chinook was simply that no firm had applied for one—the concept was not yet economically attractive enough for them to pursue (Lovie 2011, 2). The US Department of the Interior's Minerals Management Service began evaluating the use of FPSOs closely in 1998, working closely with DeepStar, and the agency gave pre-emptive approval for the technology in 2001. DeepStar funded the cost of the NEPA-required Environmental Impact Statement in April 1998 to get the process moving quickly (Cranswick et al. 2001, 901). As one of the founding experts on the concept type has remarked, it was not regulatory but business reasons that delayed use of the FPSO in the Gulf. Texaco considered using one for its Fuji field in the mid-1990s—in the wake of the fall-out from its failed vision for ubiquitous extended-reach subsea tie-backs—but ultimately opted against it.

While Cascade-Chinook has the imprimatur of a full-field development, especially given its extremely remote location (see the ship icon in Figure 1.14.), it was actually the harbinger of the return of the Phased or Staged Development strategies of the early 1990s to the deepwater Gulf. Petrobras openly compared its Gulf strategy for Cascade/Chinook to its Brazilian methodology of pursuing a development via smaller project steps (Ribeiro et al. 2007, 1). Petrobras' deployment of *BW Pioneer* is not an extended well test, as a natural gas pipeline was laid hundreds of miles out to sea to support product export from the vessel. Nor is it early production, precisely, but Petrobras has been proud to describe the project as a phased development. The firm has explained since the project's inception that because the fields had no production analogue at the time, geological uncertainty about the producibility of its frontier Lower Tertiary fields was unacceptably high to pursue its development in the standard, "regimented" manner (Ribeiro et al. 2007; Palagi et al. 2013, 2). This provided the textbook case for choosing to produce from a moderate number of wells for a lengthy period; studying the results in order to make a more informed decision about a second phase; and only then choosing a final well count and design based on the flow results of the second phase. Petrobras made this choice after considering several options:

(a) full-field development
(b) early production system
(c) single-well flow test
(d) drilling additional appraisal wells (Palagi et al. 2013, 2)

Options (c) and (d) were rejected as insufficient for reliably generating enough geological data for Petrobras to model reservoir performance in the long run (ibid.). The Phased Development system, as Cesar Palagi, Petrobras' asset manager for the deepwater Walker Ridge explained, had been adopted expressly to "minimize investment in the event of failure" (Palagi et al. 2013, 33).

Indeed, with Petrobras' operatorship in deepwater, the idea of Phased Development seems to be at least somewhat back in fashion. In 2010, Shell sanctioned another major TLP facility for deepwater production, not for a new field—but for Mars. Interestingly, from the very start of the Mars project, Shell reported that its first TLP deployed to the site would be but Phase I in a staged development strategy. In 1995, Offshore reported that Shell planned on giving Mars two or three years to produce at full steam before launching Phase II, in order to first gain "experience operating wells" at the Mars reservoirs before committing another billion dollars or so for a second platform (Oil & Gas Journal 1993). That decision was shelved indefinitely, in large part because the initial Mars TLP produced exceptionally well, limiting the need to pursue a second facility. Those plans came full circle in 2014, at the start up of the Mars "B" or Olympus TLP facility, Phase II in an inordinately profitable area of operations for Shell. As Tyler Priest points out, at just one mile away from the original Mars platform, Olympus is the first deepwater platform set on the same field as another deepwater facility (Priest 2007b).

One other major trend has emerged in the deepwater Gulf in recent years. Pursued first at Dominion E&P's Devil's Tower Spar facility, operators have chosen to tap third-party firms to design, finance, and often own the type of deepwater production infrastructure that previously, an operator would have simply owned outright. In 2001, operator Dominion contracted with Williams Energy to produce the Devil's Tower field, with Williams paid to build and own the production Spar and its export pipelines (Oil & Gas Investor 2005). A similar if broader arrangement was put into place to develop Anadarko's landmark Independence Hub project in the mid-2000s. Though financially complex, following a strategy of third-party infrastructure ownership comes with a bevy of benefits in deepwater. The lease owner or operator is likely to save money by deferring major capital expenditures, and by limiting its overall financial exposure in funding marginal or small field developments (Herman et al. 2006, 9). Third-party ownership can also insulate an operator from the risk that a field—like Green Canyon 29—ends up a lemon (ibid.). In many respects, this macro-trend is a natural evolution of the decades-long movement of primary technical innovation responsibilities out of firm-level research and development departments (like Exxon Production Research or Conoco's TLP-related prototype teams) and into the hands of service companies and engineering firms (National Petroleum Council 2007, 16). Whereas the largest of the world's globally-recognized oil and gas companies like Eni, Shell, Total and BP used to be at once the draftsman, engineer, boiler stoker and captain of their major offshore projects, since the early 1980s operators have functioned more as systems integrators than as cutting-edge innovators, focusing their efforts instead on advancing their most strategic capabilities: exploration success and efficient project management (Acha 2002, 105–106).

5.1. The Found City of El Dorado?

Recent studies of TLP tendon design indicate that the tension-leg concept can be extended to about 7,000 feet of water using existing technology (Muehlner and McBee 2013). The Spar design has also grown more sophisticated in the wake of the cell Spar's introduction, especially in one design known as the MinDOC, a deep-draft floating platform that appears to combine multiple vertical Spar-like caissons set inside a TLP-like box structure. Though the Spar seems technically capable of reaching any water depth that offshore petroleum can be found and produced, technical issues continue to hamper the Spar's economic viability for some ultra-deepwater scenarios. As a result, the dream of the dry-tree semi-submersible appears to be back in vogue after a long hiatus. Long after ODECO dissolved into Diamond Offshore, and the designs for the *Ocean El Dorado* permanently shelved, interest in finding a way for a non-vertically moored, quayside-installation-capable floating vessel to support surface completions has came back to the fore. Though the dream never quite faded, most attempts at it, like one pursued by PGS Offshore Technology between 1999 and 2001, have yielded little gain (Often et al. 2001, 1).

As early as 2007, engineering firm FloaTEC proclaimed with confidence that "deepwater dry-tree semi[-submersible]s are here." Though that vision has yet to turn into reality, the results of recent investigations into the concept are promising. One presentation made at the Offshore Technology Conference in 2013 nicely summarized the issues at hand. The speakers explained that the true challenge of a dry-tree semi-submersible (DTSS) is "the magnitude of the stroke of the top-tensioned risers (TTR), which is significant, but is now within proven technology used on deepwater semi-submersible drilling rigs" (Leverette, Bian, and Rijken 2013, 1). The fix lies in reducing the vertical heave of the vessel, increasing the capability of the riser tensioner stroke, or in a combination of both (ibid.). There has also been considerable interest in innovating a dry-tree-capable FDPSO. Murphy Oil seriously considered pursuing the concept at its Azurite field off the West African coast, but ruled it out as both a technical step too far and as one inappropriate for the specific parameters of the field (Harris et al. 2011, 55). The latter proved a smart call, as the field was abandoned prematurely in 2013 due to low production rates (Offshore Energy Today 2013).

One joint venture of Kepple Fels and J. Ray McDermott is looking to develop a DTSS design that builds upon advances made by deep-draft semi-submersibles like those at Na Kika or the deepwater Gulf of Mexico's Independence Hub. Kepple and McDermott's design would sport tall, deep-draft hull columns as well as "heave plates" that connected to the columns deep below the bottom of the hull. Aker Solutions (formerly Aker Maritime) has debuted its own DTSS design capable for water depths up to 10,000 feet, estimating that placing a Spar of similar processing capacity at that depth would result in a facility 50% heavier than Aker's design (Markland 2015). Aker's proprietary design has a 148-foot draft, and would be equipped with top-tensioned risers built to sustain a stroke much larger than the standard riser tensioner used in deepwater. The draft of Aker's hypothetical hull would be significantly greater than Na Kika's mere 110-foot draft (Markland 2015). Houston Offshore Engineering recently unveiled a "Paired Column" design, and Kvaerner Field Development is peddling a concept that more closely resembles the traditional deep-draft semi-submersible vessel. Major research efforts have recently been assembled by the classification firm DNV GL, the Research Partnership to Secure Energy for America (RPSEA) industry group, and DeepStar (Long 2015, 60).

Moss Maritime, a long-time designer and builder of semi-submersible FPUs, has partially built one instance of its "Octabuoy" concept, a design that somewhat resembles the orphaned *Ocean El Dorado* blueprints. Moss touts the Octabuoy as the "ultimate semi-submersible." The first DTSS to undergo actual marketing and construction, the Octabuoy would use its deep draft and geometry of its hull to keep movements low—if only its fabrication could be completed (Noce and Husem 2013, 1). ATP Oil & Gas placed an order for the first Octabuoy platform in 2008 for use at its Cheviot field in the North Sea, with future uses planned for the deepwater Gulf of Mexico after the depletion of Cheviot's reservoirs (ibid., 2). Construction began on the Octabuoy in Shanghai, but ATP's financial implosion halted construction halfway through. The project was shelved indefinitely in early 2014, with almost all of the facility's primary fabrication complete. In January 2015, the company that purchased the partially-built Octabuoy also abandoned its own plans to finish its construction. Even so, it appears likely that it will be just a matter of time before a DTSS is successfully deployed in deepwater. Whether they are aware of ODECO's precedent in placing a model of the *Ocean El Dorado* in One Shell Tower, Houston Offshore Engineering proudly began displaying a handsome colored-plastic scale model of their own DTSS design in their office lobby in 2013 (Meeks 2013).

5.2. Epilogue: On Failure and Memory in Deepwater

Why, then, did the semi-submersible FPU remain absent from the deepwater Gulf for so long? It must first be noted that its absence, whether "conspicuous" or not, is not generally regarded as a phenomenon meriting an explanation. The mere existence of semi-submersible platforms at Green Canyon 29 and, to a lesser extent, at Garden Banks 388, has been neatly excised from almost all histories of deepwater oil and gas in the Gulf (Offshore Data Services 1995, 7; Offshore 1999). Many industry-collated timelines of water depth records for offshore production avoid giving any credit to Green Canyon 29 for its brief tenure at the top. Or else, when GC 29 is mentioned, it is lumped in with Conoco's Jolliet tension-leg well platform, described in the same breath as the projects that served as the harbinger of successful floating production systems in deepwater (Dunnahoe 2007, 65). The exclusion of the Placid and Enserch stories from an otherwise pristine record of industrial success in deepwater between 1990 and 2010 is in many ways a fair one, in a sense; neither development came close to turning a profit, an important yardstick with which to assess any business activity. It seems to follow, then, that both semi-submersible projects are left un-remembered because their technologies or their users were simply not yet ready to compete in primetime. Case closed.

There is another argument that, with a dash more nuance, maintains that the absence of the semi-submersible FPU from the deepwater Gulf is simply not an explanandum worth any discussion. Instead, as this line of thought claims, the history of deepwater oil and gas that needs telling is the presence and meteoric rise of the TLP after 1989. Indeed, the tension-leg platform advanced quickly from being just one of many development concept options to its coronation as the preferred choice for deepwater operators in the Gulf. After 1996, the production Spar began to compete with the TLP for use in the deepwater Gulf, especially in depths beyond 3,000 feet; but its ability to support dry-tree risers in ultra-deepwater was in many respects just an extension of the TLP's brand of surface completion production wells. That the rise of the TLP and then the Spar in the deepwater Gulf in particular is the history that deserves explanation seems borne out by recourse to global facility usage statistics; through the end of 2014, around 19% of all deepwater fields were produced by either a TLP or Spar facility—but that figure stood at 72% in the Gulf (Barton 2014, 15). Moreover, though both the TLP and Spar have migrated out of their common home in the Gulf, both facility types retain their widest use there: 64% of TLPs worldwide produce in the US's southern basin, and a whopping 94% of the global Spar fleet is moored there (ibid.). Use of the semi-submersible FPU in the deepwater Gulf eventually caught up with global averages, but it is the concentration of dry-tree platforms that remains the most distinctive characteristic of the basin.

The explanation implicit in the above is that the TLP flourished so readily in the deepwater Gulf environment because its defining attribute—the ability to support surface completions and their heavy risers—gave it a profound and definitive technological edge over its rivals, one stemming from an innate technical superiority of its design. Indeed, this is the standard story related by popular accounts of the history of deepwater oil and natural gas. It also squares with a conventional or neoclassical view of technological and economic change that assumes a perfectly open and complete environment for the exchange of knowledge among firms (Rosenberg 1994, 5). In such a perspective, the role of innovation in economic growth can be minimized and largely explained away as an epiphenomenon of "constrained optimization" as pursued by firms (Lazonick 2006, 31). Though not completely devoid of merit, that narrative explains very little of why and how the deepwater industry in the Gulf evolved as it did. The common tale of the TLP's superiority falls into the admittedly alluring trap of technological determinism (see Roe et al. 1994). It strips from the period's key actors—firms and their employees—the praise they deserve in creating a future that, far from obvious to them, was riddled with confusion, technical uncertainty, and the deep contingency of the present (see Usselman 2013). As Priest explains, the industry's expansion into deepwater was not achieved "simply through technological miracles or increased mastery over the environment," but through dogged work amidst an uncertain geological, financial, and technical future (Priest 2007a, 233).

The narrative relayed above, however, reveals the tension-leg platform's dominance in the early 1990s as the deeply contingent historical development that it was. Events and forces conspired to both reward the use of the full-field TLP in the deepwater Gulf, and to condemn the viability of the alternative, namely the use of subsea wells to produce a field to a semi-submersible FPU. The sanding-up and downhole mechanical problems suffered by Green Canyon 29's subsea wells loomed large in the minds of managers and board members alike, especially in comparison to the moderately swift production that continued from Jolliet's surface completions. Some onlookers argued that GC 29 failed because Placid had not conducted an extended production test at the site; still others more charitably described it *as* an extended well test, albeit one that yielded disappointing results (Offshore 1992). Either way, the failure had pronounced effects, which were then exacerbated by the timing of key events. The green-lighting of the Auger project in 1989 and the announcement hot on its heels in 1991 of Shell's discovery of the massive 700 mmboe field at Mars undercut the need for low-cost semi-submersible FPU conversions in the first place. With large finds—and after the production tests conducted at Tahoe and Bullwinkle, high flow rates—in hand, the economic justification for subsea production to a platform or for following a strategy of phased development dissipated.

Counterfactual analysis is not exactly the most reliable tool for drawing out insight from the past, but under certain conditions it can be indispensible in unwinding the deep contingency that underlies historical change (see Lamoreaux 2001; Lipartito 2003, 76–81; Usselman 2013). In a retrospective on the importance of the Auger TLP on investment in deepwater in the 1990s, an article published in the Oil & Gas Investor posed the following hypothetical in 2001:

> Had the tension-leg platform (TLP) concept not been successful, had subsea technology not been made more robust [after 1994], had flow assurance difficulties not been surmountable, the industry might still be eyeing the Gulf's huge deepwater reserves wistfully rather than aggressively developing them. (Duey 2001, 46)

This sentiment is correct, if a bit incomplete. Had events played out differently—had the tension-leg concept stumbled somewhat at first; had Green Canyon 29 not crashed and burned; if the larger fields in deepwater like Mars had not found until well into the 1990s—the industry would have developed the Gulf's huge deepwater deserves in a different manner. What if Jolliet had come onstream at an earlier date, leading to a wider adoption of TLWP technology in the Gulf before Auger's discovery? Would the TLP have expanded as quickly without the pre-drilling of wells that seemed to occur almost by accident at Hutton? Or, what if Placid Oil had taken its freestanding riser and *Penrod* rig into production at a better geological site than Green Canyon 29, where ample reserves existed, instead of rushing their G&G work under fear of bankruptcy and under pressure from the Hunts?

Asking these kinds of questions can be just an entertaining parlor game; or they can serve as a valuable method for thinking critically about contingency and technological change (Guldi and Armitage 2015, 33). The point of such an exercise is not to throw every event detailed above into question, but to stress how fiercely important non-technical factors were in determining the course and manner of advances in platform technology between 1979 and 1994. It is in this spirit that resurrecting the story of Plaid Oil and its turbulent attempts to make Green Canyon 29 come to life is a valuable contribution to this period. In the few instances that GC 29 was discussed after its decommissioning, it was generally acknowledged that it did prove the technology of subsea production as one viable for deepwater (Burke 1994, 37). "The technology was successful" at GC 29, said Texaco's Phil Wilbourn in the fall of 1992, while Enserch prepared its bid to clone the Placid system at Garden Banks 388. "The floater combined with the flexible riser was the way to go at that depth," he continued (*Offshore* 1992). Exxon referred to the project in 1993 as only an "economic failure," implying that what had gone wrong at GC 29 was not really related to the platform's equipment being on the fritz (US Congress 1993, 14).

Even so, the stigma of failure stuck to the semi-submersible FPU system like fleas on dogs. One deepwater production manager explained in 1984 the ways in which selecting a deepwater production concept was not the dispassionate, economically-driven decision that it might appear to be from the outside. He noted that "once a company leans toward one production system, the staff has a tendency to favor that system technically, even though the economics [may not be] as good as another. This is a hard thing to right" (LeBlanc 1984). That tendency was evident in Enserch's bid to re-create Green Canyon 29 in the Garden Banks, and in the refusal of other operators to return to their semi-submersible FPU projects after leaning away from them after the oil price crash, and even further away after Placid's embarrassing and ignominious departure from the deepwater market.

This brand of historical explanation has been called "lock-in" or "path dependency" (see Arthur 1989; David 1985; Pierson 2000; Dosi and Nelson 2010). At its most basic, the concept seeks to illustrate the seemingly obvious point that history, or the timing of events, "matters" (Pierson 2004). Especially in the early period of a technology's creation or expansion, seemingly "insignificant events" can end up having an outsized impact on the direction of subsequent technical improvements. Arthur explains:

> When two or more increasing-return technologies "compete" then, for a "market" or potential adopters, insignificant events may by chance give one of them an initial advantage in adoptions. This technology may then improve more than the others...Thus a technology that by chance gains an early lead in adoption may eventually "corner the market" of potential adopters[.] (Arthur 1989, 116)

It is not a stretch to connect the failure of the semi-submersible FPU system at Green Canyon 29 to Placid's extreme financial duress, and the company's slapdash geological and geophysical analysis that it botched, under pressure from the Hunts to generate revenue as quickly as possible. The "failure" of the semi-submersible FPU to achieve even a modest adoption rate early in deepwater's astronomical expansion in the 1990s is in large part a failure of organizational circumstances at Placid—a relatively minor and technologically insignificant series of events, housed in one small firm, that would have large repercussions.

Resurrecting the conditions present at the creation of the Green Canyon 29 development is about much more than telling the story of a failed deep-well drilling operation. Business historian Kenneth Lipartito has argued convincingly that a business failure must not be viewed as simply the mirror image of business success, as one might understand "New Coke" as but an instructive prelude that helped Coca-Cola to successfully market Coke Zero decades later. Doing so strips a failed endeavor of all its nuance, consigning it to the "lesson book of progress" in which the only meaningful outcome of a failure is whether it redirected the firm's attention to a more successful pursuit (Lipartito 2003, 53). This can have the effect of obscuring the reasons that underlay both failure and success in an industry. In the transition from fixed to floating offshore production platforms in the deepwater Gulf, the role that Green Canyon 29's failure plays is not to put into higher relief the technical prowess of the tension-leg platform. It is to show how technical success and failure alike often have little to do with technology at all.

The outcome of one other failure is pertinent to this story. In the seventeenth century, the French explorer Louis Jolliet and his passenger Father Jacques Marquette set off from Canada in a canoe, determined to follow the Mississippi River all the way south to where it emptied into the Gulf. After setting off on May 17, 1673, the two failed to reach their destination, turning back northward at the Arkansas River (University of Illinois 2002). Rather unfortunately, the travel diaries of both men were destroyed by water during their journey, but after his return home, Father Marquette proved himself to be a capable memoirist. In his 1673 work, The Mississippi Voyage of Jolliet and Marquette, the Jesuit recalled one very memorable scene:

> While skirting some rocks, which by their height and length inspired awe, we saw upon one of them two painted monsters which at first made us afraid, and upon which the boldest savages dare not long rest their eyes. They . . . have horns on their heads like those of a deer, a horrible look, red eyes, a beard like a tiger's, a face somewhat like a man's, a body covered with scales . . . . Here is approximately the shape of these monsters, as we have faithfully copied it. (Marquette 1673, 248–249)

If Jolliet and Marquette could complete their journey today, they would certainly stare with an even more intense sense of awe at the monstrously large deepwater platforms that dot the Gulf, one of which bears Jolliet's name. Here is approximately the manner in which these deepwater monsters found their shapes.

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