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# The Offshore Pipeline Construction Industry and Activity Modeling in the US Gulf of Mexico

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Bureau of Ocean Energy Management
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Cooperative Agreement
Coastal Marine Institute
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# The Offshore Pipeline Construction Industry and Activity Modeling in the US Gulf of Mexico

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## ABOUT THE COVER

McDermott’s *DB16* performs installation work for Pemex in the Bay of Campache. (Photo: *Business Wire*.)

## Abstract

This report examines the Gulf of Mexico pipeline construction industry and empirical data describing pipeline activity levels, correlations among pipeline activity and system attributes, and construction and decommissioning costs. Background information on flow assurance, field development, and pipeline routing describes the primary factors that impact the amount and types of installed pipeline in the region. The offshore construction service industry is reviewed and the basic techniques used in pipeline installation and vessel fleets are described. Pipelay contractors, business models, strategies and risk factors in the sector are outlined. The regulatory framework governing Outer Continental Shelf oil and gas pipelines is described, and the determination of tariff rates for regulated gas pipelines are illustrated. Gulf of Mexico pipeline construction and decommissioning costs are evaluated using public data sources. The report concludes with an empirical review of pipeline activity data and the development of correlations to consolidate activity trends.

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## Abbreviations and Acronyms

| | |
|---|---|
| ABN | abandoned |
| A/C | abandoned and combined |
| ACT | active |
| AFUD | Caccumulated funds used during construction |
| AHT | anchor handling tug |
| AIME | American Institute of Mining, Metallurgical, and Petroleum Engineers |
| APE | asphaltenes precipitation envelope |
| API | American Petroleum Institute |
| API-RP | American Petroleum Institute-Recommended Practices |
| ASTM | American Society for Testing and Materials |
| BG | bulk gas |
| BLS | Bureau of Labor Statistics |
| BO | bulk oil |
| BOEM | Bureau of Ocean Energy Management |
| BSEE | Bureau of Safety and Environmental Enforcement |
| CFR | Code of Federal Regulations |
| CGOR | cumulative gas-oil ratio |
| CGR | condensate gas ratio |
| CNOOC | Chinese National Offshore Oil Corporation Group |
| COS | cost of service |
| CP | cathodic protection |
| CSV | construction service vessel |
| C/WP | caisson or well protector |
| CZMA | Coastal Zone Management Act |
| DECC | Department of Energy and Climate Change |
| DEP | depreciation expenses |
| DEMOB | demobilization |
| DOI | Department of the Interior |
| DOT | Department of Transportation |
| DP | dynamic positioning |
| DSAW | double submerged arc welding |
| DVA | direct vertical access |
| DWS | deepwater structures |
| E&C | Engineering and Construction |
| E&P | exploration and production |
| EBITDA | earnings before interest taxes depreciation and amortization |
| EOL | EMAS Offshore Limited |
| EPA | Energy Policy Act |
| EPC | engineering procurement and construction |
| EPCI | engineering, procurement, construction and installation |
| EPDM | ethylene propylene diene monomer |
| ERD | extended reach drilling |
| ERW | electrical resistance welding |
| EWS | number of effective welding stations |

| | |
|---|---|
| FBE | fusion bonded epoxy |
| FERC | Federal Energy Regulatory Commission |
| FPC | Federal Power Commission |
| FPSO | floating production storage offload |
| FSHR | free standing hybrid risers |
| GAAP | generally accepted accounting principle |
| G&A | general and administrative expenses |
| GoM | Gulf of Mexico |
| GOR | gas-oil ratio |
| HD/TVD | horizontal departure to true vertical depth ratio |
| HSBS | high-spec barges and semisubmersibles |
| HSV | high-spec vessel |
| IADC | International Association of Drilling Contractors |
| ICA | Interstate Commerce Act |
| IMR | inspection, maintenance, repair |
| ISOPE | International Society of Offshore and Polar Engineers |
| LNG | liquefied natural gas |
| LOA | length overall |
| LSB | low-spec barge |
| MDQ | maximum daily quantity |
| MGTS | Mardi Gras Transportation System |
| MMS | Minerals Management Service |
| MOB | mobilization |
| MPSV | multipurpose support vessel |
| NACE | National Association of Corrosion Engineers |
| NDE | nondestructive evaluation |
| NGA | Natural Gas Act of 1938 |
| NGPA | Natural Gas Policy Act of 1978 |
| NJPS | number of joints permitted per welding station |
| NOK | Norwegian Krone |
| NTAX | non-income tax |
| NWS | number of welding stations |
| O/C | out and combined |
| OCS | Outer Continental Shelf |
| OCSLA | Outer Continental Shelf Lands Act of 1953 |
| O&M | operation and maintenance expenses |
| OMC | Offshore Mediterranean Conference |
| OPS | Office of Pipeline Safety |
| OTC | Offshore Technology Conference |
| OUT | out of service |
| PE | polyethylene |
| PLEM | pipeline end manifolds |
| PLET | pipeline end terminations |
| PP | polypropylene |
| PIP | pipe-in-pipe |
| PSA | pipeline safety act |

| | |
|---|---|
| PSV | platform supply vessel |
| R/A | relinquished and abandoned |
| RCD | revenue credit |
| REM | removed |
| ROR | rate of return |
| ROV | remotely operated vehicle |
| ROW | right of way |
| R/R | relinquished and removed |
| RUE | right of use and easement |
| SEMIS | semisubmersibles |
| SARA | saturates, aromatics, resins, and asphaltenes |
| SPE | Society of Petroleum Engineers |
| SS | subsea well |
| SURF | subsea equipment, umbilicals, risers, flowlines |
| TFL | through-flowline |
| TLP | tension leg platform |
| UHSV | ultra high-spec vessel |
| WAT | wax appearance temperature |

# Summary

Oil and gas production occurs offshore every continent except Antarctica, from Tierra del Fuego, Argentina, to the Snohvit and Goliat fields offshore Norway in the Barents Sea. Over the past four decades, operators have made significant progress developing more complex and difficult fields in deeper and harsher environments. Circa 2018, offshore production contributed about a third of global oil production and a quarter of the world's gas supply.

In 2018, over 80% of crude production and about two thirds of natural gas supply in the US Gulf of Mexico (GoM) Outer Continental Shelf (OCS) was produced in water depths greater than 400 feet. Deepwater oil is on an upward trajectory. As production trends diverge, the importance of the infrastructure and activity trends will also diverge, with the structures and pipelines in deepwater becoming more critical in the years ahead and shallow water infrastructure becoming less important.

The purpose of this report is to examine the offshore pipeline construction industry and networks that operate in the GoM OCS, the regulatory structure that governs operations, pipeline activity trends, and construction and decommissioning costs in the region. Pipelines are used to deliver all of the GoM's natural gas and almost all of its oil production to shore; the pipeline network is an important and vital part of the supply chain.

In the 1950s, it was common to barge liquids to shore and use two-phase pipelines in development, but eventually single-phase export lines became the dominant mode of transport to reduce operating cost and improve efficiencies.

Trunklines were laid to the first discoveries and laterals were attached later as pipeline systems developed, moving south off the shelf into deeper water. Existing infrastructure was used when capacity was available, and new pipelines were built when capacity was not available or where, for strategic reasons, dedicated pipelines were desired. As product flows head northward they are combined with other fields and aggregated into larger pipelines. Volumes often split at platform hubs to deliver to an operator's preferred onshore destination. Gas pipeline networks are more integrated than oil corridors, and deepwater pipeline systems are partially segregated from shelf networks. Currently, few pipeline constraints or capacity bottlenecks exist.

The Bureau of Safety and Environmental Enforcement (BSEE), the Bureau of Ocean Energy Management (BOEM), and the Federal Energy Regulatory Commission (FERC) are the primary authorities that regulate pipelines on the OCS. FERC regulates pipelines that serve a transportation role; it enforces the provisions of the Natural Gas Act relating to the transportation of natural gas in interstate commerce. In determining its jurisdiction, FERC distinguishes those lines that serve a transportation function from those that serve one of production, gathering, or aggregating. FERC regulates the former but not the latter. BSEE provides oversight on lease activity and helps ensure that operations are performed in a safe and professional manner and that equipment and work areas are maintained in safe condition. BSEE is authorized to regulate exploration, development, and production operations on the OCS, from drilling operations through decommissioning. BSEE regulations cover materials and structures, production safety systems, platform and structure design, maintenance and fabrication. BOEM oversees all oil and gas leasing activities on the OCS, including granting Right of Use and Easement (RUE) over lands where developers do not have a lease for the construction of facilities attached to the seabed. BOEM administers three programs to ensure that decommissioning obligations and potential oil spills are covered: general bonding, supplemental bonding, and the Oil Spill Financial Requirements.

Circa 2018, total installed pipeline in the GoM was about 47 thousand miles, enough to circle the Earth at the equator twice, and representing more installed pipeline than any other offshore region worldwide. About 22 thousand miles of export pipeline and eight thousand miles of bulk line has been installed on the OCS, compared to about 11 thousand miles of bulk and export pipeline in deepwater. Since the mid-1980s, many of the bulk lines and export systems in shallow water are no longer needed and have been

decommissioned. Less than half of the total installed pipeline in the OCS GoM, about 22 thousand miles, was active in 2018–about ten thousand miles of active bulk and export pipeline in <400 ft water depth and eight thousand miles of active bulk and export pipeline in >400 ft water depth.

## Report Organization

This report has four parts. In Part 1, background information on flow assurance, field development, and pipeline routing describes the primary factors that impact the amount and types of installed pipeline. In Part 2, the offshore construction service industry and pipelay subsector is reviewed. The basic techniques used in pipeline installation and vessel fleets are described. Offshore pipelay contractors, business models, strategies and risk factors in the sector are outlined. In Part 3, the regulatory framework governing OCS oil and gas pipelines are described, and GoM pipeline construction and decommissioning costs are evaluated. In Part 4, the report concludes with an empirical evaluation of GoM pipeline activity data and the correlations used to consolidate activity trends.

In Part 1, background information on flow assurance, field development, and deepwater pipeline routing is described. In Chapter 1, a survey of worldwide drilling and development records circa 2017 introduces the setting and current industry capabilities.

In Chapter 2, the production components in offshore development are defined and flow assurance issues are reviewed. The primary objective of flow assurance is to keep the flow path open; flow assurance issues are the most important design criteria in subsea development. Numerous tradeoffs are involved in the design process as engineers attempt to foresee and mitigate the problems that may arise during the production life-cycle. The cost of subsea development is directly related to flow assurance considerations. A semi-technical overview of the issues is presented.

In Chapter 3, development strategy and operator preferences are discussed relative to their impact on pipeline requirements. The purpose of every offshore pipeline is to transport fluid from one point to another, but differences in field location, water depth, development strategy, time of sanction, seafloor topography, ownership, and other factors means that route selection and installed mileage will have complex site, time, and location dependences. The chapter describes some of the main factors that impact pipeline construction in the GoM.

In Chapter 4, the process of selecting a pipeline route in the deepwater GoM is described. Unlike the shallow water GoM, where the seafloor is flat and featureless and routes are usually laid in straight lines to their destination, in deepwater complex topologies, steep gradients, and geohazards makes route selection complex and time consuming. Route selection is based on considerations of bathymetry, seafloor character, seabed geology, geohazards, bioenvironmental issues, and existing infrastructure. A good strategy in routing is to avoid hazards but this is not always possible, and with every new restriction or avoidance area added, pipeline length increases, which increases cost. Several geohazards present in the deepwater GoM are examined.

In Part 2, the offshore construction service industry and the different types of pipelay contractors are described. In Chapter 5, the primary specifications of pipelay vessels are summarized, along with key relationships between vessel attributes to introduce the vessels and processes deployed in operations. Pipelay vessels range in complexity from traditional moored barges that lay pipe in shallow water to dynamically positioned ship-shaped vessels that can lay large diameter pipe in ultra-deepwater and perform multiple construction services.

In Chapter 6, the world pipelay vessel fleet circa 2017 is classified and described. Four categories are used for classification and examples of each class are provided. The chapter concludes with a survey of recent vessel construction cost.

In Chapters 7 and 8, the contractors, business profiles, strategies, and risk factors encountered in the pipeline construction market are examined. Firms typically own and operate diverse vessel fleets that include pipelay vessels in one or more regions across the world. The industry has seen varying degrees of consolidation over the years and the largest contractors are vertically integrated and diversified outside the upstream oil and gas sector. Demand for pipeline construction fluctuates from year to year and varies across regions; during periods of sustained low oil prices demand for services are reduced, causing contractors to resize operations to maintain a competitive position, to form alliances and partnerships in search of opportunities, and to stack and dismantle less competitive vessels to reduce cost. A review of corporate strategies reveal the depth and breadth of the sector, and operational and financial factors highlight the business risks.

In Part 3, an overview of the regulatory framework governing OCS pipelines is described, followed by an evaluation of GoM pipeline construction and decommissioning costs statistics. In Chapter 9, an introduction to the regulatory authorities and their jurisdiction over oil and gas pipelines on the OCS are described. Government authorities regulate OCS pipelines to address economic fair play, pipeline safety, liability, and decommissioning. Economic fair play issues involve those related to the pricing of transport services and equal access to such services. Pipeline safety concerns relate to pipeline design, construction and operation, and liability and decommissioning involves financial responsibility issues. The chapter concludes with examples of tariff rates and how they are set for FERC pipelines.

In Chapter 10, cost estimation for offshore pipeline construction is described using work decomposition. Costs are categorized according to material, services, engineering, and inspection and the characteristics of each category are discussed. Job and work requirements determine the relative contribution of each cost category, and material and construction services contribute the vast majority of costs in most projects. Two examples comparing actual final costs with estimated costs conclude the chapter.

In Chapter 11, US GoM pipeline construction costs are evaluated using public data sources. The US offshore industry is one of the most transparent markets in the world, but reliable and representative cost data is notoriously difficult to obtain across most sectors. Using data from FERC, industry publications, and press releases, pipeline construction costs in the US GoM from 1980–2014 are examined. The average inflation-adjusted cost to install FERC pipelines from 1995–2014 is computed to be $3.3 million/mi ($2.1 million/km), and industry publications yield an average pipeline cost of $3.1 million/mi ($1.9 million/km). A description of each data source and its limitations is provided.

In Chapter 12, the workflows for OCS pipeline decommissioning are reviewed. The vast majority of decommissioned pipeline in the GoM is abandoned-in-place and is a relatively simple operation that involves cleaning the line by pigging or flushing, cutting the pipeline endpoints, and then plugging and burying each endpoint below the seabed or covering with a concrete mattress.

Pipelines that are under FERC regulation require disclosure on decommissioning cost and provide a unique data source for evaluation. In Chapter 13, FERC decommissioning cost estimates for 28 gas export pipelines in the shallow water US GoM between 1995–2015 are evaluated. The average inflation-adjusted pipeline decommissioning cost was $301,000 per mile ($187,000/km) and $47 per cubic foot ($1660 per cubic meter). Hurricane damaged and leaking pipelines are about three to four times more expensive on a unit cost basis than undamaged and non-leaking lines. The chapter ends with a comparison of in situ decommissioning to complete removal costs.

In Part 4, a review of US GoM pipeline activity statistics is presented and correlations are developed to consolidate the trends. As a prelude to the empirical analysis, Chapter 14 covers the evolution of the GoM pipeline network and the role hub and transportation platforms play in the pipeline system. The GoM pipeline network is structured and organized around critical nodes containing a high concentration of linkages and high volume throughput. Hub platforms are arguably the most important structure class in the GoM to maintain economic efficiency and commercial development and several examples of hubs and transportation platforms are described along with major oil and gas pipeline systems. The scale-free structure of pipeline networks are motivated and conclude the chapter.

In Chapter 15, pipeline installation and decommissioning activity in the GoM is described along with active and out-of-service inventory trends. Pipelines are grouped into six production, four status, and two water depth categories for evaluation. Aggregate statistics and trends for oil, gas, bulk oil, bulk gas, service and umbilical pipelines for installation and decommissioning are presented.

In Chapter 16, correlations are developed that quantify pipeline activity in the GoM in terms of primary activity indicators such as wells drilled and structures installed and decommissioned. Pipeline infrastructure is best visualized using geographic information systems and maps but spatial representations provide little quantitative insight into how system attributes relate and have been impacted by development and decommissioning activity. Pipeline activity is causally related to regional activity but complications arise in interpretation if system attributes are not carefully selected and their limitations understood. The chapter begins with a general description of pipeline characteristics and modeling difficulties. A geometric representation of infrastructure links is introduced to guide the model relations explored. The chapter ends with a discussion of the limitations of correlation models.

### Data Sources

This report deals primarily with data and statistics that are usually (but not always) straightforward to understand with minimal levels of reporting uncertainty. That is, the data represents factual information that is relatively easy to interpret, assuming the data is processed properly and definitions and relationships are clearly understood. If confusion arises, it can usually be traced to incomplete information or a misunderstanding of operational issues, or both. In some cases, there may be problems with the data itself and issues may arise in interpretation or unexpected situations, but these are usually exceptional (one-off) issues and are remediated with additional work.

Operators report production, structure, and pipeline installation and decommissioning activity, drilling and wellbore abandonments in the US OCS electronically to the BOEM within a certain period of time after custody transfer of production and completion of operations. After review and quality control, which may take anywhere between three to six months, the BOEM uploads the data to the Technical Information Management System database.

Pipeline data was evaluated from the BOEM Pipeline database (BOEM 2018c). Structures were identified using the BOEM Platform Masters and Platform Structures databases (BOEM 2018a, and b). Wellbore data was assembled from the BOEM Borehole database (BOEM 2018e). FERC data was collected from public dockets and industry trade publications and press releases was used for pipeline construction cost data. Annual reports and financial statements for public companies were the primary data source for company fleets, business profiles, and financial records. Worldwide vessel fleets and specifications were supplemented with Offshore Magazine data and trade publications.

Data for the installation and decommissioning trends and correlations (Part 4) were evaluated from February to April 2017 and updated selectively for 2018. Pipeline construction and decommissioning cost data (Part 3) was evaluated in 2016 and 2017. Data from operator activity and company financial statements (Parts 1, 2) was evaluated in June-August 2017.

# Part One. Background

# Chapter 1. Offshore Development Records circa 2017

*Oil and gas production occurs offshore every continent except Antarctica, from the southernmost gas condensate field Vega Pleyade located offshore Tierra del Fuego, Argentina, to the northernmost Snohvit and Goliat fields offshore Norway in the Barents Sea. Offshore production arises from capital investment in wells and facilities that reflect multiple tradeoffs in construction cost and design risk and occur in varying water depth and oceanographic environments. Circa 2017, offshore production was responsible for about a third of global oil production and about a quarter of the world's natural gas production. Over the past four decades, operators have made significant progress developing fields in deeper and harsher offshore environments. A survey of drilling and development records circa 2017 sets the stage.*

## 1.1. Offshore Production

Global crude oil production in 2016 was about 92 million barrels per day (BP 2017), about one-third of which was produced offshore (Figure A.1). Global natural gas production was 124 trillion cubic feet per day (BP 2017), about a quarter of which was derived offshore. Offshore production has been increasing steadily as more countries open up their continental shelves to exploration and as new technologies advance deepwater development. Deepwater represents one of the most technology intensive plays, and although it may refer to various water depth thresholds, in this chapter it is defined as waters greater than 300 m (1000 ft).

Notable offshore production regions include the Gulf of Mexico (GoM), the North Sea, Brazil, West Africa, the Persian Gulf, Atlantic Canada, the Gulf of Thailand, East and South China Sea, the Caspian Sea, Southern and Western Australia, Indonesia, New Zealand, West India, Egypt, California, and Sakhalin Island in the Russian Pacific.

In recent years, exploration activity has discovered petroleum in some new areas, such as the Barents Sea, East India, and Mozambique, and new frontiers await in the Chukchi Sea and Kara Sea, and offshore the Falkland Islands, Greenland, the Atlantic US, and elsewhere. Wherever there is a continental shelf and sedimentary basins, there exists the potential for commercially viable hydrocarbon deposits.

## 1.2. Capital Expenditures

Exploration and production (E&P) companies are estimated[1] to have spent between $150 and $200 billion per year in offshore projects from 2008–2014 (Figure A.2), a majority of which was spent in deepwater. In the run-up to the oil price drop in late 2014, deepwater had spectacular investment and production growth (Dekker et al. 2016). Global deepwater investment increased from $16 billion in 2003 to more than $70 billion in 2013, with production more than doubling in that time period to almost 6 million barrels per day, about 7% of the world's total oil supply (Dekker et al. 2016).

Approximately 90% of deepwater spending is in the 'golden triangle' of the US GoM, Brazil and West Africa. A typical breakdown in expenditures for the US GoM is depicted in Figure A.3, with engineering procurement and construction (EPC) services and topsides equipment spending shown in Figure A.4.

With oil prices declining near the end of 2014 and averaging around $50 per barrel in 2015 and 2016 (Figure A.5), companies reduced their offshore capital expenditures, reducing the demand for offshore

1 Capital expenditures are estimated with uncertainty levels between 25 to 40% accuracy because national oil companies and private companies do not typically disclose their spending plans, and for public companies there is often overlap between upstream, midstream, and downstream sectors. If surveys are used to collect data, instruments and results can vary widely in quality and reliability. If annual reports are used, categories will not be consistent across companies. Hence, these numbers as well as similar data reported in the press are meant to be illustrative and should be interpreted as a general guideline to magnitudes.

construction services. In a depressed market with sustained low prices, oil and gas companies generate less revenue from production and have less capital to spend, causing project cancellations or delays in the short-term, reducing investment across the supply chain. Upstream, midstream, and downstream sectors are impacted differently, as well as regional spending patterns, onshore and offshore, shallow water and deepwater, which will impact the engineering and construction (E&C) contractors differently, depending on their degree of integration and regional concentration.

## 1.3. Deepwater Infrastructure

A pipeline is a fixed asset with large capital costs, but once installed the operation and maintenance costs are relatively small, and pipelines are by far the safest way to transport petroleum with the least environmental impacts. Offshore pipelines are used to transport oil and gas between countries, to deliver offshore production to market, and to develop fields. If hydrocarbons from offshore fields are carried to shore, a pipeline usually serves the purpose, but if product is to be exported direct to other markets, a combination of fixed platforms and a floating system, such as an FPSO (floating production storage offload) vessel, is a common choice and oil export pipelines are not required.

In the late 1970s, contractors broke 1000 ft (300 m) water depth, and today, ultra-deepwater fields in 9500 ft (2900 m) have been developed. Challenges await as operators push beyond 10,000 ft (3100 m). Exploration technology (i.e., the capacity to drill to the target reservoir in a given water depth) has always led the capability for building out the infrastructure to produce (Figure A.6), but the gap is narrowing and will eventually converge as exploration frontiers and developments are conquered on the abyssal plains of the earth’s oceans.

In 2016, there were 163 FPSOs vessels used in deepwater oil and gas developments throughout the world and 12 sanctioned or under construction, relative to 253 total floaters in operation and 22 sanctioned or under construction (Table A.1). Floaters include semisubmersibles, spars, tension leg platforms and hybrid units. When FPSOs are used, shuttle tankers pick up and offload the crude to market and use of gas export lines depends on the region. In developed regions, such as Brazil, the GoM, and the North Sea, there is a market for natural gas and export lines are commonly used to deliver gas to domestic and industrial consumption. In less developed markets or remote areas, such as West Africa, gas is reinjected back into the reservoir for pressure maintenance and later development, or liquefied and sent abroad, as in Northwestern Australia.

Intrafield pipelines carry raw oil and gas from subsea wellheads and platforms without full processing equipment to facilities with full-processing capability. All FPSOs employ flowlines to transport production from subsea wells and either export or reinject the natural gas and condensate streams. Subsea completions (wet wells) are wells where the Christmas tree is located on the seafloor and production is routed from the wellbore through a flowline before reaching a riser that pipes it to the surface facility for processing. Umbilical lines from the host supply electric and hydraulic power for wellhead or manifold control functions and chemicals to suppress the formation of scale and hydrates in the production stream.

Platforms and other floating structures also use flowlines to carry fluids between structures for gas lift or to maintain reservoir pressure, and chemicals may be transported by a dedicated pipeline if volumes exceed umbilical capacity. In fields with water injection, treated seawater may be used to displace reservoir oil. Occasionally, carbon dioxide is separated from the natural gas and reinjected as in the Sleipner field in the North Sea (Baklid et al. 1996).

## 1.4. World Records Circa 2017

### 1.4.1. Longest and Deepest Wells

Operators have drilled wells greater than seven miles (11 km) horizontally and deep, although not at the same time (Figure A.7). In 1997, BP drilled a horizontal well from land more than 10 km (6 mi) in the Wytch Farm field in England to access offshore reservoirs. In 2010, the Al-Shaheen field BD-04A well set a record horizontal displacement of 10.9 km (6.8 mi) and a measured depth of 12.3 km (7.6 mi). By 2014, the longest well had a throw of 11,739 m (7.3 mi) and a measured depth of 12,700 m (7.9 mi) drilled at Sakhalin's Chayvo field (Gupta et al. 2014).

The Sakhalin-1 project comprises the Chayvo, Odoptu, and Arkutum Dagi fields located off the northeast coast of Sakhalin Island, Russian Federation, north of Japan (Figure A.8). The Z-42 well established new records for measured depth and horizontal reach and was finished in 70 days (Figure A.9). Sixteen of the 20 longest wells in the world circa 2015 have been drilled at Sakhalin-1 and wells with horizontal displacement up to 13 km reach are on the horizon.

### 1.4.2. Largest Pipeline Networks

The US GoM has the largest offshore pipeline infrastructure in the world: over 45,000 miles (72,000 km) of pipeline laid in federal waters from 1952 to 2016, which would encircle the Earth at the equator about two times. About 26,000 miles (42,000 km) of pipeline are active circa 2016 with the rest out-of-service or abandoned (Figure A.10).

By comparison, the North Sea has the second largest pipeline network in the world with around 28,000 miles (45,000 km) installed pipeline since 1966 (Figure A.11). About 60% of the pipelines in both regions are export lines with the rest smaller diameter flowlines (Oil & Gas UK 2013). Norway has installed over 9000 miles in the North, Norwegian, and Barents Sea since 1969 (Tormodsgard 2014). Most of the pipelines in the North Sea are active and have not been decommissioned.

### 1.4.3. Most Northern, Most Southern Fields

The most northern and most southern offshore fields that were producing circa 2017 are Vega Pleyade and Snohvit. Vega Pleyade is located at 53°S, 68°W and consists of a wellhead platform in 50 m (165 ft) water depth tied back via a 77 km (84 mile) pipeline to onshore treatment facilities offshore Argentina. The field started production in February 2016.

Snohvit is located at 71°37'N, 21°5'E in 250-345 m (825–1139 ft) water depth northwest of Norway in the Barents Sea. Gas and condensate is transported through a 143 km (89 mile) pipeline to an LNG plant situated on Melkoya Island outside Hammerfest, Norway (Engebretsen et al. 2002). Goliat is located at 71°18'N, 22°20'E about 88 km (55 miles) northwest of Hammerfest and was developed using a circular FPSO (Tangvald and Kiste 2009). First oil was achieved in March 2016.

### 1.4.4. Deepest Pipelines

Deepwater production is mostly centered in the "golden triangle" of the US GoM, West Africa, and Brazil (Table A.1). In recent years, deepwater projects have become more technically complex as exploration and production (E&P) activity moved to the Paleogene in the US GoM and the pre-salt formations in Brazil and Angola (Close et al. 2008, Todd and Replogle 2010). Pipelines in deepwater are subject to increased pressures, colder temperatures, stronger currents, higher flow rates, greater lengths, challenging topography, and difficult access for installation and repair.

In 2015, Stones began production from two subsea wells tied back to an FPSO in 9500 ft (2896 m) water depth in the US GoM, and was the deepest development in the world circa 2017 (Lohr 2017). The FPSO was selected in part to avoid the expense of laying a lengthy oil line in extreme water depths. Shuttle tankers provide oil export with gas exported via an eight inch (20 cm) flowline that ties into a gathering system 22 miles (35 km) away.

Perdido is another notable deepwater development, a spar moored in the western US GoM at a water depth of 7817 ft (2383 m) six miles (10 km) from Mexican waters (Figure A.12). The Perdido host receives production from three fields–Great White, Silver Tip, and Tobago–and still lays claim to the world's deepest subsea tieback at Tobago (9627 ft, 2935 m). Perdido's export routes crossed numerous peaks and valleys following paths northward before connecting with shelf pipelines (Connelly et al. 2009).

### 1.4.5. Longest Pipelines

The most well-known examples of long distance pipelines are onshore transmission lines such as the Russian Druzba, the world's longest at 4000 km (2500 miles); the TransAlaska Pipeline at 1300 km (800 miles); and the 1510 km (940 miles) Caspian Pipeline Consortium pipeline delivering oil from the Tengiz field in Kazakhstan to the Black Sea port at Novorossiysk.

Nord Stream is the longest offshore pipeline installed to date, transporting natural gas using dual 48-inch pipelines from landfall near Vyborg, Russia across the Gulf of Finland and Baltic Sea to landfall near Lubmin, Germany, a length of approximately 1225 km (761 miles) with challenging seabed/soil conditions (Figure A.13). Reported capital cost was €7.4 billion (Zenobi et al. 2012) and the amount of steel was estimated to be 240 times the amount used in the Eiffel tower (Bruschi 2012). Maximum water depth along the route is 210 m (689 ft).

The Ormen Lange field lies in water depths between 850 and 1100 m (2800-3699 ft) and is produced directly to shore at Nyhamma, Norway, for well stream processing, gas export compression and condensate export offloaded to tankers. From Nyhamna, the gas is exported through 42 and 44-inch diameter pipes, via the Sleipner platform in the North Sea, to gas recovery facilities at Easington, UK (Figure A.14). The total length of the Langeled export line is 1200 km (745 miles) and the southern portion of the line is also used for other fields (Solberg and Gjertveit 2007).

Other notable examples of long distance pipelines include Blue Stream and Medgaz. Blue Stream is a gas pipeline from Russia to Turkey across the Black Sea from Djubga, Russia to Samsun, Turkey in 2150 m (7052 ft) water depth (Figure A.15). The project consisted of two 24-inch pipelines 390 km (242 miles) long in 2150 m (7052 ft) water depth (Bianchi and Pulici 2001). The route is characterized by long and steep slopes at both shore approaches and a 240 km (149 miles) Abyssal Plain section (Figure A.16). Medgaz is a 210 km (130 miles) 24-inch diameter pipeline from Algeria to Spain across the Mediterranean Sea reaching a maximum water depth of 2155 m, or 7068 ft (Chaudhuri et al. 2010).

### 1.4.6. Longest and Deepest Tiebacks

As water depth and subsea tieback distances increase and fluid compositions become more difficult (e.g., more viscous, higher density, sour), innovative field architectures and advanced technologies, such as subsea processing, have expanded the development envelope (Figure A.17).

The world's longest oil well subsea tieback circa 2017 was Shell's Penguin field in the North Sea at 43 miles (70 km) and 574 ft (175 m) maximum water depth, and the longest gas subsea tieback was Noble Energy's Tamar field in the Mediterranean Sea at 93 miles (150 km) and 5446 ft (1660 m) maximum water depth. Gas is easier to flow longer distances and has less flow assurance issues because of the properties of the fluid (less dense, lower friction) and advantages of compression compared to pumping.

The world's deepest oil subsea tieback circa 2017 was Shell's Tobago field in the US GoM at 9627 ft (2935 m) and 5.4 miles (8.6 km). The deepest gas tieback was Anadarko's Cheyenne field, also in the US GoM, at 9014 ft (2748 m) and 44.7 miles (72 km).

### 1.4.7. Most Difficult Wells

An extended reach drilling (ERD) well is typically defined as having a horizontal departure to true vertical depth ratio (HD/TVD) greater than two (Figure A.18). The ratio provides a crude indicator of well complexity but it is only a basic indicator of how difficult the well will be to drill and complete because many more factors are involved in drilling a well than one metric can incorporate (Mims and Krepp 2007). The HD/TVD ratio has increased since the 1970s and the highest HD/TVD well circa 2017 is greater than ten. Although long and deep wells are complex and difficult to drill because of high torque and drag, the HD/TVD ratio does not capture complex well designs such as big bore, designer wells, wellbore stability, completion design, deepwater and emerging technologies and does not describe difficulties associated with wellbore positioning and downhole tool telemetry (Mims and Krepp 2007).

### 1.4.8. Most Difficult Pipeline Projects

A difficult project is hard to do, make, or carry out, while a complex project is made up of complicated and interrelated parts, the relations of which are imperfectly known. Complexity is related to overall capital expenditures and duration, but difficulty tends to reflect upon equipment capacity and technology capability at the time of execution.

Gauging the complexity and difficulty of a project will mean different things to different operators at different times, and is therefore difficult to reliably quantify because it encompasses so many different factors, such as water depth, route topology, pipe diameter, wall thickness, seabed/soil characteristics, burial requirements, oceanographic conditions, number of pipeline/cable crossings, gravel works, transition zones, length, remediation requirements, etc.

If the pipeline project is part of field development, more factors enter the assessment, such as number of risers and riser configuration, number of inline sled assemblies, pipeline end terminations (PLET), pipeline end manifolds (PLEM), jumpers and other components, because they are often installed in conjunction with the pipelay campaign. One would expect pipeline infrastructure in field development to be more complex than trunklines with difficulty levels more comparable.

Cavicchi and Ardavanis (2003) introduced a two-dimensional difficulty index as the product of maximum water depth and pipeline diameter to rank Saipem’s projects and to draw attention to the J-lay capacity of their vessel fleet. According to this index, the Mardi Gras Transportation System (MGTS), Blue Stream, and Medgaz are the most difficult pipeline installations in the world to date, although the Perdido and Lucius fields in the US GoM, and the more recent Iracema and Cabiunas export systems in Brazil, also rank high in difficulty level (Figure A.19). MGTS is a 485 miles (781 km) system in the US GoM made up of five separate pipelines ranging in size from 16 to 30 inches in water depths up to 7300 ft, or 2200 m (Marshall and McDonald 2004).

### 1.4.9. Best Pipeline Construction Cost Data

The best publicly available pipeline construction cost data for an offshore network is for Norway. Gassco AS is wholly owned by Norway and is independent operator of the gas and oil transport system on the Norwegian continental shelf, which is the reason for the transparent and reliable cost data.

The Norwegian oil and gas transport system includes a network of pipelines more than 9000 km in length (Figure A.20). Three onshore gas facilities are integrated into the system–Karsto, Kollsnes, and Nyhamma–and there are four receiving terminals on the continent and two in the United Kingdom. Oil and condensate pipelines on the Norwegian continental shelf totaled 1261 km circa 2015.

The gas pipeline infrastructure cost NOK (Norwegian Krone) 240 billion ($36 billion) circa 2017 and construction cost averaged NOK 29.6 million per km ($7.1 million per mile) and NOK 53 thousand per km-in ($85 thousand per mi-in) (Table A.2). Total oil and condensate pipeline infrastructure cost NOK 37 billion ($5.6 billion) circa 2018 and averaged NOK 30.3 million per km ($7.3 million per mile) and NOK 177 thousand per km-in ($285 thousand per mi-in).

# Chapter 2. Flow Assurance Issues

*During production, oil and gas flow from the reservoir to the processing facilities and then onward to their sales destination through different channels and restriction points beginning at reservoir pores, through well perforations and tubing, production chokes, valves, and pipelines on the ocean floor and up through the water column to topsides equipment for processing, before returning to the seafloor onward to market via pipeline or to a shuttle tanker. Offshore subsea systems are designed to foresee the problems that may arise during all stages of production over its lifetime, but prognostications are uncertain and unanticipated issues may arise that were not considered in design. Flow assurance is the major design consideration for subsea wells. The purpose of this chapter is to introduce offshore production system terminology and to describe the physical basis and engineering considerations involved in flow assurance.*

## 2.1. Production System Components

Two views of the pathway fluids take from wellhead to a production platform and beyond is depicted in Figure B.1 (side view) and Figure B.2 (aerial view).

### 2.1.1. Pipelines

A *pipeline* is, in principle, a very simple structure, normally made from steel with the sole purpose of delivering fluid from one point to another. Most steel pipelines are 40 ft (12 m) long segments, referred to as *joints*, that are joined by welding. The joint has to be straight, the hole has to be round, and the diameter and thickness of the pipe have to be able to withstand all the forces acting upon it during installation and over its design life.

The function of offshore pipelines is distinguished according to their degree of processing. *Export pipelines* generally refers to lines associated with transporting processed oil and gas streams from a production facility to shore. Pipelines associated with delivering (unprocessed) raw fluids from subsea wellheads or another structure to a host facility for processing are referred to as *infield flowlines* (or simply flowlines). Export lines are also commonly referred to as sales quality pipelines but confusion will arise if they are referred to as flowlines. Infield flowlines are also called gathering lines and are part of SURF (subsea equipment, umbilicals, risers, flowlines) systems.

Pipelines may be *rigid steel*, *flexible line*, or *pipe-in-pipe (PIP*) systems. All types are used in the Gulf of Mexico (GoM) and elsewhere throughout the world, but rigid steel and flexible lines are by far the most common in terms of miles laid. Rigid pipe is the simplest and least expensive and considered the most reliable for long-term service. Flexible pipe is often used for smaller diameter, short distance flowlines, as jumpers from wellheads and well manifolds to rigid flowlines, and as risers.

PIPs are manufactured using two pipes separated by insulation and are the least common and most expensive of the three types because of the need for a second pipe and complexity of fabrication. PIP systems are used to maintain the temperature of the fluids to prevent formation of hydrates, reduce wax deposition or to reduce the pressure drop, the difference between the pressure at the injection (start) and delivery (end) point, by reducing the viscosity of heavy crudes (Cochran 2003).

Rigid flowlines are manufactured from carbon steel or a high performance steel alloy, with additional coatings providing corrosion protection and insulation. Flexible flowlines have the same applications as rigid flowlines but are manufactured differently, using composite layers of steel wire and polymer sheathing that provide the flexibility of the pipeline. Flowlines are often installed by reeling from a large carousel, and the preference for using a rigid or flexible flowline is driven by design requirements, installation constraints, cost, schedule, or other factors.

### 2.1.2. Wells

*Dry tree wells* have their wellheads above the waterline; production fluids only need to transit the water column through a conductor or riser to reach the facility. *Wet wells* have their wellheads and trees located on the sea floor, need to be controlled via umbilicals, and have flowlines on the seabed from the well to the host. *Direct vertical access wells* are a special type of subsea well where the wellhead is accessible from a platform rig overhead.

Below the surface, a *well path* is constructed to connect the target with the surface location. The location of the target is placed in the reservoir to optimize production if the purpose of the well is to recover oil and gas. Normally, the optimal wellbore trajectory should result in minimum drilling and completion cost. The location of the surface location is determined by seabed topology, avoidance of shallow water hazards, future development plans, and related considerations. The number of wells required in development is a key design consideration.

The well path is considered simultaneously with casing, completion program, wellbore stability, cuttings transport, and any anticipated hole problems following industry practices (Bourgoyne et al. 1991, Mitchell and Miska 2011). Wells designed to be confined to a vertical plane are referred to as *2D wells* and any well not located in a vertical plane is defined as a *3D well*. 2D wells are often recommended whenever they are possible and economically justified.

There are three basic 2D directional well profiles: *build and hold (slant)*, *catenary*, and *S-turn* (Figure B.3). A build and hold well profile consists of a vertical part, build section, and a tangent section called a hold part of slant section. The slant profile is drilled at constant angle once the tangent angle has been established from the kick-off point. The catenary profile is a variation of the slant profile that begins with a lower build rate that accelerates as the wellbore angle increases. S-shaped well profiles consist of a vertical, build-up, tangent, drop-off, and another vertical at the bottom. S-turn wells are characterized by a high angle tangent section before dropping angle as it enters the target.

Complex 3D well profiles are created by adding one or more azimuth turns (a third dimension) to high angle wellbores. 3D wells are designed for a variety of geological and engineering reasons–to avoid difficult to drill subsurface formations (e.g., salt domes), to avoid faults, and to avoid intersecting other wells.

### 2.1.3. Umbilicals

Umbilical lines provide chemicals, control, and power to wet wells from the host platform (Bai and Bai 2012). Strictly speaking, umbilicals are usually not considered pipeline because their main purpose is to provide power and control to subsea wells via electro-hydraulic signals, but many umbilicals also contain tubes for chemical delivery so they also serve a fluid transport function (Figure B.4).

Umbilicals are used to deliver chemical inhibitors for hydrate, wax, asphaltenes, corrosion, and scale and are an integral part of flow assurance. Separate tubes within the umbilical are usually used for each chemical. For high volumes dedicated delivery, service lines for methanol, water, gas lift, etc. may be used instead of umbilical tubes.

### 2.1.4. Risers

Risers are the fluid transfer system linking the seabed and the deck of the facility and are associated with drilling, production, and import/export pipelines. Risers are different than the pipelines and flowlines that reside on the seabed; they are subject to a range of changing forces over long periods of time. Ocean currents, water pressure, vessel motion, and wave actions are the primary forces that risers encounter over their lifetimes, and therefore, must be designed to minimize fatigue damage. Risers attached to fixed platforms are considerably different than risers attached to floating structures.

## 2.2. Flow Assurance

### 2.2.1. Flow Patterns

An oil and/or gas reservoir production system consists of four basic flow patterns.

*Inflow from reservoir to well bottom*. In a reservoir, fluids flow through a porous media to the well perforations. Operations are designed to produce for as long as possible above critical reservoir pressures referred to as the bubblepoint and dewpoint pressures. For oil reservoirs, if the reservoir pressure falls below bubble point, multiphase flow will reduce well productivity by reducing oil relative permeabilities. In gas reservoirs, when reservoir pressure falls below critical dew point, condensates will drop out in the reservoir, reducing flow paths and production rates.

*From well bottom to wellhead.* Wells are completed with tubing that conducts the wellbore fluids to the wellhead, which may be at the mudline (wet well) or above the waterline (dry well). Large tubing strings allow large initial production but may create liquid loading and high well abandonment pressure late in the field life and may need to be replaced. For dry wells, production fluids transit the water column protected by conductor pipe or production riser. For wet wells, flowlines transport production to platform facilities and a riser brings the fluids to the host, sometimes aided with gas lift at the base of the riser.

*Flowline flow.* Flowlines usually move uphill to their destination but downhill movement can be accommodated with additional engineering. Fluids may be commingled with multiple wells to reduce the number of flowlines and risers, but commingling fluids can present problems if fluid chemistries change during production. Flowlines may be insulated, buried, heated, or uninsulated depending on multiphase flow transport and phase equilibrium of the fluids along the well path. Flowlines are sized to ease operational difficulties for the life of the well and fluid chemistry, well pressures, and subsea conditions will determine if chemical injection is required to mitigate the onset of hydrates, asphaltenes, paraffins, scale, or corrosion.

*Export pipeline flow*. Raw oil and gas are processed to satisfy pipeline specifications on vapor pressure, water vapor, heating value, and other properties. This greatly facilitates reliable flow in the downstream systems. Raw fluids are separated into oil and gas streams, dehydrated, processed, and temperature controlled before injection into the export oil and export gas lines. The export lines usually connect with existing pipeline infrastructure and may require compression and pumping along its route. Condensate production may be reinjected into gas export lines.

### 2.2.2. Operational Requirements

Along the flow path, the produced fluids pressures and temperatures decrease, which will change the phase-equilibrium and flow behavior of the fluids along the flow path. Problems may occur at any time, during start-up, normal operations, shutdown (planned or unplanned) and re-start. Wax, asphaltenes, hydrates, scale, corrosion, and sand production need to be understood and managed throughout the life cycle of production for successful operations.

### 2.2.3. Oil and Gas Systems

Subsea developments are designed for flow assurance and to ensure that production is not interrupted on its way from the wellbore to the host during the life of the field. This is accomplished by both passive and active systems. For hydrates and paraffins, the solution for gas and oil systems in deepwater are different (Pattee and Kopp 2000, Cochran 2003).

For oil wells, dual parallel flowlines are often used to provide round-trip pigging (cleaning) but looped systems may also be employed, whereas gas wells are often developed with a single flowline. If oil quality is low or water depth and/or tieback distance is high, flow assurance will be more difficult. The different physical requirements for each configuration are obvious, but the tradeoffs in cost and risk are less obvious and difficult to quantify. Today, manifolds are commonly used to connect between four to eight wells drilled in a cluster and commingle production in the flowline. Early manifolds were large and could handle more wells but were also more cumbersome to install and replace and were eventually downsized.

Single oil flowline systems often require heating of the flowline (Louvet et al. 2016). Many different methods can be used to keep fluids warm inside a pipeline, but it is really when a pipeline shuts down and is restarted that represents a greater constraint. The use of conventional insulation is common and works in many environments. Pipe-in-pipe options are useful during normal flow but require high storage capacity during extended pipeline shutdown. Active heating systems have been used but are expensive to deploy and operate. Heated bundles include electric heating and hot fluid heating. Electric heating requires high power usage and is limited by subsea connector reliability and platform space for generators.

## 2.3. Oil Phase Diagram

A typical oil phase diagram from offshore development is shown in Figure B.5. Depending on the design and operation of the production, some or all of the phase boundaries shown may be crossed. The oil follows a path along a steadily decreasing temperature and pressure as it moves from the reservoir to the flowline. Temperature and pressure drops may cause asphaltenes to separate from solution when the oil crosses the upper edge of the asphaltenes precipitation envelope (Upper APE). Wax begins to form as the oil falls below the wax appearance temperature (WAT) line, and then the hydrate range is entered before crossing the bubblepoint line. Below the bubblepoint, lighter hydrocarbons evolve in the reservoir as gas to form a two-phase fluid before reaching the flowline. Once in the flowline, the oil is transported to the host where temperature gradients in the ocean impact fluid flow.

## 2.4 Hydrocarbon Components

Hydrocarbons have different physical and chemical characteristics that give rise to different (refinery) yields, sales prices, and flow characteristics. Here we focus only on flow. Understanding the properties of the fluids is necessary to design a successful flow assurance strategy.

### 2.4.1. Hydrates

Hydrates (sometimes referred to as “dirty snow”) form when water and light hydrocarbons or other small compounds are present together at relatively low temperatures and high pressures as shown in Figure B.6 (Cochran 2003). In deepwater development, ambient temperatures are approximately 39°F (4°C), which is well within the hydrate formation region at typical operating pressures.

Hydrates are ice-like solids classed as clathrates where a guest gas molecule is trapped within a hydrogen-bonded cage of water molecules (Figure B.7). Many different gases are capable of forming hydrates provided the molecules are small enough to fit within the cavity of the cage. High molecular weight gases are typically too large to form hydrates, but methane, ethane, propane and butane, as well as $N_2$, $CO_2$ and $H_2S$ are small enough to fit inside. The crystalline structure of gas hydrate crystals depends on gas composition, pressure, and temperature. Three crystalline structures are common at moderate pressure and ten structures are present at pressures above 100 MPa (Makogon and Makogon 2016).

### 2.4.2. Waxes

Waxes are high molecular weight saturated organic mixtures of n-alkanes, i-alkanes, and cycloalkanes with carbon numbers ranging from 18 to 65 (Figures B.6 and B.8). The formation of wax crystals depends mostly on temperature change (Lira-Galeana and Hammami 2000). The temperature at which crude oil develops a cloudy appearance due to its wax (paraffin) content precipitating out is called the *wax appearance temperature* or *cloud point*. The *pour point* is defined as the lowest temperature crude oil flows. Both are important design characteristics. Pressure and composition also affect wax formation but to a lesser extent than temperature change.

### 2.4.3. Asphaltenes

Asphaltenes are dark-colored, friable, and infusible (meaning they have no well-defined melting point but decompose with heating, leaving a carbonaceous residue) hydrocarbon solids sometimes called the "cholesterol" of petroleum. The polynuclear aromatic layers with alkane chains are folded, creating a solid structure known as a *micelle* (Figure B.9). Some rings may be non-aromatic but many are fused and share at least one side. The tendency of asphaltenes to precipitate from a given crude is broadly related to the molecular weight, aromaticity, and polarity of the asphaltenes shown schematically in Figure B.10.

Chemical analysis of asphaltenes indicates they are polynuclear aromatic compounds that contain hydrogen and carbon in a H/C ratio between 1 to 1.25 (Tavakkoli et al. 2016). Some quantities of heteroatoms, such as nitrogen, sulfur, and oxygen, and trace metals such as vanadium and nickel are contained in the rings and resist oxidation. The term originated in 1837 when J.B. Boussingault defined asphaltenes as the residue of the distillation of bitumen insoluble in alcohol and soluble in turpentine. The definition used today is similar except the solubility is defined with respect to toluene and insolubility is defined using n-alkanes, such as n-pentane or n-heptane (Figure B.11).

Asphaltenes are common in heavy viscous crude and are usually controlled using inhibitors before destabilization and flocculation occurs (Leontaritis and Mansoori 1988, Jamaluddin et al. 2002). The amount of asphaltenes does not correlate with the precipitation or deposition propensity (Akbarzadeh et al. 2007). The main factors that dictate the occurrence of asphaltenes precipitation is the extent of gas undersaturation in crude oil, the density of crude, and the extent crude is saturated with asphalt at downhole conditions (Mullins et al. 2007).

### 2.4.4. Resins

Resins are polar molecules that are insoluble in liquid propane but are soluble in n-heptane (Figure B.11). Resin molecules surround the asphaltene clusters and suspend them in crude oil and are believed to be responsible for dissolving and stabilizing the solid asphaltene molecules in petroleum (Mullins et al. 2007).

### 2.4.5. SARA Analysis

SARA analysis is a chemical procedure used to characterize crude oil into four fractions: saturates (S), aromatics (A), resins (R), and asphaltenes (A). Saturates contain the saturated aliphatic components (linear, branched and cyclic) with an H/C ratio of nearly two. Aromatics contain one of more polarizable aromatic rings usually with no more than three rings total. Resins and asphaltenes contain polar substituents with asphaltenes being insoluble in excess of n-alkanes and resins being soluble in n-alkanes. The SAR fraction of SARA is usually referred to as maltenes. Different methods used in SARA analysis will lead to different results so the procedures applied need to be understand before interpretation.

Typical SARA component range for bitumen is 5–15 wt% saturates, 30–45 wt% aromatics, 30–45 wt% resins, and 5–20 wt% asphaltenes. Typical SARA component range for light crude is 60–75 wt% saturates, 20–25 wt% aromatics, 4–14 wt% resins, 0.1–0.2 wt% asphaltenes (Tavakkoli et al. 2016).

*Example. SARA analysis–heavy crude oils*

In heavily degraded oils, there is usually a shortage of resins and aromatics and a surplus of asphaltenes. Extra-heavy oils may contain ≥ 40 wt% resins and asphaltenes content (Table B.1). Normal crude with API gravity greater than 20°API typically have high saturates content and much less than 20 wt% resins and asphaltenes.

## 2.5 Hydrate Management Techniques

Hydrates of hydrocarbon require four conditions to form and be stable: high pressure, low temperature, water, hydrocarbon gases. To control hydrate formation and stability, one or more of these conditions need to be controlled. Each approach has significantly different capital and operating expenses (Figure B.12).

### 2.5.1. Depressurization

Pressure control is a common method to remain outside the hydrate formation region during shutdown. As long as the fluids are at a pressure lower than the hydrate stability pressure, hydrates would not be stable. If hydrates form in the production system, depressurization to below the hydrate stability pressure would dissociate the formed restriction (Makogon and Makogon 2016). Chemical injection of MEG or methanol is required during the restart phase while the pressure in the line increases. Down sloping geometry at the riser base or a low gas to liquid ratio will complicate the operation if the riser remains in the hydrate zone. In deepwater, the hydrostatic pressure of liquids in the riser may be sufficiently high to maintain hydrate stability at the mudline even if the topsides facility pressure if reduced to atmospheric pressure. In this case, chemical injection may be required inside the riser or at the wellbore or pumps may be employed.

### 2.5.2. Insulation

The objective of insulation is to prevent the produced fluids temperature from dropping below the hydrate and/or wax appearance temperature by limiting heat exchange with the ambient environment. For short tie-backs and high temperature no insulation may be needed, but during shutdown, the temperature is maintained only for a limited time before entering the hydrate/wax region. In degraded production conditions (e.g., mature production) or low quality fluids (e.g., viscous), problems may develop. Burial is an option if the seabed can be trenched. Pipe-in-pipe and active heating will improve temperature performance but at a significant increase in capital and operating expense.

### 2.5.3. Dehydration

Dehydration reduces the amount of water for hydrates. Dehydration is performed topsides on offshore facilities on all oil and gas export streams for flow assurance. Subsea dehydration technologies are not yet mature or commercial.

### 2.5.4. Loop Arrangement

If depressurization with chemical injection cannot protect against hydrates formation, a loop arrangement that displaces the live hydrocarbons with dead crude (or diesel) may be employed. Dead crude (also called non-shrinkage oil) refers to crude oil where most of the associated gas and high vapor pressure components have evaporated. In some cases, a service line with dead crude in-place or stored aboard the facility may be used. One or two production flowline architectures allow round trip pigging from topsides and wax removal. Loops provide operational flexibility but capital expenditures are high, especially as distances increase, and complexity is high.

### 2.5.5. Continuous Chemical Injection

Continuous chemical injection of chemicals, such as MEG or methanol for hydrate management, act by decreasing the hydrate formation conditions to lower temperatures and higher pressures. Chemical methods of hydrate control require less upfront capital expenditures but have high operating costs during the life of the field because most chemicals cannot be recycled or reused. If the quantity of water to be inhibited is large, the amount and expense of chemical usage is unrealistic, and therefore continuous injection is usually used in conjunction with other methods. For lean gas fields, continuous chemical injection is common.

### 2.5.6. Heating

Direct electrical heating and active heated flowline bundles use hot water circulation and electrical heating to heat the pipeline above the wax and hydrate appearance temperatures. In the GoM, heated pipe technologies have been used to reach longer tie-back distances and greater water depth but they are not common because of their expense and additional operational complexity.

# Chapter 3. Gulf of Mexico Field Development

*The purpose of every offshore oil and gas pipeline is to transport fluid through a conduit from one point to another, but differences in field location, water depth, development strategy, time of sanction, seafloor topography, ownership, and other factors means that route selection and installed mileage will have complex site, time, and location dependences. To understand pipeline activity, it is necessary to understand field development strategy and operator preferences because the choices made in development have a direct impact on pipeline construction activity. Only projects as-built are observed, however, and operator preferences are unknown except as realized vis-a-vis the resulting development. The focus of this chapter is to describe and illustrate some of the factors that impact pipeline construction in the US Gulf of Mexico (GoM) through a review of offshore field developments.*

## 3.1. The Setting

The federal waters of the GoM are administered by the US Department of the Interior's Bureau of Ocean Energy Management (BOEM) and Bureau of Safety and Environmental Enforcement (BSEE) and are described in terms of three administrative areas, referred to as the Western, Central, and Eastern planning areas.

### 3.1.1. Outer Continental Shelf

Planning areas are subdivided in named protraction areas, and each protraction area is divided into 3 mi × 3 mi (5760 acres or 23 sq. km) lease blocks, unless clipped by an existing marine boundary or edge of a planning area. Area blocks adjacent to the coast lie in water depth from 10 to 20 ft (3–6 m) and the edge of the continental shelf up to 1000 ft (300 m). The large mostly rectangular interior deepwater protraction areas such as Green Canyon and Walker Ridge lie in water depth from 1000 ft to 10,000 ft.

The term *continental shelf* in the GoM often refers to areas where water depths are less than 600 ft (183 m) and the seafloor is flat and featureless. On the shelf, simple straight line pipeline routes connecting two points are generally feasible, but in water depth greater than 600 ft, often referred to as the continental slope (or simply deepwater), straight line routes are less common. The continental shelf extends seaward from the shore with an average gradient of about 1 in 500, and the continental slope has a gradient that increases to about 1 in 20 and extends to 9000 ft (2743 m) water depth (Talley et al. 2011). Seafloor topography on the slope and rise are complex and include areas of possible landsliding and faulting, mud seeps, undulations, and rocky outcrops.

### 3.1.2. Sigsbee Escarpment

The Sigsbee Escarpment is a major geomorphological feature of the GoM seafloor. It is basically an underwater mountain about 2000 ft (600 m) in height at its tallest, and extending for several hundred miles across the Central and Eastern GoM (Figure C.1). The escarpment and associated canyons were caused by deformation of underlying salt deposits and erosion during periods of low sea level in the geologic past. As the salt deforms, it creates faulting, scarps, and other potential geohazards that need to be understood and quantified to determine if development in the area is of acceptable risk. Below the slope break, the escarpment dips at steep angles (5–25°), and near the base of the escarpment, major slump activity is observed out to several miles, clear evidence of numerous past failures that would have devastating consequences for any infrastructure in the debris flow. Sediment mass failures are triggered by the deformation and steepness of the slope.

### 3.1.3. Deepwater Protraction Areas

Deepwater protraction areas represent the administrative boundaries for deepwater and were defined as 2° East-West by 1° North-South, or about 120 mi by 60 mi in areal extent. One minute arc (1′) is defined to be one geographic mile at the equator, and at the GoM's 30° latitude, $1_{lat}^{\circ}$ = 110.85 km (~65 mi) and $1_{long}^{\circ}$ = 96.5 km (~60 mi). The most central region of the GoM is deeper than 10,000 ft and includes the abyssal plain. Deepwater seafloors are more severe and complex than the shelf. In Keathley Canyon and Green Canyon, for example, the presence of large bodies of salt in the sediment have deformed the seabed creating a number of seafloor mounds (diapers), peaks, and canyons. Seabeds with complex faulting pose additional challenges for infrastructure location. Difficult conditions include irregular rocky seafloor with sharp relief of tens of feet, fault scarps of 100–300 ft (34–91 m) high, and areas of possible landslide. Rugged topography suggests failures in the geologically recent past on the flank of the domes.

## 3.2. Conceptual Development

### 3.2.1. Systems Perspective

Many different types of surface systems and subsea system designs are used in offshore development, and the selection process depends on many different factors, the importance of which varies among projects (Bai and Bai 2012). Field developments are subject to economic, engineering, technical, and regulatory requirements that are site, time, and location dependent. Engineers are responsible for designing reliable and safe systems while identifying the risk and tradeoffs involved in cost, safety, schedule, operations, and environment.

The stages of conceptual development, the processes involved, and the philosophies adopted have been described throughout the literature. A good starting point is the papers by Dekker and Reid (2014) and Reid et al. (2014). Here, the intent is to provide context for how pipelines enter into the development selection.

Offshore developments occur in a variety of water depths and environments and present a variety of subsurface conditions. The ability to understand the relationships between these requirements and the different types of development systems is key to successful development. Different development systems fit specific requirements better than others, so a systems approach is generally required to successfully integrate subsurface and surface conditions.

All systems, including well delivery, subsea systems, flowlines, structural systems, facilities, export, and operations must be considered simultaneously. Tradeoffs are often fuzzy and include differences that arise from

- Capital Expenditures and Operational Expenditures
- Standardization and Improvement
- Proven Technology and Innovative Technology
- Minimum Capacity and Future Capacity

### 3.2.2. Reservoir Geometry

Reservoir sand distribution (pay zones) and the quality of the reservoirs impact field development in terms of wells required, flow rates, artificial lift requirements, equipment rating, and other elements.

If the pay zones are visualized as a rectangular box located inside the earth, then the geometry and location of the box and its internal structure will determine the number/type of wells required in development. If the reservoir rock is faulted creating isolated reservoirs or otherwise lacks communication with other zones, underlies salt, or has significant shale streaks, more wells will be required to access the targets.

If the box is vertically long and compact–think high-rise office building like One World Trade Center–with stacked sands, multiple zones, and small areal extent, then most targets within the box can be reached from one central position above the field using deviated wellbores and wells that are completed within multiple sands. Dry tree wells are probably the preferred option. Deviated wellbores are standard in offshore development and can be drilled from a central location approximately 3–5 miles (5–8 km) laterally, so for wells drilled from a platform there is a zone 3–5 miles in radius centered at the platform that can be reached.

If the reservoir is wider than it is thick and relatively shallow–think shoe box or a Boeing manufacturing facility–it may be difficult to reach all the targets from one location, even with highly deviated wells. High angle directional wells and more than one platform or subsea wells will be adopted. Outside the 3–5 mi zone, if there is a target to be drilled or a reservoir to be developed, then either another facility needs to be installed or a MODU is required to perform the drilling and the field tied back to existing infrastructure.

*Example. Pompano*

> In the Pompano development, a fixed platform was installed in 1290 ft water depth in Viosca Knoll block VK 989 and a subsea cluster was drilled in the Mississippi Canyon block 28 with production routed back to the VK 989 platform (Figure C.2). Note that the longest development well drilled at the VK 989 platform is slightly greater than 3 mi (5 km) in lateral extent, and all Phase II wells are subsea. Field outlines in green and pink are the areal projection of oil and gas reservoirs.

### 3.2.3. Structure Type

In shallow water development, concepts and designs are relatively simple. If the field is large enough, a fixed platform is installed and wells are drilled and/or completed from the platform that also processes the production for export. For smaller reservoirs, a simple structure is installed around wellbores drilled from a jackup and production is directed back to a host platform for processing. In some cases, such as high pressure gas reservoirs, production may be routed directly to a pipeline.

In deepwater, multiple host and subsea layout configurations are possible. Wet wells are used for marginal developments or where a stand-alone facility is not employed. Subsea system layouts include both central and distributed drilling centers, single and multiple flowlines, and various flowline and/or riser configurations. There is a variety of deepwater structure types available that include floating production storage and offloading vessels (FPSOs), semisubmersibles (semis), surface piercing articulating risers (spars) and tension leg platforms (TLPs) and their varieties.

Structures hold the equipment to process production into separate oil and gas streams for efficient and reliable transportation. There are usually two export pipelines for structures that process wellbore fluids into sales quality oil and gas, but in some cases there may be just one export pipeline, while in other cases, especially for hub platforms, more than two export lines may depart a structure. The number of flowlines and pipelines that board a structure depend on whether subsea wells are used and if the structure serves as a pipeline junction or processing host.

*Example. Cognac*

> Cognac was the first platform in the GoM installed in water deeper than 1000 ft in Mississippi Canyon block 194 (Figure C.3). From 1978–1981, a total of 61 wells were drilled and cased and 38 wells were completed from two rigs. One of the rigs was later removed and replaced with production equipment. First production occurred in 1979. As operator for the group, Shell designed, fabricated, and installed the platform and pipeline to Shell's onshore production facilities.
>
> The initial development plan included 72 drainage points and seven injection wells. About half of the wells were high angle (>50°) extended reach wells. Oil production began early in the drilling cycle and flowed along with gas in a 12-inch (31 cm) two-phase export pipeline to Shell's East Bay process facility in South Pass 27, approximately 27 miles (43 km) away (Figure C.4). In 1981, a second 16-inch (41 cm) pipeline was installed to transport gas production, and the 12-inch (31 cm) gas-oil line reverted to single-phase crude oil transportation.

#### 3.2.4. Hub Platforms

If a platform serves as a hub or pipeline junction, it will likely have more than two export lines. At the time of development, oil and gas export lines are sized for the maximum total well flow rates expected from the development, but if a (unanticipated or third-party) tieback field is hosted, new export pipelines will be required if nameplate equipment capacity at the structure is exceeded. After production peaks, there will be spare pipeline (and equipment) capacity available that can be used for developing nearby fields as tiebacks, and therefore development timing is important. Export pipeline capacity is closely related to nameplate equipment capacity. It is common to install new export pipelines to handle streams from different fields and/or owners.

*Example. Enchilada*

> The Enchilada Garden Banks 128 platform in 633 ft water depth is an example of a project justified as a stand-alone development but recognized early in the development cycle as having strategic value as a pipeline and processing hub supporting deepwater and subsea development (Smith and Pilney 2003). Enchilada uses a unique lessor and/or lessee arrangement similar to an apartment complex where the operator (Shell) acts as the superintendent. Tenants gain rights to space by virtue of their capital investment and the superintendent provides operating and maintenance services. Unlike a conventional development, in which each party pays a set working interest, surface expenses are allocated to the tenants depending on what the expense was and where it occurred.

#### 3.2.5. Flowline Architecture

Pipeline design is governed by throughput, installation, and site requirements and specified by industry practice and regulation (e.g., DNV 2000, API 2009). After selection of pipeline diameter based on throughput requirements, selection of wall thickness and coating follows. Wall thickness is determined by operating pressure, external hydrostatic pressure, and the need for sufficient pipeline weight for stability (Nogueira and McKeehan 2005, Palmer and King 2008, Bai and Bai 2012, Guo et al. 2013). Wall thickness must be adequate to prevent internal pressure containment (burst) during operation and hydrotest, collapse due to external pressure, local buckling due to bending and external pressure, and buckle propagation and its arrest. Typically, wall thickness will range from 4% to 6% of the outside diameter of the pipe; for an 18-inch (457 mm) line, wall thickness may range from 18 to 27 mm.

If one or more subsea wells are required to drain the target, the wells may be flowed individually back to the host, as shown in configuration SS1 in Figure C.5. Alternatively, the well fluids may be commingled and a daisy-chain configuration used (SS2), or a loop system may be used to provide pigging capability (SS7). Wells may be drilled directionally from a central template (SS3 and SS5), or production may be commingled at a manifold and sent back to the host via a single (SS4) or dual flowline (SS6). Complex tradeoffs exist between capital spending and operational flexibility and subsea configurations are often designed fit-for-purpose.

## 3.3. Development Strategies

### 3.3.1. Field Architecture

Flowlines can range from a few hundred feet to several miles long with limited or no insulation, which can result in significant changes in fluid temperature and long residence times for fluids. In the GoM, oil tiebacks are typically in the 3 to 15 mile (5 to 24 km) range, while gas tiebacks can range up to 40 miles (64 km). The impact of changes in pressure along the flowlines may also be important, and if production from multiple wells is commingled, there may be significant chemical interactions between the fluids, which must be understood in the design stage.

*Example. Auger*

> Auger was Shell's first TLP in the GoM. Initial development consisted of ten dry tree wells, with first oil in April 1994. By mid-2000, anchor field production was about half of equipment capacity, and remaining development and recompletion opportunities at the platform were not adequate to offset production decline (Brock 2003). To keep the facility full, a decision was made to transform Auger into an infrastructure hub serving as a subsea tieback host for Shell fields and third-party production.
>
> In 1999, Macaroni was developed as a subsea tieback, and, in late 2001, the Serrano and Oregano fields were brought online (Figure C.6). Cardamom was drilled from the structure using extended reach wells. Third-party tiebacks Llano and Habanero northwest of Auger were integrated into the system in 2002. Macaroni uses a dual 6-inch × 10-inch (15 cm x 25 cm) flowline system that uses methanol for hydrate inhibition; both Serrano and Oregano use single 6-inch × 10-inch electrically heated pipe-in-pipe flowline systems. Habanero and Llano flow assurance strategies required use of hydrate inhibitors. Cumulative production to date is summarized in Table C.1.
>
> Auger oil and gas export lines provide access to multiple markets via existing shallow water gathering systems at Garden Banks 128 (Enchilada) and Vermillion 397 platforms (Figure C.7). The 12-inch (31 cm) oil line, owned and operated by Shell Pipeline Company LP, is routed to Shell's Enchilada platform at GB 128 where oil can be delivered into multiple pipelines accessing different onshore market locations. One of the gas lines owned by Shell terminates at Enchilada and delivers into the Garden Banks Gas Pipeline System. The second gas line terminates at VR 397 and delivers to the ANR pipeline system (Kopp and Barry 1994).

### 3.3.2. Looped Flowlines

The most common flowline configurations for subsea development are dual flowlines, single flowlines, and single flowline combined with a service line. Dual flowlines are standard for oil wells to allow round-trip pigging. Looped systems preserve round-trip pigging and reduce flowline cost but are less flexible and increase system and/or operational complexity. Operators attempt to balance the benefits of a system with lower initial capital spending against the potentially higher life-cycle operating cost.

*Example. Canyon Express*

> The Canyon Express project involved a commingled tieback of three gas fields owned and operated by different companies through a jointly owned tieback to a third-party host platform. The size of the individual fields (each about 50 MMboe) and distance from existing infrastructure (about 56 miles [91 km] away for the farthest field) did not justify a stand-alone development for any of the fields, but, when combined into one development, allowed the sharing of costs and risks that led to project sanction (Rijkens et al. 2003).

The three fields–King's Peak, Aconcagua, and Camden Hills–are located in several Mississippi Canyon and DeSoto Canyon blocks in 6200 to 7200 ft (1900–2200 m) water depth, and a new platform on the shelf called Canyon Station owned and operated by a third-party (Williams) was installed at Main Pass 261 in 300 ft (91 m) water depth (Figure C.8).

The subsea system was divided into a common system and infield systems (Figure C.9). The common system includes the 12-inch (31 cm) flowlines with appendices and risers, the main umbilical and methanol line, and equipment on the host platform. The common system is owned jointly. A single multiplexed electro-hydraulic control umbilical connects the platform to the three fields in a daisy-chain configuration, and a separate umbilical supplies methanol and injection chemicals. Approximately 100 miles (160 km) of umbilical was installed.

### 3.3.3. FPSOs

FPSOs do not use oil export lines because oil is stored in the hull of the FPSO vessel and picked up periodically by shuttle tankers. FPSOs still require gas export lines, however, unless the gas is reinjected back into the reservoir.

*Example. Cascade & Chinook*

The Cascade and Chinook fields are located in Walker Ridge near the base of the Sigsbee Escarpment. Cascade is located in 8200 ft (2499 m) water depth and Chinook is about 15 miles (24 km) south of Cascade in 8800 ft (2682 m) water depth. An early production phase was adopted using two wells in Cascade and one well in Chinook connected to a leased FPSO located between the fields (Figure C.10).

The produced gas is dehydrated and used to generate power for the process plant, utilities, and electrical subsea pumps. The remaining natural gas is compressed and exported to the Discovery gas pipeline on GC 598 (Figure C.11). The export pipeline crosses the Sigsbee Escarpment and heads due north for a subsea tie-in. From GC 598, the gas is transported via a non-regulated 16-inch (41 cm) line to EB 873, and then to shore through a 30-inch (76 cm) FERC pipeline where it is processed at the Larose gas plant and liquids are fractionated at the Paradis plant (Palagi et al. 2013).

### 3.3.4. Direct Vertical Access Wells

Direct vertical access (DVA) wells are a special type of wet well; the wellhead and tree are located on the seafloor but direct access is available from the structure. DVA wells are used to reduce platform weight and have the benefit of platform rig access, and, unlike other wet wells, there is very little flowline or umbilical requirements. DVA wells were first used in 1994 at Auger and have been used at other GoM developments, most recently at Perdido.

*Example. Perdido DVA wells*

> The Perdido project is an ultra-deepwater development of the Great White, Silver Tip, and Tobago fields six miles (9.7 km) north of the border with Mexico in the remote and isolated Alaminos Canyon (Riley 2016). Perdido was the first to produce from the Lower Tertiary geologic setting in the Gulf and a truss spar moored in AC 875 in 7817 ft (2382 m) water depth was selected for development (Figure C.12).
>
> Twenty-two DVA wells under the spar and an additional 12 subsea wells were used in the first phase of development (Figure C.13). Great White includes 21 initial producers and nine water injection wells, Tobago has two initial producers, and Silvertip has two initial horizontal producers. All production is co-mingled on the seafloor, with the gas production separated from liquids and liquids pumped to the host (Ju et. al 2010). Separation occurs subsea with gas flowing separately from the oil in an outer chamber of the riser and the liquid is pumped up through an inner chamber.

### 3.3.5. Oil Compared to Gas Systems

Wells are classified as oil or gas depending on the gas-oil ratio (GOR) or cumulative gas-oil ratio (CGOR). Producing gas-oil ratios are commonly used to classify wells as primarily oil (oil) or primarily gas (gas) or a cumulative measure may be used defined as the cumulative gas production measured in cubic feet (cf) to total oil production measured in barrels (bbl). A threshold of 10,000 cf/bbl is often used to delineate oil producers (CGOR<10,000 cf/bbl) from gas producers (CGOR >10,000 cf/bbl), but thresholds as low as 5000 cf/bbl may also be used. The higher the value of CGOR the drier the gas and the lower the value the blacker and thicker the oil. Black oil reservoirs are normally defined as CGOR < 2000 cf/bbl.

Condensate gas ratio CGR (also called condensate yield) delineates gas systems since condensate (liquid hydrocarbons) may be an important component of gas production. CGR is described in barrels condensate to million cubic feet (MMcf) of gas. Gas wells with a condensate yield less than 2–4 bbl/MMcf are considered dry; wells with condensate yield greater than 30 bbl/MMcf are considered rich. Rich gas systems are more valuable in terms of their production value but they also present additional challenges in transport because there are limits to two-phase pipeline operations.

The design challenges and typical engineered solutions for dry gas, oil, and intermediate systems are as follows:

- *Dry gas systems (CGOR > 50,000 cf/bbl).* Hydrates are usually the dominant concern. Continuous inhibition with methanol or MEG is a common and robust solution. The systems can be operated on a once-through basis (normal approach with methanol) or the inhibitor can be reclaimed (normal approach with glycol).
- *Oil systems (CGOR < 10,000 cf/bbl).* Both hydrates and paraffins are an issue. Lines are usually insulated to retain heat and remain outside of the hydrate and paraffin deposition regions during normal steady state operations. A common approach in the GoM during start-ups and shutdowns is to apply inhibition chemicals, depressurization (blowdown) and fluid displacement (Pattee and Kopp 2000). Wax is removed by regular pigging.
- *Intermediate systems (10,000 < CGOR < 50,000 cf/bbl).* Intermediate oil-gas systems consist of
- high fractions of liquid hydrocarbons and/or water in gas. Design solutions are site-specific.

*Example. Mensa gas system*

The Mensa reserves were deposited in a single thick turbidite reservoir. The initial development consisted of three subsea wells directionally drilled from a cluster area on Mississippi Canyon block 687 to bottomhole locations on blocks 686, 687, and 730 (Figure C.14). The reservoir structure is nearly flat and characterized by a high degree of structural complexity, marked by fault compartmentalization and lateral stratigraphic variation (Razi and Bilinski 2012). In total, six wells were drilled in the field.

A single large flowline was selected over a dual flowline because the cost of two smaller lines would have been prohibitively high and prevented commercial development. The use of glycol for continuous hydrate inhibition was selected over a methanol solution to avoid the high cost of methanol usage and resupply logistics, and because the glycol serves to dehydrate the gas as it flowed to the platform. The flowline design precluded the need for pigging.

Each well is connected to a subsea manifold five miles (8 km) away on MC 685 (Figure C.15). The manifold in turn is connected by a single jumper and 63-mile (101 km) 12-inch (31 cm) flowline to Shell's West Delta 143 platform in shallow water, by far the longest gas tieback in the GoM at the time. Mensa production is dry gas with very low condensate (1.6 bbl/MMcf) that allowed the long tieback distance without significant liquid buildup and pressure drop. A glycol dehydration system was installed on WD 143 for processing and provided the controls and chemicals for the umbilical.

*Example. Troika oil system*

The Troika development is located in the Green Canyon area and includes the four block unit GC 200, 201, 244, and 245 (Bednar 1998). The two leading candidate systems for development were a subsea tieback to Bullwinkle located 14 miles (22.5 km) away in 1350 ft (412 m) water depth on GC 65 and a floating production system with a drilling rig. The subsea tieback was selected because it provided the operator the most cost effective solution based on present value and capital utilization and accelerated development timing.

Troika used an eight slot subsea manifold dual flowline system with five initial wells (Figure C.16). Slots represent the number of wells that can be handled with the equipment. Water depth at the manifold is 2670 ft (814 m). The Bullwinkle production facilities were upgraded to handle 200,000 bopd from a prior capacity of 55,000 bopd and Troika was expected to use at least 80,000 bopd of the capacity. Each flowline had a maximum flowrate of 60,000 bopd. Dedicated high pressure separators for each flowline were installed on Bullwinkle and new export pipelines were also required to handle the additional oil and gas production streams.

Two PIP production flowlines connect the manifold to the Bullwinkle platform and provide round-trip pigging capability. A fundamental design requirement of the flowlines is to provide insulation to minimize paraffin deposits and to provide reaction time for hydrate prevention following an unplanned shut-in. As such, the flowlines were constructed with a 10-inch (256 cm) production pipe encased in open cell foam in a 24-inch (61 cm) carrier pipe pressurized with nitrogen.

Two dedicated multiplexed electro-hydraulic control umbilicals provide the communication and chemical links between the platform and subsea system. The function of the hydraulic and/or chemical umbilical is to provide high and low pressure hydraulic fluid for all the actuated valves on the manifold and subsea trees, methanol to all the subsea trees and both flowlines, and chemicals (paraffin and corrosion inhibitors) to both flowlines.

*Example. Independence Hub dry gas system*

The Independence Project consists of ten natural gas fields, the subsea system, the Independence Hub processing platform, and the Independence Trail export pipeline (Holley and Abendschein 2007). The ten fields that comprise the project range in water depths from 7800 to 9000 ft (2377 to 2743 m) in the Atwater Valley, DeSoto Canyon, and Lloyd Ridge areas spread out over a 30 mile by 60 mile (48 km x 97 km) range (Figure C.17).

The Independence Hub semisubmersible has the capacity for 1 Bcfpd, 5000 bpd condensate and 3000 bpd water and is owned by third parties but operated by Anadarko Petroleum Corporation. The Independence Trail pipeline is owned and operated by third parties. The wells and subsea system are owned and operated by the companies that have interests in the fields and contract for capacity on the platform and pipeline.

Production is a low-liquid fraction biogenic methane with condensate yields in the 1–2 bbl/MMcf range. An MEG reclamation unit is used to extract and recycle the MEG necessary for hydrate control in the flowlines in a closed loop system. MEG and water go to the glycol reclamation system, and the condensate production, allocated back to individual wells, is re-injected into the sales line with the dry gas saving on the need for a liquids export pipeline or storage and offloading via marine vessel.

The subsea system includes 220 miles (354 km) of flowline, 125 miles (201 km) of umbilical, 155 jumpers/leads, 15 10-ksi horizontal trees, and five manifolds. Seven steel catenary risers tie into the processing facility.

The 20/24-inch 134-mile (216 km) export gas pipeline terminates at a shallow water platform in 115 ft (35 m) water depth at West Delta 68 that ties into the Tennessee Gas Pipeline system. The Tennessee Gas Pipeline system was chosen due to its large diameter, multiple outlets, flexibility of service, and favorable markets (Al-Sharif 2007). The WD 68 platform is equipped with a 24-inch (61 cm) pig receiver that can catch pigs and two launchers that can send pigs to the Tennessee Main Line. A flowline heater on the platform is used to accommodate the cooling that occurs when the pipeline is started up after a shutdown.

### 3.3.6. Reservoir Quality

Wells with low gas-oil ratios and viscous crude in deepwater and long tie-backs may need help to flow, and if the fluids contain a high level of wax, water, or asphaltenes, additional precautions need to be taken. Because well fluids change over the life cycle of the field with declining reservoir pressure, models for changing gas-oil ratios, produced water, and brine chemistry, and solids from reservoir fines, asphaltenes, scale, and products of corrosion must be understood (i.e., quantified) for successful operations.

*Example. Jack/St. Malo and Julia*

The Jack and St. Malo fields were discovered by Chevron in 2004 and 2003 in the Lower Tertiary trend in about 7000 ft (2100 m) of water in the Walker Ridge area. The Wilcox or Paleogene reservoirs found in the Lower Tertiary are 38 to 65 million years old and are therefore buried deeper than the more common, younger Miocene reservoirs in the GoM, which are 5 to 24 million years old. Lower Tertiary trend reservoirs are characterized by strong rock formations, ultra deep reservoirs (25,000 to 30,000 ft), high pressure (17,000 to 24,000 psi), high temperatures (220 to 270 °F), low gas oil ratio (170–250 cf/bbl) and low permeability (Hjelmeland et al. 2017).

The fields are located within 25 miles (40 km) of each other and were co-developed with subsea completions flowing back to a semisubmersible host located between the fields (Figure C.18). The semi also serves as host for the Julia field located a few miles south. Development was sanctioned in 2010 and first production was achieved in 2014. Jack and St. Malo will be developed in multiple stages.

In the first stage, ten wells were drilled–four into Jack and six into St. Malo. The wells at Jack are tied to one subsea manifold, whereas the wells at St. Malo are tied into two daisy-chained manifolds to facilitate future tie backs. Three pumps are located downstream of the manifolds to boost the fluids to the semisubmersible through individual 10-inch (25 cm) flowlines. One power and control umbilical was laid to each of the two fields supplying the pump systems with electrical power, communication, control fluid and barrier fluid.

Crude oil is transported about 140 miles (225 km) to the Shell operated Green Canyon 19 platform (Boxer). The pipeline is 24-inch (61 cm) diameter and is the first large diameter, ultra-deepwater pipeline in the Walker Ridge area. The oil export pipeline was designed, built, and installed by Amberjack Pipeline Company, LLC, a joint venture between Chevron Pipeline Company and Shell Pipeline Company.

Gas is transported 150 miles (241 km) to the southern extension of Enbridge’s Walker Ridge Natural Gas Gathering System (WRGS), which also serves Stones (and the future Big Foot field when connected). The WRGS transports gas from WR 718 to a Ship Shoal 332 shelf platform, and then onward to shore on Enbridge’s Nautilus pipeline. Since Jack/St. Malo were designed to be powered by natural gas, the WRGS pipeline is bidirectional, providing import gas for startup operations, and later in the field life when produced gas becomes insufficient to meet fuel needs.

## 3.4. Life Extension

Structures may host third party production and extend their lives if nearby discoveries arise and the outcome of negotiations are successful.

*Example. Thunder Hawk*

> The Thunder Hawk field was developed in 2009 using a semisubmersible production unit in Mississippi Canyon in 6060 ft (1847 m) water depth with nameplate production capacity of 45,000 bopd and 70 MMcfpd (Yoshioka et al. 2016). Initially, one well was connected and two flowlines were tied back with a single control umbilical. Oil and gas export pipelines are routed to the west of the production unit.
>
> After five years of producing, and without any new wells drilled in the field, available production capacity created an opportunity for a third-party tieback. In 2015, the Big Bend and Dantzler fields located about 6 and 18 miles (29 km) away in 7200 ft (2195 m) water depth were tied back to Thunder Hawk using dual PIP flowlines and insulated SCRs (Figure C.19). Production capacity was expanded to 60,000 bopd and a third processing train was added to separate the production streams and gas lift capability was added. Two wells were connected using two production risers and two umbilicals.

# Chapter 4. Deepwater Pipeline Routing

*Pipeline routing on the Gulf of Mexico (GoM) shelf is simple because the seafloor is flat and featureless and lines are required to be buried in water depth less than 200 ft, and, when obstacles, arise they are crossed using mats. By contrast, in deepwater, seafloor topography is complex, water gradients increase, and geohazards arise, all of which increase the complexity of routing. The location of the fields, host, and destination determine endpoints, and, while the start point is above or near the field under development, usually several potential destinations are examined. Route selection is based on consideration of bathymetry, seafloor character, seabed geology, geohazards, bioenvironmental issues, and existing infrastructure. A good strategy in routing is to avoid hazards, but this is not always possible, and with every new restriction or avoidance area added, pipeline length increases, which increases cost. In some cases, out-of-service pipeline can be re-used, but this is generally a rare occurrence. In this chapter, the geohazards that may be encountered in deepwater are examined and the chapter concludes with an example of pipeline reuse.*

## 4.1. Economic Evaluation

An economic evaluation is normally performed on various routes considering the installation and material cost of the pipe, burial footage, water depth, pipeline crossings, and subsea terrain to determine the preliminary route. After preliminary routing, studies are completed, a hazard survey is performed, which includes core samples of the bottom conditions and a more detailed overview of the bathymetry, escarpments, outcrops, etc. If lease holders along the route have drilling or development plans that would conflict with the route or installation schedule, contingency plans and a contingency around the proposed activity need to be in place. Congested areas and areas with known or expected geohazards require greater planning and review.

## 4.2. Humanmade Hazards

Humanmade hazards include existing offshore installations, pipelines or cables, shipwrecks, military dumping grounds, and maritime regulations. The locations of all existing infrastructure need to be gathered and assessed before fieldwork is performed. The preference is usually to have as few pipeline crossings as possible, because they require significant engineering and regulatory work, and, if a crossing is required, it should be as close to 90° as possible to reduce the number of support mattresses. Crossings create diversions in pipeline routes and increase route length, which increases cost. The presence of ordnance dumping zones,[2] areas of known shipwrecks (Evans and Voisin 2011), and shipping fairways impose additional restrictions on route selection. Archaeological clearance on blocks in GoM shelf waters has been in existence since the 1970s.

## 4.3. Geohazards

Examples of geohazards that may be encountered include steep slopes, unstable slopes, hard seabed sediments, bedforms and scarps. Often these issues are superimposed upon and inter-related to each other (Hill et al. 2013). Integrated geohazards analysis categorizes the possibilities, to allow either direct avoidance, through choice of well or field layout, or appropriate mitigation of the desired hazard through appropriate engineering design.

2 In an ordnance zone, the pattern of debris is usually of long linear areas, consistent with items being dumped from a slow moving vessel. Cylinders and rectangular items are commonly identified shapes.

### 4.3.1. Slope Stability

Infrastructure located near or on peaks and canyons are at risk if the slope fails during the lifetime of the development. The mechanisms capable of triggering a slope failure are related to changes in the shear stress applied to the soil (Jeanjean et al. 2003a). For slope stability issues, the annual probability of occurrence of a failure is commonly estimated, along with the consequences in terms of the debris flows and damage to infrastructure. The best course of action is often to avoid steep and/or unstable slopes and potential run-offs by setting the route a safe distance from the base of the slope, but it is not always possible to avoid all areas and avoidance usually comes with increased cost.

*Example. Debris flow and salt domes at Na Kika*

> The Na Kika basin in Mississippi Canyon experienced debris flows in geologically recent time (~10,000 years ago) and may be susceptible to future debris flow events (Pirmez et al. 2004). The lines labeled L1 through Lc6 in Figure D.1 represent the paths of steepest descent in the region, and, presumably, where debris flows will travel if slope failures occur in the future. The paths were identified as the most probable failure areas posing risk for the Na Kika development.
>
> Unit CD, shown in Figure D.2 colored light blue, represents the surficial debris flow deposit that overlays with the development and export pipelines, and was used in simulation modeling to develop the best export pipeline route. Pipeline 1 from Thunder Horse and Pipeline 2, the oil export from Na Kika, both cross the profile; Pipeline 3 (gas export from Na Kika) follows a northerly route and avoids most of the unit. Pipelines 2 and 3 were routed between numerous salt domes on their way to shelf facilities.

*Example. Slope failure probability at Atlantis*

> Atlantis and Mad Dog were the first developments located very near, or on, the Sigsbee Escarpment, and presented unique challenges that required an integrated geohazards study to justify the field architectures (Angell et al. 2003). Siting of facilities in geologically active areas can proceed only if the associated risks are understood and deemed acceptable.
>
> At Atlantis, there was clear evidence of numerous past failures of the steep slopes. Each slope failure would have generated a debris flow with some of the larger blocks comparable in size with the Houston Astrodome (Figure D.3). These debris flows impacted the proposed footprint of the subsea well cluster, as well as the area where the flowlines, umbilicals, and anchors of the production unit was located (Figure D.4).
>
> The flowlines and umbilicals from the Atlantis drill centers were routed down the escarpment in areas with failure rates estimated at $10^{-4}$ with an annual probability of failure between $10^{-5}$ to $10^{-6}$ (Nadim et al. 2003). Because the subsea wells at Atlantis were located due north of the production unit, the export lines were routed south-southwest of the unit and pass up the escarpment in an area near Mad Dog. If the production unit was located north of the Sigsbee Escarpment, production from all the subsea wells would have to traverse up the escarpment which would have significantly increased the complexity of the system.

*Example. Slump block and fault avoidance at Mad Dog*

> Mooring cluster 2 at Mad Dog is composed of four anchor sites situated along the Sigsbee Escarpment within a slump area (Figure D.5). There are several small scale mounds at the seafloor believed to be slump blocks that were transported downslope from the head scarp (Berger et al. 2006). Hummocky seafloor appears to be the seafloor expression of a buried mass transport deposit. Two main fault lines were evident and avoided in anchor site selection.

#### 4.3.2. Furrows

Extensive regions of the seafloor in and around the base of the Sigsbee Escarpment are furrowed, which implies high bottom currents (Clukey et al. 2007). Some of the furrows can reach 200 ft peak to peak and be up to 30 ft deep (Figure D.6). Bottom currents appear to run parallel to the escarpment, gouging furrows across the boundary and impact pipeline routing and the orientation of risers. Risers are typically oriented in the same direction as the current to increase fatigue life. Furrows require strake flowlines and may increase pipeline routes. Span analysis is performed to ensure reliable design.

*Example. Routing across the East Breaks Slide*

> The East Breaks Slide is a late Pleistocene shelf-slope instability feature in the northwest GoM covering about 350 square miles in the East Breaks area and extending into Alaminos Canyon (Figure D.7). The two main factors that had to be addressed in selecting a pipeline route were the irregular seafloor and potential slope instability and its impact on spanning and bottom stability.
>
> The slide has a significant impact on the seafloor displaying irregular, tilted, and rotated blocks of intact stratigraphy within an amorphous and disturbed slump matrix (Hoffman et al. 2004). The rough topology restricted a direct route from the Falcon field in EB blocks 579 and 623 to the host platform in Mustang Island block 103 29 miles away (Figures D.8 and D.9).

#### 4.3.3. Mudslide Regions

Mudslide regions offshore the Mississippi River Delta are localized features, on the order of several thousand feet long by hundreds of feet across by 50 to 100 feet deep. Large hurricane waves can trigger mudslides and both Hurricanes Ivan in 2004 and Katrina in 2005 produced mudslides in this area that damaged pipelines, usually in the riser or riser tie-in near the base of platforms (Nodine et al. 2007). The optimal route for a pipeline across mudslide regions is difficult to assess, because the direction of soil movement depends on waves and not bathymetry, making it difficult *a priori* to know how to orient the pipe. To minimize the impact of mudslide damage designers minimize the length of pipeline traversing the mudslide prone area and locate pipelines in the deepest waters in the mudslide prone area.

#### 4.3.4. Faults and Scarps

Seafloor faults and scarps create risks for pipeline infrastructure from potential offset at fault crossings. To understand the causative processes and quantitatively evaluate the locations, magnitude and recurrence potential of displacement events, geologic and geotechnical survey data are used in integrated models (Angell et al. 2003).

### 4.4. Chemosynthetic Communities

Chemosynthetic communities typically occur in clusters in areas where hydrocarbons are present near seabed sediments or where active oil and gas seeps occur. They usually consist of mounds of clams, mussels and tubeworms tens of feet across and up to 10 feet (3 m) in height. These communities are protected in the GoM and according to NTL 2000-G20 on Deepwater Chemosynthetic Communities, seafloor disturbances must be avoided within 250 ft (76 m) of features that could support high-density chemosynthetic communities (Oynes 2000). If it is uncertain whether chemosynthetic organisms are associated with mounds or related features, piston core samples may be required. The presence of chemosynthetic communities along preferred routes will limit access and restrict options.

*Example. Seafans and soft coral at Shenzi.*

The Shenzi field lies in Green Canyon blocks 609, 610, 652, 653, and 654 in 4150 to 4480 ft water depth a few miles north of the Sigsbee Escarpment. Numerous fault scarps are clearly visible in the northeast quadrant of GC 653 (Figure D.10).

Clusters of seafloor mounds circular in shape and less than five feet high were identified as potential hydrocarbon seeps in the vicinity of the proposed flowlines between drill centers B and G. Piston core samples were obtained and plugs of solid tar were obtained. No evidence of active hydrocarbon seepage was seen and no chemosynthetic organisms observed (Williamson et al. 2008).

A marine biologist confirmed that the sea fans and soft coral were not chemosynthetic organisms but a type of soft coral that attached to the tar mounds for hard substrate (Figure D.11). The flowline and umbilical routes between the drill centers B and G were nonetheless modified to avoid the sea fans by passing through a corridor between the tar mounds.

## 4.5. Pipeline Reuse

Pipelines are not commonly re-used after they have been out-of-service or decommissioned, but under special circumstances, if the pipeline is of sufficient length and quality and properly located, it may be economic to re-use. About one-third of the oil pipeline in Anadarko’s Lucius development re-used abandoned gas pipeline from its abandoned Red Hawk spar, which was taken out of service in 2008. Pipeline reuse required thorough cleaning of the pipeline, caliper runs, dehydrating, ROV inspection, cathodic protection checks, and span data analysis for fatigue and stress.

*Example. Lucius and South Hadrian*

The Lucius field is located in the northern part of Keathley Canyon in blocks 874, 875, and 919 in approximately 7000 ft (2100 m) of water. A spar located in KC 875 was selected as the development strategy and the reservoirs are produced through six initial subsea wells. Seafloor hills, peaks, and canyons cover the area (Schronk et al. 2015).

The oil export pipeline is an 18-inch (46 cm), 147-mile (237 km) pipeline consisting of three segments: (1) 74 miles (119 km) of 18-inch (46 cm) new build pipe from the Lucius spar to the existing Phoenix pipeline; (2) test and re-use of an out-of-service 47-mile (76 km) section of Phoenix gas pipeline converted to oil service; and (3) 26 miles (42 km) of 18-inch (46 cm) new build pipeline to an existing South Marsh Island block 205 platform (Figure D.12). First oil was delivered in 2015.

The gas export pipeline is a newbuild 20-inch (51 cm), 209-mile (336 km) pipeline that starts further south in KC 831 at the Hadrian South development and lands at a junction platform in 350 ft (107 m) water depth in South Timbalier block 283. First gas was delivered in 2015. Discovery Producer Services, LLC designed, installed and operates the gas pipeline with a capacity of 400 MMcfd, a new build transportation platform in ST 283, and a Larose gas plant methanol recovery upgrade.

# Part Two. Offshore Construction Service Industry

# Chapter 5. Pipelay Installation and Vessel Specifications

*Pipelay vessels range in complexity from traditional moored barges that lay pipe in shallow water to dynamically positioned ship-shaped vessels, which can lay large diameter pipe in ultra-deepwater and perform multiple functions including platform and subsea construction. In this chapter, pipelay installation techniques are described and vessel specifications are defined. The primary physical and secondary operational specifications of pipelay vessels are described, along with key relationships between attributes.*

## 5.1. Welding

Welding begins with two beveled pipes. Figure E.1 depicts a typical bevel, but bevel shapes may vary depending on if the pipeline is to be welded from the internal side and if automatic or manual welding is to be conducted. The pipes are aligned using internal or external clamps (internal clamps are typical for large diameter pipelines) and the weld area may be preheated to 80°C. Preheating ensures that the pipeline is dry prior to welding (Palmer and King 2008).

In most lay barges, separate stations are used to conduct several welds. The first and most critical weld is the *root pass* which joins the non-beveled lands or “roots” of the pipeline (Figure E.2). The root pass is typically conducted from the outside of the pipeline, but care must be taken to avoid the formation of “icicles”, metal protrusions into the inside of the pipeline (Palmer and King 2008).

The next weld is the *hot pass* which is applied before the root pass has time to cool. The purpose of the hot pass is to remove deficiencies in the root pass. On completion, the hot pass is cleaned to bare metal and all welding slag removed.

*Filler passes* are frequently conducted by automatic or semiautomatic welding machines (Figure E.3), which can rapidly lay down large volumes of weld material. The filler passes fill the gap left by the bevel and are made with a slight weave from side to side which ensures complete fusion of the pipeline walls.

The final weld is *the cap pass* or cover weld. The cap pass fills the residual groove leaving the weld approximately 1 mm above the pipe surface and with an overlap of the outside surface of the pipe of approximately 1 to 2 mm.

After welding is completed, the weld is tested for defects by X-ray or ultrasonic evaluation. Following this NDE process, a field joint is applied to protect the weld area from corrosion. A heat shrink sleeve is applied around the pipeline’s circumference and a mold is placed over the pipeline. A polyurethane foam is then pumped into the mold and allowed to harden (Figure E.4).

## 5.2. Installation Techniques

*Lay barge construction* is by far the most frequently used technique for marine pipeline construction (Palmer and King 2008, Gerwick 2007). In *S-lay* and *J-lay* systems, sections of pipe are welded together on the deck of the vessel, which is then lowered to the seabed as a continuous string of pipe as the vessel moves forward (Figure E.5). In a *reel-lay* system, the pipeline is assembled onshore and spooled onto the installation vessel. Once on location, the spool is paid out and the pipeline is guided into the water via a tower or ramp equipped with a straightener and a tensioner. Towing assembled pipeline from shore to site has also been employed but is not common.

### 5.2.1. S-lay System

In S-lay systems, tensioners apply a tension force to the pipe near the stern and the pipe is supported on rollers by a stinger structure where it enters the water (Figure E.5). As a pipe is laid, it is first bent in one direction at the stinger (overbend) and then moves through the suspended section and the underbend (sagbend), where it is bent in the reverse direction. The shape of the overbend is controlled primarily by the stinger, a steel framework that provides support for the overbend, while tension devices (tensioners) serve to control the pipe in the sagbend.

The shape of the sagbend depends on the interaction between the applied tension and submerged weight of the pipe (Palmer and King 2008). If the applied tension is increased, the curvature in the sagbend decreases, and the sagbend becomes longer and flatter and the lift point moves up the stinger. Conversely, if the applied tension is reduced, the sagbend curvature increases and if the bending becomes excessive, the pipe may buckle.[3] The tension applied to the pipe controls the curvature in the sagbend and reacts on the vessel, which has to maintain its position, suggesting a correlation between tension capacity and power requirements of vessels.

In S-lay systems, a firing line composed of welding, non-destructive evaluation (NDE) and field joint application stations runs down the length of the vessel and terminates in a stinger that guides the pipeline into the water (Figure E.6). The firing line may run down the center of the vessel or the port or starboard side. On ship-shaped vessels, the firing line is often in the center of the vessel to take advantage of extra space in the ship's bow. Typical lay rates are 2–4 km/day (1–3 mi/day).

In deepwater, S-lay installations become increasingly constrained by the greater weights and tension requirements. Laying deeper implies getting stronger, since increasing water depth results in an increase in the pipeline spanning the water column, requiring increased holding tensions (Faldini et al. 2014). Stinger length could be increased but long stingers are vulnerable to wave and current forces. High tension is undesirable because of damage to the pipe coating and greater power requirements to maintain position (Perinet and Frazer 2007). The angle of the stinger may be adjustable on higher specification vessels. Steep angles are required with greater water depths.

*Example. Perdido S-lay*

> The Allseas *Solitaire* installed Perdido's oil and gas export pipelines using the S-lay method. The 120 km (75 miles) oil line was laid in 27 days, and the 168 km (104 miles) gas line was laid in 33 days (Connelly et al. 2009). The 60-day installation time included installation of four inline structures, two on each line and one PLET and one PLEM.

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3 Normal installation practice limits the allowable stresses in the overbend and sagbend to about 0.20% and 0.15% strain in the pipe (Bianchi and Pulici 2001). From this, the required stinger configuration and pipe tension are calculated.

*Example. S-lay Castoro Sei workflows*

Typical operational requirements for S-lay installation are illustrated in Figures E.7 and E.8 for the high-spec S-lay *Castoro Sei*. Pipes are loaded onto the vessel from workboats or barges (1). To prepare the pipes for welding, the ends are beveled. The inside of the pipe is then cleaned using compressed air (2). Two beveled, 40 foot (12 m) pipe joints are aligned and welded together to create a double-joint segment (3). The double-joint is moved to the non-destructive testing station where the weld undergoes ultrasonic testing to detect flaws (4). Following non-destructive testing, the double-joint is moved in a pipe elevator to the firing line. The ends of the double-joint are then pre-heated in preparation for welding onto the main pipe string (5). The prepared double-joints are now joined to the end of the pipeline in a semi-automatic welding process (6). The weld of the double-joint that has been welded onto the main pipeline also undergoes ultrasonic testing at another non-destructive testing station (7). Once the weld is confirmed acceptable, a corrosion resistant, heat-shrink sleeve is applied around the circumference of the pipeline. Then, polyurethane foam is poured into a mold surrounding the weld area (8). The pipeline then passes through the tensioner and into the water.

### 5.2.2. J-lay System

In J-lay, the pipe is assembled on a vertical tower and the pipeline enters the water at a vertical or near vertical angle, hanging like a cable and gently curving towards the horizontal as it approaches the seabed (Figure E.9). Tensions are significantly reduced, spans are shorter, and touchdown points are not as far behind the barge, which are easier to monitor and position (Springmann and Hebert 1994). However, because the ramp is high above the sea level, the line-up, welding, field joint application, and other activities are constrained, reducing the weld and lay rate (McDonald et al. 1998; Cavicchi and Ardavanis 2003). Typical lay rates are 2-3 km/day (1–2 mi/day).

J-lay systems are best suited for ultra-deep (>5000 ft, 1500 m) pipeline installation, and, because it has the smallest bottom tension of all methods, it has high flexibility for route layout in congested areas. J-lay systems can typically handle in-line appurtenances with relative ease, but may not be feasible in shallow water.

The first application of J-lay was the 20-inch (508 mm) Maui project laid in 1992 in 105 m (344 ft) water depth, west of the North Island of New Zealand in the Tasman Sea, by Heerama's *Balder* semisubmersible. The second application of J-lay was in 1993 by McDermott's *DB50* derrick barge, which laid the 12-inch (305 mm) Auger pipeline in 870 m (2854 ft) of water in the GoM.

### 5.2.3. Reel-lay Method

The reel method was first used to lay pipeline across the English Channel during World War II (Hartley 1946). It was applied in the offshore oil and gas industry in the 1960s in the GoM when Gurtler Hubert converted a landing-ship hull into a reel barge and laid 6-inch (152 mm) pipe from a vertical axis, horizontal reel (Palmer and King 2008).

Reel-lays are well suited for small diameter lines (<18 inches, 46 cm) and small diameter-to-thickness ratios, and, if all pipeline can be stored on-board, a very fast installation campaign can be achieved (Figure E.10). If recharging trips to the spooling base are needed to re-load, lay rates will be reduced and so the capacity of the reel is critical (Figure E.11). Concrete coated pipes cannot be reel-laid but PIP systems can be reel-laid.

The technology for reel-lay was acquired by Fluor in the 1970s and Sante Fe designed and built the reel ship *Apache* in 1979, which is currently owned by TechnipFMC. Global Industries operated two horizontal reel barges, *Chickasaw* and *Hercules*, before being acquired by Technip in 2011, which has a considerable track record in deepwater reeled operations (Smith and Clough 2010).

*Example. Reeled pipe-in-pipe at Canapu*

> At the Canapu field offshore Brazil in 1608 m (5274 ft) water depth, Technip installed a PIP system using reel-lay to deliver reservoir gas to an FPSO; the gas is then exported to shore (de Azevedo et al. 2009). An 8-inch (219 mm) inner pipe was inserted in a 13-inch (340 mm) outer pipe and insulated with an aerogel.

## 5.3. Vessel Specifications

Pipelay vessels are a subclass of construction service vessels (CSVs) used primarily but not exclusively for pipeline installation. CSVs are a general vessel class used to install pipelines, platforms, subsea equipment, and related field infrastructure. They include derrick barges, heavy-lift vessels, pipelay vessels, cargo barges, dive support vessels, and other vessel types. The primary physical specifications of pipelay vessels are described by hull type, vessel size, lay system, and station-keeping, which determine secondary operational characteristics, such as water depth capacity, lay rates, and maximum pipeline diameters. Each pipelay vessel is unique in its configuration and may be reconfigured to handle specific project requirements.

### 5.3.1. Hull

Three basic hull shapes are used in pipelay vessels. *Barge* hulls are box-shaped, simple to construct and standard on low-specification legacy vessels. *Semisubmersibles* (semis) are composed of a flat deck supported by columns connected to underwater pontoons. By varying the amount of ballast in the columns, the depth of the pontoons varies, controlling vessel stability. Semisubmersible hulls are common on heavy-lift vessels and several of these vessels have been fitted with pipelay equipment. *Ship-shaped* hulls are the most common hull type in the pipelay fleet and are the easiest to construct.

The hull is described by length, beam, and depth. Length overall (LOA) is associated with vessel stability and functional capabilities, including the length of the firing line, pipe storage capability, installed power, and other specifications. When naval architects design a vessel, cost is controlled by designing the smallest vessel that can meet the desired design specifications; as a result, length is often considered a reasonable proxy for vessel capability (Paik and Thayamballi 2007).

Most shallow water barges are around 200 ft or 60 m (Figure E.12) and the largest pipelay vessel in the fleet circa 2017 is Saipem's 1082 ft (323 m) *CastorOne.* Over half of the 2017 fleet of 112 pipelay vessels are between 300 and 500 ft (90–150 m) in length and only a few vessels are greater than 700 ft, or 210 m (Figure E.13).

Draft, the depth the vessel extends below the waterline, impacts a vessel's ability to work in shallow water and transition zones and the vessel's stability. Barge type hulls are particularly useful in shallow water due to their low drafts; semis large drafts increase stability.

Beam is the width of a vessel and, relative to other ship classes, pipelay vessels typically have large beams for their length. Beam is related to vessel stability, storage capability, deck space, and other characteristics (Lamb 2004). Semis have especially large beams because of the functional requirements associated with large deck spaces to hold and move equipment in construction and installation activities.

### 5.3.2. Pipelay Equipment

S-lay systems are described principally by the tension capacity, stinger geometry, and the number of welding, repair, NDE (nondestructive evaluation), and field joint stations. J-lay systems are described by tension capacity and the length of pipe that can be accommodated on the tower (single, double, triple, or quadruple joints). Reel-lay systems are described by tension machine and tension capacity and the storage capacity (diameter) of the reels. There are only a few vessels that can perform both S-lay and J-lay operations, but many J-lay vessels can also perform reel-lay.

### 5.3.3. Station Keeping

Vessels maintain position using mooring systems or dynamic positioning (DP). Station-keeping is important during pipelay since sudden unexpected movements may severely bend the pipeline which may buckle or kink. In conventional mooring, mooring lines connected to the vessel are used to keep the vessel in position and move the vessel forward along the pipeline route. The mooring lines are typically made of wire rope and the anchors are conventional drag-embedded anchors.

Mooring systems range from 4 to 14 point lines and require one or two anchor-handling tug (AHT) vessels to remain on site for the duration of the operation to position and move the anchor system forward. A typical anchored third-generation semisubmersible, such as Allseas *Piper*, has 14 mooring lines each 3050 m long. If 12 anchors are in operation, each one has to be relocated once every 3000 m of progress. If the barge is laying at 6000 m/day, one anchor has to be relocated every hour. The number of anchors needed depends on the expected current, wind, seastate and water depth.

Dynamic positioning (DP) is a station-keeping system in which the vessel is held in position or moves using on-board thrusters in conjunction with global positioning technology. A DP system consists of a control, a sensor, a thruster, and a power system. A computer receives input from wave, wind, and current sensors and responds automatically, compensating for movement (Figure E.14). DP systems are specified by their redundancy and segregation and may be double (DP-2) or triple (DP-3) redundant. DP systems increase construction costs and operating expenses relative to moored systems but eliminate the need for AHT vessel support. All deepwater lay vessels require DP-2 or DP-3 systems.

### 5.3.4. Water Depth

The operating water depth of a pipelay vessel is determined primarily by its station-keeping system, lay system, and tension capacity. Pipelay vessels are not generally designed and specified by a single value for any operational characteristic, but rather operational characteristics range over values depending on the specific project and environmental criteria.

S-lay vessels are typically limited to 3000–8000 ft (900–2400 m) depending on the length and angle of the stinger due to the stresses on the pipeline, while J-lay systems can operate in up to 10,000 ft (3000 m) of water but are usually not feasible in shallow water. In general, larger vessels are capable of operating in deeper water than smaller vessels (Figure E.15). DP systems are typically required for water depths over 3000 ft (900 m) due to limitations in mooring systems.

### 5.3.5. Work Stations

Pipeline construction requires welding joints, evaluating the quality of the joints, repairing weld defects, coating with an anticorrosion protectant, and then laying the line to the seafloor. Work stations are the location on the vessel where welding, NDE, weld repair, and field joint applications are performed. A single work station may be used for welding, NDE, repair, and field joint application, or these tasks may be divided among separate stations to improve work efficiencies.

*Example. Saipem's FDS2 working stations*

> Saipem's field development ship *FDS2* dedicate different lines to different tasks (Figure E.16). A conveyor line is used for single joint loading, beveling and anode installation. A middle firing line for quad joints construction has eight working stations for welding and one for NDT. A firing ramp has a repair line and a second firing line for construction.

Welding can be performed manually or automatically with bugs, or both. As the number of work stations used for welding increases, the number of welding passes that need to be performed at stations decreases, shortening the amount of time the pipe must remain at a single station and increasing the lay rate.

The total number of stations on S-lay vessels usually ranges from three to eight, with about half of these typically dedicated to welding and the remainder to field joint application and NDE. If the product of the number of welding stations (NWS) and the number of joints permitted per welding station (NJPS) is defined as the number of effective welding stations (EWS), then a positive correlation arises between vessel length and EWS (Figure E.17). On S-lay vessels, longer vessels typically have more welding stations. On J-lay vessels, work stations are placed on the J-lay tower and two stations (one for welding and one for NDE, repair, and field joint application) are typical.

### 5.3.6. Tensioners

Tensioners hold the pipeline in tension from the point it leaves the vessel to where it is laid on the seafloor and is measured in metric tons or kips, where 1 kip = 1000 pounds, and 1 mt = 1000 kg = 2205 lbs. The weight of the pipeline in the water column and the manner it is installed determines the stresses induced on the vessel and pipeline.

The capacity of the tensioning system determines the weight of pipe that can be supported to the seafloor which determines the size of pipes that may be installed and the water depth limitation. Capacities of 25–100 mt are typical for older, conventionally moored vessels that operate exclusively in shallow water, and capacities of 100–400 mt are typical for the majority of vessels in the fleet. Several high-specification vessels have tensioner capacities exceeding 400 mt; the maximum circa 2017 is 2200 mt on Saipem's *FDS2*.

Larger vessels have higher tensioner capacities and vessels with higher tensioner capacities are able to operate in deeper water (Figure E.18). Vessels operating in water depth greater than 6000 ft (1800 m) generally have at least 500 kips capacity.

To illustrate the relationship between tension capacity, pipe weight and maximum water depth, the operating specifications for the *Lewek Constellation*, a $625 million, 585 ft vessel are depicted in Figure E.19 for pipe ranging in diameter from 8 to 16 inches (20–41 cm) with varying wall thickness.

*Example. Water depth and pipe weight relationship at Lewek Constellation*

> The sizes of pipe are bound by minimum reelable wall thickness, the minimum wall thickness to resist collapse and the maximum static top tension (Christiani 2014). For wall thicknesses over 25 mm, the maximum water depth of installation decreases as the wall thickness increases due to the increasing pipe weight that must be supported. For wall thickness less than 25 mm, the limits on collapse resistance are controlling and the relationship is reversed. For example, for an 8-inch diameter pipe with a 15 mm wall thickness, the maximum water depth is about 3000 m because the pipe may collapse, but at 20 mm wall thickness maximum water depth increases to 4000 m. As the wall thickness of the pipeline increases, the strength of the pipe increases and the pipe may be installed in deeper waters. At a wall thickness of approximately 25 mm, the limiting factor changes from pipe collapse to the capacity of the 640 mt tensioning system and increasing wall thickness is associated with decreasing maximum water depths.

### 5.3.7. Power

Power is required for tension capacity and station-keeping for DP vessels, as well as water generation, deck equipment, electrical, utilities, ROV systems, saturation diving systems and reel deployment systems. Installed power and tension capacity are reasonably correlated for both S-lay and J-lay vessels (Figure E.20). It should be clear that DP vessels require more power than moored vessels for all other things equal. Installed power on the DP pipelay vessels fleet circa 2017 ranges from 10 to 67 MW and average 28 MW; for moored vessels, power requirements range from 1 to 5 MW and average 2 MW.

*Example. CastorOne and DB 30 power requirements*

> Saipem's DP-3 class *CastorOne* has 67 MW of installed power, whereas McDermott's *DB 30* has 3 x 910 kW + 1 x 1360 kW main generators and 1 x 320 kW emergency generator.

### 5.3.8. Cranes

Cranes and winches are used to abandon and recover pipes on the seafloor, to transfer pipe from supply vessels, and, on heavy lift vessels, for other construction activities. Abandonment and recovery operations typically occur at the commencement or end of pipelay operations, and the vessel's crane must be capable of lifting the pipeline weights supported by the tensioner. Smaller auxiliary cranes are used to load pipe onto the vessel and to move pipe around the deck. For automated systems, pipe is moved by conveyor from one location to another.

### 5.3.9. Accommodations

Operations are carried out 24 h a day using crews working 12 h shifts. J-lay and S-lay vessels have similar personnel requirements, but the variation in S-lay accommodations is much greater due to extremes in the vessel specifications; i.e., several low-spec barges have small accommodation capacity (as low as 25) and a few high-spec vessels maintain large accommodations (up to 700). Reel systems require fewer personnel, normally between 100 and 175, because pipeline fabrication occurs onshore. Accommodation capacity is measured by bed count and is determined in part by the number of welding stations (Figure E.21).

### 5.3.10. Other Capabilities

Vessels may be built exclusively for pipelay or pipelay may be a secondary capability as part of more general construction services. Semis and barges are frequently designed to accommodate other tasks while ship-shaped vessels are more likely to specialize. McDermott's 420 ft (130 m) *DB 50* with a 2400 mt crane and Heerema's *DCV Balder*, for example, are general purpose heavy-lift derrick barges that generate a significant portion of their revenue from construction lift operations.

## 5.4. Classification and Registration

Almost every offshore construction vessel, barge, or floating object must have classification and registration certificates of compliance to the rules and regulations as dictated and published by the classification society and country of registration. Classification is an indication of seaworthiness and vessel condition that was started in the late 1600s in England. American Bureau of Shipping started in 1862. Classification is normally required for the vessel to qualify for marine insurance, to obtain bank loans, and to comply with the operator's contract requirements.

Classification societies are privately owned for-profit companies that work closely with, but independent of, government bodies. Twelve societies belong to the International Association of Classification Societies. The primary societies are American Bureau Shipping (ABS, American), Det Norske Veritas (DNV, Norwegian) and Lloyd's Register of Shipping (Lloyds Registry, England).

Registration concerns the country of home port for the unit. Each country of registry has rules and regulations focused on safety, communication, lifting and cargo gear, pollution, and pollution containment. Each registry has different rules and regulations and the most popular registries are Panama, Liberia, and the Marshall Islands. The United States, England, Norway and other industrial countries are not common registries because of their more complicated rules, regulations and staffing requirements.

# Chapter 6. World Pipelay Fleet circa 2017

*At the end of 2016, the world fleet of construction service vessels totaled about 269 vessels, of which about 40%, 112 vessels or so, provide pipelay services. The inventory of construction vessels changes from year to year as new vessels enter service and old vessels retire or are repurposed; however, inventories do not change rapidly on a percentage basis. In this chapter, a new taxonomy of pipelay vessels is used to characterize the world fleet. Generations are also used as categories in vessel taxonomy, but, except for the legacy fleet, they tend to be less well defined and less useful. Examples of each class member are provided and the chapter concludes with a survey of recent pipelay vessel construction cost.*

## 6.1. Vessel Classification

Drilling rigs and marine vessels are often characterized by generation to denote the changes in technology and capacity of new build vessels that enter the fleet (Gerwick 2007, Kaiser and Snyder 2013). It is common to describe a rig or construction vessel as a third, fourth, fifth, etc., generation vessel. As long as one understands the attributes to which a generation refers, this is a convenient classification, but the distinction between capabilities is sometimes lost and the time periods used to define generations are not universally applied. Generation classification is not nearly as widespread or useful among pipelay vessels except for the legacy fleet. Instead, we adopt a four-category system to organize vessels with the addition of three generations of legacy vessels. The categories are: low-spec barges (LSB), high-spec barges and semisubmersibles (HSBS), high-spec vessels (HSV), and ultra high-spec vessels (UHSV) (Table F.1).

For legacy vessels, the first generation pipelay barges were built using a conventional barge hull and most of these vessels were delivered in the 1970s. Second generation pipelay barges are usually considered to have a semisubmersible hull with the pipe-laying assembly on one side and an articulated stinger. Third generation pipelay barges lay pipe on the centerline over a fixed cantilevered stinger. First, second, and third generation barges were built before 1980 and most are no longer in service.

### 6.1.1. Low-Spec Barges

Low-spec barges refer to the lowest specification shallow water barges which are positioned by means of mooring spreads (typically 4, 6, and 8 point spreads) and are exclusively S-lay vessels. Welding may be manual and only rigid pipelines are installed. Tensioning capacity is low (typically 25–50 mt) and 30–36 inch (76–91 cm) diameter is typical of the maximum diameter capability. Maximum water depths are frequently in the 200–400 ft (60–120 m) range with some vessels capable of working in up to 800 ft (240 m) of water.

### 6.1.2. High-Spec Barges and Semis

High-spec barges and semis are distinguished from lower spec vessels by longer length (>500 ft or 150 m), DP station-keeping (DP-2 or large mooring spreads) and greater water depth capability (>1000 ft or 300 m). High-spec barges and semis may be J-lay, S-lay, or both. In some cases, vessels are also equipped with deepwater and/or heavy lift cranes and may serve as construction or heavy-lift vessels. Most high-spec barges and semis were built before 2006.

### 6.1.3. High-Spec Vessels

High-spec vessels are ship-shaped with broad hulls for stability and deck space and are typically 300–600 ft (91–183 m) in length with DP capabilities. They are distinguished from high-spec barges by their self-propelled capability and ship-shaped hulls and are of more recent vintage built after 2006. High-spec vessels may maintain deepwater construction capacity and be equipped with heavy-lift cranes and ROVs. High-spec pipelay vessels are primarily used to lay the flowlines, umbilicals and risers associated with deepwater developments, and several vessels can install rigid, 14–18 inch (36–46 cm) reeled pipelines.

High-spec vessels are commonly equipped with reel-lay systems and may have S-lay, J-lay, or a combination.

#### 6.1.4. Ultra High-Spec Vessels

Ultra high-spec vessels are large (>600 ft or 180 m), dynamically positioned vessels that are designed for the installation of trunklines in deepwater. Ultra high-spec vessels are typically deepwater S-lay vessels that utilize their length to increase the number of work stations, but some have J-lay capabilities, as well. Ultra high-spec vessels are not typically designed for reel-lay capability. All ultra-high spec vessels have been built after 1998.

## 6.2. World Fleet Circa 2017

### 6.2.1. Data Source

Offshore Magazine's November 2013 Survey of Worldwide Offshore Pipeline Installation and Burial Contractors and Vessels was updated through May 2017 by reviewing each company's website and annual reports for newbuilds, sales, and retirements. The vessel fleet may be active (under contract or ready-for-work) or stacked (not-in-service), and no distinction is made between the two categories since vessels frequently transition between states and status data is not reported. Vessels under construction at the time of evaluation are not included in vessel fleet totals due to incomplete data and unknown vessel readiness. About 22 pipelay vessels were reported to be under construction in 2017, all equipped with DP systems for deepwater and ultra-deepwater.

### 6.2.2. Inventory Statistics

There were 112 pipelay vessels in the global fleet circa 2017: 22 low-spec barges, 31 high-spec barges and semis, 55 high-spec vessels, and four ultra-high spec vessels (Table F.2). Approximately one-third of the fleet was delivered in the 2000–2010 decade (Figure F.1), with most of the remainder delivered before 1980 or being of unknown vintage (Figure F.2).

The pipelay vessel inventory size represents the vast majority of the vessel fleet circa 2017, but not all vessels with pipelay capacity may be reported if vessels are renamed in sales or not properly classified. Chartered vessels and joint ventures may also cause ambiguity in enumeration, and because newbuilds continually enter the fleet while stacked vessels may be recycled, inventory is dynamic and ever-changing and should always be interpreted with this variation and uncertainty in mind. In this evaluation, public data sources are sufficiently accurate and representative, but for more detailed up-to-date analysis, commercial data sources from Clarkson, IHS, and other data service providers should be consulted.

A combination of legacy vessels, vessels that undergo expansions and upgrades, and newbuild vessels are used in operations. Low-spec vessels and barges are constructed or relocated to replace aging fleets and to serve emerging markets, but because of available inventory and demand expectations, the need for newbuild units has not been as significant as high-spec vessels over the past decade. A large number of high-spec vessels have been delivered since 2000 to accommodate the demands of deepwater development and the most recent deliveries are exclusively high-spec and ultra-high spec vessels (Frazer et al. 2005. Chiesa et al. 2013. Dash 2014. Ducceschi et al. 2015).

### 6.2.3. Class Comparison

Ultra-high spec vessels have the highest average number of welding stations, length, tensioner capacity and accommodations, and low-spec barges have the lowest mean values, and the high-spec vessel and high-spec barge and semi classes being intermediate (Figure F.3). Though there is less heterogeneity within vessel classes than there is among the entire fleet, there is still significant variation in specifications within each vessel class.

### 6.2.4. Deepwater Vessels

There are a limited number of vessels with the capacity to install large diameter pipelines in water depth greater than 3000 ft or 1000 m (Table F.3). Cross-plots of derrick capacity and tension can be used to classify deepwater vessels at a point in time (Figure F.4), but modifications to tensioner capacities occur as project needs change (Figure F.5). In recent years, there have been significant investments in deepwater S-lay vessels (e.g., Saipem's *CastorOne*, McDermott's *DLV 2000*, Allseas' *Pioneering Spirit*) and there has been little or no investment in the J-lay fleet, excepting reel-lay vessels with J-lay capacity.

## 6.3. Pipelay Vessels by Class

### 6.3.1. Low-Spec Barges

*Bisso Super Chief*

Bisso operates several low-spec barges in the GoM and *Super Chief* is typical of the class (Figure F.6). *Super Chief* is a 265 ft (869 m) long conventionally moored barge built in 1999 and upgraded in 2014. The firing line runs along the side of the vessel and she can accommodate a crew of 88 at five work stations, three of which are automated welding stations. *Super Chief* can install 36-inch (91 cm) diameter pipeline in up to 400 ft (120 m) of water. Storage capacity range from 4320 joints of 4 inch (10 cm) pipe (172,800 ft or 52,700 m) to 353 joints of 14 inch (36 cm) pipe (14,100 ft or 4300 m).

*Castoro 12*

Saipem's *Castoro 12* was built in 2006 and designed for shallow water work in the Caspian Sea (Figure F.7). Maximum water depth is 40 ft (12 m) and station-keeping is via conventional mooring. *Castoro 12* is 348 ft (106 m) LOA and equipped with a 30 mt tensioner and can install pipes up to 40 inches (102 cm) in diameter. She has three welding stations, one NDE station, one field joint application station, and can accommodate 150.

### 6.3.2. High-Spec Barges and Semisubmersibles

*DB 27*

McDermott's *DB 27* is a 420 ft (130 m) conventionally moored vessel built in 1974 and capable of laying pipes up to 72 inches (183 cm) in diameter in up to 3000 ft (900 m) of water (Figure F.8). She is equipped with a 275 mt tensioning system and five welding stations along with one repair station, one NDE station, and one field joint application station. A heavy-lift 1400 mt crane is used for installation and decommissioning work. Berths house 295.

*Castoro Sei*

Built in 1978, *Castoro Sei* is a semisubmersible heavy-lift vessel owned by Saipem that can perform S-lay installation in up to 4000 ft (1200 m) of water (Figure F.9). The vessel is approximately 500 ft (150 m) long and 213 ft (65 m) wide and uses a 12 point mooring system. Her firing line is designed to accommodate double-jointed pipe up to 60 inches (152 cm) in diameter and has been used on several high capacity lines, such as Nord Stream (Baltic Sea) and South Stream (Black Sea).

### 6.3.3. High-Spec Vessels

*North Ocean 105*

McDermott's *North Ocean 105* is an intermediate reel-lay vessel in the high-spec vessel class built in 2012 with accommodations for 129 (Figure F.10). *North Ocean 105* is 438 ft (134 m) long with DP-2 station-keeping and can handle rigid and flexible reel-lay pipe with diameters up to 16 inches (41 cm) in water depths up to 10,000 ft (3000 m).

*Deep Blue*

*Deep Blue* is the flagship of Technip's fleet and at the high end of the vessel class at 677 ft (206 m) long with a DP-2 system and accommodations for 160 (Figure F.11). She can reel-lay rigid pipeline up to 18 inches (46 cm) in diameter and can J-lay pipelines up to 28 inches (71 cm) in water depths up to 10,000 ft (3000 m). *Deep Blue* is capable of installing most export pipelines for deepwater development, but is not as capable as ultra-high spec vessels because she lacks deepwater S-lay capability, the ability to handle large diameter (greater than 36 inch, 91 cm) pipes, and the ability to handle double, triple, or quad joints on her J-lay tower. *Deep Blue* was delivered in 2002.

### 6.3.4. Ultra High-Spec Vessels

*CastorOne*

*CastorOne* is the largest pipelay vessel in the world, circa 2017, at 1083 ft (330 m) and one of the most flexible and capable vessels in the fleet (Figure F.12). *CastorOne* is capable of S-lay in intermediate water depths, steep S-lay in deepwater (up to 6500 ft, 2000 m), and J-lay in ultradeepwater (up to 10,000 ft, 3000 m). Station-keeping is DP-3 and she can accommodate over 700 workers. In S-lay mode, *CastorOne* uses triple joints of pipe fabricated off the main firing line, which consists of seven work stations. J-lay is accomplished by means of a removable tower capable of handling triple joints of pipe and has two stations, one for welding and one for NDE. *CastorOne* was delivered and upgraded in 2013 and is not equipped with reel capability.

*Solitaire*

Allseas' *Solitaire* is a 984 ft (289 m) long pipelay vessel with DP-3 capability and accommodations for 420 (Figure F.13). Built in 1998 and upgraded in 2005, she has a 1050 mt tensioning system and a 460 ft (140 m) stinger and can install pipes up to 60 inches (152 cm) in diameter. The extreme length of *Solitaire's* stinger allows her to S-lay pipes in over 9000 ft (2700 m) of water. *Solitaire* has two double joint production stations, five welding stations, one NDE station, and four field joint coating stations.

## 6.4. Construction Cost

### 6.4.1. Cost Components

Marine vessels require material, labor, and equipment for their construction and are built under a wide variety of designs, specifications and contracts at shipyards throughout the world. Market conditions, material and labor, design class and vessel specifications, level of competition, shipyard and the time of construction are the primary factors that impact newbuild cost.

Steel is the main component of all marine vessels (except crewboats) but is usually not the greatest contributor to cost. When prices are high, however, steel will make up a larger portion of the total cost of construction. Labor costs vary geographically and are an important component of the total cost because of the labor intensive nature of ship construction.

Equipment costs depend upon the vessel type and specification. Engines, cranes, generators, DP systems, electronics, etc., are third party materials purchased by the vessel owner or builder and installed at the shipyard. As vessel specifications and capability increase, all other things being equal, equipment and construction costs rise.

Shipyards are an important factor in cost since they vary in their expenses, efficiency, labor cost, supply chain management, reputation, and degree of integration, all of which impact how they bid and negotiate contracts. For large orders, shipyards (like aircraft manufacturers) often provide a discount to the buyer, and options on future orders are a common contractual feature.

### 6.4.2. Examples

Construction cost data of a sample of pipelay vessels costs ordered between 1998 and 2016 were collected from the industry press and financial reports (Table F.4). These public data sources are not itemized nor do they indicate contractual terms and should be considered as a first-order approximation. The majority of vessels built in this period are high-spec vessels. On average, high-spec vessels cost $378 million (2014$) with a normalized cost of $68 million per 100 feet, about two-and-a-half times greater than high-spec barges and four times cheaper than ultra high-spec vessels.

For example, in 2005, Subsea 7 ordered *Seven Oceans* from Merwede shipyard in Holland for approximately $190 million. *Seven Oceans* is a 515 ft (157 m) long DP-2 high-spec vessel equipped with 400 mt tension capacity and a reel-lay system capable of storing 3500 tons of reeled pipe.

In 2010, Heerema ordered the 694 ft (212 m) multipurpose deepwater construction vessel *DCV Aegir* from Daewoo for approximately $650 million. *DCV Aegir* was delivered in late 2013 and is a reel-lay, high-spec vessel with J-lay capability.

In 2013, Petrobras contracted with Subsea 7 to operate three high-spec DP-2 pipelay vessels on a five-year contract for $1.6 billion. Subsea 7 contracted with the shipyard IHC Merwede to construct the three vessels at a total cost of $950 million ($316 million per vessel). The three vessels are designed to lay flexible pipe in water depths up to 10,000 ft and are 478 ft (146 m) long with 550 mt tensioner systems.

The *DLV2000* is a $450 million 604 ft (184 m) DP-3 vessel built by Keppel for McDermott and delivered in 2016. With a combination of heavy-lift and deepwater S-lay capability, she has capability of handling pipes up to 60 inches (152 cm) in diameter.

*Pioneering Spirit* (formerly *Pieter Schelte*) is a $3 billion ultra high-spec vessel built by Allseas at the Daewoo shipyard. She is a combination pipelay and heavy-lift vessel and is the largest active vessel in the world by gross tonnage and displacement. The S-lay vessel has a 558 ft (170 m) long stinger and four 500 mt tensioners, and is capable of handling pipe up to 68 inches (173 cm) in diameter.

# Chapter 7. Pipelay Contractors and Business Profiles

*This chapter examines the contractors and business strategies encountered in the pipeline construction service market. Firms typically own and operate diverse vessel fleets in one or more regions across the world. The industry has seen varying degrees of consolidation over the years and the largest contractors are vertically integrated and diversified outside the upstream oil and gas sector. Business profiles are described according to business segments, vessel fleets, degree of integration and diversification, market position, and capitalization circa 2017. Engineering Procurement Construction and Installation contractors are described and examples of awards illustrate the manner in which pipeline contracts are made and the nature of competition in the sector.*

## 7.1. Pipelay Contractors

### 7.1.1. Companies

Twenty firms own and operate about 112 vessels[4] in the pipelay fleet circa 2017 (Table G.1). Chartered vessels and joint ventures, if not fully disclosed, will result in miscounts. Chartered vessels are usually included in vessel counts and joint ventures should assign vessels according to each company's interest for the contract period. For example, in 2017 DOF and TechnipFMC have a 50:50 joint venture with four vessels, and so two vessels should be assigned to each company. The number of firms in the sector is reasonably stable from year-to-year, but new entrants, consolidations, and exiting firms are not uncommon. Commercial databases are superior to collecting and processing public data when supplemented with interviews with key players and proprietary information, and the long history of involvement for several consultancies add significant value to the data.

Pipelay contractors vary from large, integrated public firms that provide EPCI (engineering, procurement, construction, and installation) services and operate a variety of sophisticated marine vessels across the offshore oil and gas supply chain to small private companies that own a small number of low-spec barges that perform specialized activities in a limited number of regional markets and environments.

TechnipFMC PLC, McDermott International Inc., Saipem S.p.A., Subsea 7 S.A., and Swiber Holdings Ltd. are the largest contractors in terms of pipelay vessel fleets circa 2017 and are the largest offshore construction contractors in the industry (Figure G.1). Allseas Marine Contractors and EMAS Offshore Limited are also significant players with high-spec vessels. EMAS is a subsidiary of Ezra Holdings Limited and filed for bankruptcy in 2017.

Larger companies are generally more broadly diversified by geography and business line, have a higher degree of integration, and usually demonstrate greater durability through multiple business cycles as they respond to changes in economic and industry conditions. Obviously, firms that want to operate in multiple regions must maintain a minimum fleet per region to provide the capacity to compete successfully. Larger size tends to facilitate access to the capital markets, implies a platform for sustainable earnings and cash flows, and often has a positive effect on a company's market position and capitalization. A diverse spread of assets can have a positive portfolio benefit because risk profiles and supply and demand dynamics vary by business line and geographic region. Large companies are also generally considered to enable greater operational flexibility and investment opportunities and timing.

Smaller companies typically have smaller, less specialized fleets and are less integrated and diversified. Small, privately owned companies tend to be regional specialists. Regional diversity decreases risk associated with declines in any single basin, but increases the fixed cost to maintain administration and port facilities, dock and warehouse space, maintenance services, etc. Hence, a regional specialist can

4 Vessel counts should always be considered approximate since vessels with pipelay capacity may not be reported or classified properly, and private and state-owned contractors may or may not fully disclose vessel fleets.

often be the low-cost provider in certain environments and successfully compete against larger firms on less complex and technically demanding projects. Shallow water vessels are typically limited to a single basin for block periods due to the time and expense in mobilization, and firms such as Ascot Constructors Offshore Ltd., Bisso Marine, and Chet Morrison Contractors, LLC, which specialize in shallow water, are usually limited to one or a few basins.

### 7.1.2. Objectives

One of the primary objectives of offshore construction contractors is to maintain the use of their fleet and personnel to generate revenue to satisfy their debt obligations and provide a suitable return to their investors. Some companies with high levels of debt may not be able to service their obligations with reduced cash flows, and, depending on market conditions and the degree of corporate leverage, may not be able to access new credit facilities or roll-over their debt by issuing bonds that mature later. Other companies may reorganize themselves to improve their processes and to seek greater efficiency and productivity. Opportunities for distressed assets may present themselves, but their acquisition, as well as acquisitions of other business lines, creates new risk that must be managed.

### 7.1.3. Ownership

Pipelay vessel operators may be privately held firms, publicly traded, or state-owned enterprises with varying degrees of government ownership and control (Table G.2). Public companies provide audited financial reporting according to the standards of the stock exchange of their listing and represent the best and most transparent source of information in the sector. Private firms do not report their business segments or results in an audited manner. Government-owned enterprises provide varying levels of reporting detail.

Public firms report business operations on a consolidated basis according to the nature of the activities and geographic segments. Nine publicly traded firms are active in the pipelay market circa 2017. Five of these firms are multi-billion dollar, vertically integrated companies that employ tens of thousands of workers. TechnipFMC PLC is the largest firm by market capitalization circa 2017, followed by Subsea 7 S.A., Saipem S.p.A., Sapura Energy Berhad, and McDermott International Inc. EMAS Offshore Limited and Swiber Holdings Ltd. are much smaller firms. DOF A.S.A. and Solstad Offshore A.S.A. are mid-tier players with growth aspirations. Ten private firms and one state-owned firm (CNOOC) do not provide detailed financial results.

About half of pipelay operators are privately held firms and they own about one-third of the pipelay fleet circa 2017. Most private companies are small, shallow water specialists, but there are exceptions. Allseas Marine Contractors, for example, which is a major player and active in both shallow and deepwater markets, is privately held, yet some small firms, like EMAS Offshore Ltd. and Swiber Holding Ltd., are publicly owned.

Saipem is partially owned by the Italian E&P firm Eni, which is itself 30% owned by the Italian government, so Saipem can be considered partially government-owned. The Chinese National Offshore Oil Corporation Group (CNOOC) is majority owned by the Chinese government and one of its four subsidiaries (CNOOC Offshore Oil Engineering Company) owns a five-vessel pipelay fleet.

### 7.1.4. Business Profiles

The business profile of contractors is described in terms of business segments, vessel fleets, degree of integration and diversification, market position, and capitalization. Each represents central features to understand industry organization. These factors are not always observable and must frequently be inferred, but knowledge of these factors provides the most useful and direct insight into market structure and business strategy.

Public firms report business operations on a consolidated basis according to the nature of the activities and geographic segments. Vessel fleets are readily compiled for most companies, but detailed activity data–whether vessels are active or stacked is usually not reported–and information on dayrates, use, and contracts is rarely reported for competitive reasons.

Only public companies describe their business segments and financial results, but the type of information provided is usually quite limited. Private companies, by contrast, provide little or no information on project activity, unless preparing for an IPO (initial public offering), which leaves a significant portion of the market hidden without additional significant work. Company integration and diversification can usually be inferred through a review of public documents, but geographic diversity and market position are more variable and difficult to track.

## 7.2. Business Profile

### 7.2.1. Business Segments

Management determines a company's reporting segments on the basis of strategic priorities and the reporting segments adopted correspond to the manner in which upper management reviews and evaluates operating performance when determining resource allocations (Table G.3).

Reporting segments may be functional, like Offshore Support and Accommodation Services, Engineering and Construction Onshore, and Anchor Handling Vessels; geographic, such as the Middle East or Asia; or some other category may be employed, such as Onshore/Offshore or Corporate. Functional categories usually have a direct and immediate interpretation but should still be reviewed to ensure that all components are identified. For example, TechnipFMC's Onshore/Offshore business segment includes EPCI for refining, gas plants, petrochemicals, fixed and floating production units, and LNG facilities. Breaking out the contribution from individual components of such broad categories is difficult and uncertain.

Pipelay services are not a distinct business segment for any listed company but are part of general construction and subsea services. This has several consequences; the most obvious and important is that pipelay project revenues are rarely, if ever, disclosed directly and are usually combined with other project elements and revenue streams. This is also due in large part to the nature of construction service contracts, which are frequently bundled together with other activities.

### 7.2.2. Fleet Composition

Fleet composition describes the number and type of vessels within a company's portfolio and is the most direct indicator of a company's capacity and degree of integration. The vessels themselves may be owned, leased, or subcontracted. It is not necessary to own construction vessels to win work, but there are risks to leasing, subcontracting and joint ventures. For example, leased vessels of the right specification for a job might not be available at the time needed or might require upgrading, and subcontracting involves performance risk. Chartered vessels frequently require equipment, such as ROVs, vertical lay towers, and pipelay equipment to be stored and maintained when not in service.

The upstream supply chain comprises many business segments; contractors serving these segments will require different vessel portfolios or the capacity to charter vessels (Figure G.2). For example, contractors serving the exploration segment will require a fleet of anchor handling tugs (AHT, AHTS) and platform supply vessels (PSVs) to serve drilling rigs while contractors serving production facilities will mostly require PSVs, crew boats, and well intervention IMR (inspection maintenance repair) vessels. These are distinct markets with different supply and demand characteristics and levels of competition.

Drilling is highly specialized. To offer drilling services requires maintaining rigs, such as jackups, semisubmersibles, and drillships. Among the pipelay contractors, only Saipem offers drilling services.

Well construction has few similarities with offshore construction and drilling rigs mostly serve the exploration and development segment (Kaiser and Snyder 2013).

Field development requires vessels that can transport, lift, and install heavy equipment and structures, such as derrick barges, lift boats, multipurpose support vessels (MPSVs), cargo and crane barges, and the like (Diab and Tahan 2005, Gerwick 2007). Construction vessels may allow some form of pipelaying or vessels may be specialized for only pipelaying. Pipe carriers are required to supply the necessary labor, vessels, pipes, equipment, materials and consumables, but barges are commoditized vessels and readily available. AHTs are required for anchor spread vessels, survey vessels are required before and after laying pipe and for preparatory work around pipeline and cable crossings, and trenching vessels may be required depending on burial requirements. Many of the vessels used for construction are also used in deconstruction (i.e., decommissioning), providing a degree of horizontal integration for contractors.

### 7.2.3. Fleet Capacity and Use

Firms may operate in only shallow water, only deepwater, or hold vessels capable of laying pipe in both water depths. When competing for contracts that cross a transition zone, a company that owns a diverse fleet may be able to offer a more competitive bid than a company that needs to subcontract for additional services. Shallow water vessels are more likely to represent a companies' paid for (fully depreciated) legacy fleet; to compete in deepwater, new vessels must be built or older vessels upgraded to acquire the latest equipment and technological innovation. Operating in a range of water depths is a diversification strategy because supply and demand in shallow and deepwater basins across the world can differ significantly.

Active and stacked vessels comprise the company fleet (Figure G.3). Newbuild and secondhand purchases expand the vessel portfolio and allow more integrated or specialized services and capabilities. Sales shift capacity to competitors while recycling or modifying to a different form of vessel removes capacity from the market. Active vessels are under contract, between contracts or ready-to-work, whereas stacked vessels have been taken out of service to reduce operating and maintenance cost. During market downturns, firms may cold-stack units to reduce maintenance cost, but, unlike the rig market (Kaiser 2014) there are fewer benefits and less savings incurred from stacking. Retirement and dismantling of less competitive vessels reduce costs further but at the potential loss of future opportunity.

### 7.2.4. Geographic Diversity

Geographic diversity corresponds to the manner in which contractors distribute their marine vessels worldwide and, for integrated companies, the revenue generated by business lines per geographic region. Firms may focus on a single market or maintain a presence in more than one market. Contractors that operate in multiple markets require larger fleets than regionally focused firms. Water depth can be considered a subclass of geographic diversity.

Contractors are described as either deepwater or shallow water specialists or generalists based on their vessel fleet capability. Saipem, McDermott, and Allseas are generalists and operate in both shallow and deepwater throughout the world (Table G.4). Deepwater specialists are typically mid-sized or large firms. Large deepwater specialists include TechnipFMC and Subsea 7. Smaller deepwater specialists include Oceanic and Ceona. Shallow water specialists are typically smaller firms and include Ascot, Bisso, Chet Morrison, and Leighton.

The type of vessels operated by a company is an indicator of their area of emphasis because low-spec barges are used exclusively in shallow water, semis and high-spec barges are used in deepwater, and high-spec and ultra high-spec vessels are used for the most challenging work requirements. Heerema operates semis and high-spec barges exclusively, and EMAS, Ceona and Sea Trucks operate only high-spec vessels. Ascot, Bisso, Chet Morrison, and Leighton operate low-spec barges.

### 7.2.5. Integration

Integration is a strategy to reduce the risks associated with a particular business segment by integrating horizontally or vertically, or both, to expand services offered (Figure G.4). Firms integrate to capitalize on existing technical knowledge and client relationships and to offer a more competitive and complete suite of services to clients. Integration is often viewed as a way to increase revenues and expand opportunities and may be achieved through mergers and acquisitions or organic growth.

Vertical integration generally describes companies that provide engineering, procurement, construction and installation to one or more of the upstream, midstream, or downstream segments. Engineering and procurement services require engineering staff and experience in design and cost estimation, whereas construction and fabrication require shipyards and facilities and, of course, installation requires construction vessels or the ability to manage subcontractors. Engineering and procurement services may be performed in-house or by third parties.

Horizontal integration generally refers to providing services within one or more of the upstream, midstream, and downstream business segments. Midstream generally covers onshore pipelines, gas plants, and LNG, and downstream covers refining, petrochemicals, and fertilizers. To some extent, all construction service companies are integrated horizontally across the upstream sector–except exploration and production–because most contractors own a variety of marine vessels such as tug boats, crane vessels, derrick barges, and dive support vessels.

Opportunities for vertically integrated firms are represented generically in Table G.5, where individual boxes represent a different potential market and revenue stream. Vertically integrated companies seek to capture market share across multiple rows and columns, whereas less integrated companies that can only deploy vessels have to compete entirely within the last column (installation) and can only capture a portion of the capital spending on projects.

### 7.2.6. Diversification

Firms are considered diversified if they operate outside of the offshore oil and gas market. Diversification is a strategy that can reduce risks associated with market declines, but because declines in the oil and gas industry tend to correlate with the general economy, market downturns in the oil and gas sector may broadly trend with other industry sectors.

Large firms are more likely to be diversified than small firms, but smaller firms are occasionally diversified similar to the exploration and production (E&P) industry structure. Because diverse firms do not generate all of their revenues from offshore operations, they are less susceptible to shocks in the price of oil and gas. Large onshore construction projects, for example, usually last for several years and provide higher levels of stability than offshore projects.

The most diversified pipelay contractors in the industry include: TechnipFMC, which conducts oil and gas plant work and designs, manufactures and services subsea and marine systems; Van Oord, which conducts civil offshore construction and dredging work; CNOOC and Sapura Energy, which are E&P firms; and Saipem, which is a construction firm and operates drilling rigs. Diversified firms generally receive only a small portion of their revenue from pipelay installation services.

### 7.2.7. Revenue

Revenue is a function of business lines, fleet size, contract types, and many other factors, most of which are not directly observable. Revenue is expected to be positively correlated with company valuation, earnings, fleet value, and backlog (if integrated), similar to drilling rig companies (Kaiser 2014), but because of the complex and diverse nature of construction service contractors and the variety of business segments, quantitative models are unlikely to reliably capture these factors.

In Table G.6, business segment revenues involving pipeline activity and total revenue are depicted for the three years ending 2014, 2015, and 2016. Segment revenues will change in relative importance over time and total revenues may increase or decrease; the decline in total revenue across the sector over the reporting period is apparent.

*Example. Subsea 7 project completion circa 2016*

> Subsea 7 S.A. is a vertically integrated company that provides services and technology for EPCI contracts as well as bespoke remote interventions. They have maintained a broad international portfolio of projects and are specialized in the sense that they primarily operate in deep water. Figure G.5 illustrates projects of greater than $100 million that were between 5% and 95% complete reported by the company as of 31 December 2016. The size, scope, and geographic diversity of projects depicted here is common amongst global integrated contractors.

### 7.2.8. Market Capitalization

The market value of a company is derived from its cash flow and earnings, which are dependent upon the quantity of sales, sales price, and cost structure (Abrams 2010). Market capitalization is the total value of tradable shares at a given point in time determined by the product of stock price and the outstanding shares.

Market capitalization for publicly traded offshore construction contractors circa May 2017 are shown in Table G.7, along with total assets and employee counts for the years ending 2014, 2015, and 2016. In 2016, market caps ranged from $16 and $36 million for EMAS and Swiber to Technip's $15 billion, a difference of three orders-of-magnitude. Subsea 7, Saipem, Sapura Energy, and McDermott are also billion-dollar capitalized companies. Integrated and diversified firms generate significant revenue streams from many different business lines, which contribute to large market caps and large employee counts.

### 7.2.9. Market Position

Market position describes a company's market share within a service offering and geographic region and derives from a company's business profile and success. There are regional and niche players and companies that dominate sectors globally. Market positions are more difficult to track and to reliably estimate, however, because of the confidential and diverse nature of contracting and the long-term multi-faceted requirements of projects.

### 7.2.10. Market Structure

Market structure characterizes the level and type of competition among contractors and determines their power to influence prices for their service. When demand is high, pricing power generally shifts to the vessel contractors, while when demand is low E&P companies demand (and often receive) price discounts. Companies attempt to balance short-term and long-term contracts in their project backlogs and contracts, but strong competition usually puts pressure on prices that may not be adequate for the risks taken, especially for the fixed-price lump-sum contract work that is common across the EPCI (engineering, procurement, construction, and installation) industry (Harris et al. 2004).

## 7.3. EPCI Contractors

### 7.3.1. Backlog

For integrated firms, backlog is commonly reported to indicate the dollar amount of revenues a company expects to recognize in the future from contracts awarded (order intake) and those that are in progress. In Figure G.6, a bathtub analogy of backlog is depicted to represent the flows and stock variable. Water level represents backlog at the end of the year, inlet flow represents bookings from new awards and additions on existing contracts during the year, and outflows represent revenues recognized during the year. Backlog additions and reductions shown are illustrative.

Backlog is not a generally accepted accounting principle (GAAP) measure, however. It is also not a reliable indicator of future revenue, because revenues projected in backlogs may not be realized, or, if realized, may not result in profits. Project delays, suspensions, scope changes, payment default, cancellations,[5] and poor project execution can materially reduce the revenues and reduce or eliminate profits.

*Example. McDermott's backlog and competitors*

> McDermott International, Inc. reported a backlog of $4.3 billion in 2016, compared to a $4.2 billion and $3.6 billion backlog in 2015 and 2014, respectively. Order intake in 2016 was reported as $2.7 billion compared to $3.7 billion intake in 2015 and $1.1 billion intake in 2014. McDermott competitors in its three operating regions include not only offshore construction firms but also several engineering firms and joint ventures (Table G.8).

#### 7.3.2. Contract Type

Every offshore project is unique and novel technologies are frequently employed as projects step out into deeper water. As a result, it is often difficult to accurately estimate project costs and cost overruns occur. Depending on contract structure, these cost overruns may be the responsibility of the contractor, as in EPCI contracts, or risks may be allocated between the contractor and the pipeline owner.

In contracts where vessels are leased on a dayrate, the operator bears the weather risk, but most construction contracts have historically been hard-dollar EPCI contracts where the risk of cost overruns falls on the contractor (Farrell et al. 1996, Harris et al. 2004). Contractors that cannot accurately estimate EPCI costs may lose money on project work; this has been a recurrent problem in the industry (Doherty 2011). Global Industries and McDermott, for example, suffered a large number of cost overruns in offshore work in 2003–2004; the former eventually went bankrupt.

#### 7.3.3. Contracting Strategy

There are many different ways in which project scopes can be defined and awarded (Figure G.7). Operators select contract strategies in field development based on project objectives and value drivers, joint operating agreement requirements, concession agreement requirements, stakeholder desires and aversions, and tax, legal and financial aspects. Strategies are selected to achieve low capital spending, reasonable cost certainty prior to investment decision, a desired schedule, a quality product, and effectively managed health, safety, and environment issues (Vickery 2004, Williams and Eckert 1996).

Contacts that are broken into a large number of small awards require greater operator interface management but often provide cost savings (Stewart 2008). A combination of EPCI contracts and in-house work scopes are typically employed. For deepwater development, EPCI strategies are common for subsea equipment supply, and fixed, lump sum strategies are often used for installation of one or more components.

5 Contracts usually provide for cancellation fees which provide for reimbursement of out-of-pocket costs, revenues for work performed prior to cancellation, and a varying percentage of the profits that would have been realized if the project had been completed, but these are subject to litigations and the outcome of claims is uncertain and potentially time consuming.

*Example. Parque das Conchas contracting*

Parque das Conchas (BC-10) is an ultra-deepwater heavy oil development located offshore Brazil in the northern Campos basin in water depths from 1600 to 2000 m (5200 to 6600 ft). The project is a joint venture between Shell, Petrobras, and ONGC developing three subsea fields using a turret moored floating production storage and offloading (FPSO) vessel (Figure G.8). The five largest project contracts were awarded to Brazilian Deepwater Floating Terminals, FMC Technologies, Subsea 7 and Transocean (Table G.9).

Subsea 7 construction vessels *Seven Oceans* and *Seven Seas* performed the installations, which, in total, amounted to: (1) Ten steel flowlines, 6 in. to 12-in. in diameter, totaling approximately 90 km (56 mi) of pipe; (2) One gas export pipeline totaling 40 km (25 mi) of pipe; (3) Seven steel lazy wave risers totaling 21 km (13 mi) of pipe; (4) Twenty-five rigid steel jumpers; (5) Fifteen flowline sleds; (6) Four manifolds with weights up to 235 mt; (7) Thirty kilometers (19 mi) of high voltage multi-control umbilical (Hoffman et al. 2010).

*Example. Cascade and Chinook contracting*

The Cascade and Chinook fields are located in the Central GoM near the base of the Sigsbee Escarpment (Figure G.9). Cascade is located in water depth of 8150 ft (2485 m) and Chinook is located about 15 miles (24 km) south of Cascade in 8857 ft (2700 m) water depth.

The initial project phase used a leased FPSO vessel located between the fields in 8200 ft (5200 m) water depth. There is one drill center with two wells in Cascade and one drill center with one well in Chinook. Dual flowlines were selected to enable round-trip pigging and flowline displacement from the FPSO. An EPC strategy was used for the subsea equipment supply and a lump sum strategy for the installation contracts. Eleven major contracts were awarded (Table G.10).

The seabed flowlines and gas export pipeline are connected to the FPSO by five free-standing hybrid risers (FSHR) anchored to the seabed. The production FSHR pipe is 9.625 in. diameter with 1.32 in. wall thickness, and the gas export FSHR pipe is 7.5 in. diameter with 0.75 in. wall thickness. Gas is exported through an export pipeline about 40 miles (64 km) long.

The dual production flowlines in both fields are looped at the drill center manifolds to allow round trip pigging. The Cascade flowlines are 9.625 in. diameter with 0.995 in. wall thickness and thermally insulated with 3.386 in. polypropylene. The Chinook flowlines are pipe-in-pipe with outer pipe 14 in. diameter and 0.756 in. wall thickness and carrier pipe 9.625 in. with 1.211 in. wall thickness. The entire 23 mile (37 km) length of the two Chinook pipe-in-pipe flowlines was straked because of seabed furrows. The control umbilical length is 25,085 ft (7648 m) for Cascade and 74,237 ft (22,633 m) for Chinook.

# Chapter 8. Business Models, Strategies, and Risk Factors

*The offshore pipeline construction service industry has seen varying degrees of consolidation and integration over the years. The demand for pipeline construction fluctuates from year-to-year and during periods of sustained low oil prices demand for services are reduced, causing contractors to resize operations to maintain a competitive position, to form alliances and partnerships in search of opportunities, and to stack and dismantle less competitive vessels to reduce cost. The purpose of this chapter is to describe the business models employed by offshore construction companies and their impact on operations. A review of corporate strategies reveals the depth, breadth and complexity of the sector. Operational and financial risk factors are highlighted and business strategies are summarized. The chapter concludes with company portraits circa 2017.*

## 8.1. Business Model

### 8.1.1. Net Cash Flows

All construction firms that own and operate offshore vessels follow broadly similar business models, when viewed from a cash flow perspective (Figure H.1). Firms generate revenue from their business segments and investments, which are used for required spending to remain a going concern and discretionary spending to pursue opportunities and strategic objectives. Contractors use cash generated from operating activities to maintain their vessel fleet and personnel and other costs and they supplement this with stock offerings (if public) to raise capital. They borrow money through conventional bank loans and by entering the bond market to refinance or to raise funds for the construction of new vessels or secondhand purchases to upgrade or expand their existing fleet. Companies may sell shares and assets to pay down debt.

Financing may be internally or externally sourced and spending may be required or discretionary. Required spending is needed to maintain the firm as a going concern and include operations and maintenance, interest and debt payments, taxes and administration. Discretionary spending includes acquisitions, stock buybacks, and dividends. A company's leverage often determines the flexibility in which it operates. If a company misses a debt repayment, for example, covenants and other conditions may kick-in immediately, restricting the use of their credit facilities. Management's ability to manage and foresee the opportunities and risks in the business lines are a key component in successful operations.

When vessels are used, they generate cash flows for the firm and are used to pay back the interest and principle of its loans and return dividends to its shareholders. Integrated and diversified firms will generate revenue from one or more business segments; this may act to smooth out the variation in cash flow across business cycles. Operators can idle or stack vessels to reduce operating cost, sell vessels that are not deemed strategic assets to raise revenue, or scrap vessels to remove them from the market.

*Example. Subsea 7 cash flows*

> On December 31, 2015, Subsea 7 had $947 million on its balance sheet compared to $1676 million at the end of the year on December 31, 2016 (Figure H.2). Earnings before interest taxes depreciation and amortization (EBITDA) were $1142 million. Capital spending for the year for vessels and equipment and related long-term purchases was $300 million, repurchase of notes was $106 million, and taxes paid were $141 million.

### 8.1.2. Business Risk

The different types of business that make up a company and sector entail different degrees of business risk and result in different levels of cash flow volatility and debt capacity. The total revenue generated from all company (and subsidiary) activities must be adequate to service corporate debt in times of low demand, or the firm will be forced to issue additional debt or sell assets. Offshore contractors generally maintain sizable credit facilities, primarily for acquisitions and capital spending, because business lines require steady working capital. If companies are unable to refinance maturing debt or to renew their bank lines, they will be pressed to meet their debt obligations and distributions.

Cash flow volatility and a company's ability to repay its debt and/or acquire additional credit facilities are a primary source of business risk and serve as the primary indicator of corporate credit and/or default ratings. Credit rating is directly related to a company's cost to raise capital and access credit markets. Companies with a strong and/or high credit rating can acquire greater capital and at lower cost than companies with lower ratings. Business risk often varies within the same business activity depending on supply and demand fundamentals, the quality of contracts, strength and diversity of customers, geographic diversity, competition, regulatory risk, and significance of market-driven revenues.

Companies that expand into business lines and acquire new vessels may have higher exposure to commodity price and volume risk, which increase their business risk to grow and pursue other opportunities. Legacy vessels are long-lived assets that generally have low reinvestment needs but are constrained in their ability to compete against newer vessels. Over any given period, vessel uses may not result in adequate cash flows to pay off debt, in which revolving bank loans may be used or asset sales to meet obligations. As long as the daily revenue made by leasing the vessel exceeds the daily operating cost, the firm will choose to operate the vessel.

## 8.2. Business Strategies

### 8.2.1. Integration

Fleet specification is usually associated with firm integration and firms with high-spec fleets are commonly integrated (Figure H.3). Integrated firms operate in non-pipelay segments and/or provide engineering, procurement, and commissioning services. Firms that operate high specification fleets are frequently large and integrated but there are exceptions. For example, Chet Morrison has a low specification fleet but is relatively integrated and diversified because they operate in a number of onshore and offshore business segments. Company positions change over time but over the short run can be considered relatively stable.

*Example. GoM spoolbase operations*

> Pipelay contractors may operate spoolbases to fabricate rigid and flexible steel pipe strings. In the Gulf of Mexico (GoM), McDermott operates a spoolbase in Gulfport, Mississippi, Technip operates a spoolbase near Mobile, Alabama, EMAS operates a spoolbase in Ingelside, Texas, and Subsea 7 operates a spoolbase in Port Isabel, Texas. Ownership of a spoolbase allows a firm to compete for reeled pipeline installation contracts which are common in the deepwater GoM.

#### 8.2.2. Growth Paths

Companies grow organically by building on their core businesses and existing capabilities, through mergers and acquisitions, or a combination of approaches. Organic growth is usually more controlled with less risk exposure but is also less able to adapt to rapid changes in industry dynamics. Mergers and acquisitions can deliver a step change in asset base and value but risk exists on consolidating business lines and creating the synergies to extract value from the larger company. There are advantages and disadvantages and risk inherent in all paths.

#### 8.2.3. Vessel Acquisitions

Contractors acquire vessels through newbuild programs and secondhand sales to expand their service offerings and to maintain the latest technology capability. The arrangements companies use to account for these vessels are as varied as the vessels themselves. Similar to the logistics sector (Kaiser 2015e), leaseback and bareboat charters are common.

*Example. Leaseback and bareboat charters*

> In January 2017, McDermott purchased the *Amazon* pipelay and construction vessel for $52 million and then simultaneously sold the vessel to an unrelated third party for total cash consideration of $52 million and entered into an 11-year bareboat charter agreement with the purchaser. The bareboat charter provides McDermott with options to purchase the *Amazon* at a predetermined value periodically over the charter term. The transaction was accounted as a sale leaseback and the bareboat charter agreement was recorded as an operating lease.

#### 8.2.4. Vessel Sales

Firms sell vessels to raise revenue, to divest older assets, to maintain a specialization in a higher specification fleet segment, and to reduce operating expenses. Since the pipelay fleet is relatively small and the number of operators is limited, transactions in the secondhand market are sporadic. For distressed assets, the purchaser has the opportunity to acquire a vessel at a reduced price. Companies also sometimes buy bonds offered by a distressed firm in anticipation that the distressed firm will be unable to pay and the company will receive one or more vessels during bankruptcy proceedings. These are low-cost, high reward speculative bets with uncertain outcomes.

*Example. Distressed asset sales*

> In 2012, Helix sold its three-vessel pipelay fleet to investors for $250 million and exited the market. In 2015, Cal Dive sold *Sea Horizon*, a 361 ft derrick/lay barge for $8.8 million to Holmen Engineering during bankruptcy proceedings.

#### 8.2.5. Alliances and Partnerships

Alliances and partnership models attempt to improve cost savings and project performance through risk sharing and commercial collaboration between suppliers and producers (Khurana et al. 2017). With EPCI companies and equipment suppliers increasingly compelled to take on a greater share of project risks, a number of subsea service companies have formed partnerships and joint ventures in recent years. The acquisitions of Cameron by Schlumberger and FMC Technologies by Technip and the merger of Baker

Hughes and General Electric furthered this trend of consolidation. One Subsea is an alliance between Schlumberger, Cameron, and Subsea 7; Saipem and Aker Solutions have also formed an alliance. In January 2018, General Electric announced its plans to spin-off or sell its Baker Hughes subsidiary.

#### 8.2.6. Joint Ventures

Joint ventures are another mechanism to spread risks among multiple parties and to leverage firms' assets and strengths. Joint ventures are relatively rare in the pipelay contracting industry, but Sapura Energy Berhad, an oil and gas services provider and relatively new entrant to offshore construction, has recently been involved in multiple joint ventures and operates pipelay vessels with Seadrill, a drilling contractor, and Larsen and Toubro, an Indian engineering firm.

#### 8.2.7. Mergers and Acquisitions

Companies seek mergers and acquisitions as a source of growth opportunity, to expand horizontal and vertical integration or geographic presence, to take advantage of distressed assets, to consolidate in times of low demand and prices, and for various other reasons.

*Example. Subsea 7–Acergy*

> In June 2010, Acergy, a U.K. provider of oil services, agreed to buy Subsea 7, a Norwegian firm, for \$2.5 billion in shares, and the merger was finalized in January 2011. Executives from both Acergy and Subsea 7 were involved in the leadership of the merged company, and circa 2017, Subsea 7 is among the largest players in the market.

*Example. Technip–Global Industries*

> In September 2011, Technip agreed to acquire Global Industries for approximately \$1 billion. At the time of purchase, Global Industries operated 14 vessels, including two newly-built S-lay vessels, and had strong market positions in the GoM, Asia, and the Middle East. Since the purchase, Technip has sold, scrapped, or no longer operates many of the vessels acquired.

*Example. McDermott–Oceanteam*

> In December 2014, J. Ray McDermott, S.A., a wholly owned subsidiary of McDermott International Inc., exercised its option to purchase Oceanteam ASA's 50% ownership interest in the entities that own the *North Ocean 102* subsea construction vessel for \$33 million.

*Example. Swiber–Deltatek Offshore Limited*

> In January 2016, Swiber Offshore Construction Pte. Ltd., a wholly-owned subsidiary of Swiber Holdings Ltd., acquired 38% of the equity interest in Deltatek Offshore Limited (DOL), which became an associate of the company. DOL provides offshore EPCI and commissioning services in the Sub-Saharan African region.

*Example. FMC Technologies–Technip*

> In January 2017, FMC Technologies and Technip completed a business combination agreement in which FMC Technologies, a private company that designs, manufactures, and services systems and products for subsea production and marine loading systems for the energy industry, and Technip, an integrated EPCI offshore service provider, merged to create a larger and more diversified company.

## 8.3. Risk Factors

Risks are defined as a potential future event that, if it occurs, will negatively impact business outcomes also known as downside risk or threat. In this section, the primary downside risks related to business operations and financial conditions are identified (Figure H.4). The order is random and does not imply importance. Opportunities that can arise from joint ventures, asset purchases, portfolio readjustments, entry into new markets, and related factors are not described.

### 8.3.1. Factors Related to Business Operations

*Oil and Gas Prices*

Activity in the offshore oil and gas sector is dependent on commodity prices, which are unpredictable and historically cyclical. When oil and gas prices decline, offshore exploration activity eventually responds and demand for services decline, but because of the long lead times and contract terms for offshore projects, there are typically longer delays between price signals and responses depending on the water depth, region, and country. For example, in the US GoM, the response is expected to be quicker in shallow water than in deepwater, and internationally where National Oil Companies are dominant (e.g., Brazil, Persian Gulf) the delay will typically be longer.

*Prospectivity*

As development activity and production declines in a region, the need for pipeline installation will also decline, while regions with high levels of exploration and development and growing production will typically require greater pipeline capacity, either in the form of infield flowline work and/or export pipelines. In offshore regions with significant FPSO vessel capacity, such as Brazil, West Africa, and Southeast Asia, shuttle tankers are the primary means for oil export and most of the pipelay work is associated with subsea well development and gas export. If regional markets are not available or sufficiently developed, gas will be reinjected into the reservoir and gas export lines will not be needed.

*Weather*

Marine operations are typically seasonal and dependent on weather conditions. Firms operating in the US GoM, for example, experience low vessel use rates during the winter and early spring when weather conditions are least favorable for operations. In competitive market conditions, contractors typically bear the risk of delays caused by some, but not all, adverse weather conditions; hurricane activity is often covered by Force Majeure clauses.

*Capital Intensity*

Offshore construction requires investment in expensive, specialized vessels that are long-lived, not frequently used, and competing against other vessels that perform similar activities. Some vessels may not be capable of serving all markets and may require additional maintenance and capital expenditures due to age or other factors, creating periods of downtime. Vessel construction is often financed through debt and, as a result, firms may be highly leveraged. Because of the cyclic nature of the industry this can cause cash flow problems for firms at times of low demand. Newer and more technologically advanced vessels are often in higher demand, require less maintenance, and have a higher uptime than older vessels. Companies that are unable to manage their fleet efficiently and find profitable opportunities for their vessels will have deteriorating operations and their financial position and cash flows could be adversely affected.

*New Business Lines*

Company operations and acquisitions that expand into new business lines may expose the company to business and operational risks that are different from those experienced historically. Management may not be able to effectively manage these additional risks or implement successful business strategies in new lines of business. Competitors in new lines of business may possess substantially greater operational knowledge, resources and experience than the company.

*Joint Ventures*

Joint ventures in foreign areas with local companies may be a requirement in doing business. Though the joint venture partner may provide local knowledge and experience, entering into joint ventures requires a company to surrender a measure of control over the assets and operations devoted to the joint venture, and occasions may arise when disagreements over the business goals and objectives occur, which could make the continuation of the relationship unwise or untenable. Assets dedicated to the joint venture may be at risk or affect the continuity of business. Unwinding a joint venture may prove difficult or subject to a partial or complete loss.

*International Operations*

International operations are exposed to risks that are not typically experienced in domestic operations. These risks include changes in currency valuation, government expropriation, terrorism, labor strikes, trade barriers, complications associated with repair of equipment in remote areas, and changes in governmental regulatory requirements, especially cabotage laws. Changing political conditions and changing laws and policies may affect trade and investment.

*Customer Base*

Offshore contractors may derive a significant amount of revenues and profit from a relatively small number of customers. Problems or cut-backs from one or more customer may materially impact business operations. Customers change over time as contracts are fulfilled, but, if new contracts are not replaced or found, financial conditions and cash flows could be adversely affected. Loss of a major customer may impact financial conditions adversely.

*Marine Operations*

Marine operations are inherently risky and vessels can suffer damage, grounding or sinking during operations. Storms and hurricanes greatly increase these risks. Vessels are insured against most losses. If vessels are the only means by which firms generate revenue, loss or damage to a vessel may result in a relatively long-term impairment of cash flow.

*Regional Development*

As oil and gas producing regions mature and new discoveries decline, the number of new developments decline along with the demand for construction services. As a result, pipeline contractors will periodically reposition their fleets to take advantage of new geographic opportunities, but it may not be cost effective to reposition vessels and build out port facilities, especially for low-spec barges, or where a high degree of competition already exists. Field developments in regions that do not have extensive export pipelines, such as West Africa and the South China Sea, require a different vessel fleet to perform offshore work.

*Consolidation*

Oil and gas companies and energy service companies have undergone consolidation and additional consolidation is always possible. Consolidation reduces the number of customers for a company's equipment and may negatively affect exploration, development and production activity. Such activity could adversely affect demand for pipeline services.

*Competition*

High levels of competition can depress charter and vessel dayrates and utilization and adversely affect financial performance. Construction service companies compete on the basis of price, reputation, quality, technical capabilities and availability of vessels, safety and efficiency, and national flag preference. Competition in international markets may be adversely affected by regulations, flagging, ownership and control of vessels, and various local content restrictions (construction, awarding contracts, employment, purchase of supplies).

*New Entrants*

New entrants increase competition. Market entry is capital intensive because vessel construction is expensive and establishing experienced crews requires time, which provides protection to current participants and reduces the frequency of new entrants, but once new vessel capacity is constructed it is long-lived and will continue to impact the market. Asset sales, upgrades and modifications are common and contribute to varying levels of market supply and competition over time.

*Vessel Construction and Upgrades*

Vessel construction, upgrade, refurbishment, and repair projects are subject to risks, including delays and cost overruns that can have an adverse impact on a firm's cash resources and results of operations. These risks may result from: shipyard delays and performance issues, shortages of skilled labor, failures or delays of third-party equipment vendors or service providers, unanticipated change orders, design and engineering problems, work stoppages, and unforeseen increases in the cost of equipment, labor, and raw materials. Vessels undergoing upgrade, refurbishment, and repair activities do not earn revenue when they are out of service.

*Overcapacity*

Excess construction vessel capacity usually exerts downward pressure on dayrates and contract prices in competitive markets. Excess capacity can occur when newly constructed vessels enter regional fleets. An increase in vessel capacity without a corresponding increase in demand could result in an oversupplied condition, which may have the effect of lowering charter rates and use, which, in turn, would result in lower revenues.

*Acquisition Risks*

Acquisitions may incur substantial indebtedness or equity issue (i.e., stock) to finance, which may impose a significant burden on operations and financial conditions. It may not be possible to successfully consolidate the operations and assets of an acquired business or vessel within existing business lines. Acquisitions may not perform as expected and may be dilutive to operating results. Management may not be able to effectively manage a substantially larger business or successfully operate a new line of business.

*Restricted Markets*

Many markets have regulatory or political barriers to market entry and this is often the case when the E&P market is state-run. For example, Brazil, Mexico, and Nigeria all have local content laws which makes market entry difficult (de Oliveira 2015). Joint ventures with state-run firms may be pursued, but these are subject to risk of compliance and issues related to joint ventures. Cabotage laws are another means to restrict access to particular market participants.

*Contracting*

EPCI contractors entail significant risk of cost overruns since the contractor agrees to provide a fully-functional pipeline (or other offshore infrastructure) to the customer at a specified price and time. Most cost risk associated with weather delays, pipe quality, subcontracting delays, cost inflation, or installation problems are borne by the contractor, with certain specified exceptions (e.g., hurricanes). To compensate for this increased risk, EPCI contracts command a price premium, but reliable cost estimation is notoriously difficult. Smaller firms are either technically unable to conduct the engineering and project management associated with EPCI contracts and/or unwilling to take on the risk associated with potential cost overruns. Change order awards are common and can have a negative effect on revenue if change orders are under dispute or not resolved in the contractor's favor.

*Unconventional Production*

The rise in production of unconventional crude oil and natural gas resources in North America and the commissioning of a number of new LNG export facilities around the world may contribute to oversupplied oil and gas markets. Prolonged increases in the worldwide supply of crude oil and natural gas, whether from conventional or unconventional sources, without a commensurate growth in demand will act to depress prices. Prolonged periods of low prices will likely have a negative impact on development plans and may result in a decrease in demand for offshore construction services.

### 8.3.2. Factors Related to Financial Conditions

*Financial Market Volatility*

Operations and initiatives are primarily financed with cash and cash equivalents, including proceeds from term loans and senior secured notes, investments, and cash flows from operations. If economic conditions deteriorate, a company may not be able to refinance outstanding indebtedness when it becomes due, and may not be able to obtain alternative financing on favorable terms.

*Reduced Lending*

Credit risk that develops in distressed industries will transfer to the facilities that provide loans. Credit facilities and lenders under stress may reduce their loan exposures to the energy sector and impose increased lending standards, collateral requirements, or refuse to extend new credit or amend existing credit facilities. All of these factors may complicate the ability of borrowers to achieve a favorable outcome in negotiating solutions to stressed credits.

*Debt and Funded Debt Levels*

Debt and funded debt levels and debt service obligations can have negative consequences, including: requiring a company to dedicate significant cash flow from operations to the payment of principle, interest, and other amounts payable; making it more difficult to obtain necessary future financing; reducing a company's flexibility in planning or reacting to changes in the industry or market conditions; making a company more vulnerable to downturns; exposing a company to increased interest rate risk for variable interest rate loans.

*Letter of Credit Capacity*

EPCI contractors are often required to post letters of credit to customers which indemnify customers should the company fail to perform its obligations under the applicable contracts. If a letter of credit is required for a particular project but the contractor is unable to obtain it due to insufficient liquidity or other reasons, the contractor may not be able to pursue that project. The market capacity for letters of credit is limited, and letters of credit may be difficult to obtain in the future or may only be available at significant cost. Inability to obtain adequate letters of credit could have an adverse effect on a contractor's business, financial condition and results of operations.

*Foreign Exchange Risk*

Contractors that work on a worldwide basis with substantial operations outside their domestic market are subject to currency exchange risk. To manage some of the risks associated with foreign currency exchange rates, companies may enter into foreign currency derivative instruments, but these actions may not always eliminate all currency risk exposure. A disruption in the foreign currency market could adversely affect hedging instruments and subject a contractor to additional currency risk exposure.

*Counterparty Risk*

Companies with significant international operations may enter into various financial derivative contracts, including foreign currency forward contracts with banks and institutions, to manage foreign exchange rate risk. Financial derivative contracts involve credit risk associated with hedging counterparties.

## 8.4. Corporate Review

### 8.4.1. Public Firms

TechnipFMC PLC is a diversified French company that carries out a broad range of activities in the oil and gas sector. In 2016, TechnipFMC reported three business segments: a subsea segment, an onshore/offshore segment, and a corporate segment. The subsea segment includes services for subsea fields, flexible pipe and umbilical supply, the operation of long-term charter vessels in Brazil, turnkey pipeline projects, and IMR (inspection, maintenance, and repair) work. The onshore/offshore segment includes development, refinery engineering, gas plant engineering, petrochemical engineering, and the design, manufacture and installation of fixed and floating production units and natural gas liquefaction facilities. The corporate segment relates to holding company activities and group subsidiaries. TechnipFMC's subsea segment accounted for about three-fourths of its 2016 revenues, and although TechnipFMC has no direct connection with the French E&P major Total, it is frequently the contractor of choice for much of Total's project work.

Saipem S.p.A. is a major player in offshore drilling, construction, heavy lift, and pipelay markets. Saipem reports its business activities in four market segments: offshore construction and engineering, onshore construction and engineering, offshore drilling, and onshore drilling. Construction and engineering represent integrated services from design, procurement, management, and construction services principally to the oil and gas, civil and marine infrastructure, and environmental markets. Saipem's 2016 offshore fleet consist of 11 pipelay vessels, 18 cargo/accommodation/support barges, and two leased FPSOs. Saipem's offshore drilling fleet consisted of 14 vessels–two drillships, five semisubmersibles, two high-spec jackups, four standard jackups, and one barge tender. Saipem's onshore drilling rig fleet was composed of 100 units, 96 owned by Saipem. Offshore construction and engineering was the largest of Saipem's four operating segments in 2016.

Subsea 7 S.A. is a U.K. firm headquartered in London. The company operates a worldwide fleet of 36 high specification subsea construction and inspection vessels–25 owned, seven chartered, and four stacked–circa June 2017. Subsea 7 operations concentrate on the markets in SURF, life-of-field, hook-up, ROV and intervention support, renewables, heavy lifting and decommissioning. Subsea 7 operates globally with a strong presence in the North Sea, West Africa, and Brazil; however, they also operate in the GoM and own a spoolbase in Port Isabel, Texas. The SURF and conventional segment accounted for the majority of operating revenues in 2016. A three-vessel newbuild program was completed in January 2017.

McDermott International is incorporated under the laws of Panama and operates globally through one or more subsidiaries. McDermott focuses primarily on designing, constructing, and installing facilities for offshore oil and gas projects (fixed and floating production facilities, pipeline fabrication, subsea systems), but also pursues projects through ventures with other parties in new industries and regions. McDermott's reporting segments are geographic and grouped according to America, Europe, Africa; the Middle East; and Asia. Approximately half of their 2016 revenues were associated with installation activity with over three-fourths of their revenues generated in Saudi Arabia and Australia. McDermott owns and leases construction yards in Altimira, Batam, Quingdao, Dammam, and Dubai.

EMAS Offshore Limited (EOL) was incorporated in February 2007 to provide offshore services to the oil and gas industry in Asia Pacific and Africa. EOL is owned by Ezra Holding's Limited of Singapore and has business segments in offshore support vessels, marine (shipyard) services, and subsea services. EOL did not release a 2016 annual report or 2017 semi-annual report due to financial exigency, and Ezra is in discussion with various stakeholders to obtain additional working capital. In the event that these efforts do not achieve a favorable and timely outcome, Ezra and EOL may not be able to continue as a going concern.

Swiber Holdings Ltd. is an EPCI contractor headquartered in Singapore with international operations, but is much smaller than the largest public players in the market. Swiber operates three major segments, including construction, charter hire, and diving services. Pipelay activities are included in the construction segment and in 2016 accounted for about two-thirds of total revenues.

Sapura Energy Berhad is a Malaysian integrated offshore services firm that conducts drilling, EPCI services, fabrication, and explores and produces hydrocarbon resources. They are involved primarily in the Southeast Asian, Indian, and Australian markets, but also have some activities in Latin America. In 2013, SapuraKencana began accepting delivery of a variety of pipelay vessels, and as of 2016 has a fleet of six pipelay vessels and barges, as well as five pipelay support vessels.

Solstad Rederi A.S. was established in 1964 by Captain Solstad and in 1997 was listed on the Oslo Stock Exchange under the name Solstad Offshore ASA. In 2016, the Aker Group entered as majority owner and merged with Rem Offshore ASA. The company's mission is to conduct integrated shipping to petroleum and renewable energy activities using their own or chartered vessels. The vessel fleet in 2016 consisted of 61 wholly or partially owned vessels–26 CSVs, 16 AHT vessels, and 19 PSVs. The vessels operate worldwide, but the North Sea was the company's largest market circa 2017. A merger with Farstad Shipping and Deep Sea Supply is expected to be complete in 2018, and the new group is expected to operate 154 ships–33 CSVs, 55 AHTs, and 66 PSVs. In 2016, the company took delivery of a large construction vessel *Normand Maximus* and commenced on an eight-year charter with Saipem.

DOF ASA is organized into two business segments: subsea projects and vessel chartering. Subsea projects cover operations in the Asia Pacific region, the Atlantic region, Brazil, and North America. Vessel chartering is managed and operated by DOF Management (associated company) and Norskan (sister company). At year-end 2016, DOF operated a fleet of 21 subsea vessels and 65 ROVs. Twenty of the operated vessels were owned by the group and one vessel was chartered from a third-party owner. Four subsea vessels were under construction in 2017 and four ROVs on order, with three of the newbuilds owned by a joint venture with TechnipFMC.

### 8.4.2. Private Firms

Allseas was founded in 1985 by Edward Heerema and is the largest privately held pipeline contractor circa 2017. In 2015, Allseas took delivery of *Pioneering Spirit,* which is one of the most capable pipelay vessels in the world. Allseas operates primarily high specification deepwater pipelay vessels and competes throughout the world.

Bisso is a shallow water GoM specialist that has been in business for many years and offers an array of marine services, including salvage, heavy lift, pipeline installation, and offshore construction, diving services, and tow boat services. In addition to its three pipelay barges, Bisso's 2016 fleet includes five derrick barges, one dive support vessel, and one tug.

Ceona is a privately-held pipelay specialist established in 2012 with Goldman Sachs as its major shareholder. Its first newbuilt vessel, *Ceona Amazon*, was delivered in early 2015, but was later sold to McDermott. Ceona has a small fleet of deepwater vessels purchased on the second hand market and operates in Brazil, the North Sea, and West Africa.

Chet Morrison is a shallow water GoM specialist with pipelay and other shallow water marine operations capability. Chet Morrison operates fabrication services, land construction, marine construction, offshore services, riser services, and well services divisions.

Sea Trucks is primarily a West African offshore contractor and operates six high-spec pipelay vessels, 29 AHT/AHTS vessels, eight crew/utility boats, 13 cargo barges, and three accommodation barges.

Oceanic Marine Contractors operates a single high specification barge that works primarily in the Persian Gulf, Ascot Offshore is a Nigerian firm, Van Oord is a civil engineering construction specialist that entered the offshore pipelay market in 2012 with the delivery of the shallow water pipelay barge *Stingray*, the only pipelay vessel in its fleet.

### 8.4.3. State-Owned Firms

CNOOC is majority owned by the Chinese government and one of its four subsidiaries, CNOOC Offshore Oil Engineering Company, owns a five-vessel pipelay fleet. Shares of the subsidiaries are traded on the Hong Kong Stock Exchange. CNOOC operates its pipelay fleet within Chinese territorial waters and does not currently lease the vessels to outside E&P firms.

### 8.4.4. Recent Departures

Several pipelay market participants that were active as recently as 2009 have left the market. Oceaneering is a US-based offshore engineering services provider that owns a fleet of dive support and IMR vessels but no longer maintains any pipelay installation capability. Boskalis is a marine construction and dredging firm that operates a diverse fleet of vessels and previously owned two pipeline burial vessels. International Marine Contractors is a supply and utility boat operator in the US GoM that has divested its one shallow water pipelay barge.

On March 3, 2015, Cal Dive International, Inc. and five of its subsidiaries that provided diving, pipelay, platform installation and salvage, and light well intervention services filed for relief under Chapter 11 of the US Bankruptcy code. The Houston-based company listed $286 million in secured debt during its Chapter 11 filing and most of its fleet of ships and businesses were sold for $46 million. On February 7, 2017, Cal Dive asked the bankruptcy judge to convert the case to Chapter 7 liquidation because it has no remaining assets and wants to wind down the business.

# Part Three. Pipeline Construction and Decommissioning Costs

# Chapter 9. OCS Pipeline Regulatory Framework

*Government authorities regulate oil and gas pipelines on the Outer Continental Shelf to address economic fair play, pipeline safety, liability, and decommissioning. Economic fair play issues relate to pricing of transport services and open and nondiscriminatory access. Pipeline safety concerns relate to pipeline design, construction, and operation, while liability and decommissioning involves both operational and financial responsibility issues. The pipeline's reach and who it serves are the main factors that determine regulatory authority. If a pipeline serves only a single party and does not put product into interstate commerce, it may avoid extensive federal regulation. On the other hand, if a pipeline serves a larger population and/or engages in interstate commerce, it will likely be subject to significant regulatory oversight. The purpose of this chapter is to provide a quasi-legal introduction to the regulatory jurisdiction over oil and gas pipelines in the Outer Continental Shelf. The chapter concludes with a brief review of tariff rates and examples of cost-of-service calculations.*

## 9.1. Economic Fair Play

Determining regulatory jurisdiction over natural gas pipelines on the OCS frequently turns upon application of the "gathering exception" (Boudreaux 2007). This is the legal test applied to determine whether a natural gas pipeline "transports' gas in the open market or merely "gathers" gas for subsequent transport to the marketplace. As a general rule, natural gas pipelines used for transportation are more highly regulated, while gathering lines escape extensive oversight (Figure I.1). In contrast to natural gas, jurisdiction over oil pipelines on the OCS depends less on a specific legal test and more upon which general category is being regulated. The various laws affecting oil pipelines on the OCS apply differently and depend more upon their statutory mandate rather than any single physical distinction (Poitevent 2003).

### 9.1.1. Natural Gas

The legal distinction between the "gathering" of natural gas, as opposed to its "transportation" is fundamental for the purpose of regulation on the OCS. It is important in determining whether a gas pipeline's operation, rates, or associated facilities will be subject to regulation under the Natural Gas Act of 1938 (NGA), the Natural Gas Policy Act of 1978 (NGPA), the Outer Continental Shelf Lands Act of 1953 (OCSLA), and the Revised Pipeline Safety Act of 1994 (Malet 1983, Grauberger and Downer 2016).

Under the NGA, the Federal Energy Regulatory Commission (FERC) regulates the "transportation" and sale of natural gas in interstate commerce. The "gathering" of natural gas, however, is exempt from federal regulation. Section 1(b) of the NGA states that the NGA does not apply "… to the local distribution of natural gas or the facilities used for such distribution or to the production or gathering of natural gas." Thus, if they are only gathering facilities, these facilities are generally not subject to the NGA. Conversely, if gas pipeline's facilities are deemed to be transportation facilities, virtually every aspect of their operation is subject to regulation by the FERC.

Business entities try to avoid FERC regulation because falling under FERC's jurisdiction imposes additional rules, annual reporting requirements, disclosure of additional information, and the potential imposition of civil penalties. If a company can avoid FERC jurisdiction, this additional scrutiny does not apply, and so companies often litigate to contend FERC jurisdiction.

*Gathering Exception Tests*

The FERC and its predecessor agency the Federal Power Commission (FPC) have traditionally applied three tests to determine whether a pipeline is a non-jurisdictional gathering line or a jurisdictional transportation facility regulated by the NGA. They are: (1) the behind-the-plant test; (2) the central point test; and (3) the primary function test (Boudreaux 2007, Poitevent 2003).

*Behind-the-Plant Test*

The behind-the-plant test is based on the presumption that gathering takes place until the gas is considered to be pipeline quality. This is most often applied to pipeline facilities when gas requires processing before it is placed in the market. In developing the test, the FPC reasoned that "production and gathering of gas do not constitute an end in itself, but a means to an end … [i.e.,] the sale of the gas and of products extractable by processing." Accordingly, facilities located behind a gas processing plant are deemed to be gathering facilities, while those located downstream of the plant are deemed to be transportation facilities. The processing plant itself also has also been traditionally considered a part of non-jurisdictional gathering facilities.

*Central Point Test*

The central point test has generally been applied when a gas processing plant is not included in the facilities configuration. The test focuses on the configuration of pipelines that bring gas to a central point for delivery into a single line. The FPC stated that "in the ordinary concept of the word, 'gathering' as used in the natural gas industry means the collecting of gas from various wells and bringing it by separate and several individual lines to a central point where it is delivered into a single line." Under this test, gathering ends at the central point in the field.

*The Primary Function Test*

The FPC introduced the primary function test in 1963 in determining whether a company's services are jurisdictional pipeline transportation. It stated its intent was that this was to be a factual analysis dependent on "whether a company's primary function consists of the interstate transportation of gas or some other function." With the primary function test, the FPC moved away from the mechanical application of a facilities configuration standard and focused on primary use made by the facilities. If the facilities were used primarily to perform a gathering function, they were gathering facilities. If used primarily for transportation service, they were transportation facilities.

In the primary function test, the FERC included the behind-the-plant and central point tests among several criteria used to determine whether a facility performs primarily a gathering or transportation function. The primary function test criteria include: (1) the diameter and length of the pipeline, (2) the location of compressors and processing plants, (3) the pipeline's extension beyond the central point in the field, (4) the location of wells along all or part of the facility, and (5) the geographical configuration of the system. FERC clarified that a pipeline need not meet all of the criteria, rather that "in any given situation, the criteria can and frequently do overlap."

*The Modified Primary Function Test*

Before 1989, FERC applied the primary function test developed for onshore facilities to its analyses of OCS pipeline facilities. Often FERC found facilities to be non-jurisdictional, even though they did not meet standard gathering criteria (Poitevent 2003). In 1989, in *EP Operating v. FERC*, the 5$^{th}$ Circuit Court of Appeals led FERC to re-examine its approach on the OCS by reversing FERC's determination that a 51 mile long, 16 inch diameter OCS pipeline originating at a production platform 80 miles offshore in 1600 ft water depth was a jurisdictional transportation facility (Grauberger and Downer 2016). In ruling the pipeline to be a jurisdictional transportation facility, FERC had found the pipeline's length, diameter, and operating pressure to be determinative.

The Court found it significant that no jurisdictional pipeline was willing to build a line out to EP's production facility and concluded the pipeline to be a gathering line because it was "simply the most practical way to move the product from the seabed to a point nearer to shore where it can be processed and introduced into a pipeline."

Regarding the EP decision, FERC set upon a review of its OCS gathering exception policy that culminated with its articulation of the "modified primary function test," which consists of applying the standard primary function test with a modification of its application to take into consideration the changing technical and geographic nature of exploration and production facilities. FERC indicated that it would apply a sliding scale to allow the use of gathering pipelines of increasing lengths and diameters in relation to the distance from shore and the water depth of the offshore production area.

In 1996, FERC further clarified the jurisdictional status of offshore facilities by issuing a policy statement with regard to OCS operations (Grauberger and Downer 2016). In its statement FERC established the presumption that facilities designed to collect gas produced in water depth of 200 meters or more are gathering facilities up to their connection with the interstate pipeline grid.

#### 9.1.2. Oil

*Interstate Commerce Act*

Unlike natural gas pipelines, interstate oil pipelines are governed by the Interstate Commerce Act (ICA) and have been the responsibility of FERC since 1977 (Malet 1983). Tariff and rate requirements do not extend to a pipeline that is owned by, and available only to, the owner of the oil being moved. Also, the ICA's terms extend only selectively to oil pipelines operating on the OCS.

*Open Access and the OCSLA*

FERC has no jurisdiction to enforce the rate reasonableness, nondiscrimination, or tariff filling provisions of the ICA with regard to oil pipelines on the OCS, but OCS pipelines must still adhere to policies of nondiscrimination and open access. Section 5(f) of the OCSLA requires all OCS pipelines to "provide open and nondiscriminatory access to both owner and nonowner shippers." As a result, although FERC has limited jurisdiction on the OCS pursuant to the economic regulatory terms of the ICA, it still enforces obligations of open access and nondiscrimination pursuant to the OCSLA where oil pipelines are concerned. OCS oil pipelines that FERC determines to be a common carrier of oil under the ICA are subject to significant regulation with regard to its transportation rates and fees.

Interstate oil pipelines are regulated under the ICA as common carriers. The ICA includes the requirements that "all charges made for any service … shall be just and reasonable," and the corollary prohibition against "unjust and unreasonable change[s]." The act also prohibits special rates and rebates, as well as undue preferences or prejudice. Section 6 of the Act mandates that every common carrier pipeline file rate tariffs with FERC and make available to the public schedules "showing all the rates, fares, and charges for transportation between different points on its own route and between points on the route of any other carrier … when a through route and joint rate have been established."

Oil pipelines are specifically prohibited from providing transportation other than in accordance with the rates published and in effect at the time service is rendered. A failure to comply with the terms of any FERC regulation or order issued under the provision of Section 6 is subject to a monetary penalty and may also entail liability for damages to any injured party.

*Energy Policy Act of 1992*

The Energy Policy Act of 1992 is the other major statue regulating oil pipeline rates and services. It directs FERC to simplify its ratemaking methodology and contains directives to streamline and simplify oil pipeline regulation under the ICA. FERC implemented the Energy Policy Act through three major rulemakings that established three ways by which oil pipeline rates are set: indexing; cost of service; and market-based rates.

Order No. 561 established inflation indexing as the primary method of oil pipeline rulemaking and provided that initial rates could be established either through a cost-of-service filing or through agreement with at least one non-affiliated shipper that intends to use the service. Under this method, pipelines are able to revise rates to account for inflation without having to file a cost-of-service hearing.

Order No. 571 established requirements for pipelines seeking to justify rates on a cost-of-service basis and confirmed that methodology as the primary one for setting rates. Order No. 572 allows pipelines to seek market-based rates on a showing that they lacked significant market power in the affected markets.

Oil pipelines on the OCS determined to be subject to FERC regulation under the ICA are subject to that law's tariff and open access provisions as well as the rate-setting provisions of the EP Act (Mogel 1983). The open access provisions of the OCSLA also apply.

#### 9.1.3. Gathering and Transportation Fees

Transportation and gathering cost depend on the location of the property, volumes and distance transported, pipeline ownership and regulation, product transported, age of the pipeline(s), and capital investment. The reservation rate is paid to reserve the firm capacity regardless of usage. The commodity rate is paid based on volumes committed and shipped. Interruptible service is based on the transportation on an interruptible basis.

Old, partially full pipelines generally require more maintenance than new full lines, and if line volumes are low, tariff rates will often be higher than on packed lines unless the capital costs are fully depreciated. Generally, transportation and gathering costs on the OCS to deliver oil and gas to onshore markets are a small part of overall operating cost (<$1–2/bbl, <$0.50/Mcf) but there are exceptions. Typically, because transportation and gathering costs are volume-based, fees change in proportion to production changes and will usually vary less than other cost categories and in smaller proportion to the total expense.

Gathering and transportation refer to the cost to gather and transport the raw fluids to the processing facility and the cost to transport the processed oil and gas to shore. These costs are usually not broken out and they may or may not be reported separately from direct lease operating expense in public company financial statements. Export fees are frequently reported separately when the export pipeline owner is a third-party. If the export pipeline owner is a subsidiary of the structure owner or an affiliate, exports fees may be included within other lease operating expense or allocated and accounted for differently. Most pipeline tariffs in the GoM are proportional rates and on a per barrel basis are usually no more than 3 to 5% commodity prices at any point in time.

*Example. Energy XXI Pipeline, LLC*

> The cost to transport crude from South Timbalier block 27 to Fourchon terminal, Lafourche Parish, Louisiana is 77.79 cents per barrel and from South Timbalier block 63 to Fourchon terminal is 155.56 cents per barrel, effective July 1, 2016.

## 9.2. Pipeline Safety

#### 9.2.1. Pipeline Design and Construction

Pipeline design, construction and safety on the OCS are issues over which both the Department of Transportation (DOT) and the Department of the Interior (DOI) have been granted jurisdiction.

DOI's responsibility arises from its role as the administrative authority for the OCS as provided by the OCSLA. It exercises its authority via the BSEE and BOEM, and is responsible for the promulgation and enforcement of regulations for the promotion of safe operations, protection of the environment, and conservation of the natural resources of the OCS.

DOT's authority stems from its general responsibility for pipeline safety under the Pipeline Safety Acts (PSA). DOT administers its authority through the Office of Pipeline Safety (OPS) and is responsible for promulgating and enforcing regulations for the safe and environmentally sound transportation of gases and hazardous liquids by pipeline.

Given the jurisdictional overlap, DOI and DOT have had to work closely to avoid administrative redundancies and inefficiencies. Since 1976, DOI and DOT have operated under a Memorandum of Understanding by which they apportion their regulatory responsibilities on the OCS. In 1996, they revised the Memorandum to clarify that the OPS was to establish and enforce design, construction, operation, and maintenance regulations and investigate accidents for all transporter-operated pipelines on the OCS; the MMS (now BSEE) was to do the same for all producer-operated pipelines. BSEE has further clarified the matter by issuing a rule specifying that producer-operated pipelines crossing directly into state waters without connecting to a transporter-operated pipelines remain within its regulatory authority.

### 9.2.2. OCS Regulatory Framework

Any pipelines that are part of an OCS lease development project must be included as part of the lease's Development and Production Plan and receive approval from the BSEE before the development of any lease property. Additionally, an application must be submitted and receive approval from the BSEE Regional Supervisor before the modification or abandonment of any OCS pipeline that is subject to regulation. There is a similar requirement for any right-of-way across which a pipeline will transport product outside the boundaries of the lease parcel. If the right-of-way is to be jointly owned, all potential owners must execute the right-of-way application and the application must specify the percentage of ownership of each applicant.

### 9.2.3. Bond Requirements

Before the construction of a pipeline on the OCS, and before BSEE will approve operations or the assignment of right-of-way, the pipeline right-of-way applicant must provide a general bond in the sum of $300,000 to guarantee compliance with all terms and conditions of the right-of-way permit. BSEE requires that all right-of-way be covered by this general bond, regardless of the applicant's financial strength or the supplemental bond waiver status of the applicant or any leases.

### 9.2.4. Additional OCS Design and Construction Regulatory Authority

In addition to DOT and DOI regulation, the US Coast Guard and the Army Corps of Engineers also have regulatory roles with regard to the design, construction, and safety of pipelines on the OCS (Poitevent 2003). Under Section 10 of the Rivers and Harbors Act of 1899, the Army Corps of Engineers administers a permit insurance program authorizing structures or works in or affecting navigable waters of the United States and a permit is required for the construction of artificial islands and fixed structures on the OCS. The OCSLA also creates a role for the US Coast Guard, giving it certain responsibilities for matters relating to the safety of life and property on onshore artificial islands and structures.

Finally, if it is determined, pursuant to the primary function test, that FERC has regulatory authority over a proposed natural gas pipeline, Section 7(c) of the NGA may require FERC to issue a certificate of public convenience and necessity before the acquisition or construction of any such pipeline. With regard to oil pipelines, should FERC be deemed to have regulatory authority, the ICA includes no analog to the NGA's Section 7 certificate requirement.

In addition to the general Right-of-Way Grant Bond, BSEE may require the posting of additional security in the form of a supplemented bond, especially with regard to facility abandonment and site clearance. At BSEE's discretion, BSEE may waive the supplemental bond requirement for a specific right-of-way if at least one record title lessee can demonstrate sufficient financial strength, based on its hydrocarbon production level, its net worth relative to any potential end-of-lease liability, or its general financial wherewithal to meet present and future financial obligations.

The holder of a pipeline right-of-way must pay an annual rental for the right-of-way's use, payable in advance. Failure to construct an approved pipeline within five years from the date of the grant will cause the grant to expire.

## 9.3. Pipeline Abandonment

### 9.3.1. FERC Authority

Abandonment of pipeline service is an issue that receives significant regulatory attention, both from an economic as well as a safety and liability standpoint. There are significant differences between oil and natural gas pipelines and FERC's regulatory framework.

*Oil*

Oil pipelines are regulated under the ICA; gas pipelines are regulated under the NGA. FERC has no authority under the ICA with respect to the abandonment of pipeline service. There is no counterpart in the ICA as it applies to oil pipelines to the NGA's Section 7(b), which requires advance FERC approval of the abandonment of regulated pipeline facilities or services using those facilities (Mogel 1983).

*Natural Gas*

With regard to natural gas, FERC authority over the abandonment of service by jurisdictional pipelines is described in Section 7(b) of the NGA. Companies operating on the OCS whose gas pipelines are subject to FERC jurisdiction may not discontinue jurisdictional services or facilities without first obtaining FERC approval. Before approving any application for abandonment, the FERC must find that the available gas supply is sufficiently depleted such that continuing service is unwarranted or that the public convenience or necessity requires it.

Generally, abandonment consists of either the removal of jurisdictional facilities or the termination of service via those facilities. A substantial reduction of the volume of gas delivered may also constitute abandonment, unless an approved contract contemplates such reductions. The cessation of the purchase and transportation of gas from a particular certified gas supply source, even where the jurisdictional transport facilities continue to be used in some fashion, can be considered an abandonment of service. The sale, lease, or transfer of pipeline facilities also constitutes an abandonment, even if the sale is to a subsidiary that proposes to continue service.

*Public Convenience and Necessity*

Public Convenience and Necessity describes the applicant's position on the long-term needs of the existing and future customers and the service obligations through the facilities. To be granted FERC approval for abandonment, the pipeline company has to demonstrate no adverse impact on services or customers. The services to be abandoned usually results from the cessation of production in the region, no firm transportation over an extended period of time, and no shipper interest for receipt or delivery.

Operators may invoke one or more of the following conditions in their applications:

- The segment has not been used for an extended period of time (e.g., more than 6–9 months) and producers indicate there are no plans to drill or otherwise stimulate the wells attached to the platform pipeline.
- There is no expectation that the segment will be used in the future as a primary receipt or delivery point because there are no transportation agreements in place or the transportation agreements are interruptible.
- If production in the area is ongoing, producers have alternative routes for transportation, do not object to the abandonment, or there are commercial options for construction.
- No adverse impacts to any services that the operator provides to remaining customers will be incurred.

- Abandonment will reduce operations and maintenance expense and eliminate future capital expenditures for repair and replacement.
- If there is production on the line, the operator must show that the line operation is costly or they are unable to maintain safety.
- If lines are damaged or have low flow rates, the pipeline operator may request a rate increase or agree not to increase rates until shippers build a new line, and producers subsequently agree not to oppose abandonment when the operator files with FERC.
- If the producer of the platform in which a pipeline is connected is planned to be abandoned, the pipeline operator needs to seek authorization for abandonment because once a riser is disconnected from an offshore pipeline, the pipe must be disconnected from its source and flanged or bolted as per DOT disconnection provisions (49 CFR 192.727).

### 9.3.2. BSEE Authority

Unlike the FERC regulation of pipeline abandonment, BSEE draws no distinction between oil or natural gas pipelines. Under OCSLA regulations, an OCS pipeline operator must file a request for abandonment with the BSEE Regional Supervisor before abandonment of a pipeline or relinquishment of a right-of-way. Before approval of any abandonment request, a right-of-way holder must agree to: (1) remove along the right-of-way all hazards to navigation or fishing, or demonstrate that any abandonment in place does not constitute an unreasonable hazard; (2) demonstrate that the pipeline is appropriately plugged and buried; (3) remove within one year any improvement required to be moved; (4) submit a map where appropriate; and (5) agree that any improvements or structures not removed within one year will become property of the United States.

*OCS Decommissioning Regulations*

Pipeline decommissioning and removal procedures required by BSEE are detailed in 30 CFR 250.1750 through 250.1754. The type and scope of decommissioning work performed depends on the time the pipeline is scheduled to be out of service (Table I.1).

If a pipeline is to be out of service for one year or less, the pipeline is isolated with a blind flange or a close block valve at each end of the pipeline. For pipelines out of service for more than one year but fewer than five years, the pipeline is flushed and filled with inhibited seawater. For a pipeline out of service for more than five years, the pipeline is decommissioned according to requirements found in 30 CFR 250.1750-250.1754.

As described in 30 CFR 250.1754, a pipeline is required to be removed rather than abandoned-in-place when the Regional Supervisor of the BSEE determines that the pipeline is an obstruction. If it is determined that a decommissioned pipeline must be removed, the requirements of 30 CFR 250.1752 must be met; these state, in part, that:

"Before removing a pipeline, you (the operator) must:

A. Submit a pipeline removal application in triplicate to the Regional Supervisor for approval that includes the following information:
    1. Proposed removal procedures
    2. If the Regional Supervisor requires it, provide a description, including anchor pattern(s), of the vessel(s) you will use to remove the pipeline
    3. Length (feet) to be removed
    4. Length (feet) of the segment that will remain in place

5. Plans for transportation of the removed pipe for disposal or salvage
6. Plans to protect archaeological and sensitive biological features during removal operations, including a brief assessment of the environmental impacts of the removal operations and procedures and mitigation measures that you will take to minimize such impacts
7. Projected removal schedule and duration

B. Pig the pipeline, unless the Regional Supervisor determines that pigging is not practical

C. Flush the pipeline."

## 9.4. Transportation and Gathering

### 9.4.1. Tariff Rates

Transportation and gathering fees are volume-based and are owner, location, and age dependent, but generally do not depend on oil and gas prices. Age-related factors can act in favor of or against the operator. For example, after the pipeline is fully depreciated, and if the pipeline is well maintained and has adequate flow, tariffs may decline after the investment cost are fully depreciated. On the other hand, when volumes in the line decline, corrosion usually increases and maintenance becomes more difficult, and the pipeline owner may raise rates on transporters to recover their cost of service.

Historically, ownership of export pipelines in the GoM, especially gas trunklines, has seen significant activity from gas transmission companies. Producers contract for export services for oil and gas with an affiliated company or third-party. The transportation agreements set forth the terms and schedules. If pipelines are regulated by FERC, the agreements are in the public domain, otherwise, the agreements are generally confidential.

The monthly bill for deliveries usually includes a reservation and commodity charge, and other charges as applicable:

- Reservation charge: Equal to the product of the reservation rate multiplied by the Maximum Daily Quantity (MDQ) specified in the service agreement, multiplied by the shipper specific heating value and the number of days in the month.
- Commodity charge: Equal to the commodity rate multiplied by the quantity of gas allocated to the delivery point in the month.
- Other charges: Any applicable surcharges, new facilities charges, repair charges, and any incidental expenses.

The sum of the charges is equal to the transportation fee for a particular segment of line. If product is delivered using two or more segments, a separate tariff will apply to each segment.

*Example. Destin Pipeline firm transportation rate FT-1*

A traditional firm service with fixed maximum daily quantity and reservation charge (FT-1 service) is depicted in Table I.2 for the Destin Pipeline (Figure I.2). For a shipper reserving 50 MMcf/d capacity with a heat content of 1000 Btu/cf, the monthly reservation rate is computed as:

$$\frac{\$7.19}{\text{Dth/mo}} \cdot \frac{50\ \text{MMcf}}{\text{d}} \cdot \frac{1000\ \text{Btu}}{\text{cf}} \cdot 30\ \text{d/mo} = \$10.785\ \text{million}.$$

If the actual average amount of gas delivered to the pipeline was 48 MMcf/d for the month, the commodity rate is computed as:

$$\frac{\$0.237}{\text{Dth}} \cdot \frac{48\ \text{MMcf}}{\text{d}} \cdot \frac{1000\ \text{Btu}}{\text{cf}} \cdot 30\ \text{d} = \$341{,}280.$$

The transportation rate 0.3¢/Dth = $0.03/Dth is computed based on volumes delivered and being more than an order-of-magnitude smaller than the commodity rate is negligible in this case. The fuel retention percentage 0.3% represents a percentage of the quantity of gas delivered for transportation and used by the pipeline company for compressor fuel and gas otherwise used, lost, or unaccounted for and is also negligible in this example. The total cost for service for the month is $11.126 million, 3% of which is due to the variable cost and 97% for the reservation rate.

*Example. Mars pipeline tariffs*

The Mars platform (Figure I.3) in Mississippi Canyon block 801 was one of the first regional hubs in the GoM and currently serves as a central processing facility for several fields. The Mars pipeline is a 163-mi line originating approximately 130 miles offshore and delivers crude to salt dome caverns in Clovelly, Louisiana. Crude production from Mars A is transported to West Delta 143 at the rate of $2.61/bbl and then onward to Bay Marchand block 4 at $1.16/bbl if <30,000 bbl/mo was delivered and $0.7/bbl if >30,000 bbl/mo was transported (Table I.3). A discounted rate applies because greater volumes for the pipeline means greater revenue for the transporter to cover fixed cost. From Bay Marchard product is delivered to Fourchon and into storage at Clovelly/Caverns. Crude production from Mars B (Olympus) to WD 143 is delivered in a newly constructed pipeline and because it is newer and its capital cost of construction greater than the adjacent Mars A pipeline, its tariff rate for the first pipeline segment will be higher.

### 9.4.2 Costs of Service

When a pipeline is installed, the tariff is used to recover the investment, operating, and maintenance expense and various other secondary costs. The investment and owner of the line and the manner in which it is regulated are the most important factors that determine tariffs, but the age of the line, number of customers, volume throughput, and special circumstances (e.g., hurricane damage) are also important in determining rates at different times in the lifecycle of the pipeline. The underlying principal of cost recovery is the universal theme in ratemaking.

Producer and producer affiliate owners will charge different rates than third-party owners and, if the line is FERC-regulated, the process is open to public review. If the pipeline is old and the capital investment is mostly recovered (i.e., pipeline construction cost is fully depreciated), fees will need to cover only operating and maintenance cost. If the number of customers and amount of product transported through the pipeline at this time is low, however, then the operator may have to increase rates on remaining subscribers to generate adequate revenue to cover operations and maintenance. The conditions governing each system are unique and therefore many factors potentially impact tariffs.

The cost-of-service formula is the most common ratemaking basis and is the easiest to understand. Cost-of-service (COS) is defined as the amount of revenue a regulated gas pipeline company must collect from rates charged consumers to recover the cost of doing business. These costs include operating and maintenance expenses, depreciation expense, taxes, and a reasonable return on the pipeline's investment.

The total COS includes the product of the pipeline's Rate Base (investment, or capital expenditures) and the Overall Rate of Return (ROR), which is negotiated with FERC, plus its Operation and Maintenance Expenses (O&M), General and Administrative Expenses (G&A), Depreciation Expenses (DEP), Non-Income Taxes (NTAX) and Income Taxes (TAX), less Revenue Credit (RCD). The COS formula collects all of these terms:

COS = Rate Base × Overall ROR + OPEX + G&A + DEP + NTAX + TAX – RCD.

The Rate Base represents the total investment of the pipeline and is used to compute certain components of the COS, including the return on its investment, and the depreciation expense that permits the pipeline to recover its investment.

Rate Base = Gross Plant – Accumulated Depreciation – Accumulated Deferred Income Taxes + Working Capital.

Gross plant is the original cost of the plant or facilities owned by the pipeline and includes the cost of land and land rights, right of way, surveys, line pack, construction costs, overheads, and accumulated funds used during construction (AFUDC). The cost of the investment in gross plant is recovered through the cost of service as depreciation expense. For a detailed treatment of FERC cost of service methodology, see (FERC 1999). The procedures are well known and relatively easy-to-follow, but in many cases calculations become tedious because of special situations. An example illustrates the basic steps.

*Example. Garden Banks Gathering System reservation rate*

The Garden Banks Gathering System (GBGS) was constructed in the mid-1990s to serve deepwater and shelf natural gas production developed in the Garden Banks area offshore Louisiana, including the Auger, Baldpate and Enchilada projects (Figure I.4). GBGS is a 30-inch diameter, 50-mile natural gas pipeline extending from the Garden Banks 128 A platform to the P platform in South Marsh Island 76. The line was determined to be a FERC jurisdictional facility, and, under protest, the pipeline owner Garden Banks Gas Pipeline LLC (GBGP)–a limited liability company made up of Shell Enchilada Gas Pipeline Company (SEGP) and Hess Garden Banks Gas Gathering, Inc. (HGB)–filed an application to section 7(c) of NGA requesting authorization to construct the 30-inch line and appurtenant facilities.

GBGP proposed a maximum reservation rate under two firm transportation services FT-1 and FT-2 and a maximum interruptible service IT-1 commodity rate of $0.1214 per MMBtu. The proposed initial rates were based on:

- Estimated facility cost of $108 million, which include AFUDC.
- Straight fixed variable cost classification.
- A proposed return on equity of 13.75%.
- Btu factor[6] of 1100 Btu/cf based on expected average Btu content of Auger, Baldpate, and Enchilada production.

6 A thermie (th) is a metric unit of heat energy, and is equivalent to the amount of energy required to raise the temperature of one ton (or 1000 kilograms) of water by one degree Celsius. A Btu (British thermal unit) is the amount of energy needed to heat or cool one pound of water by one degree Fahrenheit. In North America, the heat value or energy content of a fuel is often expressed in Btus. When dealing with larger quantities of energy, larger

- Initial billing determinant of 241 MMBtu based on a 60% average annual load factor for the 1000 MMcf/d capacity of the 30-inch line.
- Debt/equity structure of 21.5/78.5 percent, which is the weighted debt/equity structure of Shell Oil Company and Amerada Hess Corporation at the time of application.

  Though the volume of gas must be calculated at a standard temperature and pressure so that the measurements are consistent, the heat or energy content of natural gas is dependent on the composition of the gas, which is independent of the temperature and pressure.

  The cost of service is calculated using GBGP’s estimated cost of facilities ($108 million), engineering estimates for operation and maintenance expenses, a pre-tax return of 13.75%, and a depreciation rate of 6.67% based on a 15-year depreciation rate. The pre-tax return is negotiated with FERC and based on approved settlement rates and the final cost is based on the actual cost of construction. For calculation purposes, we assume no reserve for depreciation, $1 million working capital, operation and maintenance expense of $3 million per year, and taxes other than income tax at $2 million.

  Based on the contract quantity of 600 MMcf/d, the annual heat content delivered is computed as:

$$\frac{600\text{ MMcf}}{\text{d}} \cdot \frac{1100\text{ Btu}}{\text{cf}} \cdot \frac{\text{Dth}}{\text{MMBtu}} \cdot \frac{365\text{d}}{\text{y}} = 241\text{ MMDth.}$$

  The daily reservation rate calculation steps are shown in Table I.4. and yield $0.112/Dth (= $26.912 million/241 MMDth).

### 9.4.3 Rate Schedules

Pipelines are built in segments. Each segment has a different cost associated with construction, operation, and maintenance, and different rates apply to transport fluid from one area to another depending on the segment of pipeline where the fluid is injected. The tariff transmission rate schedule indicates where product is received from and where it will be delivered to. Statement of Rates varies based on business practices and the drafter of the instrument. Despite the wording used, all costs usually indicate the maximum rate unless specifically designated as minimum rates. In addition, certain additional charges or surcharges may be negotiated for and will be indicated in the rate schedule.

Interruptible transportation service and firm transportation services are usually available and the terms will vary depending on the type of service provided.

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standards of measure are often used. In many natural gas pipelines energy content is measured in decatherms (Dth). A decatherm equals ten therms, or 1,000,000 Btu (1 MMBtu).

*Example. Garden Banks Gas Pipeline rate schedules*

IT-1 Service

Interruptible transportation service for GBGS is available under Rate Schedule IT-1 to anyone who requests transportation of natural gas on an interruptible basis through the 30-inch line and who has executed an IT-1 agreement with GBGP. The rate schedule applies to the Maximum Daily Quantity (MDQ) and offered at the maximum commodity rate of $0.1168 per MMBtu.

Firm Transportation

FT-1 service describes a traditional firm service with fixed MDQ and reservation charge while FT-2 service describes flexible firm service with variable MDQ and rates determined, in part, on the basis of volumes committed and shipped.

FT-1 service uses a fixed MDQ and a reservation charge regardless of actual throughput, and is offered at the maximum reservation rate of $0.1168 per MMBtu of demand. There is no commodity rate.

FT-2 service provides flexible firm service with variable MDQs and rates determined on the basis of volumes committed and shipped. To be eligible for FT-2 service, a shipper must execute a Reserve Commitment Agreement making a life of reserves commitment of its share of production from specified OCS blocks. The shipper is not required to warrant or guarantee that any particular quantity of gas will be produced.

*Example. Sea Robin Pipeline tariffs*

Sea Robin Pipeline operates two major transmission pipelines in the shallow water GoM labeled the East Area and the West Area (Figure I.5). A detailed map of the points of receipt/delivery for the West Area is shown in Figure I.6 and the firm and interruptible rate schedules are summarized in Table I.5.

# Chapter 10. Offshore Pipeline Construction Cost Estimation

*Offshore pipeline construction costs are commonly categorized according to material, services, engineering, and inspection. Work decomposition represents standard techniques used in offshore construction cost estimation and requires engineering knowledge of the work processes and duration and market knowledge of vessel capability and dayrates. Material and construction services contribute the vast majority of project cost, but the nature of the job and work requirements determine the relative contribution of each cost category. In this chapter, the elements that comprise each cost category are described and two examples illustrate cost estimation procedures.*

## 10.1. Construction Stages

Offshore pipeline projects consist of the following operations:

1. Gather and analyze data to select flowline route;
2. Design, engineer, and procure pipelines;
3. Mobilize the pipelay vessel and auxiliary equipment to the job site;
4. Lay pipe between subsea well(s) and platform, and between platform or pipeline endpoint(s);
5. Install risers on platforms or subsea assembly tie-ins to pipelines;
6. Install all umbilicals, jumpers, flying leads, and other subsea equipment, as required;
7. Inspect, test, and commission.

A survey of the proposed route and contingency routes are performed collecting bathymetry data and core samples to determine soil characteristics (Tootill et al. 2004; Haneberg et al 2013). The soil information is used to predict potential span and perform stability checks. Oil and gas companies typically perform or oversee the route selection process and are involved to varying extents with the engineering, procurement, and construction processes. Pipeline routes are selected to avoid archaeological sites or biological resources, and areas of possible landsliding and faulting, mud seeps, undulations, and rocky outcrops. Routes may be selected to avoid difficult terrain, but the added length needs to be compared with the cost to rectify the spans (Wincheski et al. 2002), and in many cases avoidance is not practical or cost effective.

## 10.2. Cost Categories

Pipeline costs are typically categorized according to material, construction services, engineering, and inspection (Figure J.1). Material and construction services contribute the vast majority of total project cost, but the relative contributions vary with each project. For example, short pipeline installations may incur more than half of their construction cost for mobilization/demobilization (mob/demob), but for longer, more complex installations, mob/demob cost may be less than 5% of total construction costs.

### 10.2.1. Material

Material costs include all the facilities and equipment to construct the pipeline and ancillaries, and include the pipeline, pipeline coatings (e.g. thin-film epoxy, concrete, internal epoxy), anodes, subsea valve assemblies, buckle arrestors, pipeline end manifolds (PLEMs), pipeline end terminations (PLETs), pig launchers, platform piping, meters, and risers. Inspection of the material, transportation cost, and related miscellaneous cost may also be included in the material cost category.

Material costs are typically estimated on a per foot or unit basis. The number of feet of pipe of each wall thickness is specified and multiplied by an estimated cost per foot based on historical data or industry quotes. The costs of epoxy coating and concrete weight coatings are similarly estimated. The spacing of anodes is estimated based on the environmental conditions and service life of the pipeline. Anodes, buckle arrestors, PLEMs, PLETs, pig launchers, fittings, tees, risers, assemblies, and subsea valves are estimated on a unit basis using historic costs or industry quotes.

### 10.2.2. Construction

Construction costs include all the vessels, equipment, and labor to perform the installation, including mob/demob cost of the lay vessel and spread, field joint coating, riser work, subsea crossings, hazards survey, hydrotesting and dewatering, installing subsea assemblies, tie-in work, and commissioning. Engineering and construction may be broken out separately or portions may be included within the construction category.

Construction costs are estimated on a footage, time, or job basis. The costs to mobilize and demobilize the vessel spread are estimated as one-time costs unless the work is expected to be performed over multiple work campaigns. The costs to lay and bury the pipe are typically estimated on a per foot basis. The number of pipeline crossings are estimated and costs are specified per pipeline crossing. Historic or current dayrates for pipelay and bury, dive boats, utility boats and other vessel spreads are estimated along with the expected duration of operation. Hazards survey and permitting and inspection may be estimated per job or by foot.

Cost estimates are performed by multiplying the estimated production rate by the estimated dayrates. Production rate is determined by historic data or is empirically determined using seasonal curves based on a theoretical rate, weather efficiency, and crew efficiency. In general, small conventional barges have the lowest dayrates and the slowest production rate. They are more limited in their capability compared to high-specification vessels which have the most flexibility in operations and the fastest installation rates but at the highest dayrates. Production rates are uncertain and at the time of the evaluation dayrates also need to be estimated; the accuracy of cost estimation will depend on the experience of the estimator and their knowledge of the job requirements and market conditions.

### 10.2.3. Engineering and Inspection

Engineering and inspection includes the portion of the pay and expenses of engineers, surveyors, draftsmen, inspectors, superintendents and their assistants applicable to construction work. Engineering and project management costs are estimated on an hourly or monthly basis. The time required for engineering and management tasks is estimated and multiplied by the hourly or monthly wage of engineers and managers.

## 10.3. Cost Components

### 10.3.1. Material

*Pipeline*

Offshore pipelines are purchased on terms that vary with the grade, specifications, lot size, delivery, location, and various other factors. High-strength steel costs more than low grade steel, but allows smaller wall thickness to be used in design, thus reducing total tonnage. Steel prices are frequently reported on a per ton basis, but pipeline prices are typically specified using footage, which is not an especially convenient measure because tonnage varies with pipe diameter and wall thickness.

Oil and gas industry pipe is made using seamless manufacturing methods, electrical resistance welding (ERW), helical or spiral welding, and double submerged arc welding (DSAW). ERW and DSAW apply longitudinal welds. The manufacturing process has a direct impact on costs, with seamless pipe typically being the most expensive and helically welded pipe being the cheapest. ERW pipe is more expensive than hot rolled coiled pipe and depends on supply and demand conditions.

The price history of ERW and hot rolled coiled steel provides an indication of relative values and trends (Figure J.2). From 2007–2015, steel prices ranged from about \$600 to \$2800 per ton (\$661 to \$3086 per mt), and pipeline prices generally scale with these values. DSAW pipe is common for large diameter lines and X-60 and X-65 are typical grades[7]. Prices for flexible pipes and pipe-in-pipe are significantly greater than prices for conventional pipes. Conventional pipe prices vary with composition, mechanical or plastic lining, and alloy content.

*Weight Coating*

Concrete weight coating is frequently used to add weight to the pipeline to ensure stability on the seabed. The cost of concrete weight coating may add between 15–20% to the pipeline cost (e.g. $18/ft for a $60/ft steel pipeline). Weight coatings in the GoM have historically ranged from $15 to $25/ft ($49 to $82/m) and do not vary significantly because of the price stability of concrete. Weight coatings are not required on thick-walled or small diameter pipes because these pipes are heavy enough to remain stable on the bottom without additional weight. For thin walled and large diameter pipes, concrete weight coatings are used because they are less expensive than adding wall thickness to the pipe. In deepwater, heavier wall pipe is commonly used in lieu of concrete coating so that tie-ins or repairs not accessible by divers do not have to contend with concrete removal. Burial reduces the hydrodynamic forces acting on the pipelines and reduces concrete coating required for stability, but the tradeoff is the added cost of trenching.

*Corrosion Coating*

The purpose of coating a pipeline is to isolate the pipeline steel from the soil and seawater and to present a high resistance path between anodic and cathodic areas. The principal coatings in approximate order of cost are asphalt, coal tar enamel, fusion bonded epoxy (FBE), cigarette wrap polyethylene (PE), extruded thermoplastic PE and polypropylene (PP), and elastomeric coatings (EPDM). FBE is the most commonly used coating for reeled pipelines and for bundled pipes, and EPDM coatings are used for high temperature pipelines and risers. The cost ratio among coal tar, FBE, PE/PP, and EPDM has been reported as 1:1.5:2:4 by Palmer and King (2008). EPDM requires autoclaving to vulcanize the elastomeric coatings and accounts for its high cost. The cost of the coating includes the material cost and the application cost at a shore-based facility. Epoxy coating costs in the GoM historically have ranged from $4 to $12/ft ($13 to $39/m).

*Cathodic Protection*

Coatings are the primary barrier to corrosion and cathodic protection (CP) prevents corrosion in areas of permeable, missing, or damaged coating. Seawater is very corrosive and highly conductive and sulfate–reducing bacteria may exist in seabed sediments, which can receive electrons. The purpose of CP is to transfer electrons into the pipe by draining an electric current from it using impressed current or sacrificial anodes.

Offshore pipelines are almost always protected by sacrificial anodes attached to the pipe at regular spacing and electrically connected with welded or brazed cables (NACE International 2007). As the anode corrodes, it provides its electrons to the pipe. Water temperature is generally the most important factor because it is correlated to the concentration of dissolved oxygen. Other factors used in the design of CP systems include the seabed current, fluid temperature, coatings, and design standards. Anodes are typically zinc and manganese component attachments and depend mostly on the market (ingot) price of the metal. Historically, prices have ranged from $100 to $500 per anode. Cathodic protection costs depend on the pipeline diameter and water depth; smaller diameter pipelines in shallow water require smaller anode attachments.

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7 The two-digit number following the “X” indicates the Minimum Yield Strength (in 1000's psi) of pipe produced to this grade.

*Other Equipment*

PLETs and PLEMs, risers, hot tap assemblies, buckle arrestors, swivels, balls, valves, pig launchers, fittings, anodes, and meters are minor contributors to cost and collectively do not usually account for more than 10% of material costs. Buckle arrestors, for example, typically cost between $1000 and $3000 apiece. Each piece of equipment costs at least as much as steel weight plus the cost to manufacture and deliver to an onshore base.

### 10.3.2. Construction

The costs to lay offshore pipeline are approximately proportional to the total time on the job, including the time required for mobilization, installation of risers and subsea assemblies, and the time required for laying pipe. The time required for these operations depends on the overall complexity of the project, weather conditions, and the success of the operations (McCarron 1968). The contractor estimates these times with a contingency and allowance and prepares a lump-sum bid to win the work. An allowance is a cost for a requirement known to exist but with little scope definition. Most offshore contracts are let on a turnkey basis with weather risk assumed by the contractor. Hence, the contractor will add to their bid an allowance for bad weather. The risk and/or reward contract structure and the degree of competition in the market will impact how the contractor bids.

*Vessel Dayrates*

Pipeline projects are typically contracted on a lump-sum basis to the low cost bidder, and because cost estimates are prepared using estimated duration and dayrates, mismatches between the estimates and actual job requirements are often responsible for differences between estimated and actual cost.

Dayrates vary depending on market conditions and vessel specifications, and, because there is not a transparent spot market for pipelay vessels in the GoM (or worldwide for that matter), it is necessary for the engineer performing the estimate to infer approximate values based on previous experience and knowledge of market conditions. Additional vessels required for pipelay operations include dive support vessels, ROVs, supply barges, utility vessels, and tugboats. The costs for these services are considerably less than for the pipelay vessel and are often provided by the contractor or subcontracted out depending on the contractor’s vessel fleet and the preferences of the operator.

Factors that impact vessel dayrates have a significant impact on costs because construction services are usually the dominant cost component. Dayrates are expected to be higher in periods of high demand and in regions with low levels of competition, and dayrates for high specification vessels are greater than dayrates for lower specification vessels. High specification vessels are required for deeper water or large diameter or particularly heavy pipes.

Derrick barge dayrates in the GoM serve as a proxy for pipelay vessels in the region but the correspondence is only approximate (Figure J.3). Pipelay barges have enhanced functionality over derrick barges and higher operating cost due to the need for larger crews and higher investment cost. Derrick barges and pipelay barges are also used for general construction activities, and the supply and demand factors in these markets will impact prices.

*Mobilization and Demobilization*

Mobilization costs for the pipelay vessel is a function of the distance the vessel has to travel to reach the worksite and drop anchor, the speed of the transport system, and transit dayrate, all of which are unknown at the time of the estimate. It is common practice in the GoM to assume one day to mobilize and one day to demobilize to site for vessels located within the region. Low spec barges do not typically leave the GoM and most work sites in the region can be reached within one day. High specification vessels for deepwater projects may need to be moved into the GoM from outside the region; this can add significantly to the cost of mobilization but in some cases these costs may be shared with the contractor.

For deepwater projects, mob/demob costs may be a significant portion of the construction costs, but on other jobs if the vessel is available between jobs elsewhere the costs may be negligible. In all cases, mob/demob estimates are rough guidelines but a known component of activity cost. In some cases, one or more pipelay vessels may need to be mobilized multiple times to complete operations.

Pipelines that transition from deepwater to shallow water or continue to shore may require two or more installation vessels, which will increase costs due to the extra mobilization and demobilization, interface management, and increased operational complexity. Landfalls increase the complexity of a project due to different environmental impacts and regulations and the use of different installation methods (Howitt et al. 2012).

*Lay Method and Rate*

Factors that impact the rate of lay and burial include the type and size of the pipeline, water depth, and the method of installation. Reeled pipes can be laid faster than welded line, and small diameter pipe can be welded faster than larger diameter pipe, leading to lower costs for all other things equal. The most common method in shallow water is the S-lay method, an assembly line process of feeding, welding, coating, and laying pipe with pipe arriving on transport barges as work progresses. The capacity of the barge determines the inventory of pipe that can be held and re-stocking frequency. Lay rates are determined in part by the number of welding stations. (See Chapter 5, above)

*Burial*

Pipelines greater than 8 and 5/8 inches (22 cm) and installed in water depths less than 200 feet (61 m) in the US OCS are required to be buried at least three feet below the mudline (CFR 2015). Pipeline burial adds cost to the installation process because of the need for route selection and extra equipment to perform burial operations. In deepwater, operators may bury pipe to increase heat retention for flow assurance, but very few deepwater pipelines in the GoM are buried.

Burial costs may account for a significant portion of the total installation cost.  For example, in the Mars export line, burial costs were estimated to be $16/ft ($52/m) relative to a lay cost of $56/ft ($184/m). In the case of the Garden Banks line, burial costs were estimated to be about half of the lay cost, and in the Nautilus pipeline, burial costs were $10/ft ($33/m) relative to lay costs of $35/ft ($115/m).

*Pipeline Crossings*

In developed basins, it is often not possible to design a route that avoids all existing pipelines.  Installing a new pipeline over an existing pipeline adds costs because the two lines must not touch and lay rates are impacted. Typically, a mat or bridge-like structure is constructed over the existing line, but, in some cases, the existing pipeline may be lowered into the seabed. In the GoM, federal regulations require an 18-inch (46 cm) separation between crossing pipelines, and in water depths less than 500 ft (152 m) the crossed pipelines must be covered by mats from touchdown to touchdown. Typically, two 9-inch (23 cm) thick articulated concrete mats are used for protecting crossed pipeline. Pipeline crossings may add an additional $100,000 to $200,000 per crossing.

*Field Joint Coating*

Field joint coating refers to the coating placed on the joints formed offshore when two sections of pipe are welded together. Typically, the weld area is wrapped with a corrosion-resistant polymer sleeve and a mold is placed over the weld area. The mold is then filled with a polyurethane and allowed to set. Field joint coating costs are often categorized as labor costs but if the materials are procured separately they may be individually defined. Field joint coating is frequently the rate limiting step in the construction sequence and costs are determined by the type of anti-corrosion coating employed and pipe diameter.

*Riser and Tie-in Work*

Risers add expense to projects, especially in deepwater where they can be technically complex. The type of riser and its associated installation technique are the primary factors influencing costs. Tie-in work is also technically demanding and expensive because it involves the use of divers and/or ROVs. A variety of pipeline tie-in structures is used in construction including PLETs, PLEMs, and inline tees, and the offshore work and cost depends on the system architecture.

*Survey*

Survey costs include both pre-installation surveys and post installation surveys. Survey costs may be specified on a footage or lump-sum basis and are performed by utility or specialized vessels at dayrates considerably cheaper than pipelay vessels.

*Commissioning and Hydrotesting*

In shallow water pipeline designs, parameters, such as product gradient, water depth, hydrostatic pressure, and hydrotest location, are well understood and R 250.1003 and require testing with water at a stabilized pressure of at least 1.25 times the MAOP (minimum acceptable operating pressure) for at least 8 hours when installed, relocated, accepted (Mappus and Torstrick 2007). BSEE design and hydrotest requirements are specified in 30 CF uprated, or reactivated after being out-of-service for more than one year. A utility boat and dive boat spread may be required to perform the operations, or pump equipment may be located on a platform.

### 10.3.3. Engineering & Inspection

*Project Management and Engineering*

Project management and engineering costs scale with the size and complexity of the project. Factors that add to the complexity and engineering work of a project are a large number of subsea pipeline crossings, the installation of multiple PLETs or PLEMs, tie-ins to existing infrastructure, deepwater, and difficult terrain.

*Inspection*

Final inspections are performed to confirm that operator construction standards and specifications according to the contract were followed. ROV video inspection is often performed simultaneously with the pipelay operation and may be specified in the contract (Winters and Holk 1997). In areas of rough seafloor terrain, ROVs are used to determine if there are unsupported pipeline spans, and, if there are, to rectify them. If the contractor performs the final inspection after the entire line is on the seafloor and problems are found, costs will be greater than if problems are resolved during operations.

*Repair*

Diving and ROV services are usually required to repair damage and the time and costs may be significant. The current state of remote intervention based pipeline repair technology is still in its infancy but continues to increase beyond diving limits (Brown et al. 2014).

## 10.4. Cost Estimation Examples

The data for the Nautilus pipeline example is from FERC Docket CP96-790 and the data for the Discovery pipeline example is from FERC Docket CP96-712.

### 10.4.1. Nautilus

The Nautilus pipeline system is a 56-mile long, 30-inch diameter, 0.577-inch thick (90 km long, 76.2 cm diameter, 14.7 mm thick) pipeline that transverses from Ship Shoal block 207 in approximately 300 ft (91 m) water depth to an onshore facility in Burns, Louisiana (Figure J.4).

The 30-inch OD x 0.577-inch WT X-65 pipe cost $672/ton in 1997 dollars ($59/ft), and the thicker wall 0.875-inch (222 mm) pipe cost $2192/ton or $96/ft ($315/m), and was used sparingly (Figure J.5). Epoxy corrosion coating was applied at $5/ft ($17/m) for the 0.577-inch (147 mm) line and concrete weight coating for the thin pipe cost $20/ft ($66/cm). Anodes costing $441 each were spaced every 615 ft (188 m) and a total of 750 anodes were used. Three subsea valves, one pig launcher, and one meter were installed. Internal epoxy coating was removed from the final design.

One vessel was used to lay the line in shallow waters and another was used in deepwater. Mob/demob for the deepwater vessel was much more expensive than forthe shallow water vessel and was obtained cheaper than the expected cost, but the shallow water mobilization was more expensive than anticipated. Together, mob/demob represented about 15% of construction costs. Approximately 56 miles (90 km) of pipe were laid by the deepwater vessel at a cost of $21/ft ($69/m) compared to $68/ft ($223/m) for the shallow water pipeline, which partially reflects the need for burial in shallow water, which can add $10 to 15/ft ($33-$49/m) additional cost and the shore transition.

Forty pipeline crossings were anticipated to cost $100,000 per crossing but actually cost about one-third of the estimate, at $35,600 each. Field joint coating was estimated to cost $1 million but final cost was $1.8 million. The riser and installation at Ship Shoal 207 was anticipated to cost $550,000 but actually cost $157,000.

Total project cost was $74.1 million and about 60% of the cost was due to materials. The original estimated labor and/or contractor cost was $42 million, but the actual realized cost was $32 million, mostly due to favorable developments in the mob/demob cost and cheaper deepwater pipelay cost.

### 10.4.2. Discovery

The Discovery Gas Transmission system was built in 1997 and is a network of 147 miles (237 km) of pipelines originating at Ewing Bank block 873 platform (Lobster), and including a 30-inch (76.2 cm) diameter 104-mile (167 km) main line, a 20-inch (508 mm) diameter 11-mile (18 km) lateral, which connects the mainline to a platform in Grand Isle block 115, a 26 mile (42 km) lateral that connected the mainline to a platform in South Timbalier block 200, and a six-mile (10 km) bypass line (Figure J.6). The main line included approximately 37 miles (59 km) of onshore lines, which was budgeted separately.

The offshore section of the mainline was expected to cost $73 million and actually cost $70 million, or about $1.0 million/mile, $0.62 million/km (Figure J.7). About half of costs were associated with the pipe and coatings ($515,000/mi or $320,000/km) and 44% of costs were associated with operations ($459,000/mi or $285,000/km). Material cost estimates exceeded actual costs and construction cost estimates understated actual costs.

The 11-mile (18 km) lateral that extended from the mainline to the GI 115 platform cost $7.2 million, or $650,000/mi ($404,000/km). The lower costs were partly associated with lower pipe costs ($245,000/mi, or $152,000/km), which were likely due to the smaller diameter line used, and the construction costs ($318,000/mi or $198,000/km) saved by avoiding burial requirements.

The 26 mile (42 km) lateral from the mainline to the ST 200 platform cost $13.3 million, 25% less than expected due to material and construction costs savings. Pipe and coatings costs were $180,000/mi ($112,000/km) and accounted for 35% of total costs. Construction costs were $284,000/mi ($176,000/km) and accounted for 56% of total costs.

# Chapter 11. US Gulf of Mexico Pipeline Cost Statistics

*The US offshore industry is one of the most transparent markets in the world, but reliable and representative cost data is notoriously difficult to obtain and operators generally do not provide detailed cost on project developments. The purpose of this chapter is to evaluate public sources of offshore pipeline construction costs in the US Gulf of Mexico (GoM) to expand the knowledge base in the area. Using data from the Federal Energy Regulatory Commission, industry publications, and press releases, pipeline construction costs in the US GoM from 1980–2014 are examined. The average inflation-adjusted cost to install FERC pipelines from 1995–2014 was $3.3 million/mi ($2.1 million/km), and industry publication pipeline cost average $3.1 million/mi ($1.9 million/km). Data sources vary in their scope and quality and need to be interpreted with an understanding of their limitations. A description of each data source and its limitations are provided.*

## 11.1. Data Sources

### 11.1.1. FERC Pipelines

FERC approves the construction, operation, and decommissioning of interstate natural gas pipelines under Section 7 of the Natural Gas Act (15 US Code 717). FERC determines whether gas pipelines are gathering lines or transportation lines on a case-by-case basis using the "modified primary function test" (McGrew 2009). If a line is determined to be gathering, it is classified as non-jurisdictional and is not regulated by FERC. Flowlines that transport subsea well production to an offshore facility are exempted from FERC regulation, and lines that transport production from a single offshore platform to another offshore location are also typically exempt. All oil pipelines are outside of FERC jurisdiction. For pipelines determined to be under FERC jurisdiction, pipeline owners must submit detailed applications to FERC before and after construction on the estimated and actual capital costs of pipeline construction. (See Chapter 9, above.)

### 11.1.2. Industry Publications

Industry conferences and publications, such as the Offshore Technology Conference (OTC) and Society of Petroleum Engineers (SPE), occasionally report on the engineering, construction, hardware systems, installation techniques, project management, and contracting strategies used in field development.

The first OTC meeting was held in 1969, and, over the years, a significant technical knowledge base has been documented. Operators often publish detailed project descriptions to document learning and outcomes, not only as a way of publicizing the project successes, but also the failures and opportunities for improvement. In the 1980s and early 1990s, operators sometimes reported development costs for offshore projects, but post-2000 cost descriptions at industry conferences have been much less frequent.

System descriptions in OTC and SPE publications are as-built at the time of installation and/or publication. When pipeline construction is described, contracting philosophy, vendor selection, problems, and installation techniques are usually discussed. Most project descriptions do not include cost data, and therefore case studies assembled from industry publications where costs are reported do not represent a random selection of projects, but rather projects where cost data are available. There is no reason to believe these projects are unusual in any significant way (i.e., top performers, worst case, etc.) and therefore the costs reported are considered representative. For some projects, operators report cost across specific categories according to export pipeline, infield flowlines, SURF, etc., while for other projects operators report only total development cost or other aggregate cost categories, necessitating separate cost categories in evaluation. Detailed cost comparisons are not possible using OTC and/or SPE data.

### 11.1.3. Press Releases

Oil and gas companies occasionally announce development costs for contracts via press release and contractors and service providers may describe awards won via press releases and on their company website, if material. Press release and annual report data is usually not as detailed or descriptive as OTC and/or SPE publications, but project scopes are frequently described, along with contract award, vessels, and methods used or expected to be used, and locations where the engineering and fabrication occurred or are expected to occur. On some announcements, contract values are reported, but there is frequent ambiguity on what is or is not included in the project scope and most descriptions do not provide cost data. The trade press and other organizations repeat or paraphrase the announcements, the latter sometimes introducing errors in the account. Contract terms and conditions are never discussed in detail.

EPCI contracts are typically fixed price, lump-sum awards, and for these contracts useful data can be inferred from press releases if the work scope is not too broad. Besides pipeline, contracts typically include PLETs, PLEMs, in-line assemblies, and related appurtenances, and may or may not include risers and umbilicals. It is usually not possible to separate individual component costs.

### 11.1.4. Data Type and Quality

FERC pipelines represent high-quality cost data because they represent actual final construction costs reported using a common categorization (Figure K.1). FERC pipelines most often serve single phase processed gas export flow and are generally large-diameter systems that use rigid steel pipeline and connect fixed platforms via risers to subsea tie-in assemblies, shelf platforms, or to shore gas plants. Gas pipelines are not significantly different from oil pipelines, but the configurations and installation requirements are simpler and gas lines are more homogeneous than infield flowlines and deepwater developments.

Industry publications and press releases report deepwater projects involving oil and gas flowlines, risers, export pipelines, and related equipment. These projects are more complex and varied than FERC pipelines, and may occur over multiple work seasons in congested areas with complicated subsea arrangements using a variety of pipe sizes and types, vendors, and installation methods. Project scopes and contractual agreements are more complicated, and the cost data that is reported is less detailed and is usually presented at higher and less uniform levels of aggregation. System components are usually described according to the contract requirements set forth by the operator to meet schedule and ambiguity in system descriptions are not uncommon. Cost comparisons are more complicated because of the differences in scope and the unobservable nature of project characteristics.

## 11.2. Data Processing

### 11.2.1. Categorization

Projects are categorized as exclusively export pipelines, exclusively infield flowline systems, and projects that combine export and infield construction. The resource title owners almost always own and operate the flowlines from the well to first processing, and an affiliate of the lease holders own and operate the oil export lines and sometimes also the gas export lines. Gas transmission companies may own and operate gas export lines and may own all or a portion of the processing facility and structure.

### 11.2.2. Unit Cost

Unit costs normalize for pipeline mileage and are computed for export systems, infield flowline systems, and export/infield systems by dividing project costs by mileage. Export systems include only export pipeline, and infield flowlines include only flowlines and umbilicals. Export/infield systems is a composite category that considers all export and infield pipe and normalizes by the total mileage of the system.

Export systems: $\frac{\text{Export pipeline cost}}{\text{Export pipeline mileage}}$

Infield flowline systems: $\frac{\text{Flowline cost} + \text{Umbilical cost}}{\text{Flowline mileage} + \text{Umbilical mileage}}$

Export & Infield systems: $\frac{\text{Export pipeline cost} + \text{Flowline cost} + \text{Umbilical cost}}{\text{Export pipeline mileage} + \text{Flowline mileage} + \text{Umbilical mileage}}$

An aggregate all-in pipeline cost is used to consolidate total pipeline mileage and cost regardless of project type:

Pipeline system: $\frac{\text{Total pipeline cost}}{\text{Total pipeline mileage}}$

Water depth and contract type plays no role in differentiating projects in this assessment because the sample data is not large enough to capture the project differences in a statistically sound manner. Also, no distinction is made between line diameter and thickness.

Infield contracts typically include umbilicals, which may or may not be broken out separately from flowline cost, but, if included with the system costs, are included in the mileage total. PLETs, PLEMs, subsea sleds and jumpers, tie-in assemblies, flying leads, and other subsea components are typically included in construction contracts and cost but cannot be evaluated separately. Additional offshore work such as riser work and system components such as riser work are also not considered. For example, riser[8] work may be included in the contract cost but does not appear in the denominator term unless explicitly described.

#### 11.2.3. Inflation Adjustment

The BLS Producer Price Index for steel pipes and tubes (WPU101706) and for oil and gas services (WPU60110401) were used to inflation-adjust cost to 2014 dollars. The steel pipe and tube index was used to inflate material cost in the FERC data and the oil and gas services index was used for all other inflation adjustments. The year of contract award is used as the baseline year, and if not available, the year of installation or first production serves as a proxy.

From 1980–1995, the BLS indices increased at rates reflective of general inflationary trends in the US economy, and both indices were relatively stable over the 1995–2003 period before increasing dramatically over the 2004–2008 period, due in large part to increased demand from intense hurricane destruction and cleanup activity (Figure K.2). The selection of cost indices is not unique and a variety of

8 Riser footage can be excluded in most cases, but in some deepwater developments with multiple risers and short export lines, riser length may be a significant part of total footage. At Bullwinkle, nearly 17 miles of conductor pipe for 50 wells were initially installed.

indices can be used, but these indices were chosen because they are readily available over the period of analysis and are expected to reasonably represent market changes.

## 11.3. FERC Cost Evaluation

### 11.3.1. Data Source

Twenty FERC pipeline projects with detailed costs over the 1995–2014 period and 173 FERC pipelines with summary costs from 1980–1995 were examined. FERC dockets available from the government website were reviewed from 1995–2014 and Oil & Gas Journal (OGJ) summary reports that source the FERC data were used from 1980–1995. In the OGJ summaries, costs are categorized into material, labor, miscellaneous, and Right of Way (ROW)/damage in the September issue for projects completed between July 1 and June 30 of the previous year. FERC electronic reports are not available before 1995 and detailed cost analysis was not performed.

The 20 projects from 1995–2014 cover 1139 pipeline miles and include the majority of offshore projects considered or approved by FERC over the past two decades (Table K.1). Eleven of the 20 projects from 1995–2004 were built and for these projects final costs are reported. Ideally, cost statistics should not mix estimated and actual cost, but, after review, cost estimates appeared reliable (see Section 11.3.7), and were included in the evaluation to increase sample size.

### 11.3.2. Normalized Costs

The normalized, inflation-adjusted costs to engineer, procure, and install offshore gas pipelines in the GoM was approximately $3.31 million/mi ($2.06 million/km) from 1995–2014 with a standard deviation of $2.70 million/mi or $1.68 million/km (Table K.1). Normalizing with pipeline diameter yields an average of $136 thousand/mi-in and a standard deviation of $115 thousand/mi-in. From 1980–1994, the inflation-adjusted cost was $1.40 million/mi ($870,000/km) with a standard deviation of $1.46 million/mi ($907,000/km).

Both cost distributions are roughly lognormal with large standard deviations indicating wide differences between projects (Figure K.3). The 1995–2014 data period is considered more representative of current and future construction cost than the legacy projects because of the potential bias of the cost adjustment and changes in technology that have occurred as well as the deeper water location of projects. Construction costs have increased over time and the spread between low and high cost projects was particularly pronounced during 2005–2009, a time of several major hurricanes and market volatility (Figure K.4). FERC pipeline construction was particularly intense during the 1980s but has become much less common in recent decades.

Short pipelines are expected to be more expensive to install on a per-mile basis, all else being equal, due in part to the costs associated with vessel spread mobilization because costs are allocated over fewer miles. All other factors are rarely equal, however, and there may be project-specific learning effects that increase the rate of installation as a project proceeds. As the length of a pipeline increases, the technical complexity may also increase, due to increasing numbers of subsea crossings, the need to connect with or provide future connection points with other pipelines, geological hazards, greater weather exposure, etc. No meaningful relationship was found between pipeline length and normalized costs; this suggests that economies of scale are weak or non-existent or project scopes simply too variable to detect.

Historically, labor and material costs were roughly equal contributors to total cost, but in recent years labor has played a larger role (Figure K.5). From 1995–2014, labor accounted for about half of total costs with materials accounting for between a quarter to a third of total costs (Table K.2). Not all firms report data for all cost categories, either because there was no cost in the category or because cost was allocated elsewhere. Some categories are recorded as having zero costs, and including these data points as zeros artificially lowers the average cost for the category. Excluding the zero values, the average inflation-adjusted cost for FERC pipelines installed from 1995–2015 is \$3.95 million/mi (\$2.54 million/km).

### 11.3.3. Labor and Contract Services

Projects with the highest labor costs have all occurred since 2003; the Algonquin and Triple T projects had particularly high labor costs. The Triple-T project was the shortest in the sample and the fixed costs associated with vessel mobilization and demobilization may partially account for the high normalized costs. Algonquin is the only project located outside the GoM included in the assessment which may also contribute to a higher mobilization cost.

Labor and contract services are usually the largest component of total costs and are strongly associated across the sample (Figure K.6). Though labor costs account for only about half of project costs, it explains nearly all of the variation in total costs. According to model regression, total cost is about 25% greater than labor cost plus a fixed-term component of \$1031/mi (\$641/km). The fixed cost component ranges from less than 10% to over 50% of project cost.

### 11.3.4. Materials

Inflation-adjusted material costs average \$814,000 per mile (\$504,000 per km) and range from \$368,000 to \$1.6 million per mile (\$228,000 to \$994,000 per km) from 1995–2014. Material costs are all-inclusive and include pipeline, coatings, anodes, buckle arrestors, assemblies, etc. Material costs and pipeline diameter are closely related after removing the Triple-T project, a particularly short pipeline, and the Ocean Express project, which proposed using stainless steel line across a naval restricted area but was never built (Figure K.7). From the project data, pipe coating ranged from \$232,000 to \$382,000 per mile (\$144,000 to \$237,000 per km) with an average of \$288,000 per mile (\$179,000/km). Cathodic protection systems cost between \$12,000 and \$20,000 per mile (\$7500 to \$12,000 per km). Anodes cost between \$500 and \$1,000 each depending on pipeline diameter.

### 11.3.5. Engineering

Engineering costs ranged broadly from \$19,000 to \$709,000 per mile (\$11,000 to \$440,000 per km) with an average of \$182,000/mi (\$113,000/km) and a median of \$117,000/mi (\$72,700/km). Larger more complex projects require greater preparation and planning and exhibit larger staff and engineering expense. Though engineering costs account on average for only 5% of total costs, normalized engineering costs explains a surprisingly large proportion of the variation in normalized costs (about two-thirds), suggesting that other cost factors are linearly related with engineering requirements (Figure K.8).

### 11.3.6. Time Trends

The late 1970s and early 1980s was a time of numerous discoveries and intense development activity on the GoM shelf. During this time 127 FERC pipelines were installed at an average inflation-adjusted cost of \$1.3 million/mi, or \$807,000/km (Table K.3). Installation cost declined with the decline in oil prices over the 1985–1989 and 1990–1994 periods, and the number of FERC pipelines has declined significantly with the maturation and production decline in the shallow water region. In recent years, the number of new FERC pipelines has averaged less than one per year.

Larger diameter lines are expected to be more expensive than smaller diameter lines due to the increased material costs and the longer time required for welding, and when category counts are statistically meaningful, these trends are generally observed (Table K.4). Small diameter lines were common in the 1980–1984 period but in most other periods medium diameter lines predominated. Short (<10 mi, or 16 km) pipelines appear slightly more expensive per mile than medium length (10–50 mi, or 16–80 km) pipelines, and pipelines greater than 50 mi (80 km) are the most expensive on a unit basis (Table K.5).

The standard deviation of unit costs as a percentage of the average has generally decreased over time indicating greater commonality in project execution, and perhaps, greater levels of competition.

#### 11.3.7. Estimated and Actual Costs

Data on 11 completed FERC projects were available to compare actual costs at the conclusion of the project with estimated costs performed at the beginning of the project (Table K.6). Cost estimates are based on the assumption that all work will be carried out and completed according to the schedule and task defined at the time the estimate was performed; final costs depend on the contracts awarded and the market conditions at the time of tender, which are likely to differ to varying extent from the original estimates (Figure K.9).

On average, the error between actual and estimated costs was -8.3%, indicating a slight optimism bias in the estimates. Seven of the 11 cost estimates were within 11% of the actual costs and only two cost estimates exceeded a 25% error.

Material cost estimates were significantly more accurate than labor cost estimates. This is not surprising because project scopes are usually well-defined at the time of cost estimation and quotes from vendors will not materially change unless market conditions change dramatically. Material cost errors across the projects averaged a mere 2.6% with cost estimates exceeding realized costs.  In contrast, labor and service cost estimates were generally optimistic and underestimated costs by about 20%.

Labor costs were approximately evenly distributed above and below estimates and the difference between actual and realized costs was largely due to a small number of underestimates. Labor cost differences arise from a larger set of factors, such as market conditions, contract structure, and schedule objectives, that cannot be reliably modeled. Engineers perform cost estimates based on time and dayrate assumptions on work tasks, while the contractors that submit bids typically provide a lump-sum (turnkey) rate, and winning bids are often determined by being the low bidder. Hence, levels of competition and local market conditions determine in part the variance observed. Cost estimates performed by experienced engineers may also be better than from less experienced engineers.

### 11.4. Industry Cost Evaluation

#### 11.4.1. OTC and/or SPE Data

OTC/SPE publications provide cost data for 20 projects in the US GoM from 1979–2015 (Table K.7). These projects include ten oil and gas export pipelines, 13 infield flowlines, and two infield/export systems. All of the projects except Mobile Bay describe deepwater projects. Most installations were constructed from 1990 to 2005 from 1000 ft (305 m) to 3000 ft (914 m) water depth, with three projects reported before 1990 and five projects after 2005. Independence Hub represents the deepest pipeline project in the sample at about 8000 ft (2400 m), Mardi Gras the longest line at 489 miles (757 km), and Morpeth the shortest line at about two miles (3.2 km). This data represents the majority of pipeline cost data reported in OTC/SPE publications.

The average aggregate all-in cost for OTC/SPE pipeline installation was $2.8 million/mi ($1.7 million/km) and ranged from $520,000/mi ($323,000/km) to $12.9 million/mi ($8 million/km). High cost construction tend to be short segments, deepwater or specialized pipeline. Excluding the two cost endpoints, the majority of costs ranged from $1 to $6 million/mi ($621,000 to $3.7 million per km). Export and export/infield projects cost about $2 million/mi ($1.2 million/km) and infield flowline projects cost about $3.5 million/mi, or $2.2 million/km (Table K.8). Standard deviations are on-the-order of the mean indicating significant variation within each category. Infield flowlines cost almost twice as much as export pipelines, with cost distribution approximately lognormal (Figure K.10).

### 11.4.2. Press Release Data

Press release data for 16 GoM projects from 1998–2015 were assembled with summary descriptions provided in Section 11.6. There was no significant overlap with OTC/SPE project data (Table K.9). Cameron Highway was the longest pipeline in the sample, at 390 miles (630 km), and several projects exceeded 100 miles (160 km). The shortest project was less than 10 miles (16 km), and, along with systems in greater water depths, tended to characterize high unit cost construction. Both export and infield networks were represented and there were two combined export/infield systems. All projects are deepwater and used a breadth of marine contractors, including Allseas, EMAS, McDermott, Subsea 7, and Technip.

The average aggregate cost for press release data was \$3.7 million/mi (\$2.3 million/km) with a range of \$800,000 to \$10.0 million/mi, or \$497,000 to \$6.2 million/km (Table K.8). Export pipeline and infield flowline system cost were reported at about \$3.8 million/mi (\$2.4 million/km) with a standard deviation of the same order-of-magnitude matching the OTC/SPE infield cost data. Export project costs were greater in part due to a greater number of more recent projects reviewed. Similar to OTC/SPE projects, the distribution of the press release cost data was approximately lognormal (Figure K.10).

### 11.4.3. Comparison

The OTC/SPE and press release data was combined by project type and in aggregate to form a composite data sample. The average export pipeline installation cost was \$2.7 million/mi, the infield system cost \$3.6 million/mi, and the aggregate all-in pipeline cost was \$3.1 million/mi (\$1.7 million/km, \$2.2 million/km, and \$1.9 million/km, respectively). FERC pipeline cost is exclusively export pipeline and so the relevant comparison with OTC/SPE and press release data is with export systems. FERC pipeline inflation-adjusted cost was \$3.3 million/mi (\$2.1 million/km) versus \$2.7 million/mi (\$1.7 million/km) for industry data. Both cost distributions are approximately lognormal (Figure K.11).

## 11.5. Limitations

FERC data are limited by the nature of the projects and small sample size.  All FERC projects represent gas export systems, and all pipelines in the sample except one were at least 20 inches (51 cm) diameter and at least 6 miles (9.7 km) long, with an average distance of 57 miles (92 km). All of the installations were in relatively shallow water and usesd rigid steel pipeline and S-lay installation methods. FERC pipelines generally do not involve complex subsea architectures or installations in congested seafloor terrains. Commissioning and inspection requirements for FERC gas pipelines are likely to be significantly easier than deepwater oil and gas hydrotesting requirements.

OTC/SPE and press release data reflect broader project scopes, including infield flowlines and combined export/infield systems, but lack detailed descriptions to extract granular cost as with FERC pipeline. Infield flowlines are likely to be shorter in length than export pipelines, smaller in diameter and reel-layed in deeper water, and include umbilicals and related ancillaries which may not be reported. Cost categories are less consistent than FERC projects because of differences in reporting preference and contract structures. If a third-party (non-affiliated company) owns and operates a pipeline system, it is more likely the cost will be reported for greater transparency with their customers. The manner in which costs are reported determine the aggregation level required for normalization. Missing or incomplete components limit evaluation.

Project data occur over a 20-year time period of technological improvement and market changes.  A long period is needed to provide adequate sample sizes, but over-long evaluation periods inflation adjustment introduces uncertainty in the assessment because the BLS indices are not specifically designed for the offshore GoM, nor do other offshore indicators (e.g. IHS-CERA upstream index) necessarily provide a more reliable gauge of inflation levels. The most specific BLS index available was used to adjust costs but an argument could also be made for using hybrid indices.

A number of unobserved variables were not included in evaluation. Contract structure and the manner in which risk is apportioned between the contractor and oil and gas company are important factors not considered in this assessment. Risk allocation can have important impacts on project costs but these effects are not observed in the data or captured in the statistics. Firms that adopt lump-sum contracts price risk within the contract, while dayrate contracts may yield more favorable economics for resource owners if interfaces are properly managed and projects do not encounter unexpected problems or weather.

## 11.6. Press Release Data

In this final section, the press release data summarized previously is provided for completeness.

### 11.6.1. Allseas: Ursa

The Ursa field was developed with a TLP in 1999 in 3950 ft water depth and is located 6 miles east of the Mars field. It is made up of the Crosby and Princess subsea developments. An 18-inch 47-mile oil pipeline and a 20-inch 47-mile gas pipeline to WD 143 was installed in 1998 by Allseas and reported to cost $76 million, or about $810,000/mi.

### 11.6.2. McDermott: Brutus

McDermott installed 26 miles of 20-inch pipeline for oil production and 24 miles of 20-inch line for gas production for Shell's Brutus development in 2002 in 2998 ft water depth. Pipeline fabrication and installation is estimated at $85 million, or $1.7 million/mi.

### 11.6.3. Technip Coflexip: Falcon

In 2002, Technip Coflexip was awarded an EPCI contract from Pioneer Natural Resources and Mariner Energy for 32 miles of 10-inch rigid pipe and hydraulic control umbilical between two deepwater subsea wells and the shallow water Falcon Nest Platform. The umbilicals were fabricated by Technip-Coflexip at its DUCO manufacturing plant in Houston. Installation was completed by *CSO Deep Blue*. The contract was valued at $35 million, or $0.6 million/mi.

### 11.6.4. Subsea 7: Thunder Horse and Atlantis

Subsea 7 was awarded a $30 million installation contract in 2002 by BP for its Thunder Horse and Atlantis developments. The work scope included the installation of 37 miles of umbilicals, flying leads, and rigid jumpers for Thunder Horse, and 26 miles of umbilicals at Atlantis. Installation cost is estimated at $476,000/mi.

### 11.6.5. Cameron Highway

In 2003, Valero and GulfTerra Energy built the $458 million Cameron Highway system, a 390-mile oil pipeline that extends from the Southern Green Canyon area to refining centers in Port Arthur and Texas City, Texas. Unit cost is $1.2 million/mi.

### 11.6.6. Subsea 7:Glider

In 2003, Shell's Glider subsea tieback development used two wells and a 6-inch, 6-mile buried and insulated flowline for about $150 million. Flowlines and umbilical procurement and installation is estimated to cost approximately $6.8 million/mi.

### 11.6.7. Technip, Subsea 7: Cascade-Chinook

In 2008, Technip was awarded two contracts worth $300 million by Petrobras for the Cascade-Chinook field development in water depths from 8200 to 8800 ft. The contracts covered five hybrid riser systems, construction and installation of 74 miles of 6-inch flowlines and gas export pipeline, 10 PLETs, and two in-line tees. The pipelines were welded at the Group's spoolbase in Mobile, Alabama. Unit cost was approximately $4.1 million/mi. Subsea 7 was awarded a $50 million contract by Petrobras to install 43 mi of power cables and control umbilicals and to fabricate and install 16 jumpers in water depths from 7544 ft to 9840 ft. Installation cost is estimated at $1.2 million/mi.

#### 11.6.8. Enbridge: Big Foot

Enbridge entered into an agreement with Chevron, Statoil, and Marumbeni in 2009 to construct and operate a 20-inch 40-mile oil pipeline from the Big Foot TLP in 5500 ft water depth to a subsea connection for $250 million, or about $6.3 million/mi.

#### 11.6.9. Subsea 7: Droshky

Subsea 7 was awarded a $45 million contract for the fabrication and installation of two 8-inch reeled flowlines totaling 36 mi from Marathon's Droshky field in 3000 ft water depth to the Bullwinkle platform in 1350 ft water depth. The contract also included two 8-inch risers, four PLETs, two PLEMs, and three rigid jumpers. Pipeline was fabricated at the company's spoolbase facility at Port Isabel, Texas, and laid in 2009 using the reeled vessel *Seven Oceans*. Unit cost is $1.3 million/mi.

#### 11.6.10. Keathley Canyon Connector: Lucius, South Hadrian

In 2013, Williams Partners and DCP Midstream Partners reported spending $600 million to expand the Discovery pipeline system to connect production from the Keathley Canyon, Walker Ridge, and Green Canyon areas. The Keathley Canyon Connector is a 20-inch, 215-mile natural gas pipeline that terminates into Discovery's 30-inch mainline near ST 283. Unit cost is $2.8 million/mi.

#### 11.6.11. Technip: Delta House

Technip was awarded a lump-sum EPCI contract by LLOG Exploration Offshore LLC in 2013 valued between $107 to $268 million for 124 miles of infield and export flowlines and risers in the Delta House development. Technip's *Deep Blue* laid the reeled lines and the construction vessel *G1200* installed the export lines in 2014. Unit construction cost for procurement, construction and installation is estimated to be $1.5 million/mi.

#### 11.6.12. EMAS: Gunflint, Big Bend, Dantzler

EMAS AMC announced three EPCI contracts worth $300 million in October 2014 from Noble Energy for subsea tieback projects in the Big Bend, Dantzler, and Gunflint developments in the deepwater Mississippi Canyon area. The project scope includes 80 miles of pipe-in-pipe flowlines and 56 miles of umbilicals in water depths up to 7200 ft, or about $2.2 million/mi. *Lewek Constellation* performed the installation.

#### 11.6.13. Technip: Julia

Technip was awarded a lump-sum EPCI contract valued between $133 and $333 million by ExxonMobil for the Julia field in the Walker Ridge area at a water depth of 7200 ft. Genesis, Technip's wholly owned subsidiary, performed the flowline design, and welding operations were performed at its spoolbase in Mobile, Alabama. The project scope covered 30 miles of 10.75 inch insulated flowlines, steel catenary risers, and PLETs, at an estimated cost of $7.8 million/mi.

#### 11.6.14. Subsea 7: Shell

In late 2014, Subsea 7 was awarded a contract by Royal Dutch Shell, valued between $50 to $100 million for the installation of 27 miles of 8-inch flowlines and steel catenary risers, including PLETs and inline structures. The main construction phase took place in 2016. Unit cost is estimated at $2.8 million/mile.

### 11.6.15. Walker Ridge Gathering System: Jack, St. Malo, Big Foot

Enbridge built the Walker Ridge Gathering System pipeline to provide natural gas transportation for the Jack, St. Malo, and Big Foot fields. Construction cost of the system is estimated at $500 million, and includes 170 miles of 8-inch and 10-inch pipeline at depths of up to 7000 feet with the capacity to transport 120 MMcf/d of gas. Unit cost is approximately $2.9 million/mi.

### 11.6.16. Enbridge: Stampede

Enbridge announced in January 2015 that it would construct a $130 million crude oil pipeline to link Hess's Stampede development to existing infrastructure. The 16-mile long 18-inch pipeline will be constructed in water depths up to 3500 ft and have a cost of $8.1 million/mi.

# Chapter 12. US Outer Continental Shelf Pipeline Decommissioning Workflows

*At the end of its useful life or because of a catastrophic event, such as a hurricane, offshore pipelines are decommissioned. This typically involves cleaning the line by pigging or flushing, cutting the pipeline endpoints, and then plugging and burying each endpoint below the seabed or covering with a concrete mattress. The vast majority of decommissioned pipeline in the US Gulf of Mexico (GoM) is abandoned-in-place, but in designated Significant Sediment Resource areas pipelines may be removed to avoid interfering with other uses of the outer continental shelf (OCS). In 2016, BOEM determined that any infrastructure located in a Significant Sediment Resource region is an obstruction, interfering with development of sediment resources, and takes the position that such pipelines should be decommissioned by removal. This chapter begins with a description of the life-cycle issues that arise when pipeline flow rates are significantly lower than their design capacity. A detailed description of decommissioning workflows is provided, and the chapter concludes by reviewing the OCS sediment resources policy.*

## 12.1. Life-Cycle Issues

### 12.1.1. Operational Considerations

After an export pipeline is installed, utilizations are high and flow rates are near line capacity. After a period of time, as production declines, pipeline flow rates and utilizations will also decline. If new fields are discovered in the vicinity of the platform from which the export line originates or crosses, are economic to tie-back to the platform, and an agreement can be reached with the structure owner (if different from the field owner), the line will continue to be used. At some point, however, there will be no new discoveries in the vicinity of the platform, or the distance to the platform will be too great for a tieback, and load factors on the line will decline.

*Load factor* is the throughput volume divided by the pipeline capacity. For the first few years after installation, load factors usually exceed 90% because pipelines are designed to match the maximum expected flow rates from wells. A load factor of 5–10% is generally considered low. At low load factors, the fixed costs of operations have to be allocated over decreasing volumes, leading the operator of the pipeline to potentially seek rate increases on existing customers. If the pipeline is regulated by FERC, the proposed tariff rate increase requires FERC approval. If the pipeline is not FERC regulated, the shipper has little recourse. Although FERC has no jurisdiction to enforce rate reasonableness on oil pipelines in the OCS, OCS pipelines must still adhere to policies of nondiscrimination and open access. Section 5(f) of the OCSLA requires all OCS pipelines to "provide open and nondiscriminatory access to both owner and non-owner shippers."

If the well owners or a subsidiary or affiliate of the well owners operate the export line, the line will likely stay in service until the "system" is no longer economic, but if a third party operates the export line, the benefit of maintaining the line near the end of the field life will differ significantly, because the pipeline company revenues are based entirely on demand and commodity charges for the use of the pipeline, not for other strategic considerations or benefits.

The issue with flowlines is similar because of ownership considerations. As field production declines, the utilization of flowlines that bring subsea well production to a facility for processing decline and eventually will be uneconomic to operate, but because the flowlines are owned and operated by the owner(s) of the subsea wells, and the costs are sunk and system cost is known, there is no conflict of interest between the flowline operator and well owners. As long as the well is producing and the system is economic to operate, the flowline will be serviced to maintain production.

For a third-party operated line, rate cases may be administered and increased rates passed on to its customers to maintain operations, but these proceedings take time and outcomes are uncertain. Well owner(s) transporting gas in a FERC pipeline may object to a line abandonment because it may strand hydrocarbons and limit future development options, and, of course, the well owners would prefer the line remain in-service for as long as possible regardless of the cost to the pipeline operator. FERC attempts to balance these competing interests using guidelines referred to as Public Convenience and Necessity (see Chapter 9).

### 12.1.2. End-of-Life Indicators

There are several indicators that a transmission pipeline is near the end of its life. If the pipeline has no and/or low revenue, no firm contracts, no customers or only a small number of customers on interruptible service, expensive repairs, pigging problems, corrosion, and operational issues, then the pipeline is likely near the end of its useful life.

Pipelines (including risers) are inspected on a schedule defined by BSEE regulations, usually on a 3 to 5-year period. If pipes lose more than 50% of their thickness, they must be replaced or shut down. When flow rates are low, pigging becomes more complicated because pigs require pressure to push through the line, and it may be expensive to buy gas or gas supply may not be available. Reduced pigging accelerates corrosion and leads to safety and environmental issues, depending on the age and condition of the line.

Pipelines that carry two-phase fluids (oil-gas, gas-condensate) are more prone to corrosion than those that carry single-phase fluids. Crude with high water vapor and sulfur content, and gas with high sulfur, CO2, and water vapor content are corrosive, and the lower the flow pressure the more corrosive the impact. Seafloor resistivity, water salinity, and seabed composition may promote corrosive activity and affect the probability of active corrosion.

## 12.2. Decommissioning Workflow

### 12.2.1. General Considerations

Pipeline decommissioning is generally considered an inexpensive, low tech operation, involving relatively simple procedures that are easy and quick to perform under normal conditions. Shallow water operations in regions that are not designated Significant Sediment Resource regions typically require a dive boat and divers that perform cuts without explosives at the ends of the pipeline. The vast majority of pipelines in areas that are not Significant Sediment Resource regions are abandoned-in-place, and therefore the decommissioned pipeline segments are not removed from the seabed. Only small portions of the pipeline, typically the risers and tube turns, are removed, or if a pipeline is damaged or leaking, the damaged portion will need to be repaired or replaced prior to decommissioning. Regulations require that the ends of the pipeline are buried three feet (0.9 m) below the seabed or covered by a concrete mat. The procedures in deepwater are similar[9] to shallow water but more involved (Burke and Stokes 2015; Philip et al. 2014).

In OCS areas that are designated OCS Significant Sediment Resources, BOEM requires that pipelines are decommissioned by removal, which is a longer and more complex operation. Companies are required to obtain BSEE authorization before operations to relinquish the right-of-way (ROW), and because no blasting is performed during decommissioning operations, usually no additional environmental clearances must be obtained. The Coastal Zone Management Act (CZMA) in the State of Louisiana requires all pipeline decommissioning in place be reviewed because the State has identified all activity on the coastal shelf of significance and value to the State. In addition, concurrence from the State of Louisiana through the CZMA on a case by case basis is required.

9 These procedures are also similar but not identical to other offshore regions such as the North Sea (DECC 2011) where differences in regulatory regimes and seabeds create differences in decommissioning practices.

Other states in the GOM vary on their CZMA enforceable policies and management of pipelines. Pipeline endpoints that lie entirely within federal waters qualify for categorical exclusion from the requirement to prepare an environmental assessment or environmental impact statement, but pipelines that traverse state and federal waters require additional preparation and review, typically involving an environmental impact statement. Pipelines that are not under FERC regulation only require BSEE authorization and permit to abandon.

### 12.2.2. Basic Procedures

The workflows associated with pipeline decommissioning depend on the requirements, the status and nature of the system at the time of operation, and the procedures established by the company or contractor. No generalized procedure applies to all facilities because system configurations are unique although on a functional level there is a high degree of commonality of work activities. Work duration and market rates for the vessels and equipment required to perform operations vary and lead to different workflows and costs. One of the most important factors that distinguish differences in project cost is the status of the pipeline. If the pipeline is damaged or leaking, costs are expected to be at least two or three (or more) times greater than normal operations.

The basic procedures used in pipeline decommissioning for abandonment-in-place are as follows:

1. Isolate line.
2. Pig pipeline and collect contaminants.
3. Cut and bury tube turns near platform base; install fitting and caps.
4. Remove appurtenant facilities, including valves, pig launchers, meters and risers.
5. Dispose of flush water and pipeline materials.

For pipeline decommissioned by removal, step three is replaced by the complete removal of all pipeline, including appurtenant facilities, valves, pig launchers, meters, and risers.

### 12.2.3. Cleaning

Pipelines are cleaned via a process called *progressive pigging* to ensure that the pigs do not get stuck in the pipeline. The process involves sending a series of polyethylene foam pigs and cleaning fluids through the pipeline with chemical agents and flush water to remove all hydrocarbons (Culwell and McCarthy 1998; MacLeod and Pierson 2000). The progressive nature of pigging refers to the sequence, type, and number of pigs applied.

Pigs are described by their diameter and type (Figure L.1). The type of pig used in cleaning is based on the condition of the pipeline, previous cleaning history, and the expected buildup of corrosion, wax, hydrates, or other residues (e.g., asphaltenes) from hydrocarbon production.

Poly (foam) pigs are bullet-shaped and slightly larger in diameter than the inside diameter of the pipeline; come in low, medium, and high density. A low-density pig can deform as it is pushed through the pipe, and so can pass through partially blocked lines with only low force applied, but because it doesn’t move much of the material collected on pipeline walls, more passes are required in cleaning. Medium- and high-density pigs require greater applied force and reduce the number of runs required but also increase the chance of the pig getting stuck in the pipeline. This is referred to colloquially as *aggressive pigging*. A pipeline that has been kept clean or was cleaned at the time of shutdown may require only low-density poly pigs and flush water for cleaning.

Brush pigs have wire brushes or other types of brushes to remove material residue; scraper pigs have a number of scrapers built in to scrape the residue off pipeline walls. A poly pig with steel brush strip (referred to as a Javelina pig) is more aggressive than a regular poly pig. Cast polyurethane pigs are better able to traverse joints, valves, bends, and reduced pipe diameters. Disk pigs, cup pigs, and mag pigs (also known as tri-cup pigs) are also frequently used in pigging operations. Pig trains are used if operators anticipate a stuck pig. Recovered pigs are examined for impregnation with paraffin, deposits, and hydrates.

During normal operations, pipelines are pigged at a frequency depending on the characteristics of the hydrocarbon streams and flowrates (MacLeod and Pierson 2000). Normal pigging operations may be performed every few days, weekly, monthly, biannually, or yearly using the pipelines flowing energy to push the pig. Due to the risk that the pig may get stuck in the pipeline, operations are planned carefully.

The pig is introduced into the pipeline through a pig launcher, a pressure vessel connected to the end of the pipeline which may be above the surface or below the waterline. The pig is pushed from the launcher into the pipeline by pumping air, nitrogen, water or chemicals into the launcher behind the pig. For active gas lines, natural gas is used if available in adequate supply and pressure. The progression continues with the corresponding amount of driving chemicals or flush water to remove all remaining hydrocarbons. The pigs are received in a pig catcher located at the opposite end of the pipeline either above or below water and plumbed to allow fluids or gas to flow through.

Verification of the pipeline cleaning is based upon flush water quality checks, which often rely on visual verification and the absence of hydrocarbon sheen. Measurements by instrumentation may also be used. Flush water is typically pumped down disposal wells at the platform if wells are available, processed for disposal, or shipped to an approved dump site.

*Example. Stuck pig at Marlin*

> The Marlin TLP is located in Viosca Knoll 915 in 3250 ft water depth and is host to several dry tree and wet tree wells (Fung et al. 2006). Oil export is via a 22-mile non-insulated 10-inch line to facilities at Main Pass 225 in 200 ft water depth. The oil export management plan used a regular single-trip pigging technique to remove the wax build up every 14 days; this was selected over continuous wax inhibition because of the high operating expense of the chemical treatment.
>
> Oil leaves the Marlin TLP at a temperature of approximately 120 °F and drops to 40 °F over the first 7300 ft (1.4 miles) of flowline and then warms to about 65 °F at the MP 225 location (Figure L.2). Because the pipeline does not have any insulation, higher flowrate fluids will retain heat for longer distances. The WAT of the co-mingled oil streams is approximately 95 to 100 °F. Heavy molecular weight paraffinic hydrocarbons begin to solidify and deposit on the pipe wall over time and give rise to an increasing pressure drop due to reduction in the flow diameter and increase in the pipe roughness.
>
> Equipment failure stopped the 14-day pigging cycle and resulted in a stuck pig. The stuck pig was estimated to be approximately nine miles from the MP 225 facility in approximately 1200 ft water depth (Figure L.3). Pumping equipment at MP 225 was used to pump the pig back to Marlin using crude with 5000 gallons of wax solvent and 300 ppm of wax inhibitor.

### 12.2.4. Cutting

A platform pipeline is cut near the base of the platform by divers using an arc oxygen torch and a cap is installed on the end. The pipeline end is buried below the mudline, typically by diver-operated jetting. The pipeline end may alternatively be covered by a concrete mat, which provides a cover for the pipeline. Concrete mattresses are commonly used in deepwater where it is not practical to bury the ends using divers, and are also more common in the North Sea than the Gulf of Mexico due to differences in practice and soil type (Oil & Gas UK 2013).

The riser that extends through the water column may be removed or left in place along with platform meters and associated equipment depending on agreement between the pipeline and platform owners (Figure L.4). The riser may be partially or wholly removed. A partially removed riser will be cut below the waterline and near the base of the platform. Tube turns are cut, the end on the seafloor plugged and buried three feet (0.9 m) or covered, and the remaining section removed.

### 12.2.5. Removal and Recovery

Recovering removed pipeline sections is done by rigging a winch wire to the pipeline and lifting it to a barge. A crane may be used in conjunction with the winch to hoist the pipeline onto the recovery vessel. Other methods can be used, but this is the primary and most cost effective procedure. Excavation may be required to remove the pipeline or it may be recovered without excavation if enough lifting force can be applied.

Risers, appurtenances, and meter facilities are usually owned by the pipeline company and removed at opportune times, or transferred, sold, or left-in-place during pipeline decommissioning (Figure L.5). If pipelines are damaged by hurricanes or corrosion, they are either first repaired to permit pigging or the damaged portions are removed. Either operation will add significant cost and uncertainty to project operations. Pipelines in a Significant Sediment Resource area are removed in decommissioning.

Pipelines that come onshore may be removed through the surf zone and capped. The onshore pipeline may be removed completely or some sections may be abandoned in place due to their transition through a sensitive environment. The pipeline end seaward of the surf zone is capped and jetted down three feet (0.9 m) below mudline by divers. Pipeline crossings may be an obstacle to decommissioning, particularly if the pipeline to be decommissioned crosses under a live (in-service) pipeline.

### 12.2.6. Disposal

Pipeline materials are transported by truck or barge to an approved dump site. The scrap value of the steel is usually exceeded by the cost of cutting and removing the pipeline coatings, and therefore, the resale value is often negligible. Pipeline materials must be reduced in length according to the dump site requirements and may be as short as six feet (1.8 m). A hydraulic shear is usually an effective way to section the pipeline to meet these requirements.

## 12.3. Onshore and Offshore Work Decomposition

Typical workflows for onshore pipeline segments are as follows:

- Isolate pipeline valves.
- Launch cleaning pigs.
- Collect and dispose of all contaminants, liquids, etc., after pig(s) receipt is confirmed.
- Isolate and close valves to relieve residual pressure and confirm gas free.
- Stopple fittings on either cut of the pipeline.
- Tap and drain portion of pipe to be abandoned and/or removed.
- Once pipe section removed, insert pipe caps.

Typical workflows for offshore pipeline segments are as follows:

- Locate, uncover, and operate subsea valves on one or more side taps to pig line.
- Load pig at platform and launch.
- If no pigs can be launched, flush with seawater from a utility boat or platform.
- Launch and run pig with high pressure inhibited sea water.
- Collect pig and fluids.
- Close subsea valves on side tap.
- Remove all appendages (valves, subsea assemblies).
- Cut pipeline at base of riser and remove section.
- Open side taps.
- Remove risers, if connected to platform.
- Remove related piping and appurtenant equipment and/or meters on platform, if applicable.

## 12.4. OCS Significant Sediment Resources Policy

In addition to oil and gas, OCS resources include sediment deposits such as clay, silt, sand, gravel, and shell found on or below the surface of the seabed, as well as commercially extracted critical minerals. Public Law 103-426 allows BOEM to negotiate, on a non-competitive basis, the right to use OCS sand, gravel, or shell resources for shore protection or beach or wetlands restoration projects by Federal, State, or local agencies, or for use in construction projects funded or authorized by the Federal government.

In 2009, the Minerals Management Service implemented the Significant OCS Sediment Resources Policy and issued a Notice to Lessees and Operators (NTL 2009 G04) to clarify how the Bureau would implement the regulatory requirements aimed at preventing waste of OCS natural resources and identified use conflicts to prevent oil and gas infrastructure installations and abandonment from unduly interfering with other uses of the OCS and its surface and shallow subsurface mineral deposits.

In 2016, BOEM and BSEE clarified that pipelines on the OCS in areas with potential reserves of hard minerals must be decommissioned and removed. BOEM considers abandoned pipelines in these designated areas to unduly interfere with other uses of the OCS and takes the position that such pipelines must be decommissioned by removal (Celata 2016).

BOEM and BSEE reviews for approximately 100 pipeline segments proposed to be abandoned in place in significant OCS sediment resource areas in 2016 determined that in-situ abandonment would obstruct the development of known mineral resources in about half of the 100 segments and require complete removal and seven would require partial removal. BOEM determined, for the remainder of the applications submitted in 2016, pipelines could be abandoned in place due, primarily, to the high density of wells in the vicinity which precluded resource extraction operations.

# Chapter 13. Gulf of Mexico Pipeline Decommissioning Cost Statistics

*Pipelines that are under FERC regulation require disclosure on construction and decommissioning costs that provides insight into operational expenditures. Using project cost data from FERC, decommissioning cost estimates for 28 gas export pipelines in the shallow water US Gulf of Mexico (GoM) between 1995–2015 are evaluated. The average inflation-adjusted pipeline decommissioning cost was $301,000 per mile ($187,000/km) and $47 per cubic foot ($1660 per cubic meter). Hurricane-damaged and leaking pipelines are about three to four times more expensive on a unit cost basis than undamaged and non-leaking lines; no time trends or scale economies were observed. The factors that affect decommissioning costs introduce the topic and are followed by examples and an evaluation of sample data. The chapter concludes with a comparison to complete removal cost.*

## 13.1. Cost Factors

Pipeline systems are described in terms of their segments and associated features such as length, diameter, endpoint type and location (Figure M.1). All cost estimation is site-, time-, and location-specific, and many factors can influence pipeline decommissioning (Table M.1). As with most offshore activities, the project scope and time spent offshore are typically the most important factors in determining cost, while the experience of the engineer and/or manager and the time available to perform the estimate, as well as the time between when the estimate was performed and the project executed, will affect the reliability of the estimation.

### 13.1.1. Project

The work activities required and time spent offshore are directly related to pipeline decommissioning costs. The length, diameter, and service of the line determine the amount of fluids that are required to flush and clean the line. Oil lines carrying high sulfur crude will likely require more pig runs and fluid volume than gas or condensate lines, time on site will be longer, and there will be greater disposal volumes than sweet gas service. A line that has been kept clean will require fewer pig runs and less flush water at the end of service than a line that has not been serviced regularly and disposal cost will be higher, all other things being equal. Sour gas lines will likely require greater service than sweet gas lines.

The scope of work activity, the number of interconnects and appurtenances needing to be cut and removed, and the endpoint and interconnect water depths are important factors in determining the time and complexity of the operation. Complex projects require more planning and labor, will be more expensive, and more uncertain to execute than less complex projects. Lines that come ashore require additional environmental review and scrutiny, which increase costs. Large retrieval and remove requirements will add costs to projects relative to abandon-in-place projects.

Pipelines that are inactive for a long period of time may not maintain their cathodic protection (Roche Total 2005). They are also exposed to natural disturbances (hurricanes, slope failures, etc.), stress induced motions, and third body impacts. Pigging operations may reveal leaks and repairs will need to be made before pigs can be run to perform decommissioning (Brown et al. 2014). Repairs typically involve the use of a clamp placed over the damaged area(s) or the damaged area is removed and a pup piece is welded in place between two points. Repairs are expensive and add significantly to the cost of pipeline decommissioning.

Hurricane-damaged platforms and pipeline increase project complexity and are associated with greater project costs[10] and risk. Hurricane-damaged platforms and pipelines require significantly greater time to

10 For example, Wild Well Control was awarded a fixed sum contract in 2008 worth $750 million to decommission seven downed platforms in the shallow water GoM for subsidiaries BP, Chevron, and Apache (Superior Energy Services 2008).

plan, access, and safely perform (Collins 1995; Coyne and Dollar 2005). If a pipeline is leaking, leaks need to be repaired before abandonment operations can proceed. This adds to project costs. Stress-induced (bent) pipes are a safety issue. Hurricane-damaged pipelines will require a larger number of cutting operations and may require retrieval, which will increase cost due to the additional support requirements and time spent offshore.

As the number of side valves that need to be cut and flanged increases, diver time and set-up time increases, which increases project costs. The diameter, thickness, pipe coating, and water depth will determine access by divers or ROVs, time, and cost to cut.

#### 13.1.2. Time

Time enters project costs across many different dimensions: according to the time required to perform the work activity, the year and season work is performed, market conditions at the time the service contract is let, and the uncertainty that arises when using a price index to adjust cost over long periods.

The time to perform work relates directly to cost because vessel spreads are based on market dayrates and are usually the greatest contributor to project costs. If a fixed price lump-sum contract is used instead of a dayrate contract, contractors will use their estimate of the expected time of operations to value the contract and bid on work; in this case, time enters contracts indirectly. Market conditions may change dramatically due to changes in vessel supply and demand, and identical offshore work performed in adjacent years may have dramatically different cost. When comparing project costs performed over long evaluation periods (e.g., decade or longer), a reliable means to adjust cost is necessary.

Waiting on weather is usually a function of the season work is performed. In the GoM, winter demand for decommissioning vessels is usually less than in the summer, leading to a reduced dayrate, but winter work has greater exposure to adverse sea states that can delay work and increase time offshore. Summer work is exposed to delays due to tropical depressions and hurricanes. Waiting on weather increases time on site and leads to higher costs.

The difference in time when cost estimates are made and when operations are performed is an often overlooked factor in the reliability of the estimation. As one would expect, when the difference in these times increases, the reliability of estimates decreases because market conditions and project scopes are more likely to change. Projects that are performed within a few months of the preparation of the estimate are expected to be more reliable than when delays exceed a year. In some cases, project delays may work to the operator’s advantage, if for example, market conditions weaken and vessel dayrates decline from when the cost estimates were prepared, but in other cases, if project scopes expand and market conditions tighten project costs will likely increase over estimates, assuming all else equal.

#### 13.1.3. Location

The water depth of the pipeline endpoints and side valve interconnects impact project complexity and selection of diver and/or ROV options, and, if there is an onshore endpoint, access may require barge or service boat entry. Pipeline endpoints that lie entirely within federal waters qualify for categorical exclusion from the requirement to prepare an environmental assessment, but pipelines that traverse state and federal waters require additional preparation and review, typically involving an environmental impact statement.

### 13.2. Decommissioning Cost Estimation Examples

Once a FERC pipeline is declared to no longer serve Public Convenience and Necessity, FERC regulations require companies to describe the decommissioning workflows and the estimated cost of decommissioning in their application.

### 13.2.1. Shallow Water Platform to Subsea Assembly

Tennessee Gas Pipeline Company (Tennessee) abandoned-in-place approximately 1200 ft (366 m) of 12-in. (31 cm) diameter pipeline that connected a platform in West Cameron block 609 to an underwater tap at a platform in WC 617 (Figure M.2).

Newfield Exploration advised Tennessee in May 1999 that it intended to remove its platform in WC 617 where the lines connect, which prompted Tennessee to submit its authorization request to FERC. At the time of the request for authorization, all gas purchase and sales agreements were terminated, no measurable volumes on the pipeline were received for nine months, and there were no transportation agreements to receive natural gas on the segment.

Tennessee estimated that the cost to abandon-in-place the supply lateral was \$41,375, or, on a normalized length basis, \$182,200/mile (\$113,000/km), and on a normalized volume basis, \$44/cf (\$1500/$m^3$) in 1999 dollars. Using the Bureau of Labor Statistics (BLS) offshore oil field services index, the inflation-adjusted cost is \$74,400, \$328,000/mile (\$204,000/km), or \$79/cf (\$2790/$m^3$) in 2014 dollars.

### 13.2.2. Another Shallow Water Platform to Subsea Assembly

In September 2008, Tennessee Gas Pipeline Company (Tennessee) supply lateral from XTO Offshore Inc.'s (XTO) platform in West Cameron block 485 to an interconnection with Tennessee's line in East Cameron 313 sustained damage from Hurricane Ike and was taken out of service (Figure M.3).

The supply lateral includes one interconnect with an Energy Resources Technology, Inc. (ERT) platform in East Cameron block 282. XTO decided to construct a parallel line to transport its production to an interconnect with Stingray's facilities in WC 509, and ERT decided to abandon its platform in May 2010, which prompted Tennessee's request for authorization abandonment.

The estimated cost to abandon 21 miles (23 km) of 16-inch (41 cm) pipeline with four side valve assemblies was \$2.8 million, or \$139,000/mile (\$86,000/km), or \$19/cf (\$660/$m^3$) in 2008 dollars. In 2014 dollars, the inflation-adjusted costs are \$3.3 million, \$159,000/mile (\$98,600/km), or \$79/cf (\$760/$m^3$).

### 13.2.3. Shallow Water Platform to Onshore Facility

Columbia Gulf Transmission Company (Columbia Gulf), a wholly-owned subsidiary of Columbia Energy Group, which is a wholly owned subsidiary of NiSource Inc., and Southern Natural Gas Company (Southern) filed an application of Public Convenience and Necessity in October 2010 to abandon-in-place a 16-inch (41 cm) pipeline connecting a platform located in East Cameron block 23 to Columbia Gulf's onshore pipeline system (Figure M.4).

The assets abandoned include 6.3 miles (10 km) of 16-inch (41 cm) offshore pipeline and appurtenances, three miles (4.8 km) of 16-inch (41 cm) onshore pipeline, one meter, and appurtenances. Decommissioning cost was estimated at \$0.7 million, \$111,000/mi (\$69,000/km) and \$15/cf (\$534/$m^3$) in 2010 dollars. In 2014 dollars, decommissioning cost is estimated at \$0.8 million, or \$127,000/mi (\$78,900/km), or \$17/cf (\$607/$m^3$).

### 13.2.4. Shallow Water Damaged Platform to Subsea Assembly

Tennessee Gas Pipeline Company (Tennessee) sought to decommission the Triple T Extension located within Eugene Island in 2010 because of continued problems with pipeline integrity due to corrosion (Figure M.5).

The Triple T Extension is a 24-inch (61 cm) pipeline that extends 6.2 miles (10 km) from a toppled platform in EI 371 in water depth 363 ft (111 m) to a subsea tie-in assembly in EI 349 in 380 ft (116 m) water depth. Tennessee disconnected the line 150 ft (46 m) downstream of the riser on the toppled platform and left the piping, valves, and appurtenances abandoned-in-place on the seabed. Approximately 60 ft (18 m) of pipe was expected to be removed at the subsea tie-in assembly.

The cost of the operation was estimated at $3.7 million, or about $588,000/mile ($365,000/km), or 36/cf ($1250/m$^3$) in 2010 dollars. The high cost of the operation is due to the combination of deepwater damaged line with retrieval requirements. In 2014 dollars, decommissioning cost is estimated at $4.2 million, about $672,000/mi ($418,000/km), or $41/cf ($1400/m$^3$).

## 13.3. Processing

### 13.3.1. Data Source

Companies with FERC jurisdictional pipelines are required to request permission to abandon transportation facilities. These requests are reviewed by FERC in public dockets available on the FERC website using the "eLibrary" link by entering the docket number excluding the last three digits in the docket number field. Applications include abbreviated and full descriptions. Full applications include a detailed description of the abandonment process along with cost and/or revenue and accounting statements. Abbreviated applications contain less detailed information.

### 13.3.2. Description

All public records from 2000–2015 and a sample of public records before 2000 were reviewed (Table M.2). A total of 25 projects were identified and they represent the majority (if not all) of FERC pipelines decommissioned during the period. The FERC website serves as a repository for documents and it is not especially easy to navigate and/or confirm that all decommissioned projects were compiled.

Applications include a description of the system and services to be abandoned, a discussion of Public Convenience and Necessity, a system map, ownership interest, pro-forma accounting entries, and a list of affected customers. Decommissioning projects are described in terms of the pipeline segment numbers and meter numbers impacted and the general work activities required. An environmental report is typically included if the pipeline transverses federal and state waters or runs ashore. Each company reports the accounting treatment of abandonment and pro-forma estimated activity cost. Companies do not report the final actual cost of decommissioning.

### 13.3.3. Exclusions

Projects were excluded from consideration when complex ownerships distorted and/or confused the cost accounting. Abandonments by sale were excluded because these are a non-related issue and abandonments of equipment, such as compressor units and meters, were not considered because of their minor nature. Consolidated abandonments (e.g., pipelines and structures) were not considered unless each cost component was separately reported.

### 13.3.4. Normalization

Estimated costs are presented by project type on a normalized basis with respect to pipeline miles, pipeline miles-cuts, and pipeline volume in cubic feet. SI units kilometers, km-cuts, and cubic meters are also presented. A mile-cut includes both the length of the pipeline segment(s) decommissioned and the number of cuts involved. All projects require at least two cuts (one at each endpoint) and some may require more. Special conditions are identified, such as leaking pipelines and hurricane-damaged facilities, and projects with onshore work. Project complexity is proxied by the number of interconnects, which translate roughly to the number of cuts required, and enters the normalization as miles-cuts. All costs were adjusted to 2014 US dollars using the BLS offshore oil field services index.

## 13.4. Expectations

Offshore pipeline decommissioning in the GoM is generally an inexpensive, low tech operation involving procedures that are relatively easy and quick to perform under normal conditions. Pipeline decommissioning projects are less expensive than well plugging (Kaiser and Dodson 2007) and structure removal (Kaiser et al. 2009), but are usually more involved than the trawling operations required for site clearance and verification (Kaiser and Martin 2009).

Pipeline length is expected to be positively correlated with decommissioning cost due to the greater time and additional fluids required to clean the pipeline, for all other factors fixed. *System complexity* is described by the number and type of interconnects and the water depth of the cuts and endpoints. As system complexity increases, decommissioning cost is expected to increase. Hurricane damaged and/or leaking pipelines are expected to cost more than normal pipeline operations.

The year in which activity is performed will impact costs because service vessel dayrates depend on market supply and demand conditions which are variable and change over time. Inflation adjustment is expected to normalize for time effects and will partially account for market changes. Linear relations among factors are not to be expected because of the uncertain nature of the project data. Standard deviations are expected to be high and on-the-order of the mean, which is typical for offshore cost statistics.

Different assumptions are employed in decommissioning cost estimation across companies, and, unlike the standardized categories FERC requires in construction (Chapter 11), standardized categories are not used in FERC applications. Engineers apply different categories and procedures, including, for example, different weather contingency allowances, work provisions, and work contingencies. If estimates are made following good engineering judgment, these differences are not expected to be significant, but other factors may have a role in reliability, such as limited resources and time constraints when performing the estimate, and, of course, good engineering practices may not always be followed and experienced cost estimators may not be available. These factors are unobservable and cannot be controlled for when evaluating FERC data.

Offshore decommissioning work in the US GoM uses a combination of dayrate and turnkey (lump-sum) contracts; dayrate contracts are the most common. Contract terms specify the obligations of each party and the risk of individual projects but such terms and conditions are rarely publicly available. Generalized statements about the cost of a project without reference to contract terms or empirical evidence is problematic and should be avoided. For example, if a project with a significant amount of unknown and/or uncertain work (e.g., hurricane cleanup) is let on a turnkey contract, a price premium would be expected relative to a dayrate contract, unless the market for vessels at the time the contract was let was high, in which case differences would be minor if the contract winner underbid to obtain work. In normal pipeline decommissioning, the impact of contract type on cost differences are expected to be small, but for damaged lines contract terms are expected to be a significant factor.

## 13.5. Cost Evaluation

The average inflation-adjusted cost for pipeline decommissioning between 1995–2015 was $3.1 million and ranged over approximately three orders-of-magnitude, from $30,000 to $21.8 million per project. The primary sample period was from 2000–2015, with most projects clustered after 2008. Standard deviations exceeded the mean values in all cases due in large part to differences in project scope and complexity.

The average inflation-adjusted unit cost was $301,000/mile, or $57/ft ($187,000/km), and ranged from $7000 to $2.1 million per mile, or $1.3 to $398/ft ($4400 to $1.3 million per km). The average cost per mile-cut was $190,000/mile-cut ($118,000/km-cut) and ranged from $2000 to $2.1 million per mile-cut ($1.2 million per km-cut). The average cost per pipeline volume was $47 per cubic foot ($1660/m$^3$) and ranged from $0.4 to $124/cf ($14 to $4400/m$^3$).

The cost distribution by length and by volume is approximately exponential with large tails (Figure M.6). There were no noticeable trends over time (Figure M.7) or by pipeline length (Figure M.8), and only a very weak relationship exists between length and volume normalized cost (Figure M.9).

The inflation-adjusted project cost for hurricane damaged and leaking pipelines was $6.9 million but $1.8 million for non-damaged and non-leaking lines. On a normalized basis, hurricane-damaged and leaking lines was estimated to cost $663,000/mi ($109/ft), $400,000/mile-cut ($248,000/km-cut), and $126/cf ($4450/m$^3$) versus $180,000/mi ($112,000/km), $90,000/mile-cut ($56,000/km-cut), and $34/cf ($1200/m$^3$) for non-damaged and non-leaking lines. Hurricane-damaged and leaking lines were about three to four times more expensive than undamaged and/or non-leaking lines.

## 13.6. Comparison to Complete Removal

If an abandoned pipeline is to be removed from the seabed, several or a combination of methods may be used, including reverse lay barge or reel recovery, tow recovery, or sectional recovery (John Brown Engineers 1997).

Scandpower Risk Management subcontracted Global Industries in 2004 to perform a generic pipeline removal cost estimate for the GoM. Pipelines of various diameters and at least four miles long were considered, assuming operations within 200–500 ft (61–152 m) water depth using a reverse lay method as removal technique. A two-day mobilization radius was applied in the estimation.

Cost estimates range from $81 to $177/ft and were adjusted to 2014 dollars using the BLS price index (Table M.3). The cost does not include transport or processing of the pipe sections (e.g., removing concrete, removing protective coatings, cutting pipe, crushing concrete) in landfills. Relative to the abandon-in-place estimates performed for shallow water FERC pipelines, the cost estimates were two to three times greater and similar to the cost to decommission hurricane-destroyed pipelines. No historic data was reviewed to calibrate or validate the estimates, but the procedures are reasonable for these sorts of hypothetical cases.

## 13.7. Limitations

The final costs of FERC pipeline decommissioning projects are not available and therefore no comparison of the estimated costs with actual cost was possible. Estimated costs are not necessarily a reliable indicator of actual costs and actual costs do not indicate future cost, but we believe the estimated cost described herein are a reasonably good guide for the expected cost of operations.

Differences in project scope and work activity will translate into cost differences, and these are accounted for in the cost estimation, but the ability of the analysis to distinguish granular differences in work activity (e.g., removing meters and risers vs. leaving meters and risers in place), is simply not possible.

All projects occurred in water depths less than 400 ft (120 m), which is considered a homogeneous category for vessels and work activities, and, so, water depth subcategories were not applied. Projects were distinguished by pipeline length, complexity (i.e., damaged, number of cuts required), type and year. Complexity is a multi-dimensional attribute, which would ideally be incorporated as an additional factor or in terms of subcategory analysis, but the sample set was too small for further decomposition and the application of granular analysis on estimated data is also of questionable value and utility.

BOEM pipelines are more diverse than FERC pipelines, but the pipeline decommissioning procedures will be quite similar even if oil pipelines are considered, and so the estimates in this evaluation should apply broadly to BOEM pipelines of similar scope, water depth, and type. Hurricane-damaged and destroyed pipelines exhibited a price premium of three to four times normal costs, which is also consistent with decommissioning other hurricane impacted infrastructure. The decommissioning cost of flowlines and deepwater pipelines were not part of this assessment and extrapolation of the results does not apply to these pipeline classes.

# Part Four. Pipeline Networks, Activity Statistics, and Correlations

# Chapter 14. Platform Hubs and Pipeline Network structure

*Hub platforms are arguably the most important structure class in the Gulf of Mexico (GoM) for economic efficiency and commercial development because they provide transportation services and connection points into pipeline networks to access onshore customers. The GoM pipeline network has evolved over a period of 70 years and structure has emerged due to the confluence of a variety of factors. Pipeline networks organize around critical nodes containing a high concentration of linkages and high volume throughput. Oil and gas systems are segregated with gas pipeline corridors more highly integrated than oil networks. About 22 thousand miles of export pipeline and nine thousand bulk line miles have been installed on the shelf, compared to about six thousand miles of export and bulk lines in deepwater. This chapter concludes by examining the scale-free structure of corporate pipeline systems.*

## 14.1. Hub Classification

There is no standard definition of a hub platform but they are generally recognized as central points for the gathering, redistribution, and transportation of oil and gas (Huff and Heijermans 2003). Three hub types are defined, based on configuration and whether the platform is primarily serving in a field development role, primarily in transportation services, or for both development and transportation functions (Figure N.1).

Three hub classes are identified:

I. Structures that process production from one or more platforms or subsea wells;

II. Structures that serve as a receiving station for processed production and export;

III. Structures that process production from one or more platforms and/or subsea wells and receive processed production for export.

Hub class III is a composite of hub classes I and II because it performs both functions. All hub platforms have one or more pipelines entering and exiting, otherwise they could not serve as a transit point for production. Processed product flows through export lines referred to as oil and gas regardless if it enters or exits a structure, whereas unprocessed (raw) product enters or exits a structure through flowlines (also referred to as bulk lines).

Structures may serve as a central point to gather and process production in field development, or as host to tieback fields or other structures without full processing capacity. Historically, platforms were sometimes referred to as hubs when they acted as a central station to receive and process (raw) production from several drilling platforms in a field (Figure N.2). Today this connotation still applies to facilities that develop multiple fields, as in the Na Kika (Figure N.3) development.

A structure may transition to hub status if it receives production from subsea developments. For example, Bullwinkle was already well past its peak production when it began to accept tiebacks from the deepwater Rocky, Troika, Aspen, and Angus fields (Figure N.4).

Falcon Nest is an example of a shelf platform built to accept deepwater tiebacks (Figure N.5), not a particularly common strategy, but a dozen or more fields have been developed in this manner. Shallow water platforms at West Delta 73 and Main Pass 252 are examples of shelf structures that serve deepwater fields.

A structure may transition to hub status if wet wells are tied back to the platform. Many of the deepwater fixed platforms in >400 ft water depth fall into this category and many floaters remain in service today because of tieback service. If a structure cannot serve as a tieback host, it may instead be used as a destination for export pipelines such as the Ship Shoal 332A platform.

At service and/or junction structures (also called transportation platforms), product pipelines board the structure and compression and/or pumping stations raise the pressure and then reinject the fluid into export systems to enable flow onward to shore. Transportation platforms serve as connecting points for oil and gas (export) pipelines to enter the shelf pipeline network and connect to one or more destinations. Operators often put a premium on having multiple routes to different destinations to increase the netback value of their production, and several of the larger GoM operators have established a robust pipeline network to maximize their options.

## 14.2. Hub Platforms

### 14.2.1. Process and Export Capacity

Hub platforms are described by their oil and gas processing capacity, number of interconnects, and oil and gas export capacity. Processing capacity refers to the equipment used to handle, separate, treat, heat, and cool raw hydrocarbons into pipeline quality oil and gas streams. Service and junction platforms do not have processing capacity and are characterized primarily by their pumping and compression capability, slug catching facilities, metering, and dehydration services. *Slug* refers to large quantities of liquid that arrive at a zone. Volumes processed and shipped are more relevant factors than nameplate capacity but require much more work to evaluate. For non-hub platforms, oil and gas processing equipment capacity is a reasonably good indicator of oil and gas export capacity and pipeline diameter, but for hub platforms export capacity usually greatly exceed processing capacity.

### 14.2.2. First Generation Hubs

Shell’s Bullwinkle, Enchilada, and Auger developments were the first generation of deepwater hub platforms installed in the mid-1990s. The same development formula was applied in each case. After field production began to decline, nearby discoveries (mostly, but not always, from the owners of the platform) out of reach of the platform were tied back and processed. Processing capacity expansion at the host with subsea wells and their attendant costs and risks was considered more economic than installing a new structure and simultaneously extends the operating life of the facility.

Generally speaking, operators are better able to schedule and re-purpose their own platforms than soliciting or commercializing production from third parties because of timing and engineering constraints, negotiation uncertainty, and other issues. The deciding factor for operator-owned facilities and tiebacks are strategic and economic, while for third-party tiebacks economics is usually the deciding factor. Planning, development and negotiation between parties may take a year or longer, and as long as the structure is producing the owner(s) will maintain their bargaining position, but once the structure stops producing the balance of power will shift quickly.

*Example. Enchilada*

The Enchilada development originally consisted of several fields covering five lease blocks: Garden Banks 83/84 (Elmer), Garden Banks 127/128 (Chimichanga/Enchilada), and Garden Banks 172 (Salsa). In 1994, two nearby subsalt discoveries in GB 127 (Chimichanga) and GB 172 (Salsa) by Shell and Amerada Hess formed the basis of a two-platform co-development with Shell as operator (Smith and Pilney 2003). The layout of the facility circa 2000 is shown in Figure N.6 and the layout circa 2005 is shown in Figure N.7.

The Enchilada GB 127A platform was installed in 633 ft of water in December 1996. It is a four-leg, eight-pile structure with 24 slots, 15 allocated for wells, eight for pipelines, and one for an emergency sump. The Salsa GB 172B platform was installed in 695 ft water depth in November 1997, also a four-leg, eight-pile structure with 20 slots (15 for wells, four for pipelines, one emergency sump). Salsa production is sent to Enchilada and the Salsa B platform was designed only for primary separation and testing of the Salsa wells. Processing facilities at Enchilada were designed to handle 40 Mbopd of high sulfur oil, 20 Mbopd of low sulfur oil, and 40 MMcfpd of gas. Export pipeline capacities meanwhile were in the range of 250 Mbopd and 1000 MMcfpd gas.

In 1997, as part of capacity expansion at Shell's Auger TLP, a gas pipeline, a gas compressor, and an oil pipeline booster pump station were added on Enchilada. Auger production is not processed on Enchilada, but accepts gas where it is measured and reinjected into the 30-inch gas export pipeline, and accepts oil where it goes through a booster pump station and re-injected down the 20-inch sour oil export line.

In 2000, the Conger 3-well subsea development in GB 215 was flowed back to the Salsa platform. To incorporate Conger fluids into the Enchilada complex, major topsides modifications were required at the Salsa and Enchilada platforms. At Salsa, the facility needed to be occupied, and new quartering and power systems were required. Methanol and chemical storage and injection systems, along with separation and testing equipment, pigging and blowdown equipment was also added. Expansion at Enchilada included slug catchers on both boarding pipelines from Salsa, additional treating capacity and compression. The Sangria 1-well subsea development in GC 177 was tied back to the Salsa platform and required the addition of subsea controls systems, chemical storage and injection systems, and additional process heat and heat exchangers.

In 2002, gas-lift was provided to the Cinnamon development in GC 89 to help further oil recovery. The expansion involved reversing the direction of an existing pipeline between GC 89 and GB 128 and performing topsides revisions. Cinnamon production ceased to be economic shortly thereafter and in 2009 the platform was decommissioned

In 2004, a 16-inch gas and a 14-inch oil sales pipeline from Conoco's Magnolia prospect in GB 783 were routed through the Enchilada platform, and another subsea well at Conger was tied back to Salsa. A helicopter re-fueling station on the Salsa platform was upgraded to service mid-size to large helicopters.

Circa September 2017, the Garden Banks 83 field, which includes the Elmer, Enchilada, and Chimichanga fields in GB 83, 84, 127, and 128, produced 7.8 MMbbl oil and 136 Bcf gas (Figure N.8), with current production levels less than 100,000 bbl oil and 200 MMcf gas. The Garden Banks 171 field (Salsa) in GB 172 and 215 has produced 144 MMbbl oil and 573 Bcf gas through September 2017 (Figure N.9).

### 14.2.3. Second Generation Hubs

Second generation and later hubs were built with wider flexibility and equipment sizes, tied back to a greater number of subsea wells, and were designed with excess transportation capacity in addition to production processing. A greater variety of third-party operators also became interested in hub business models in the mid-2000 time period. Two examples illustrate the class.

*Example. Falcon Corridor*

The Falcon gas field was discovered in April 2001 on East Breaks blocks 579 and 623 in 3450 ft water depth. A two subsea well tieback to a new host platform 33 miles away in Mustang Island A-103 in 389 ft water depth was the development solution selected. A strategic decision was made to focus on prospects within 15 miles of the manifold so that the development of any new discovery could be expedited (Hall et al. 2004). Shortly before first production at Falcon, the Harrier discovery was made, and then two additional discoveries (Tomahawk and Raptor) occurred during the Harrier development (Figure N.10).

The Harrier completion in EB 758 in 4114 ft water depth required a new flowline to be installed from the manifold to the shelf platform, and for the nearby discoveries Tomahawk at EB 624 (1.5 mi away) and Raptor at EB 668 (5.5 mi away), it was decided to remove the pigging loop to allow two new well tie-ins to the manifold. The Falcon wells were brought online two years after discovery; Harrier, Raptor and Tomahawk were tied-in about one year after discovery (Figure N.11).

*Example*. *GB 72 platform* (*Spectacular Bid*)

The GB 72 platform (aka Spectacular Bid) is located in Garden Banks block 72 in the Western GoM in 514 ft water depth (Figure N.12). The platform was designed and installed by a midstream company to use for off-lease processing and as a junction platform for its pipeline systems (Heijermans and Cozby 2003). The platform originally processed production from the GB 72 and VR 408 field and four off-lease fields and also served as the anchor portal for the deepwater Stingray gas pipeline and Poseidon oil pipeline systems. The Cameron Highway Oil Pipeline System (CHOPS) designed for the movement of the Atlantis, Mad Dog, and Holstein crude from the southern Green Canyon area also cross this platform to markets in Port Arthur and Texas City, Texas.

### 14.2.4. Transportation Hubs

Strictly speaking, transportation platforms do not have processing capacity available unless the structure previously served in a field development role and the equipment is still operable. The fluids boarding service and/or junction platforms have already been processed to pipeline specification and only need to be pumped or compressed to reach their destination. Ancillary services offered at the facility normally include metering, liquids removal, pig catcher, heating, and cooling. Dehydration facilities and slug catchers are often needed for gas transport. If the service and/or junction structure handles multiple deliveries and departures for different operators, it will likely have several export lines leaving the platform and its connectivity will be high.

*Example*. *SS 332A&B platforms*

The SS 332A platform was installed in Ship Shoal block 332 in 438 ft water depth to develop a gas field (Figure N.13). El Paso Energy Partners (EPN) acquired the structure from Arco in the early 1990s after production ceased to support the Leviathan Offshore Gathering System, the predecessor of the Manta Ray Gathering System (Figure N.14). EPN was required by the FTC to sell the platform to a new company, Atlantis Offshore LLC, a joint venture between EPN and Manta Ray Offshore Gathering Company LLC, itself a joint venture company owned by Shell Gas Transmission LLC, Marathon Oil Company, and Enterprise Oil Products LP.

In 1995, EPN constructed the Poseidon oil pipeline and in 1999 the Allegheny oil pipeline, which used the SS 332A platform. A new platform (SS 332B) was constructed adjacent to SS 332A to serve as transport hub for CHOPS and the interconnection between the Caesar oil pipeline and Cameron Highway.

## 14.3. Gulf of Mexico Pipeline Evolution

Oil and gas export pipeline installation activity per decade is depicted in Figures N.15(a-g), and in Figures N.16(a-d) the active oil and gas pipeline network is shown for the year ending 1969, 1989, 2009, and 2018. Flowlines (bulk oil and bulk gas) and umbilicals are not depicted for simplicity. In Table N.1 and Table N.2 the total mileage of bulk and export lines is tabulated by decade. About 22 thousand miles of export oil and gas pipeline and nine thousand miles of bulk line has been installed on the shelf in less than 400 ft water depth, compared to about six thousand miles of export and bulk lines in deepwater.

In the 1950s, it was common to barge liquids to shore or use a two-phase export pipeline from a central processing facility to onshore treatment facilities. As larger fields were discovered further from shore, single phase oil and gas pipelines became the preferred mode of transport to reduce operating cost and improve efficiencies. Pipeline systems developed in a stepwise fashion, moving south off the shelf into deeper water and tying into existing infrastructure when capacity was available, and building out new networks when capacity was not available or where, for strategic reasons, companies decided to build dedicated pipelines.

All pipeline installation up through the end of the 1970s was on the shelf in <400 ft water depth and followed straightline paths to their destinations. On the shelf, straight paths are common because the seafloor topology is flat with few obstacles and the gradient is small. Federal regulations require pipeline greater than 8 and 5/8 inches (22 cm) and installed in water depth less than 200 ft (61 m) to be buried at least three feet below the mudline. Some of the early lines represent the spines to which laterals were later attached.

In the 1950s and 1960s, gas pipelines direct to gas plants and refineries dominated with few interconnects between systems. In the 1970s, pipeline segments grew longer with a larger number of interconnects forming at hub platforms and more east-to-west lateral connections were established.

In the 1980s, the character of installation activity changed as many small laterals connected into existing networks and the first deepwater pipelines began to cross the continental slope. The random orientations of the laterals to their connecting trunkline is also a visually distinctive feature. Several deepwater systems were direct to shore for strategic reasons, especially oil trunklines. In the 1990s, pipelines originating from Green Canyon and Mississippi Canyon came ashore, and, as operators developed fields in deeper water, pipeline networks followed. Over the past two decades, connections to existing infrastructure have dominated and activity levels on the shelf have dropped. In recent years, pipeline systems have approached the international boundary with Mexico.

## 14.4. Oil and Gas Pipeline Systems

### 14.4.1. Oil Pipeline Corridors

A sample of the main oil pipeline corridors in the GoM are shown in four cartoons in Figures N.17–N.20. Pipeline schematics do not represent primary data and considerably simplify the pipeline system but are sufficiently descriptive to depict key network components.

In Figure N.17, the regional pipelines that transport most of the deepwater crude oil in the GoM is depicted along with several hub platforms. System maps from Poseidon Oil Company (Figure N.18), Shell Midstream Partners (Figure N.19) and El Paso (Figure N.20) depict corporate networks and service and/or junction platforms supporting the regional systems.

Poseidon Oil Company is currently owned 64% by Genesis Energy LP and 36% by Shell Midstream Partners (SMP). Genesis Energy maintains 19 transportation platforms in its GoM pipeline network circa 2017, four multi-purpose platforms used as hubs and production handling and pipeline maintenance facilities, and 14 service and junction platforms. Genesis Energy hub platforms include EC 373, GB 72, Independence Hub, and Marco Polo. Junction and service platforms include HI A5 (CHOPS), HI 264A, HI 264B, HI 264C, HI 330 (HIOS), HI 343 (HIOS), HI 573 (HIOS), HI 582 (HIOS), SS 207, SS 332A, SS 332B (CHOPS), SMI 205 (Poseidon), ST 292, WC 167 (HIOS), and WD 68 (Independence Trail).

Shell Midstream Partners maintains eight transportation platforms at SMI 205A, GC 19 (Boxer), SS 241, Caillou Island, WD 143, SS 30, SP 89E, MP 69. Most of the transportation platforms were the sites of formerly producing fields.

*Example*. *Poseidon and Cameron Highway Oil Pipeline System*

> Poseidon and the Cameron Highway Oil Pipeline System (CHOPS) run parallel to each other along the edge of the shelf but transport crude in different directions and to different markets. Poseidon moves crude from east-to-west and then northward to Louisiana markets, while CHOPS runs in the opposite direction from west-to-east delivering crude to Texas markets.
>
> Poseidon delivers to three locations at Houma, Louisiana, via Poseidon’s 24-inch line from Ship Shoal 332A; at St. James, Louisiana, via SMP’s 18-inch line from Houma, Louisiana; and for certain barrels at SS 332A, Poseidon can deliver oil into SMP’s Auger pipeline via South Marsh Island 205A, in addition to receiving oil from Auger in a bi-directional line.
>
> CHOPS is owned by Genesis Energy LP and was completed in 2003 after a new platform at SS 332B was installed and a 30-inch pipeline connection to GB 72 was finished. The system originates at the SS 332B hub and passes through GB 72 and extends into two 24-inch pipelines at the High Island A5-C platform. One 24-inch leg terminates in Texas City, Texas, and the second terminates in Port Arthur, Texas.

### 14.4.2. Gas Pipeline Corridors

Two deepwater gas pipeline systems, the Walker Ridge Gathering System (WRGS) and Keathley Canyon Connector, serve as examples of gas pipeline networks.

*Walker Ridge Gathering System*

> Enbridge owns and operates the WRGS that provides natural gas gathering services to Chevron's Jack and St Malo fields and Shell's Stones FPSO developments. Big Foot will be tied-in when development is complete. WRGS consists of 190 miles of 8/10/12-inch pipeline at depths of up to 7000 ft with a capacity of 100 MMcf/d. At an estimated cost of $500 million, all-in construction cost was $2.6 million per mile. WRGS delivers gas to the Manta Ray and Nautilus gas pipeline systems via the Ship Shoal 332 platform interconnect. Manta Ray goes ashore at Burns Point, Louisiana, and serves the Eugene Island, Ship Shoal, South Timbalier, Ewing Bank, and Green Canyon areas (Figure N.21). Nautilus is a FERC pipeline.

*Keathley Canyon Connector*

> The Keathley Canyon Connector is a 20-inch, 209 mile gas pipeline originating in the southeast portion of the Keathley Canyon area to serve the Lucius and Hadrian South developments and terminates into Discovery's 30-inch diameter mainline near South Timbalier block 283 (Figure N.22). The capacity of the line is more than 400 MMcf/d and the construction cost was estimated at $2.8 million per mile. Williams and DCP Midstream own and operate the system.

## 14.5. Pipeline Networks

### 14.5.1. Description

Offshore oil and gas infrastructure is described as a *network*, defined as a collection of nodes and links in a mathematical graph. *Nodes* represent supply sources and sinks and include wells, structures, manifolds and (onshore) destinations such as compressor and/or pumping stations, refineries, gas plants, and storage facilities. Links represent the pipelines and flowlines that gather and transport processed and unprocessed production. To simplify discussion, only oil and gas (export) pipeline between nodes are considered; unprocessed oil and gas are transported on flowlines (bulk lines) but are usually not considered in pipeline network studies because they are specific to field development.

A network *path* is a sequence of links and nodes leading from one node to another node, and the length of a path represents the physical distance along the path. Each segment of pipeline is defined by its physical characteristics, operator, regulatory agency, and if applicable, tariff rate.

The *degree* of a node is the number of links connected to the node. A node with a degree of three means there are three links connecting the node to the rest of the network. Most processing platforms have a degree at least two because there is usually at least one oil export and one gas export departing lines. Simple platforms, such as caissons, will have degree zero since they transport raw product to a host platform for processing and flowlines are not considered pipeline. Hub platforms may have a dozen or more links. A count of the number of import and export risers at a structure determines its degree.

### 14.5.2. Random and Structured Networks

The GoM pipeline network is not random but has structure due to the nature of its evolution. This structure emerged and was determined by a variety of factors, including the location and type of hydrocarbon deposits, the type and number of owners, the location, capacity, and ownership of pipeline networks and onshore facilities at the time of development, technology changes, regulatory conditions, and economic criteria. The construction of the system, long north-to-south links supporting one or more large fields direct to shore or to a hub platform created the network backbones (trunklines), followed by lateral links and more east-west connections. There is a large number of nodes with one or two links and a small number of high-degree nodes, or nodes with more than an average number of links.

### 14.5.3. Scale-Free Networks

The idea of a *scale-free* network does not refer to the physical size of the network but rather the manner in which pipeline networks are structured and connect. At any time, as new structures are installed in a given region, new laterals will connect to the existing network or a trunkline will be installed to shore or another platform and the pipeline network will expand with additional branches and links. As structures are installed, one oil export pipeline will usually be linked to an existing node and one gas export pipeline will be linked to the same or a different node, increasing node counts and node degrees by one at every connection point.

Pipeline networks build out in a way that is broadly reflective of the network configuration at the time of its connection. The number of low-link nodes will increase at a faster pace than high-link nodes and the most useful high-link nodes will increase their connectivity. More formally, Barabasi (2003) defines a network as scale-free when the number of links at each node is distributed according to a power law. If the probability of a node having $k$ links is proportional to $1/k$ raised to a power greater than one, then the network is considered scale-free. Normally, the power term varies between one and three (Lewis 2005), and to improve model fits the proportional factor can be taken as $1/(k+a)^p$ for parameter $a$ user-defined. If the rate of decline approximates the curve $(1/k)^p$ or $1/(k+a)^p$ for $p > 1$ the network is considered scale-free.

*Example. Corporate pipeline network scale-free determination*

A portion of Shell's oil pipeline network in the Central GoM is shown in Figure N.23. The network depicted consists of 16 nodes, excluding LOOP and Port Fourchon. The most common nodes have one link and there are 11 such nodes, hence the proportion of one-link nodes in the network is 11/16 = 69%. Platform SS 301 has six links (6%) and there is one 5-link node (13%), one 4-link node (6%), and two 2-link nodes (13%). The power law $1/(k+a)^p$ was fit to the histogram and the sum of the square error (SSE) was minimized for four values of $a$ (Table N.3). All the power law models yield $p > 1$ and the best power law model (minimum SSE) yields $a = 0.5$ and $p = 1.7$. Thus, the pipeline network in Figure N.23 is scale-free.

*Example. Scale-free determination expanded system*

Now, consider the more complete representation of Shell's oil network in Figure N.19. There are 18 one-link nodes representing 64% (18/28) of the links, three two-link nodes and three four-link nodes (each 3/28 = 11%), and four three-link nodes (4/28 = 14%). The proportions of the pipeline degree nodes are roughly the same as Shell's smaller network and would therefore be expected to yield network parameters broadly similar. In this case, the best power law model (minimum SSE) was for $a = 0.5$ and $p = 1.6$ (Table N.3). The variation in the model value of $p$ was about 5% from the previous simpler schematic.

As Shell's pipeline network representation expanded in size and complexity, the value of $p$ remained relatively stable, and this notion can be generalized by considering larger and more connected networks, until ultimately the entire GoM network is evaluated. The argument is that the scale-free parameter for the GoM network should be approximately the same as derived in the example (the exercise is left to the reader).

### 14.5.4 Segmented Networks

If no path exists between one part of the network and another part, the network is divided or segmented into components. In the GoM, oil and gas pipelines are segmented networks, and pipelines that originate in shallow water and deepwater show varying levels of integration. Gas networks are more integrated and have relied on historic trunklines for many years. Deepwater oil is more segregated, with dedicated lines direct to shore. As flows within trunklines decline, their ability to handle new fields increases and is pursued by transportation companies. Connections permit delivery to the western, central and eastern GoM pipeline systems.

### 14.5.5 Directional Flows

A directed graph is a graph containing links with a direction. In terms of pipelines, this means that a directed link from node A to node B allows flow from A to B but not in the reserve direction from B to A. Most pipelines in the GoM flow north from the source of supply and then northeast or northwest to Gulf Coast refineries, gas plants, and storage facilities from Texas to Mississippi. The more options operators have to transport their hydrocarbons, the better prices they can negotiate. A few pipelines in the deepwater GoM such as Poseidon are bi-directional and allow volume flow in either direction (although not at the same time).

# Chapter 15. US Gulf of Mexico Pipeline Activity Statistics

*Petroleum activities in the Gulf of Mexico (GoM) started on the continental shelf in the early 1940s and have gradually moved south, reaching both the 400 and 1000 ft thresholds in 1978. In 2018 the deepest structure was moored in 9560 ft water depth. Circa 2017, about 45 thousand miles (72,500 km) has been installed in the region, enough to circle the Earth at the equator almost twice and representing more installed pipeline than any other region worldwide. In this chapter, pipeline installation and decommissioning activity in the US GoM is described along with active and out-of-service inventory trends. Pipelines are grouped into six production, four status, and two water depth categories for evaluation. Aggregate statistics and trends for oil, gas, bulk oil, bulk gas, service, and umbilical pipelines for installation and decommissioning are presented.*

## 15.1. Source Data

### 15.1.1. Pipeline Attributes

Pipelines in federal waters are described in terms of pipeline segment number. Individual segment numbers are associated with a numbering system established by BOEM and its predecessor organization, the Minerals Management Service (MMS). Offshore pipelines are composed of segments and are described by length, diameter, thickness, maximum allowable operating pressure, service type, installation date, endpoint type, and other attributes. The endpoint of a pipeline may be connected to surface equipment, a subsea well or manifold, a riser at a host platform, a subsea tie-in at an existing tap valve assembly, or a Pipeline End Termination skid or Pipeline End Manifold.

### 15.1.2. Production Group

BOEM identifies 39 production codes for OCS pipelines (Table O.1). The production code identifies the pipeline segments by fluid (oil, gas, condensate), impurities (water, hydrogen sulfide), location relative to destination (before and after first processing), and function (e.g., service, gas lift, corrosion inhibitor, supply gas). Umbilicals are identified according to four classes (pneumatic, electro/hydraulic, chemical, electrical). Several categories are used to identify pipelines that are used to support or service operations by product or function (e.g., acid, gas injection, gas lift, methanol, natural gas liquids). Some categories are no longer used (e.g., liquefied sulfur) or not currently populated (e.g., renewable energy power cable). One category does not refer to a physical asset (tow route).

The 39 production codes are categorized into six product groups to consolidate the number of pipeline types and simplify designations (Table O.2). Oil and gas pipelines are grouped into four categories based on fluid type and location relative to first processing: bulk gas (BG), bulk oil (BO), gas (G), and oil (O). Bulk lines or flowlines refers to pipelines before first processing. Export or trunk lines refer to pipelines after first processing. Condensate pipelines are grouped with the oil category because it is a liquid hydrocarbon even though condensate is not considered crude oil. Umbilicals (U) refer to the control and chemical lines associated with subsea completions. All other pipeline production codes are labeled as service (S).

### 15.1.3. Water Depth Categorization

Water depth is assigned according to the maximum water depth of the pipeline segment which normally, but not always, coincides with its start (source) point. Three water depth categories were employed to group activity data: <400 ft, 400–1000 ft, and >1000 ft. Water depth <400 ft is referred to as shallow water and >400 ft is referred to as deepwater, although the cut-off is somewhat arbitrary and 600 or 1000 ft thresholds could also be used. The 400–1000 ft water depth category represents a transition zone between shallow and deepwater, and, despite its large areal extent, the region is relatively barren in terms of oil and gas developments.

### 15.1.4. Status Group

BOEM identifies 15 pipeline status codes with a time stamp (Table O.3). The primary codes include abandoned, active, cancelled, combined, out of service, proposed, relinquished, and removed. Eight two-code categories are also used; e.g., relinquished and abandoned. The status of a pipeline segment changes over time as it transitions between different states during its lifetime (Figure O.1).

For this analysis, five status group categories were created to reduce the number of status codes (Table O.4). *Active lines* are defined by the active (ACT) status code. *Idle lines* include out and combined (O/C) and out of service (OUT). *Abandoned lines* include abandoned and combined (A/C), abandoned (ABN), and relinquished and abandoned (R/A). *Removed lines* include relinquished and removed (R/R) and removed (REM) and are a special class of abandoned pipeline because they are physically removed from the seabed. *Decommissioned lines* refer to abandonment or removal. Proposed activity describes possible future installation or abandonment.

Active lines are used in operations; out-of-service lines are inactive (idle) and not being used for operations but have not been abandoned or removed. Proposed pipelines are under construction or before commissioning (hydrostatic testing). Abandonment or removal is the final status of all pipelines, as shown by the terminal states in Figure O.1. Out-of-service pipelines have specific requirements to garner their designation; a time clock (five-year countdown) governs the maximum length of time before an out-of-service pipeline transitions into abandoned status or returns to service, unless exemptions are granted.

Abandoned lines are no longer used for operations and have been decommissioned according to regulatory guidelines. To date, pipelines are usually abandoned-in-place if they do not constitute a hazard to navigation and commercial fishing or unduly interfere with other uses of the OCS, but in 2017 removals have been required in shallow water regions with significant sediment resources (Celata 2016). Removals are a special case of abandonment in which the pipeline is physically removed from the seabed. Proposed abandonments and removals provide an indicator of the near-term likely future status of a line. Relinquished lines lose their operating privilege because of permit expiration, termination, or similar event. Cancelled lines may have received a permit or submitted design plans but were never built; cancelled lines do not physically exist.

### 15.1.5. Data Limitations

Not all pipeline attribute data are fully populated in BOEM databases. The installation date of pipelines was assigned using construction date, if available, and hydrostatic pressure test date and approval date if not available. Installation data for the primary product groups (BG, BO, G, O) in all water depths is well populated and only a small percent of pipeline segments could not be assigned to an individual year. For the umbilical and services product groups, however, the majority of data does not have installation data available, which precludes time trends and correlations for these groups to be examined.

Another feature of BOEM pipeline data regards the dynamic nature of the databases and the application of time stamps because the status of pipelines changes but only the latest status category is reported. Hence, unless the database has been regularly archived over a long period of time, some information can no longer be accessed. For example, it is not possible to break-out active and idle pipelines inventories in the past because this information is not available as status updates are performed.

## 15.2. Aggregate Statistics

### 15.2.1. Cumulative Installed

Circa 2016, between 36,745 and 45,310 miles of pipeline has been installed in the GoM, about 60% in water depth <400 ft, 8% in water depth from 400–1000 ft, and 32% in water depth >1000 ft (Table O.5). Installation data is not available for 8564 miles. In terms of diameter, about 63% of installed pipeline is

<12 inch, 20% is between 12-24 inches, and about 5% is greater than 24-inch. Totals do not sum to 100% because not all pipeline data with diameters are reported.

Pipeline mileage with no installation date available is depicted in Table O.6 by product group. This data is provided for completeness and to illustrate potential pitfalls and uncertainties in evaluation. Export pipelines have the lowest occurrence of missing data, at around 5% of total installed mileage, followed by bulk oil and gas lines at about 10%. The majority of service lines (56%) and almost all umbilicals (96%) are in deepwater and significant installation date deficiencies exist. Most of the reported data has been installed, but, for various reasons, a time has not been assigned to a segment. It would be possible to populate and validate the missing data but it is a tedious and time-consuming exercise and was not performed. All tables and discussion in this section assume all pipelines reported were installed.

By product group, gas is the largest category of installed pipeline at 16,778 miles followed by bulk gas (8332 mi), oil (7586 mi), service (4751 mi), bulk oil (4091 mi) and umbilicals (3770 mi). In shallow water, gas is the largest pipeline group, followed by bulk gas, oil and bulk oil. In deepwater, gas and oil export, followed by bulk oil and bulk gas, are all of similar magnitudes. Umbilicals and service lines are the two largest pipeline categories in deepwater and the smallest categories in shallow water.

Most early developments in the GoM required point-to-point (e.g., platform to shore) export connections, and because shallow water is primarily a gas province, most early pipelines were two-phase gas lines. Smaller gas fields utilized bulk lines after additional structures in the region were installed. The large amount of gas and bulk gas lines are due to the large number of gas fields in shallow water. Installed gas to oil export line mileage is about 3:1 in shallow water with gas to bulk gas and oil to bulk oil mileage about 2:1.

The deepwater GoM, on the other hand, is primarily an oil region. Oil developments require both oil and gas export lines because gas is a byproduct of oil processing and is prohibited from being flared except in emergencies and process upsets. After on-site gas use is satisfied for utilities, the excess gas can be reinjected into the reservoir to be produced at a later date, but these are expensive options with higher cost and smaller revenue streams. Gas injection has found some use to support oil production but the practice is not common. On the other hand, gas lift, where gas is injected directly into wellbores to support oil production and in risers to facilitate flow, is a common practice. In the GoM, designs evolved to install facilities to process and transport both oil and gas streams independently.

Because the pipeline shelf network in which oil and gas export lines connect were built out to approximately the same extent at the start of deepwater development in the mid-1990s, deepwater oil and gas export lines generally need to traverse similar distances (on average) to make a connection. Thus, deepwater oil and gas export mileage from >1000 ft water depth is expected to be approximately equal and this is observed (2183 miles and 2384 miles), with gas export slightly larger than oil export. The similarity in oil and gas export mileage is not coincidental but rather indicates the “oily” nature of field development in the region which requires gas export pipeline to be installed for every development.

Gas export mileage in deepwater is expected to be greater than oil export mileage because gas lines are needed for all developments, and some reservoirs (dry gas, gas-condensate) only require gas export and some development concepts (FPSO) do not require any oil export mileage. Because there has only been one dry gas deepwater structure development (Independence Hub) and only two FPSOs installed to date (Cascade & Chinook, Stones), the export mileage differences between oil and gas are relatively small.

Only a few wet wells in shallow water have been installed because they provide limited advantages over simple structures and were constructed mostly to test and refine the technology in the 1960s and 1970s (Keprta 1976). Shallow water umbilical mileage is therefore miniscule (293 miles), whereas deepwater umbilicals are the largest mileage category (2964 miles). There are significant gas lift, chemical, water, and other service lines used throughout the shallow water region, with total mileage on-the-order of the bulk oil mileage (1802 miles). In deepwater, service lines comprise the second largest mileage category (2521 miles).

Bulk lines in deepwater are nearly as prolific as export mileage due to the large number of wet wells used in development. In deepwater, the gas to bulk gas mileage ratio and the oil to bulk oil mileage ratio is about 1:1 indicating the importance of both export and bulk lines in development. Gas wells can be tied-back a greater distance than oil wells because gas flows easier and is subject to less constraining flow assurance issues relative to oil. Bulk oil flowline architectures typically require dual (two) lines unless they are buried, heated, or of pipe-in-pipe variety, and gas flowlines are often single, so the relationships are complex.

The product pipeline groups in the 400–1000 ft water depth category have characteristics similar to the shelf and deepwater region. Gas and oil line mileage have the same relative magnitude as in deepwater with gas dominating oil, but bulk lines are relatively small in comparison because dry tree wells are prevalent and there are only a limited number of tiebacks. Simple structures cannot be installed in water depth >400 ft. There are subsea tiebacks in the region and relative to oil and gas export mileage, the ratio of export to umbilical mileage is about 8:1, compared to 60:1 in <400 ft and 1.5 in >1000 ft.

### 15.2.2. Cumulative Decommissioned

A total of 19,236 miles of pipelines in the GoM was reported decommissioned through 2016 (Table O.7). A total of 3033 miles did not report the time of decommissioning (Table O.8). Gas and bulk gas have about 10% missing decommissioning time data, and oil and bulk oil decommissioning dates are not reported for about 20% total mileage. Service and umbilical lines do not report data for around 40% of mileage data. Most pipelines without a decommissioning date reported are believed to have been decommissioned and all tables and discussion in this section assume all pipelines reported as decommissioned have been decommissioned.

In-situ abandonment is widespread and only 486 miles of pipeline in the GoM has been removed from the seabed, or about 3% of total decommissioned mileage. The majority of decommissioned pipeline originate in water depth <400 ft (78%), 6% in water depth from 400-1000 ft, and 13% in water depth >1000 ft (Table O.9). A greater percentage of decommissioning activity is concentrated in shallow water because that is where the vast majority of aging and out- of-service pipeline is located. In shallow water, slightly higher removal rates are observed. About 1% of decommissioned umbilicals were removed.

After small structures and subsea wells stop producing or are no longer useful, the bulk lines associated with the structures and wells no longer serve a useful purpose unless the operator intends to drill more wells at site. If pipelines are not used for an extended period of time, waiting for repairs or an operator's decision on drilling, for example, the pipeline will be classified as out-of-service. Out-of-service pipeline may return to active status or transition to abandonment.

In general, a larger percentage of bulk lines will be decommissioned relative to export lines because export lines originate at platforms and can continue to serve fields farther afield even after its own wells stop producing because the export lines interconnect via the pipeline network. For example, although Independence Hub has currently stopped production, the Who Dat field routes its export gas through the Independence Trail export system. Circa 2017, about 71% of bulk gas lines installed and 38% of bulk oil lines have been decommissioned, compared to about 41% of installed gas lines and 22% of installed oil lines. The lower percentages of decommissioned export lines are due in large part to their integration in pipeline networks.

Bulk lines, on the one hand, have limited use after wells stop producing because they are small diameter and designed for a specific field. The constraints related to the field location, fluid quality, flow rates, and product type are significant and bulk line reuse is rare. On the other hand, export lines are potentially useful for reuse because they originate from a structure and connect to the pipeline network through large diameter lines and also, because they transport processed production, corrosion is less likely if regular maintenance and pigging operations are performed. Export lines are also rarely reused when out-of-service for several years. The only example of export pipeline re-use was in the Lucius development where Anadarko converted 46 miles (76 km) of an out-of-service gas export line for oil export (Schronk et al. 2015).

### 15.2.3. Active

A total of 21,872 miles of pipeline were active circa 2016 (Table O.10). Gas export and oil export are the largest pipeline categories comprising about two-thirds of all active pipelines (14,174 miles), followed by bulk lines (15%), service (12%), and umbilicals (8%). Active pipeline in shallow and deep water have nearly the same mileage, 9906 miles (<400 ft) compared to 9462 miles (>1000 ft). Active pipelines in 400–1000 ft water depth comprise 2281 miles circa 2016.

Active bulk gas and bulk oil line mileage as a percent of installed mileage are lowest in <400 ft water depth at 11% and 34%, respectively, where most decommissioning has occurred, increasing to 30% and 70%, respectively, in water depth greater than 1000 ft (Table O.11). About 42% of gas lines and 63% of oil lines in <400 ft water depth are active and both values approach 90% in water depth greater than 1000 ft. In total, 37% of all pipelines installed in <400 ft water depth was active circa 2016 compared to 69% of all pipelines in water depth >1000 ft.

Active pipeline circa 2016 by decade of installation provides a snapshot of the age of the current networks (Table O.12). About one-third of the active shallow water pipeline was installed after 2000, compared to nearly 80% of deepwater pipeline. About half of shallow water pipelines are 25 years or older compared to less than 5% of deepwater pipelines. About 10% of shallow water pipeline is older than 50 years and continues to serve the giant oil and gas discoveries of the 1940s and 1950s, such as West Delta 30, Tiger Shoal, Bay Marchand, Main Pass 41, and Vermillion 14.

### 15.2.4. Out-of-Service

Active pipeline inventories at any point in time represent the difference between cumulative installed and cumulative decommissioned mileage reduced by the amount of out-of-service lines. Circa 2016, there was 45,310 miles of pipeline installed and 19,236 miles decommissioned, with the difference of 26,075 miles representing both active and out-of-service lines. With 21,872 miles of active pipeline circa 2016, the remaining 4203 miles were out-of-service. Out-of-service line is a temporary stage and pipeline that enters this classification may transition back into active status or enter decommissioned status in the future.

## 15.3. Trends

### 15.3.1. Installed

The shallow water GoM is gas prone and many early discoveries used two-phase export pipeline, but, as discoveries were made in deeper water and more oil fields were developed, single-phase oil and gas pipeline became the preferred transportation option (Figure O.2). In the mid-1980s bulk lines began to be installed as an increasing number of caissons and well protectors tied into existing infrastructure. In the recent decade, the amount of new bulk and export mileage in shallow water has been reduced, as observed through the flattening of the cumulative curves.

Over the past decade, cumulative installed mileage in shallow water of export and bulk lines increased by 2171 miles or about 220 miles per year (Table O.13). Gas and bulk gas were responsible for about two-thirds of the increase, contributing 83 mi/yr and 62 mi/yr on average, followed by oil and bulk oil at 45 mi/yr and 28 mi/yr, respectively.

In 1978, the first structures in water depth >400 ft were installed (Bourbon in 441 ft and Cognac at 1021 ft) and in the early 1990s installation of the first floater developments in >1000 ft water depth began. The deepwater GoM is an oil-prone province and (most) fields require both oil and gas export lines in development (Figure O.3). Oil and gas export lines from a given structure usually travel different routes to reach their destination and so cumulative installation curves are not expected to match precisely, but their degree of correspondence is certainly striking and not coincidental. All deepwater field developments in the GoM that require a stand-alone structure (except one, Independence Hub) are primarily oil developments. Circa 2016, a total of 120 fixed, compliant, and floating deepwater structures have been installed in water depth >400 ft, with 50 active in water depth >1000 ft circa 2017. About half of deepwater structures host subsea developments.

In deepwater, cumulative installed mileage increased from 7521 miles in 2007 to 10,718 miles in 2016, a difference of 3197 miles or about 320 miles per year (Table O.14). Gas and bulk oil contributed about two-thirds of the increase, 107 mi/yr and 104 mi/yr, followed by oil and bulk gas at 62 mi/yr and 47 mi/yr. In shallow water <400 ft, total installed export and bulk lines were about two times greater than in water depth >400 ft (Figure O.4).

### 15.3.2. Decommissioned

Shallow water structures first began to be decommissioned in the early 1970s, and deepwater decommissioning started in the 1990s. The amount of activity in each region are significantly different, with 100–200 shallow water removals per year common, but, at most, a handful of deepwater structures are decommissioned each year. In both shallow and deepwater, gas and bulk gas lines dominate activity, gas and bulk gas in shallow water and bulk gas in deepwater (Figures O.5 and O.6), which makes sense because gas exports in shallow water are usually decommissioned with the structure but bulk lines in deepwater are decommissioned with subsea producers.

In shallow water, gas and bulk gas cumulative decommissioning total 6011 miles and 4246 miles circa 2016, followed by 1081 miles and 896 miles for oil and bulk oil, respectively. In deepwater, decommissioning activity is much lower, with bulk gas and gas dominating (968 miles and 348 miles), followed by bulk oil and oil (347 miles and 215 miles). The number of structures decommissioned in shallow water is more than two orders-of-magnitude greater than deepwater (~5000 shallow water structures compared to 21 deepwater structures circa 2016), and the decommissioned mileage reflect these differences.

Total oil and gas export and bulk line decommissioning is depicted in Figure O.7. In recent years, the pace of shallow water pipeline decommissioning activity has declined, which is counterintuitive because record numbers of shallow water structures have been decommissioned. Part of the explanation for the lower levels of activity lies in the five-year time window during which pipelines may transition from out-of-service into decommissioned status, and key shelf corridors will remain active as long as deepwater pipelines continue to push their fluids through. Most deepwater gas and some oil production connect into pipeline which serves shelf production and requires an active coastal network to handle.

### 15.3.3. Active and Out-of-Service

Active and out-of-service pipeline inventories are depicted in Figures O.8– O.10 for the shallow and deepwater categories and the entire region. Active and out-of-service pipeline represent the difference between the cumulative installed and cumulative decommissioning trends and are combined in the graphics. Circa 2016, there were 9906 miles of active bulk and export pipeline in <400 ft water depth and 9462 miles of active bulk and export pipeline in >400 ft water depth. In shallow water, active inventories fall below decommissioned mileage and the gap is likely to widen in the years ahead. In deepwater, active mileage tracks installed pipeline indicating high levels of use.

# Chapter 16. US Gulf of Mexico Pipeline Activity Correlations

*The best way to visualize pipeline infrastructure and their spatial relationships are through geographic information systems and maps, but maps provide little quantitative insight into how system attributes relate and are impacted by development and decommissioning activity. The purpose of this chapter is to develop correlations that quantify pipeline activity in the Gulf of Mexico (GoM) in terms of system attributes. Shallow and deepwater regions are described separately. The chapter begins with a general description of pipeline characteristics and highlights the modeling difficulties. Geometric schematics are used to motivate the model correlations examined. The chapter ends with an application to lease sales and a discussion of the limitations of correlation models.*

## 16.1. Pipeline Characteristics

### 16.1.1. Causal Relationships

Offshore pipeline activity in the GoM is causally related to development and decommissioning activity because the installation and decommissioning of offshore infrastructure triggers the installation and decommissioning activity of pipeline. The relations are not perfectly correlated in a temporal sense, and may either proceed or follow base activity, but they are causal in a physical sense, and it is these causal relations that are the central feature that motivates the development of correlative relations.

### 16.1.2. Dimensional Variables

Pipeline data is different from other offshore activity variables, such as wells drilled and structures installed, due to the dimensional (spatial) character of pipelines, which is a distinct feature of the description. A pipeline segment is laid between two points and the distance the pipeline route takes represents the mileage installed and, at the time of decommissioning, abandoned. Pipelines can range from a few miles to several hundred miles and everything in between. Bulk pipelines and umbilicals depend on the size, areal extent, complexity and architecture of the field development, whereas export mileage depends on the location of the discovery and distance between host and destination, which can be another platform, pipeline tie-in, or onshore connection. The spatial variability that accompanies the location of deposits and the multiple potential destination outlets means that pipeline attribute relations are stochastic. The wide spectrum in development options makes pipeline construction inherently variable from project to project and makes standard modeling practices of limited predictive ability.

### 16.1.3. Complex Dependencies

Pipeline variables are more complicated to evaluate than traditional offshore infrastructure variables. Pipeline projects depend upon both field-specific (internal) and network (external) characteristics at the time of development, and the interplay between the two creates complexities that usually preclude sophisticated modeling. Pipeline mileage captures location effects of development as well as temporal effects related to the status of existing networks and their available capacity at the time of construction. Ownership considerations are also paramount because the owners of the pipeline will determine its destination; different types of owners have different criteria and business objectives. Most new export systems connect with existing offshore pipeline networks to save costs and accelerate schedule. For some developments, however, operators may choose to build new lines to shore to handle large production volumes or for strategic reasons. Pipelines are often routed to operator-owned structures and onshore infrastructure. Pipeline variables have complex spatial, time, and owner dependencies that for all practical purposes cannot be modeled.

### 16.1.4. Ownership Issues

Pipeline ownership has important implications in destination selection and mileage. Third-party owners like transmission companies are not reserves owners and do not apply the same return on investment criteria in decision-making. Gas export pipelines are commonly owned and operated by gas transmission companies, which charge a fee for access and destinations are often determined by the location of the (transmission companies) existing pipeline network and not minimum distance. Ownership and competing gas destinations and terms of service are key factors in selection. Similarly, for export lines owned by reserves owner subsidiaries or affiliates, operators often prefer to route production through their existing pipeline networks even if at a greater distance/cost than alternatives through third-party lines. For operators that do not own export pipeline, terms of service and netback prices at destination are primary factors in decision making. The closest host and export pipeline may not be the cheapest option. Onshore destination where the pipeline ships, oil quality, and marketing preferences may be determining factors in selection.

### 16.1.5. Lumpy Volatile Data

Pipelines, flowlines, and umbilicals are installed over one or more work seasons and/or years. They are reported as installed after hydrotesting, which may occur at times different than the actual construction time and create a time divergence between activity performed and project completion. Pipelines are not reported in terms of projects but rather mileage laid, and thus calendar data will appear lumpy and contribute to large swings in mileage totals from year-to-year. Pipeline installation date does not necessarily correspond to the period of actual construction activity, unlike well spudding, which occurs at the time of well drilling.

## 16.2. Infrastructure Relations

### 16.2.1. Phenomenological Approach

The location of the field, available pipeline capacity at the time of development, pipeline ownership, and other factors collectively determine the amount of pipeline required in a given project. Because these variables are not amenable to quantitative modeling, one should not expect correlative relationships to exist among all variables. A phenomenological approach is required where relationships are explained by variables specific to the relationship under investigation. Field development strategies motivate or dictate the selection of correlating attributes. Because there are many topological configurations, the inputs and outputs depend on the specified time period, geographic region, and manner of aggregation and classification.

### 16.2.2. Geometric Representation

The geometric relationships between pipelines, structures and wells are shown schematically in Figure P.1 and summarized in Tables P.1 and P.2. Blocks denote structures and lines represent pipelines, flowlines and umbilicals distinguished by category and type. Each component of a pipeline project–oil and gas export pipelines, flowlines, umbilicals and risers–represents a unique combination of components driven by separate considerations.

Risers are a special class of (vertical) pipeline designed to more exacting standards than pipelines and are not considered in evaluation. There are at least two risers for oil and gas export and one riser per well provides an upper bound, but if production is commingled, or oil and/or gas is separated subsea, riser counts and riser mileage will be reduced. Risers may be considered a subcomponent of the pipeline data or considered separately. Riser mileage is approximated by the product of water depth and number of risers.

Not all possible relations are shown and only primary attributes are depicted. The geometric representation does not consider the number of lines of a given type entering or departing a structure, but instead groups each line type together for simplification. The primary purpose of the cartoons is to depict the relationships that commonly arise among infrastructure to provide insight into the correlations that should be examined.

### 16.2.3. Structure and Well Configurations

Whenever a caisson or well protector (C/WP) is installed around a wellhead, a bulk oil or bulk gas line is required to deliver product to a processing host or transmission pipeline. In some cases, a service line from the host or another platform may enter the wellheads delivering chemicals (methanol) or water injection into the reservoir. In some cases, no bulk lines exist if the structure was installed to support production and does not surround wellbores.

Fixed platforms perform a variety of functions and exhibit a broad spectrum of potential connections. For major structures with processing capacity, both oil and gas export lines typically exit the structure, but this was not always the case and at the beginning of the pipeline build out two-phase (oil and gas, gas and condensate) pipelines were common, meaning only one export pipeline was employed (Massad and Pela 1956, Lipari 1963, Swift 1966). By the mid-1970s, most hydrocarbon streams from major processing platforms were separated and transported individually (e.g., Frankenberg and Allred 1969, Hicks et al. 1971).

Minor fixed platforms that do not perform processing or partial processing have only bulk and service lines similar to caissons and well protectors, and in cases where a structure was installed to support equipment capacity or quarters for an existing platform, no pipeline at all is required. For service junctions, oil and/or gas export lines enter and exit the structure on their way to their final destination.

### 16.2.4. Deepwater Structures and Subsea Well Configurations

Wet well developments in deepwater are similar to C/WPs in shallow water in terms of flowline requirement, with the additional need for umbilicals and redundancy. Dual lines are typically used for oil to provide pigging capability and single lines are used for gas wells for field architectures that range from simple one or two well tiebacks (e.g., Thunder Hawk, South Hadrian) to complex arrangements involving multiple interconnected subsea wells (e.g., Na Kika, Independence). Dry tree and direct vertical access wells do not trigger flowline requirements because risers bring product to the host.

For dry tree only developments oil and gas export lines are required unless the field is dry gas or gas-condensate, in which case only a gas export line is needed. For wet tree developments bulk oil and gas lines are also needed to transport production to the host, umbilicals are required to control and manage the wet wells, and service lines are applied as determined by field design. For FPSO vessels, oil export lines are not required because crude is stored in the unit and offloaded via shuttle tanker.

## 16.3. Correlations

### 16.3.1. Installation: Shallow Water

*Bulk Pipeline and Simple Structures*

In Figure P.2, installed bulk oil and bulk gas mileage in shallow water is depicted along with the number of installed caissons and well protectors per year from 1954–2016. Pipeline mileage shows greater variation from year-to-year than structure installations due to differences in development and the nature of the variables. Pipeline projects are described by mileage and structures are counted individually. The two attributes show a higher correspondence in the second half of the time series (Figure P.3).

Bulk line has always been installed at some level; the greatest amount of construction was from 1990–2008. Similarly, from 1970 through 2008, large numbers of caissons and well protectors were installed most years, with levels ranging between 50 to 100 structures per year. In recent years, installation levels of C/WPs and bulk lines have declined considerably.

From 1990–2016, bulk oil and gas mileage [BO+BG] was correlated against C/WP installations and the following relation derived:

$$[BO + BG] = 2.8\ C/WP + 71.5,\ R^2 = 0.66.$$

For every caisson or well protector installed, on average 2.8 miles of bulk line was required plus a fixed term component of 71.5 miles representing activity not captured through the C/WP variable. Forcing the fixed term component in this relation to zero will (obviously) increase average bulk mileage per structure and reduce the model fit since now an additional constraint is added to the model relation:

$$[BO + BG] = 4.0\ C/WP,\ R^2 = 0.51.$$

The preference of which model to employ depends upon the user, and what appears to be low-fit models may actually provide better predictive capability than higher-fit relations. Adding constraints to regression models will always reduce model fits.

*Export Pipeline and Fixed Platforms*

In Figure P.4, export oil and gas pipeline miles [G+O] installed in shallow water are graphed with installed fixed platforms (FP). Large swings in pipeline activity are due to the large distances that must be traversed in export systems. For the last 50 years, export mileage has fluctuated wildly from year to year, reaching upwards of 800 miles installed in one year and exceeding 400 miles per year about half the time. Observations indicate a weak correspondence between the two attributes with changes in fixed platforms followed by changes in export installation.

From 1990–2016, installed gas and oil export mileage correlated against installed fixed platforms yields (Figure P.5):

$$[G + O] = 3.0\ FP + 114,\ R^2 = 0.42.$$

The result is similar to the bulk line model but with a larger fixed term component and a less robust fit. Removing the fixed term and re-parameterizing allows direct comparison between unit activity:

$$[G + O] = 4.8\ FP,\ R^2 = 0.23.$$

For every fixed platform installed over the past quarter century, 4.8 miles of export line was required to connect into existing networks. Similar relations can be broken out by decade but do not depart significantly on an aggregate basis.

### 16.3.2. Installation: Deepwater

*Bulk Pipeline andvs. Subsea Wells*

In Figure P.6, bulk oil and gas mileage installed in water depth >400 ft shows a positive correspondence with the number of subsea wells (SS) drilled. From 1998 to 2015, more than 100 miles of bulk oil and gas line were installed each year, while the annual amount of subsea drilling typically ranged between 50 and 100 wells spud. From 1982 to 2016, the following relations are derived (Figure P.7):

$$[BO + BG] = 2.4\ SS + 20.3,\ R^2 = 0.64$$

$$[BO + BG] = 2.7\ SS,\ R^2 = 0.62.$$

Field architecture and the requirements for dual and single lines contribute to the variation observed. Both model fits are surprisingly strong. A better observational variable would be subsea wells completed (successful wells) with a time delay introduced to optimize the model, but these modifications can quickly become pedantic.

*Bulk Pipeline and Subsea Wells and Structures: Variable Time Period*

In some cases, two or more activity variables may be used in establishing relations if there is an *a priori* belief or knowledge that the variables are causal and carry useful information. Unfortunately, there is a strong tendency in the academic community to prefer sophisticated (and over-specified) models that apply all possible combinations of all potential variables seeking to maximize $R^2$ without regard to engineering or market fundamentals. Application of sophisticated econometric approaches using all its machinery is therefore discouraged because it provides limited practical information and conveys a sense of accuracy almost never warranted. Linear regression models with careful selection of descriptor variables are believed to provide the most robust and meaningful relations.

Deepwater bulk pipeline is primarily related to subsea wells. The number of deepwater structures (DWS) installed is a less relevant variable because not all deepwater structures use subsea solutions and subsea wells may tie-back into existing infrastructure. DWS includes fixed, compliant, and floating structures in water depth greater than 1000 ft. The results for four different time periods are shown in Table P.4. From 1982 to 2016 and from 1997 to 2016, the results yield:

$$[\mathrm{BO} + \mathrm{BG}]_{1982\text{-}2016} = 19.1 + 0.5\ \mathrm{DWS} + 2.4\ \mathrm{SS},\ \ R^2 = 0.80$$

$$[\mathrm{BO} + \mathrm{BG}]_{1997\text{-}2016} = 64.9 + 3.7\ \mathrm{DWS} + 1.6\ \mathrm{SS},\ \ R^2 = 0.50$$

The statistical significance of individual variables is sensitive to the time period selected and may improve or deteriorate with the time periods selected. No generalized statements are possible except in reference to a specific data set and relationship. For example, the relative significance of deepwater structures improves over shorter time periods, while the importance of subsea wells declines. For this data, the model fit deteriorates over the shorter period, while in many cases shorter periods often exhibit superior model fits because less data is involved.

*Export Pipeline and Deepwater Structures*

In deepwater, structure installations almost always require both oil and gas export pipeline. In Figure P.8, gas and oil export mileage is depicted compared to the number of deepwater structures installed in >400 ft water depth. Since 1978, a total of 120 deepwater structures have been installed, an average of about three structures per year. From 1996 through 2010, pipeline installation usually exceeded 300 miles per year. So, roughly speaking, one would expect about 100 miles per year export mileage per structure installed.

From 1990 to 2016, the following relations were established:

$$[\mathrm{G} + \mathrm{O}] = 54.8\ \mathrm{DWS} + 51.5,\ R^2 = 0.35$$

$$[\mathrm{G} + \mathrm{O}] = 75.3\ \mathrm{DWS},\ R^2 = 0.32$$

The unit coefficients are about an order-of-magnitude greater than in shallow water, which is reasonable because deepwater structures are more distant from existing pipeline networks and fewer structures are installed per year. The combination of fewer structures and greater distances imply larger pipeline requirements per installation on average. Model fits deteriorate due to small samples and greater project variation.

*Export Pipeline and Deepwater Structures: Time Normalization*

When analyzing volatile time series or where model fits are considered unacceptable (i.e., too small) for application, it is often useful to normalize the data over different time periods or use larger spatial categories, or both, to reduce volatility and improve model fits. The analyst is simply integrating and smoothing out the data in a pre-processing step to improve the model fit, but whether this is an acceptable or even valid procedure is usually not discussed or contemplated. We are skeptical of such approaches in general, but in certain restricted contexts they may be appropriate. Here we show what can be accomplished by averaging data over time blocks. If such approaches are used, model interpretation must be amended specific to the processing technique applied. This is also not often discussed.

Using five-year time blocks over the 1990–2016 period and re-estimating the deepwater export pipeline and structure correlation yields a model fit of $R^2 = 0.56$, and by reducing the period of analysis further to 2000–2016 yields another "improvement" to $R^2 = 0.87$ (Table P.3):

$$[G + O]_{1990\text{-}2016} = 61.1\ \mathrm{DWS} + 137,\ R^2 = 0.56$$

$$[G + O]_{2000\text{-}2016} = 80.1\ \mathrm{DWS} + 163,\ R^2 = 0.87$$

Either or neither of these normalizations may be considered appropriate, depending on the needs of the user and the particular problem setting. User-preferences and the availability of various statistical techniques means that many outcomes are possible using the same data, and, unless clearly identified and discussed, are prone to misinterpretation and manipulation.

### 16.3.3. Decommissioning: Shallow Water

*Bulk Pipeline and Simple Structures*

In Figure P.9, decommissioned bulk gas and bulk oil mileage is graphed with abandoned caissons and well protectors in water depth <400 ft. Since 2007, bulk pipeline mileage has fallen rapidly. The period of evaluation begins in 1973 and was truncated in 2007:

$$[\mathrm{BG} + \mathrm{BO}] = 1.6\ \mathrm{C/WP} + 48.6,\ R^2 = 0.47.$$

*Export Pipeline and Fixed Platforms*

In Figure P.10, decommissioned gas and oil mileage is graphed with the number of decommissioned fixed platforms. Export pipeline mileage exhibits significant annual variation, which presents an obvious problem in developing useful correlations because both increasing and decreasing mileage are associated with small or no changes in structures for the first two decades of the time series, and then after 2008 structure removal rates were high while pipeline decommissioning was flat or near zero. No meaningful correlation is possible. The lesson learned is that useful correlating relations cannot always be constructed.

## 16.4. Lease Sale Application

OCSLA was enacted in 1953 to establish a regime for offshore oil and gas leasing. OCSLA prescribes a multi-stage process for development of offshore leases with environmental review at each stage. This multi-stage process provides a "continuing opportunity for making informed adjustments" that ensures that OCS oil and gas activities are conducted in an environmentally sound manner.

The first stage is the five-year program involving the development and publication of schedules of proposed OCS lease sales over a five-year period to best meet the nation's energy needs. BOEM develops five-year leasing plans that identify all offshore leasing that may take place during the period of plan coverage. Historically, two lease sales were offered each year (the Western GOM in the fall and the Central GOM in the spring) and occur on an area-wide basis in which all areas not specifically prohibited from leasing or already leased are available for bidding. Starting with Lease Sale 249 in 2017, the Western and Central Planning Areas are combined and BOEM holds two combined sales each year.

BOEM geologists and engineers evaluate regional resources in the GoM by planning area and water depth region and, along with economists, social scientists, and other staff members forecast offshore drilling, construction, and decommissioning activity arising from future GoM lease sales. BOEM staff forecast the number of exploratory and development wells expected to be drilled; the number of caissons, well protectors, fixed platforms, and floaters expected to be installed and decommissioned; and the amount of pipelines and flowlines expected to be installed and decommissioned annually associated with future lease sales (Figure P.11). The time horizon covers a five-year period of lease sales (e.g., 2012–2017, 2018–2022) consistent with regulatory requirements. Various scenarios are examined which cover multiple cases.

The use of pipeline correlations allow pipeline mileage to be forecast based on the user input of primary model inputs and improves the consistency and accuracy of the approach and documents the relations applied. In this manner, pipeline activity is derived based on primary variables and enhances the credibility of the results. Historic correlations need to be viewed cautiously, however, especially when used as a predictor of future activity because of changes in design and technology and the specific nature of project work. Historic trends do not necessarily extrapolate to the future if these factors change from historic activity, and the relations derived can be modified in various ways to take account of the expected variation. Correlations between disparate variables may be spurious or meaningless if not understood in the proper context and with an appreciation for the nature of field development. With these limitations understood, correlations represent one of the best means to populate the activity models.

## 16.5. Limitations

Offshore developments are guided by similar engineering, technical, and economic considerations, but the manner in which fields are developed are site specific. This is the main reason why pipeline modeling needs to be performed at large spatial and temporal scales to capture average or field-level characteristics. Different factors impact different projects in different ways and impact pipeline requirements in a myriad and complex fashion. Many factors influence decision making at a project level and, when aggregated system-wide, are replaced with average correspondences.

Field developments are site-, time-, and location-specific and pipeline requirements are therefore site-, time-, and location-specific. Each component of a pipeline project (oil and gas export pipelines, flowlines, umbilicals and riser) are driven by separate considerations.

Export oil and gas pipeline projects usually do not have the same destination, but mileage requirements are nonetheless expected to be similar on an average basis since regional build-outs for oil and gas export pipeline in the GoM have occurred at similar rates and provide multiple options and route choices for developers. Flowlines and umbilicals run along the same routes between host and well and/or drill center but, because the number of flowlines and umbilicals are not identical, mileage will differ.

In some projects, there may be a common and/or dominant company that wants to seek an integrated export solution for multiple fields (e.g., Mardi Gras); in other developments, different fields owned by different operators may be combined (e.g., Canyon Express, Independence Hub). The simplest case occurs when structure owners are the same as tieback owners (e.g., Na Kika, Auger) because business drivers become more apparent. Unless models incorporate field ownership, they will not reflect market reality and available pipeline options and choices. Phased development (e.g., Cascade-Chinook) compared to full field development (e.g, Prince) is another complicating factor that influences the timing and amount of pipeline required at a specific point in time.

Pipeline models that do not consider the type of production fluid or structure type will over-estimate export pipeline requirements in dry-gas fields and FPSO developments (no oil export lines). Export pipeline depends on available capacity at destination and is time dependent. Production fluid (sweet or sour crude, dry or wet gas) may impact selection of host destination. Subsea tiebacks to host platforms are usually timed so that new export pipelines from the host are not required, but in some cases and if technically feasible, new export pipeline may be installed.

Infield flowline and umbilical requirements depend on the size and areal extent of the reservoirs, the number of wells required, field development strategy, technology applications, and other factors. Flowlines and umbilicals for individual projects vary in complexity from single well uninsulated single flowlines and umbilicals requiring less than five miles of line, to multiple well looped insulated pipe-in-pipe heated flowlines stretching over several dozen miles per clustered manifold and requiring 100 or more miles for the entire system. Typically, oil developments have more complex and complicated flow assurance issues and employ dual flowlines and one or two umbilicals; gas developments may be able to deploy one flowline and one umbilical. Looped systems are used to provide pigging capability but are more expensive to construct and operate.

Because pipeline and structure categories are not perfectly distinct but combine characteristics of different types and overlap to a varying extent in spatial and functional aspects, model fits greater than 0.75 are rarely observed in practice and should not be expected. For most purposes, relations between 0.50 to 0.70 would be considered adequate.

When analyzing volatile data series it is often useful to normalize the data and aggregate granular categories to better reflect activity and improve relations. Normalized data may use longer time periods or larger spatial categories or both to reduce volatility and improve model correlations. A distinction is made between variable selection and normalization based on an understanding of the engineering and operational requirements of development compared to seeking simply to maximize model fit through econometric techniques. Good practice will favor the former and avoid the later. Whenever normalization occurs, interpretation for the relations obtained need to be adjusted specific to the processing technique.

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# Appendix A: Chapter 1 Tables and Figures

**Table A.1. Offshore infrastructure by deepwater region circa March 2017**

| Region | FPSO[a] | Other[b] |
|---|---|---|
| Australia | 10(1) | 11(2) |
| Brazil | 40(6) | 15 |
| India/Middle East | 3(1) | 0 |
| Mexico GoM | 4 | 0 |
| SE Asia | 25 | 5(2) |
| US GoM | 2 | 46(4) |
| West Africa | 39(4) | 7(2) |
| North Africa/Mediterranean | 3 | 0 |
| Total | 163(12) | 90(10) |

Source: Offshore Magazine.
[a]Numbers in parenthesis represents sanctioned or under construction.
[b]Includes compliant towers, floating production units, spars, tension leg platforms.

**Table A.2. Norwegian oil and gas export pipeline construction cost (2016$)**

| Pipeline | Start-up (year) | Dimension (inches) | Length (km) | Investment (Billion NOK 2013) | Unit cost $MM/mi | Unit cost $MM/mi-in |
|---|---|---|---|---|---|---|
| Europipe | 1995 | 40 | 620 | 24.3 | 9.5 | 237 |
| Europipe II | 1999 | 42 | 658 | 10.9 | 4.0 | 95.3 |
| Franpipe | 1998 | 42 | 840 | 11.4 | 3.3 | 78.1 |
| Norpipe | 1977 | 36 | 440 | 30.1 | 16.5 | 459 |
| Oseberg Gas Transport | 2000 | 36 | 109 | 2.3 | 5.1 | 142 |
| Statpipe | 1985 | 29 | 894 | 52 | 14.0 | 485 |
| Tampen Link | 2007 | 32 | 23 | 2.3 | 24.2 | 755 |
| Vesterled | 1978 | 32 | 360 | 36.8 | 24.7 | 772 |
| Zeepipe | 1993–1997 | 40 | 1443 | 27.4 | 4.6 | 115 |
| Åsgard Transport | 2000 | 42 | 707 | 12 | 4.1 | 97.6 |
| Langeled | 2006–2007 | 43 | 1170 | 19.4 | 4.0 | 93.1 |
| Norne Gas Transport System | 2001 | 16 | 128 | 1.4 | 2.6 | 165 |
| Kvitebjørn Gas Pipeline | 2004 | 30 | 147 | 1.3 | 2.1 | 71.2 |
| Gjøa Gas Pipeline | 2010 | 29 | 131 | 2 | 3.7 | 127 |
| Draugen Gas Export | 2000 | 16 | 78 | 1.3 | 4.0 | 252 |
| Grane Gas Pipeline | 2003 | 18 | 50 | 0.3 | 1.4 | 80.5 |
| Haltenpipe | 1996 | 16 | 250 | 3.3 | 3.2 | 199 |
| Heidrun Gas Export | 2001 | 16 | 37 | 1 | 6.5 | 408 |
| Grane Oil Pipeline | 2003 | 29 | 220 | 1.8 | 2.0 | 68.1 |
| Kvitebjørn Oil Pipeline | 2004 | 16 | 90 | 0.5 | 1.3 | 83.9 |
| Norpipe Oil | 1975 | 34 | 354 | 18.5 | 12.6 | 371 |
| Oseberg Transport System | 1988 | 28 | 115 | 10.9 | 22.9 | 818 |
| Sleipner Øst Condensate Pipeline | 1993 | 20 | 245 | 1.8 | 1.8 | 88.7 |
| Troll Oil Pipeline I | 1995 | 16 | 86 | 1.4 | 3.9 | 246 |
| Troll Oil Pipeline II | 1999 | 20 | 80 | 1.3 | 3.9 | 196 |
| Huldra Condensate | 2001 | 8 | 16 | 0.4 | 6.0 | 755 |

Source: Norwegian Petroleum Directorate.

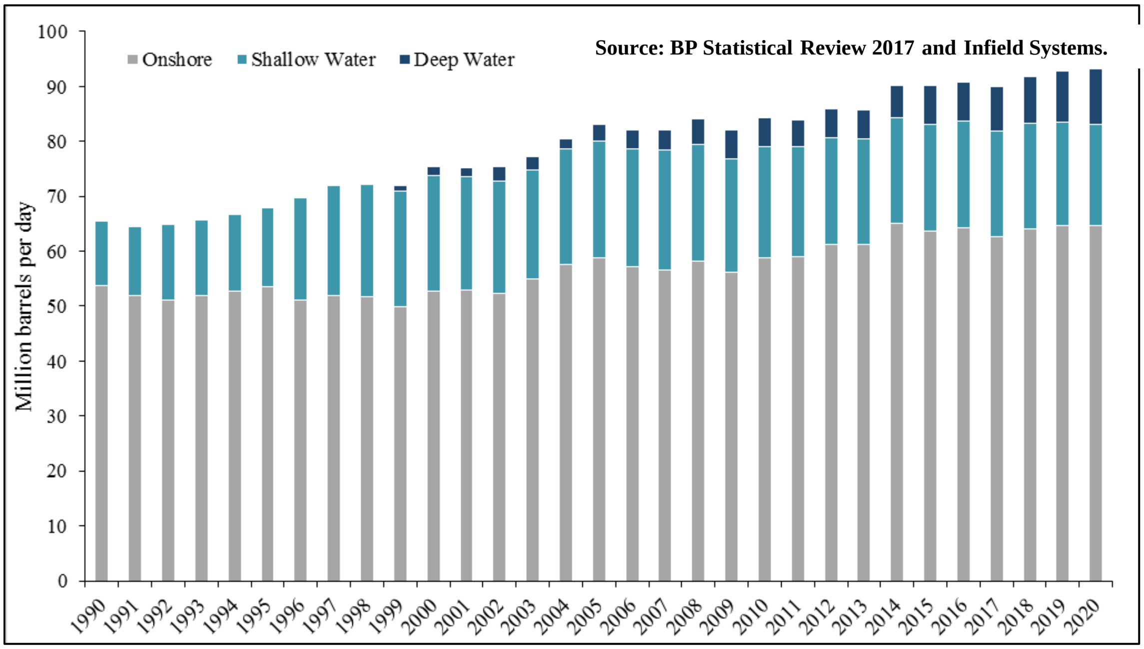



Figure A.1. Global crude oil production and offshore share.

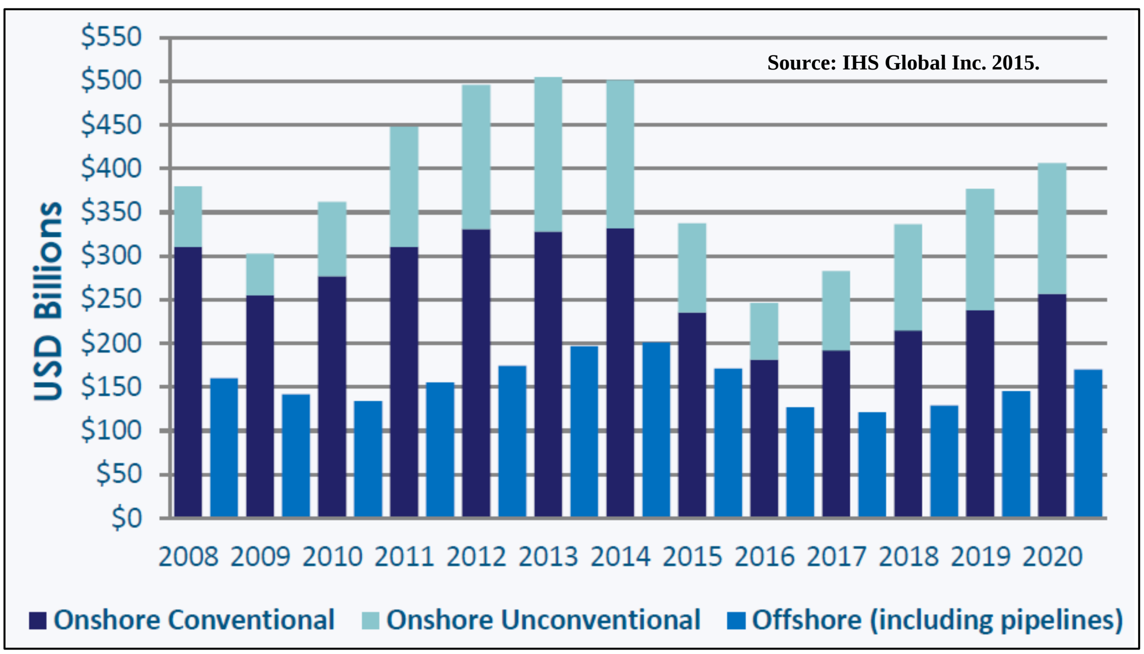



Figure A.2. Global exploration and development capital expenditures circa 2017.

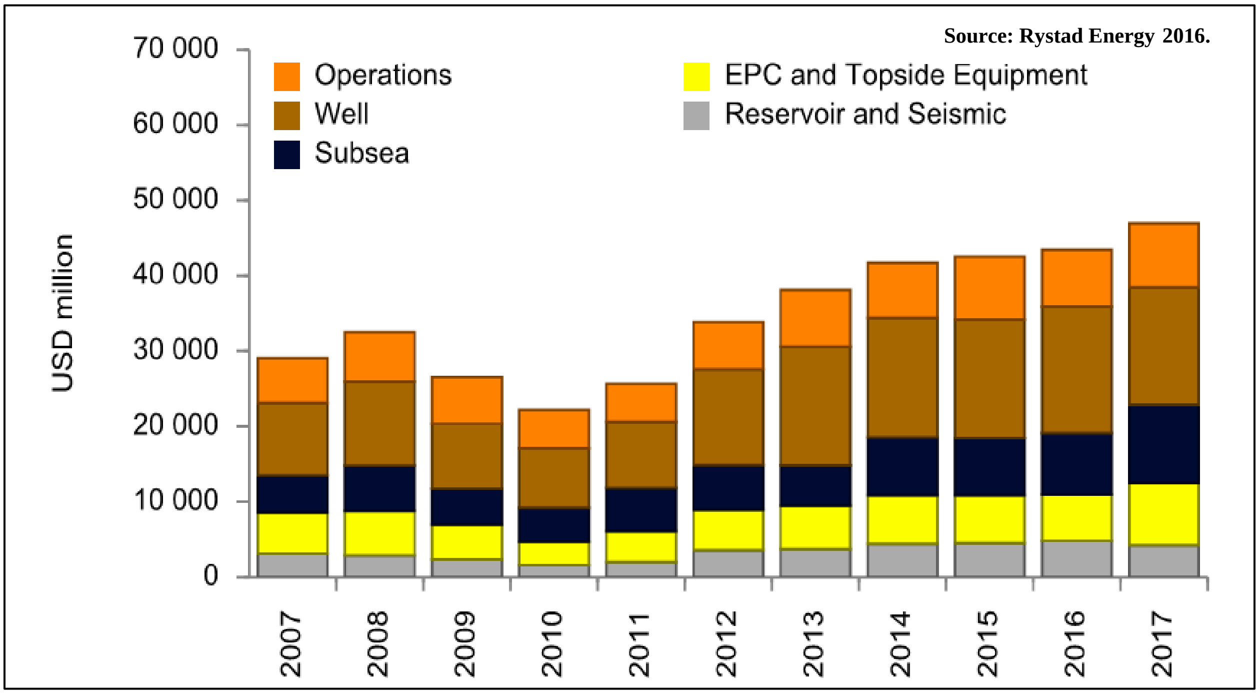



Figure A.3. US Gulf of Mexico offshore capital expenditures, 2007–2017.

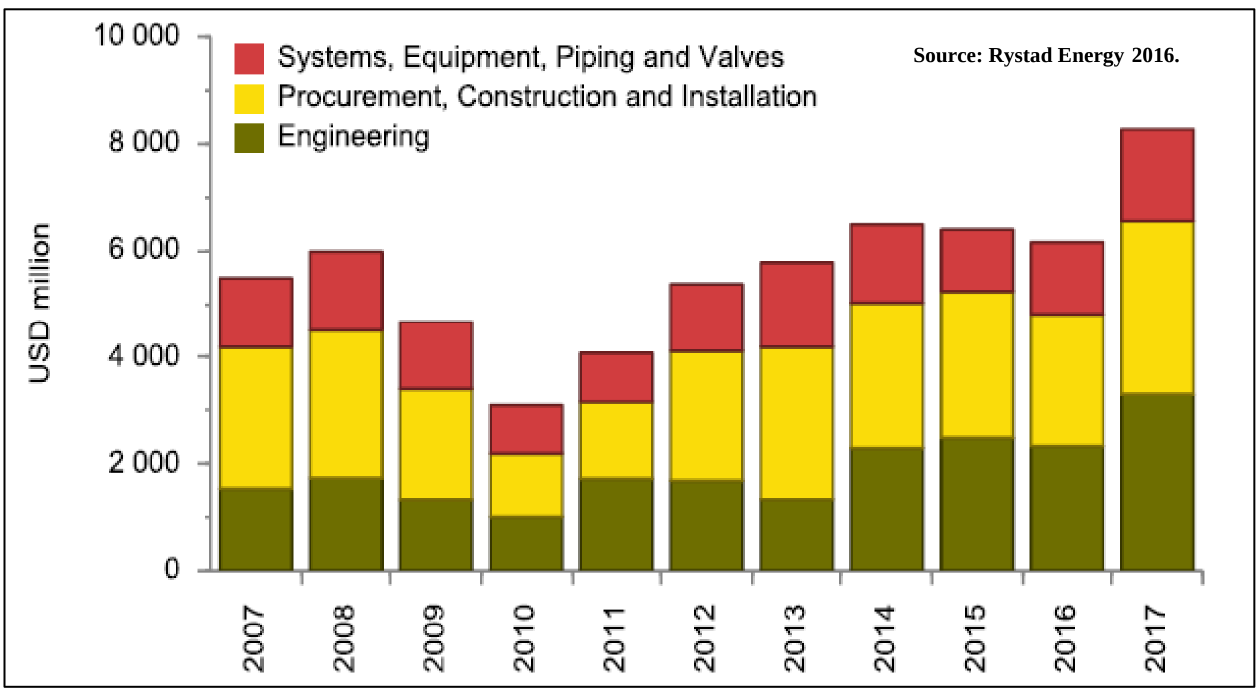



Figure A.4. US Gulf of Mexico EPC and topside equipment expenditures, 2007–2017.

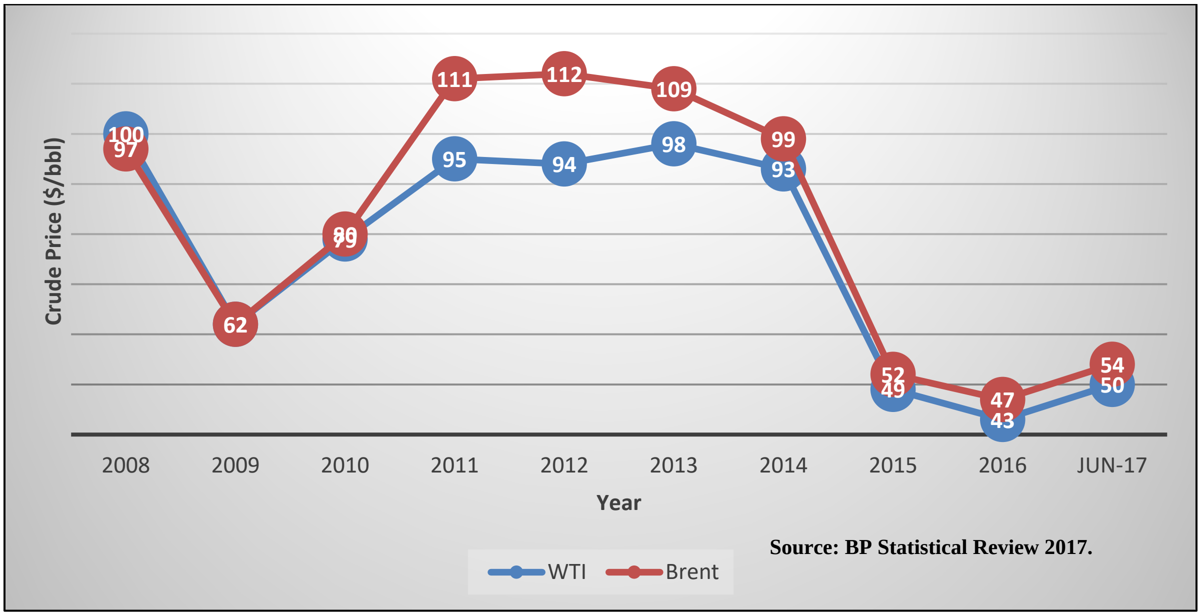



Figure A.5. Average crude oil benchmark prices West Texas Intermediate and Brent, 2009–2017.

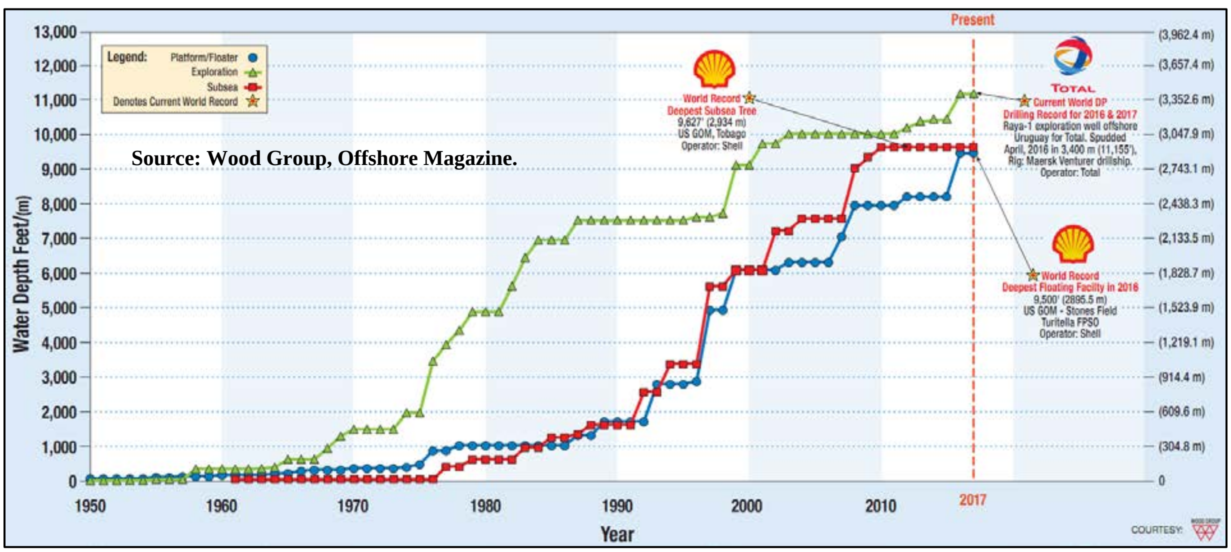



Figure A.6. Worldwide progression of water depth capabilities for offshore drilling and production.

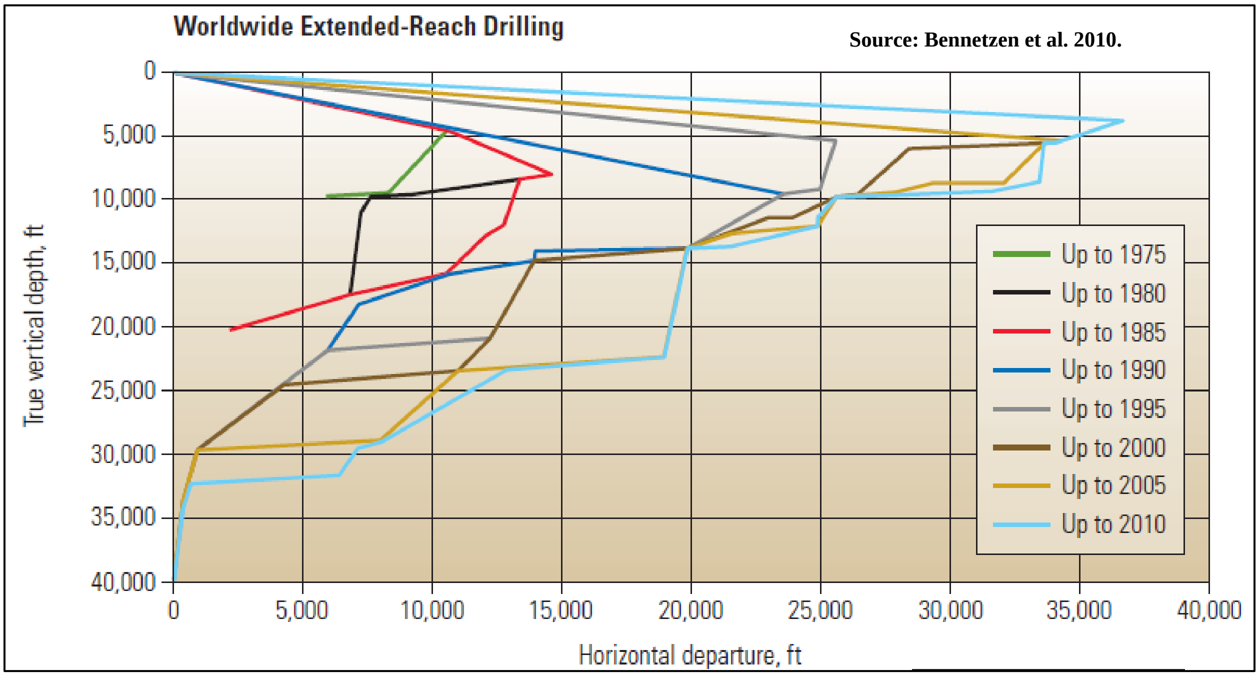



Figure A.7. Worldwide extended reach well drilling circa 2010.

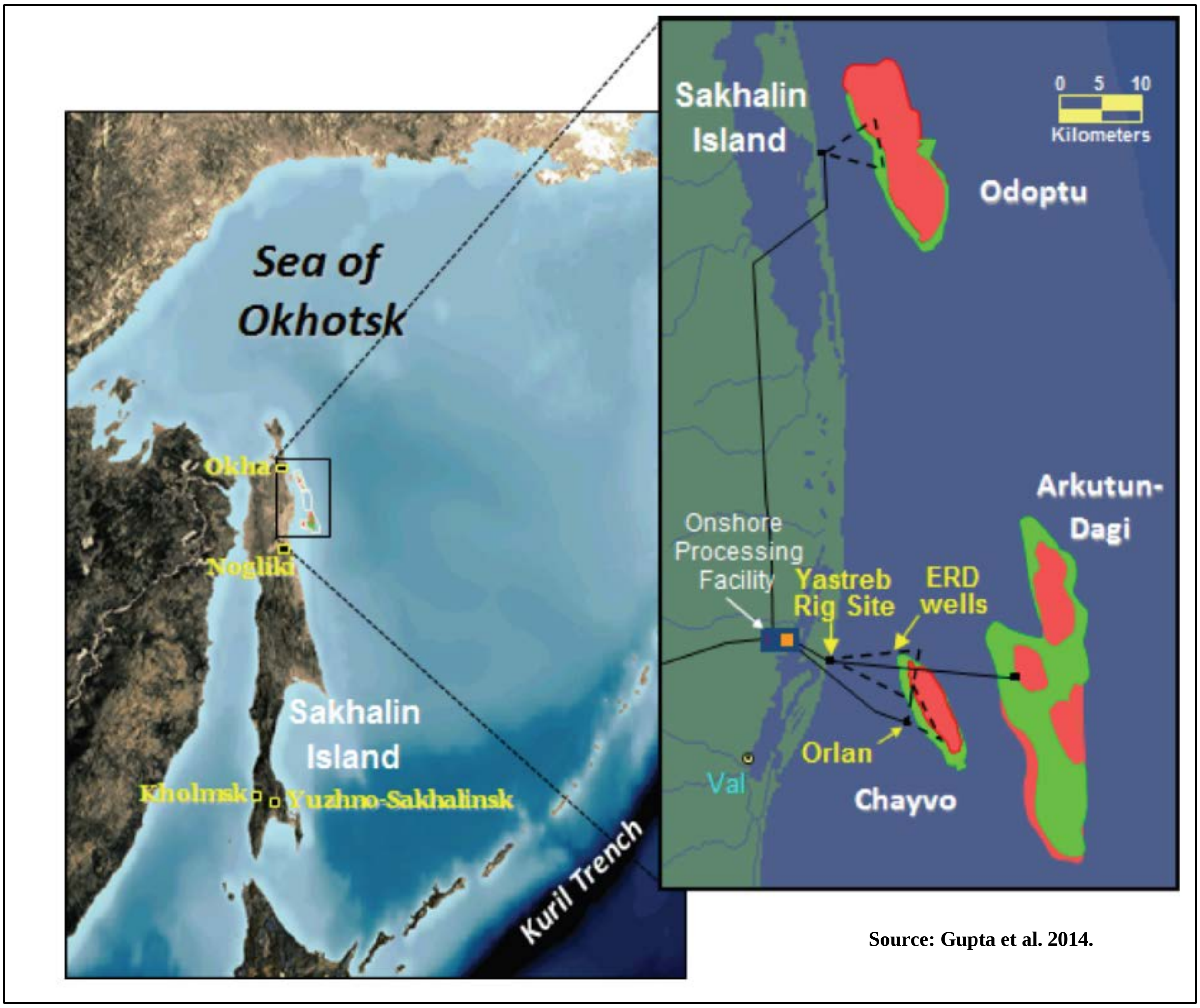



Figure A.8. Location of the Chayvo field in the Sakhalin-1 Production Sharing Agreement.

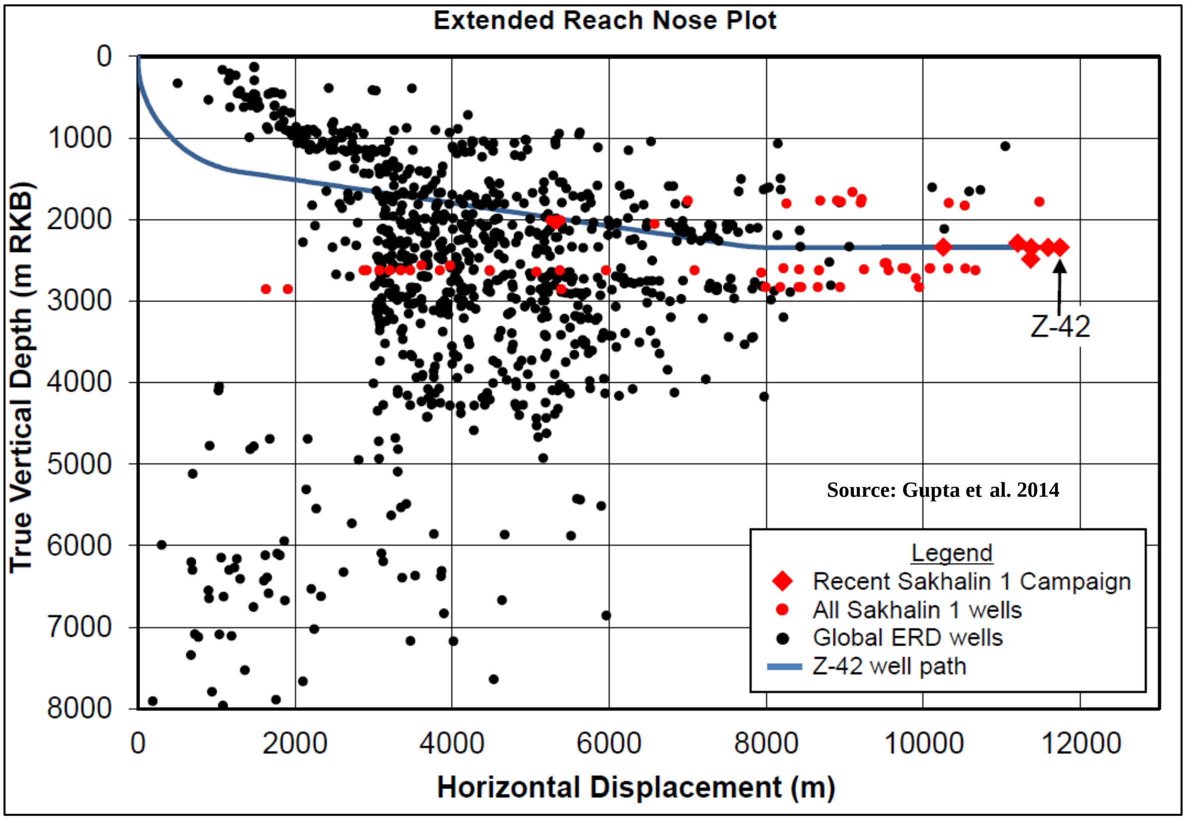



Figure A.9. Extended reach nose plot at Chayvo Z-42 directional well profile.

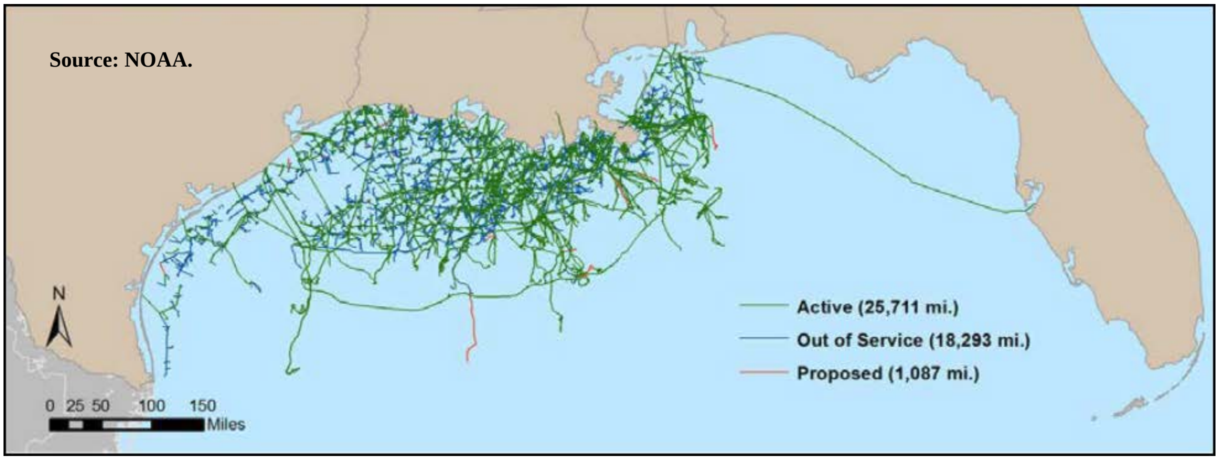



Figure A.10. Oil and gas pipelines in the Gulf of Mexico circa 2012.

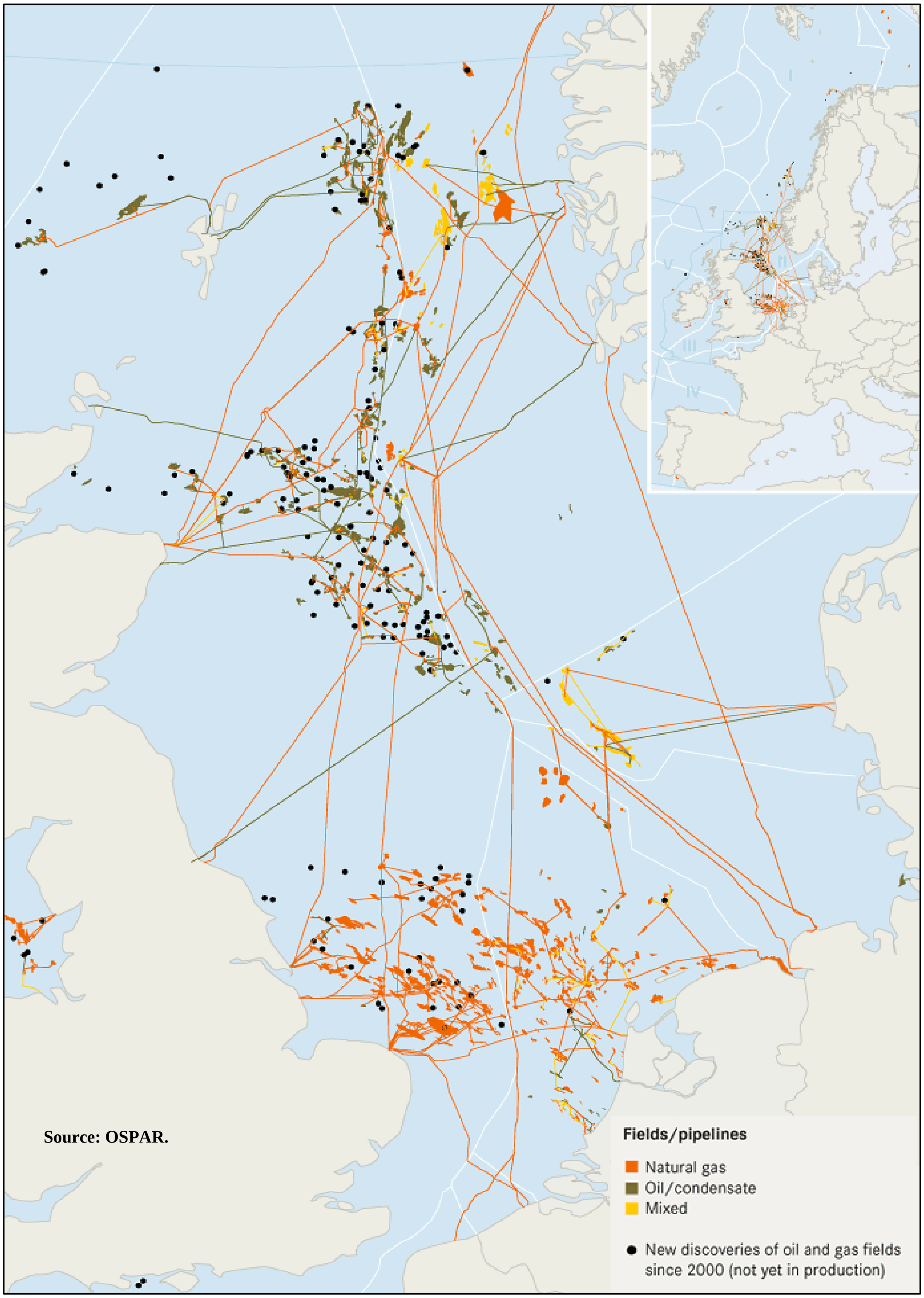



Figure A.11. Offshore oil and gas fields in the North Sea and pipeline network circa 2012.

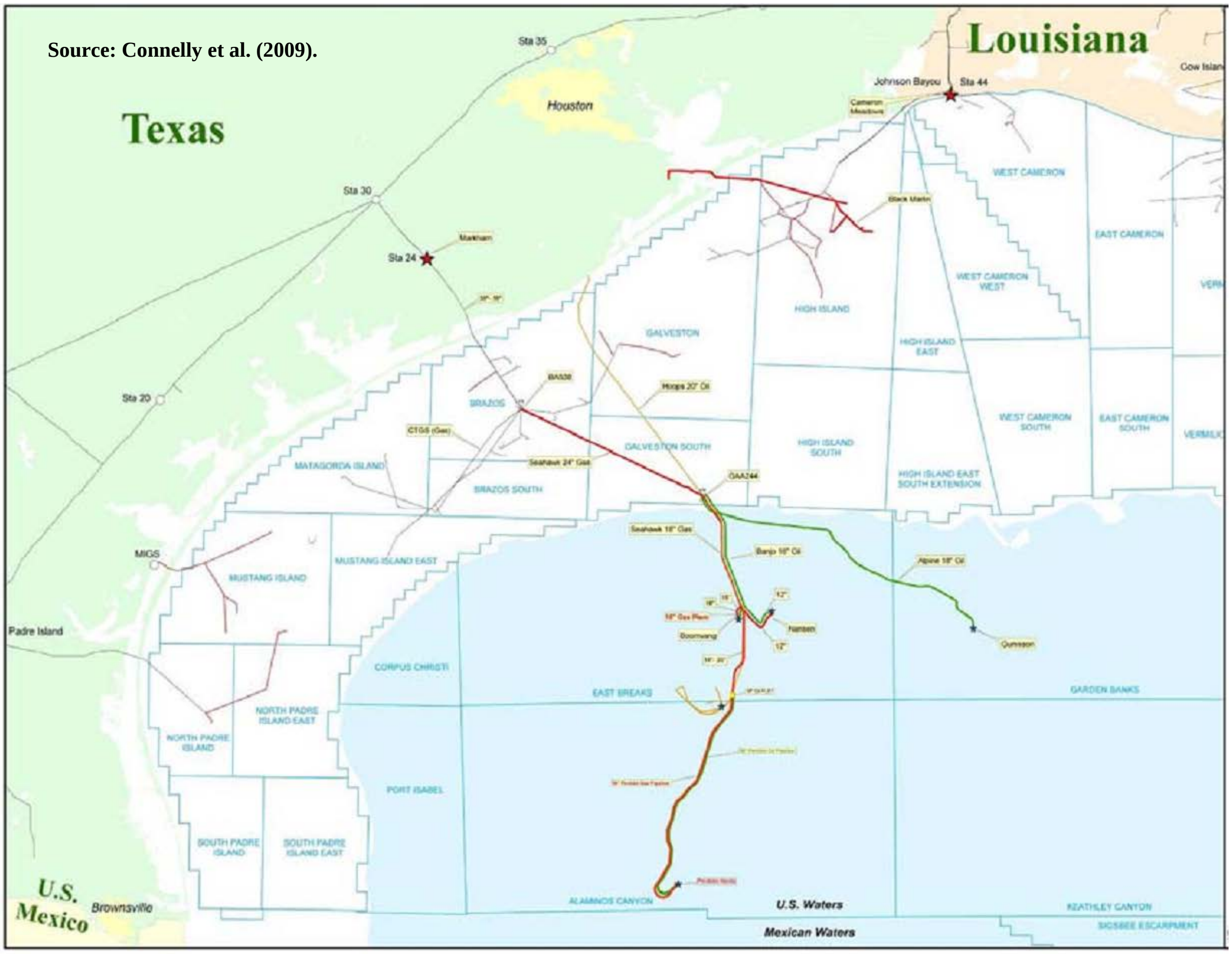



Figure A.12. Perdido oil and gas export system.

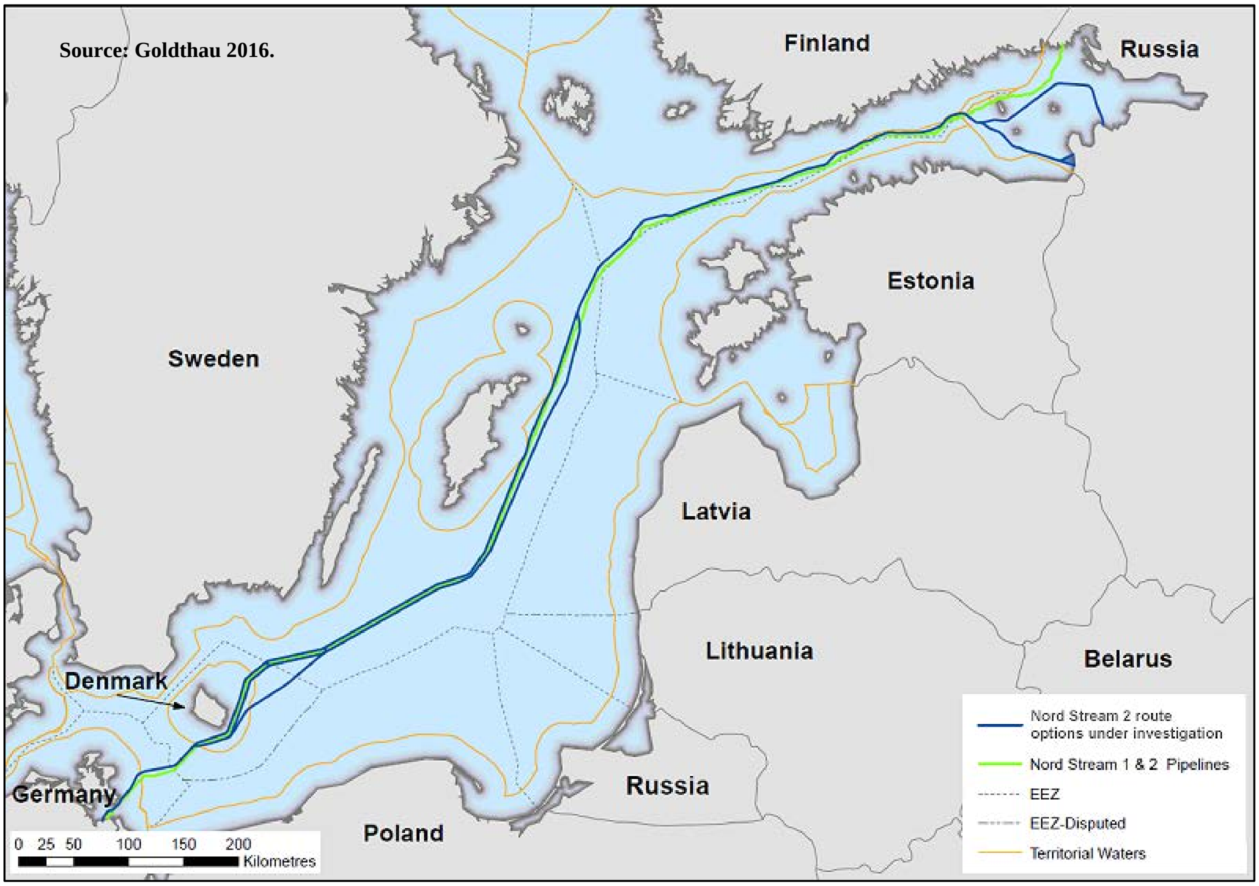



Figure A.13. Nord Stream and Nord Stream 2 route.

Figure A.14. The Langeled gas transport system.


Figure A.15. Blue Stream pipeline system.

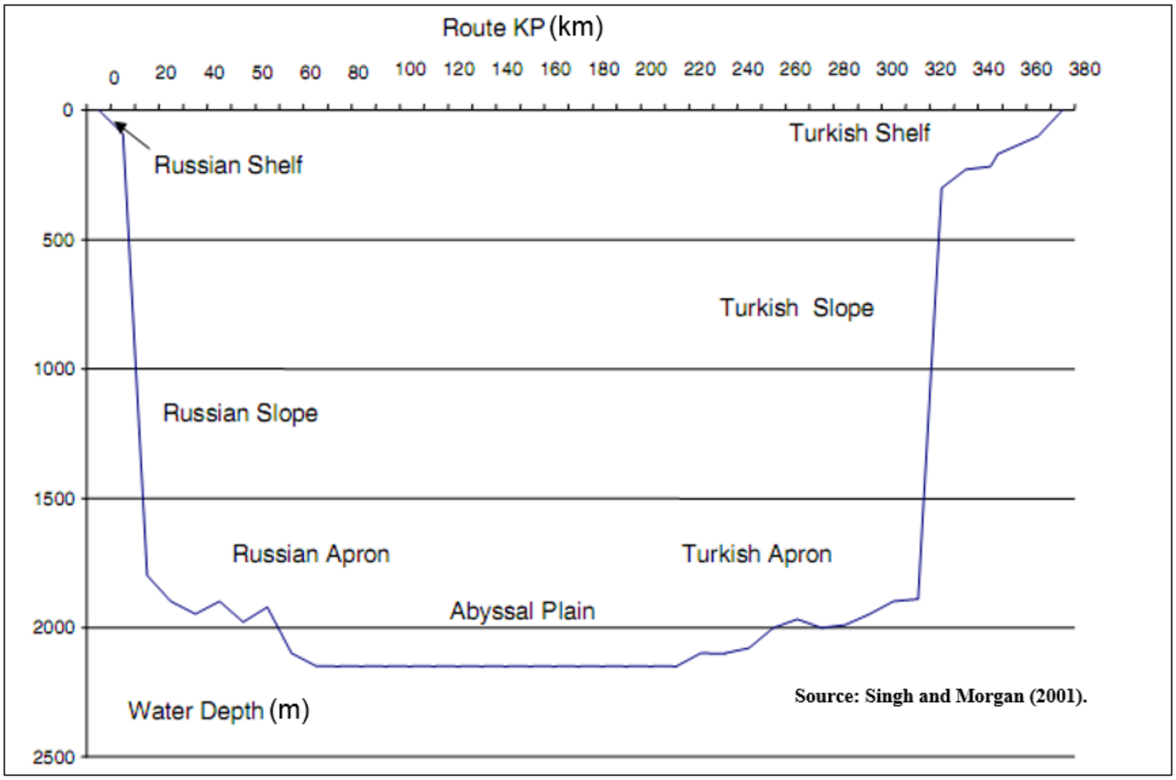



Figure A.16. Blue Stream longitudinal profile.

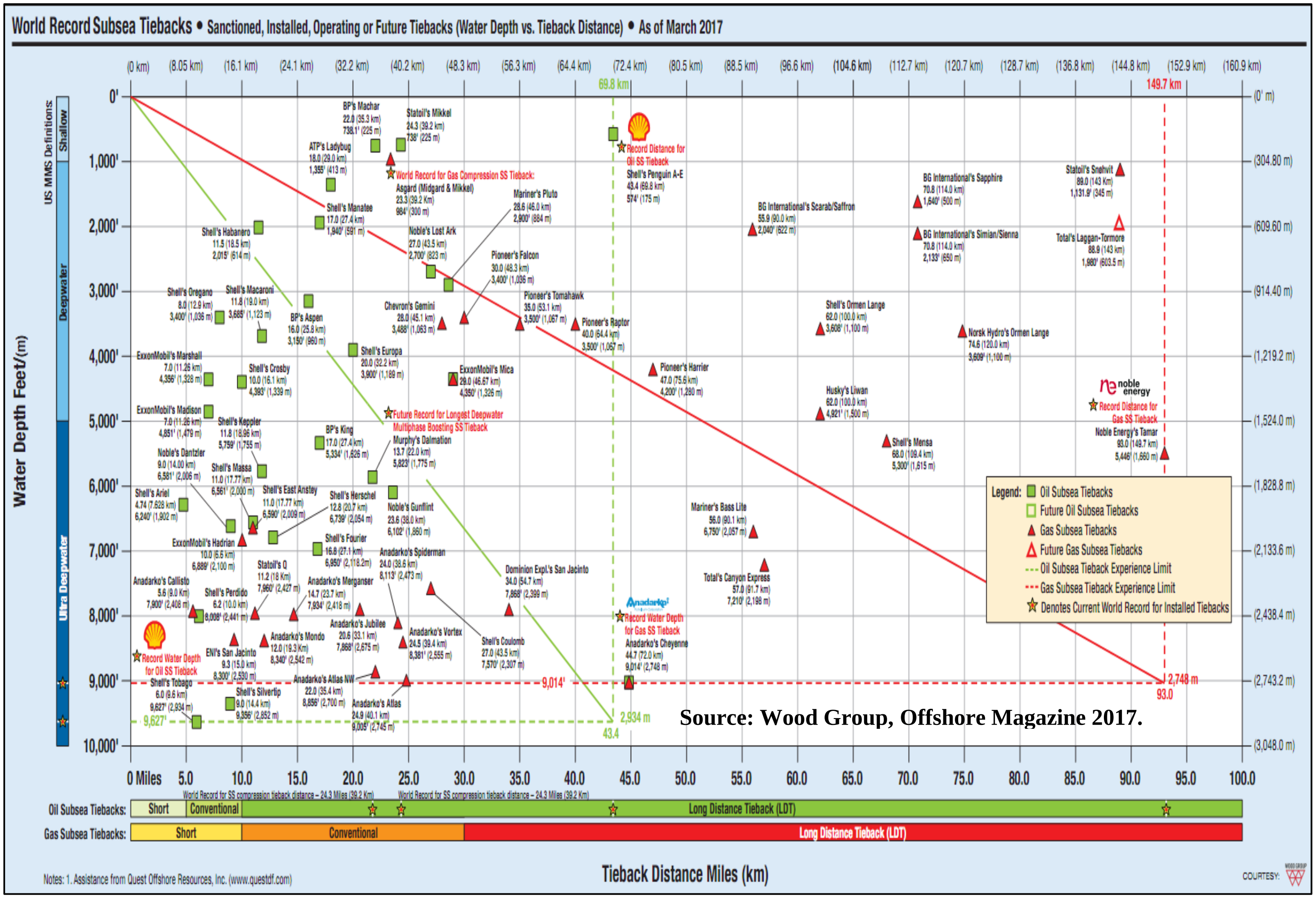



Figure A.17. World record subsea tiebacks water depth and tieback distance circa 2017.

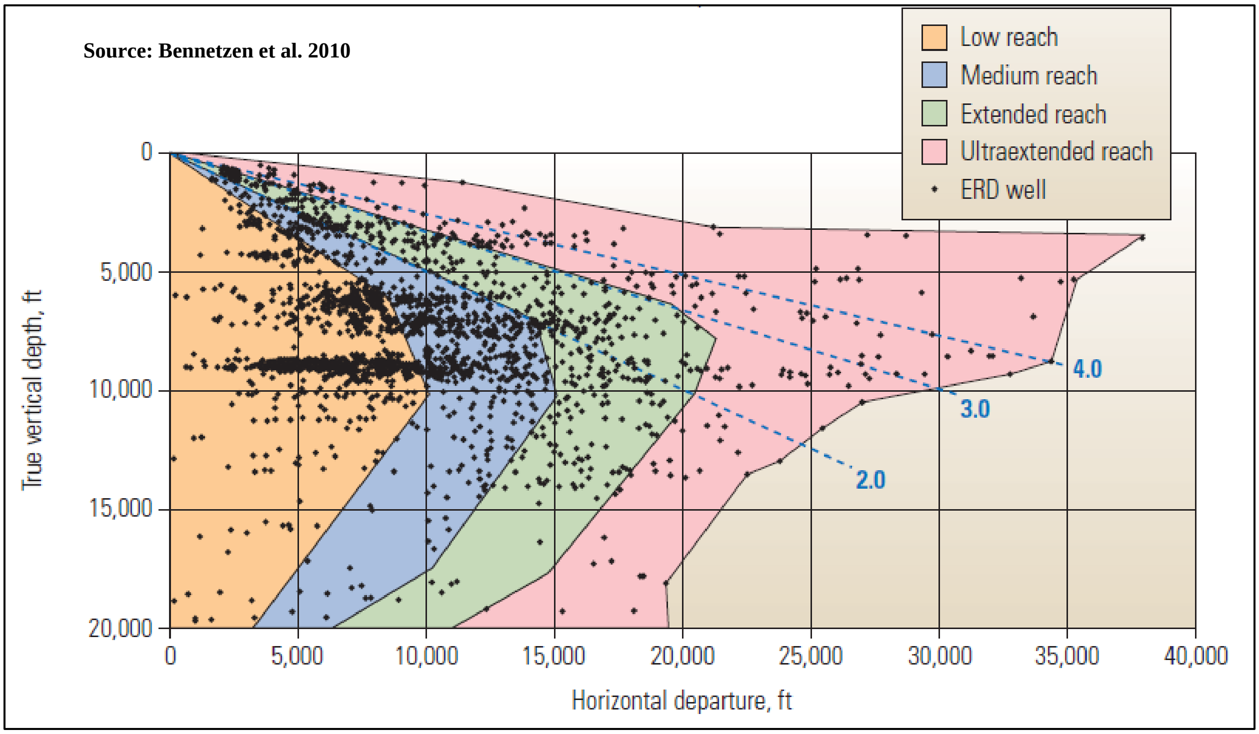



Figure A.18. Worldwide extended reach well drilling vertical depth and horizontal departure circa 2010.

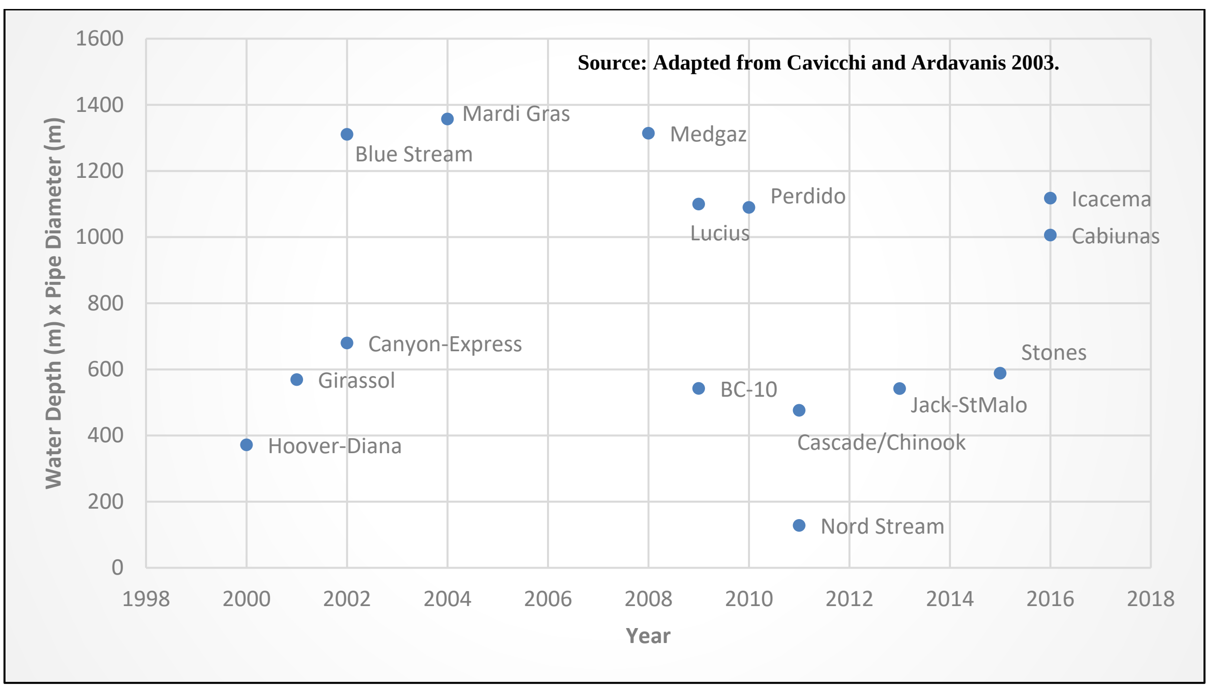



Figure A.19. Measure of difficulty of offshore pipeline construction.

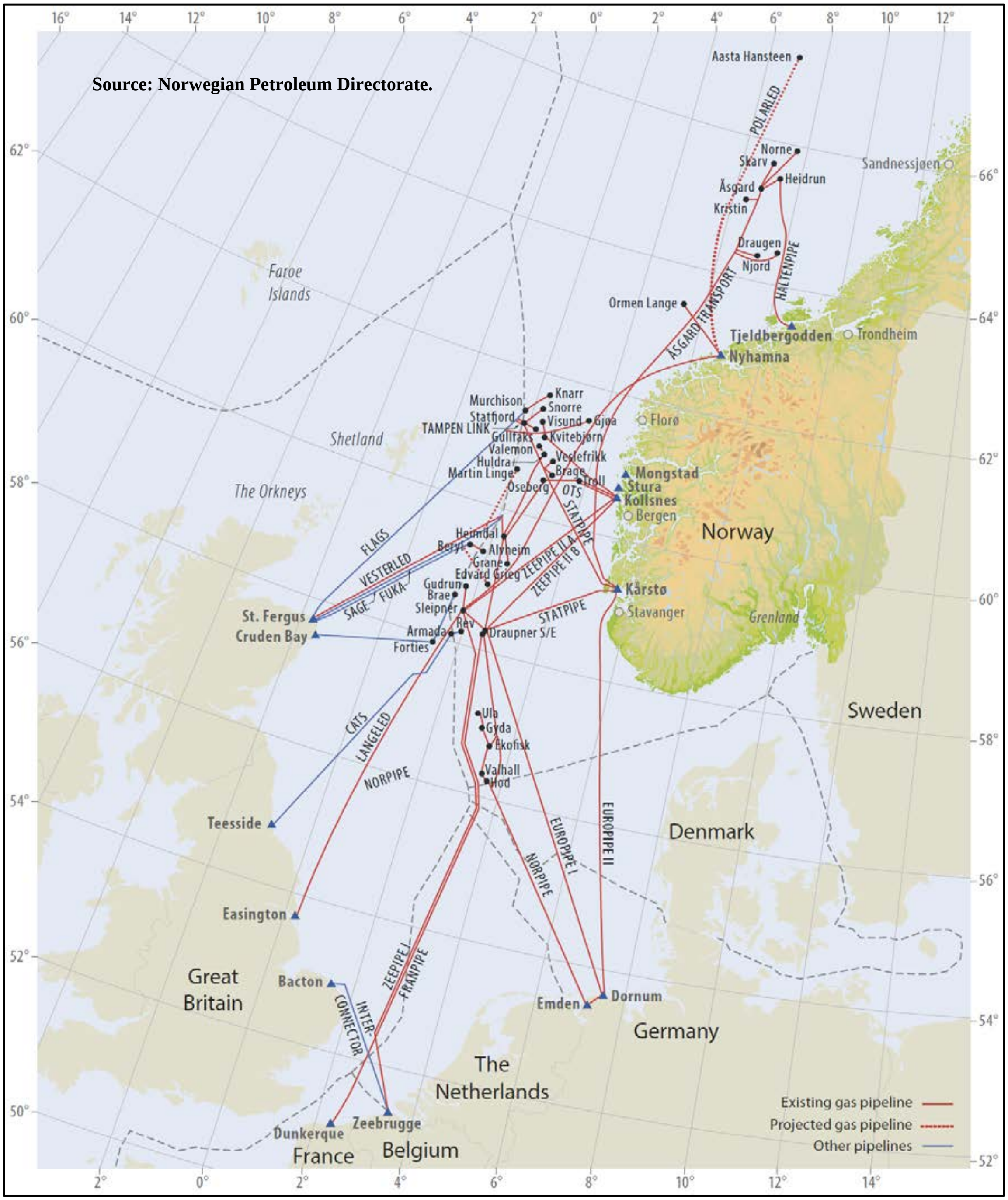



Figure A.20. Gas pipelines originating on Norway’s continental shelf.

## Appendix B: Chapter 2 Table and Figures

**Table B.1. Heavy crude oils and their properties**

| | Boscan | Belridge | Green Canyon | Hondo | Atkinson |
|---|---|---|---|---|---|
| API | 10.9 | 13.6 | 19.5 | 19.6 | 22.9 |
| Sulfur (%) | 5.5 | 1.0 | 1.9 | 4.3 | 1.88 |
| Viscosity (cSt) | | | | | |
| 0 ºC | $8.83\times10^{6}$ | $9.26\times10^{4}$ | 514 | 3507 | 790 |
| 15 ºC | $4.85\times10^{5}$ | $1.26\times10^{4}$ | 177 | 735 | 164 |
| SARS (wt%) | | | | | |
| Saturates | 25 | 28 | 38 | 33 | 44 |
| Aromatics | 35 | 39 | 40 | 31 | 30 |
| Resins | 22 | 30 | 14 | 24 | 17 |
| Asphaltenes | 18 | 3 | 8 | 12 | 9 |
| Metals (ppm) | | | | | |
| Ni | 117 | 70 | 29 | 75 | 49 |
| Vn | 1320 | 86 | 106 | 196 | 112 |

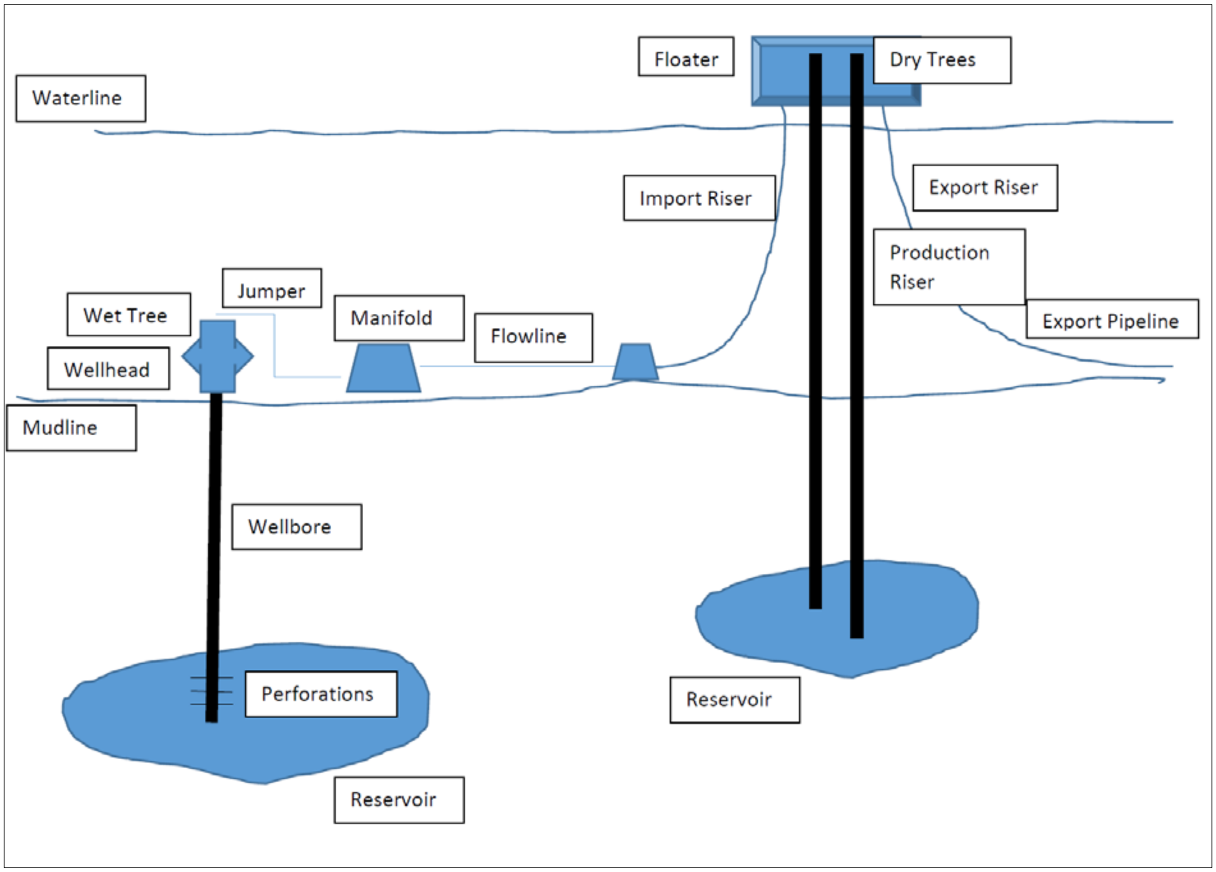
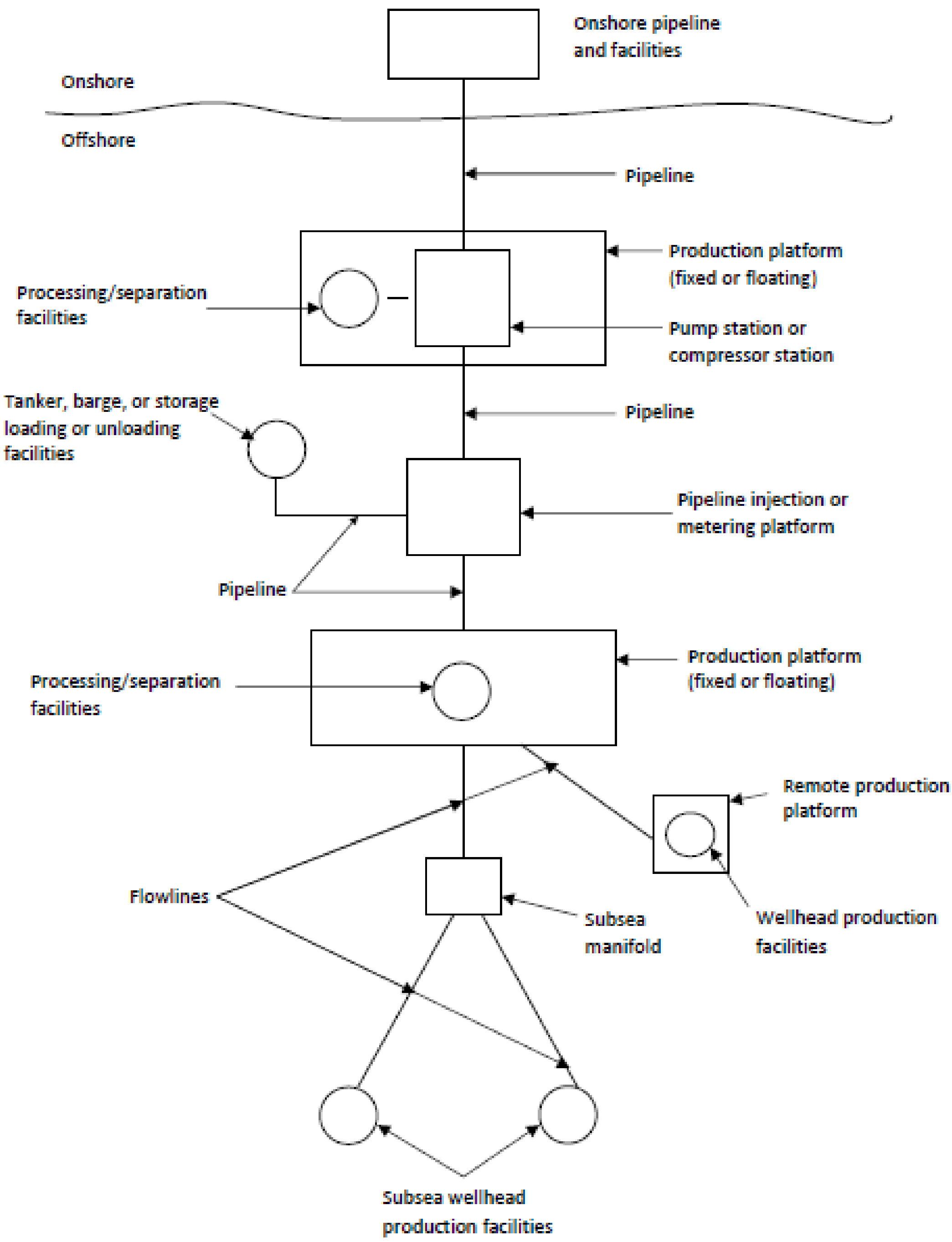



Figure B.1. Schematic of production system components–plan view.




**Source: Adapted from API Recommended Practice 1111.**

Figure B.2. Schematic of production system components, top view.

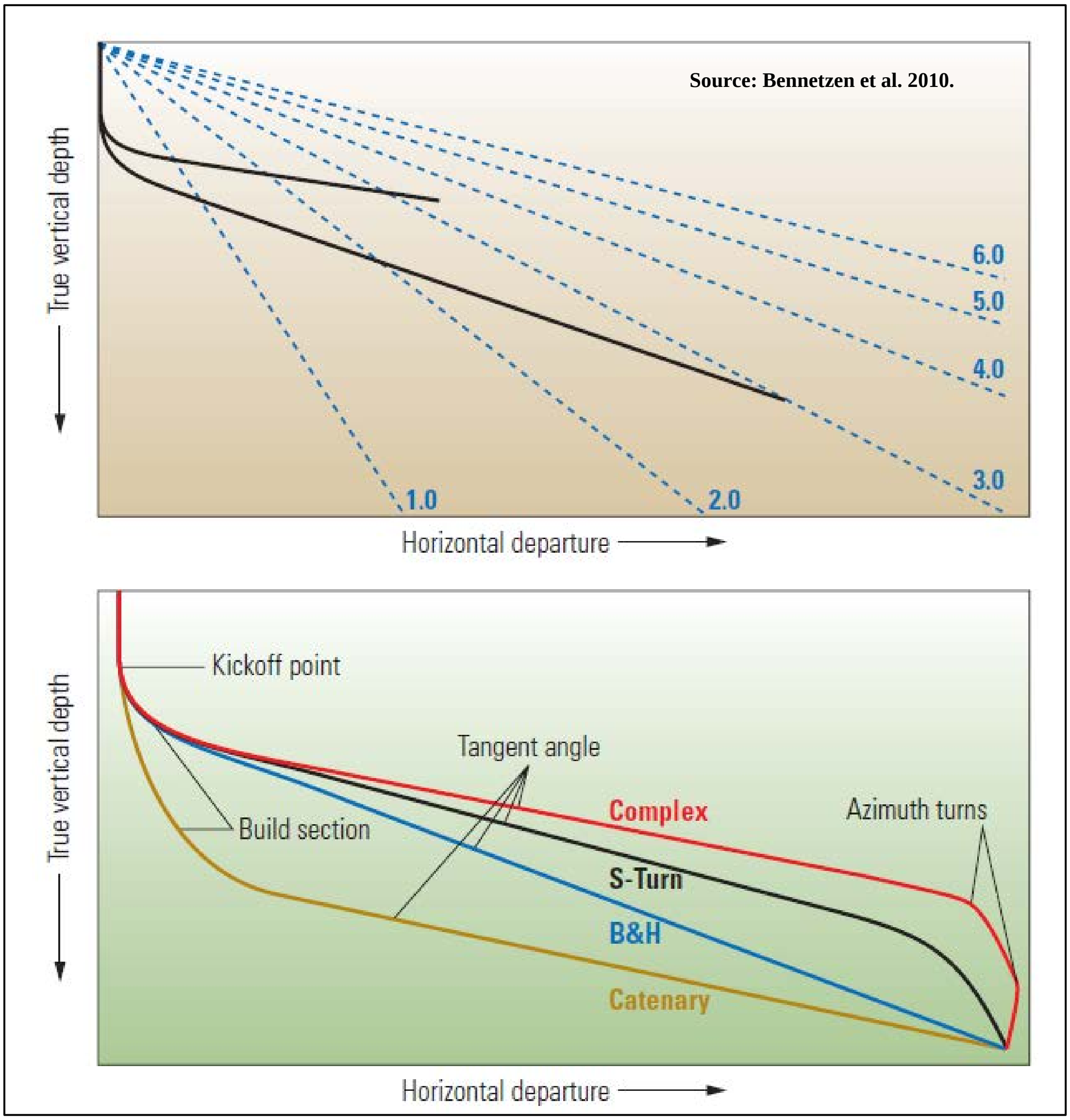
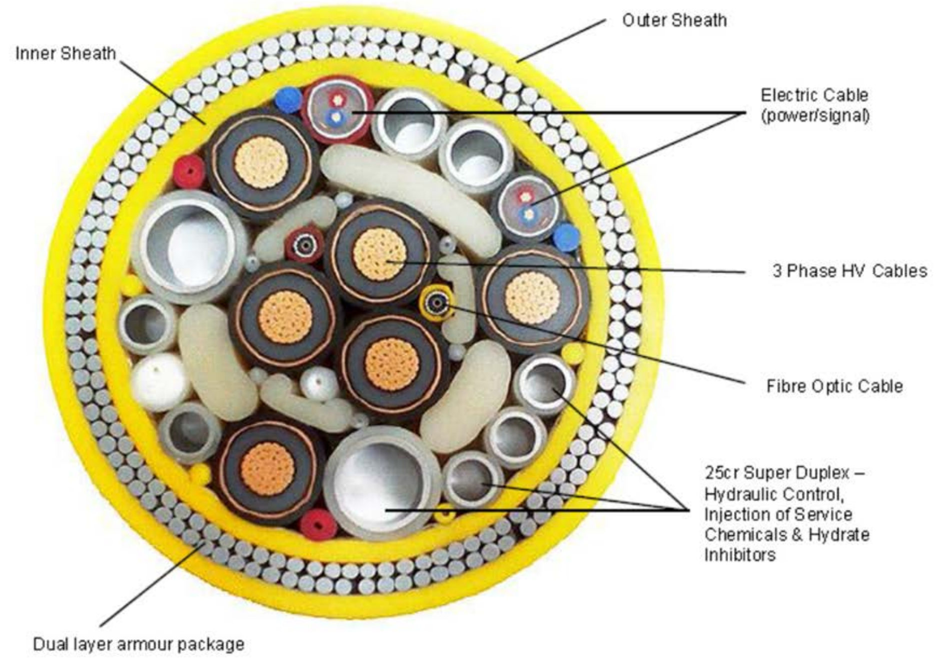



Figure B.3. Extended reach well types.




**Source: Koto 2017.**

Figure B.4. Umbilical cross-section showing electric and fiber optic cable and chemical lines.

**Source: Amin et al. 2005.**

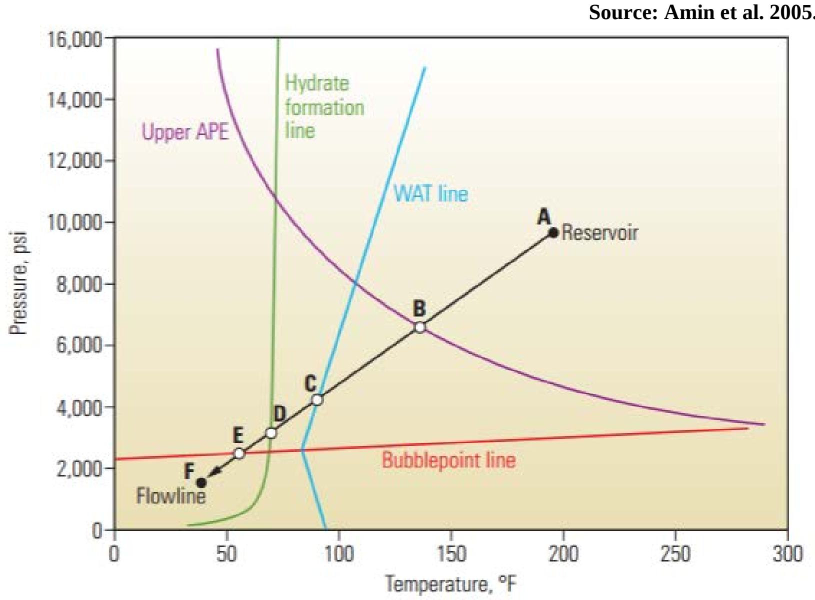



Figure B.5. Schematic of an oil phase diagram from reservoir to flowline.

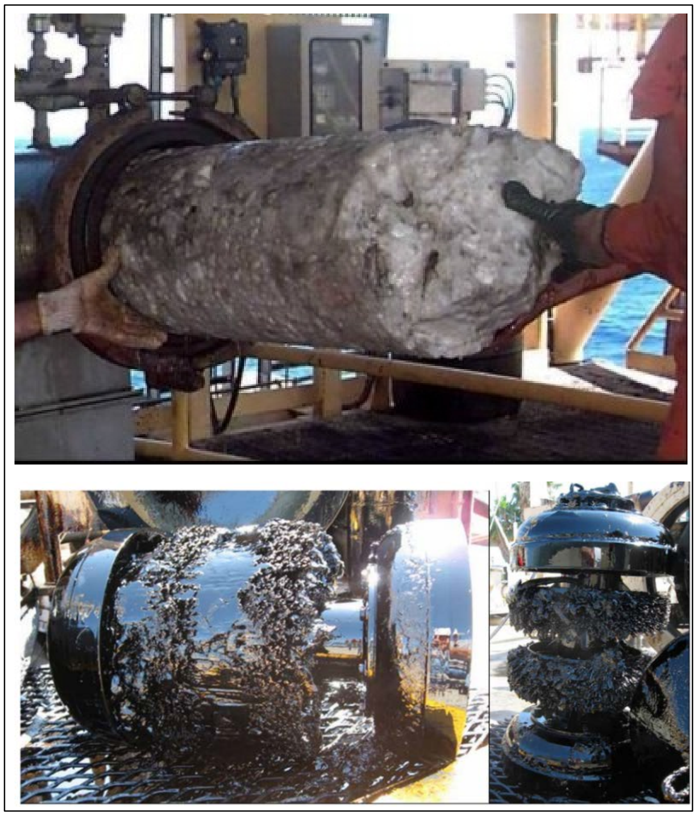


Figure B.6. Hydrates (top) and wax (bottom) removal in pipeline.

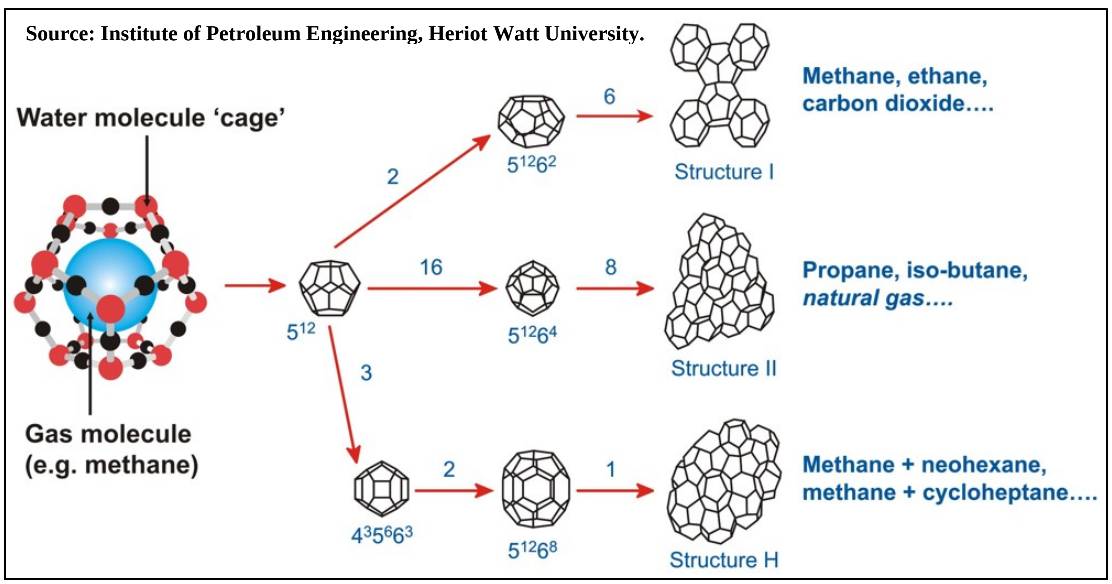



Figure B.7. Molecular representation of cages for different captive species.

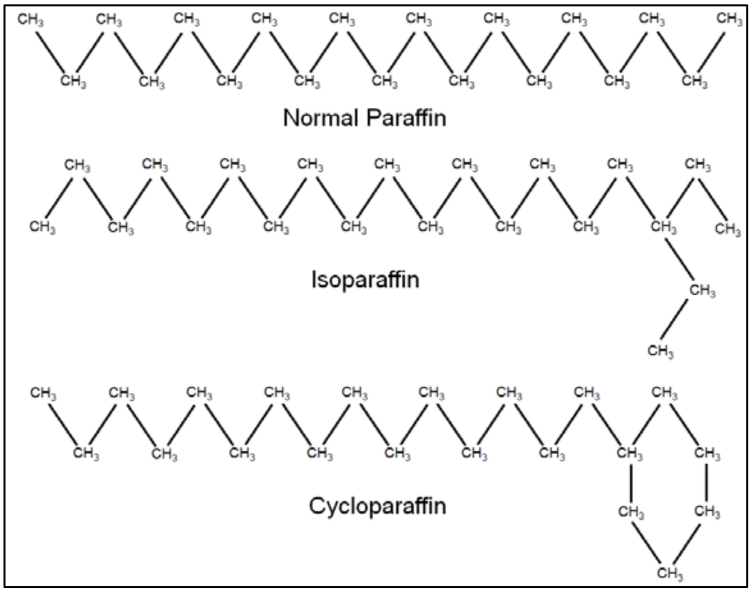



Figure B.8. Example structure of wax-forming components.

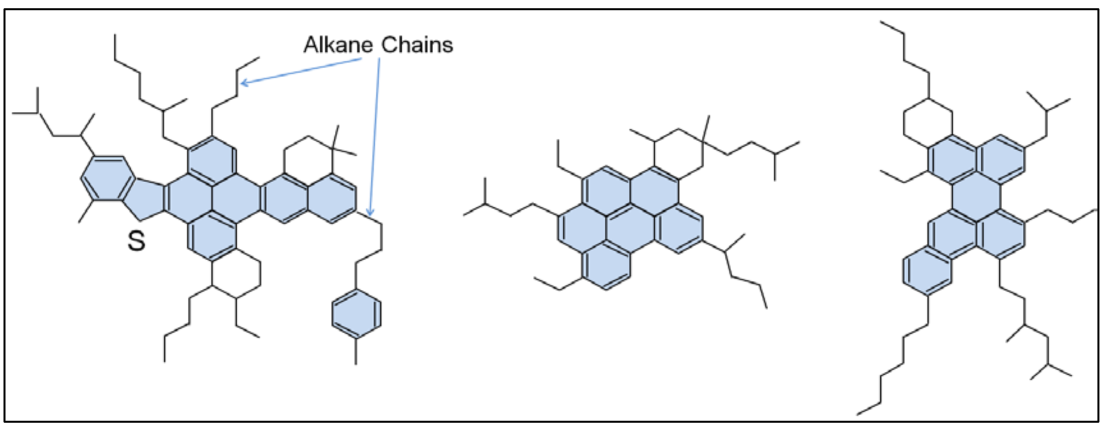



Figure B.9. Asphaltene molecular structures.

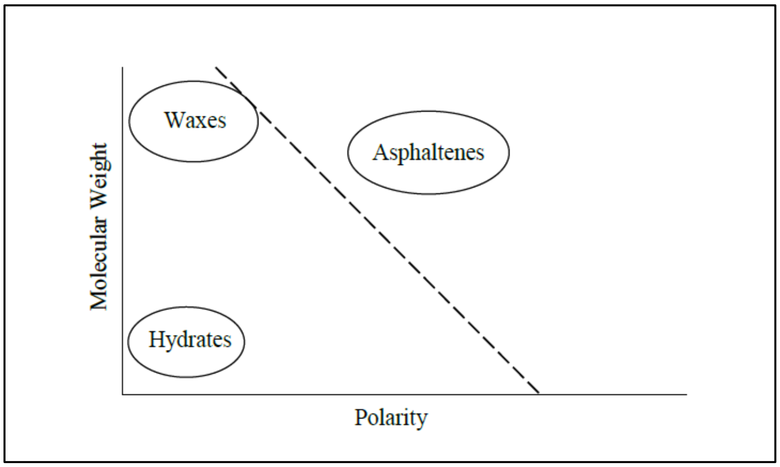



Figure B.10. Molecular weight and polarity define asphaltenes, hydrates, and wax in crude oil.

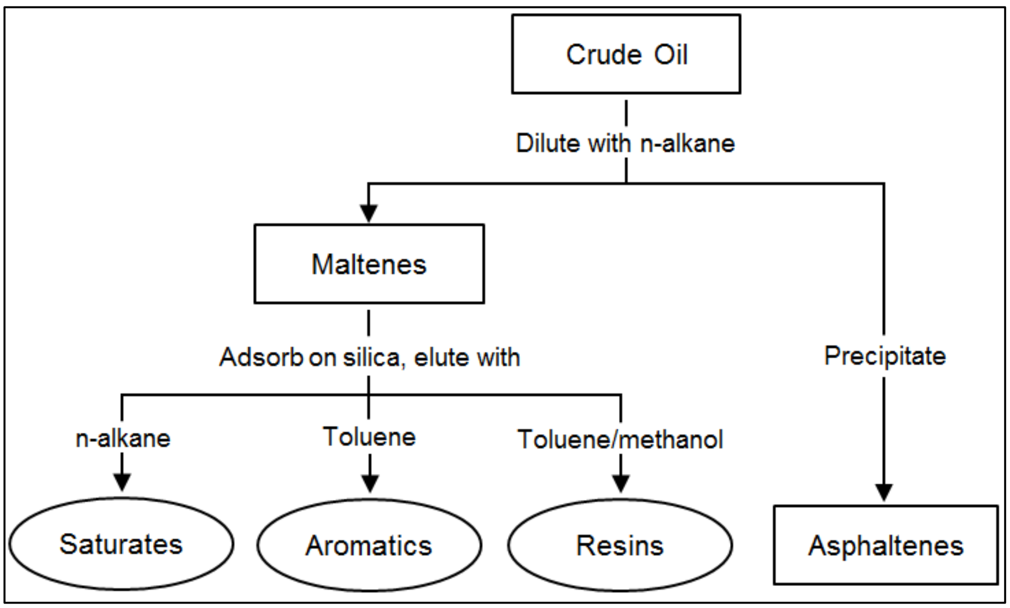



Figure B.11. Separating crude oil into saturates, aromatics, resins, and asphaltenes.

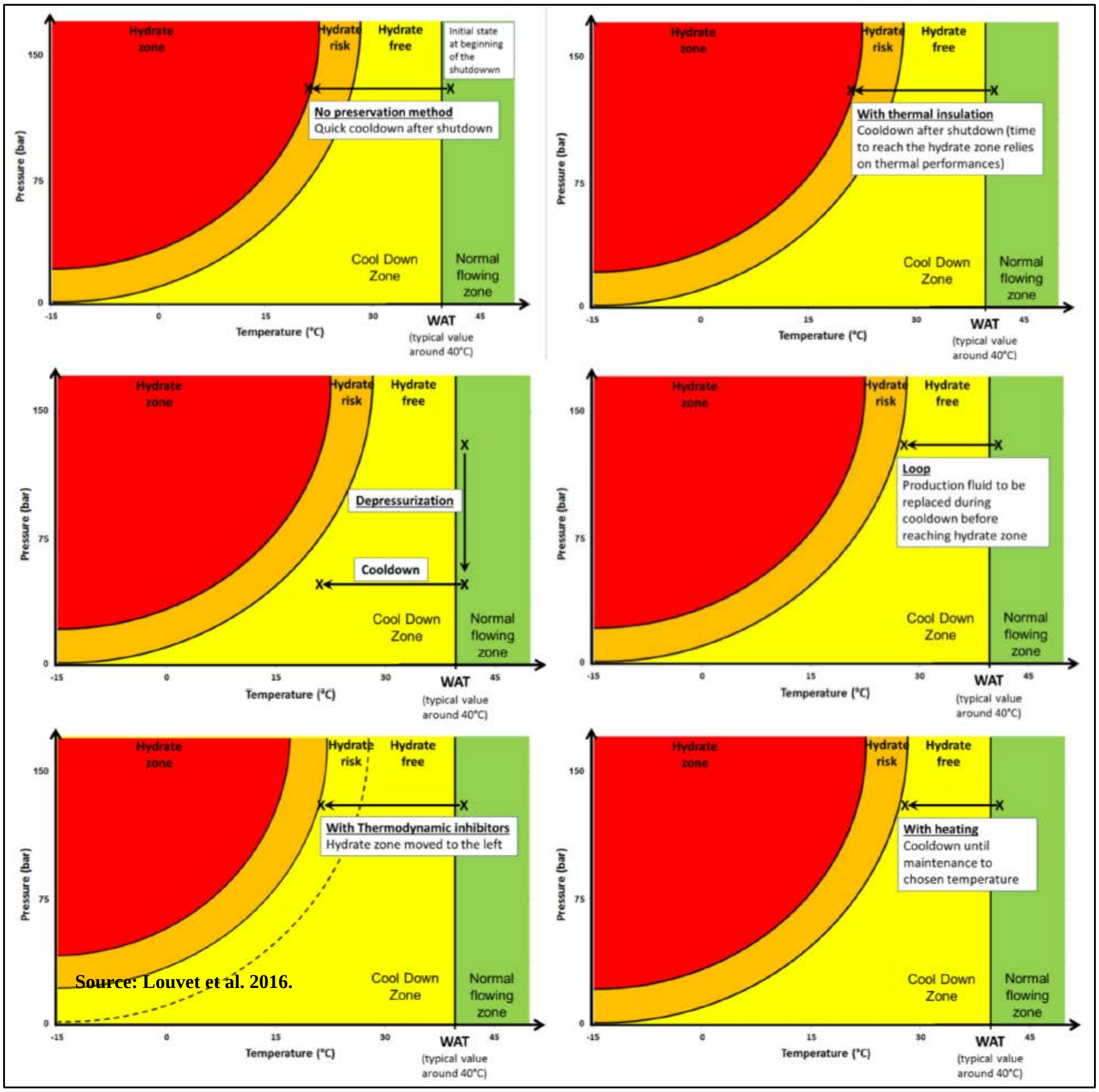



Figure B.12. Schematic illustration of different hydrate management techniques.

## Appendix C: Chapter 3 Table and Figures

**Table C.1. Auger and subsea tieback cumulative production circa September 2017**

| Name | Field | First Production | Garden Bank Lease Blocks | Cum. Oil (MMbbl) | Cum. Gas (Bcf) |
|---|---|---|---|---|---|
| Auger | GB 426 | 1994 | 426, 427, 470, 471 | 267 | 935 |
| Macaroni | GB 602 | 1999 | 602 | 13.4 | 24.9 |
| Oregano | GB 559 | 2001 | 559 | 33.1 | 49.5 |
| Serrano | GB 516 | 2001 | 515, 516, 472 | 3.9 | 47 |
| Llano | GB 387 | 2002 | 341, 385-387 | 94.7 | 223 |
| Total | | | | 412 | 1279 |

Source: BOEM 2018d.

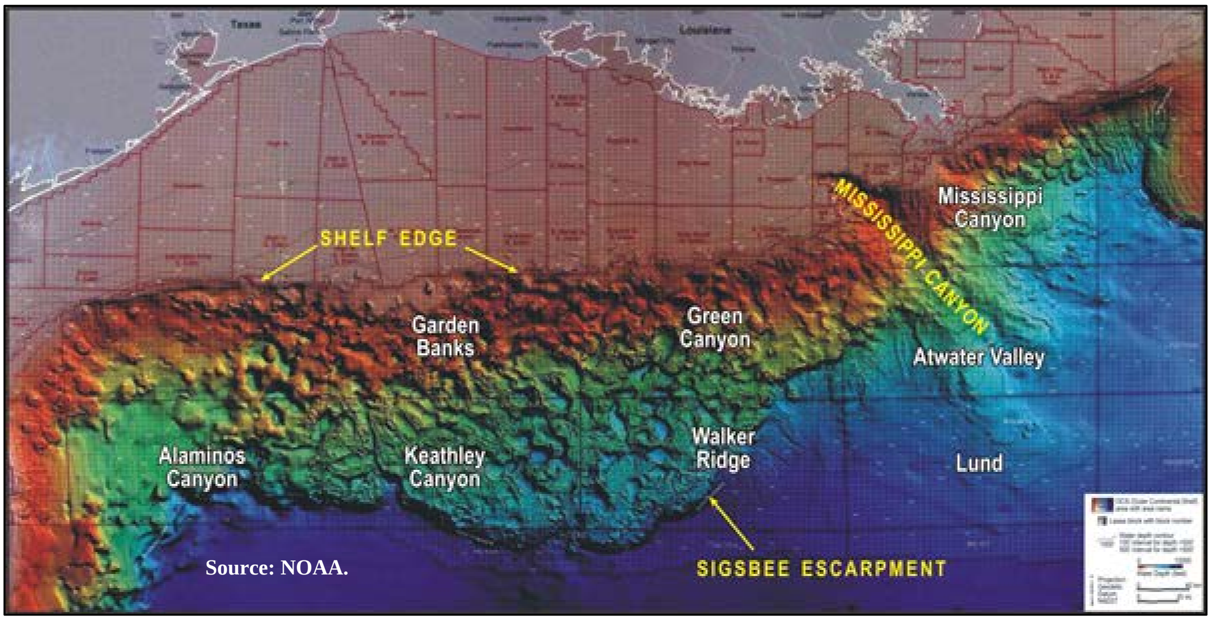
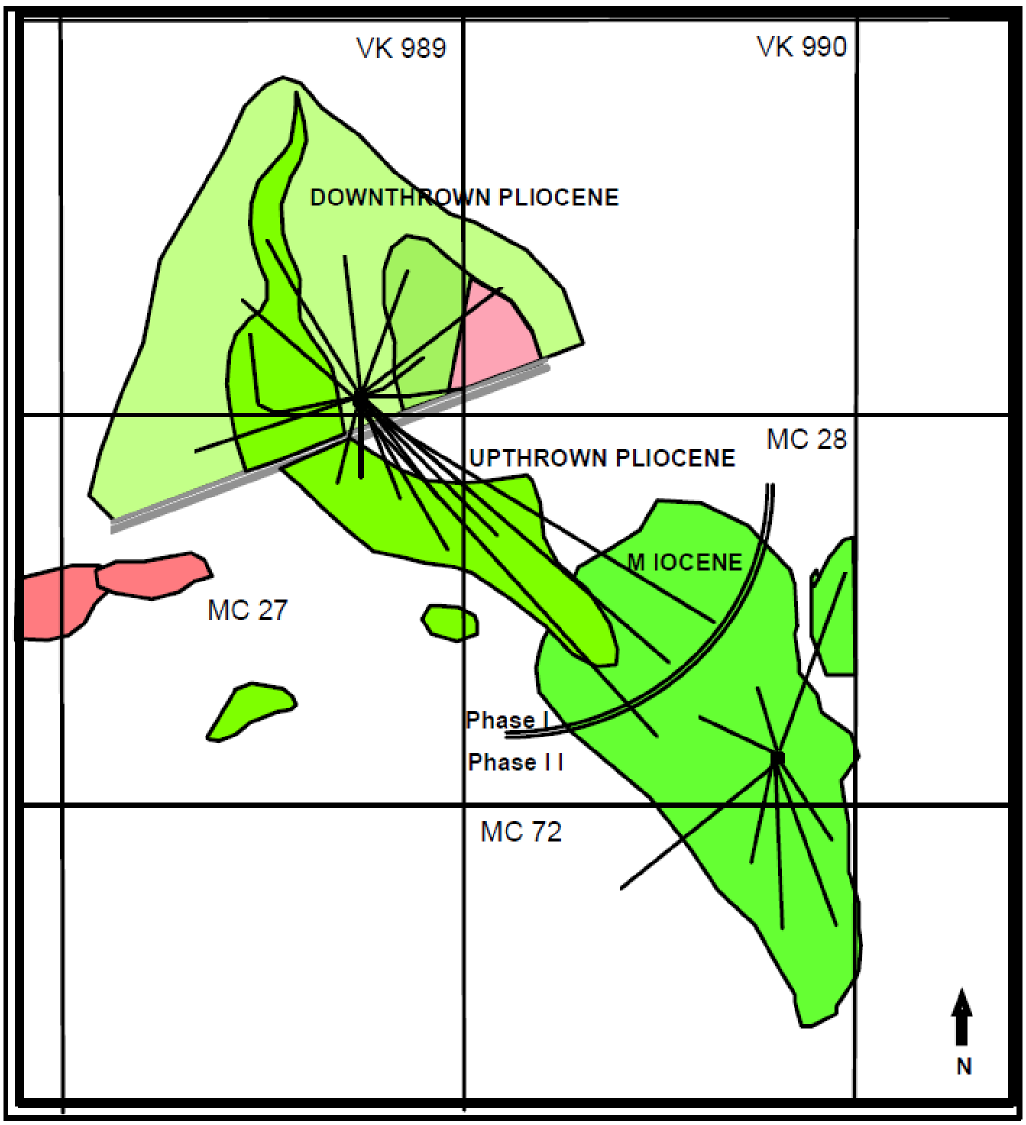



Figure C.1. Bathymetry of the Northern Gulf of Mexico and Sigsbee Escarpment.




**Source: Willson et al. 2003.**
Figure C.2. Pompano reservoirs and development well trajectories.


Figure C.3. Cognac platform in Mississippi Canyon 194 in 1025 ft water depth.

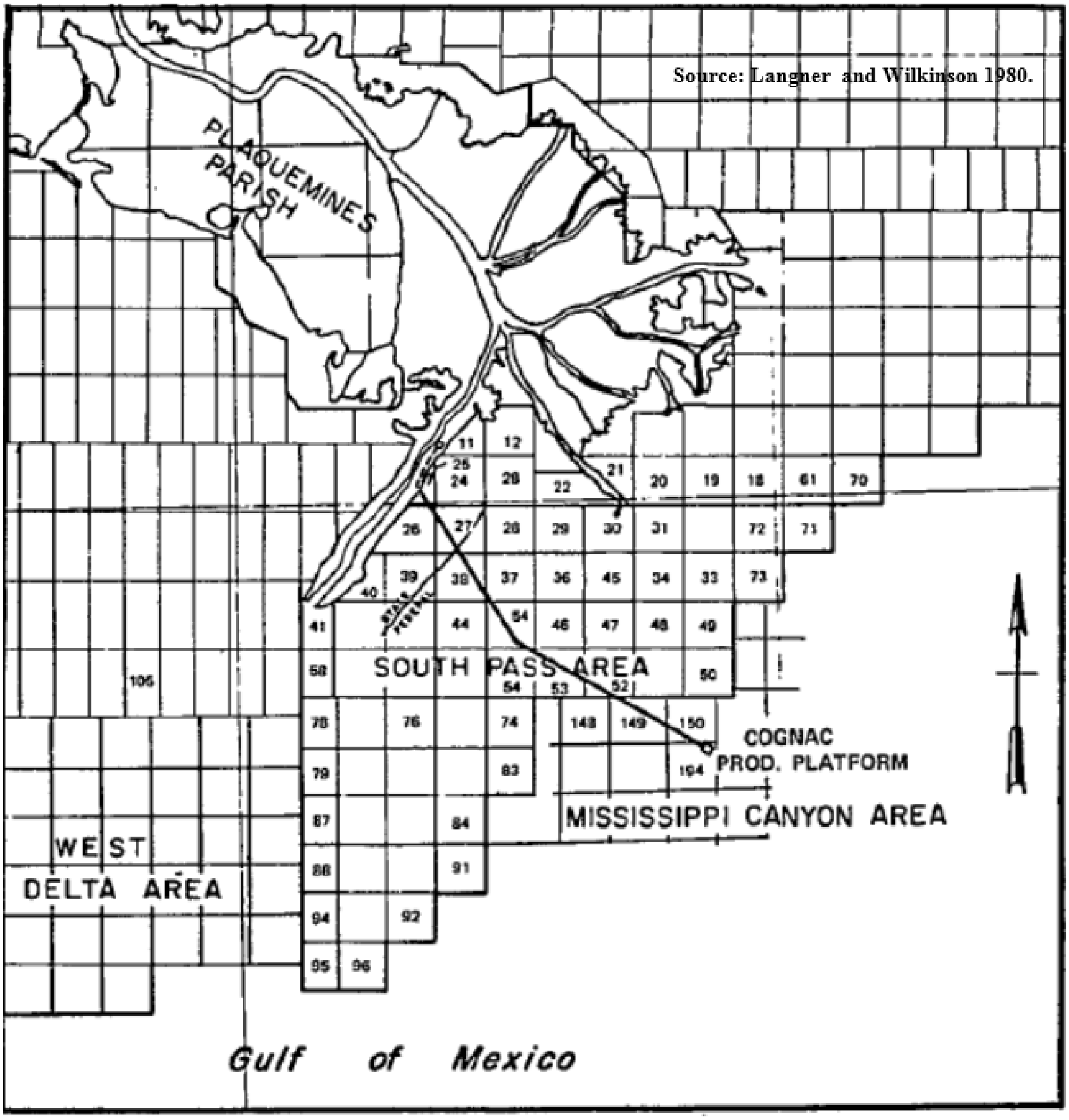



Figure C.4. Location of Cognac initial two-phase export pipeline.

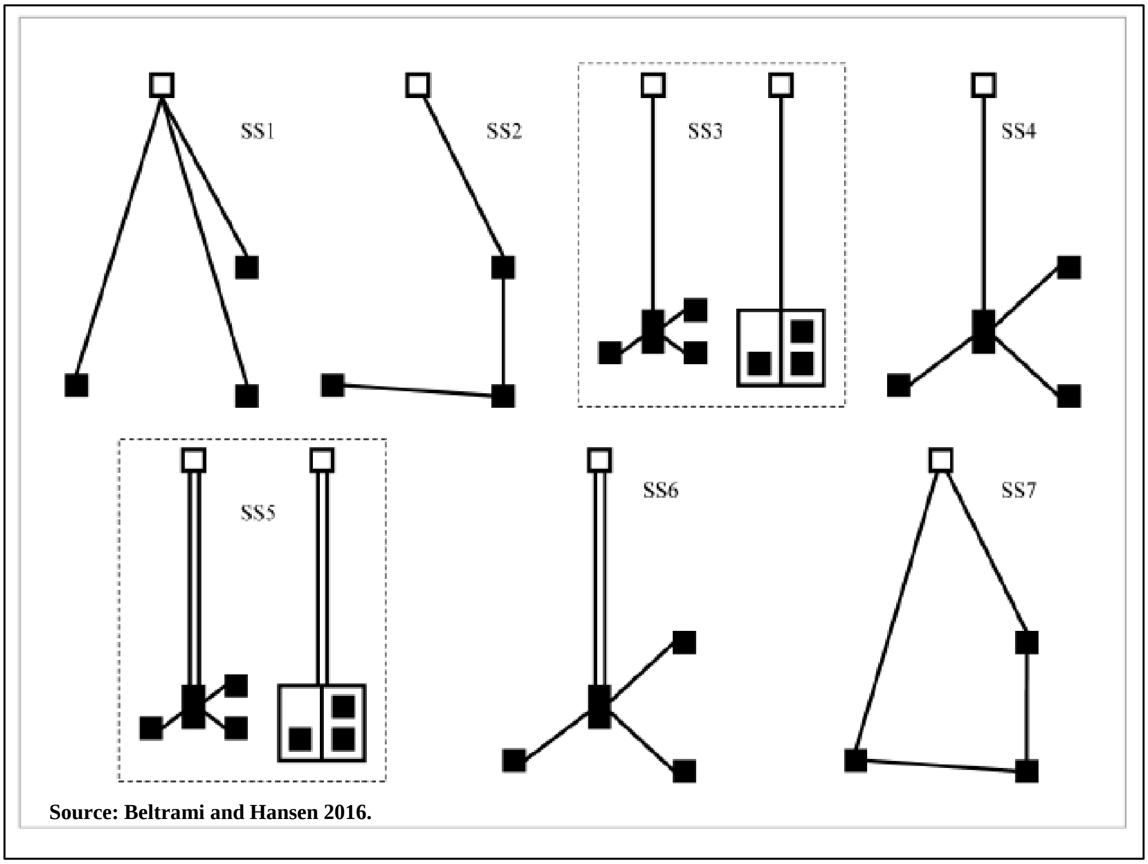



Figure C.5. Schematics of typical subsea configurations.

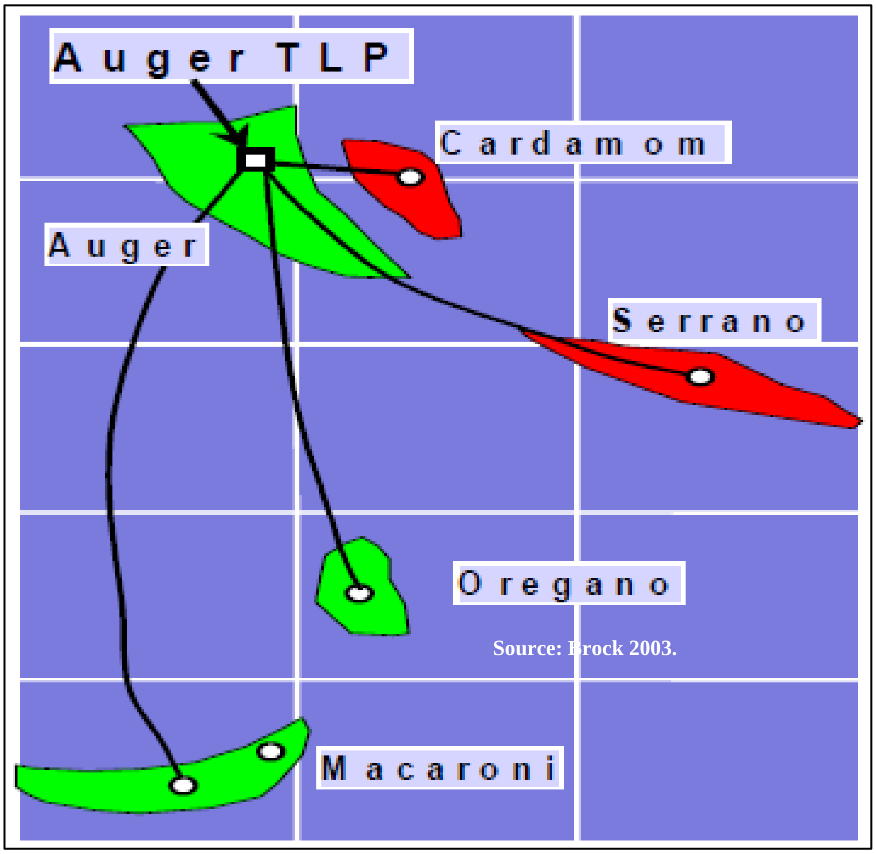



Figure C.6. Auger TLP subsea tiebacks Macaroni, Oregano, and Serrano circa 2000.

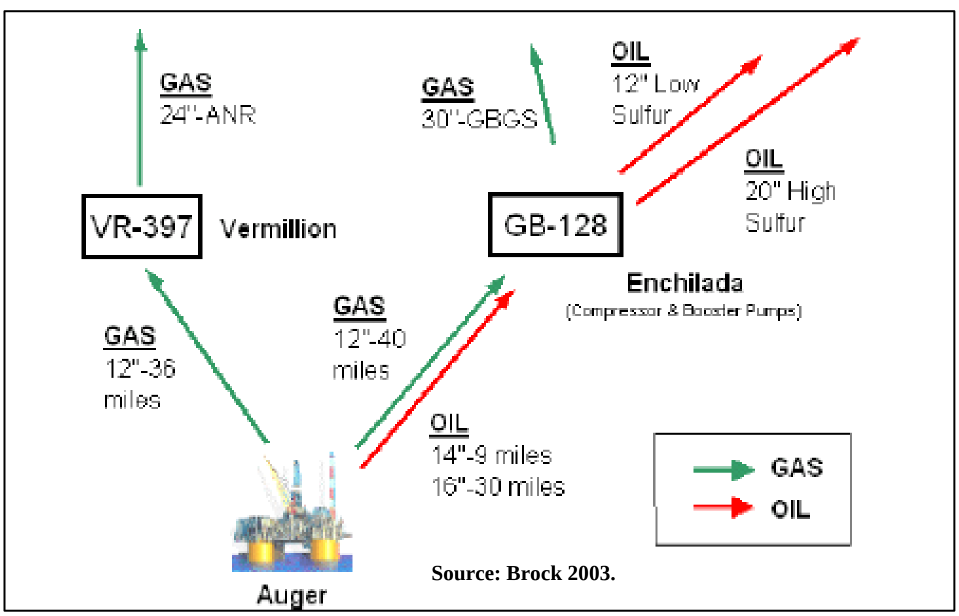



Figure C.7. Auger oil and gas export pipelines.

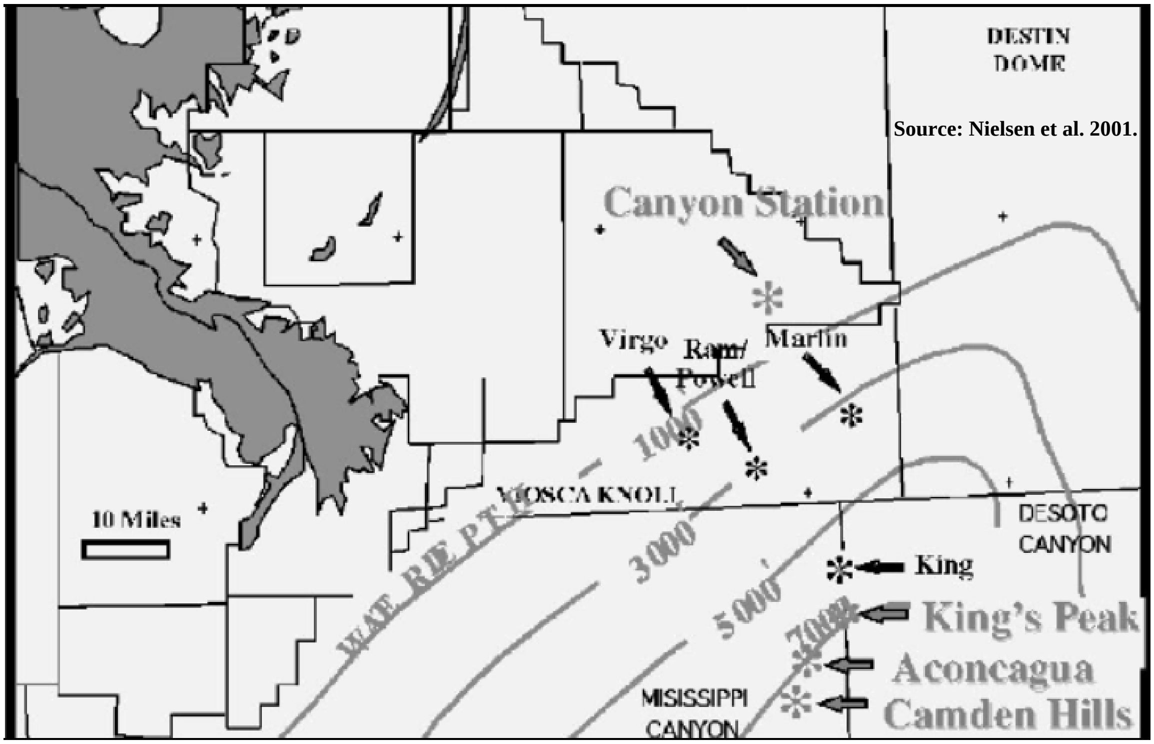



Figure C.8. Map of Canyon Express fields (King's Peak, Aconcagua, Camden Hills) and Canyon Station.

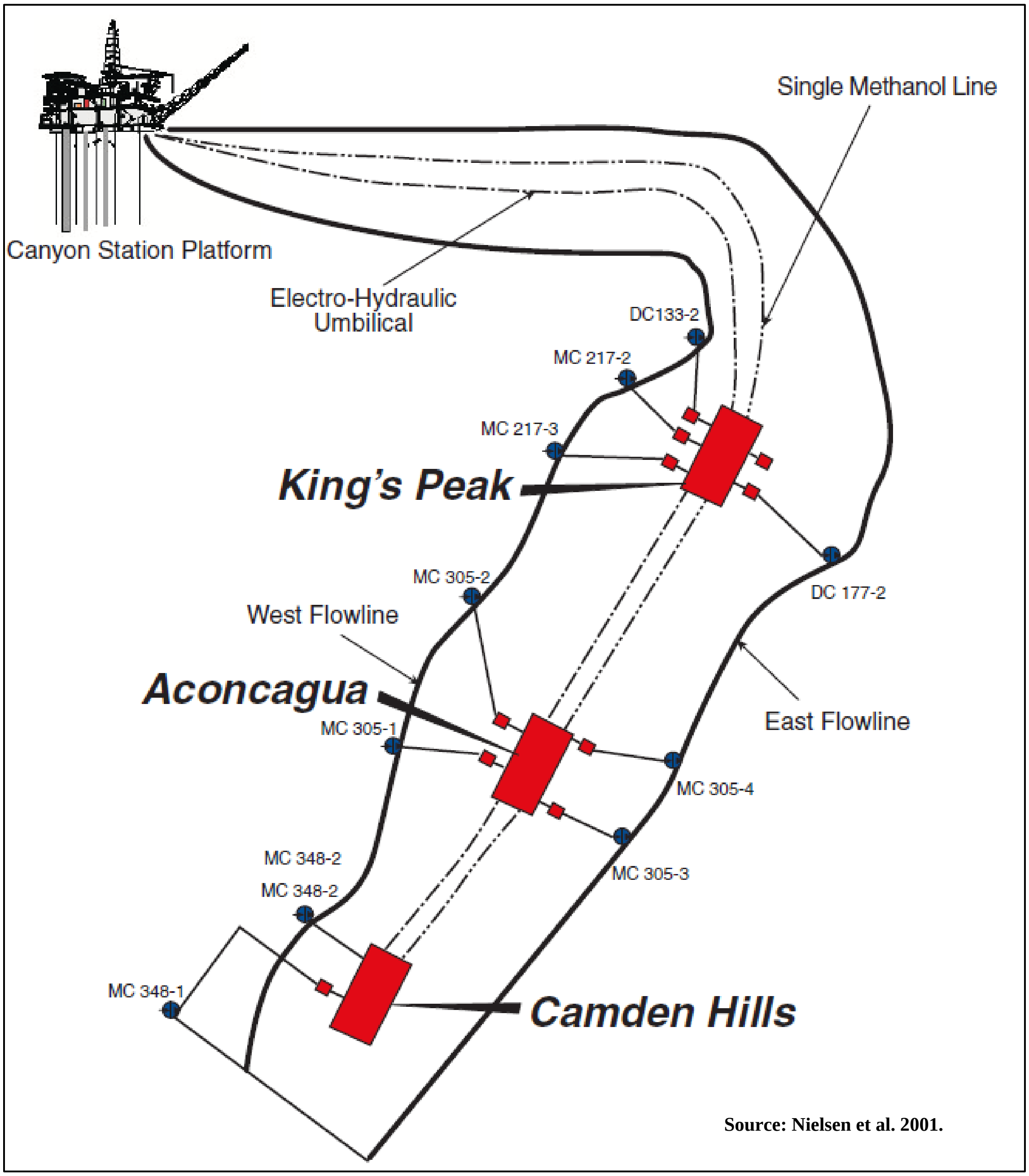



Figure C.9. Schematic of Canyon Express flowline and umbilical configuration.

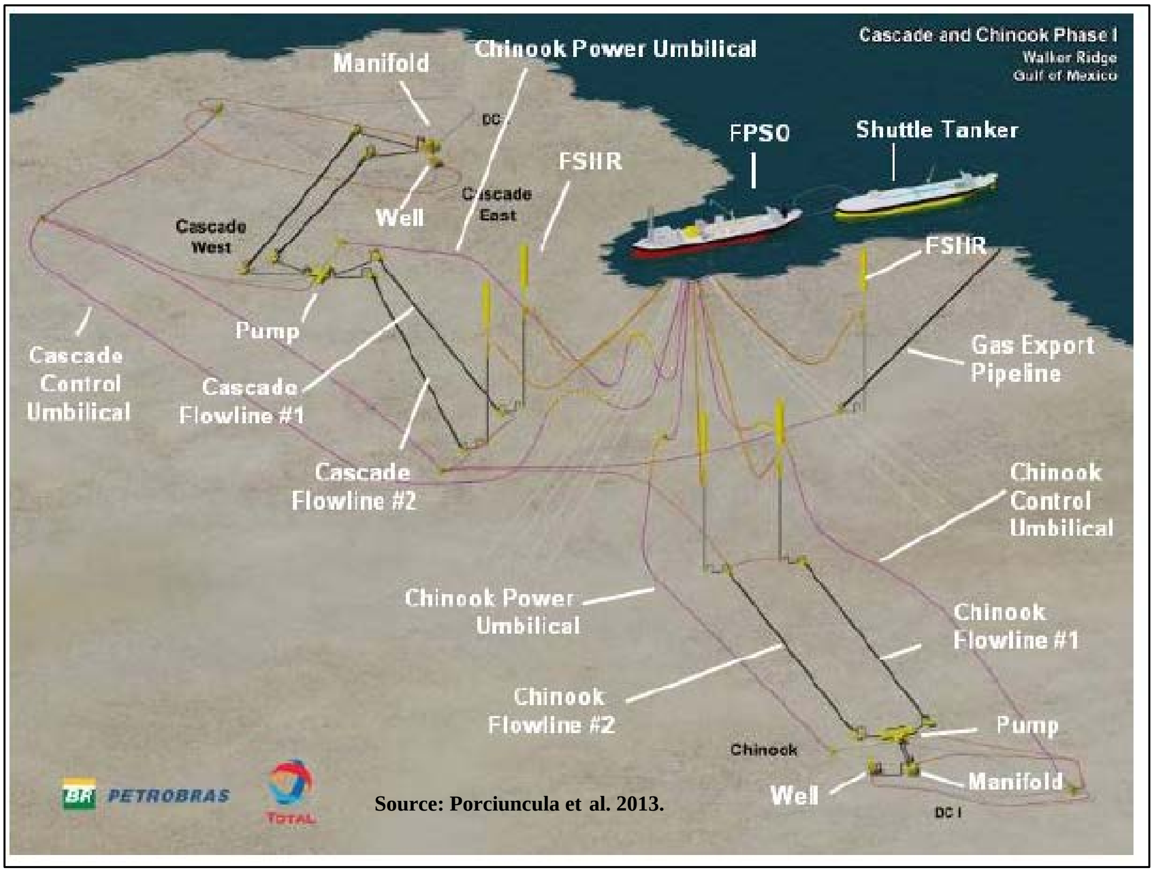
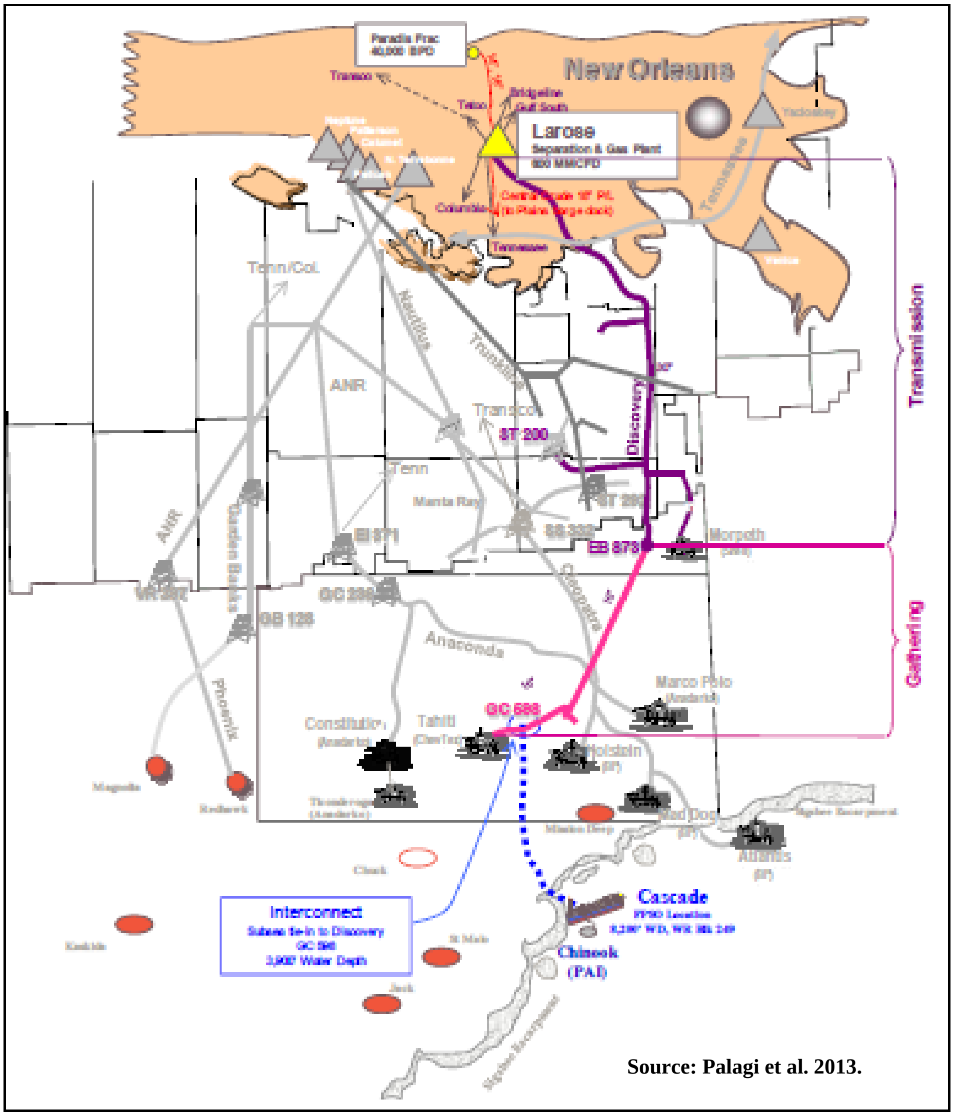



Figure C.10. Cascade and Chinook subsea development layout.




Source: Palagi et al. 2013.

Figure C.11. Cascade and Chinook natural gas export and transportation systems.

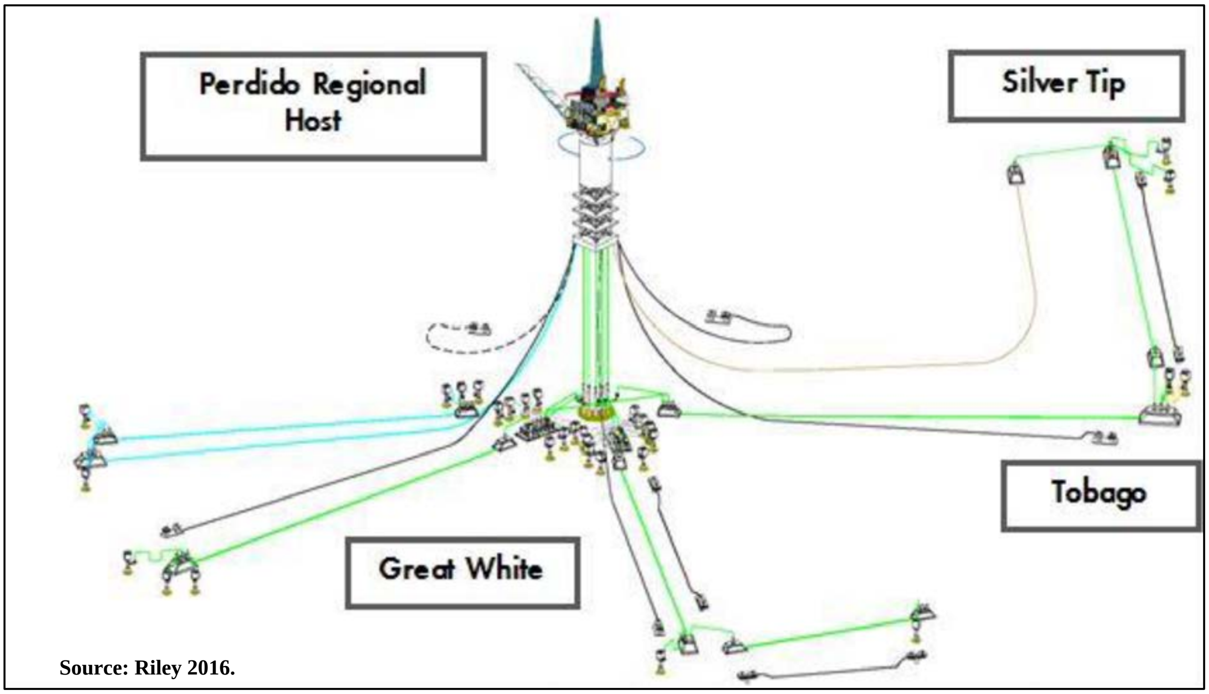



Figure C.12. Perdido field development map.

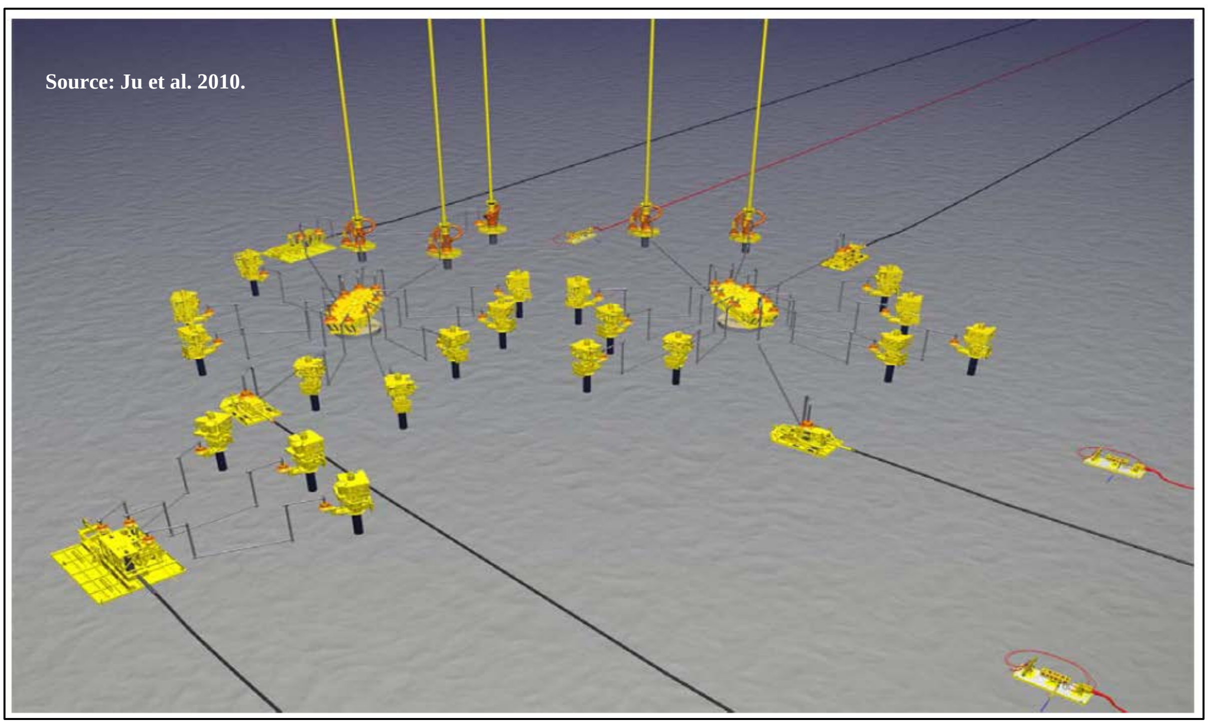



Figure C.13. Schematic of direct vertical access cluster at Perdido.

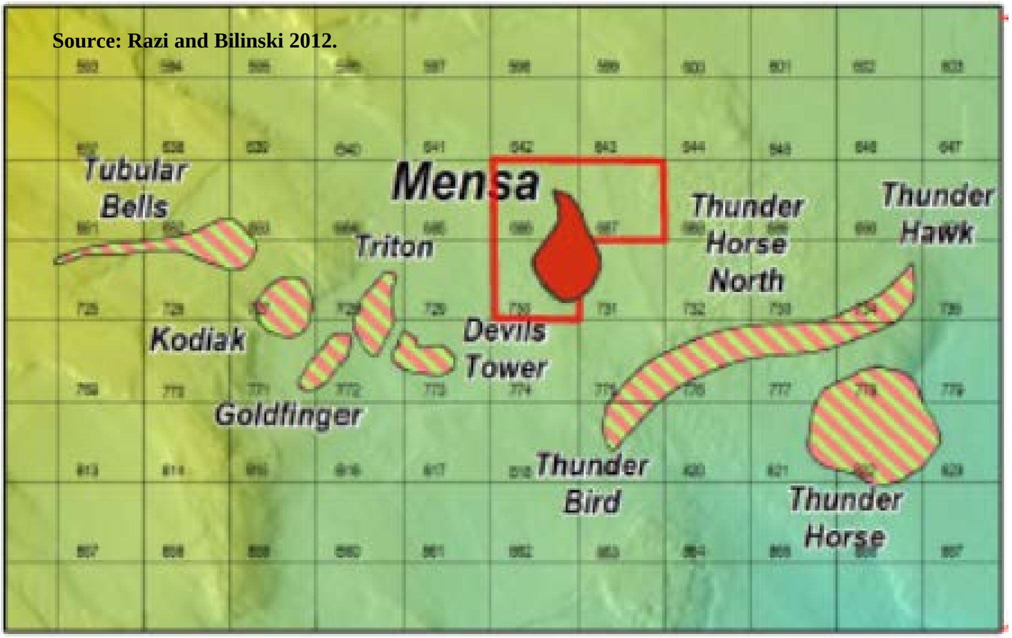



Figure C.14. Mensa field location map.


Figure C.15. Mensa subsea production system.

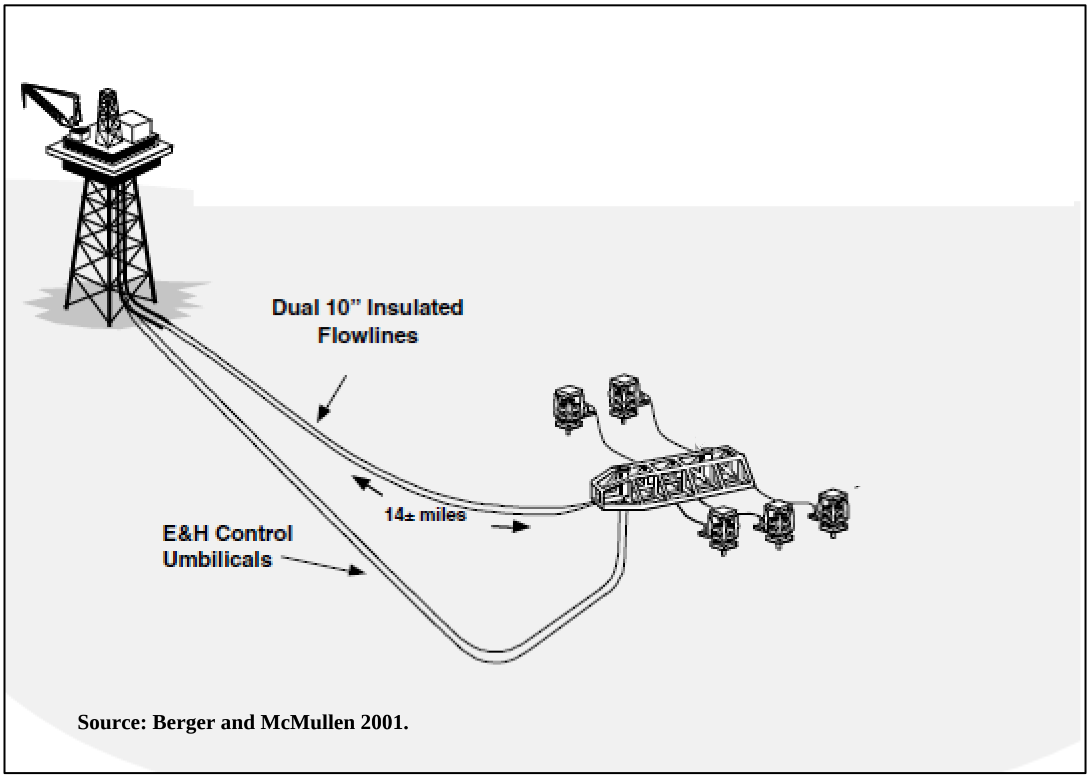



Figure C.16. Troika subsea system layout and tieback to host platform Bullwinkle.

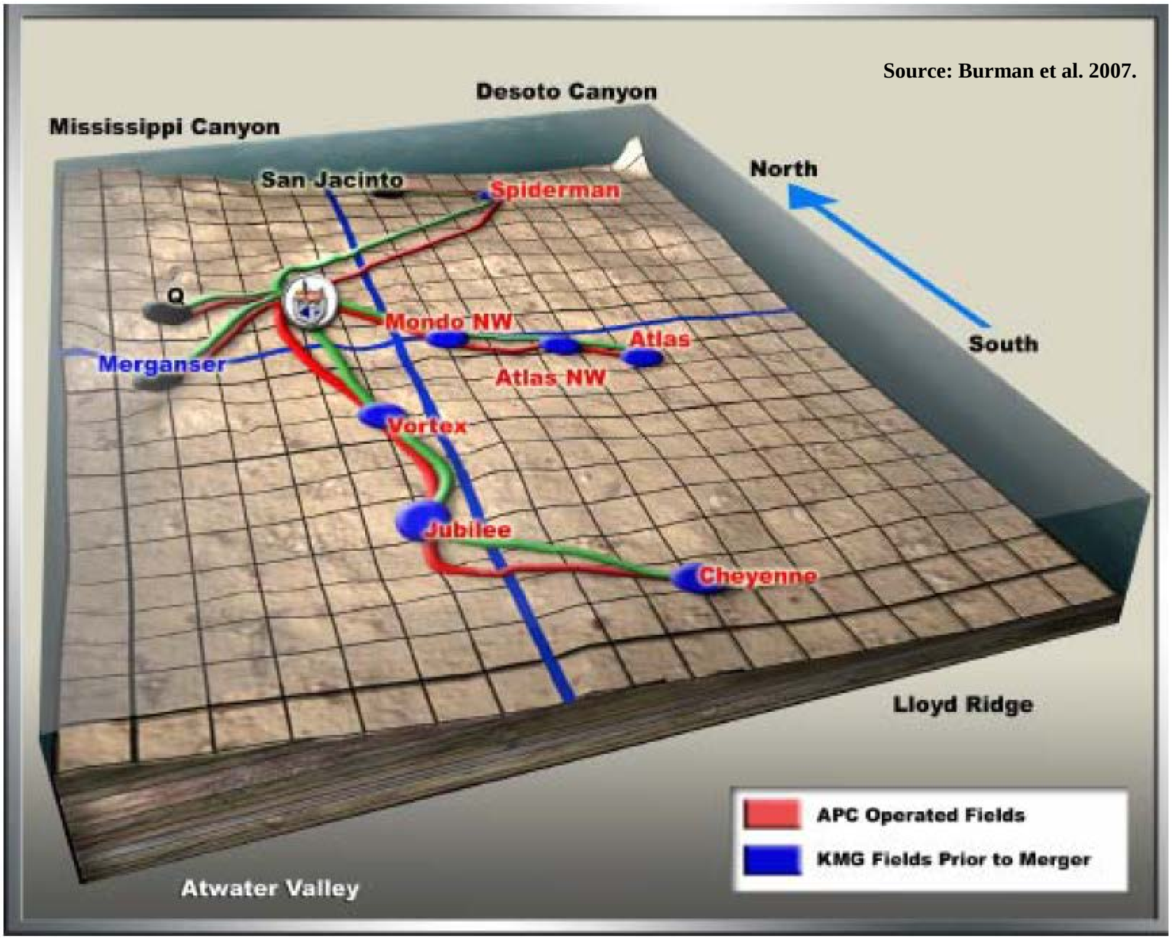



Figure C.17. Independence project layout.

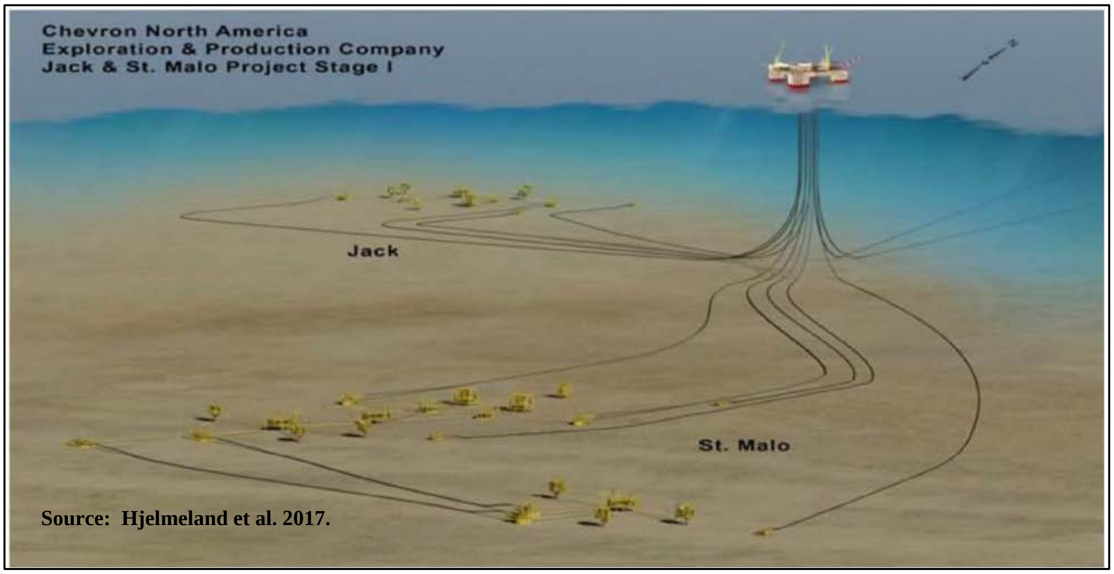



Figure C.18. Jack and St-Malo stage one field layout.

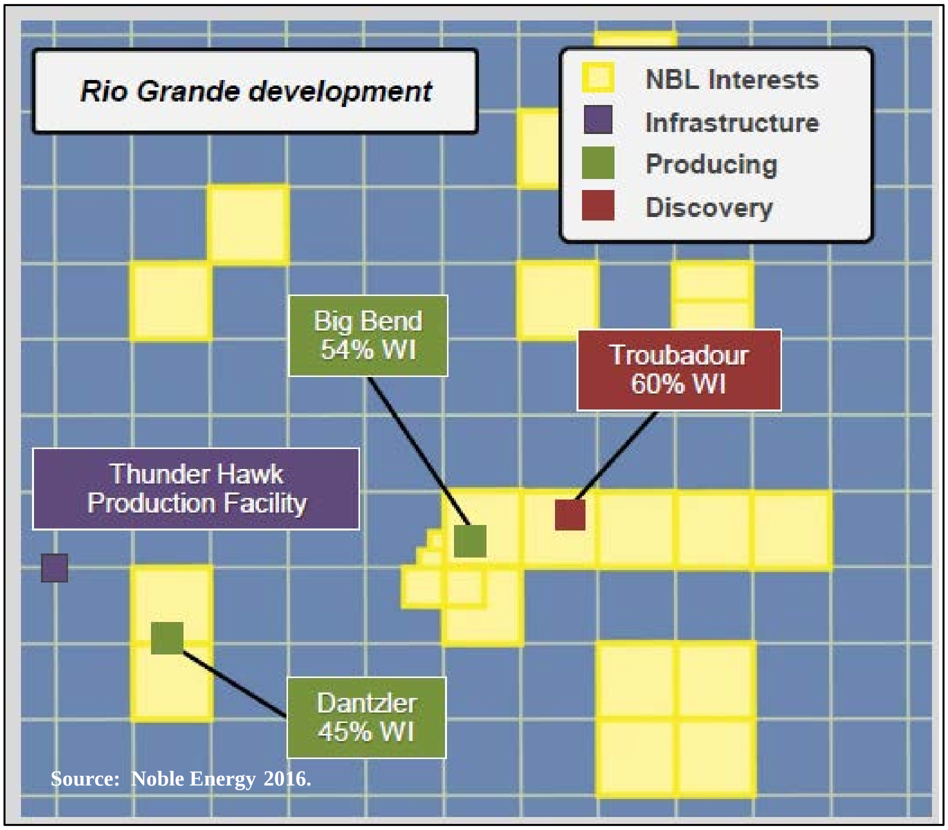



Figure C.19. Big Bend and Dantzler fields and Thunder Hawk host location.

## Appendix D: Chapter 4 Figures

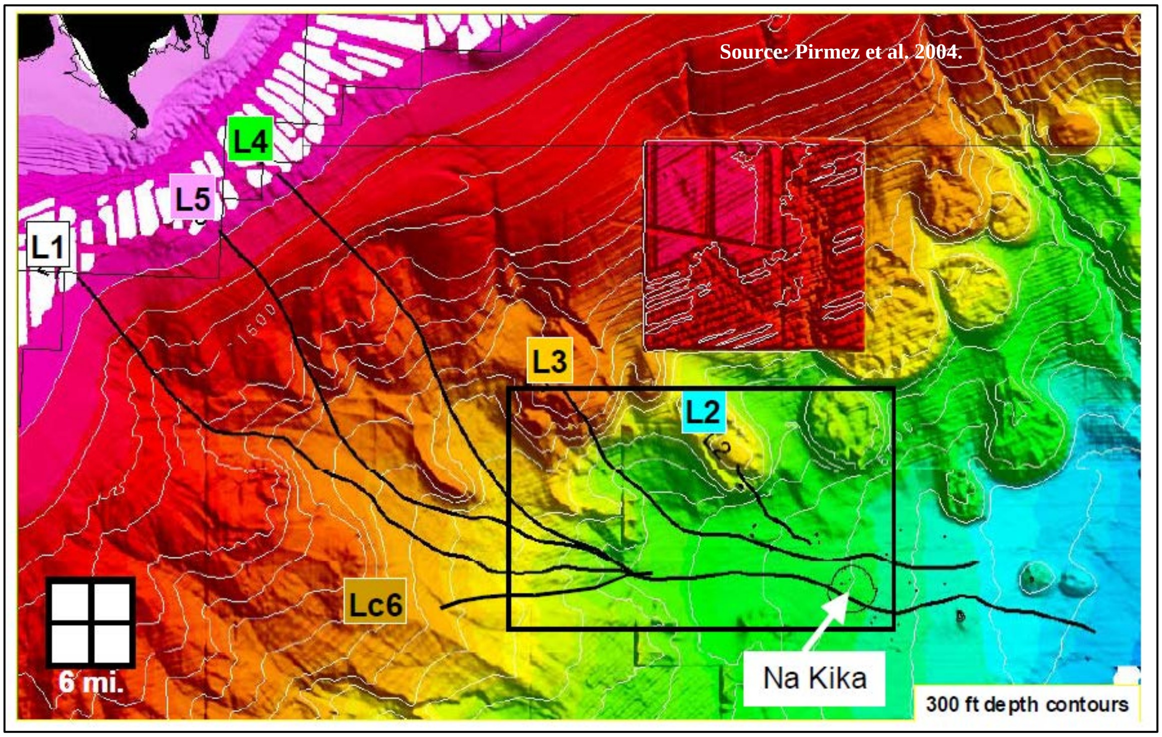



Figure D.1. Location map of the Na Kika Basin and production facility.

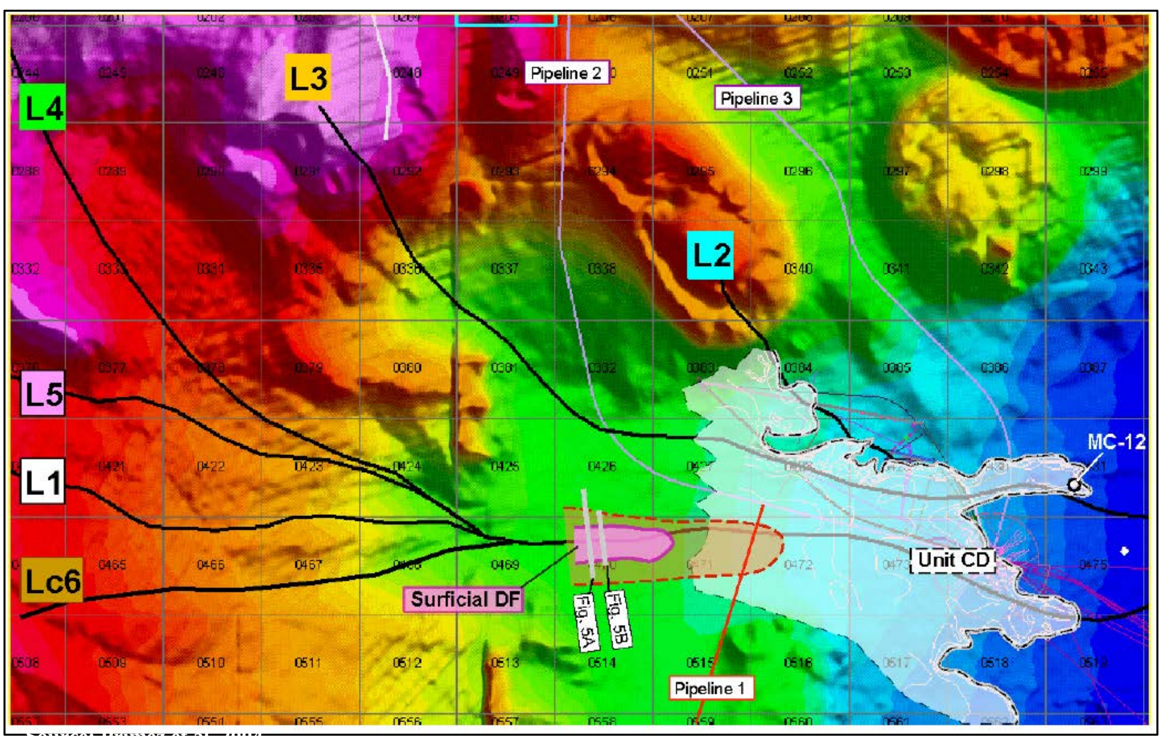



Figure D.2. Bathymetry of Na Kika Basin showing location of surficial and buried debris flow deposits.

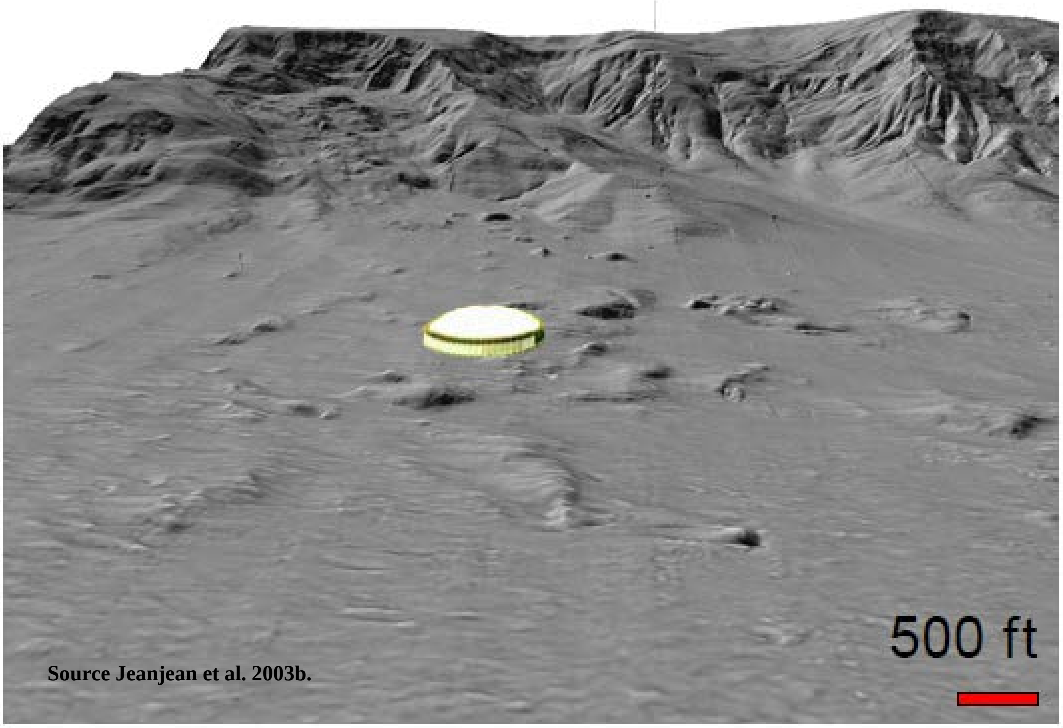



Figure D.3. Overlay of Houston Astrodome and intact blocks of debris flow at Atlantis Slump A.

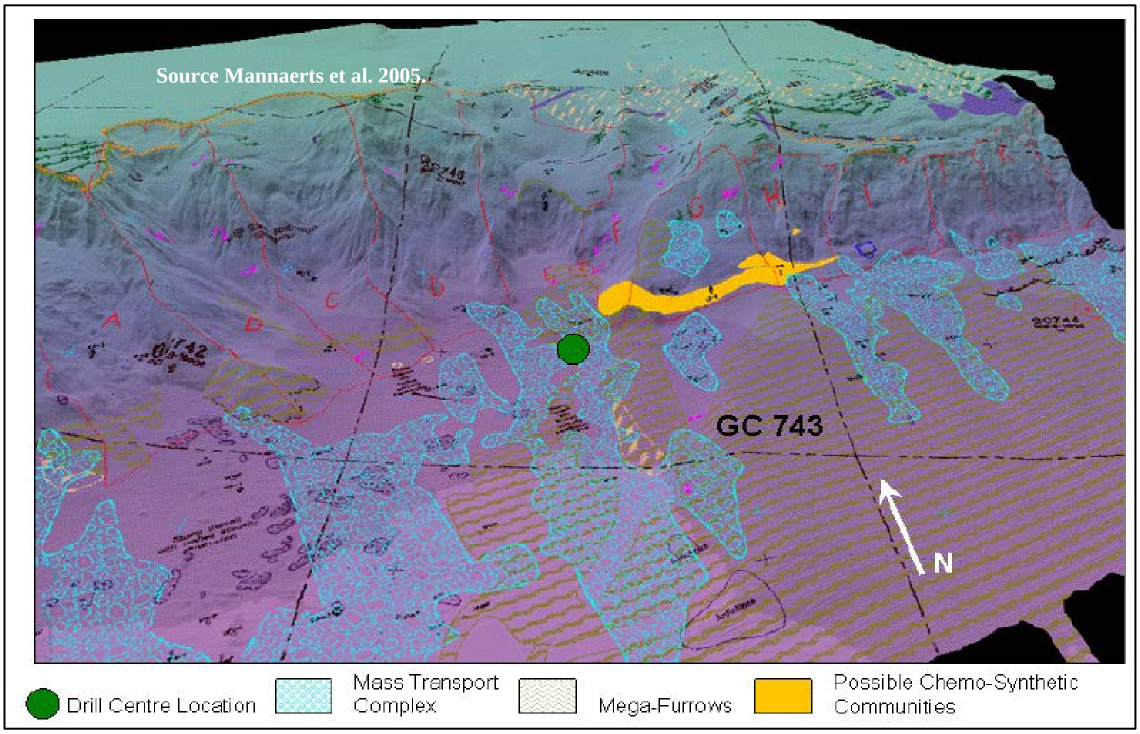


Figure D.4. Perspective view of Sigsbee Escarpment near Atlantis development.

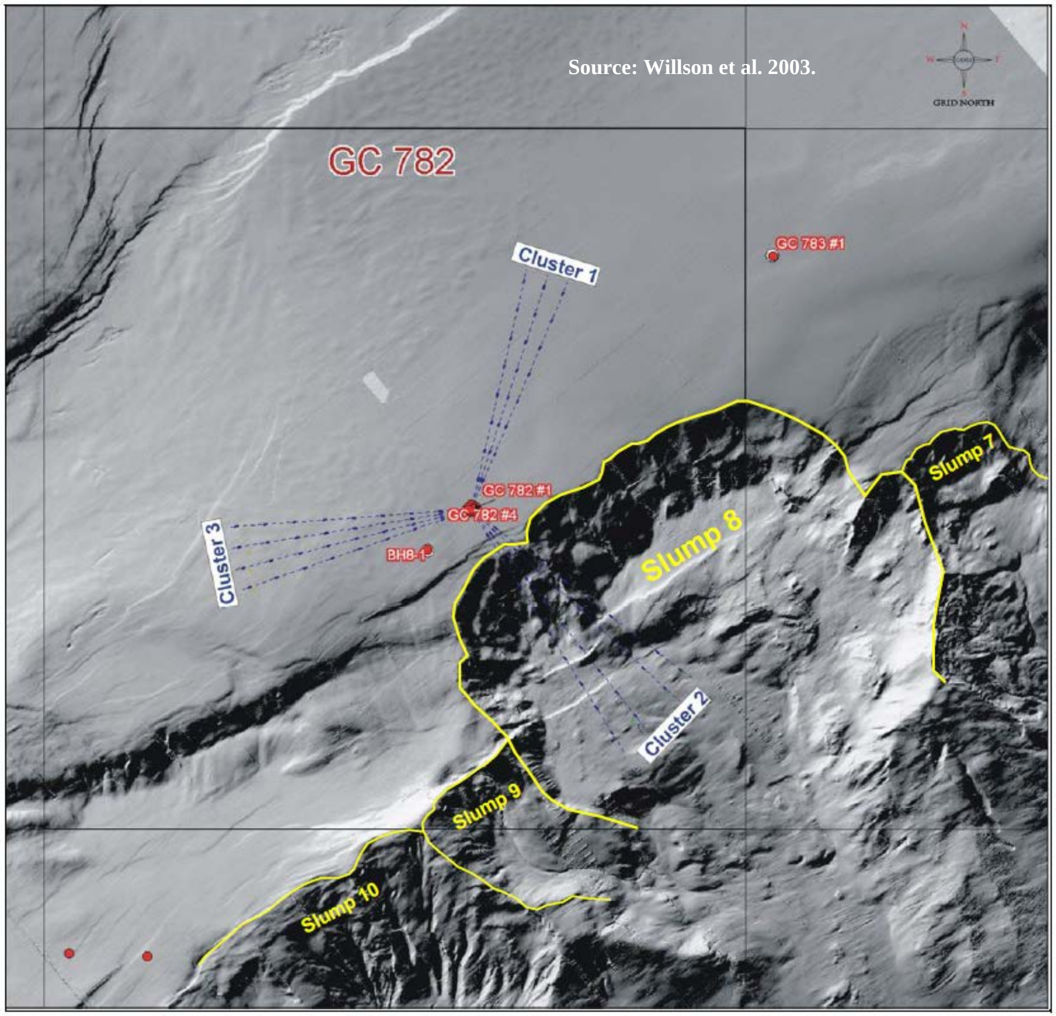


Figure D.5. Mad Dog spar and mooring layout.

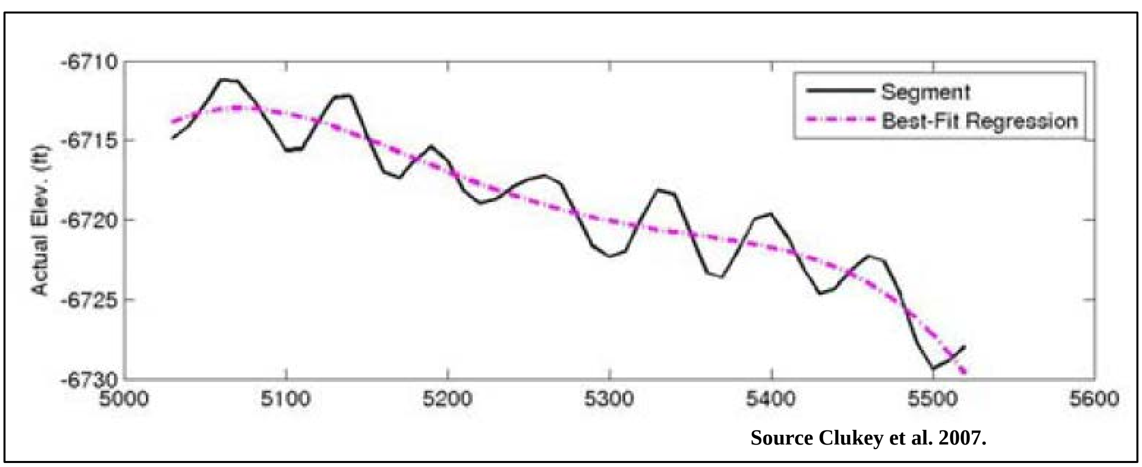


Figure D.6. Sample furrow profile.

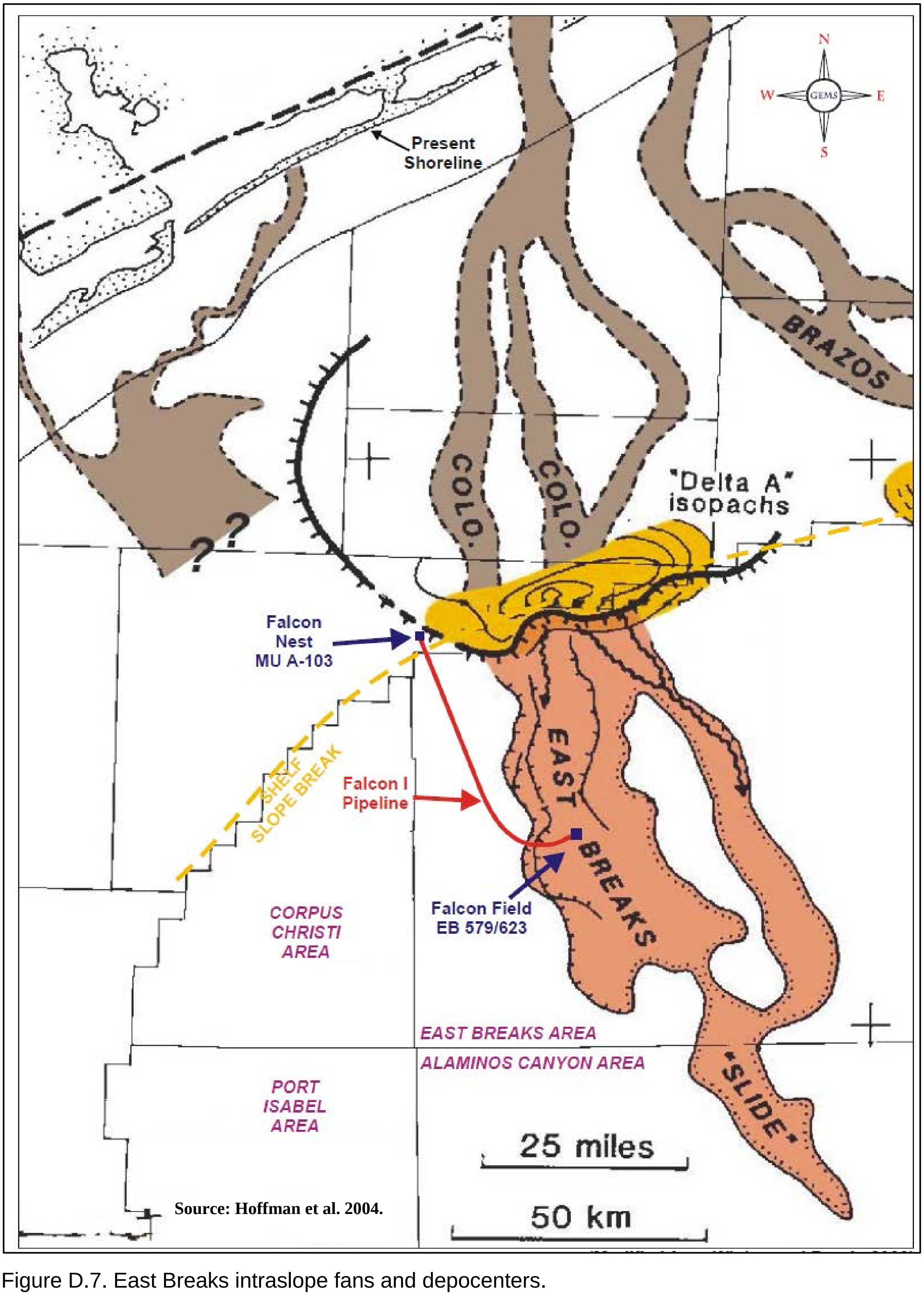



Figure D.7. East Breaks intraslope fans and depocenters.

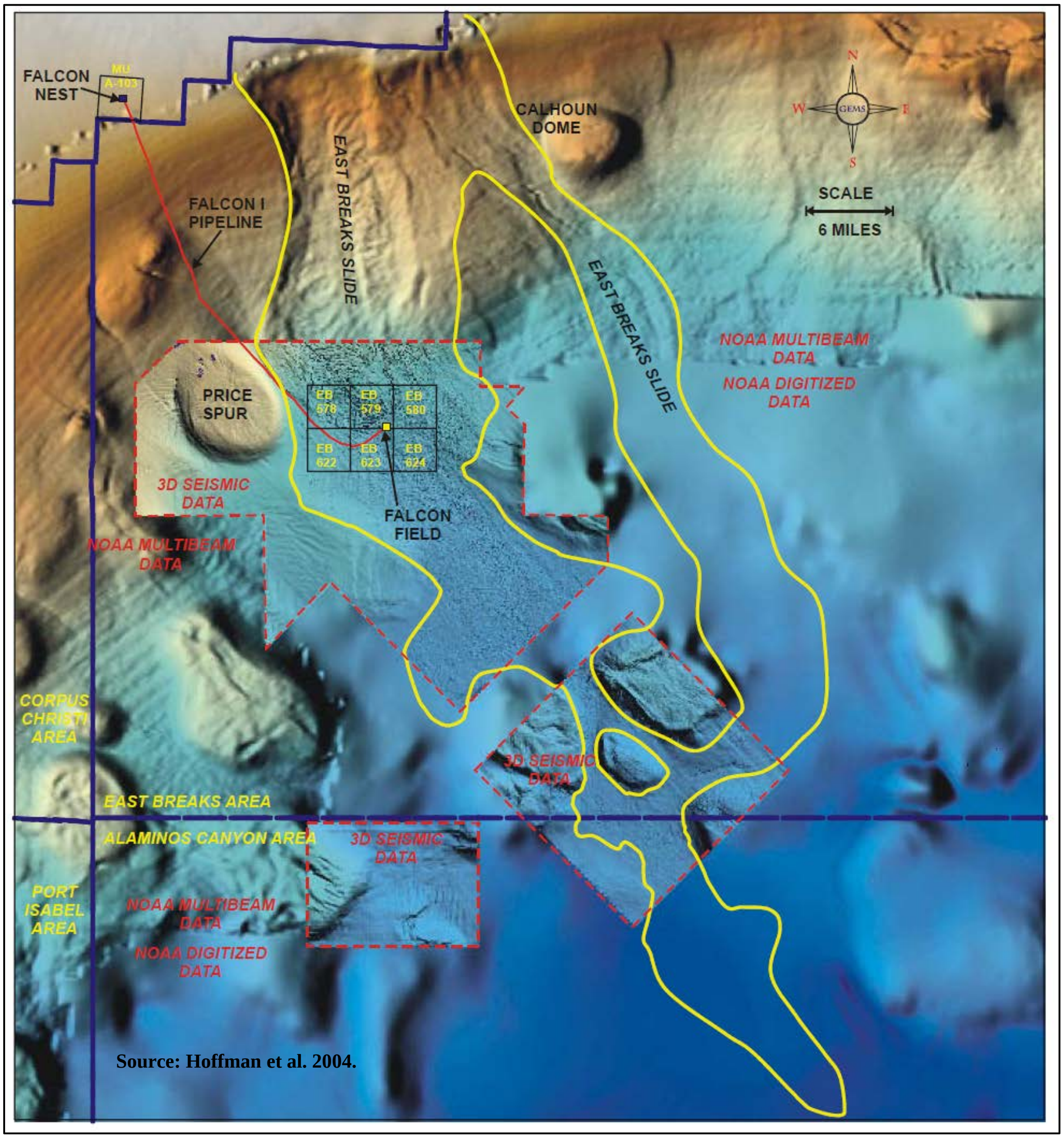



Figure D.8. Seafloor rendering at East Breaks slide.

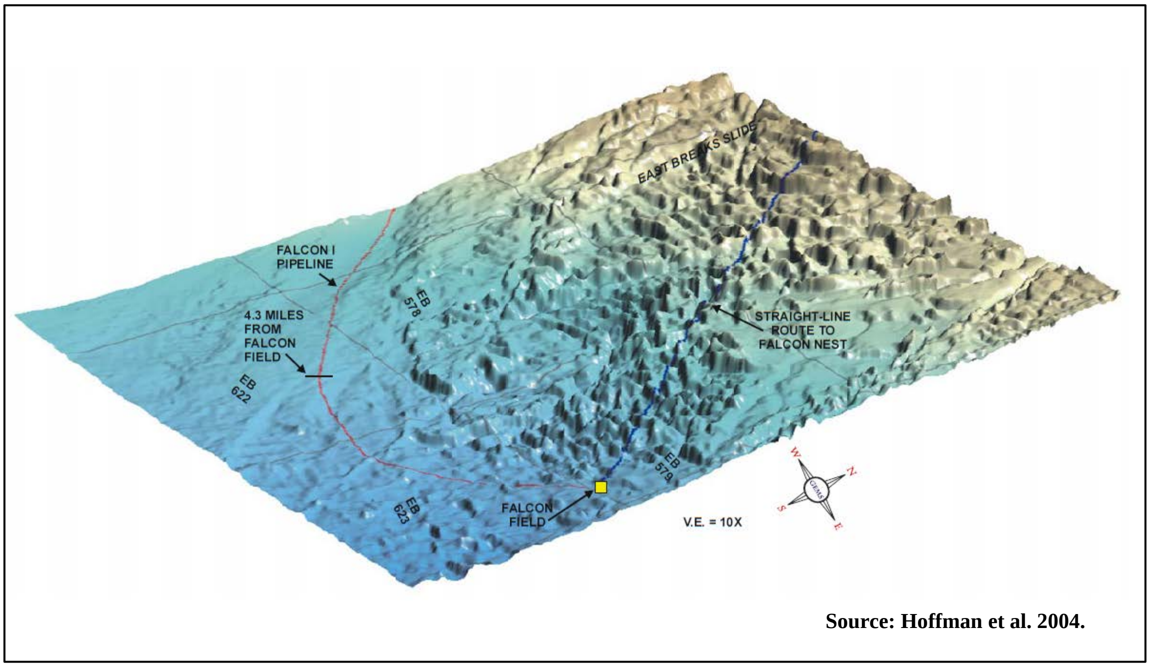



Figure D.9. Rendering of seafloor and flowline path.

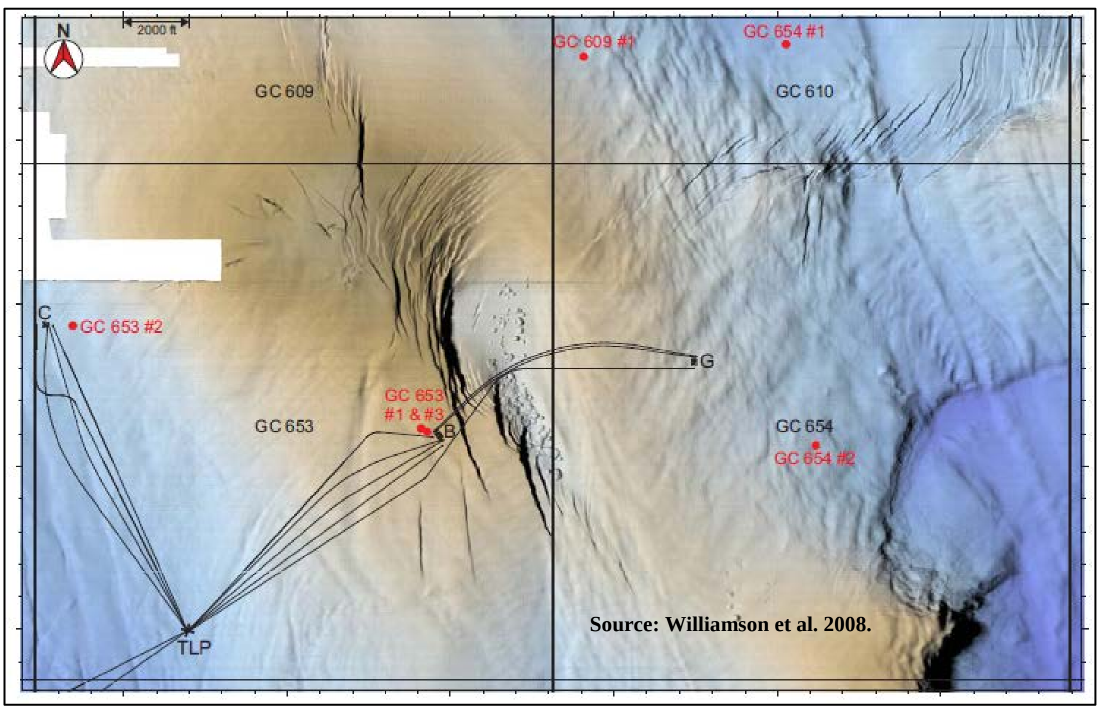



Figure D.10. Shenzi infield layout from three drill centers.


Figure D.11. Sea fans and bush-like soft coral on tar pillow at Shenzi.

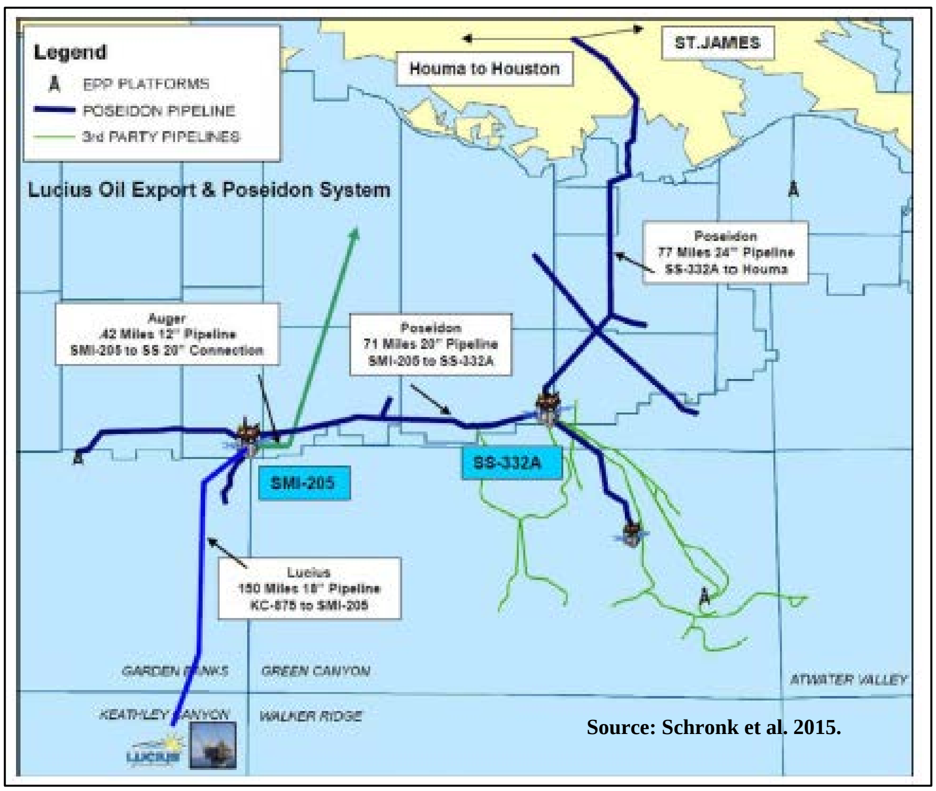



Figure D.12. Lucius oil export and Poseidon syste

# Appendix E: Chapter 5 Figures

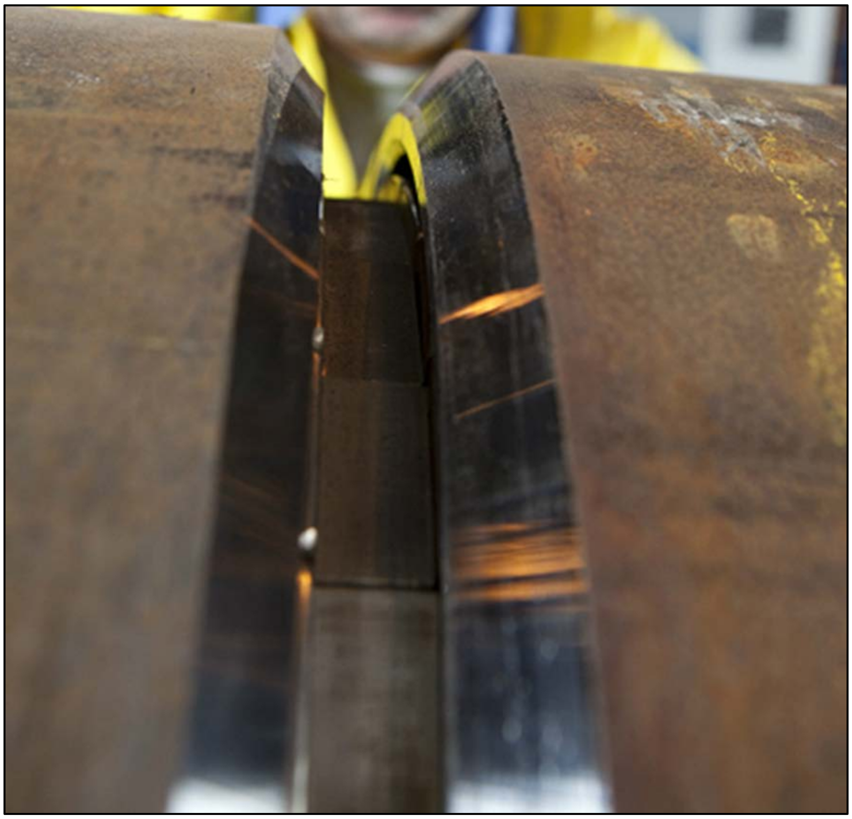


Figure E.1. A typical bevel on an offshore pipeline.

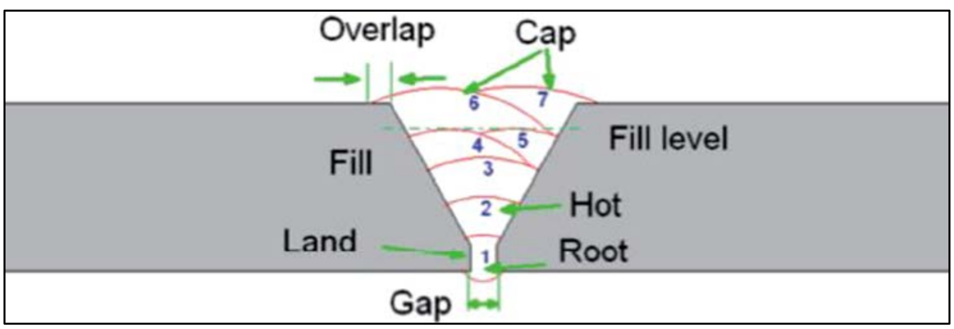



Figure E.2. Weld passes for pipeline construction.

Figure E.3. Automatic welding of a pipeline.


Figure E.4. Polyurethane foam being pumped into a joint mold.

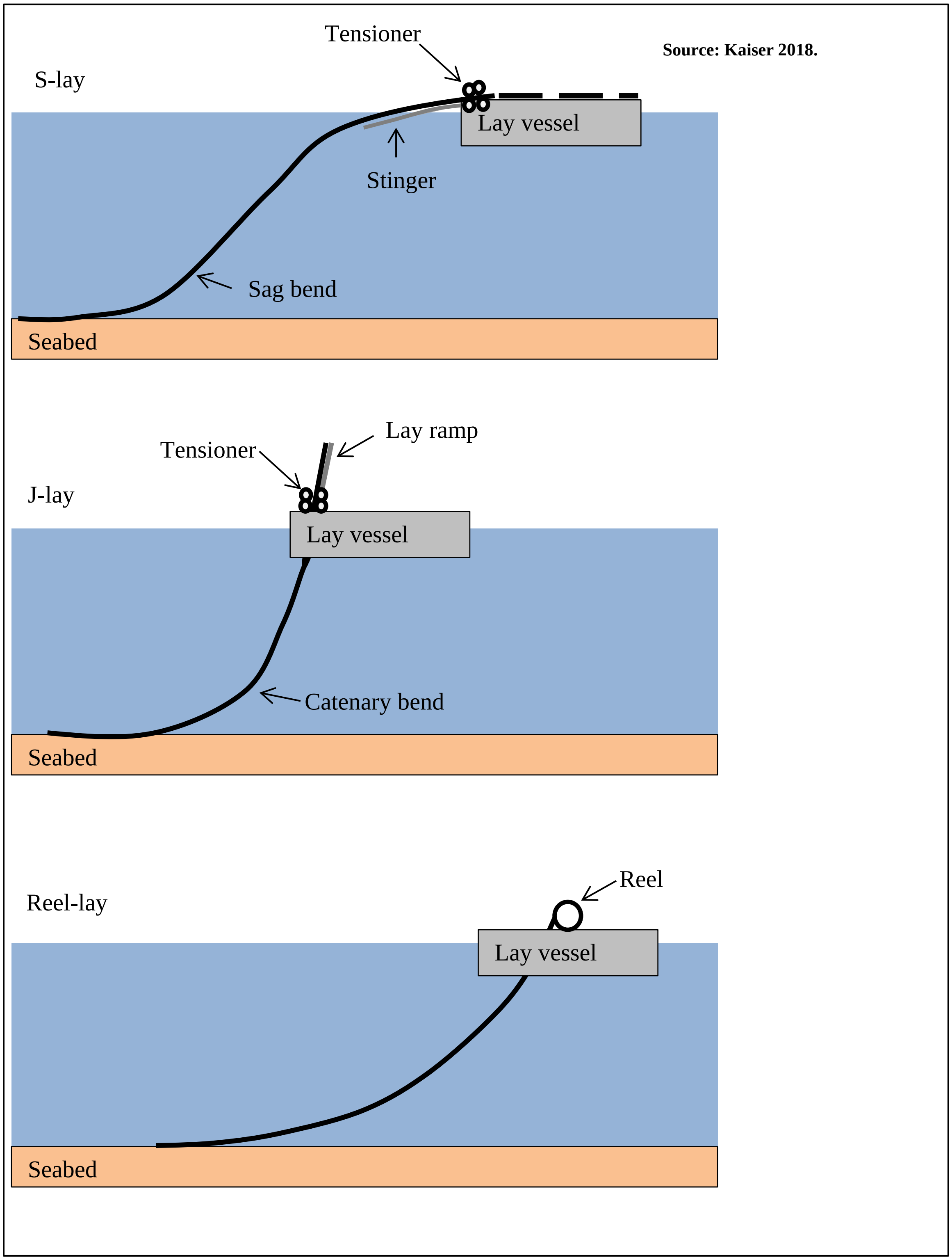



Figure E.5. S-lay, J-lay and reel-lay pipeline installation methods.

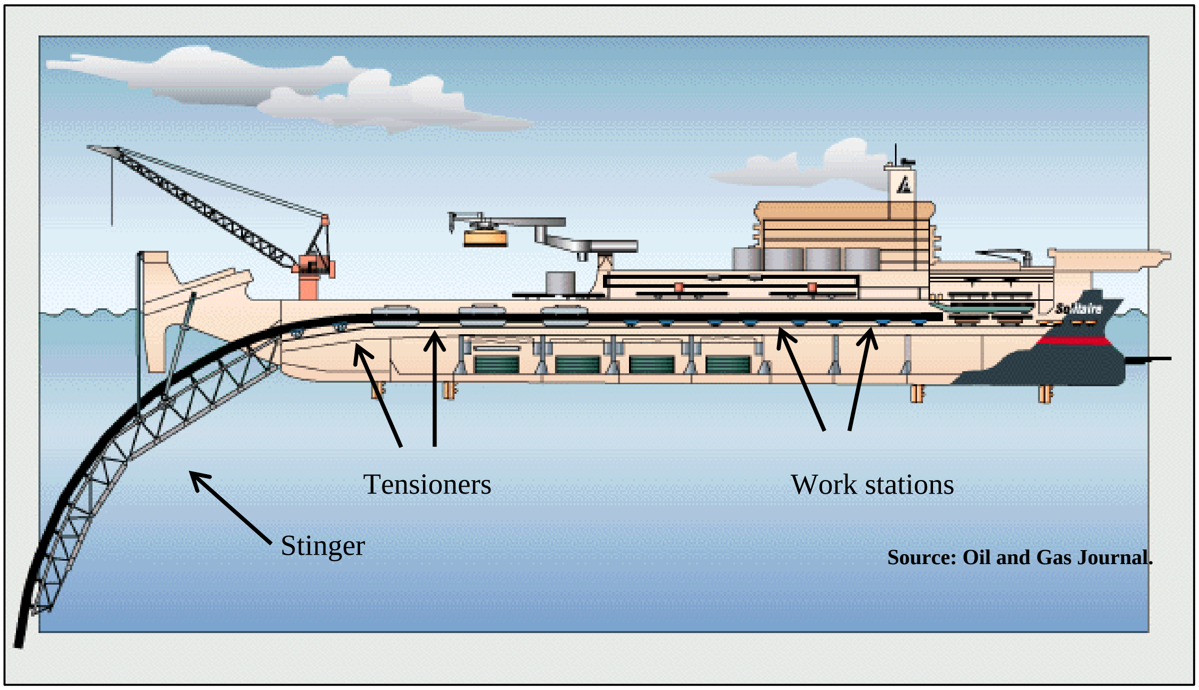



Figure E.6. Diagram of the S-lay system on Allseas *Solitaire.*


Figure E.7. Pipeline installation process on *Castoro Sei*.

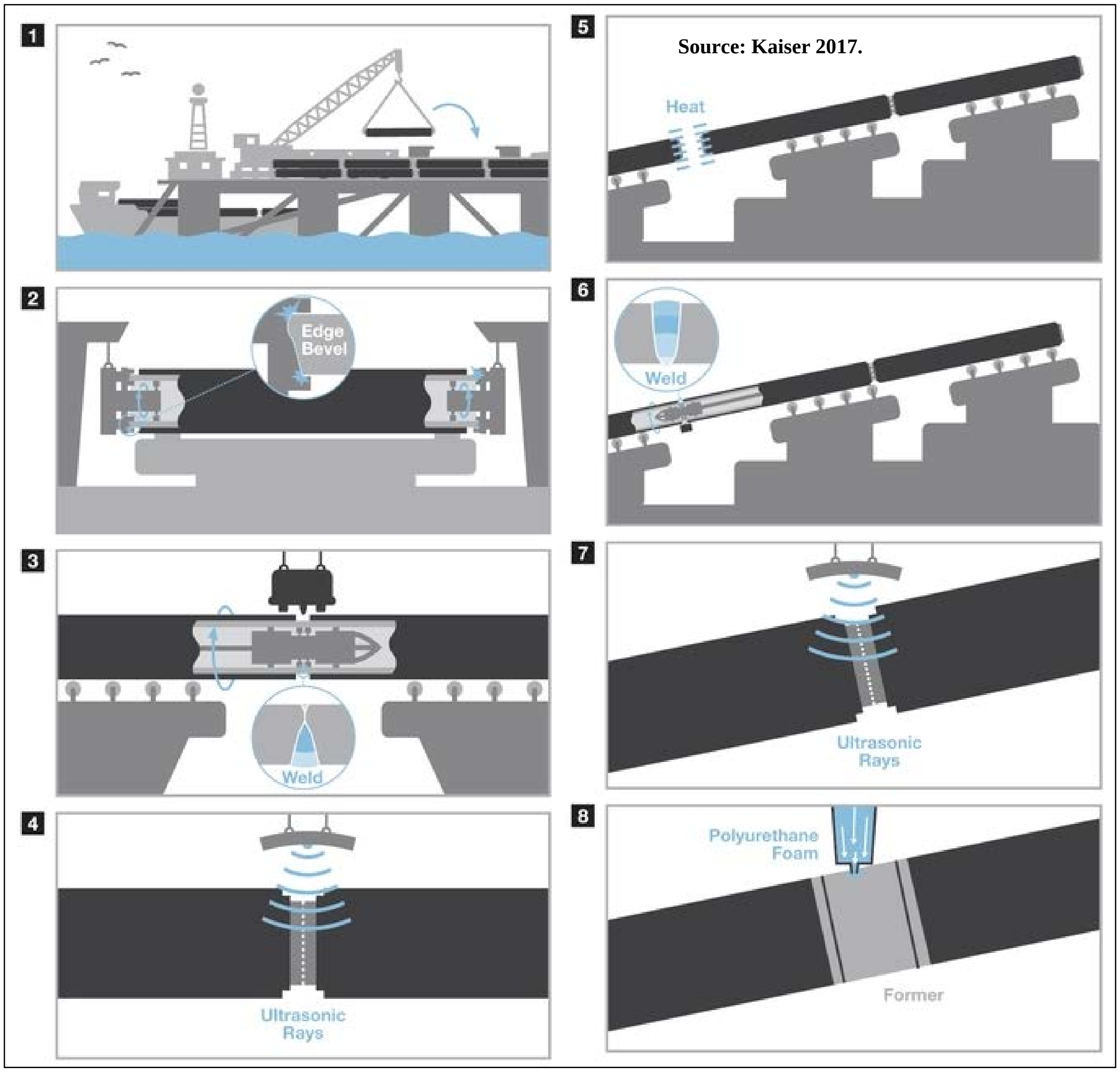



Figure E.8. Installation process for high-spec S-lay on *Castoro Sei.*

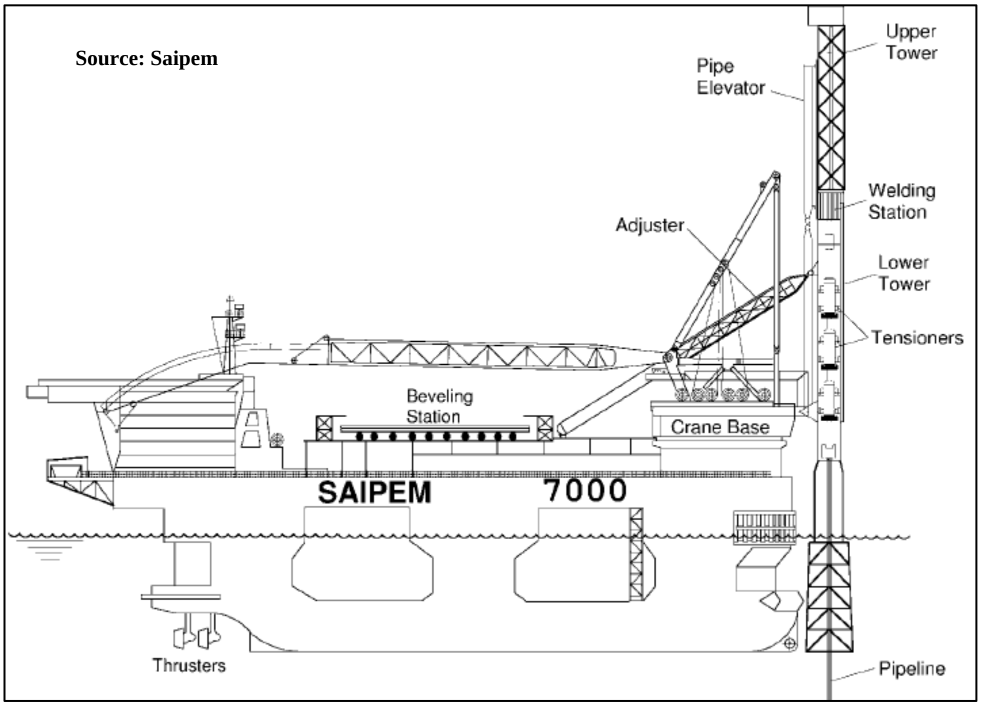



Figure E.9. Schematic of a J-lay system on *Saipem 7000*.

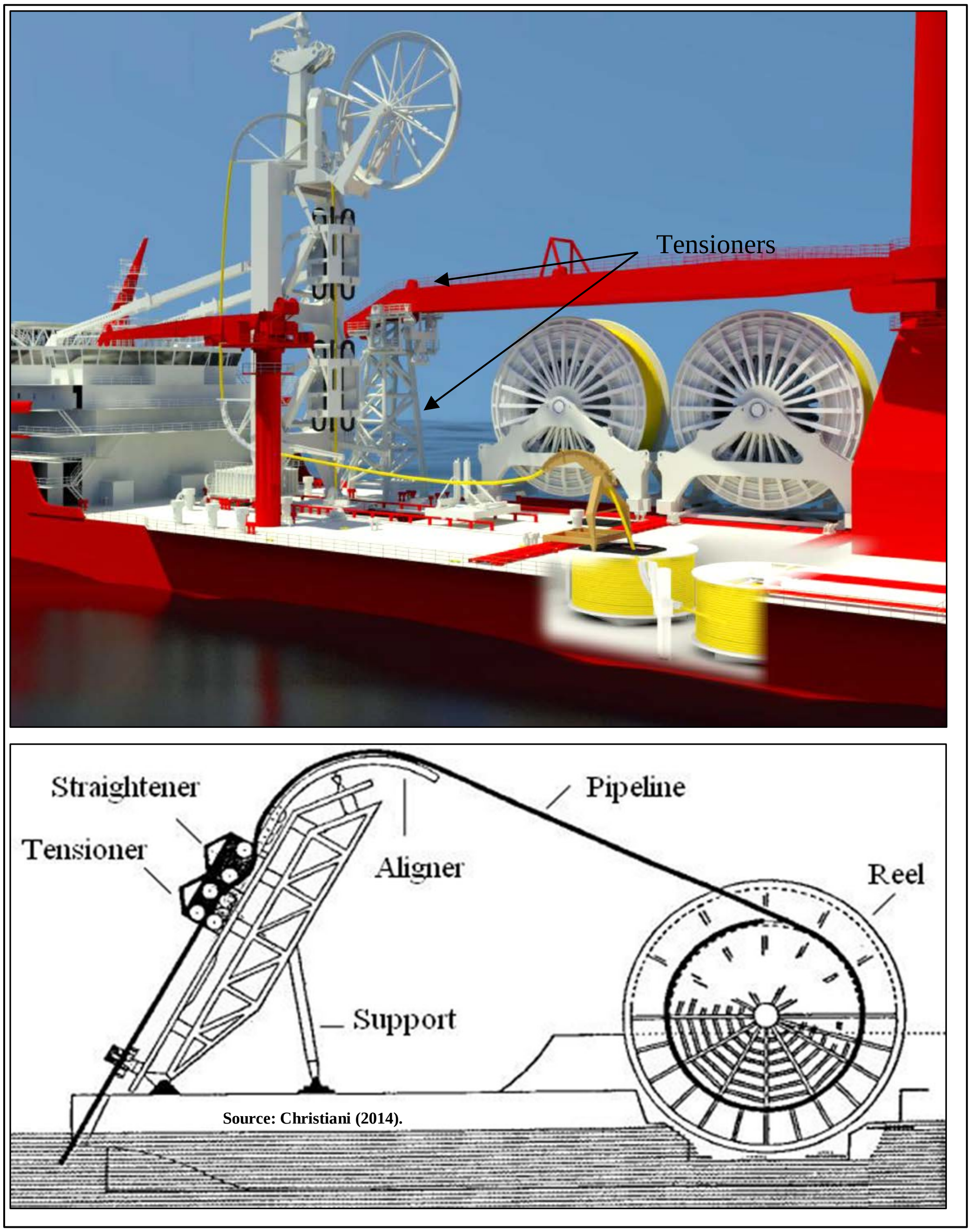



Figure E.10. Schematic of a reel-lay system.

Figure E.11. A reel on *North Ocean 105*.

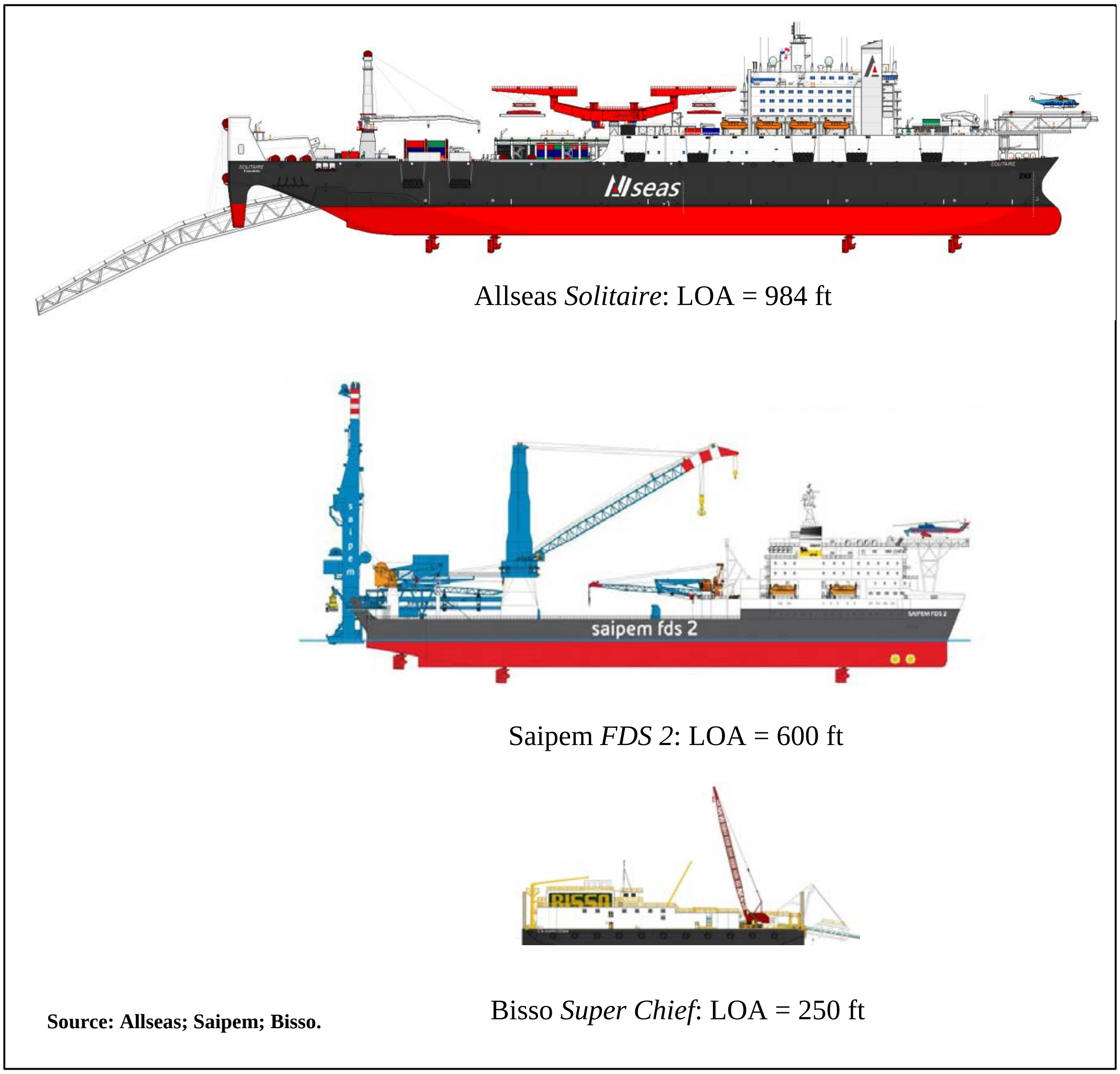
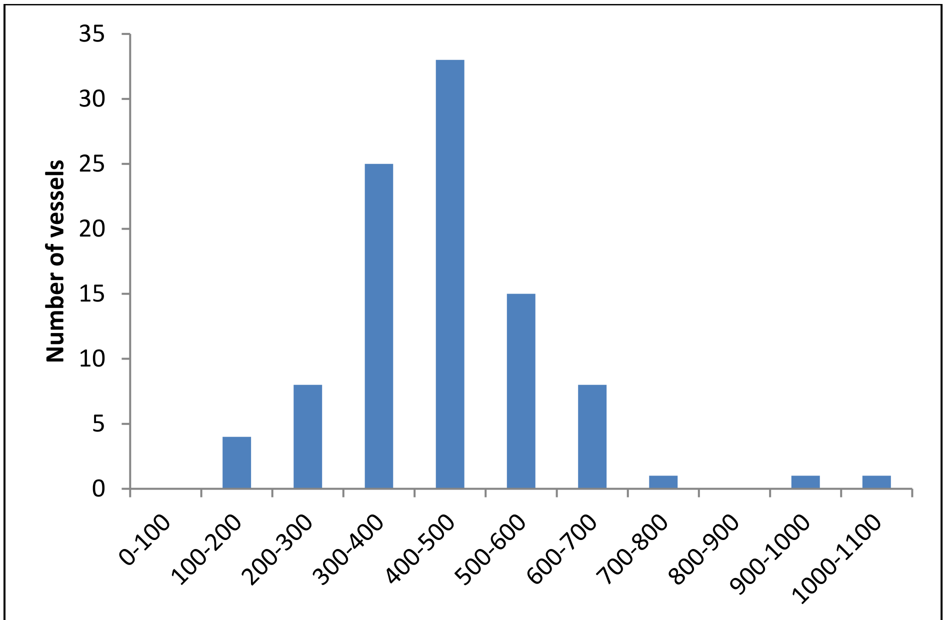



Figure E.12. Size comparison of the Allseas *Solitaire*, the Saipem *FDS 2* and the Bisso *Super Chief.*




**Source: Offshore Magazine.**

Figure E.13. Distribution of lengths of pipelay capable vessels in the global fleet circa 2017.

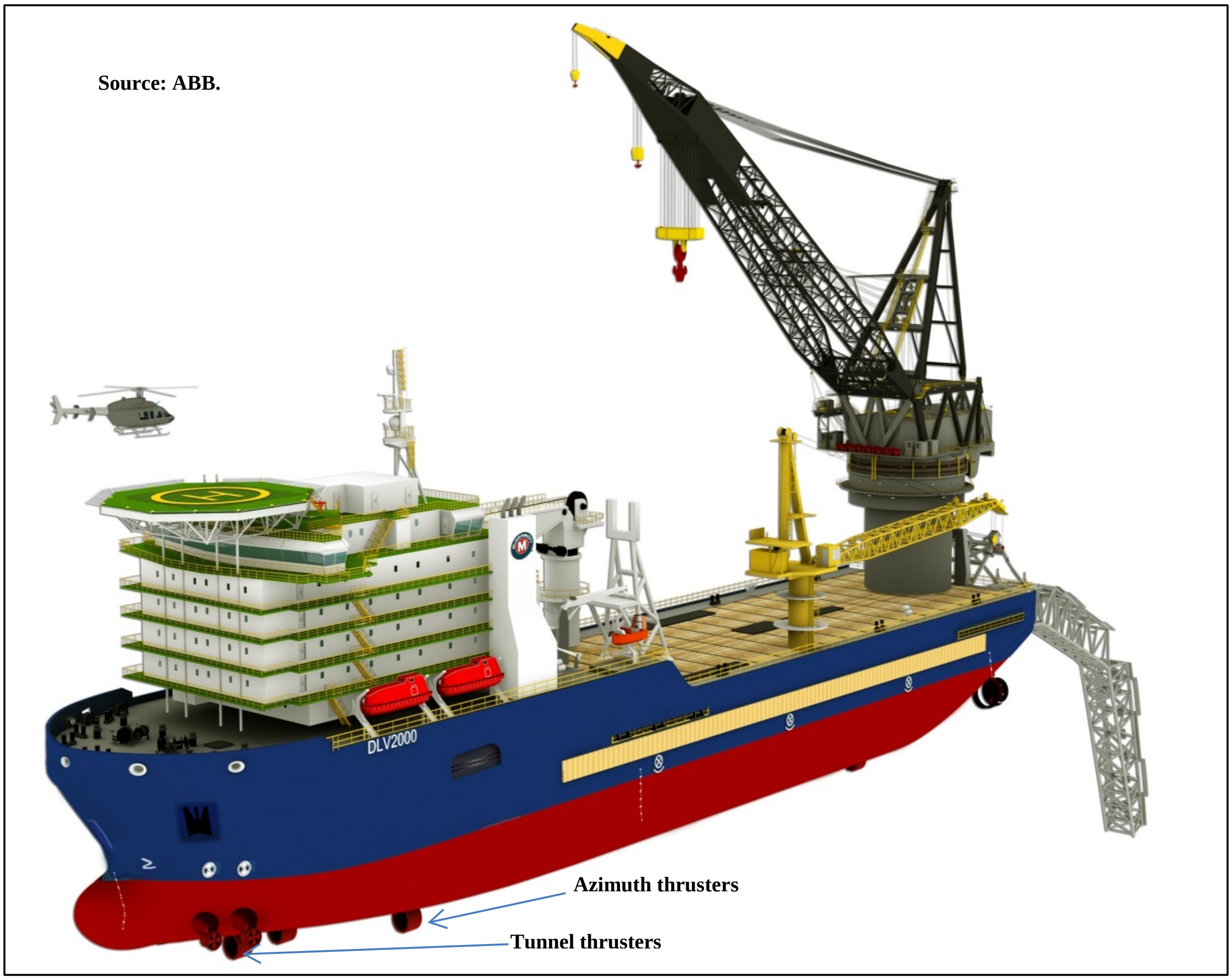


Figure E.14. McDermott's *DLV2000*, an S-lay vessel with azimuth and tunnel thrusters for DP-3.

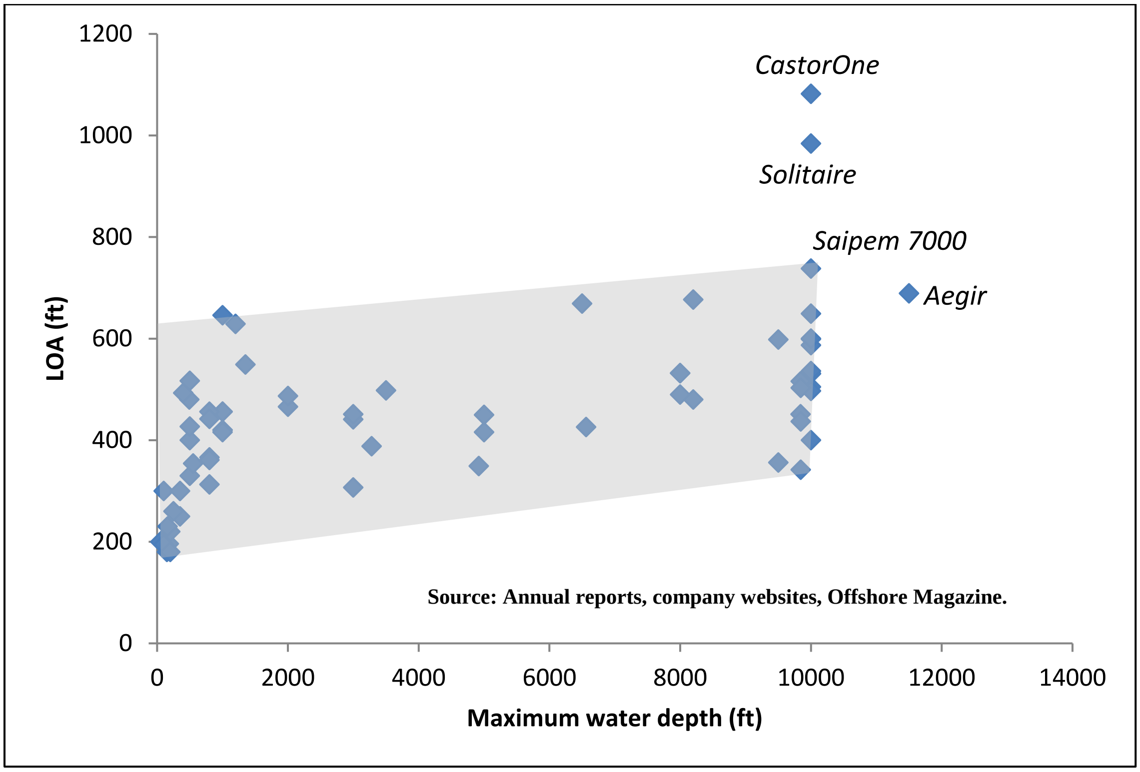



Figure E.15. Relationship between water depth and vessel length of pipelay vessel fleet.

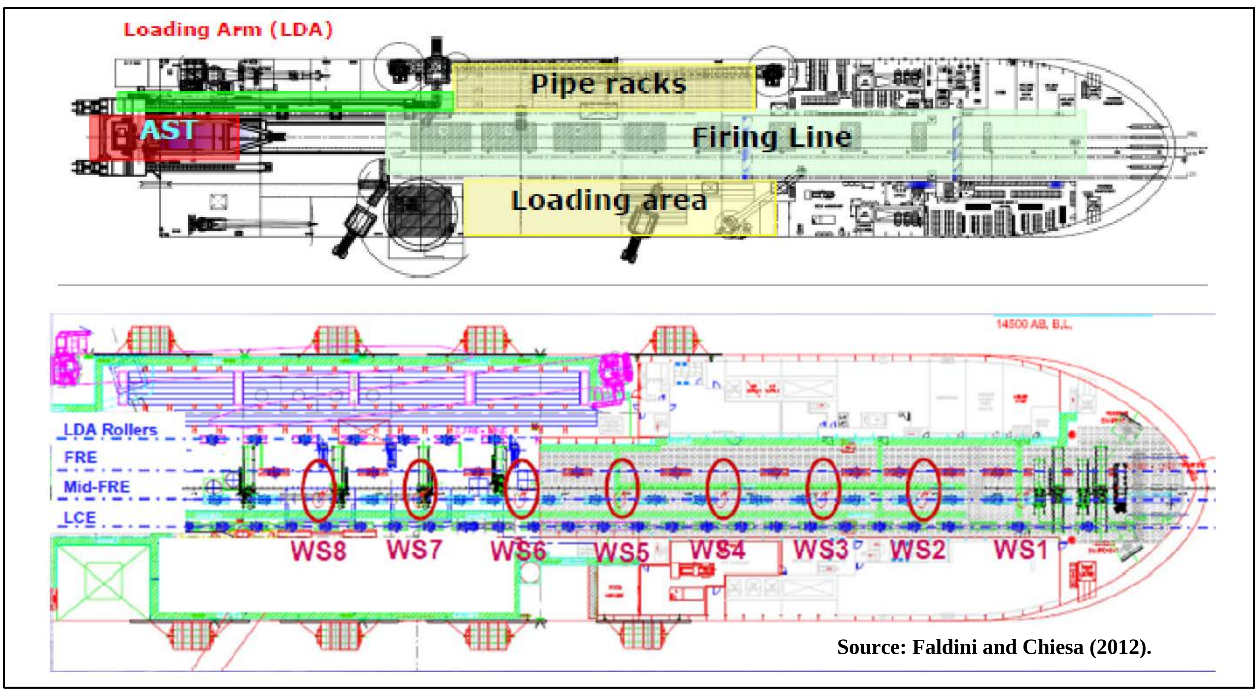
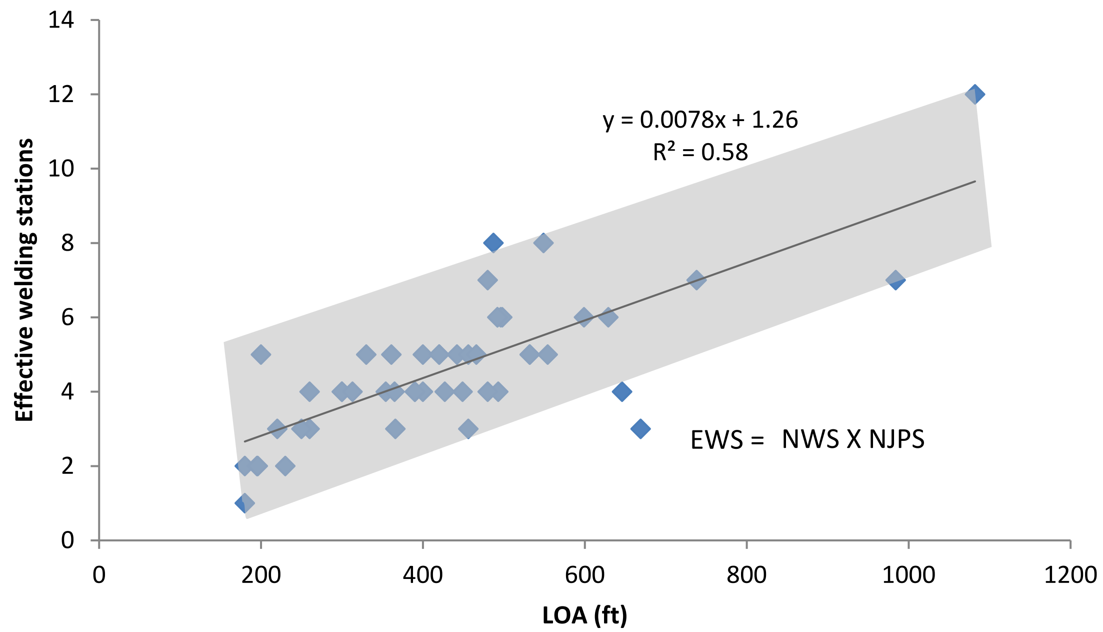
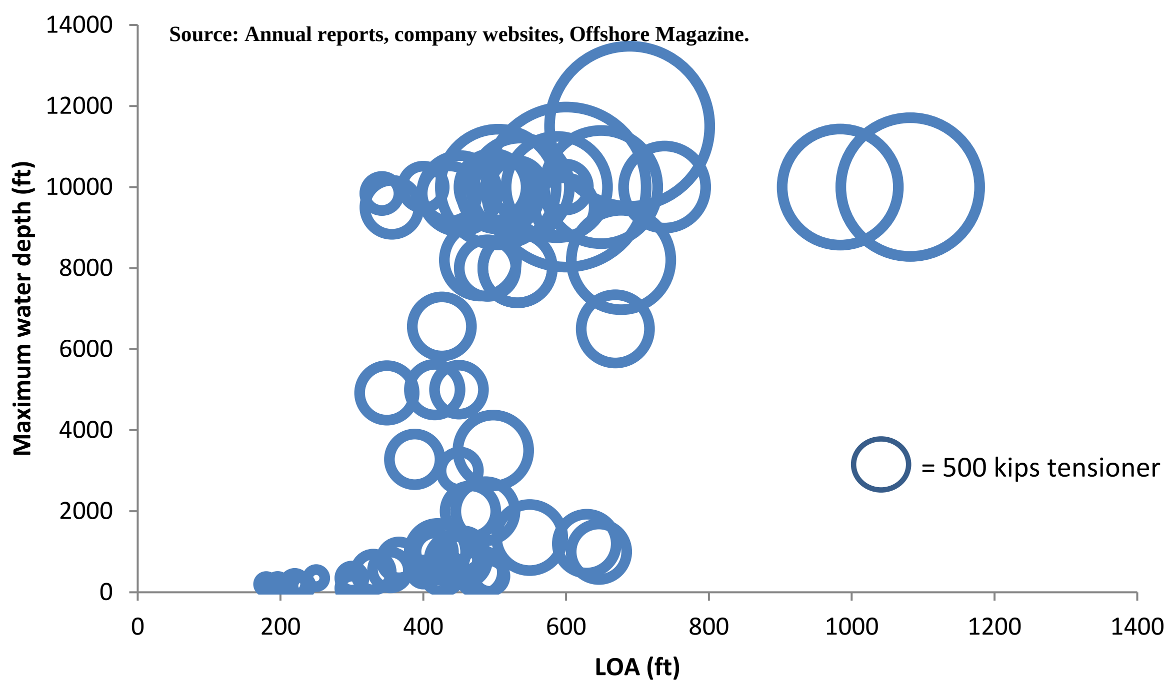



Figure E.16. Deck area and working stations for Saipem's *FDS2*.



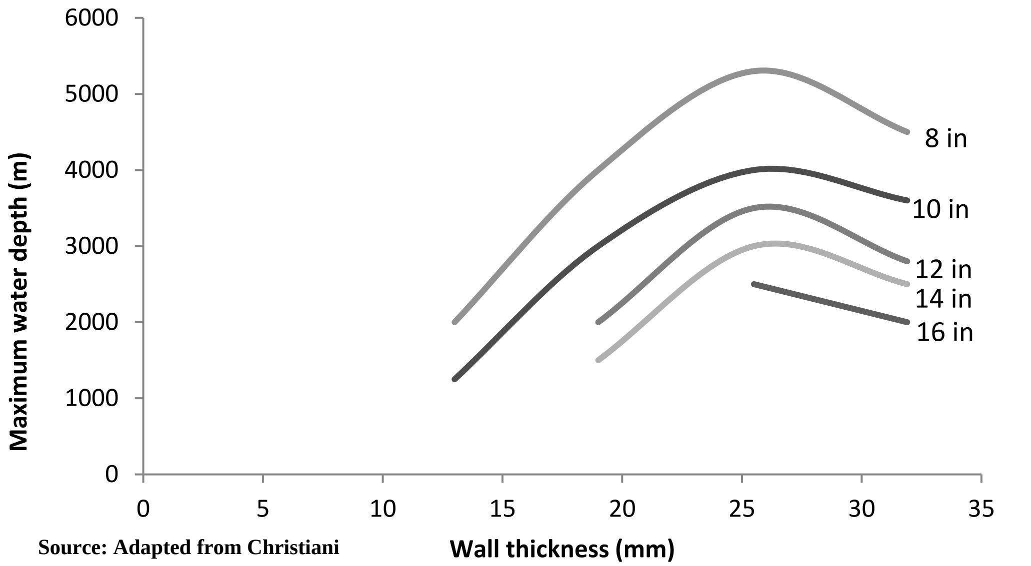

Source: Annual reports, company websites, Offshore Magazine.

Figure E.17. Vessel length and the effective number of welding stations in the S-lay vessel fleet circa 2017.



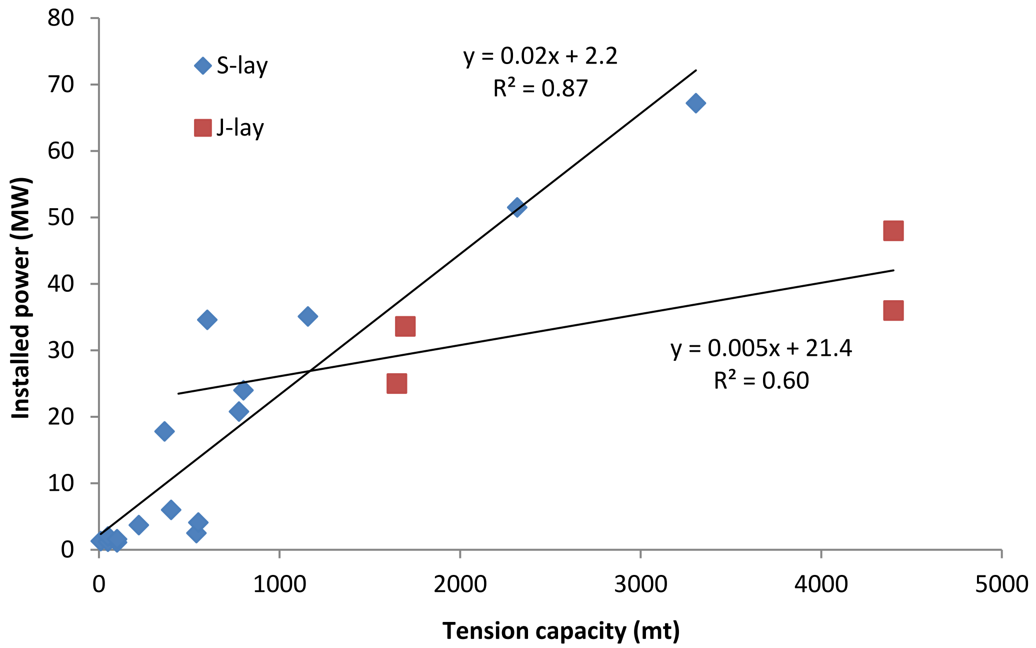

Source: Annual reports, company websites, Offshore Magazine.

Figure E.18. Vessel length, maximum water depth and tensioner capacity for pipelay fleet circa 2017.



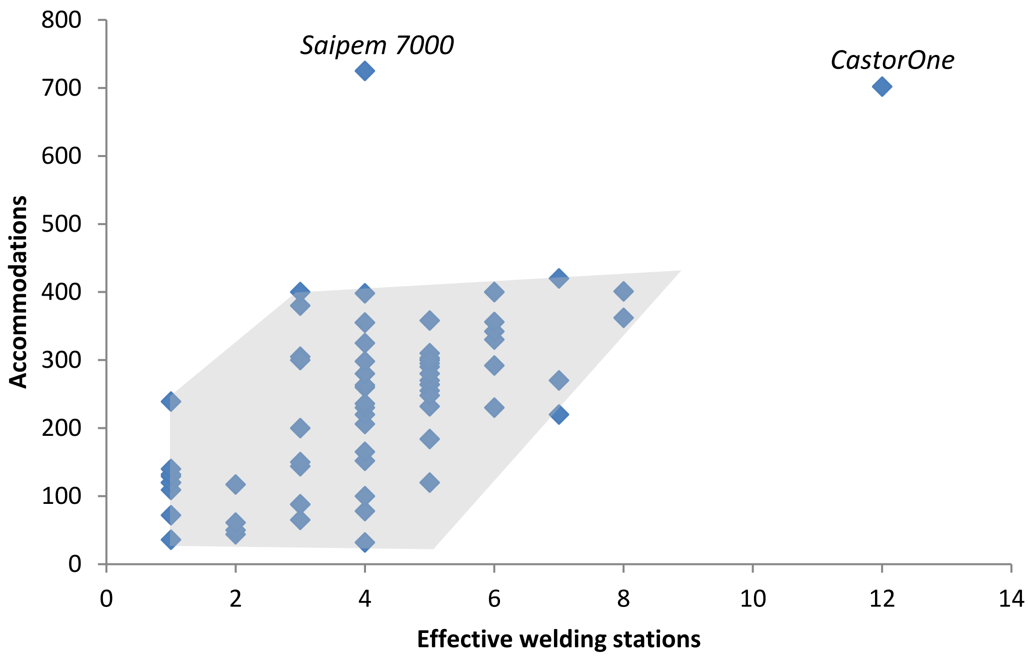

Source: Adapted from Christiani

Figure E.19. Relationship between wall thickness, outside diameter and water depth for *Lewek Constellation*.




**Source: Offshore**

Figure E.20. Installed power and tension capacity relationship for S-lay and J-lay vessel fleet circa 2017.




**Source: Offshore Magazine.**

Figure E.21. Number of accommodations by effective welding stations for pipelay fleet circa 2017.

## Appendix F: Chapter 6 Tables and Figures

**Table F.1. Typical pipelay vessel class characteristics**

| Class | Length (ft) | Lay systems | Station-keeping | Maximum water depth (ft) | Welding stations | Tensioner capacity (mt) |
|---|---|---|---|---|---|---|
| Low-spec barges | 200–400 | S | Moored 4–8 point | 400 | 2–4 | 25–50 |
| High-spec barges and semis | 400–700 | S, J | DP, moored 8–12 point | 3000–10,000 | 3–6 | 100–1000 |
| High-spec vessels | 300–600 | Reel, S, J | DP2 | 7000–10,000 | 0–3 | 200–1000 |
| Ultra high-spec vessels | 600–1000 | S, J | DP2, DP3 | 10,000 | 3–7 | 1000–2000 |

**Table F.2. Offshore pipelay fleet capacity circa 2017**

| Class | Abbreviation | Number |
|---|---|---|
| Low-spec barges | LSB | 22 |
| High-spec barges and semis | HSBS | 31 |
| High-spec vessels | HSV | 55 |
| Ultra high-spec vessels | UHSV | 4 |
| Total | | 112 |

Source: Annual reports, company websites, Offshore Magazine.

**Table F.3. Deepwater dynamically positioned pipelay vessels circa 2017**

| Derrick Lay Vessels | Owner | Station-keeping | Derrick capacity (mt) | Tensioning capacity (mt) | Install capability | | | Install methods | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | Pipe type | | | | | | |
| | | | | | Rigid pipe | Reeled line pipe | Flexible pipe | S-lay | J-lay | Reel-lay | Flex lay |
| Rigid S-lay and J-lay | | | | | | | | | | | |
| Aegir | Heerema | DP3 | 4000 | 2000 | ● | ● | | | ● | ● | |
| Saipem FDS 2 | Saipem | DP3 | 1000 | 2000 | ● | | ● | | ● | ● | ● |
| Solitaire | Allseas | DP3 | 300 | 1050 | ● | | | ● | | | |
| DCV Balder | Heerema | DP3 | 6300 | 1050 | ● | ● | | | ● | | |
| CastorOne | Saipem | DP3 | 600 | 750 | ● | | | ● | | | |
| Seven Borealis | Subsea 7 | DP3 | 5000 | 600 | ● | | | ● | ● | | |
| Saipem FDS | Saipem | DP3 | 600 | 550 | ● | | ● | | ● | ● | ● |
| Saipem 7000 | Saipem | DP3 | 14000 | 525 | ● | | | | ● | | |
| Audacia | Allseas | DP3 | 150 | 525 | ● | | | ● | | | |
| SapuraKencana 1200 | SapuraKencana | DP3 | 1200 | 520 | ● | | | ● | | | |
| Lewek Centurion | EMAS | DP2 | 300 | 405 | ● | | | ● | | | |
| SapuraKencana 3500 | SapuraKencana | DP3 | 3500 | 390 | ● | | | ● | | | |
| Global 1200 | Technip | DP2 | 1200 | 375 | ● | | | ● | | | |
| Global 1201 | Technip | DP2 | 1200 | 375 | ● | | | ● | | | |
| HYSY 201 | CNOOC | DP3 | 4000 | 363 | ● | | | ● | | | |
| DB 50 | McDermott | DP2 | 3991 | 352 | ● | ● | | | ● | ● | |
| Sapura 3000 | SapuraKencana | DP2 | 3000 | 240 | ● | | | ● | ● | | |
| Lewek Champion | EMAS | DP2 | 800 | 200 | ● | | | ● | | | |
| Lorelay | Allseas | DP2 | 300 | 165 | ● | | | ● | | | |
| Seven Polaris | Subsea 7 | DP3 | 1440 | 136 | ● | | | ● | | | |
| Rigid Reel-lay/flex lay | | | | | | | | | | | |
| Lewek Constellation | EMAS | DP3 | 3000 | 800 | | ● | ● | | | ● | ● |
| Sapura Diamante | S. Navegacao | DP3 | 400 | 550 | | | ● | | | | ● |
| Deep Blue | Technip | DP3 | 400 | 550 | ● | ● | ● | | ● | ● | ● |
| Deep Energy | Technip | DP3 | 150 | 450 | | ● | ● | | | ● | ● |
| LV105 | McDermott | DP2 | 400 | 400 | | ● | ● | | | ● | ● |
| LV108 | McDermott | DP2 | 400 | 400 | | ● | ● | | | ● | ● |
| Seven Oceans | Subsea 7 | DP2 | 350 | 400 | | ● | ● | | | ● | ● |
| Seven Seas | Subsea 7 | DP2 | 400 | 400 | | | ● | | | | ● |
| Seven Mar | Subsea 7 | DP2 | 300 | 345 | | | ● | | | | ● |
| NO102 | McDermott | DP2 | 100 | 240 | | ● | ● | | | ● | ● |
| Seven Pacific | Subsea 7 | DP2 | 250 | 236 | | | ● | | | | ● |
| Seven Navica | Subsea 7 | DP2 | 60 | 227 | | ● | ● | | | ● | ● |
| Constructor | Technip | DP3 | 300 | 200 | | | ● | | ● | ● | |
| Apache II | Technip | DP3 | 100 | 186 | | ● | | | | ● | |
| Lewek Express | EMAS | DP3 | 400 | 160 | | ● | | | | ● | |

Source: Annual reports, company websites, Offshore Magazine.

**Table F.4. Construction costs of pipelay vessels (2014$)**

| Vessel | Owner | Length (ft) | Type | Order year | Cost ($ million) | 2014 Cost ($ million) | Unit cost ($MM/100ft) |
|---|---|---|---|---|---|---|---|
| Lewek Champion | EMAS | 466 | HSB | 2005 | 84 | 104 | 22 |
| Hilong 106 | Hilong | 554 | HSB | 2013 | 164 | 164 | 30 |
| FDS | Saipem | 515 | HSV | 1998 | 150 | 263 | 51 |
| Seven Oceans | Subsea 7 | 515 | HSV | 2005 | 190 | 235 | 46 |
| Seven Seas | Subsea 7 | 505 | HSV | 2006 | 185 | 196 | 39 |
| Seven Borealis | Subsea 7 | 594 | HSV | 2007 | 460 | 472 | 79 |
| Seven Pacific | Subsea 7 | 436 | HSV | 2008 | 190 | 192 | 44 |
| Saipem FDS2 | Saipem | 600 | HSV | 2008 | 559 | 566 | 94 |
| Aegir | Heerema | 689 | HSV | 2010 | 650 | 726 | 105 |
| Seven Rio | Subsea 7 | 479 | HSV | 2011 | 350 | 366 | 76 |
| Lewek Constellation | EMAS | 584 | HSV | 2011 | 625 | 654 | 112 |
| DLV2000 | McDermott | 604 | HSV | 2012 | 450 | 456 | 75 |
| Ceona Amazon | Ceona | 666 | HSV | 2013 | 350 | 350 | 53 |
| Sapura Jade | Sapura Brasil | 479 | HSV | 2013 | 266 | 266 | 56 |
| Sapura Esmeralda | Sapura Brasil | 479 | HSV | 2013 | 266 | 266 | 56 |
| Sapura Ruby | Sapura Brasil | 479 | HSV | 2013 | 266 | 266 | 56 |
| Jascon 18 | SeaTrucks | 492 | HSV | 2013 | 400 | 400 | 81 |
| Pioneering Spirit | Allseas | 1253 | UHSV | 2010 | 3000 | 3352 | 268 |
| Average | | | HSB | | | 134 | 26 |
| Average | | | HSV | | | 378 | 68 |

Source: Industry press.

Note: Inflation adjusted using the BLS PPI for support activities for oil and gas operations

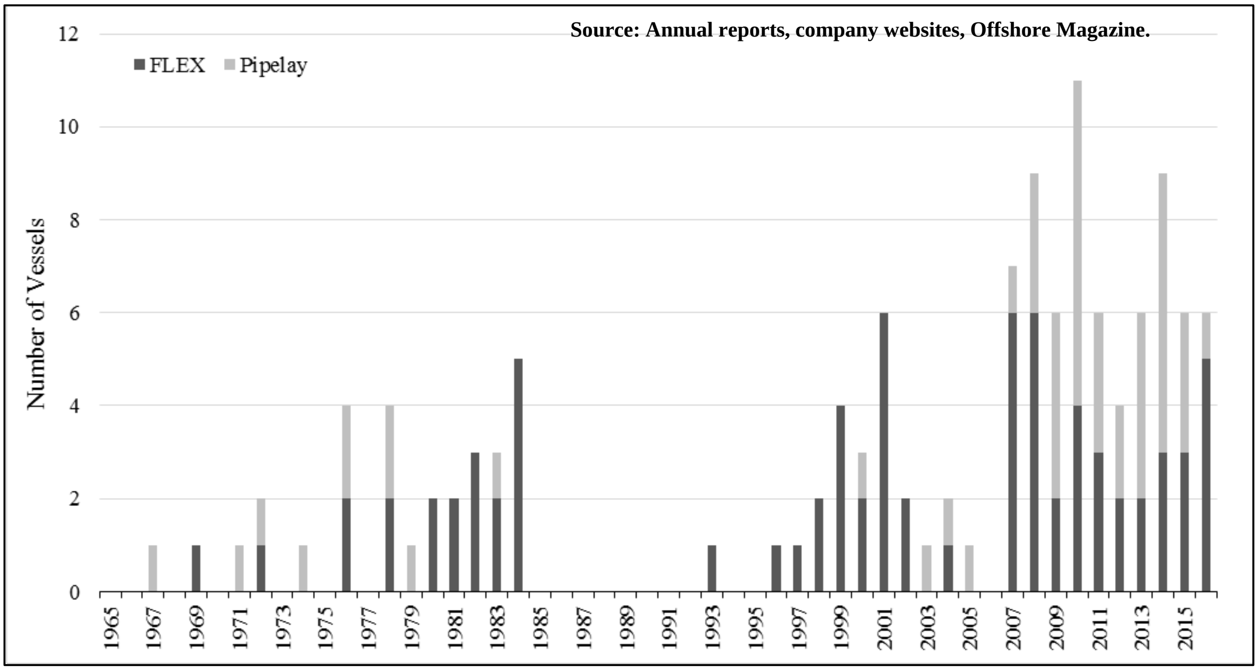



Figure F.1. Number of pipelay vessels delivered by year, 1965-2016.

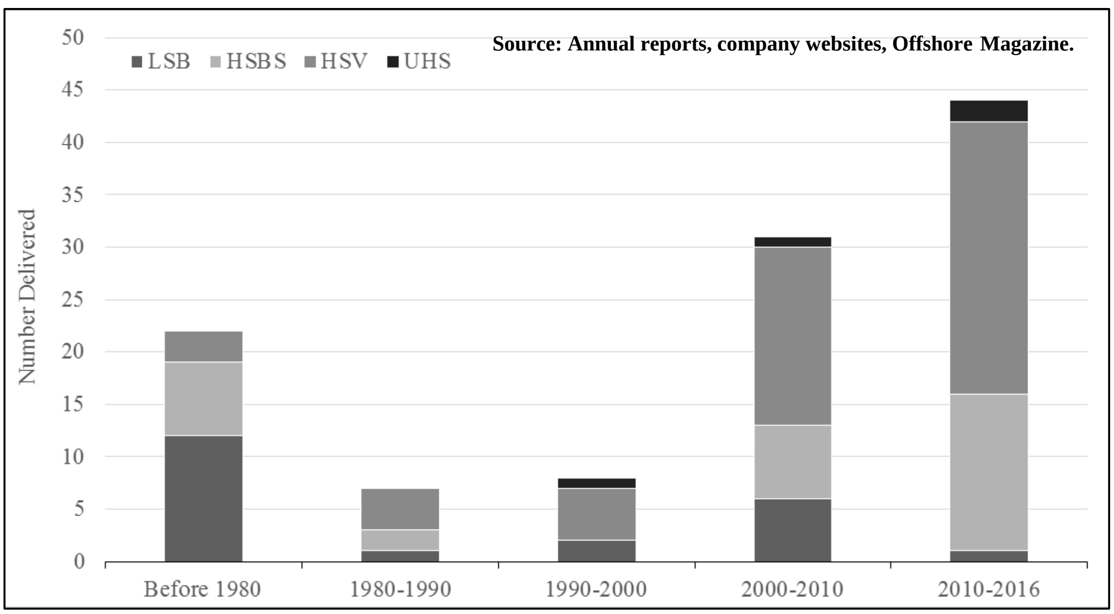
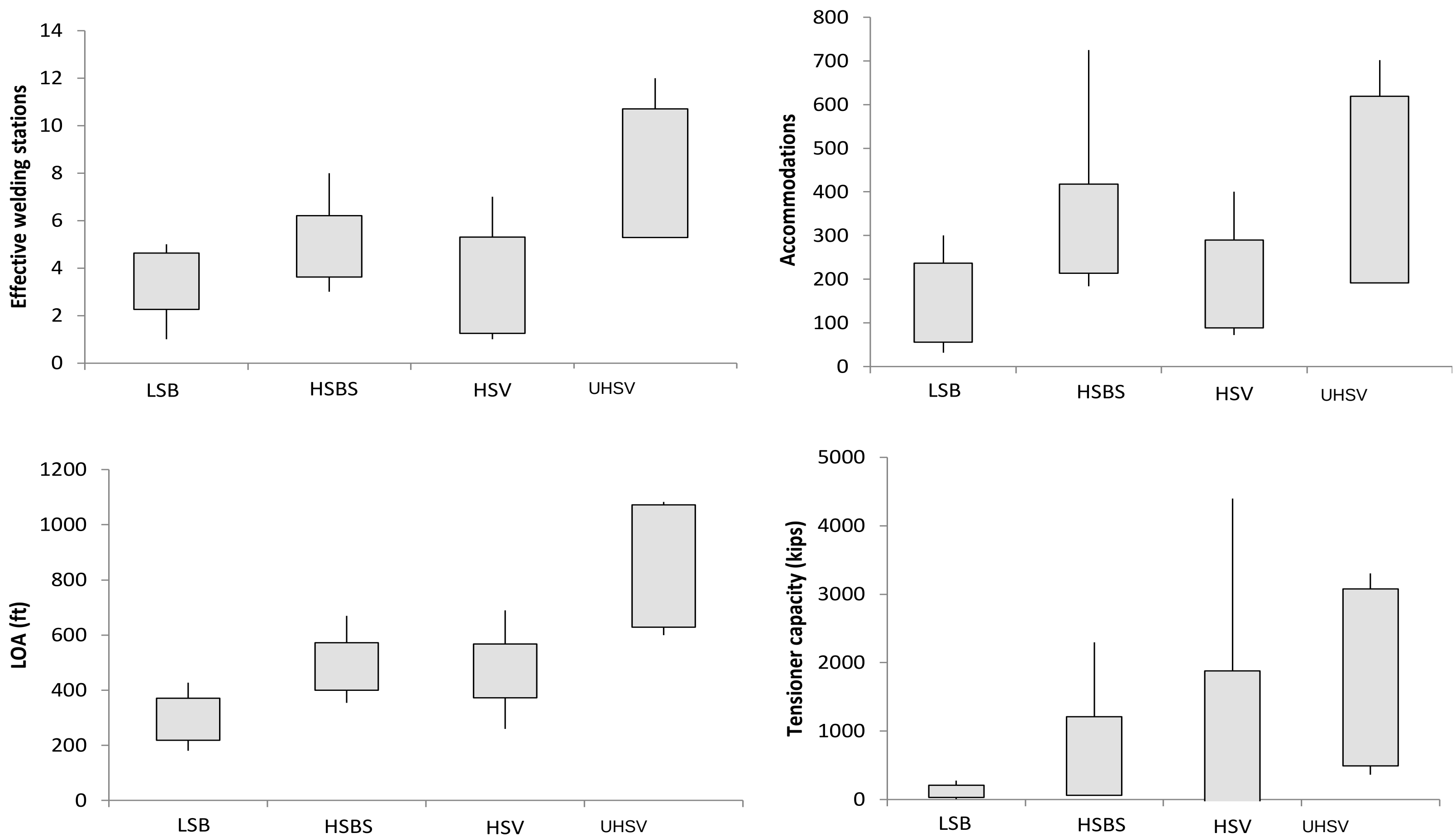



Figure F.2. Distribution of vessel ages by vessel class number delivered circa 2017.




**Source: Annual reports, company websites, Offshore Magazine.**

Figure F.3. Vessel class characteristics for pipelay fleet circa 2017.

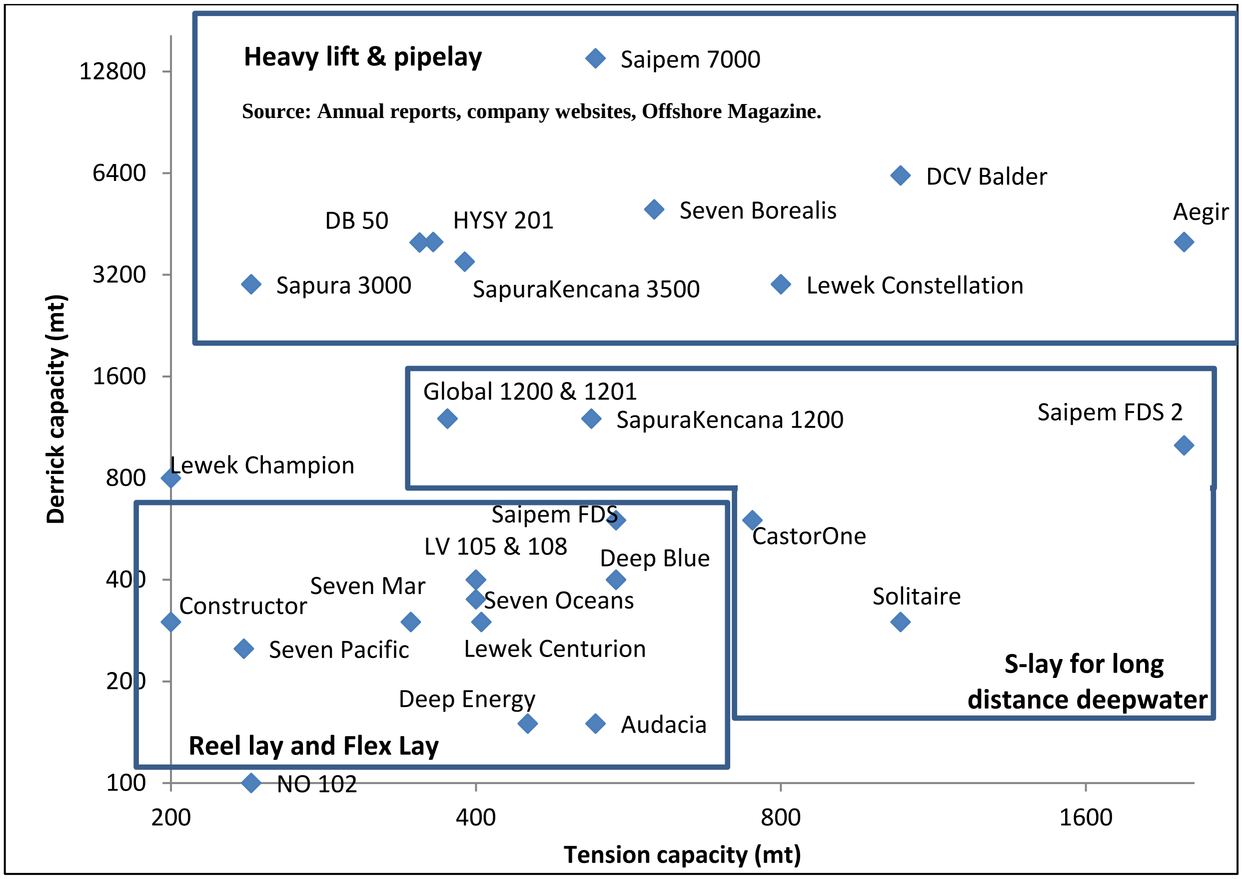



Figure F.4. Pipelay vessel derrick and tension capability circa 2017.

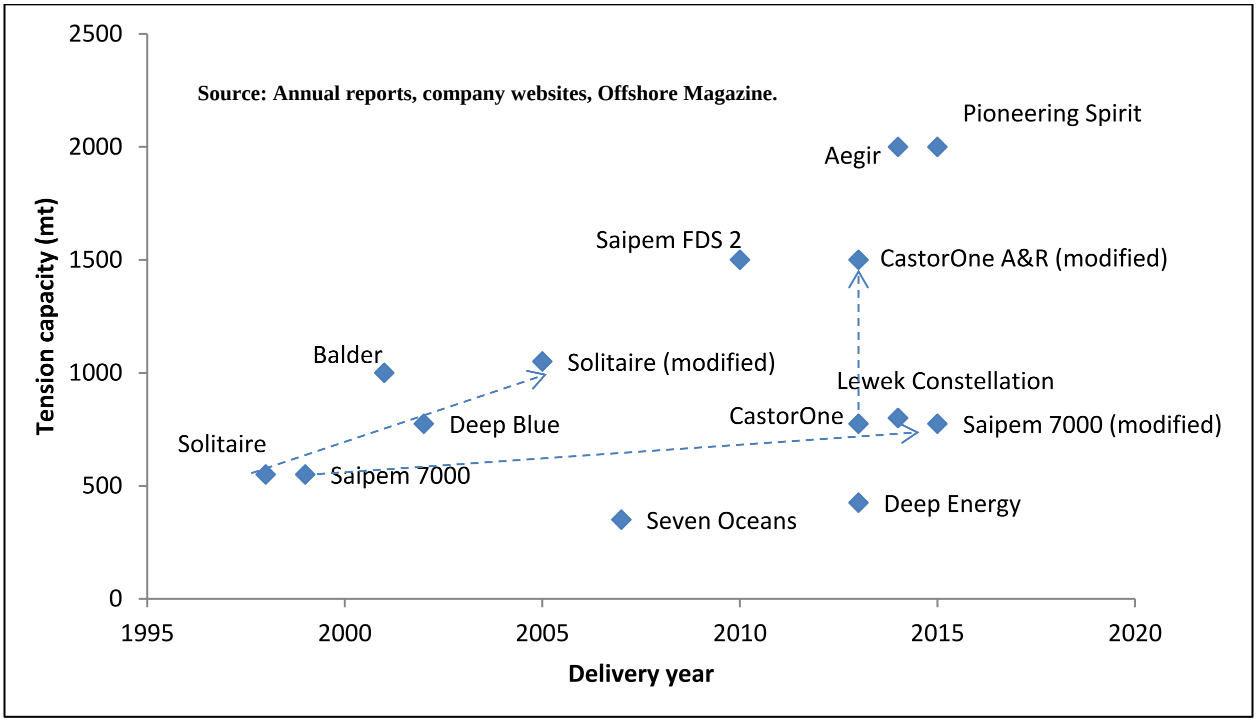



Figure F.5. Laying capacity of select new build vessels and their modifications circa 2017.

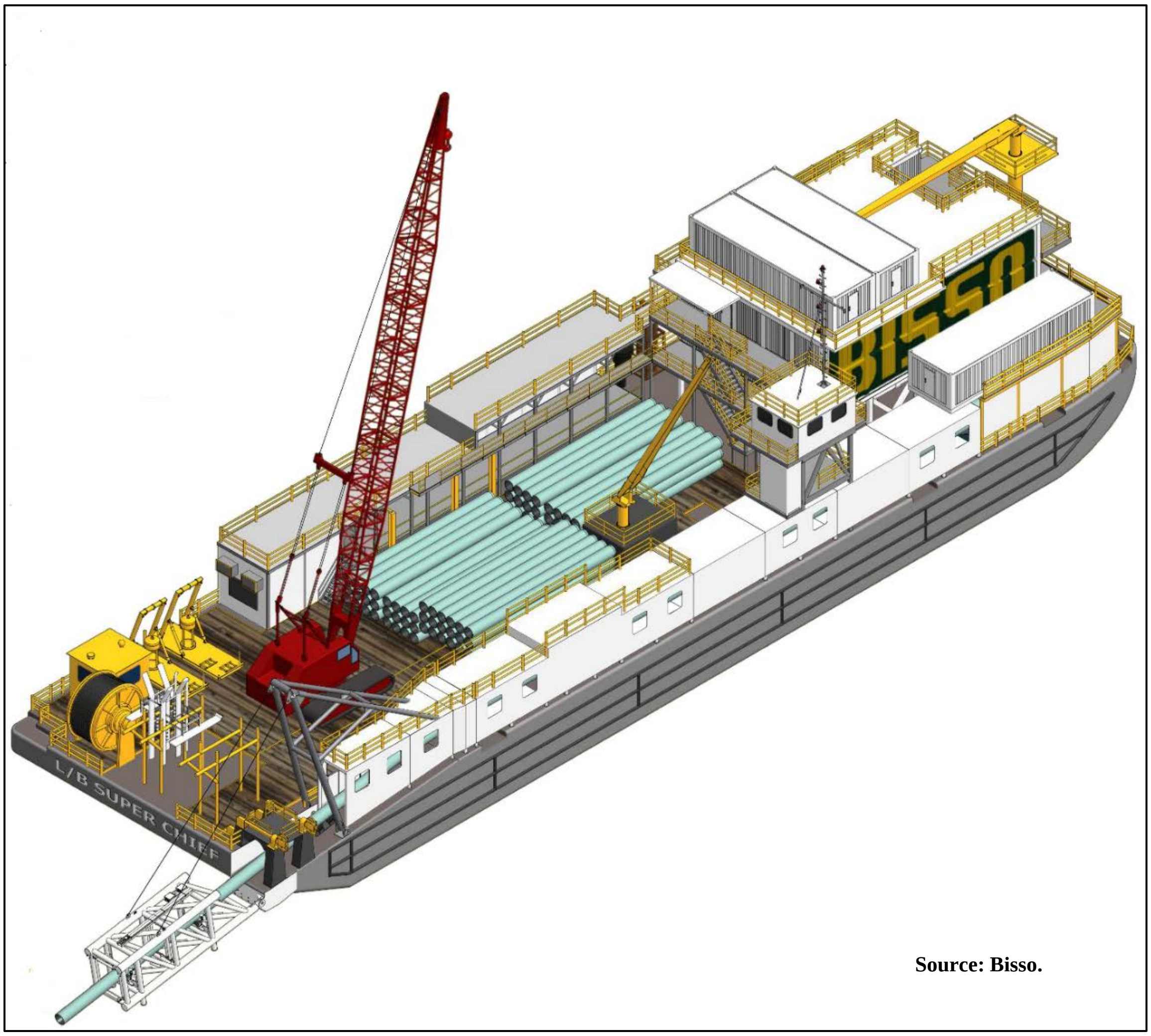



Figure F.6. Bisso's *Super Chief*, a shallow water low-spec lay barge.


Figure F.7. *Castoro 12*, a shallow water low-spec lay barge.

Figure F.8. McDermott's *DB 27* high-spec barge.


Figure F.9. *Castoro Sei*, a semi-submersible heavy-lift vessel.


Figure F.10. McDermott's *North Ocean 105* high-spec pipelay vessel.


Figure F.11. Technip's *Deep Blue* high-spec pipelay vessel.


Figure F.12. Saipem's *CastorOne* ultra high-spec pipelay vessel.


Figure F.13. Allseas' *Solitaire* ultra high-spec pipelay vessel.

# Appendix G: Chapter 7 Tables and Figures

**Table G.1. Companies with offshore pipelay capacity (2017)**

| Company | Fleet size | Low-spec barges | High-spec barges and Semis | High-spec vessels | Ultra high-spec vessels |
|---|---|---|---|---|---|
| Allseas Group S.A. | 6 | 1 | | 2 | 3 |
| Ascot Constructors Offshore Ltd. | 2 | 2 | | | |
| Bisso Marine | 6 | 6 | | | |
| Ceona Ship Holdings Ltd. | 2 | | | 3 | |
| Chet Morrison Contractors, LLC | 4 | 4 | | | |
| China National Offshore Oil Corp | 5 | 2 | 3 | | |
| DOF ASA | 4 | | | 4 | |
| EMAS Offshore Ltd. | 5 | | | 5 | |
| Heerema Marine Contractors | 3 | | 3 | | |
| Leighton Offshore | 3 | 3 | | | |
| McDermott Int. Inc. | 10 | | 4 | 6 | |
| Ocean Marine Contractors, Inc. | 1 | | 1 | | |
| Saipem, S.p.A. | 10 | 1 | 6 | 2 | 1 |
| Sea Trucks Group | 4 | | | 4 | |
| Sapura Energy Berhad | 6 | | 6 | | |
| Solstad Offshore ASA | 1 | | 1 | | |
| Subsea 7 S.A. | 18 | | 2 | 16 | |
| Swiber Holding Ltd. | 7 | 2 | 5 | | |
| TechnipFMC PLC | 14 | | | 14 | |
| Van Oord | 1 | 1 | | | |
| Total | 112 | 22 | 31 | 55 | 4 |

Source: Annual reports, company websites, Offshore Magazine.

**Table G.2. Marine construction service companies with pipelay capacity circa 2017**

| Company | Headquarters | Ticker | Stock Exchange | Website |
|---|---|---|---|---|
| Allseas Group S.A. | Switzerland | | | https://allseas.com |
| Ascot Constructors Offshore Ltd. | Nigeria | | | |
| Bisso Marine | USA | | | http://www.bissomarine.com |
| Ceona Ship Holdings Ltd. | UK | | | |
| Chet Morrison Contractors, LLC | USA | | | https://chetmorrison.com |
| China National Offshore Oil Corp. | China | | | http://www.cnooc.com.cn/en |
| DOF ASA | Norway | DOF | Oslo | http://www.dof.no |
| EMAS Offshore Ltd. | Singapore | EOL | Oslo, Singapore | http://www.emasoffshore.com |
| Heerema Marine Contractors | Netherlands | | | https://hmc.heerema.com |
| Leighton Offshore | Australia | | | http://www.leightonoffshore.com |
| McDermott Int. Inc. | USA | MDR, MIQ | New York, Frankfurt | https://www.mcdermott.com |
| Ocean Marine Contractors, Inc. | USA | | | http://www.oceanmarinecontractors.com |
| Saipem, S.p.A. | Italy | SPM | Borsa Italiana | http://www.saipem.com |
| Sea Trucks Group | Nigeria | | | http://www.seatrucksgroup.com |
| Sapura Energy Berhad | Malaysia | SAPE | Bursa Malaysia | http://www.sapuraenergy.com |
| Solstad Offshore ASA | Norway | SOFF | Oslo | https://solstad.no |
| Subsea 7 S.A. | UK | SUBC | Oslo | http://www.subsea7.com |
| Swiber Holding Ltd. | Singapore | SWIP | Singapore | http://www.swiber.com |
| TechnipFMC PLC | UK | FTI | New York, EN Paris | http://www.technipfmc.com |
| Van Oord | Netherlands | | | http://www.vanoord.com |

**Table G.3. Business units and reporting segments for public companies with pipelay vessel capacity circa 2017**

| Company | Business Segments | Description |
|---|---|---|
| DOF ASA | Platform Supply Vessels<br>Anchor-Handling Vessels<br>Subsea | Chartering platform supply vessels<br>Chartering anchor handling tug supply vessels<br>Services related to subsea construction and installation |
| EMAS Offshore Ltd. | Offshore Support and Accommodation Services | Offshore support and accommodation vessels for charter primarily in development and production phases. Ship management services for third-party vessels. |
| | Offshore Production Services | Provision and operation of FPSO systems and related services, engineering and project management for FPSO conversions and production facilities. |
| McDermott Int. Inc. | America, Europe, Africa Middle East, Asia | Fabrication and offshore installation of fixed and floating structures and the installation of pipelines and subsea systems. |
| Saipem, S.p.A. | Offshore E&C | Design and construct hydrocarbon production facilities, products and services, including platforms, pipelines, and subsea developments. |
| | Onshore E&C | Design and construct hydrocarbon production facilities, hydrocarbon treatment facilities and large onshore treatment and transportation systems and facilities. |
| | Offshore Drilling | Offshore drilling services and project management. |
| | Onshore Drilling | Onshore drilling services and project management. |
| Sapura Energy Berhad | E&C | Engineering, procurement, construction and commissioning services. Installation of offshore platforms, marine pipelines and subsea services. |
| | Drilling | Offshore drilling services and project management. |
| | Energy | Repairs and refurbishment of industrial gas turbines, supply, installation, commissioning and maintenance of point-of sale systems for petrol stations and asset management services for offshore installations. |
| Solstad Offshore ASA | Anchor-Handling Vessels<br>Platform Supply Vessels | Services related to rig moves and anchoring of rigs and other vessels at sea.<br>Services relating to transportation of material to offshore installations. |
| | Construction Services | Services relating to development of both subsea and floating installations. |
| Subsea 7 S.A. | SURF and Conventional | Engineering, procurement, construction and installation of complex offshore systems. |
| | I-Tech Services | Inspection, maintenance and repair services, integrity management of subsea infrastructure and remote intervention support |
| | Corporate | Renewables and heavy lifting services. |
| Swiber Holdings Ltd. | Offshore Construction Services<br>Offshore Marine Services<br>Engineering Services | Turnkey project management, procurement, transportation and installation of offshore structure, subsea completion works and decommissioning services.<br>Marine transportation and management, ship repair and maintenance services, shipbuilding services, start up and commissioning, operations and maintenance.<br>Upstream oil and gas engineering, project management, FEED and detailed design services. |
| TechnipFMC PLC | Subsea | Design, manufacture, procurement and installation of subsea equipment. |
| | Onshore/Offshore | EPCI for refining, gas plants, petrochemicals, fixed and floating production units, and LNG facilities. |
| | Corporate | Holding company activities and central services rendered to Group subsidiaries. |

Source: Annual reports, company websites.

**Table G.4. Pipelay vessel contractor classification circa 2017**

| Company | Ownership | Area of emphasis | Geographic diversity | Business integration |
|---|---|---|---|---|
| Allseas Group S.A. | Private | Generalist | Global | Specialized |
| Ascot Constructors Offshore Ltd. | Private | Shallow water | Regional | Integrated |
| Bisso Marine | Private | Shallow water | Regional | Integrated |
| Ceona Ship Holdings Ltd. | Private | Deepwater | Global | Integrated |
| Chet Morrison Contractors, LLC | Private | Shallow water | Regional | Integrated |
| China National Offshore Oil Corp. | State | Deepwater | Global | Diversified |
| DOF ASA | Public | Deepwater | Global | Integrated |
| EMAS Offshore Ltd. | Public | Deepwater | Global | Integrated |
| Heerema Marine Contractors | Private | Deepwater | Global | Integrated |
| Leighton Offshore | Private | Shallow water | Global | Integrated |
| McDermott Int. Inc. | Public | Generalist | Global | Integrated |
| Oceanic Marine Contractors, Inc. | Private | Deepwater | Global | Integrated |
| Saipem, S.p.A. | Public | Generalist | Global | Diversified |
| Sapura Energy Berhad | Public | Deepwater | Regional | Integrated |
| Sea Trucks Group | Private | Deepwater | Global | Integrated |
| Solstad Offshore ASA | Public | Deepwater | Global | Integrated |
| Subsea 7 S.A. | Public | Deepwater | Global | Integrated |
| Swiber Holding Ltd. | Public | Deepwater | Global | Integrated |
| TechnipFMC PLC | Public | Deepwater | Global | Diversified |
| Van Oord | Private | Shallow water | Global | Diversified |

Source: Annual reports, company websites.

**Table G.5. Vertical integration across upstream oil and gas segment, excluding drilling**

| | Engineering | Procurement | Construction | Installation |
|---|---|---|---|---|
| SURF | | | | |
| Subsea equipment | | | | |
| Umbilicals | | | | |
| Risers | | | | |
| Flowlines | | | | |
| | | | | |
| Structure | | | | |
| Fixed | | | | |
| Floater | | | | |
| | | | | |
| Topsides | | | | |
| | | | | |
| Export systems | | | | |
| Oil | | | | |
| Gas | | | | |

**Table G.6. Business segment involving pipeline activity for marine contractors, 2014–2016 ($ million)**

| Company | Segment | 2014 | | 2015 | | 2016 | |
|---|---|---|---|---|---|---|---|
| | | Segment revenue | Total revenue | Segment revenue | Total revenue | Segment revenue | Total revenue |
| DOF[1] | Construction | 1079 | 1437 | 903 | 1227 | 691 | 994 |
| EMAS[2] | Marine services | 285 | 285 | 245 | 247 | | |
| McDermott | Installation | 1041 | 2301 | 1256 | 3070 | 1074 | 2636 |
| Saipem[3] | Offshore E&C | 8695 | 19,000 | 10,293 | 16,656 | 8653 | 14,355 |
| Sapura[4] | E&C | 1066 | 2562 | 1441 | 2744 | 1,361 | 2455 |
| Solstad[1] | Construction | 263 | 503 | 257 | 403 | 222 | 286 |
| Subsea 7 | SURF | 5303 | 6869 | 3701 | 4758 | 3011 | 3567 |
| Swiber | Construction | 478 | 727 | 750 | 833 | 750[2] | 833[2] |
| Technip[3] | Subsea | 6484 | 14,247 | 6519 | 13,546 | 5854 | 12,232 |

Source: Bloomberg, annual reports, company website.
Note: (1) Converted from NOKs; (2) Fiscal year ends August 31 and 2016 revenues not reported because of financial exigency; (3) Converted from Euros; (4) Converted from MYR, the fiscal year ends Jan 31.

**Table G.7. Publicly traded offshore construction contractor statistics, 2014–2016 ($ million)**

| Company | Market cap[1] | 2014 | | 2015 | | 2016 | |
|---|---|---|---|---|---|---|---|
| | | Total assets | Employees | Total assets | Employees | Total assets | Employees |
| DOF | 167 | 4350 | 5,375 | 3589 | 4,819 | 3449 | 4,072 |
| EMAS[2] | 16 | 966 | - | 1490 | - | - | - |
| McDermott | 1862 | 3417 | 13,800 | 3387 | 10,600 | 3222 | 12,400 |
| Saipem | 4431 | 23,373 | 49,580 | 18,106 | 42,408 | 15,813 | 36,859 |
| Sapura[3] | 2619 | 8198 | - | 9539 | 13,000 | 8799 | - |
| Solstad | 606 | 2387 | 1848 | 1843 | 1638 | 2585 | 1048 |
| Subsea 7 | 5360 | 8624 | 13,400 | 7854 | 9800 | 7803 | 8500 |
| Swiber | 36 | 2149 | 1800 | 2005 | 2700 | - | - |
| Technip | 14,898 | 17,828 | 38,000 | 15,166 | 34,000 | 19,680 | 29,400 |

Source: Bloomberg, annual reports, company website.
Note (1) As of May 5, 2017; (2) Fiscal year ends August 31; (3) Fiscal year ends Jan 31.

**Table G.8. McDermott's competitors in its three geographic regions**

| America, Europe, Africa | Middle East | Asia |
|---|---|---|
| Allseas Marine Contractors | | Allseas Marine Contractors |
| Heerema Group | | Heerema Group |
| EMAS AMC | | EMAS Group |
| Saipem S.p.A. | Saipem S.p.A. | Saipem S.p.A. |
| Subsea 7 S.A. | | Subsea 7 S.A./Sapura Acergy |
| Seaway Heavy Lifting Shipping Ltd. | | |
| Technip FMC PLC | Technip FMC PLC | Technip FMC PLC |
| | | Sapura Kencana Petroleum & TL Offshore |
| | | Sembcorp Marine Offshore Engineering |

Source: McDermott Int. Inc. annual report.

**Table G.9. Parque das Conchas (BC-10) project major contracts**

| Contract type | Scope | Provider |
|---|---|---|
| Dayrate | Drilling and completion operations | Transocean |
| Lease | A joint venture between SBM and MISC, a contractor owned and operated FPSO | Brazilian Deepwater Floating Terminals |
| EPCI | Onshore fabrication and offshore installation and commissioning of the pipelines, flowlines, risers and jumpers | Subsea 7 |
| Lump-sum installation | Transportation and installation of the umbilicals, manifolds and subsea distribution hardware | Subsea 7 |
| EPC | Fabrication of subsea tress, controls, manifolds, subsea distribution hardware, and jumper kits. | FMC Technologies |

Source: Stingl and Paardekam 2010.

**Table G.10. Cascade and Chinook project major contracts**

| Contact type | Scope | Provider |
|---|---|---|
| EPC | Trees and manifolds | FMC Technologies |
| EPC | Control system | FMC Technologies |
| EPC | Subsea boosting pumps | FMC Technologies |
| EPC | Control and power umbilicals | Aker Solutions |
| EPC | Line pipe and bends | Tenaris |
| EPC | Risers supply and pump installation | Technip |
| Lump sum installation | Cascade flowlines, gas export pipeline | Technip |
| Lump sum installation | Chinook PIP flowlines | Heerema |
| Lump sum installation | Control umbilicals | Subsea 7 |
| Rental | Integrated workover and control system | Aker Solutions |
| Dayrate | Multi-service vessel | Veolia |

Source: Porciuncula et al. 2013.

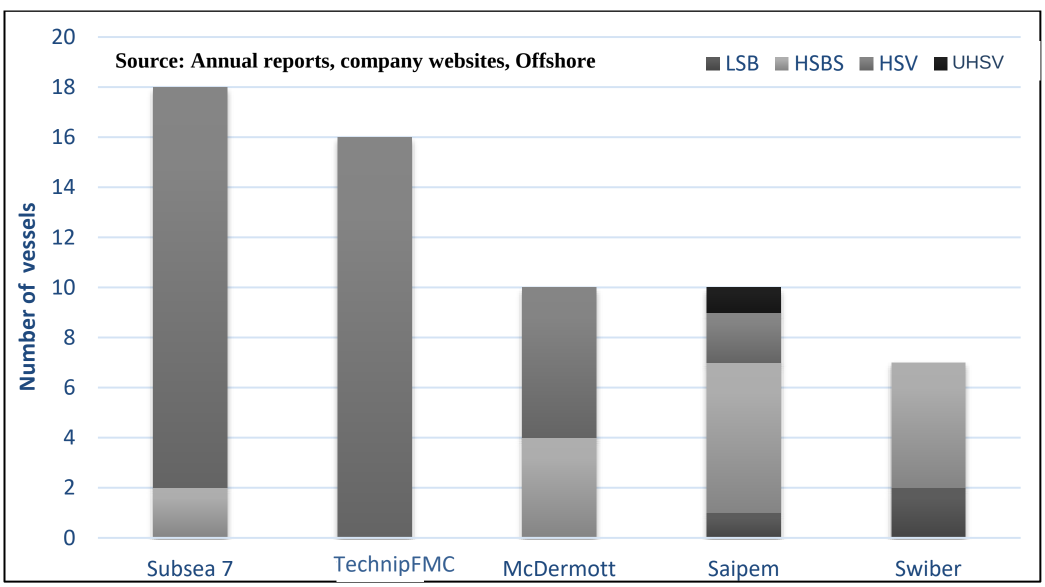



Figure G.1. Pipelaying fleets of the five largest contractors circa 2017.

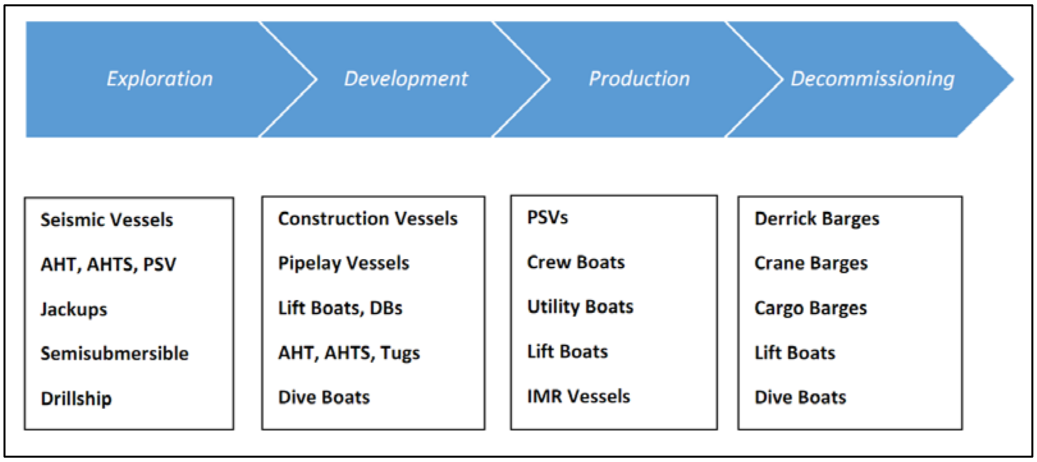



Figure G.2. Upstream business segments and vessel requirements.

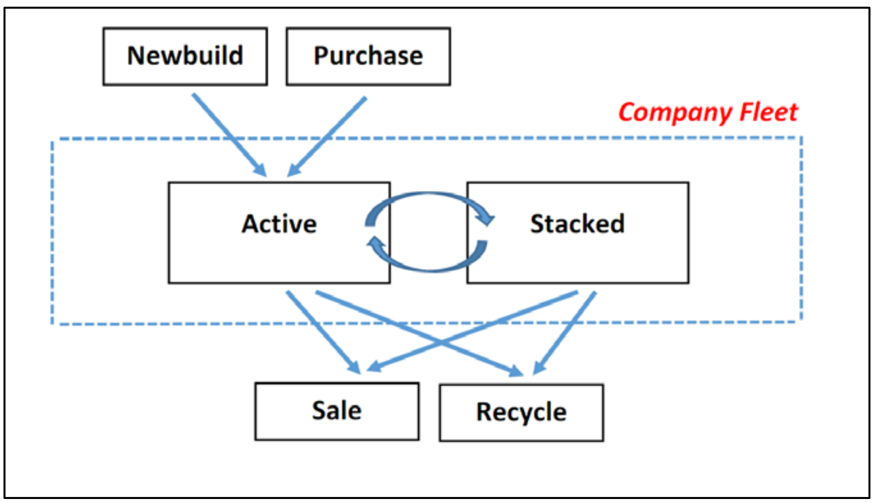



Figure G.3. Company fleet changes due to newbuild, purchase, sale, and recycle activity.

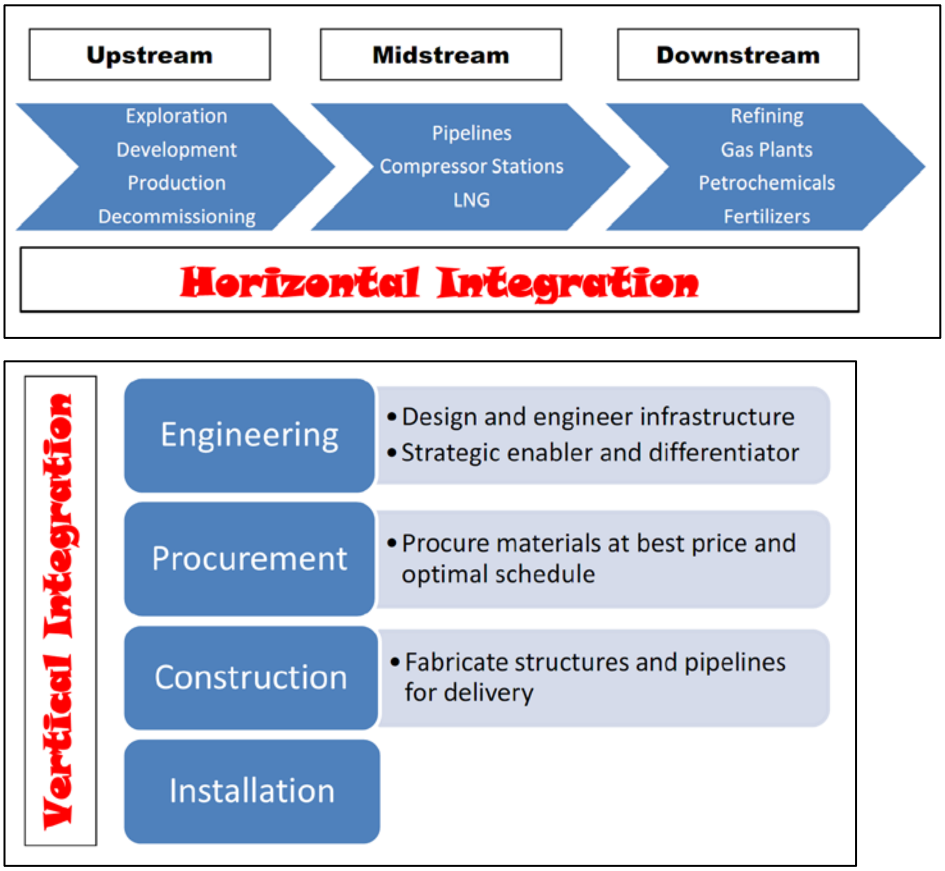



Figure G.4. Offshore construction company integration strategies.

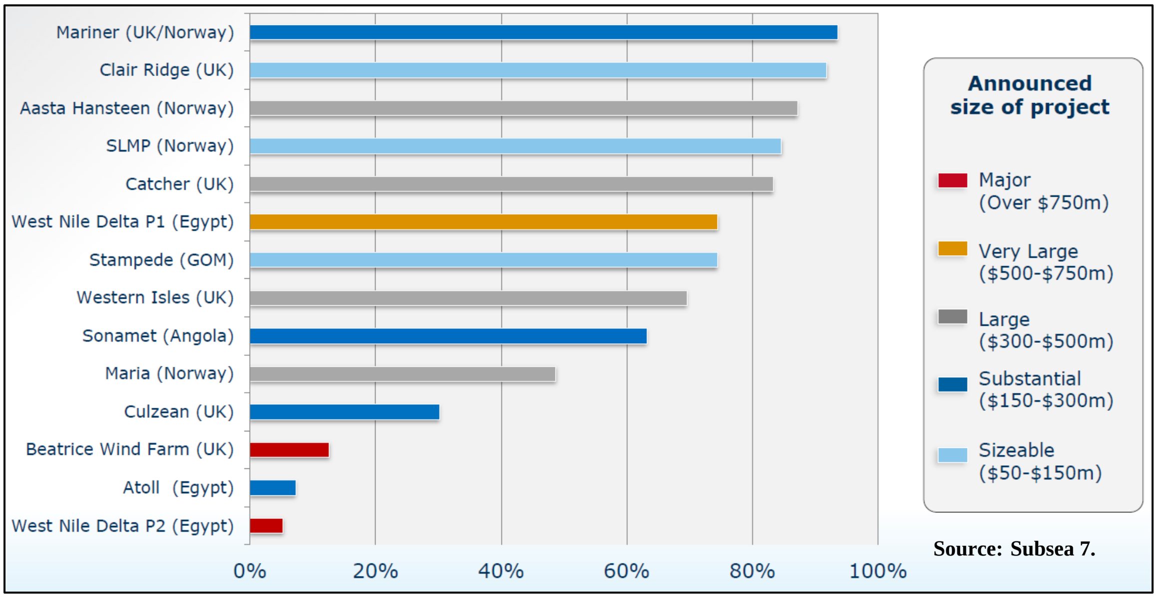



Figure G.5. Subsea 7 major project progression as of Dec 31, 2016.

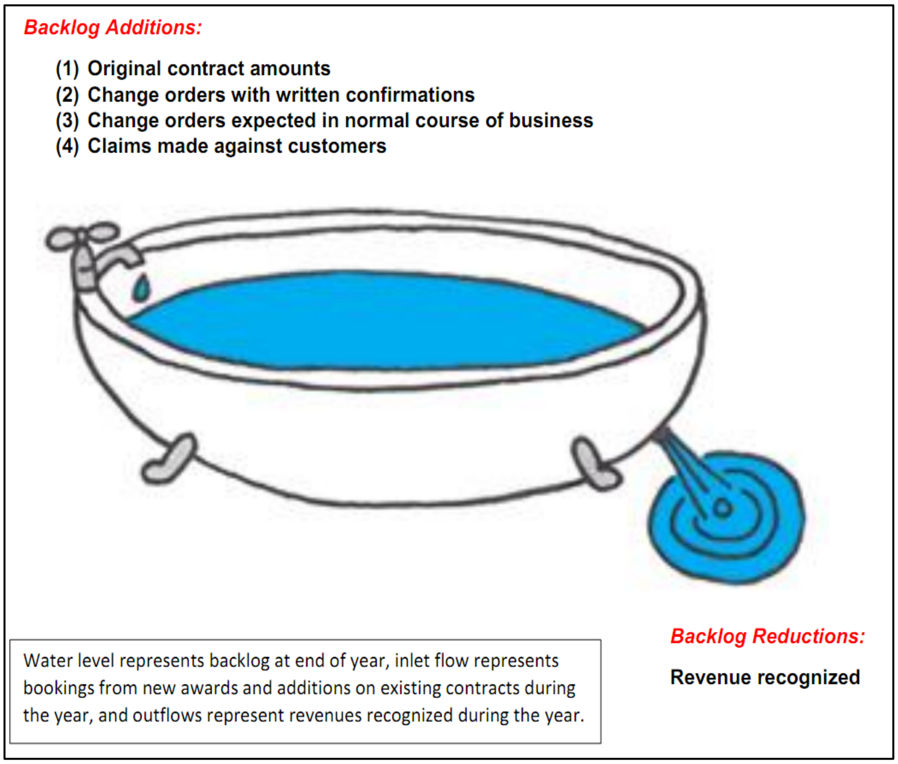



Figure G.6. Bathtub analogy of backlog.

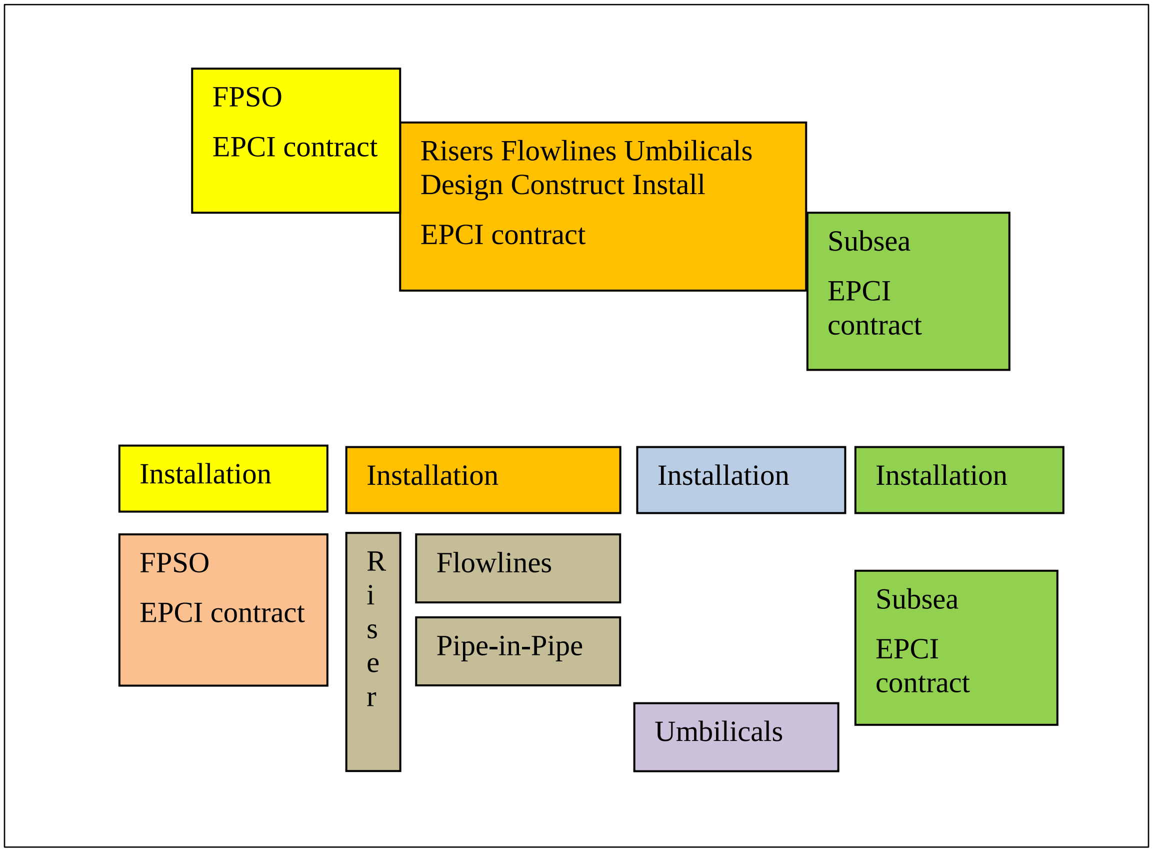



Figure G.7. Schematic depicting small number of large EPCI contracts compared to large number of small contracts.

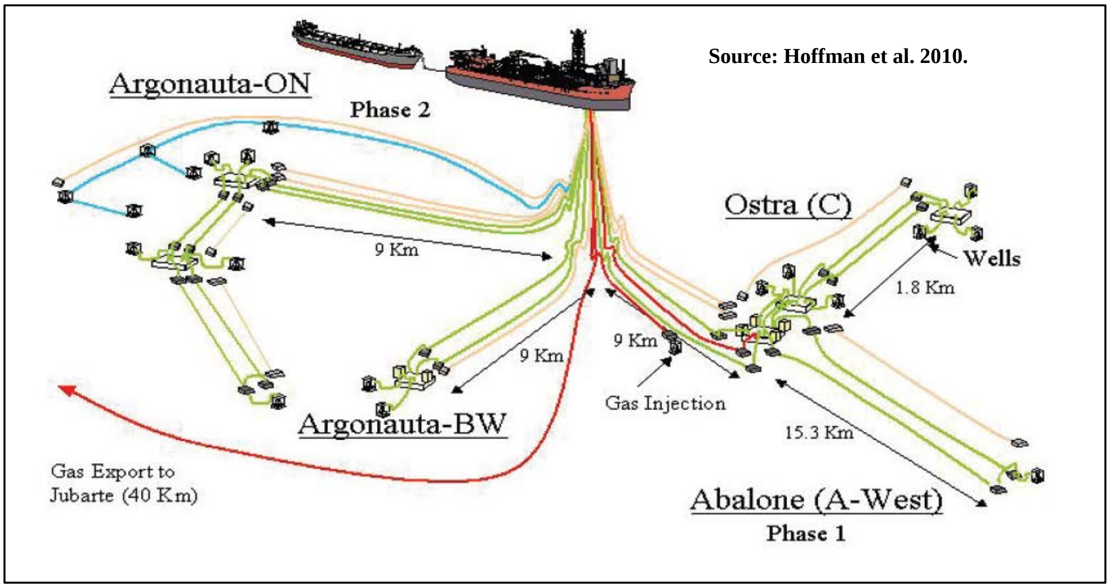



Figure G.8. Parque das Conchas (BC-10) subsea development layout.

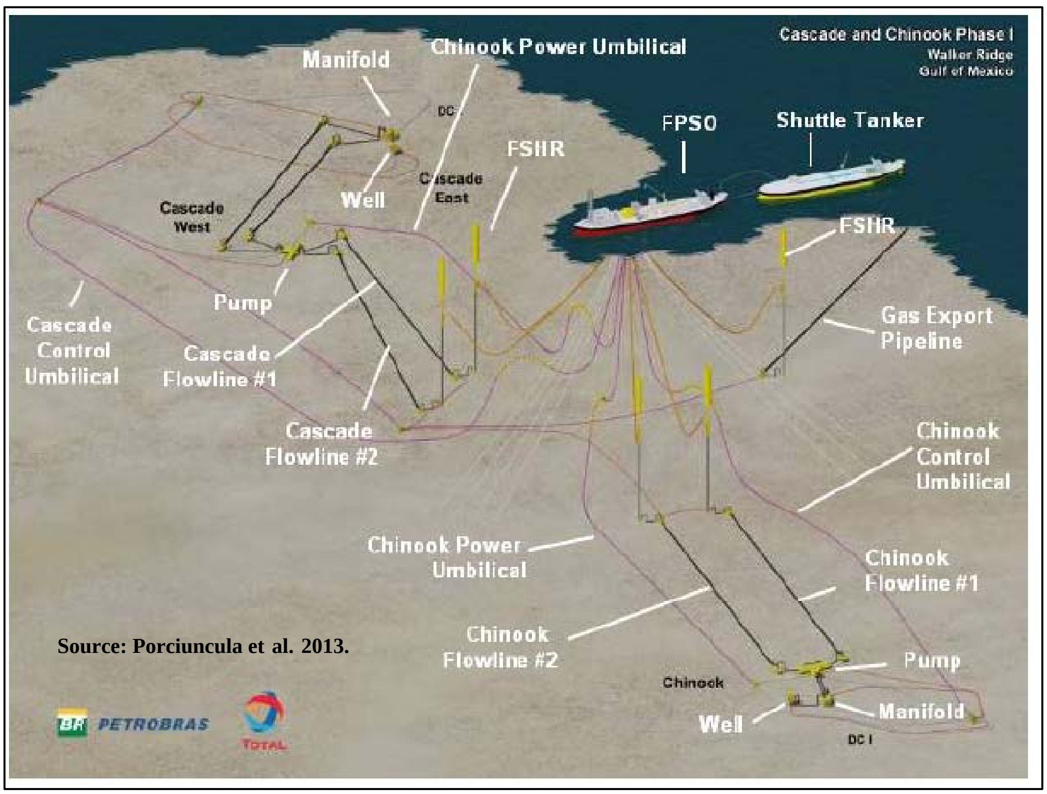



Figure G.9. Cascade and Chinook subsea development layout.

## Appendix H: Chapter 8 Figures

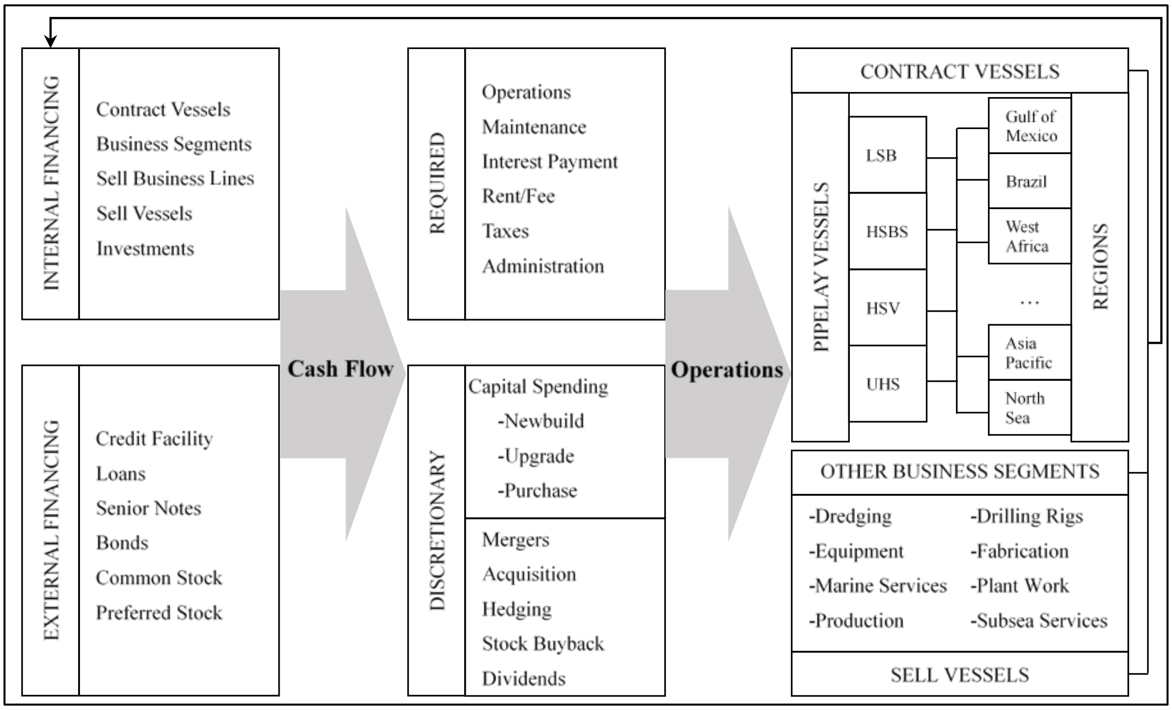



Figure H.1. Business model for pipelay construction service companies, cash flow perspective.

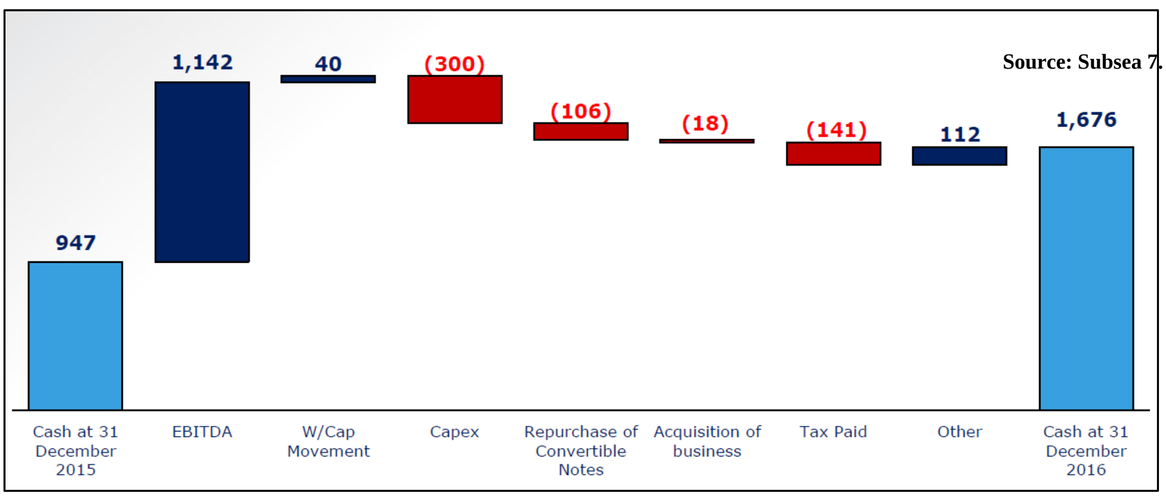



Figure H.2. Subsea 7 cash flow summary for year ending December 31, 2016.

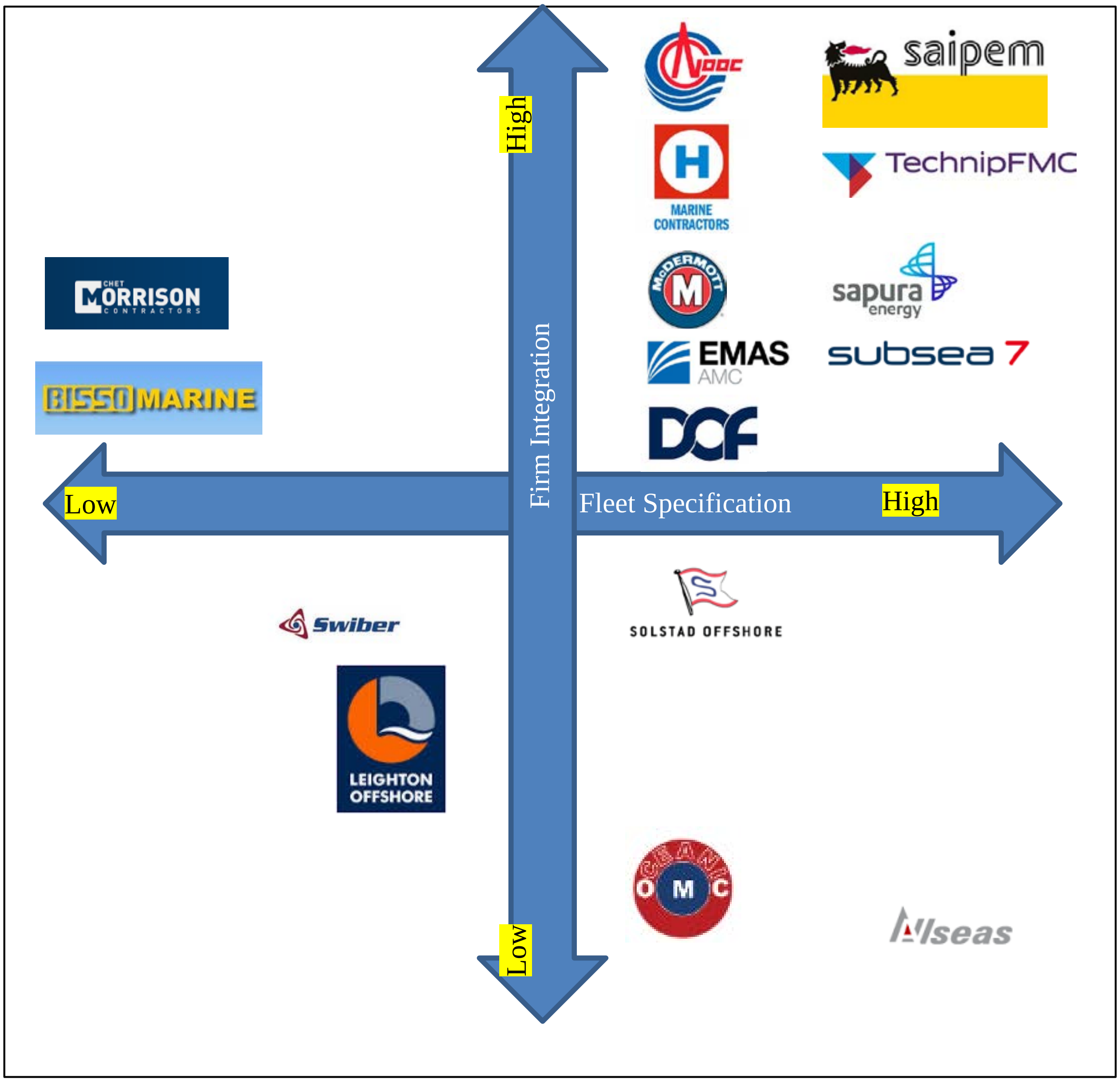



Figure H.3. Construction service contractor integration and fleet specification market position circa 2017.

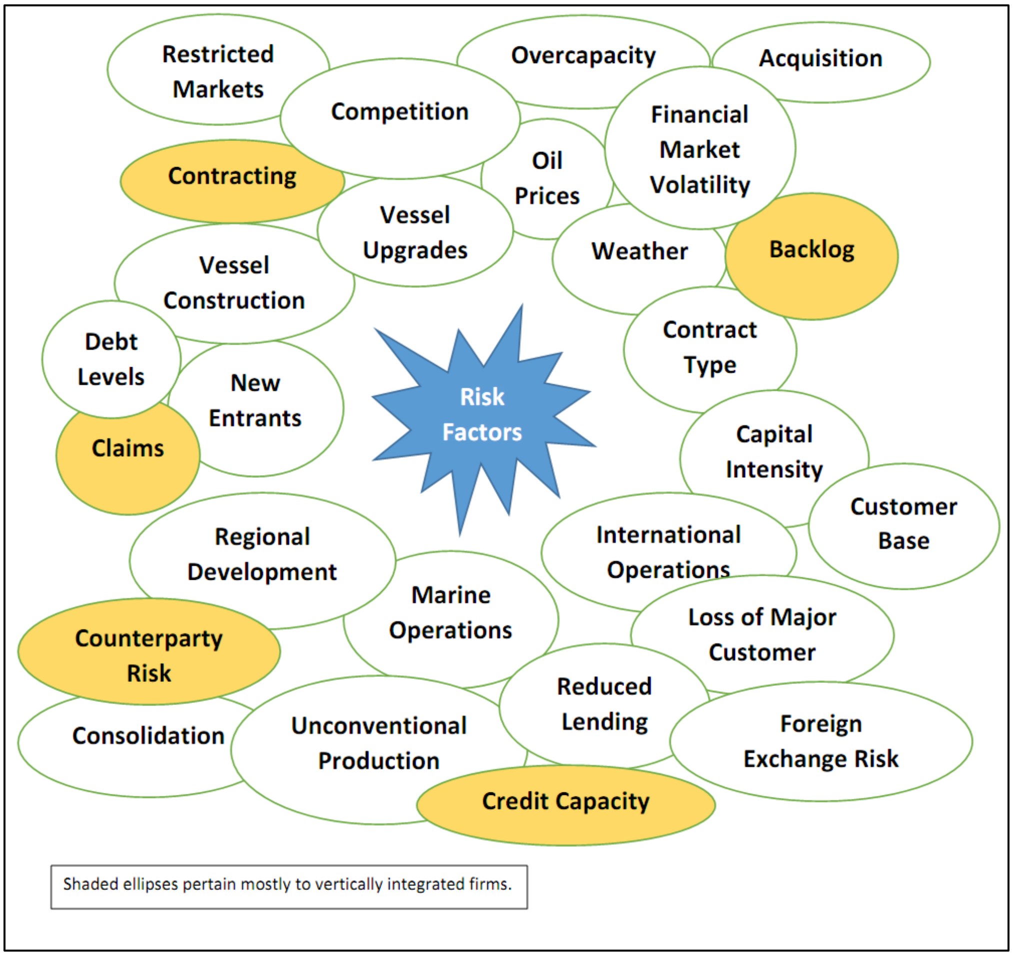



Figure H.4. Risk factors encountered by offshore construction service companies.

# Appendix I: Chapter 9 Tables and Figures

**Table I.1. Federal OCS pipeline requirements for time out of service**

| Time out of service | Action |
|---|---|
| 1 year or less | Isolate the pipeline with a blind flange or a closed block value at each end of the pipeline |
| More than 1 year, but less than 5 years | Flush and fill the pipeline with inhibited seawater |
| 5 or more years | Decommission the pipeline according to 30 CFR 250.1750–250.1754 |

Source: BSEE.

**Table I.2. Destin pipeline, rate schedule FT-1 firm transportation rate**

| | Monthly Reservation Rate ($/Dth/mo) | Daily Reservation Rate ($/Dth) | Transportation Rate (¢/Dth) |
|---|---|---|---|
| Maximum Rate | $7.19 | $0.237 | 0.3¢ |
| Minimum Rate | 0.00 | 0.00 | 0.3¢ |
| Fuel Retention Percentage | 0.3% | | |

**Table I.3. Mars pipeline tariff firm transportation**

| From | To | Rate |
|---|---|---|
| MC 807 (Mars A) | WD 143 | $2.61/bbl |
| WD 143 | Bay Marchard 4 | $1.16/bbl, if <30,000 bbl<br>$0.70/bbl, if >30,000 bbl |
| Bay Marchard 4 | Fourchon Terminal | $0.15/bbl |
| Fourchon Terminal | Clovelly/Caverns | $0.43/bbl |

Source: Shell Midstream Partners.

**Table I.4. Garden Banks gathering system rate base and cost of service**

| Description | | Costs |
|---|---|---|
| Rate Base and Return | | |
| Gas Plant in Service | $ | 108,000,000 |
| Working Capital | | 1,000,000 |
| Rate Base | $ | 107,000,000 |
| Cost of Service | | |
| Pre-tax Return (@13.75% of Rate Base) | $ | 14,712,500 |
| Operation and Maintenance Expenses | | 3,000,000 |
| Depreciation Expense (@ 6.67% Gas Plant) | | 7,200,000 |
| Taxes Other than Income Taxes | | 2,000,000 |
| Total Cost of Service | $ | 26,912,000 |
| Annual Contract Quantity (Dth) | | 241,000,000 |
| Daily Reservation Rate | $/Dth | 0.112 |

Source: FERC.

**Table I.5. Sea Robin Pipeline Company, LLC, rate schedule–firm and interruptible**

| | Maximum Rate ($ per Dth) | FT-2 ($ per Dth) | IT ($ per Dth) |
|---|---|---|---|
| WEST AREA | | | |
| Transmission | | | |
| A. Volumetric Rate | | $ 0.1590 | |
| B. Reservation Rate | $ 4.0949 | $ 4.0949 | |
| Usage Rate | $ 0.0244 | $ 0.0244 | $ 0.1590 |
| Overrun Rate | $ 0.1346 | $ 0.1346 | |
| Gathering Charge | | | |
| A. Volumetric Rate | | $ 0.3300 | |
| B. Reservation Rate | $ 10.0377 | $ 10.0377 | |
| Usage Rate | | | $ 0.3300 |
| Overrun Rate | $ 0.3300 | $ 0.3300 | |
| EAST AREA | | | |
| Transmission | | | |
| A. Volumetric Rate | | $ 0.2290 | |
| B. Reservation Rate | $ 6.9656 | $ 6.9656 | |
| Usage Rate | - | - | $ 0.2290 |
| Overrun Rate | $ 0.2290 | $ 0.2290 | |
| Gathering Charge | | | |
| A. Volumetric Rate | | $ 0.1480 | |
| B. Reservation Rate | $ 4.5012 | $ 4.5012 | |
| Usage Rate | - | - | $ 0.1480 |
| Overrun Rate | $ 0.1480 | $ 0.1480 | |

Source: FERC.

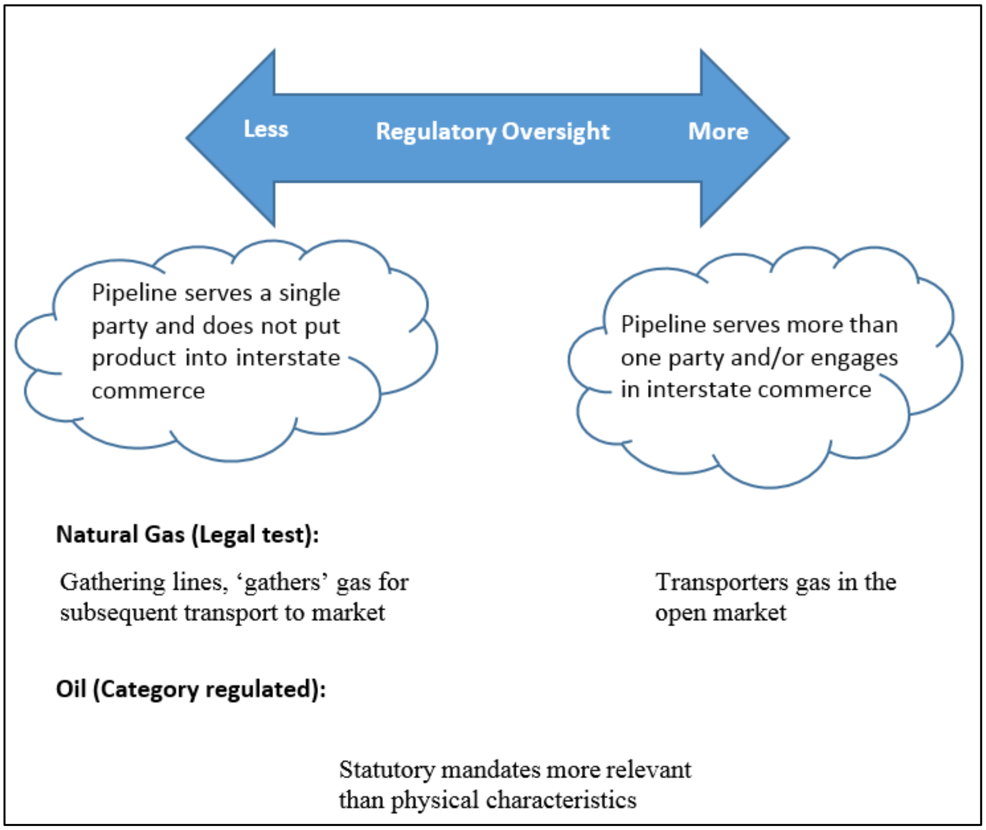
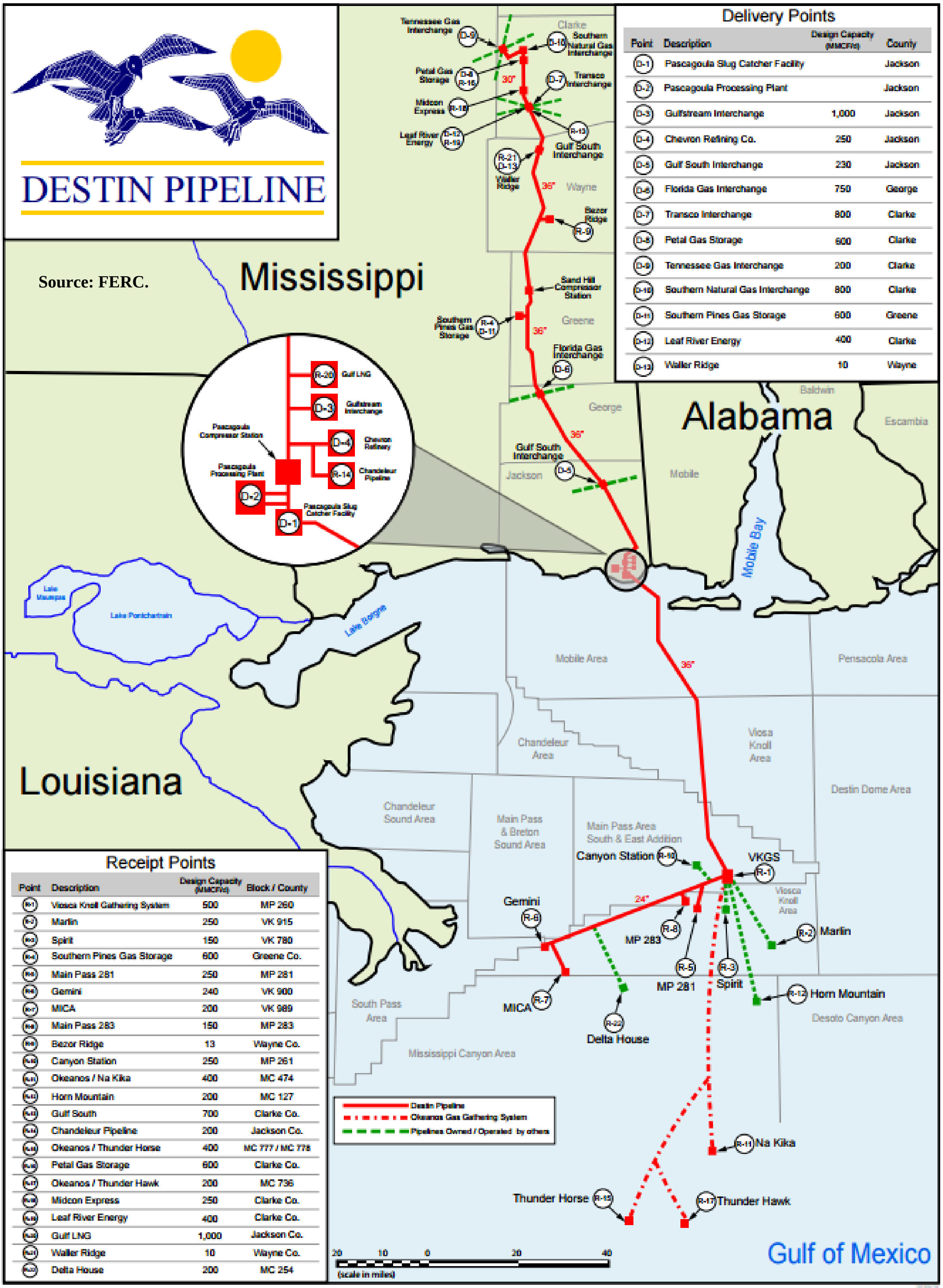



Figure I.1. OCS pipeline regulatory oversight spectrum.




## Delivery Points

| Point | Description | Design Capacity (MMCF/d) | County |
|---|---|---|---|
| D-1 | Pascagoula Slug Catcher Facility | | Jackson |
| D-2 | Pascagoula Processing Plant | | Jackson |
| D-3 | Gulfstream Interchange | 1,000 | Jackson |
| D-4 | Chevron Refining Co. | 250 | Jackson |
| D-5 | Gulf South Interchange | 230 | Jackson |
| D-6 | Florida Gas Interchange | 750 | George |
| D-7 | Transco Interchange | 800 | Clarke |
| D-8 | Petal Gas Storage | 600 | Clarke |
| D-9 | Tennessee Gas Interchange | 200 | Clarke |
| D-10 | Southern Natural Gas Interchange | 800 | Clarke |
| D-11 | Southern Pines Gas Storage | 600 | Greene |
| D-12 | Leaf River Energy | 400 | Clarke |
| D-13 | Waller Ridge | 10 | Wayne |

## Receipt Points

| Point | Description | Design Capacity (MMCF/d) | Block / County |
|---|---|---|---|
| R-1 | Viosca Knoll Gathering System | 500 | MP 260 |
| R-2 | Marlin | 250 | VK 915 |
| R-3 | Spirit | 150 | VK 780 |
| R-4 | Southern Pines Gas Storage | 600 | Greene Co. |
| R-5 | Main Pass 281 | 250 | MP 281 |
| R-6 | Gemini | 240 | VK 900 |
| R-7 | MICA | 200 | VK 989 |
| R-8 | Main Pass 283 | 150 | MP 283 |
| R-9 | Bezor Ridge | 13 | Wayne Co. |
| R-10 | Canyon Station | 250 | MP 261 |
| R-11 | Okeanos / Na Kika | 400 | MC 474 |
| R-12 | Horn Mountain | 200 | MC 127 |
| R-13 | Gulf South | 700 | Clarke Co. |
| R-14 | Chandeleur Pipeline | 200 | Jackson Co. |
| R-15 | Okeanos / Thunder Horse | 400 | MC 777 / MC 778 |
| R-16 | Petal Gas Storage | 600 | Clarke Co. |
| R-17 | Okeanos / Thunder Hawk | 200 | MC 736 |
| R-18 | Midcon Express | 250 | Clarke Co. |
| R-19 | Leaf River Energy | 400 | Clarke Co. |
| R-20 | Gulf LNG | 1,000 | Jackson Co. |
| R-21 | Waller Ridge | 10 | Wayne Co. |
| R-22 | Delta House | 200 | MC 254 |

Figure I.2. Destin Pipeline system map.

**Source: Shell Offshore.**

Figure I.3. Mars A platform.

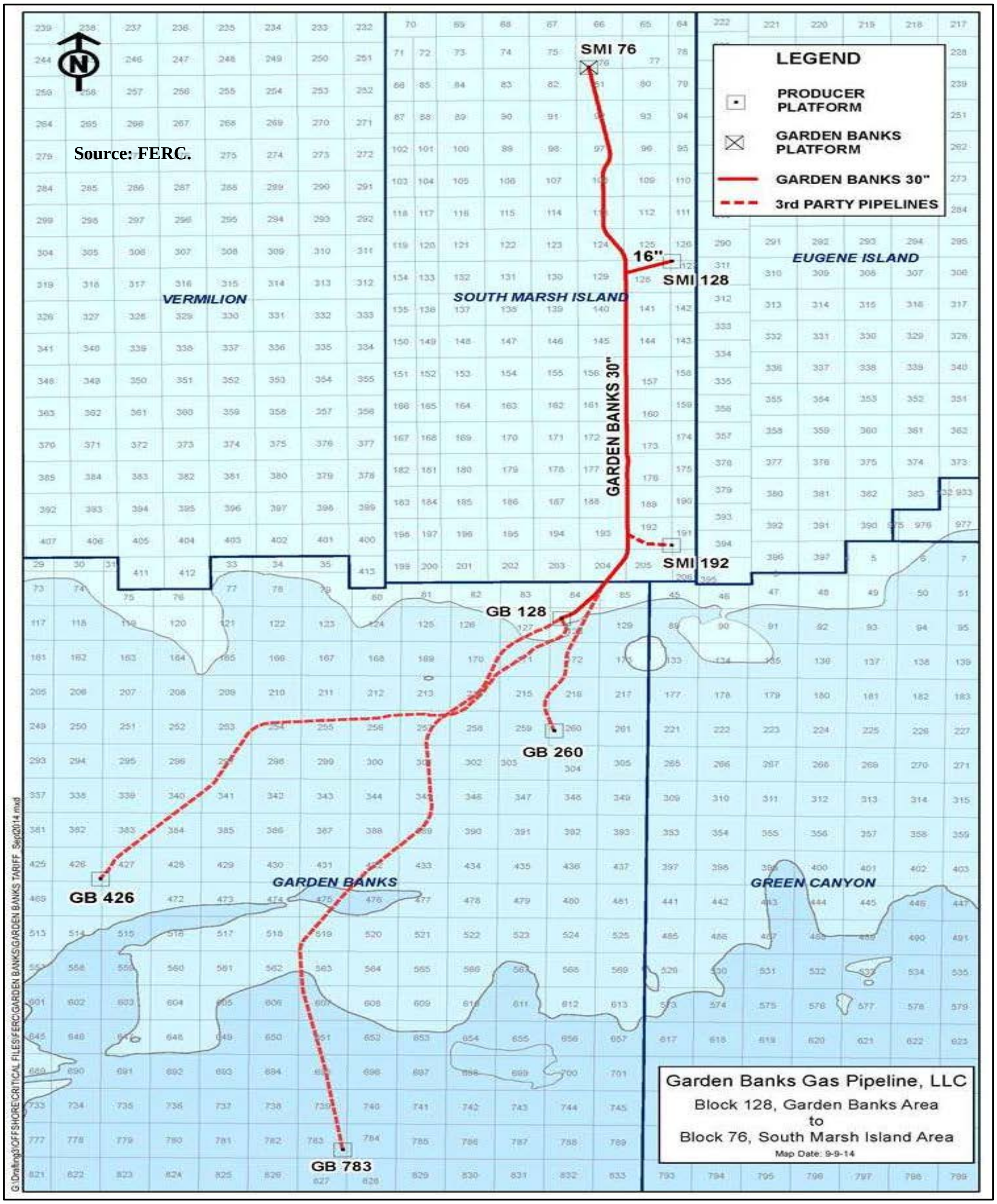



Figure I.4. Garden Banks gas pipeline system map.

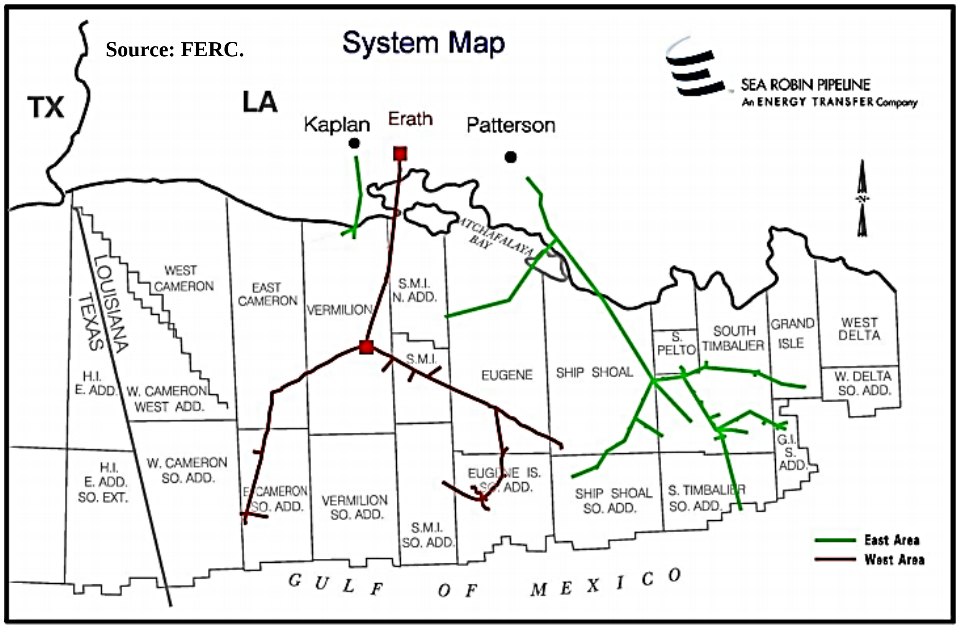



Figure I.5. Sea Robin Pipeline Company east and west area system map.

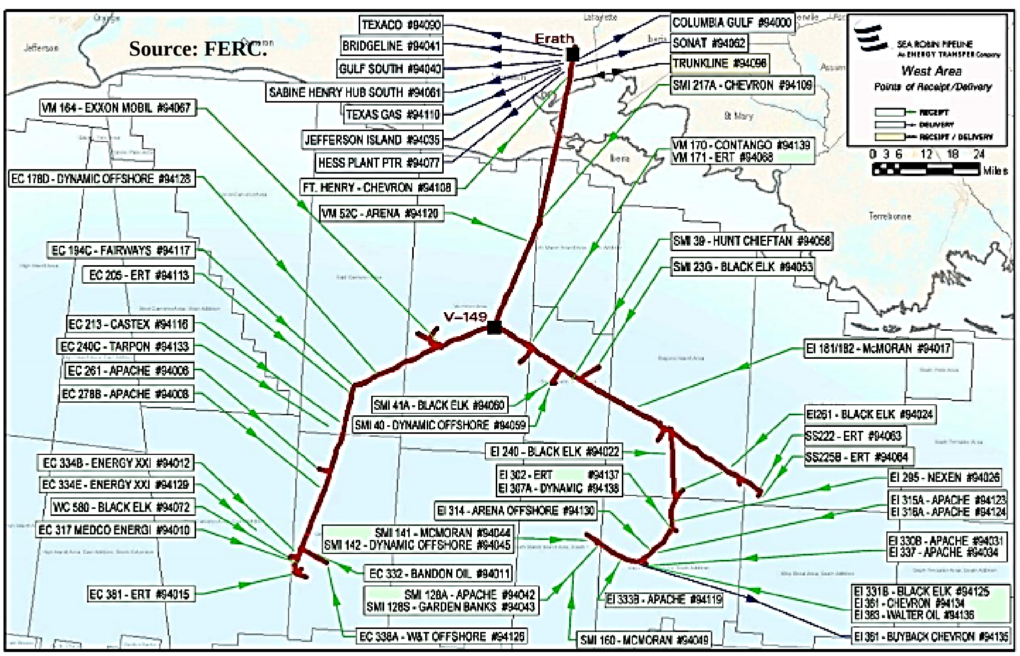



Figure I.6. Sea Robin Pipeline Company west area system map.

# Appendix J: Chapter 10 Figures

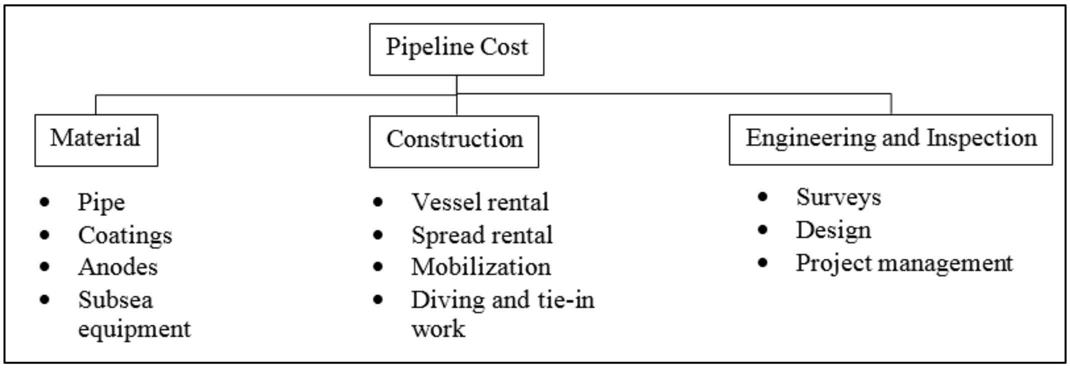



Figure J.1. Pipeline construction cost categories and primary components.

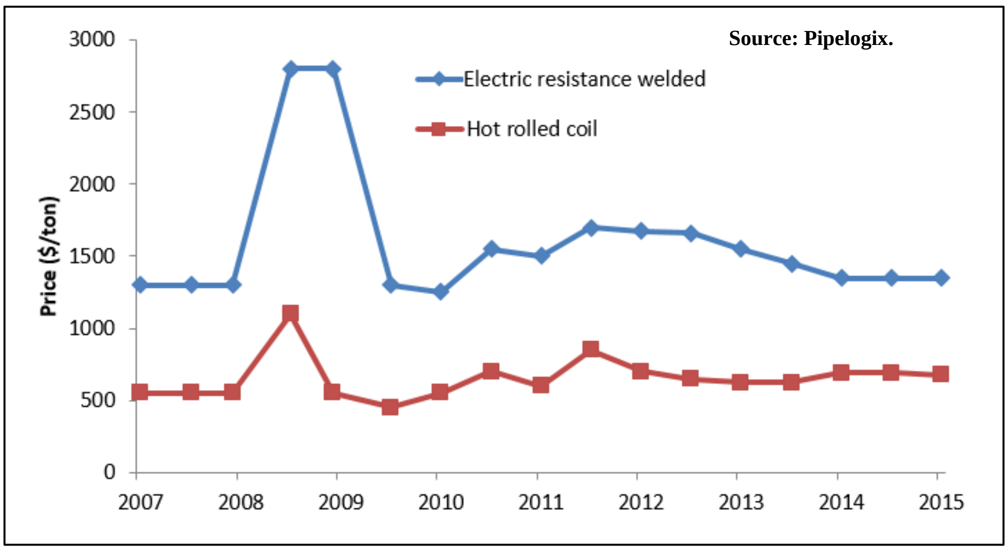



Figure J.2. Steel pipeline prices, 2007–2015.

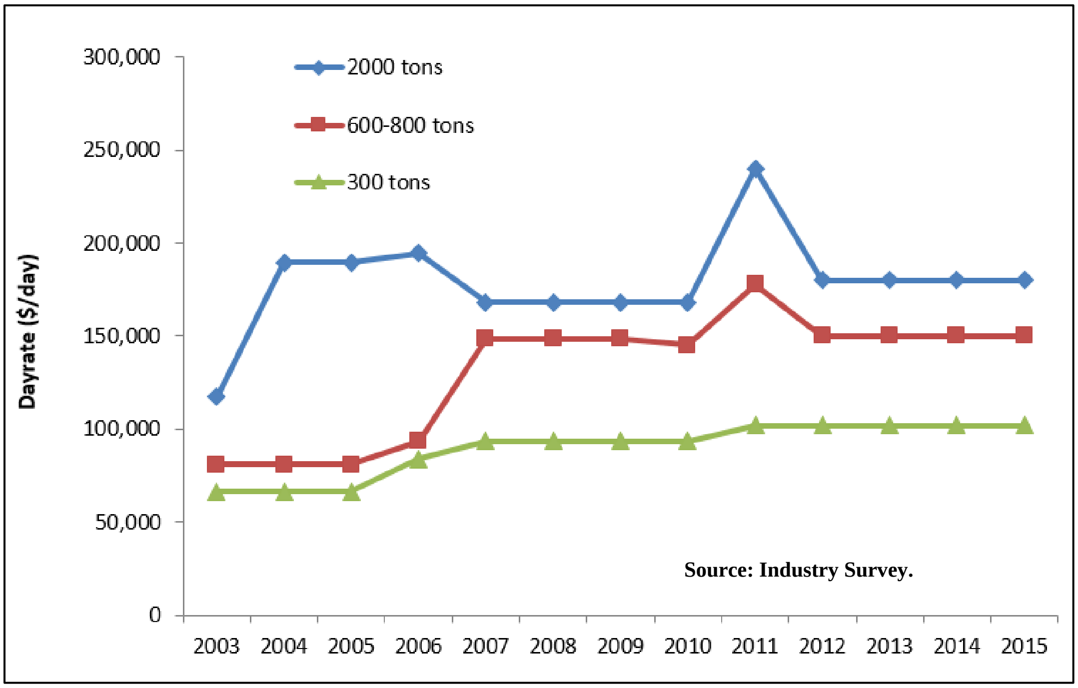
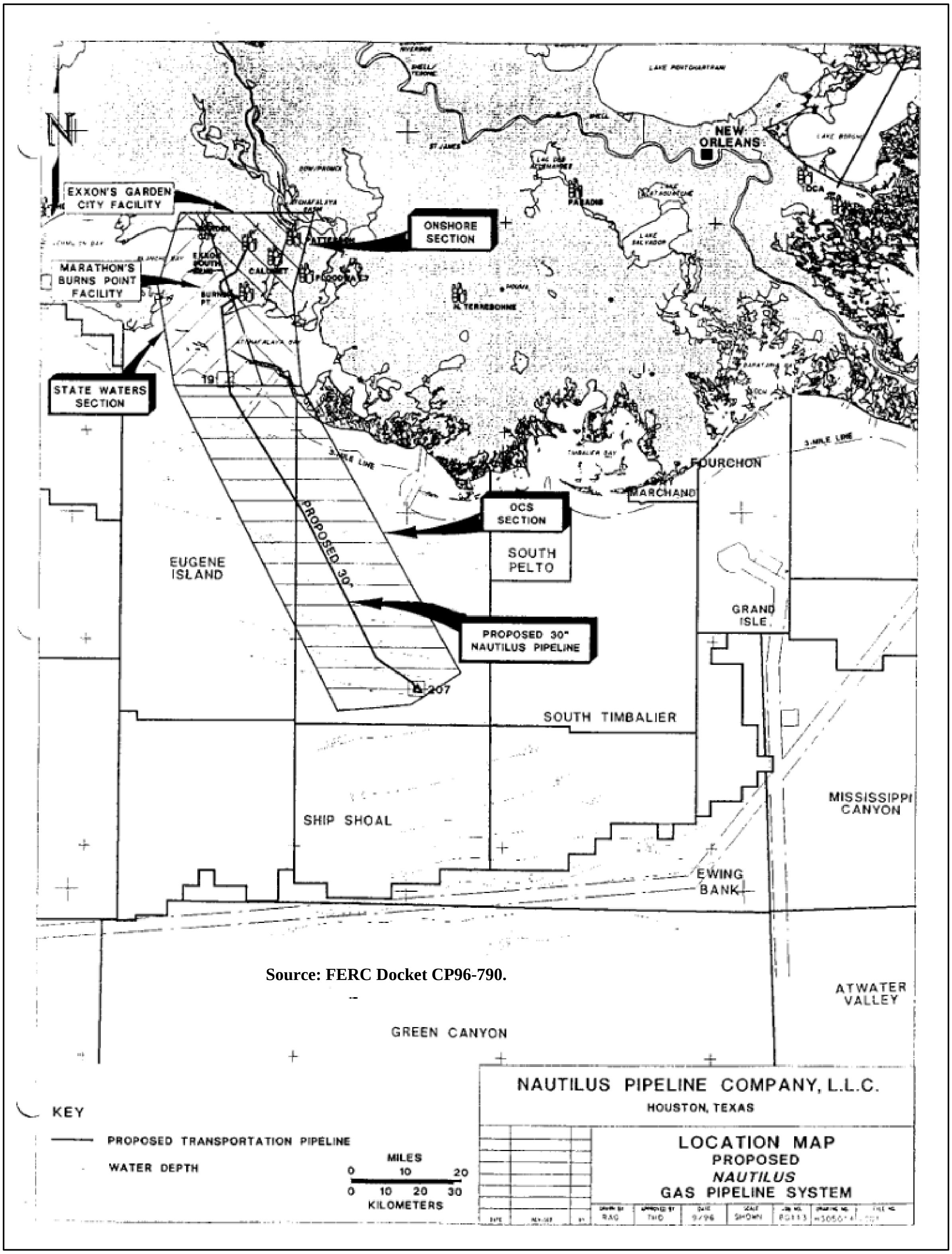



Figure J.3. Average estimated dayrates for derrick barges by lift capacity in the Gulf of Mexico, 2003–2015.




**Source: FERC Docket CP96-790.**

Figure J.4. Nautilus pipeline route.

| Component | Revised Units Required | Revised $/Unit | Revised Exhibit K | Actual & Estimated Expenditures |
|---|---|---|---|---|
| **Materials** | | | | |
| 1 Pipe: 30" OD x 0.577" WT. X-65 | 460,000 | 59.20 | 27,232,000 | 28,024,449 |
| 2 Pipe: 30" OD x 0.875" WT. X-65 | 500 | 98.00 | 49,000 | 149,187 |
| 3 Thin Film Epoxy Coating (0.577 wall) | 460,000 | 5.20 | 2,392,000 | 2,441,563 |
| 4 Thin Film Epoxy Coating (0.875 wall) | 500 | 6.32 | 3,160 | 0 |
| 5 Concrete Weight Coating | 460,500 | 17.87 | 8,229,135 | 9,279,933 |
| 6 Anodes | 750 | 700 | 525,000 | 330,856 |
| 7 Subsea Valves | 3 | 70,000 | 210,000 | 0 |
| 8 Pig Launcher, Platform Piping | 1 | 550,000 | 550,000 | 1,413,181 |
| 9 Meter @ SS 207 | 1 | 500,000 | 500,000 | 0 |
| 10 Internal Epoxy Coating | 460,500 | 4.50 | 2,072,250 | 0 |
| | | | 41,762,545 | 41,639,169 |
| Construction | | | | |
| 11 Contractor Management Cost | 2 | 100,000 | 200,000 | 513,586 |
| 12 Mobe/Demobe Deep Water | 1 | 5,500,000 | 5,500,000 | 3,945,878 |
| 13 Mobe/Demobe Shallow Water | 1 | 1,000,000 | 1,000,000 | 1,555,866 |
| 14 Pipe Lay Deep Water | 300,000 | 35.00 | 10,500,000 | 6,320,563 |
| 15 Pipe Lay Shallow Water, Burial included | 160,000 | 70 | 11,200,000 | 10,861,693 |
| 16 Field Joint Coating | 1 | 1,000,000 | 1,000,000 | 1,795,333 |
| 17 Pipeline Crossings | 40 | 100,000 | 4,000,000 | 1,424,218 |
| 18 Riser @ 207 | 1 | 550,000 | 550,000 | 156,619 |
| 19 Shore Approach - Directional Drill | 1 | 1,500,000 | 1,500,000 | 0 |
| 20 NDT/Diving Support | 460,000 | 2.00 | 920,000 | 1,049,083 |
| 21 Postlay Survey | 460,000 | 1.00 | 460,000 | 0 |
| 21 Burial | 300,000 | 10 | 3,000,000 | 3,145,760 |
| 22 Hydrotest | 2 | 500,000 | 1,000,000 | 967,972 |
| 23 Commissioning | 1 | 500,000 | 500,000 | 122,006 |
| 24 Tie-in work @ SS207 | 1 | 250,000 | 250,000 | 640,186 |
| 25 Future Tap Installations | 3 | 300,000 | 900,000 | 0 |
| | | | 42,480,000 | 32,498,763 |

Figure J.5. Nautilus pipeline estimated and actual cost.

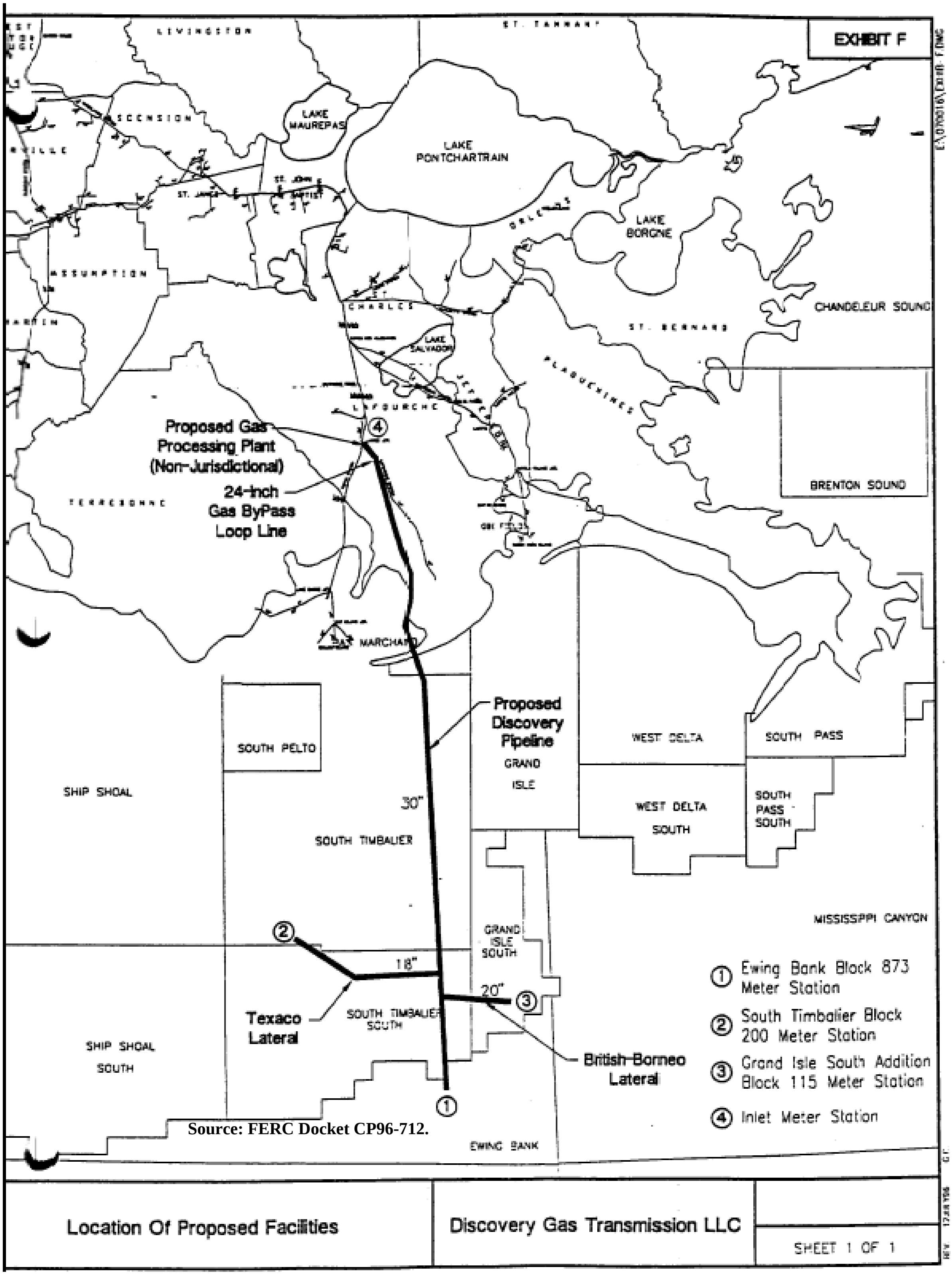



Figure J.6. The Discovery Gas Transmission system.

| No. | Source: FERC Docket CP96-712.<br>Particular | Exhibit K Estimate | Actuals & Estimated Expenditures |
|---|---|---|---|
| 1.0 | Land and Land Rights | | |
| | 1.1 Right of way (Onshore Mainline) | $ 2,502,500 | $ 2,135,393 |
| | 1.2 Mitigation/Damages (Onshore Mainline) | $ 2,000,000 | $ 2,001,296 |
| 1.0 | Subtotal | $ 4,502,500 | $ 4,136,689 |
| 2.0 | Pipeline (Mainline and Laterals) | | |
| | 2.1 Offshore Mainline | | |
| | a. Pipe and Coatings | $ 38,917,200 | $ 35,164,967 |
| | b. Valves, Flanges, Misc. Materials | $ 1,033,200 | $ 1,621,230 |
| | c. Inspection | $ 2,657,400 | $ 1,628,244 |
| | d. Traceability | $ 100,000 | $ 236,873 |
| | e. Construction | $ 30,068,100 | $ 31,199,477 |
| | f. Survey, Mapping | $ 270,000 | $ 207,981 |
| | Subtotal | $ 73,045,900 | $ 70,058,772 |
| | 2.2 Onshore Mainline | | |
| | a. Pipe and Coatings | $ 21,573,100 | $ 19,836,559 |
| | b. Valves, Flanges, Misc. Materials | $ 2,047,200 | $ 1,995,436 |
| | c. Inspection | $ 997,900 | $ 1,922,187 |
| | d. Traceability | $ 100,000 | $ 196,846 |
| | e. Construction | $ 23,444,400 | $ 28,985,413 |
| | f. Survey/Mapping/Permitting | $ 1,125,000 | $ 1,700,248 |
| | Subtotal | $ 49,287,600 | $ 54,636,689 |
| | 2.3 Offshore Lateral to Grand Isle 115 Platform | | |
| | a. Pipe and Coatings | $ 2,523,200 | $ 2,682,617 |
| | b. Valves, Flanges, Misc. Materials | $ 442,000 | $ 645,221 |
| | c. Inspection | $ 574,300 | $ 253,297 |
| | d. Traceability | $ 20,100 | $ 37,031 |
| | e. Construction | $ 5,127,800 | $ 3,524,172 |
| | f. Survey, Mapping | $ 70,200 | $ 57,737 |
| | Subtotal | $ 8,757,600 | $ 7,200,075 |
| | 2.4 Offshore Lateral to South Timbalier 200 Platform | | |
| | a. Pipe and Coatings | $ 5,616,300 | $ 4,741,491 |
| | b. Valves, Flanges, Misc. Materials | $ 498,000 | $ 675,608 |
| | c. Inspection | $ 1,594,800 | $ 357,649 |
| | d. Traceability | $ 32,100 | $ 51,226 |
| | e. Construction | $ 9,863,300 | $ 7,429,920 |
| | f. Survey, Mapping | $ 185,000 | $ 75,201 |
| | Subtotal | $ 17,789,500 | $ 13,331,095 |
| 2.0 | Subtotal | $ 148,880,600 | $ 145,226,631 |
| 3.0 | Compressor Stations | $ - | $ - |
| 4.0 | Meter Stations/SCADA | | |
| | 4.1 Offshore Mainline | $ 348,400 | $ 572,094 |
| | 4.2 Onshore Mainline | $ 972,800 | $ 2,941,321 |
| | 4.3 Offshore Lateral to GI115 | $ 323,200 | $ 452,286 |
| | 4.4 Offshore Lateral to ST200 | $ 292,500 | $ 780,769 |
| 4.0 | Subtotal | $ 1,936,900 | $ 4,746,470 |
| 5.0 | O&M Capital | | |
| | 5.1 Spare Parts | $ 200,000 | $ 200,000 |
| | 5.2 Other | $ 300,000 | $ 300,000 |
| 5.0 | Subtotal | $ 500,000 | $ 500,000 |

Figure J.7. The Discovery Gas Transmission system pipeline estimated and actual cost.

| No. | Particular | Exhibit K Estimate | Actuals & Estimated Expenditures |
|---|---|---|---|
| 6.0 | Project Management & Engineering | | |
| | 6.1 Project Management/Company Cost | $ 2,013,600 | $ 4,714,105 |
| | 6.2 Engineering | | |
| | a. Offshore Lateral | $ 350,000 | $ 934,406 |
| | b. Onshore Lateral | $ 600,000 | $ 634,510 |
| | c. Offshore Lateral to GI115 | $ 250,000 | $ 160,201 |
| | d. Offshore Lateral to ST200 | $ 400,000 | $ 213,020 |
| 6.0 | Subtotal | $ 3,613,600 | $ 6,656,242 |
| 7.0 | State and Local Taxes on Materials | $ 1,810,700 | $ 1,884,045 |
| 8.0 | Pre-Permit | $ 267,600 | $ 440,121 |
| 9.0 | Contingency | $ 16,878,200 | |
| 10.0 | AFUDC | $ 8,941,000 | $ 12,807,939 |
| 11.0 | Line Pack | $ 549,000 | $ 570,483 |
| 12.0 | TOTAL COST | $ 187,880,100 | $ 176,968,620 |

Figure J.7. The Discovery Gas Transmission system pipeline estimated and actual cost.

# Appendix K: Chapter 11 Tables and Figures

**Table K.1. FERC pipeline projects and inflation-adjusted costs, 1995–2015 (2014$)**

| Project | Year | Diameter (in) | Length (mi) | 2014 cost ($1000/mi) | 2014 cost ($1000/mi-in) |
|---|---|---|---|---|---|
| Stingray Vermillion (E) | 1995 | 20 | 15.6 | 1086 | 54.3 |
| Stingray Garden Banks (E) | 1996 | 20 | 15.5 | 1103 | 55.2 |
| Discovery | 1997 | 30 | 105 | 1952 | 65.1 |
| Garden Banks | 1997 | 30 | 50.5 | 1860 | 62.0 |
| Nautilus | 1997 | 30 | 101 | 1607 | 53.6 |
| Dauphin Island Phase 1 (E) | 1997 | 24 | 65.0 | 1584 | 66.0 |
| Destin | 1998 | 36 | 73.0 | 4296 | 119 |
| Mobile Bay Expansion | 1998 | 24 | 56.6 | 2561 | 107 |
| Main Pass Lateral (E) | 1998 | 24 | 13.0 | 1583 | 66.0 |
| Stingray East Cameron (E) | 1998 | 16 | 12.9 | 2325 | 145 |
| Destin (Gemini) | 1999 | 24 | 31 | 2494 | 104 |
| Texas Eastern | 2000 | 24 | 9.7 | 2130 | 88.8 |
| Gulfstream | 2002 | 36 | 430 | 2719 | 75.5 |
| Ocean Express (E) | 2002 | 24 | 46.1 | 3272 | 136 |
| Islander East (E) | 2003 | 24 | 22.8 | 4776 | 199.0 |
| Seafarer (E) | 2005 | 26 | 29.4 | 2595 | 99.8 |
| Triple T | 2007 | 24 | 6.2 | 8293 | 345.5 |
| Algonquin | 2007 | 24 | 16.4 | 12,185 | 508 |
| Gulfstream IV | 2008 | 20 | 17.7 | 5303 | 265 |
| South Timbalier (E) | 2012 | 30 | 20.0 | 3321 | 111 |

Source: FERC reports.

Note: (E) indicates estimated costs.

**Table K.2. Average inflation-adjusted costs for FERC offshore pipelines, 1995–2015 (2014$)**

| | Excluding zero values ($1000/mile) | Including zero values ($1000/mi) |
|---|---|---|
| Right of way | 18.2 | 8.2 |
| Damages | 8.9 | 0.4 |
| Surveys | 36.8 | 29.4 |
| Materials | 814 | 814 |
| Labor | 1867 | 1867 |
| Engineering | 182 | 182 |
| Line pack | 13.3 | 4.0 |
| Taxes | 32.3 | 1.6 |
| Freight | 65.3 | 9.8 |
| Pipe coating | 288 | 43.3 |
| Cathodic protection | 16.6 | 1.7 |
| Telecom | 9.5 | 1.4 |
| Overheads | 128 | 95.9 |
| AFUDC | 155 | 139 |
| Contingencies | 103 | 46.4 |
| Legal fees | 55.4 | 8.3 |
| Other services | 155 | 54.1 |
| Regulatory fees | 0.0 | 0.0 |
| Total | 3949 | 3307 |

Source: FERC reports.

**Table K.3. FERC pipeline costs in the Gulf of Mexico by period ($1000/mi, 2014$)**

| Period | Sample | Average | Std. Dev | Max | Min |
|---|---|---|---|---|---|
| 1980–1984 | 127 | 1286 | 1180 | 9376 | 118 |
| 1985–1989 | 40 | 899 | 546 | 2973 | 265 |
| 1990–1994 | 6 | 777 | 296 | 1255 | 454 |
| 1995–1999 | 11 | 1959 | 786 | 3914 | 1086 |
| 2000–2004 | 4 | 3224 | 1135 | 4776 | 2130 |
| 2005–2009 | 4 | 7094 | 4823 | 12,185 | 2595 |
| 2010–2014 | 1 | 3321 | NA | 3320 | 3320 |
| All | 193 | 1399 | 1466 | 12,185 | 118 |

Source: Oil and Gas Journal.

**Table K.4. FERC pipeline costs in the Gulf of Mexico by diameter ($1000/mi, 2014$)**

| | <14 in | | 14-24 in | | >24 in | |
|---|---|---|---|---|---|---|
| Period | Sample | Average | Sample | Average | Sample | Average |
| 1980–1984 | 70 | 1293 | 51 | 1272 | 6 | 1318 |
| 1985–1989 | 12 | 531 | 23 | 940 | 3 | 1679 |
| 1990–1994 | 1 | 631 | 4 | 768 | 1 | 961 |
| 1995–1999 | 0 | | 7 | 1746 | 4 | 2333 |
| 2000–2004 | 0 | | 3 | 3392 | 1 | 2719 |
| 2005–2009 | 0 | | 3 | 8594 | 1 | 2595 |
| 2010–2014 | 0 | | 0 | | 1 | 3321 |
| All | 83 | 1175 | 91 | 1514 | 17 | 1875 |

Source: Oil and Gas Journal.

**Table K.5. FERC pipeline costs in the Gulf of Mexico by length ($1000/mi, 2014$)**

| | <10 mi | | 10–50 mi | | >50 mi | |
|---|---|---|---|---|---|---|
| **Period** | **Sample** | **Average** | **Sample** | **Average** | **Sample** | **Average** |
| 1980–1984 | 86 | 1480 | 40 | 866 | 1 | 1364 |
| 1985–1989 | 17 | 995 | 21 | 777 | 2 | 785 |
| 1990–1994 | 2 | 943 | 4 | 694 | 0 | |
| 1995–1999 | 0 | | 5 | 1615 | 6 | 2246 |
| 2000–2004 | 1 | 2130 | 2 | 4024 | 1 | 2719 |
| 2005–2009 | 1 | 8293 | 3 | 6694 | 0 | |
| 2010–2014 | 0 | | 1 | 3321 | 0 | |
| All | 107 | 1467 | 76 | 1227 | 10 | 1913 |

Source: Oil and Gas Journal.

**Table K.6. Difference between actual and estimated costs of FERC offshore pipelines**

| | Total error (%) | Material error (%) | Labor error (%) |
|---|---|---|---|
| Discovery | 9.2 | -1.5 | 6.9 |
| Destin (Gemini) | -0.8 | -3.1 | 1.7 |
| Garden Banks | 5.4 | 2.9 | 6.8 |
| Nautilus | 4.5 | 0.3 | 30.7 |
| Triple T | -57.3 | -10.8 | -74.5 |
| Gulfstream | -4.4 | 0.5 | -37.7 |
| Algonquin | -11.0 | -14.3 | -31.2 |
| Texas Eastern | 17.2 | 31.1 | 14.4 |
| Destin | -21.9 | -10.2 | -42.9 |
| Gulfstream IV | -40.9 | -22.7 | -51.9 |
| Mobile Bay Expansion | 8.5 | 56.5 | -26.9 |
| Average | -8.3 | 2.6 | -18.6 |

Source: FERC dockets. Note: Error = Estimated cost – Actual cost.

**Table K.7. Gulf of Mexico OTC and/or SPE pipeline projects with cost data, 1979–2015 (2014$)**

| Project | Description | Type | 2014 Cost ($million/mi) | Source |
|---|---|---|---|---|
| Cognac | 27.5 mi, 12 inch two phase | Export | 5.02 | Nations and Speice 1982 |
| Lena | 16 mi, 10 inch gas; 16 mi, 12 inch oil | Export | 2.05 | Boening and Howell 1984 |
| Bullwinkle | | Infield/Export | 2.19 | Sterling et al. 1989 |
| Mobile Bay | 200 mi, 6/24 inch flowline | Infield | 3.38 | Gallagher et al. 1994 |
| Jolliet | 12 mi, 8/10 inch flexible; 12 mi, 4 inch oil, gas 29 mi, 12 inch oil | Export | 1.55 | Koon and Langewis 1990 Tillinghast 1990 |
| GB 224 | 14.5 mi, 4 inch flexible | Infield | 0.52 | Cooke and Cain 1992 |
| GB 224 | 14.5 mi, 4 inch umbilicals | Infield | 0.66 | Cooke and Cain 1992 |
| Auger | 72 mi, 12.75 inch oil; 36 mi, 12.75 inch gas | Export | 1.24 | Kopp and Barry 1994 |
| Macaroni | 12 mi flowline | Infield | 12.94 | Kopp and Barry 1994 |
| Serrano | 6 inch x 10 inch pipe-in-pipe | Infield | 2.45 | Kopp and Barry 1994 |
| Oregano | 6 inch x 10 inch pipe-in-pipe | Infield | 3.36 | Kopp and Barry 1994 |
| Pompano | Two 4.5 mi, 8 inch flowlines Two 4.5 mi, 3 inch test lines | Infield | 2.59 | Clarke and Cordner 1996 |
| Mars | 43 mi, 18 inch oil; 79 mi, 24 inch oil; 43 mi, 14 inch gas | Export | 1.19 | Godfrey et al. 1997 |
| Baldpate | 17 mi, 16 inch oil; 13.2 mi, 12 inch gas | Export | 0.72 | Simon et al. 1999 |
| Morpeth | 19 mi, 12 inch oil; 19 mi, 8 inch gas | Export | 1.98 | Kennefick et al. 1999 |
| Morpeth | 2.3 mi, 4 inch flowlines; 1.3 mi umbilical | Infield | 5.76 | Kennefick et al. 1999 |
| Prince | 10 mi, 10 inch oil; 16 mi, 12 inch gas | Export | 1.29 | Koon et al. 2002 |
| Canyon Express | 2 x 56 mi, 12 inch flowlines | Infield | 3.65 | Rijkens 2003 |
| NaKika | 100 mi, 8/12 inch flowlines 74 mi, 18 inch oil export; 74 mi, 20/24 inch gas | Infield/Export | 1.98 | Kopp et al. 2004 |
| Mardi Gras | 489 mi, 20 to 30 inch | Export | 2.11 | Marshall and McDonald 2004 |
| Independence | 134 mi, 24 inch export | Export | 2.24 | Holley and Abendschein 2007 |
| Independence | 210 mi flowline; 135 mi umbilicals | Infield | 1.12 | Holley and Abendschein 2007 |
| Spiderman-San Jacinto | 56 mi, 9 inch flowline | Infield | 2.34 | Vercher and Blakeley 2007 |
| Spiderman-San Jacinto | 25 mi, 8 inch flowline | Infield | 3.97 | Vercher and Blakeley 2007 |
| Spiderman-San Jacinto | 22 mi, 10 inch flowline | Infield | 2.75 | Vercher and Blakeley 2007 |

**Table K.8. Average EPCI contract costs by project type and time period ($million/mi, 2014$)**

| | OTC/SPE | Press Release | All |
|---|---|---|---|
| Export | 1.96 (1.17) | 3.79 (2.66) | 2.67 (2.02) |
| Infield | 3.50 (3.17) | 3.84 (3.53) | 3.61 (3.19) |
| Export/Infield | 1.98 (NA) | 2.80 (1.82) | 2.53 (1.37) |
| All | 2.76 (2.49) | 3.68 (2.80) | 3.11 (2.61) |
| 1979–1989 | 3 | 0 | 3 |
| 1990–2005 | 17 | 6 | 23 |
| 2005–2015 | 5 | 10 | 15 |

Note: Standard deviation denoted in parenthesis.

**Table K.9. Gulf of Mexico press release pipeline cost data, 1998–2015 (2014$)**

| Project | Year | Contractor | Description | Type | 2014 Cost ($million/mi) |
|---|---|---|---|---|---|
| Ursa | 1998 | Allseas | 18 inch, 47 mi oil 20 inch, 47 mi gas | Export | 1.45 |
| Brutus | 2002 | McDermott | 20 inch, 26 mi oil 20 inch 24 mi gas | Export | 2.46 |
| Falcon | 2002 | Technip-Coflexip | 32 mi, 10 inch flowline and umbilical | Infield | 0.80 |
| Thunder Horse and Atlantis | 2002 | Subsea 7 | 63 miles of umbilicals, flying leads and jumpers | Infield | 0.70[a] |
| Cameron Highway | 2003 | Valero | 390 mi oil | Export | 1.73 |
| Glider | 2003 | Subsea 7 | 6 inch, 6 mi flowlines | Infield | 10.0 |
| Cascade/Chinook | 2008 | Technip | 5 risers, 74 mi, 6/9 inch reeled pipeline, 10 PLETs | Export/Infield | 4.09 |
| Droshky | 2008 | Subsea 7 | 8 inch, 36 mi flowline | Infield | 1.26 |
| Big Foot | 2009 | Enbridge | 20 inch, 40 mi oil | Export | 7.05 |
| Keathley Canyon | 2013 | Allseas | 20 inch, 215 mi | Export | 2.81 |
| Delta House | 2013 | Technip | 124 miles of infield and export lines | Export/Infield | 1.51 |
| Gunflint | 2014 | EMAS | 80 mi pipe-in-pipe, 56 mi umbilicals | Infield | 2.20 |
| Julia | 2014 | Technip | 30 mi insulated flowlines, risers, PLETs | Infield | 6.00 |
| Shell | 2014 | Subsea 7 | 27 miles of 8 inch flowlines, SCR and PLETs | Infield | 2.77 |
| Walker Ridge | 2015 | Enbridge | 8 and 10 inch, 170 miles gas | Export | 2.94 |
| Stampede | 2015 | Enbridge | 18 inch, 16 mi oil | Export | 8.10 |

Source: Press releases.

Note: (a) Installation only.

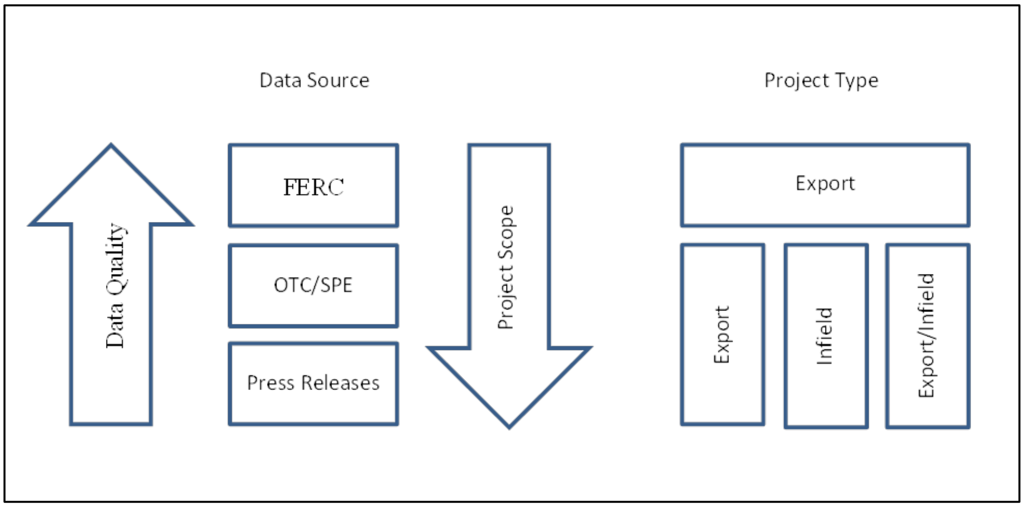
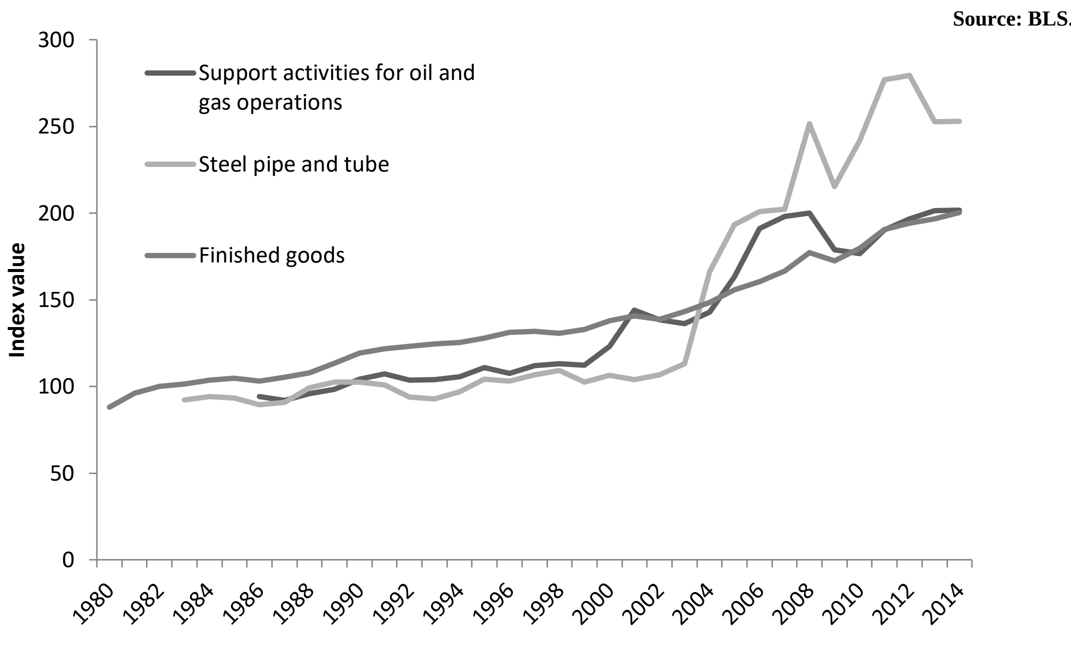



Figure K.1. Data quality and project scopes for FERC, OTC and/or SPE, and press release projects.




| PPI | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 |
|---|---|---|---|---|---|---|---|---|---|---|
| Support activities for oil and gas operations | 163.4 | 191.2 | 198.2 | 200.0 | 178.9 | 176.6 | 190.3 | 196.6 | 201.4 | 201.8 |
| Steel pipe and tube | 193.3 | 200.9 | 202.4 | 251.7 | 215.5 | 241.8 | 277.0 | 279.4 | 252.8 | 253.0 |
| Finished goods | 155.7 | 160.4 | 166.6 | 177.1 | 172.5 | 179.8 | 190.7 | 194.3 | 196.7 | 200.4 |

Figure K.2. BLS Producer Price Indices used to inflate cost data.

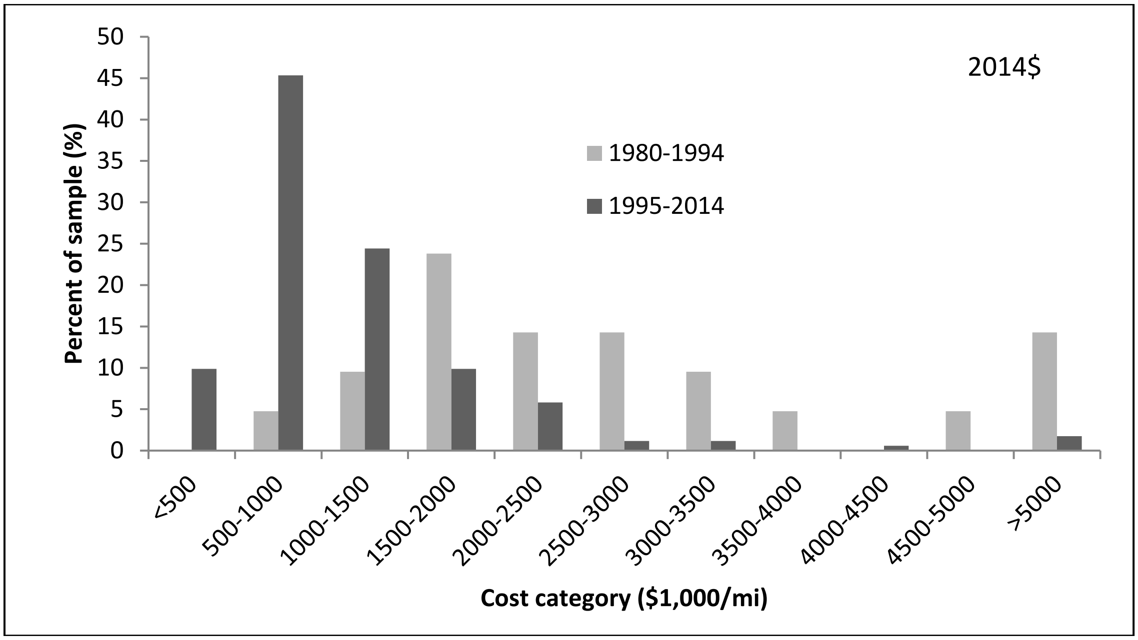



Figure K.3. Distribution of normalized inflation-adjusted FERC pipeline costs, 1980–1994 and 1995–2014.

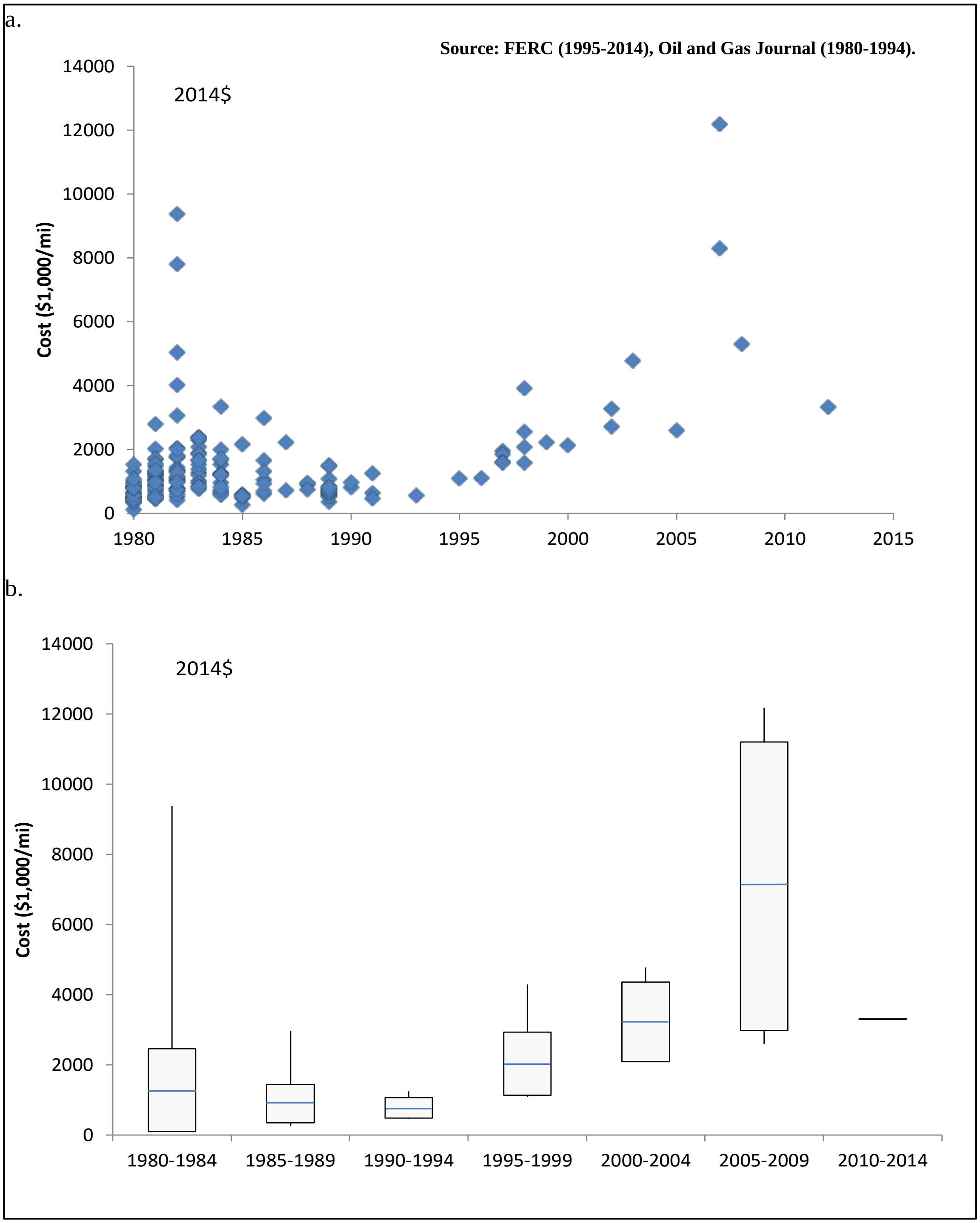



Figure K.4. Inflation-adjusted FERC pipeline costs and period distribution.

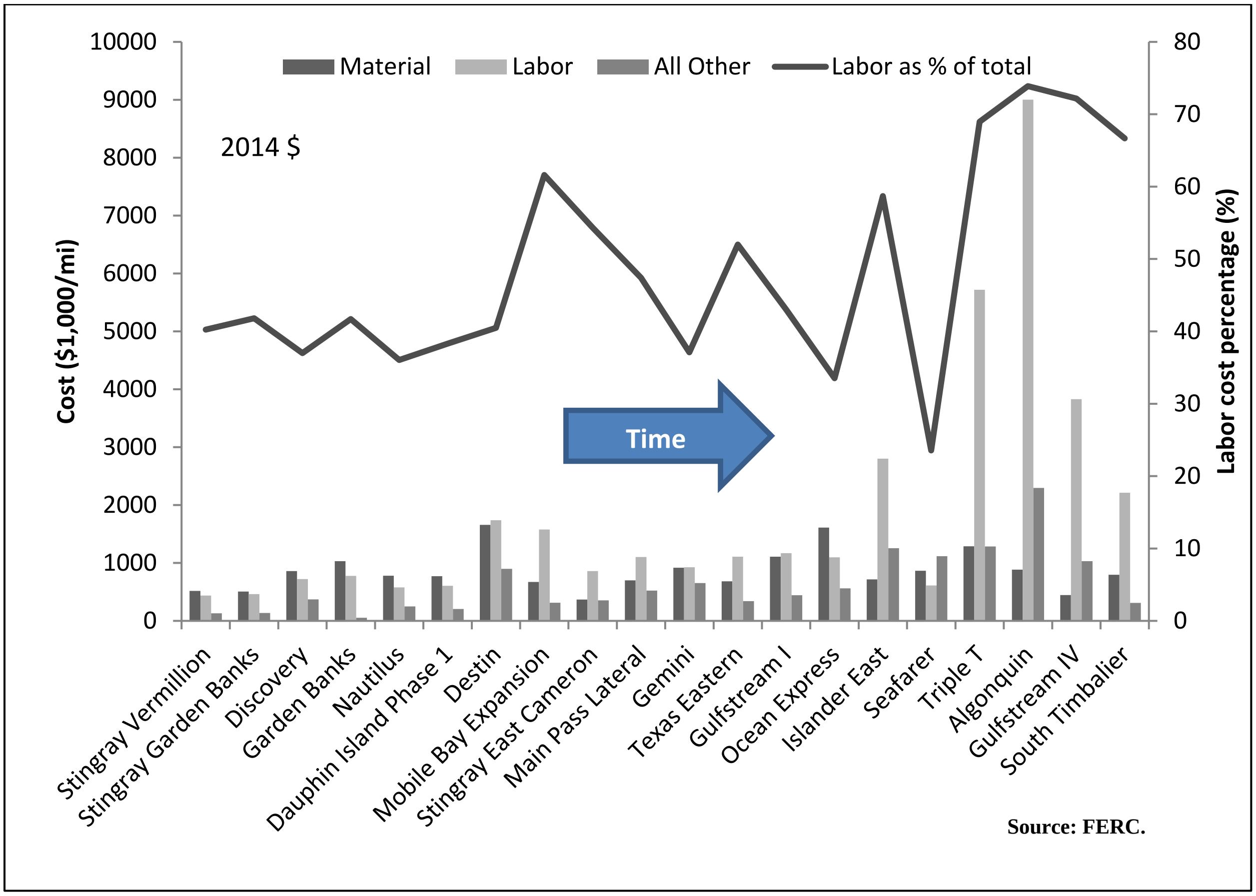



Figure K.5. FERC pipeline cost components and labor as a percentage of total cost.

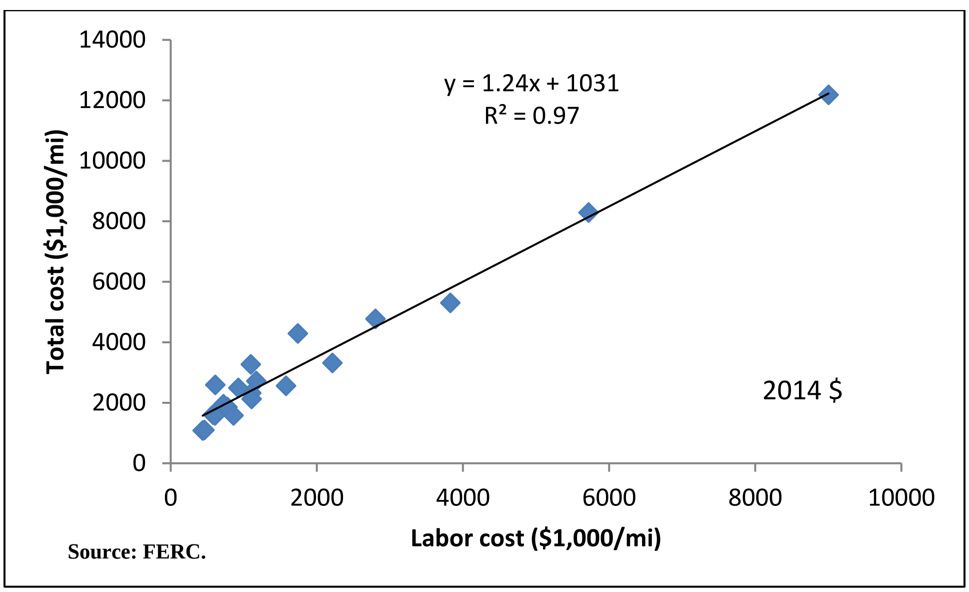



Figure K.6. Relationship between labor costs and total pipeline costs.

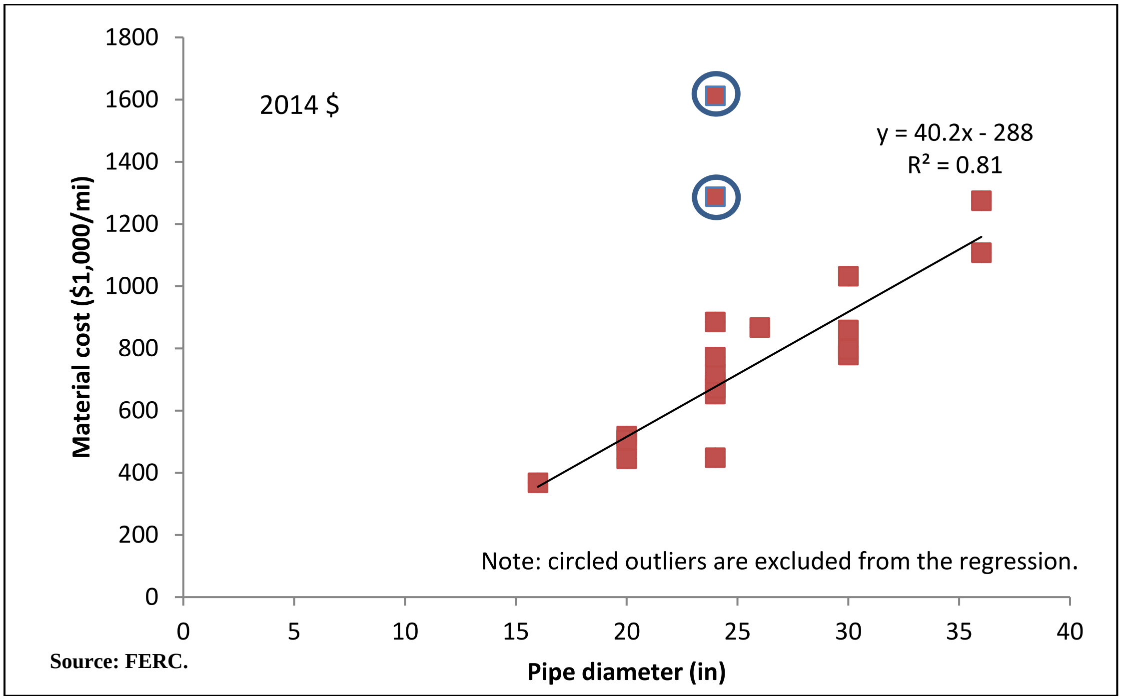



Figure K.7. Relationship between pipe diameter and normalized material costs.

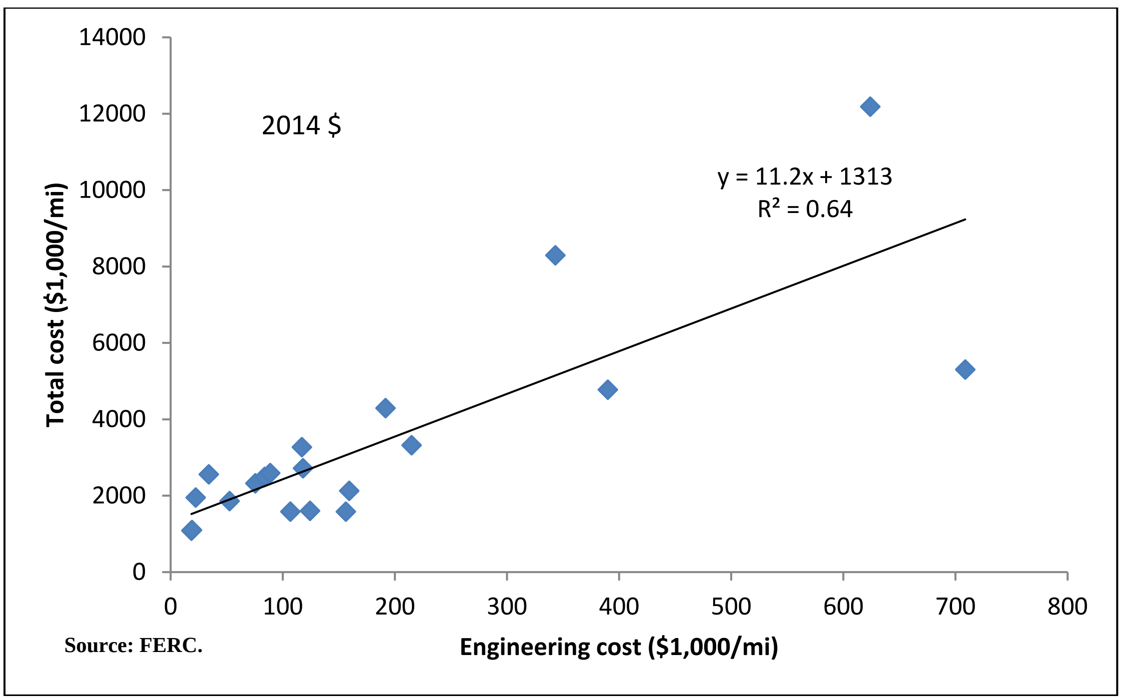



Figure K.8. Relationship between engineering cost and total cost.

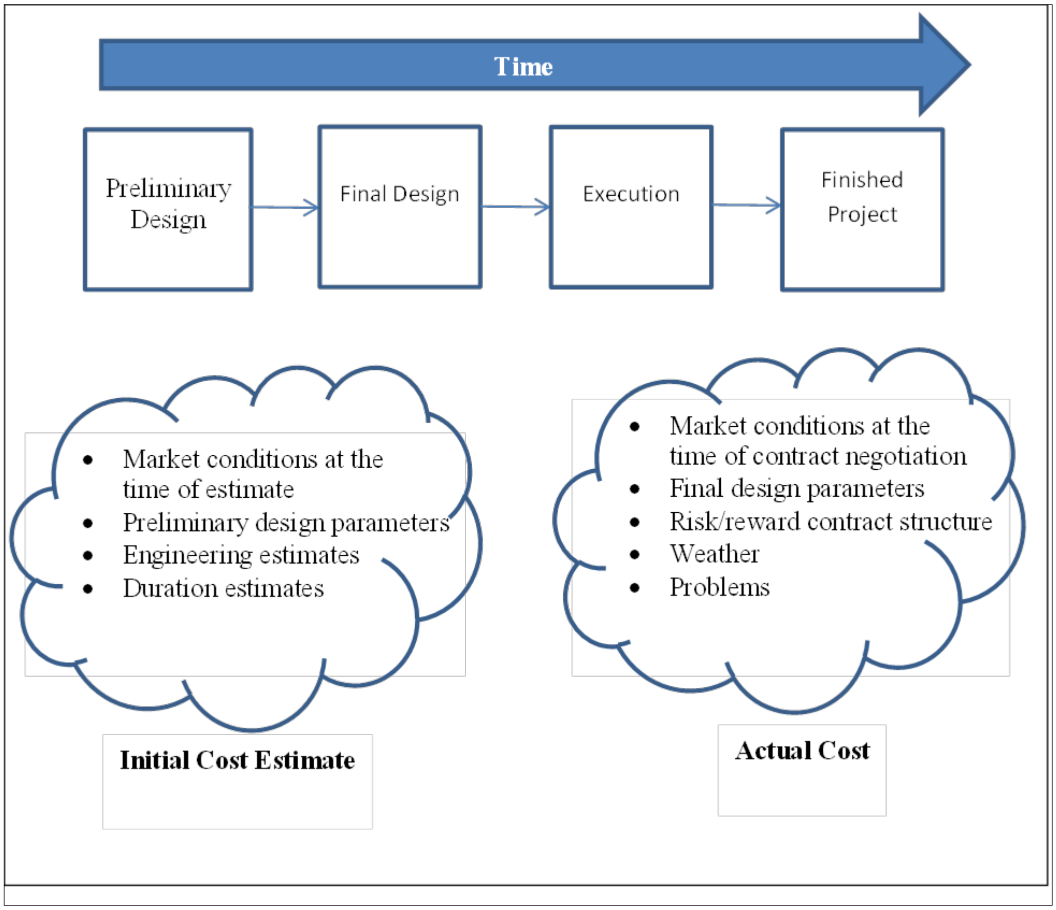



Figure K.9. Numerous factors potentially impact cost estimates.

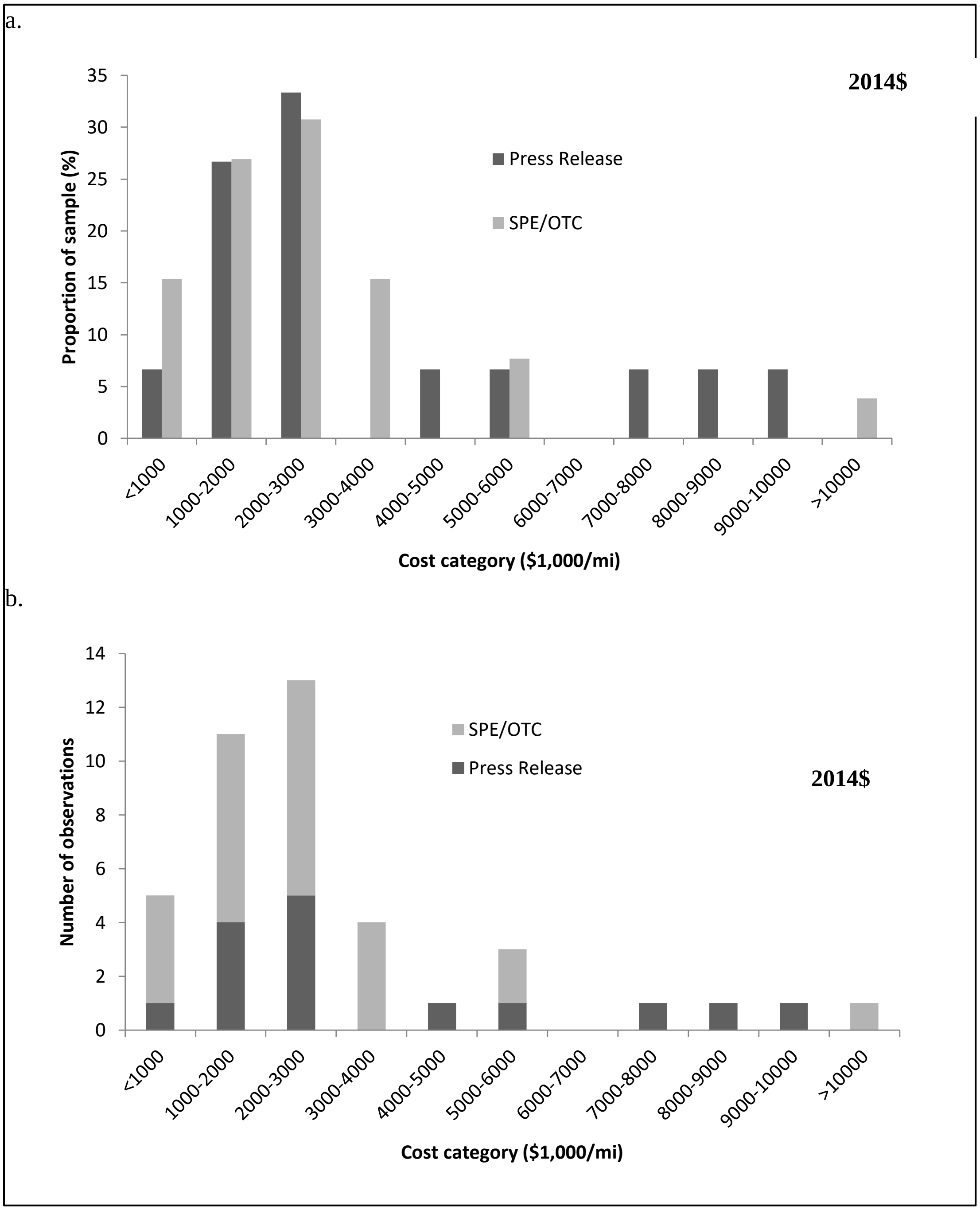



Figure K.10. Inflation-adjusted OTC/SPE and press release cost distribution.

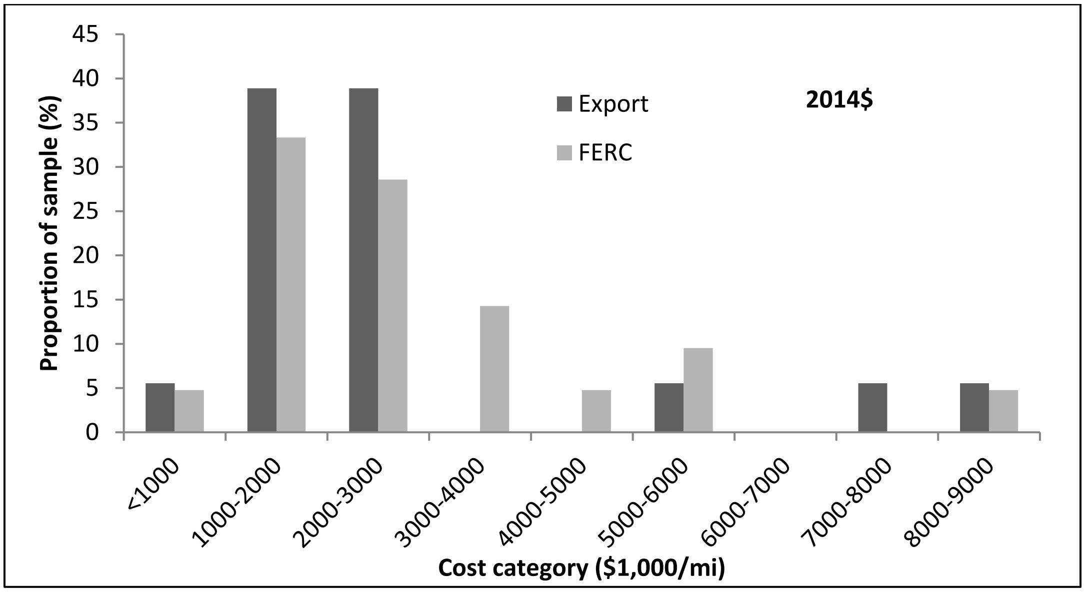



Figure K.11. FERC pipeline cost versus the composite OTC and/or SPE and press release export cost data.

# Appendix L: Chapter 12 Figures


Figure L.1. An assortment of pipeline cleaning pigs.

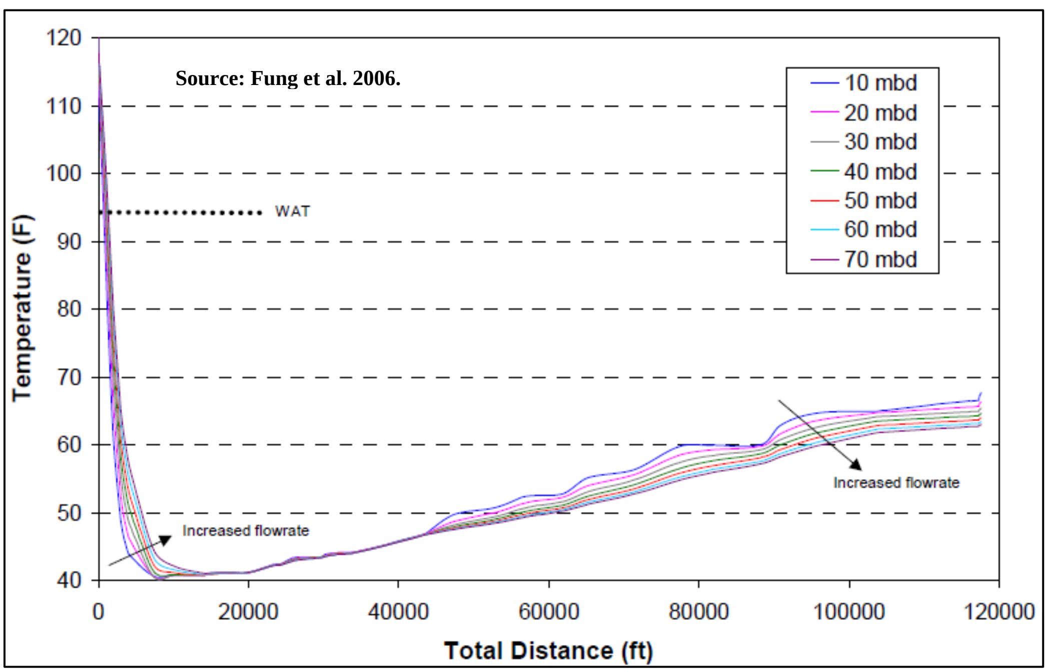


Figure L.2. Marlin oil export line temperature profile.

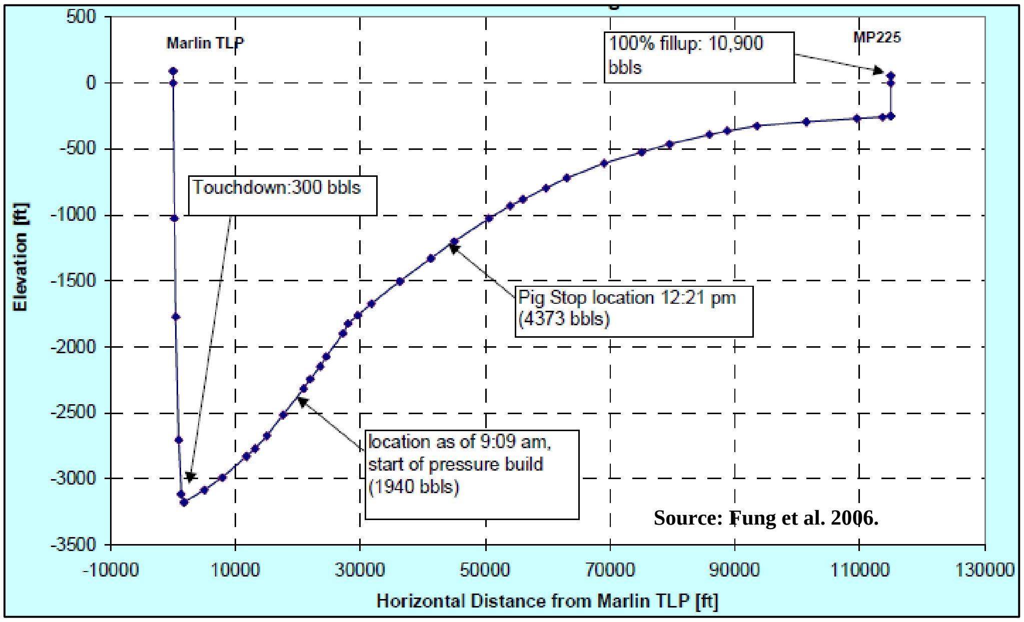



Figure L.3. Marlin oil export pipeline profile estimated stuck pig.

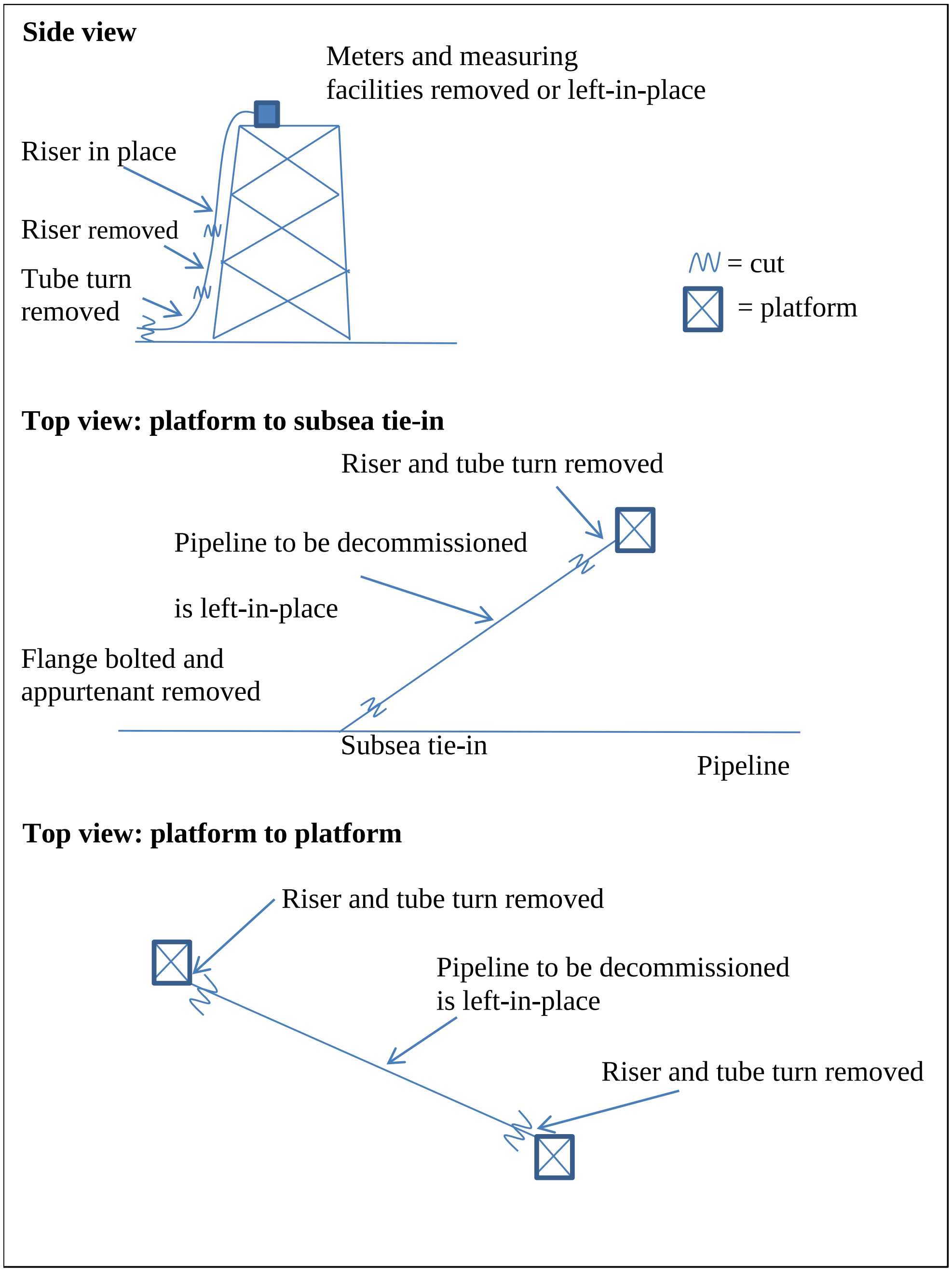



Figure L.4. Typical work requirements in pipeline decommissioning operations.

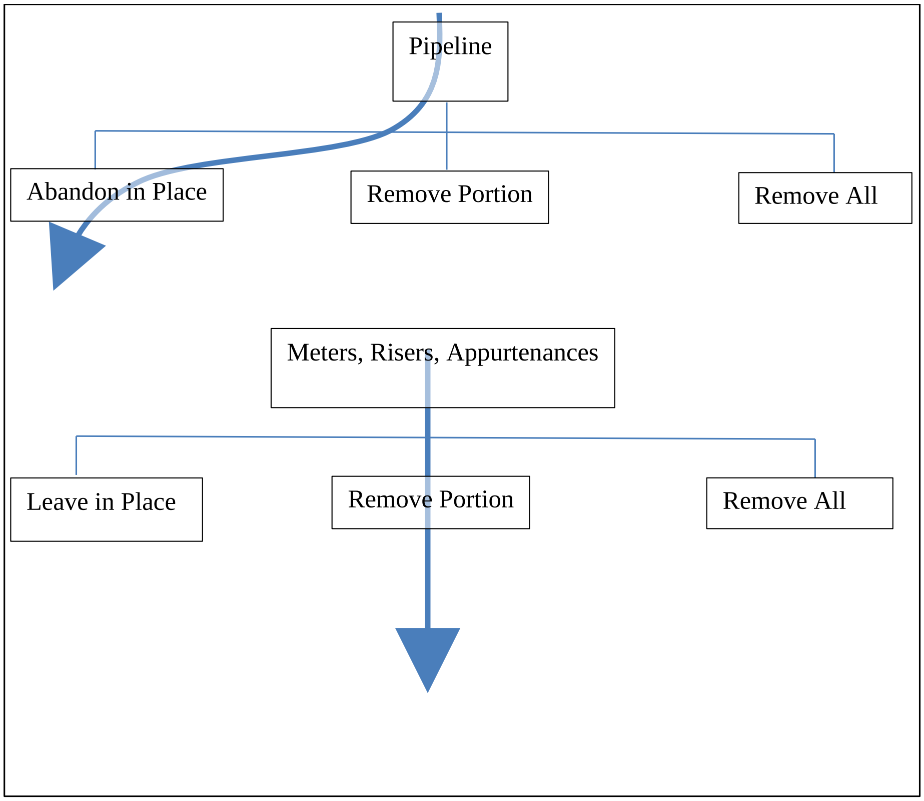



Figure L.5. Typical decommissioning pathways for offshore pipeline, meters, risers, appurtenances.

## Appendix M: Chapter 13 Tables and Figures

**Table M.1. Factors that impact pipeline decommissioning cost**

| Site | Time | Location |
|---|---|---|
| Size (length, diameter)<br>Type (abandon-in-place, remove)<br>Service (oil, gas, condensate)<br>Status (in service, out of service)<br>Endpoint (platform, pipeline)<br>Complexity<br>Number of interconnects<br>Number of appurtenances<br>Special (hurricane destroyed)<br>Integrity (damaged/leaking)<br>Contract type (dayrate, lump sum) | Market conditions (dayrates, labor rates)<br>Season (summer, winter)<br>Year (inflation)<br>Level of completion<br>Environmental conditions (weather)<br>Problems | Water depth<br>Endpoint water depth<br>Tie-in water depths<br>Onshore landing<br>Distance to port<br>Special (environmental) |

**Table M.2. FERC pipeline decommissioning cost estimates in the US Gulf of Mexico, 1995–2015 (2014$)**

| Docket | Year | Length (miles) | Diameter (in) | Volume (cf) | Cuts (#) | E(cost) ($) | Cost/Length ($/mi) | Cost/Length-Cut ($/mi-cut) | Cost/Volume ($/cf) |
|---|---|---|---|---|---|---|---|---|---|
| CP95-255 | 1995 | 7 | 6 | 7257 | 2 | 1,640,000 | 234,285 | 117,142 | 226 |
| CP98-721 | 1998 | 1.6 | 6 | 1659 | 2 | 29,845 | 18,653 | 9326 | 18.0 |
| CP99-449 | 1999 | 0.23 | 12 | 941 | 2 | 41,375 | 182,268 | 91,134 | 44.0 |
| CP08-91 | 2008 | 20.8 | | 239,361 | 2 | 7,000,000 | 336,862 | 168,431 | 29.2 |
| CP08-469 | 2008 | 8.4 | 16 | 61,557 | 2 | 1,061,500 | 127,125 | 63,562 | 17.2 |
| CP08-153 | 2008 | 17.2 | 20 | 198,124 | 2 | 5,360,000 | 311,627 | 155,814 | 27.1 |
| CP09-429 | 2009 | 5.5 | 16 | 40,546 | 2 | 3,000,000 | 545,454 | 272,727 | 74.0 |
| CP10-20 | 2009 | 25 | 26 | 486,671 | 1 | 4,800,000 | 192,000 | 192,000 | 9.9 |
| CP09-108 | 2009 | 9 | 26 | 175,201 | 1 | 19,315,326 | 2,146,147 | 2,146,147 | 110 |
| CP11-9 | 2010 | 10.3 | 12 | 42,712 | 2 | 400,000 | 38,835 | 19,417 | 9.4 |
| CP10-413 | 2010 | 7.5 | 10 | 21,627 | 2 | 2,256,344 | 300,445 | 150,222 | 104 |
| CP10-361 | 2010 | 20.5 | 16 | 151,127 | 2 | 2,847,983 | 138,926 | 69,463 | 18.8 |
| CP10-110 | 2010 | 6.2 | 24 | 103,338 | 2 | 3,665,532 | 588,367 | 294,183 | 35.5 |
| CP10-45 | 2010 | 4.3 | 20 | 49,070 | 2 | 2,404,885 | 564,527 | 282,263 | 49.0 |
| CP11-20 | 2010 | 23.5 | 12 | 97,449 | 2 | 930,000 | 39,574 | 19,787 | 9.5 |
| CP11-14 | 2010 | 6.3 | 16 | 46,444 | 1 | 700,000 | 111,111 | 111,111 | 15.1 |
| CP10-64 | 2010 | 15 | 12 | 62,202 | 2 | 2,945,332 | 196,355 | 98,177 | 47.4 |
| CP11-491 | 2011 | 8.91 | 12 | 36,927 | 4 | 550,000 | 61,763 | 15,440 | 14.9 |
| CP11-477 | 2011 | 5.7 | 12 | 23,637 | 2 | 600,000 | 105,263 | 52,631 | 25.4 |
| CP11-139 | 2011 | 10 | 10 | 28,797 | 2 | 1,500,000 | 150,000 | 75,000 | 52.1 |
| CP12-55 | 2012 | 25.9 | | 473,992 | 6 | 7,664,060 | 296,023 | 49,337 | 16.2 |
| CP12-482 | 2012 | 37.2 | 36 | 628,319 | 4 | 250,000 | 6722 | 1680 | 0.4 |
| CP12-157 | 2012 | 16.8 | 24 | 278,664 | 2 | 2,300,000 | 136,904 | 68,452 | 8.3 |
| CP13-491 | 2013 | 7.8 | | 128,550 | 4 | 1,461,631 | 188,597 | 47,149 | 11.4 |
| CP13-131 | 2013 | 56.5 | | 743,088 | 8 | 986,000 | 17,439 | 2179 | 1.3 |
| CP13-38 | 2013 | 15.8 | 30 | 408,458 | 2 | 699,600 | 44,390 | 22,195 | 1.7 |
| CP15-4 | 2015 | 12.3 | | 90,094 | 4 | 580,000 | 47,112 | 11,778 | 6.4 |
| CP15-511 | 2015 | 11.6 | 12/16 | 85,640 | 6 | 3,000,000 | 257,953 | 42,992 | 35.0 |
| Average | | | | | | | 300,926 | 190,151 | 47.3 |

Source: FERC.

Note: Cost adjusted using BLS index.

**Table M.3. Pipeline removal cost estimates in 200–500 ft water depth in the Gulf of Mexico (2014$)**

| Pipe diameter (in.) | Avg. cost ($1000/mi) | Avg. cost ($/ft) |
|---|---|---|
| < 4 | 430 | 81 |
| 4 - 12 | 560 | 106 |
| 14 - 16 | 644 | 122 |
| 18 - 24 | 683 | 129 |
| 26 - 30 | 801 | 152 |
| > 30 | 932 | 177 |

Source: Scandpower Risk Management 2004.
Note: Costs adjusted using BLS index.

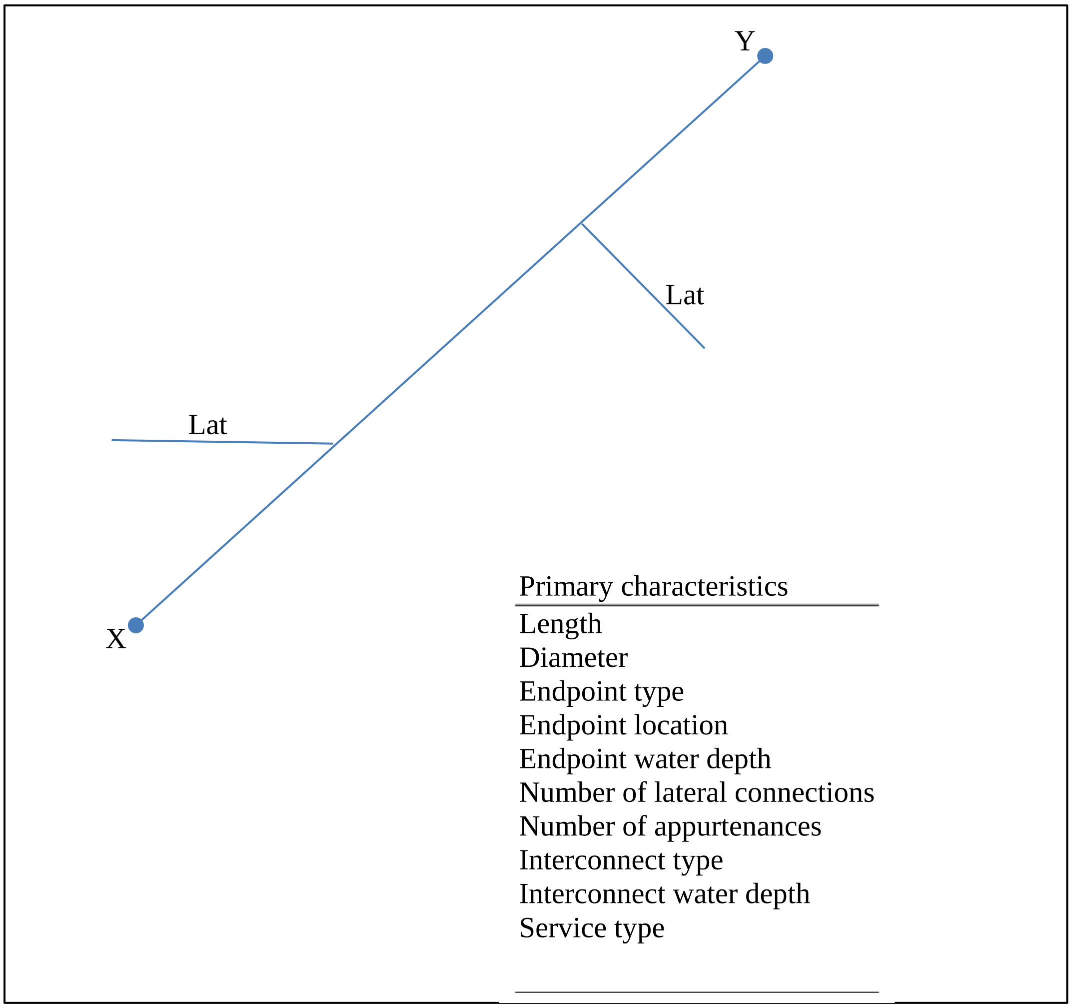



Figure M.1. Pipeline systems are described in terms of their segments and associated features.

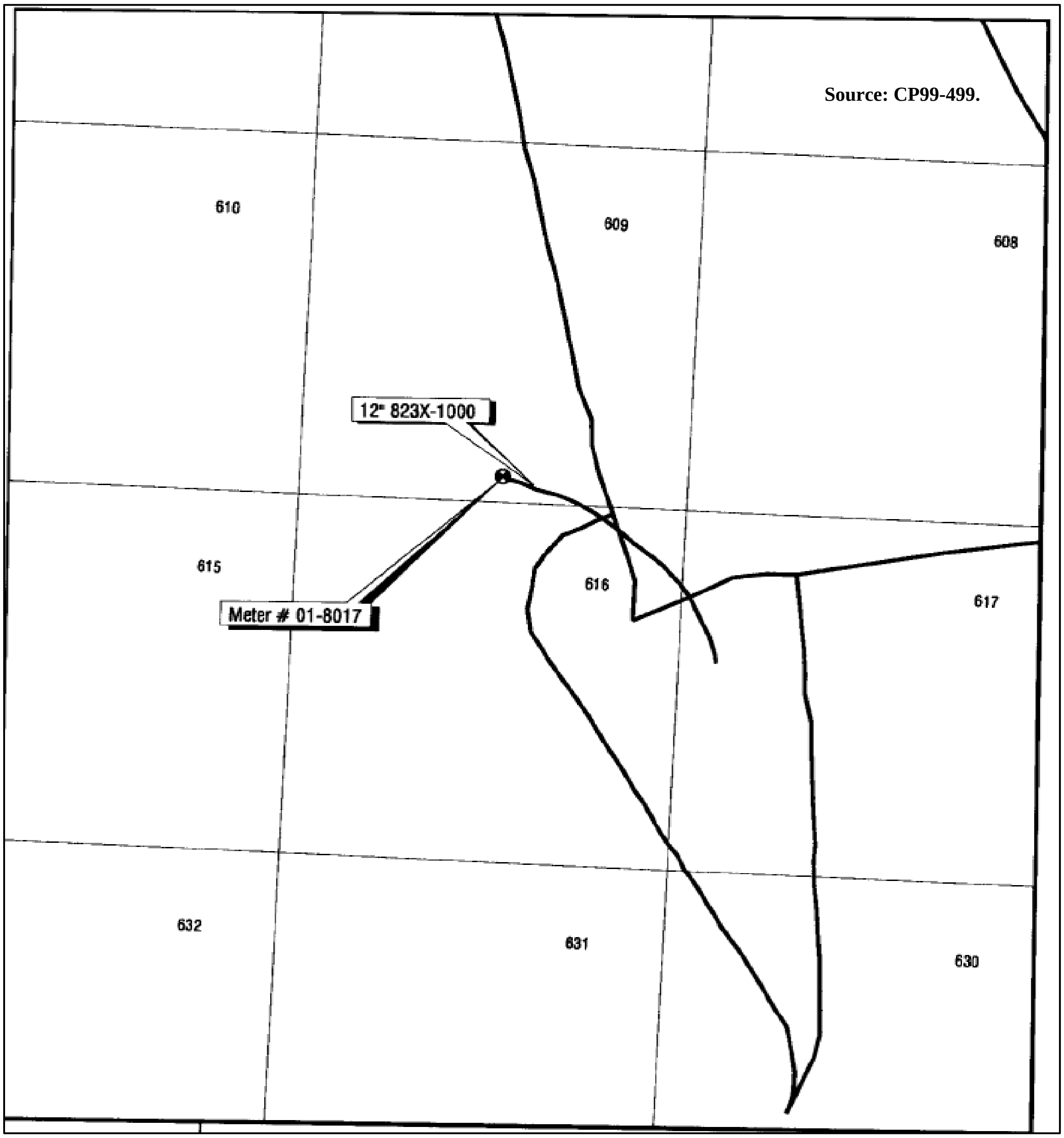



Figure M.2. Tennessee's 823X-1000 pipeline segment decommissioned.

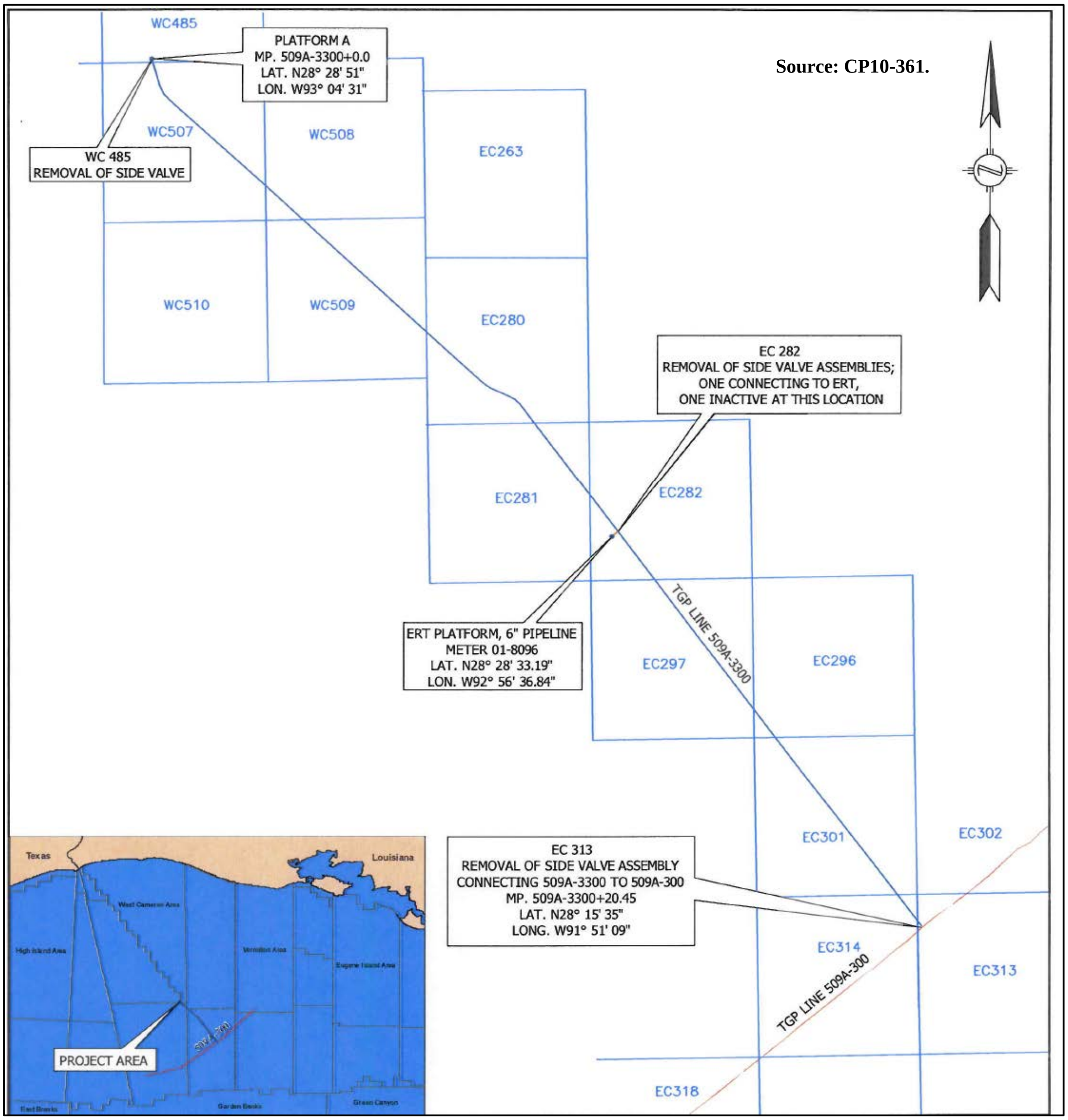



Figure M.3. Tennessee's 509A-3300 pipeline segment decommissioned.

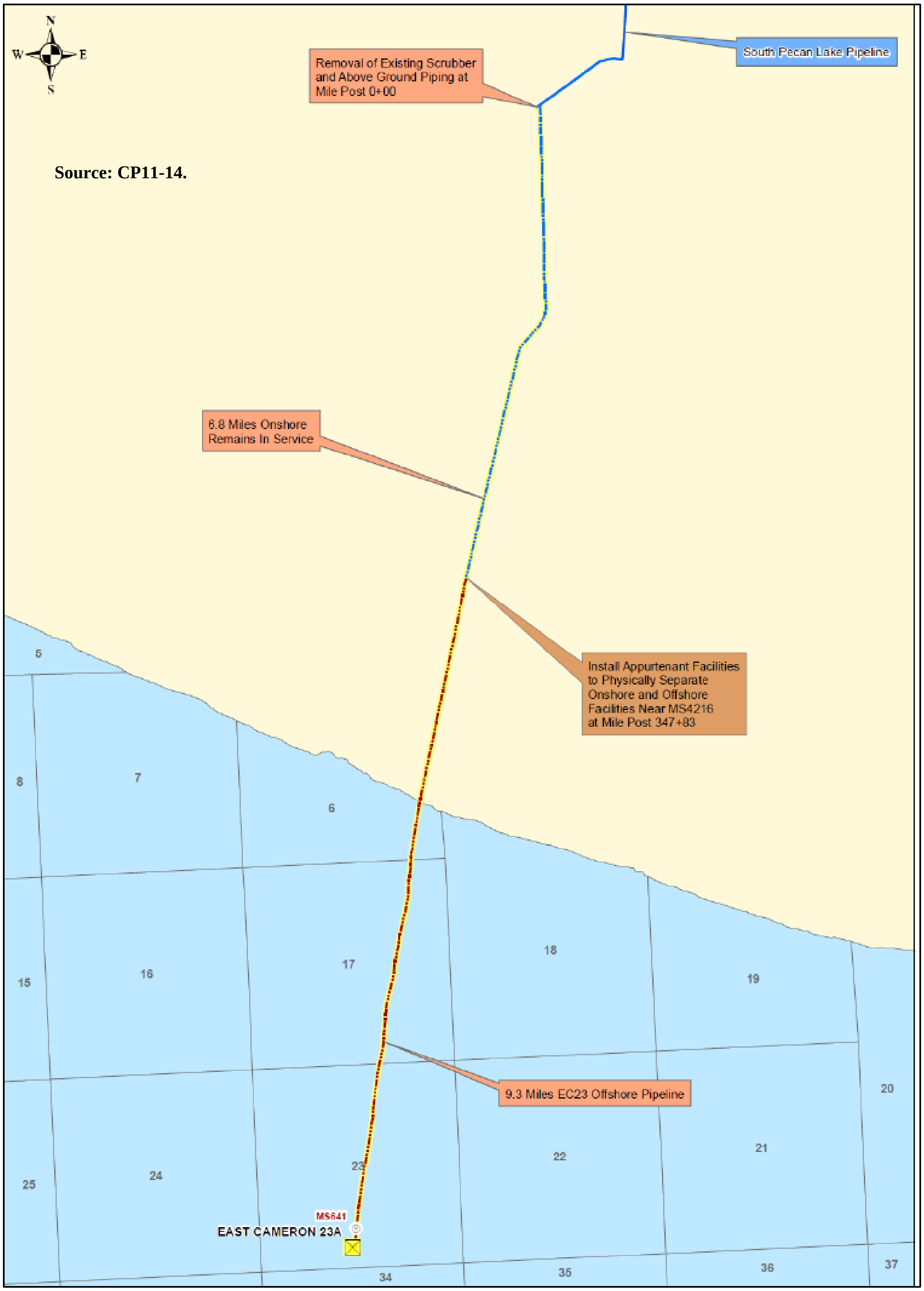



Figure M.4. Pipeline abandoned by Columbia Gulf and Southern and onshore landing.

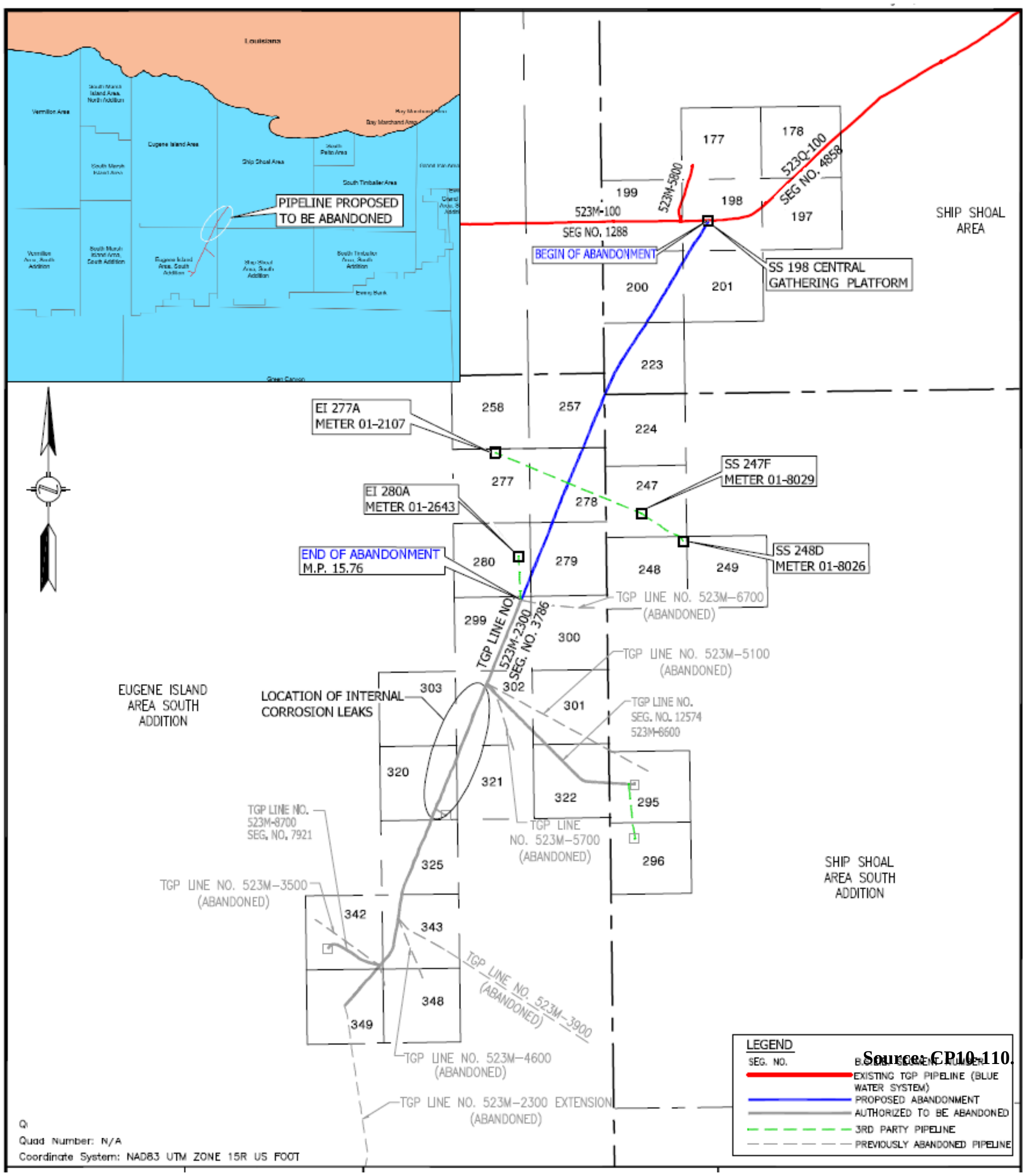



Figure M.5. Location of the Triple-T pipeline abandoned by Tennessee.

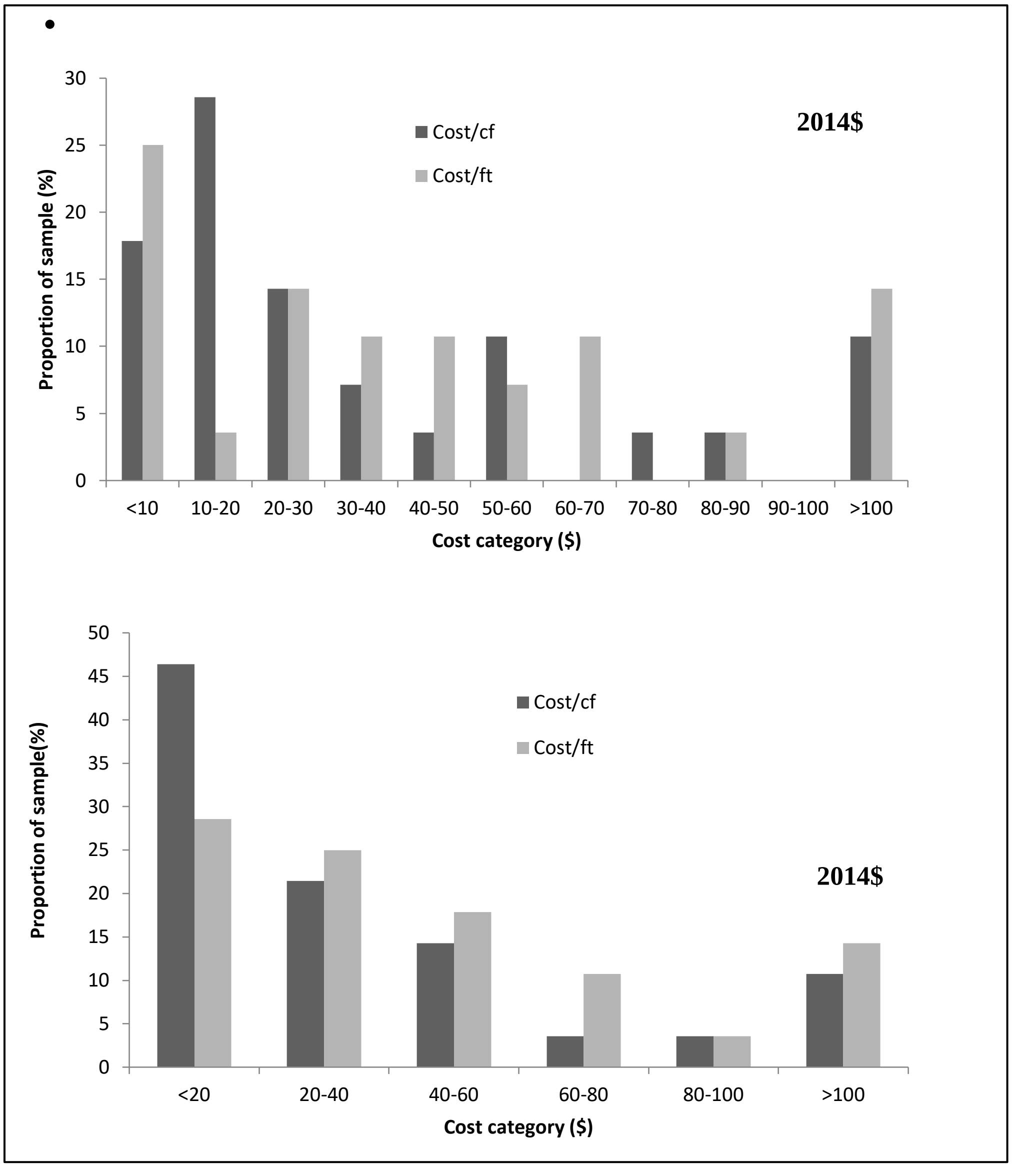



Figure M.6. Inflation adjusted normalized pipeline decommissioning cost distribution.

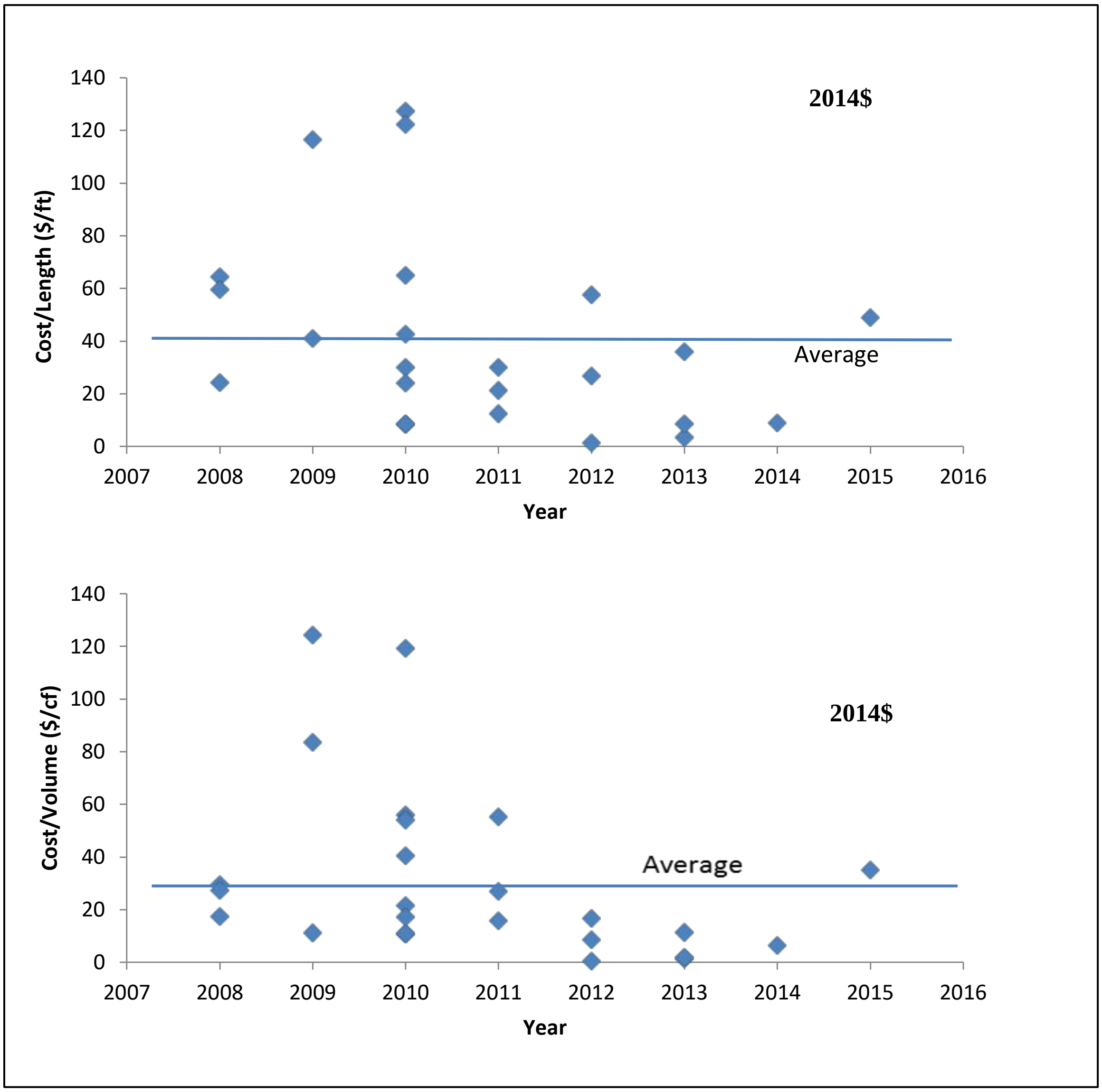



Figure M.7. Inflation adjusted normalized pipeline decommissioning costs over time.

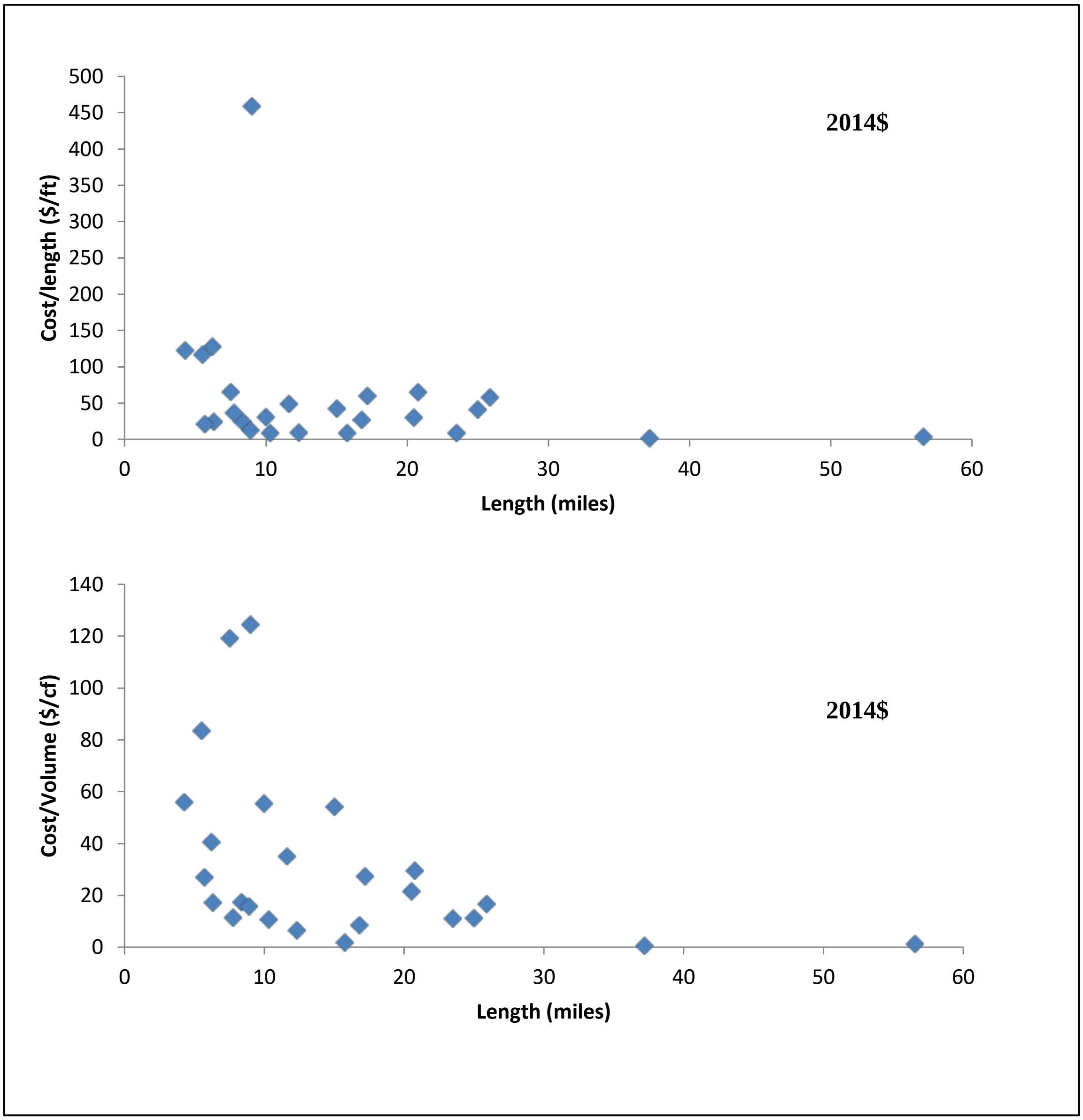



Figure M.8. Inflation adjusted normalized pipeline decommissioning costs by pipeline length.

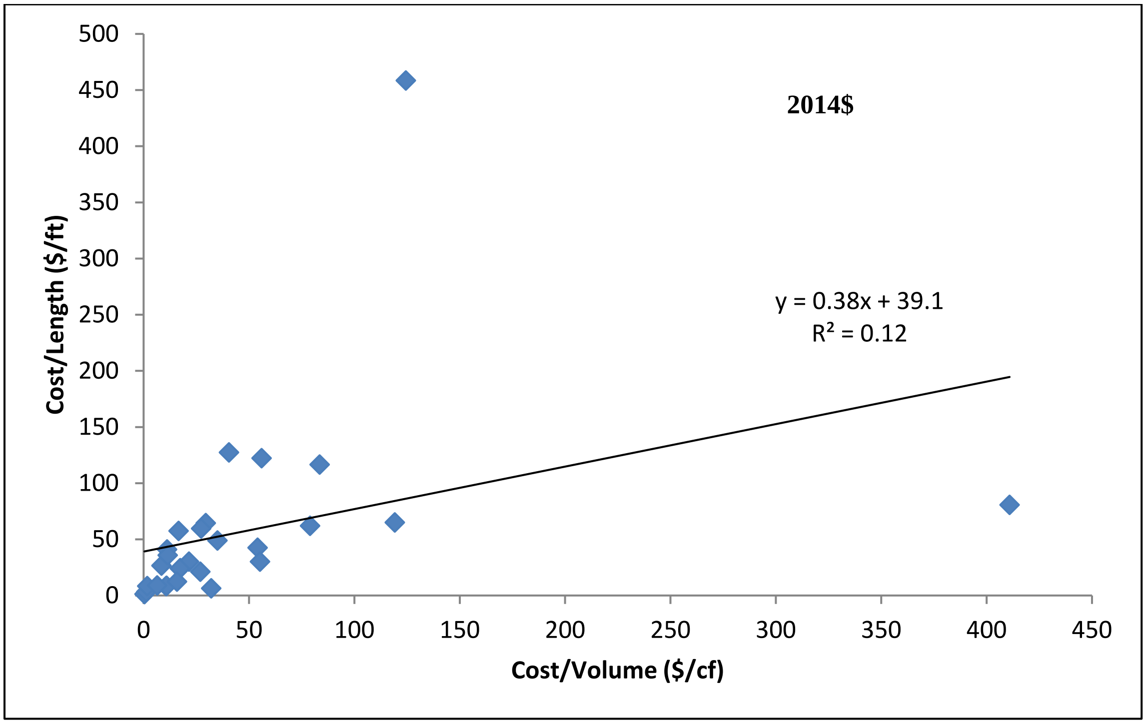


Figure M.9. Relationship between cost per cubic foot and cost per foot.

# Appendix N: Chapter 14 Tables and Figures

**Table N.1. Total mileage of bulk oil and gas lines in shallow and deepwater by decade**

| Decade | <= 400 ft | | | > 400 ft | | | Grand Total |
|---|---|---|---|---|---|---|---|
| | Bulk Gas | Bulk Oil | Total | Bulk Gas | Bulk Oil | Total | |
| 1950s | 7 | 9 | 16 | | | | 16 |
| 1960s | 55 | 49 | 104 | | | | 104 |
| 1970s | 358 | 265 | 623 | | | | 623 |
| 1980s | 1,086 | 332 | 1,417 | | 23 | 23 | 1,440 |
| 1990s | 2,269 | 603 | 2,873 | 186 | 209 | 395 | 3,268 |
| 2000s | 2,803 | 641 | 3,444 | 967 | 666 | 1,634 | 5,078 |
| 2010s | 481 | 431 | 912 | 372 | 990 | 1,362 | 2,274 |
| Total | 7,059 | 2,331 | 9,390 | 1,526 | 1,887 | 3,413 | 12,803 |

Source: BOEM, 2018c.

**Table N.2. Total mileage of export oil and gas lines in shallow and deepwater by decade**

| Decade | <= 400 ft | | | > 400 ft | | | Grand Total |
|---|---|---|---|---|---|---|---|
| | Gas | Oil | Total | Gas | Oil | Total | |
| 1950s | 55 | 63 | 117 | | | | 117 |
| 1960s | 1,059 | 338 | 1,397 | | | | 1,397 |
| 1970s | 3,538 | 967 | 4,505 | | | | 4,505 |
| 1980s | 3,350 | 844 | 4,194 | 68 | 62 | 130 | 4,324 |
| 1990s | 3,037 | 1,529 | 4,566 | 230 | 160 | 390 | 4,957 |
| 2000s | 3,389 | 1,676 | 5,065 | 741 | 842 | 1,583 | 6,648 |
| 2010s | 1,142 | 576 | 1,718 | 442 | 461 | 903 | 2,621 |
| Total | 15,569 | 5,993 | 21,562 | 1,481 | 1,526 | 3,007 | 24,569 |

Source: BOEM, 2018c.

**Table N.3. Shell pipeline network scale-free parameter illustration**

| | Model: $P(k) = 1/(k + a)^p$ | | | |
|---|---|---|---|---|
| | Model 1 | | Model 2 | |
| *a* | *p* | *SSE* | *p* | *SSE* |
| 0 | 2.9 | 0.11 | 2.4 | 0.15 |
| 0.5 | 1.7 | 0.06 | 1.6 | 0.03 |
| 1.0 | 1.3 | 0.13 | 1.2 | 0.07 |
| 1.5 | 1.2 | 0.17 | 1.0 | 0.10 |

Note: Model 1 refers to pipeline network in Figure N.23. Model 2 refers to pipeline network in Figure N.19.

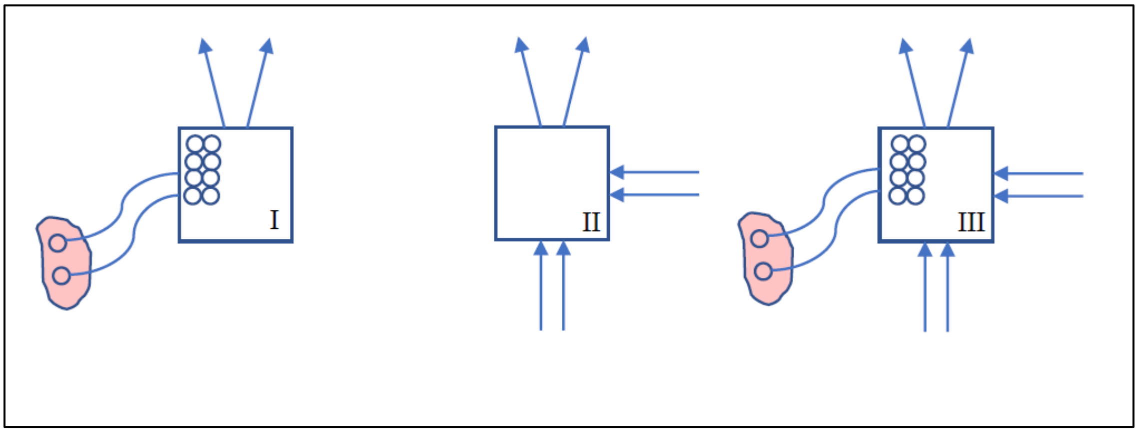



Figure N.1. Hub platform classes: field development (I), transportation (II), and combined services (III).

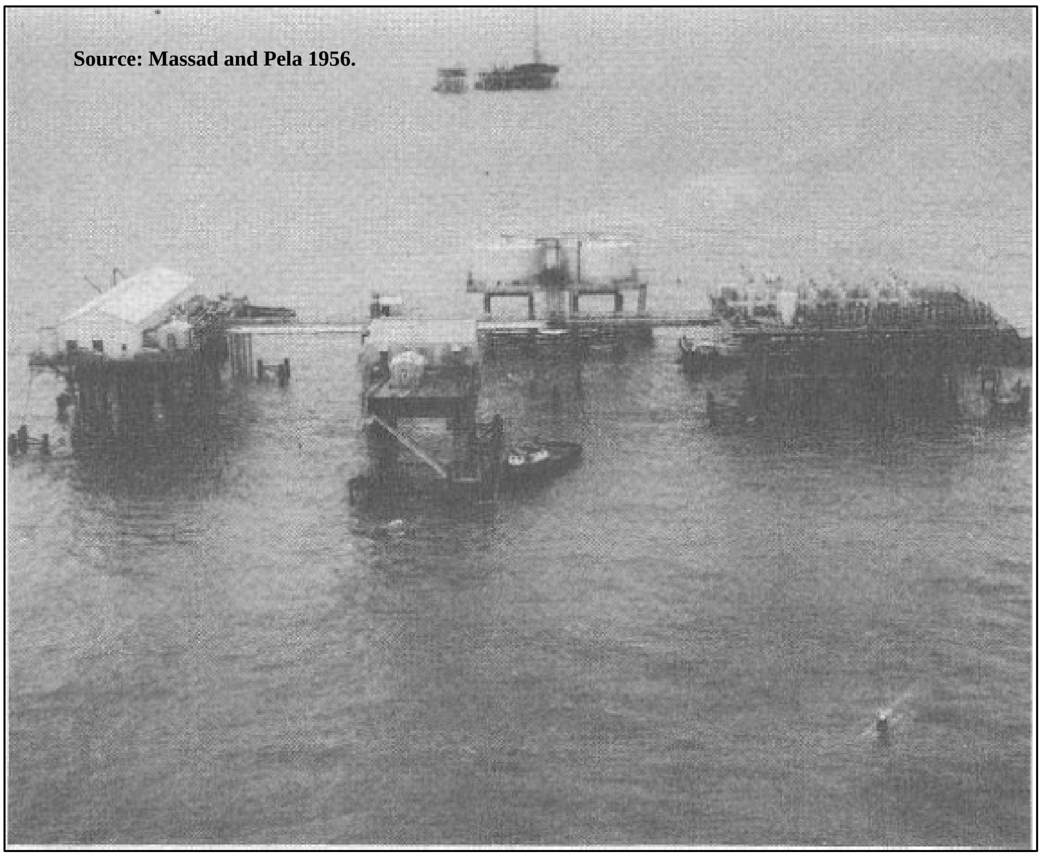



Figure N.2. Central production facility at the Eugene Island 126 field circa 1956.

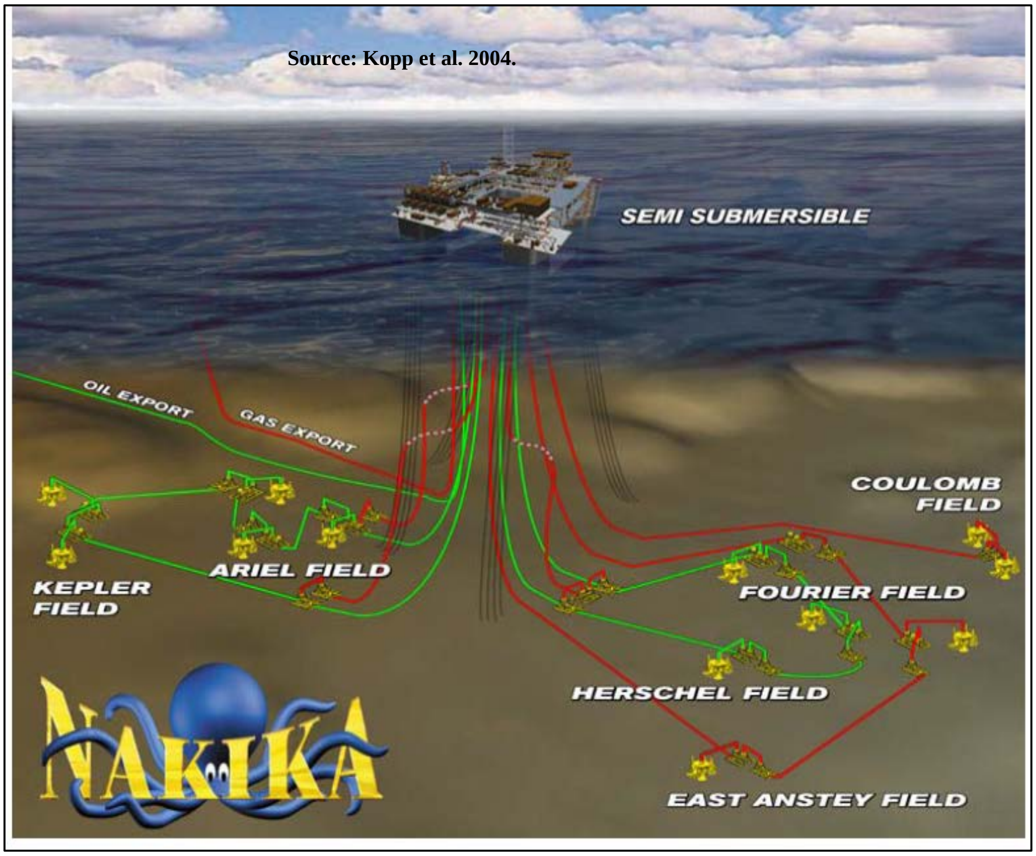



Figure N.3. Schematic of Na Kika host and subsea layout.

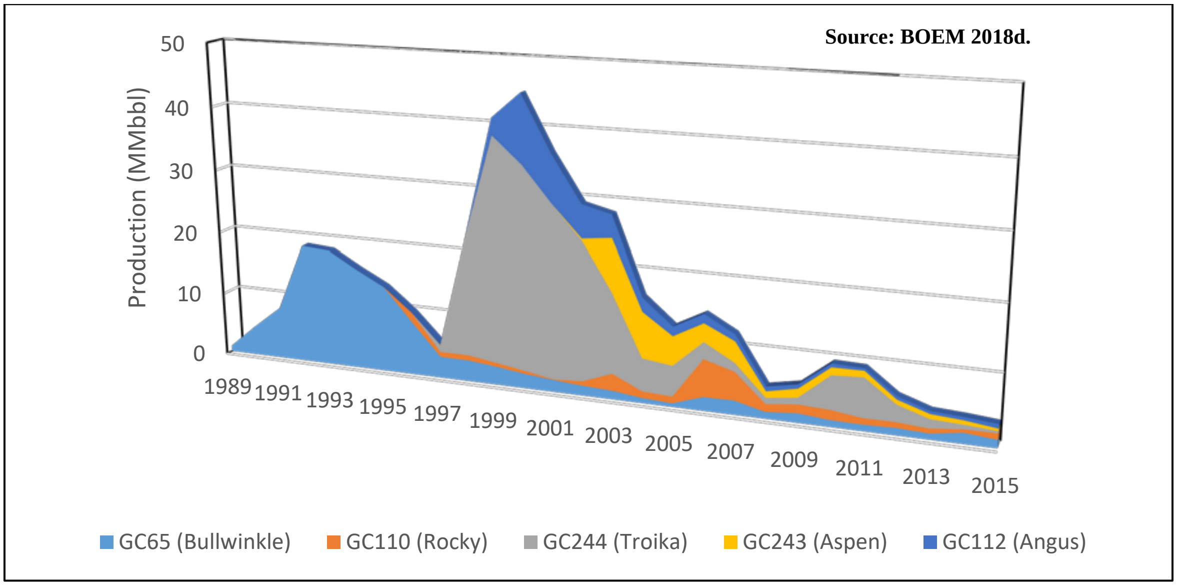



Figure N.4. Bullwinkle oil field production and subsea tiebacks Rocky, Troika, Angus, and Aspen.

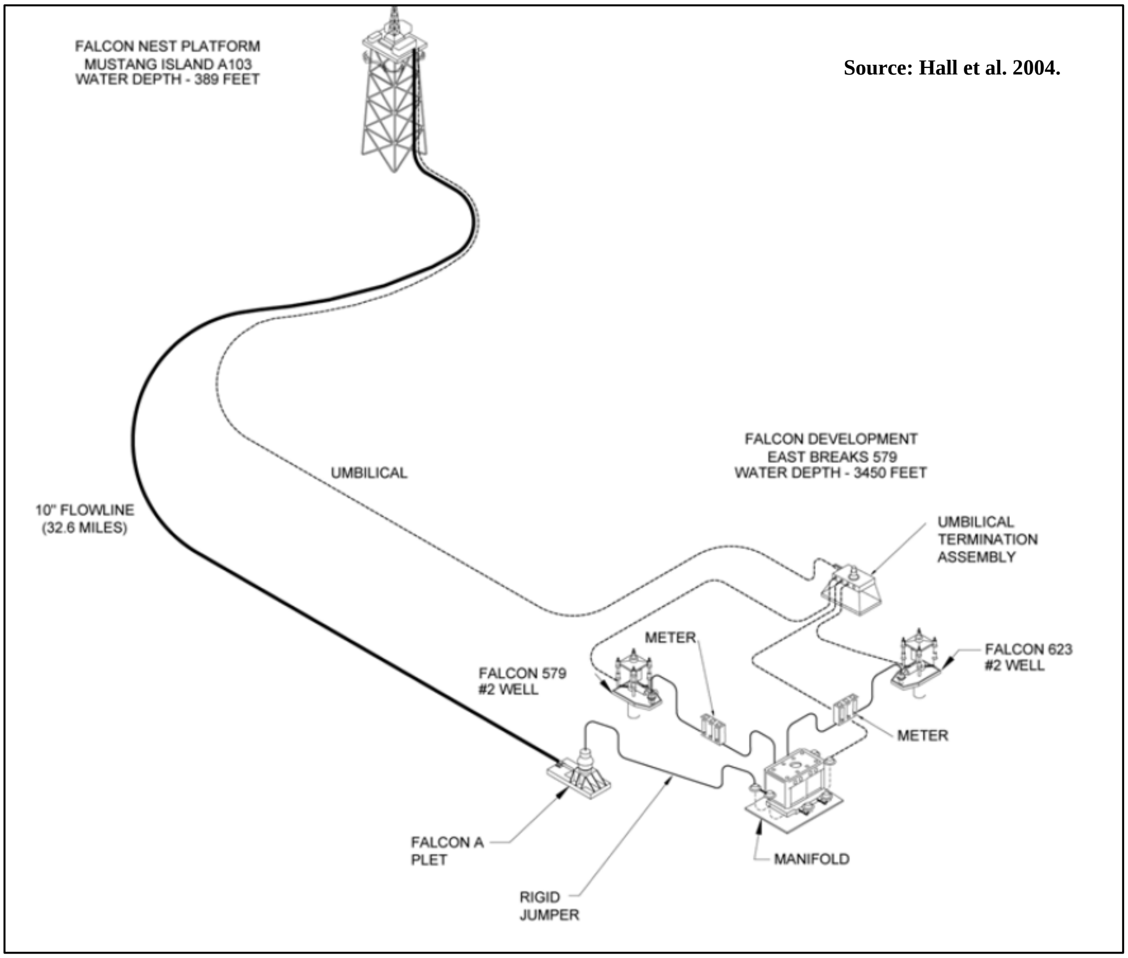



Figure N.5. Falcon Nest field development schematic.

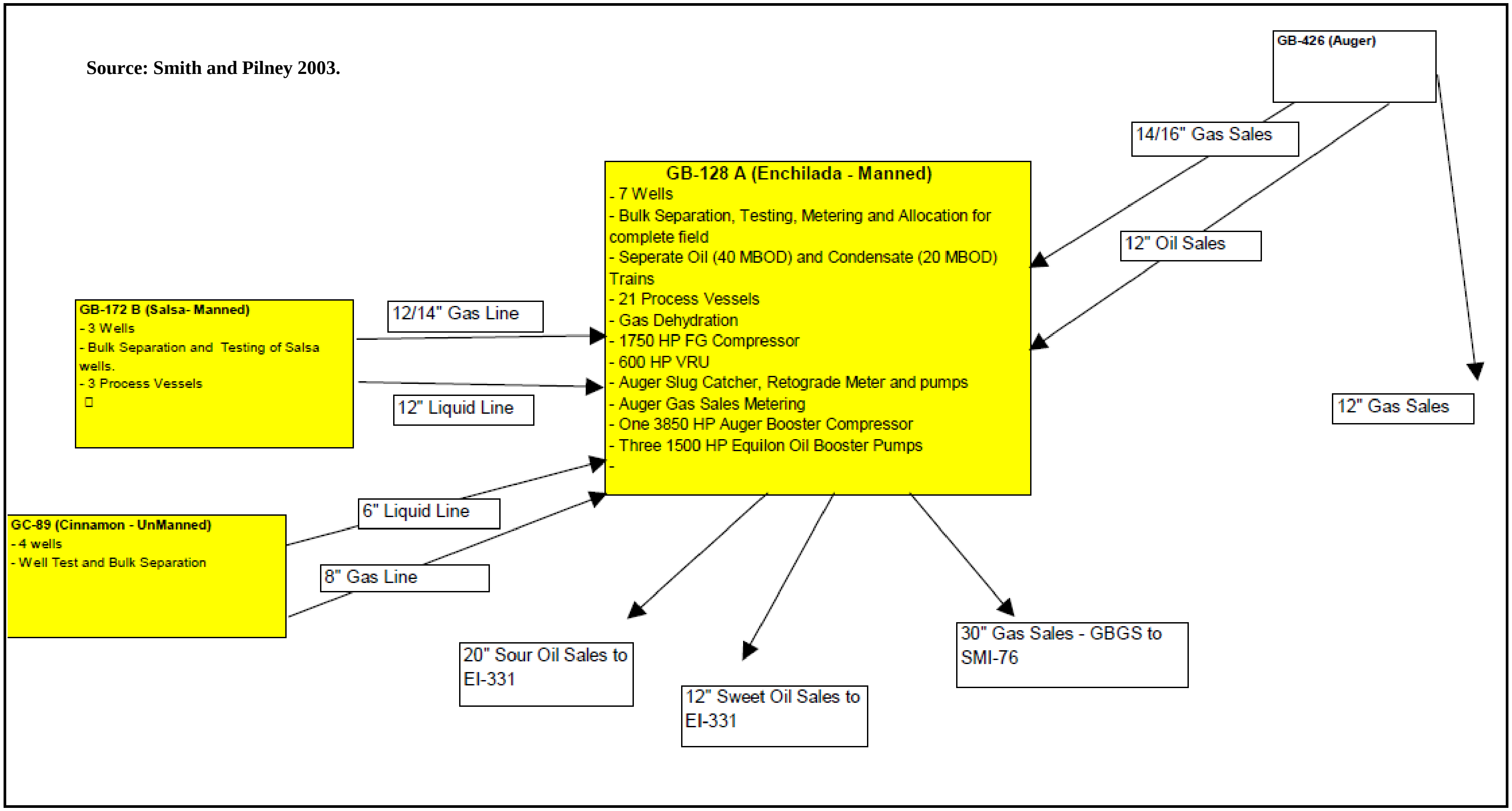



Figure N.6. Enchilada field layout circa 2000.

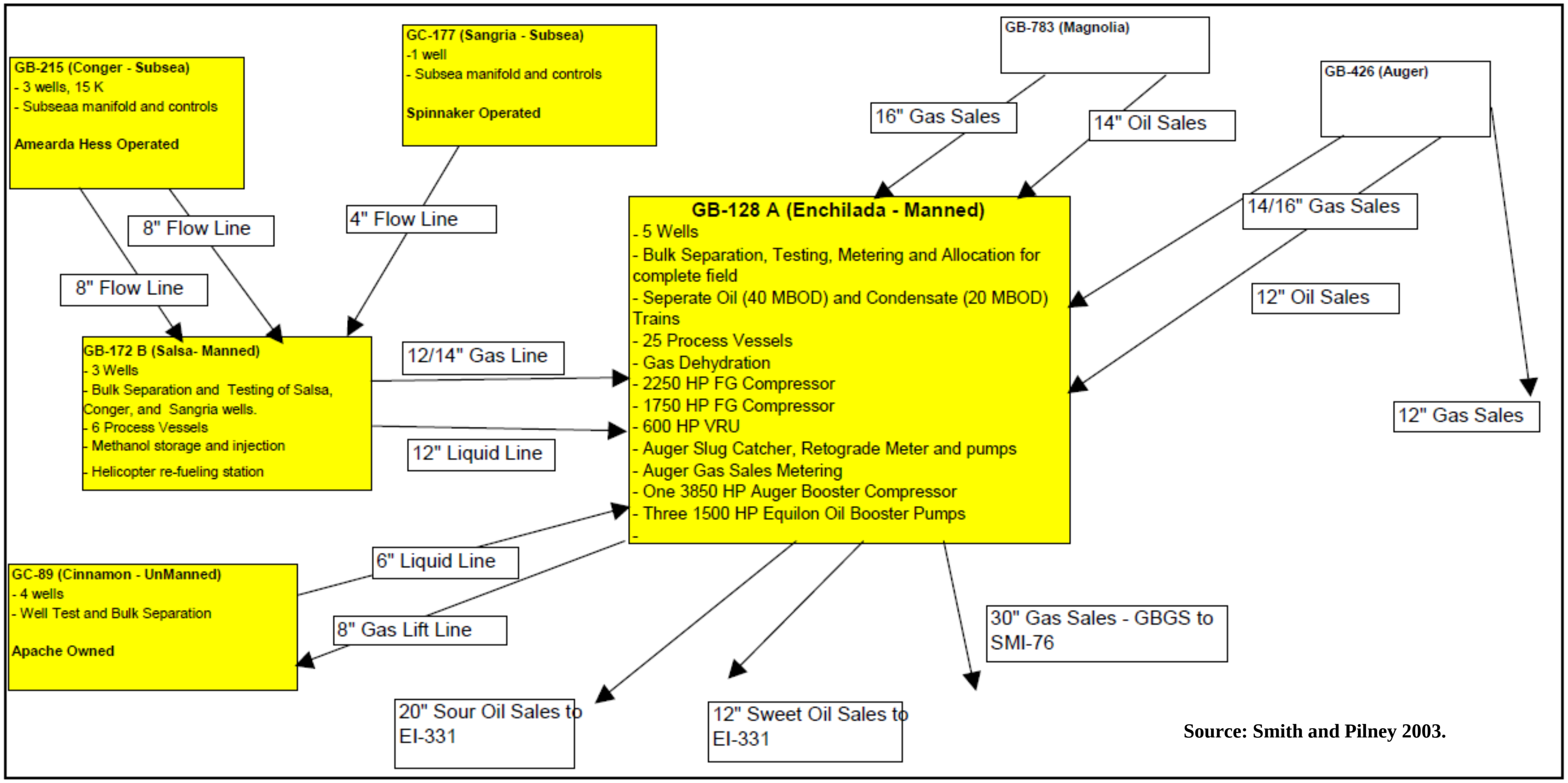



Figure N.7. Enchilada hub layout circa 2005.

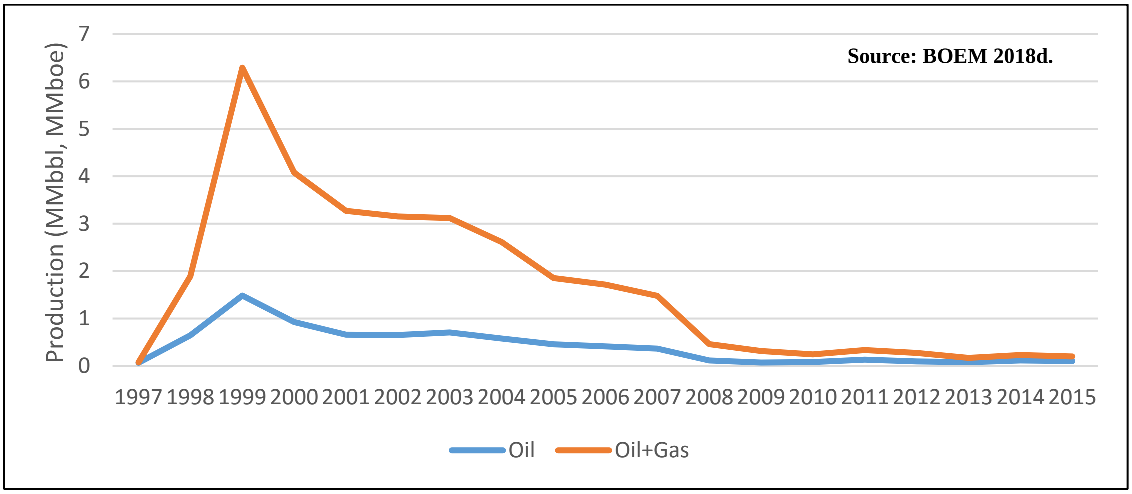



Figure N.8. Garden Bank 83 (Enchilada) field oil and gas production profile, 1997–2015.

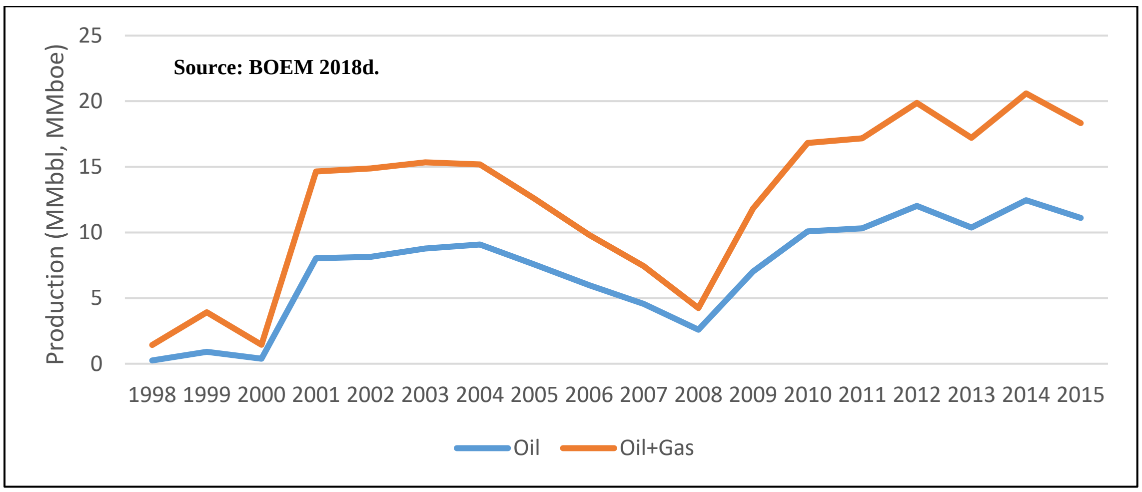



Figure N.9. Garden Bank 171 (Salsa) field oil and gas production profile, 1998–2015.

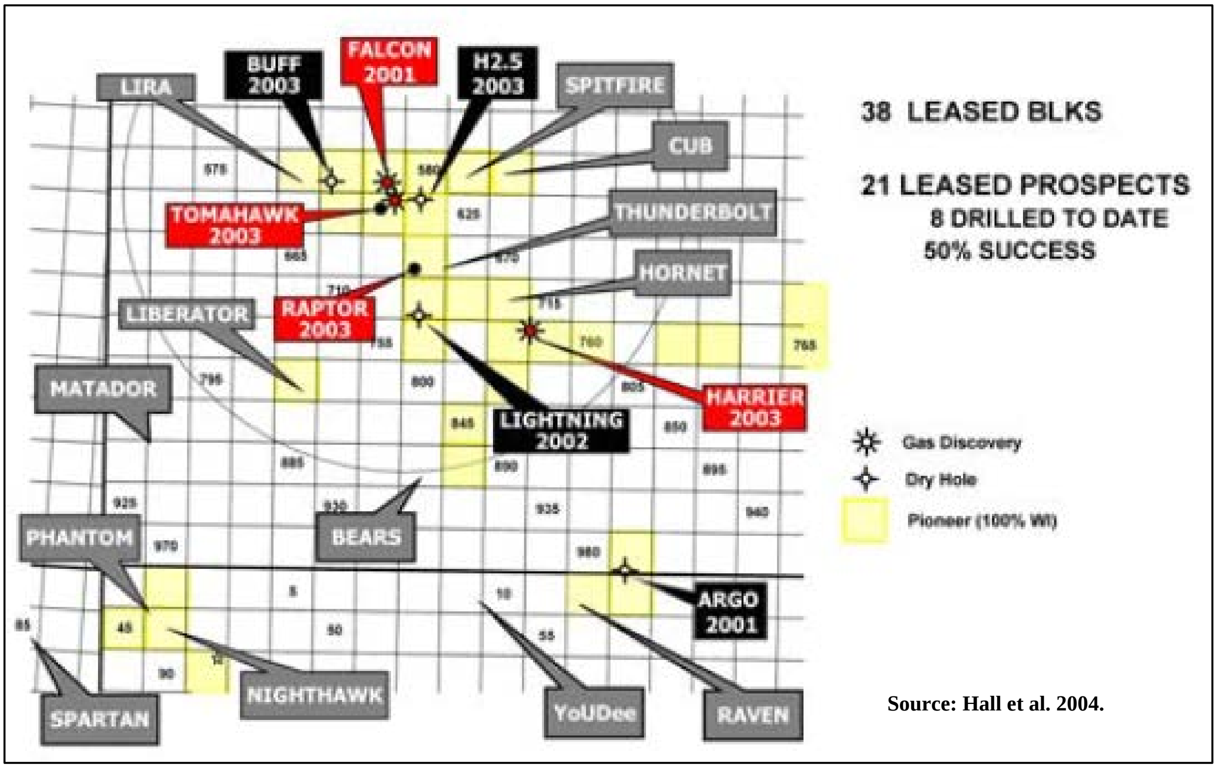



Figure N.10. Falcon Nest discoveries, prospects and leased acreage.

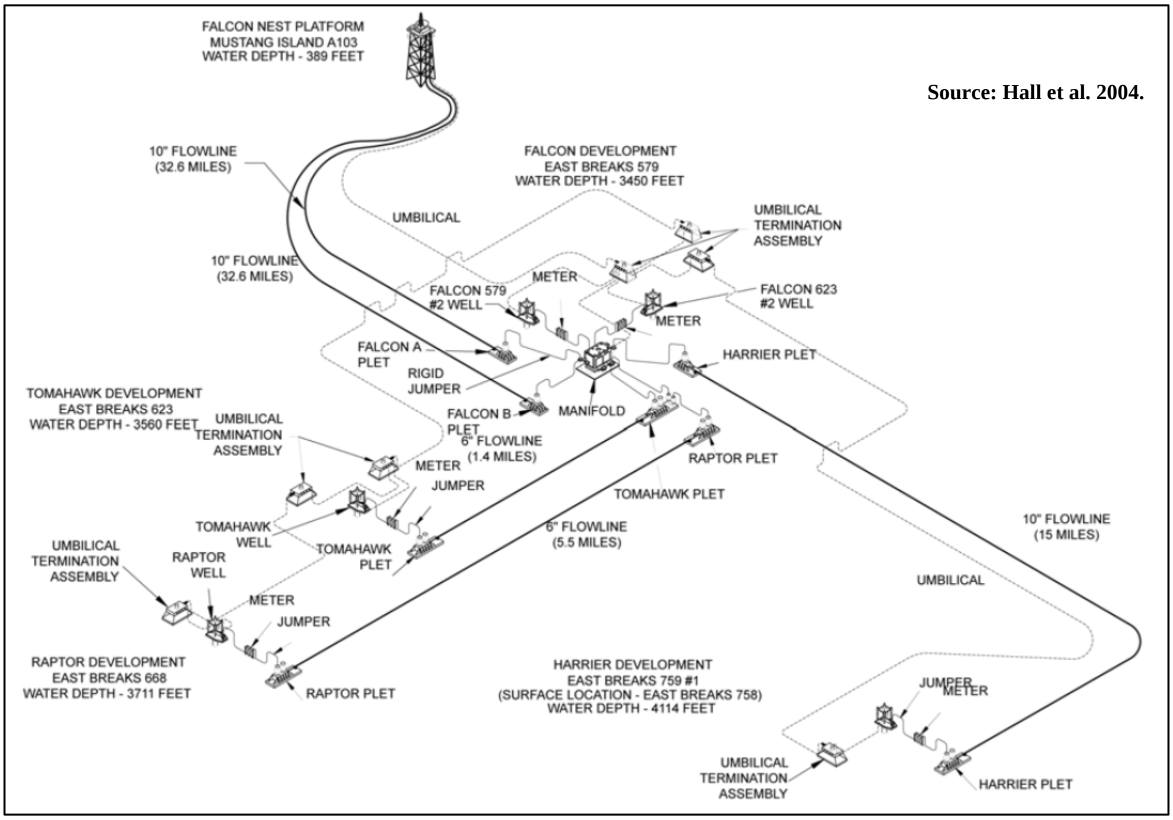



Figure N.11. Harrier, Tomahawk, and Raptor fields are tied back through the Falcon Nest manifold.

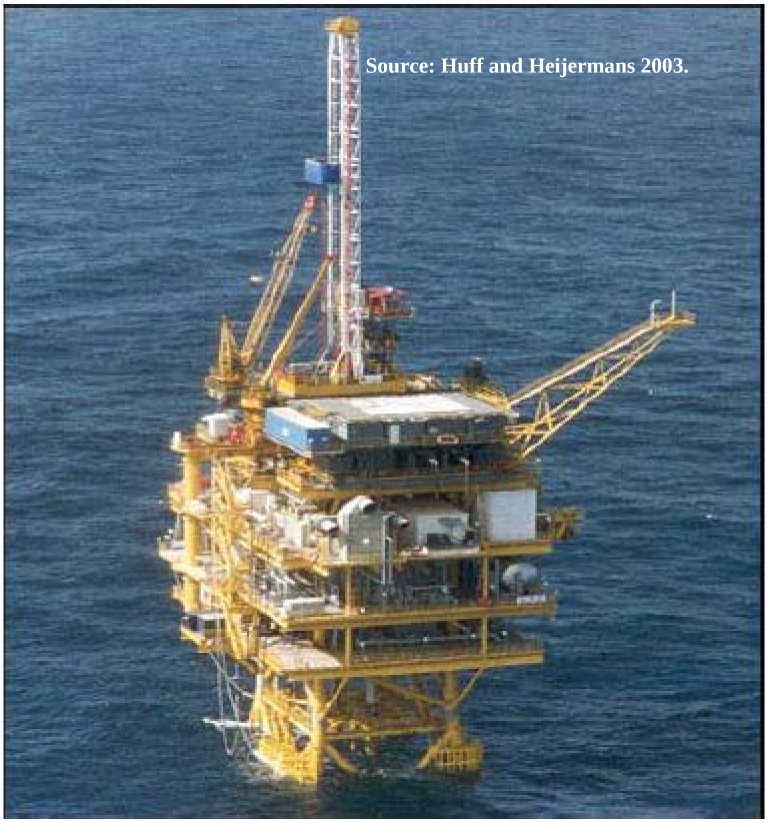



Figure N.12. Garden Bank 72 (Spectacular Bid) platform.

**Source: Genesis Energy 2017; Huff and Heijermans 2003.**

Figure N.13. Ship Shoal 332 A&B platform hub for the Cameron highway pipeline system and close-up of SS 332A.

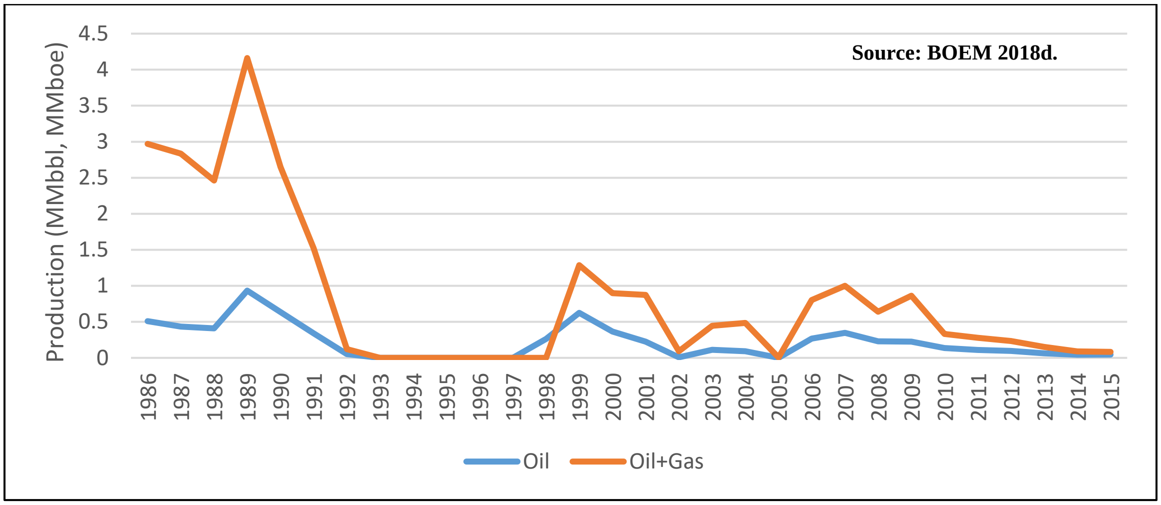



Figure N.14. Ship Shoal 332 field oil and gas production profile, 1986–2015.

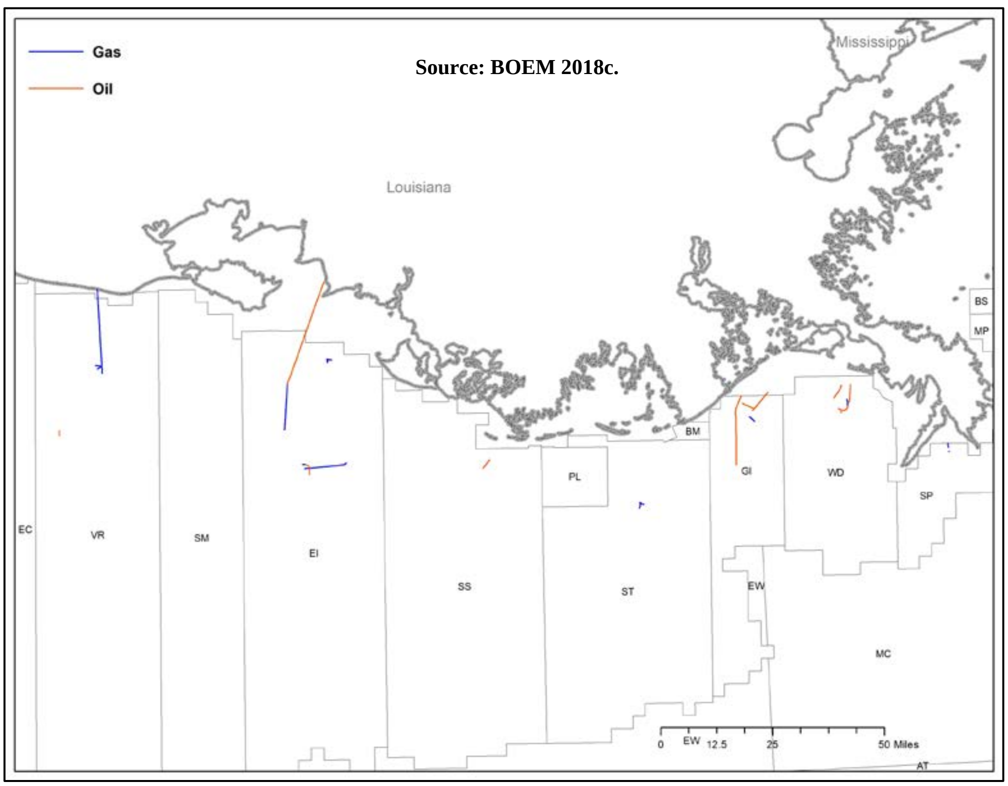



Figure N.15a. Oil and gas export pipeline installed in the Gulf of Mexico in the 1950s.

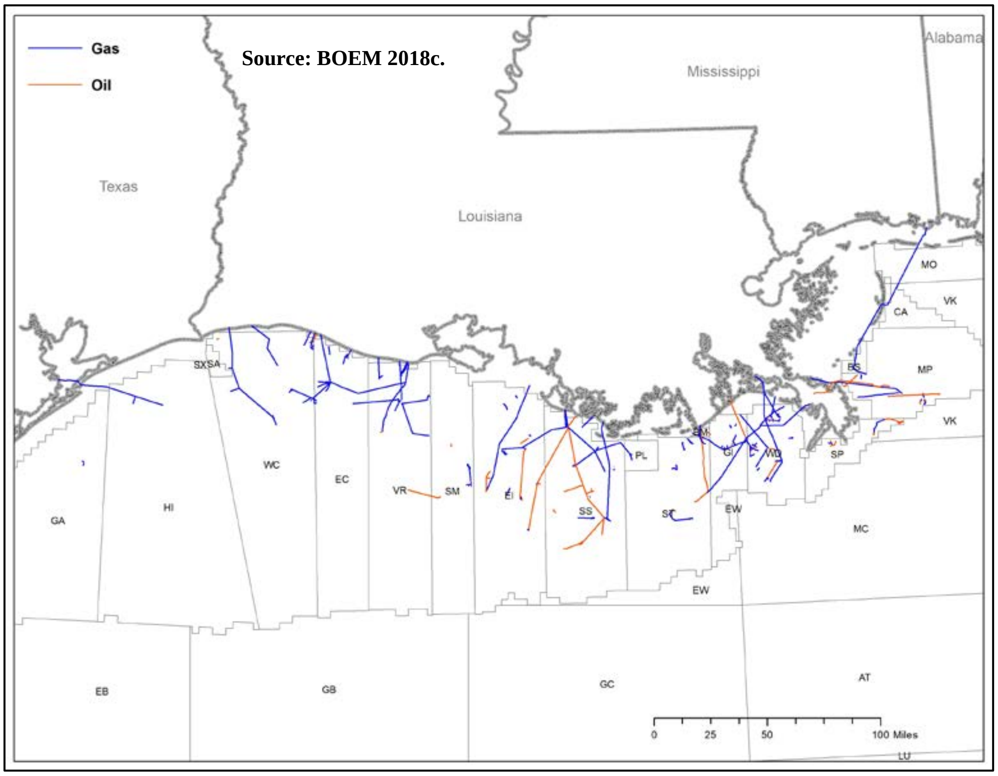



Figure N.15b. Oil and gas export pipeline installed in the Gulf of Mexico in the 1960s.

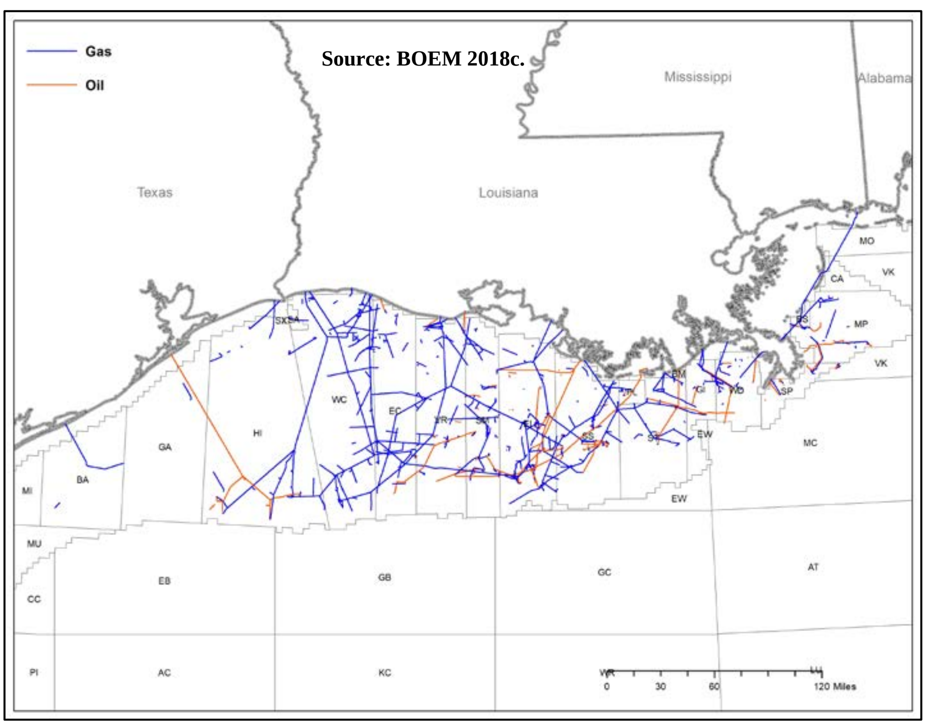



Figure N.15c. Oil and gas export pipeline installed in the Gulf of Mexico in the 1970s.

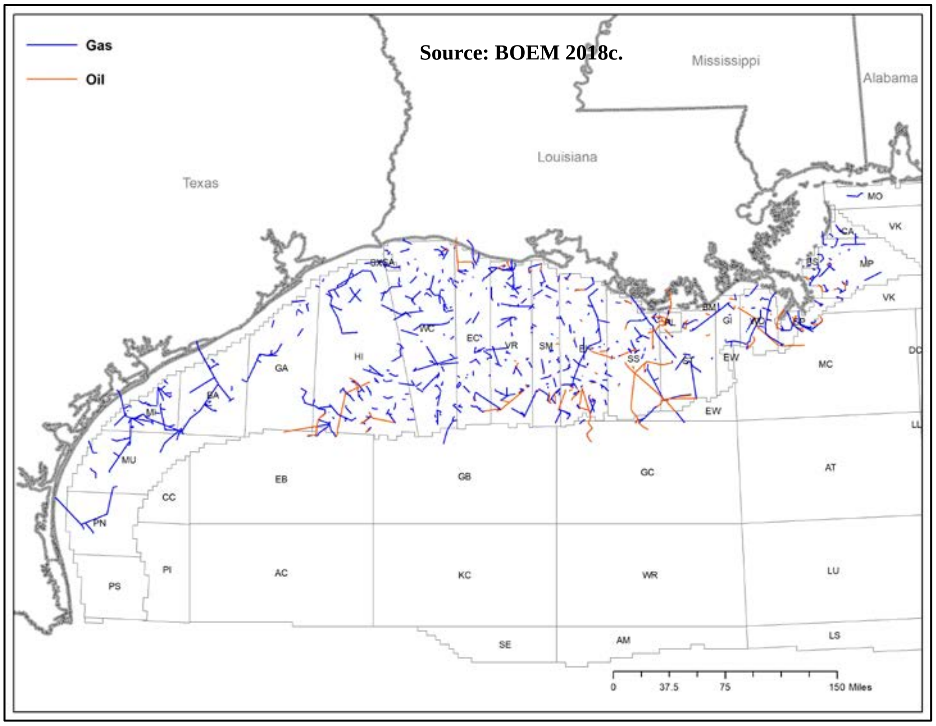



Figure N.15d. Oil and gas export pipeline installed in the Gulf of Mexico in the 1980s.

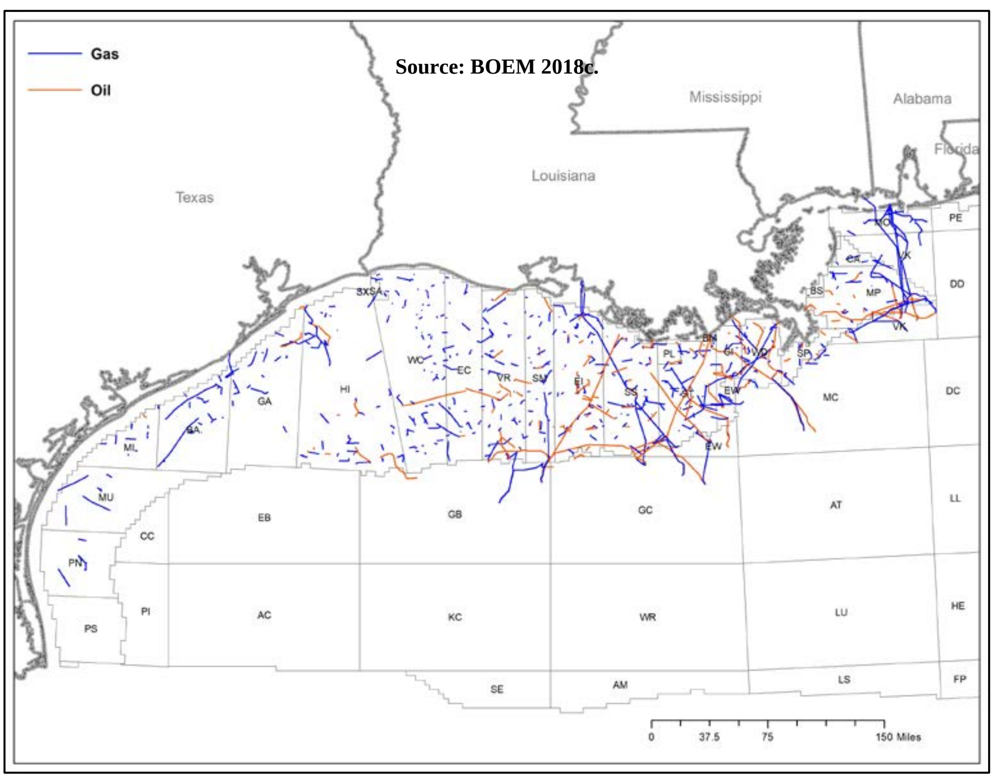



Figure N.15e. Oil and gas export pipeline installed in the Gulf of Mexico in the 1990s.

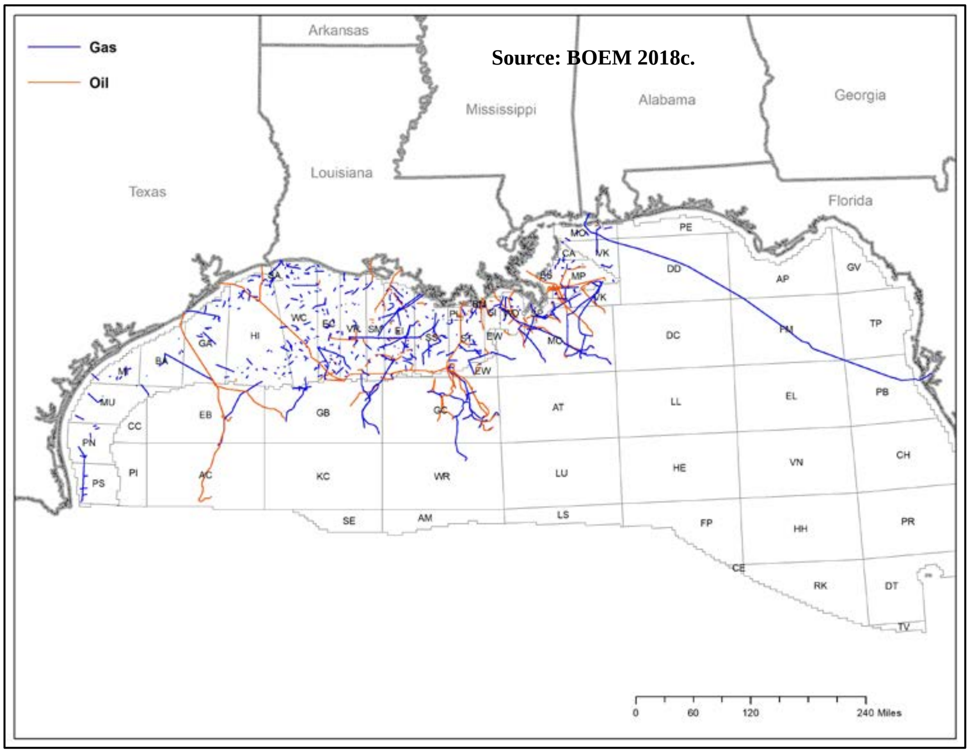



Figure N.15f. Oil and gas export pipeline installed in the Gulf of Mexico in the 2000s.

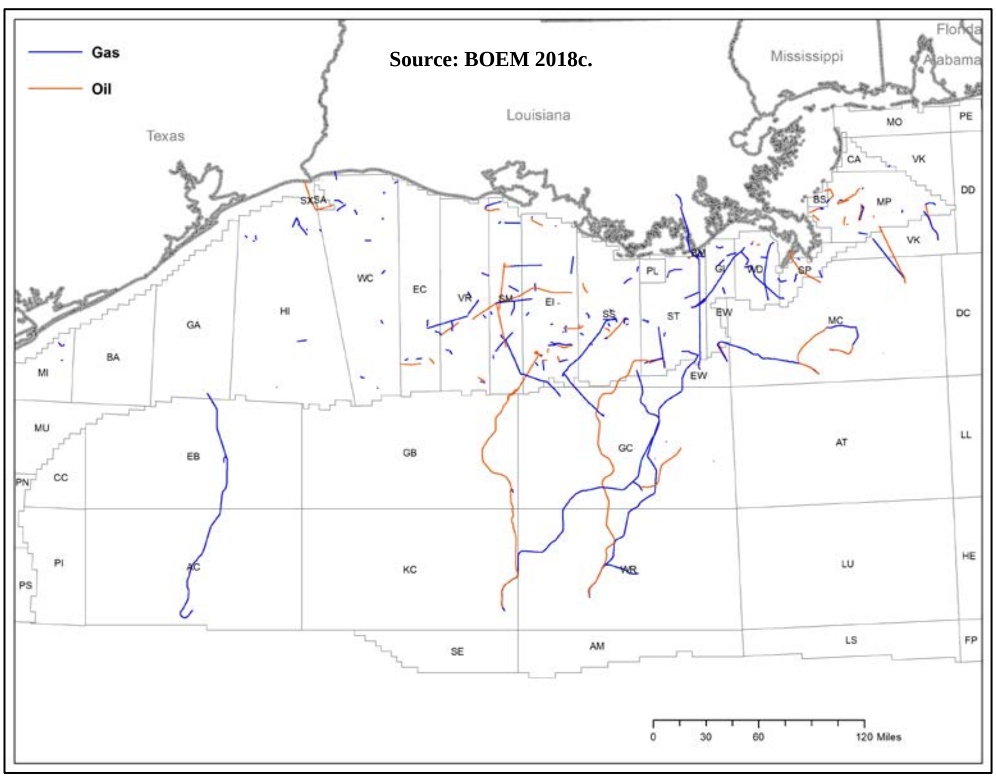



Figure N.15g. Oil and gas export pipeline installed in the Gulf of Mexico in the 2010s.

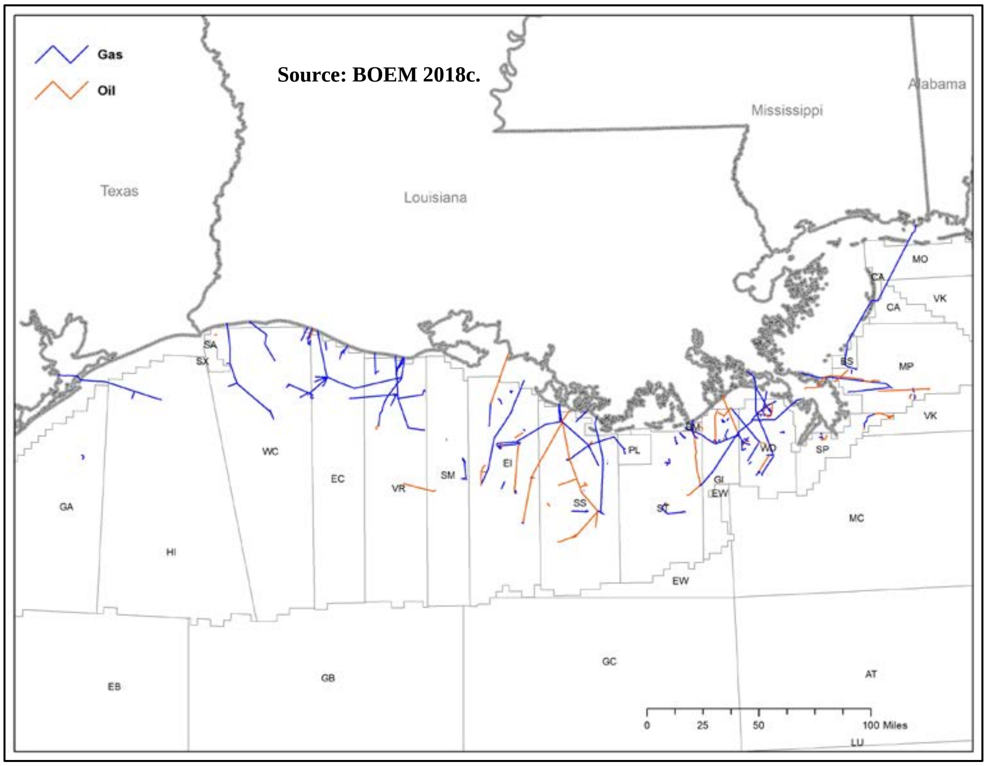



Figure N.16a. Active oil and gas export pipeline in the Gulf of Mexico circa 1969.

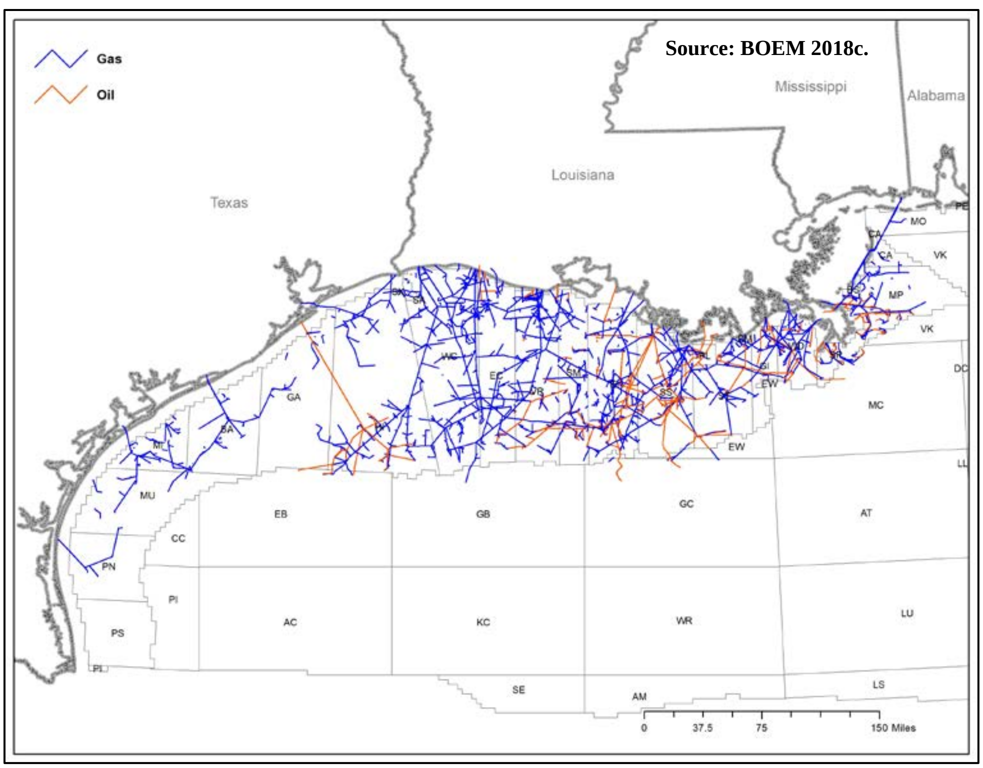



Figure N.16b. Active oil and gas export pipeline in the Gulf of Mexico circa 1989.

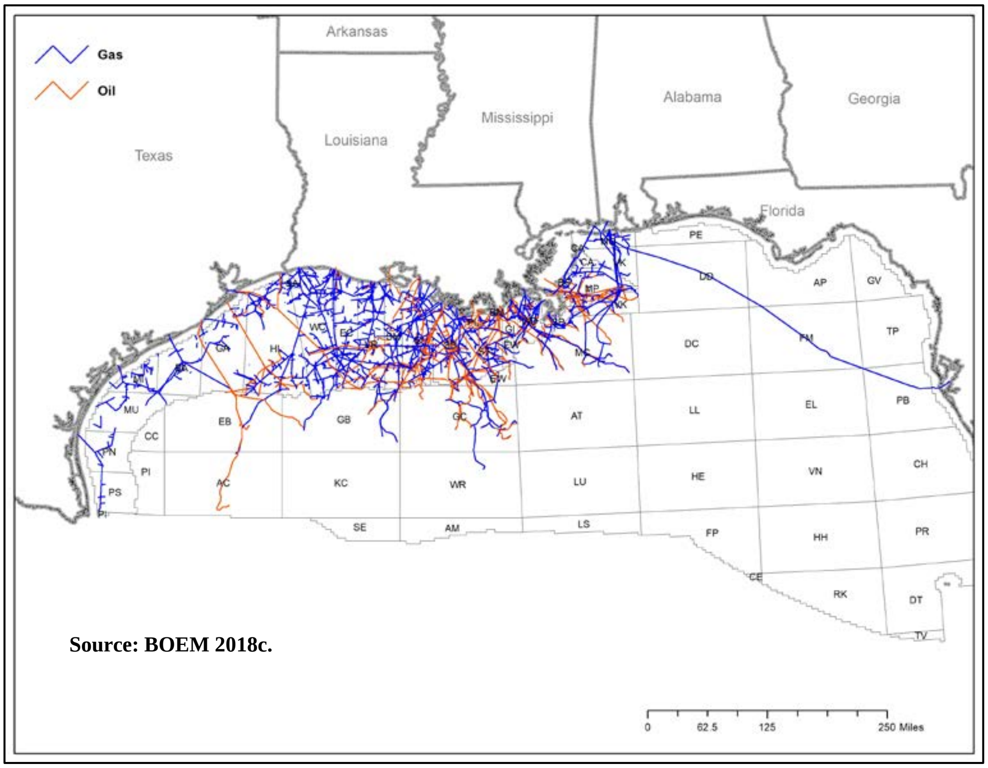



Figure N.16c. Active oil and gas export pipeline in the Gulf of Mexico circa 2009.

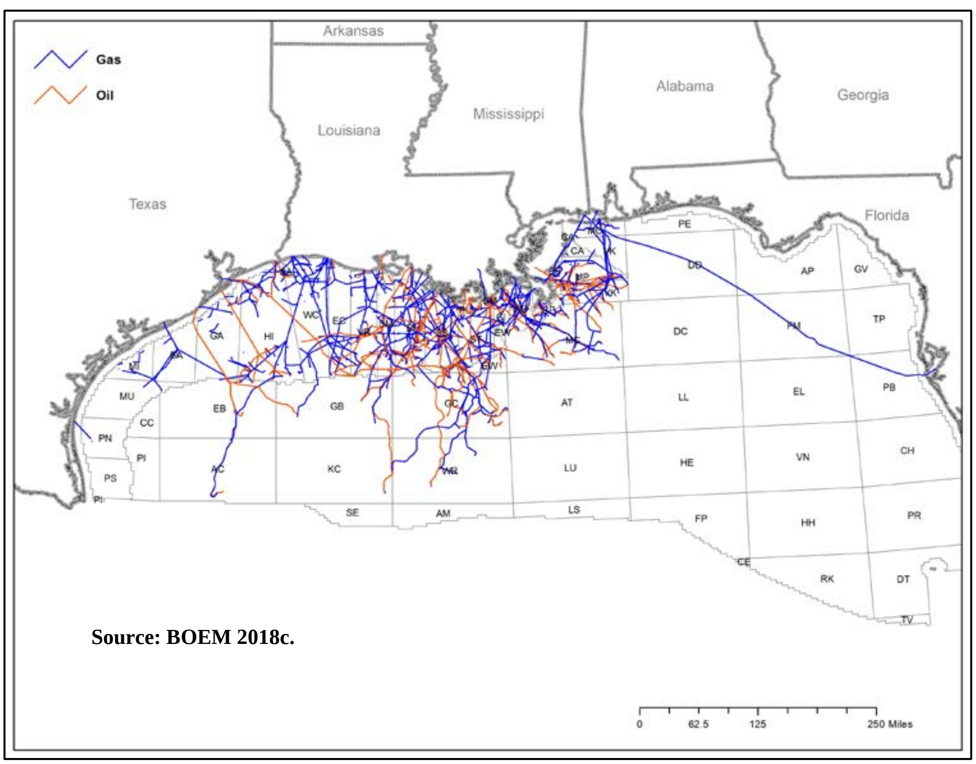



Figure N.16d. Active oil and gas export pipeline in the Gulf of Mexico circa 2018.

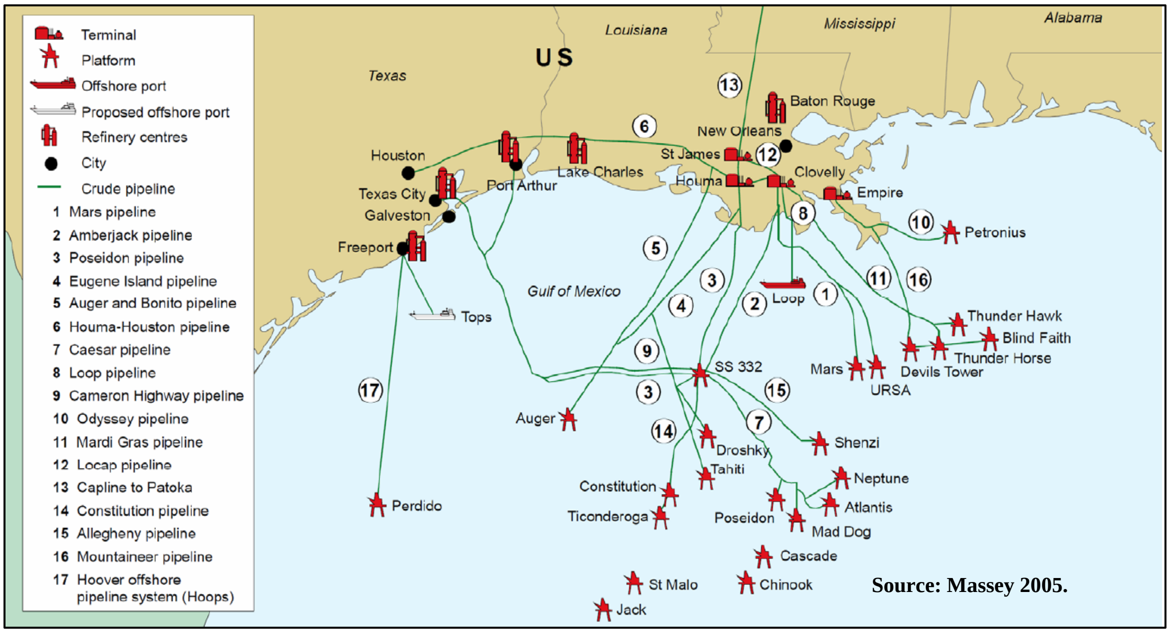
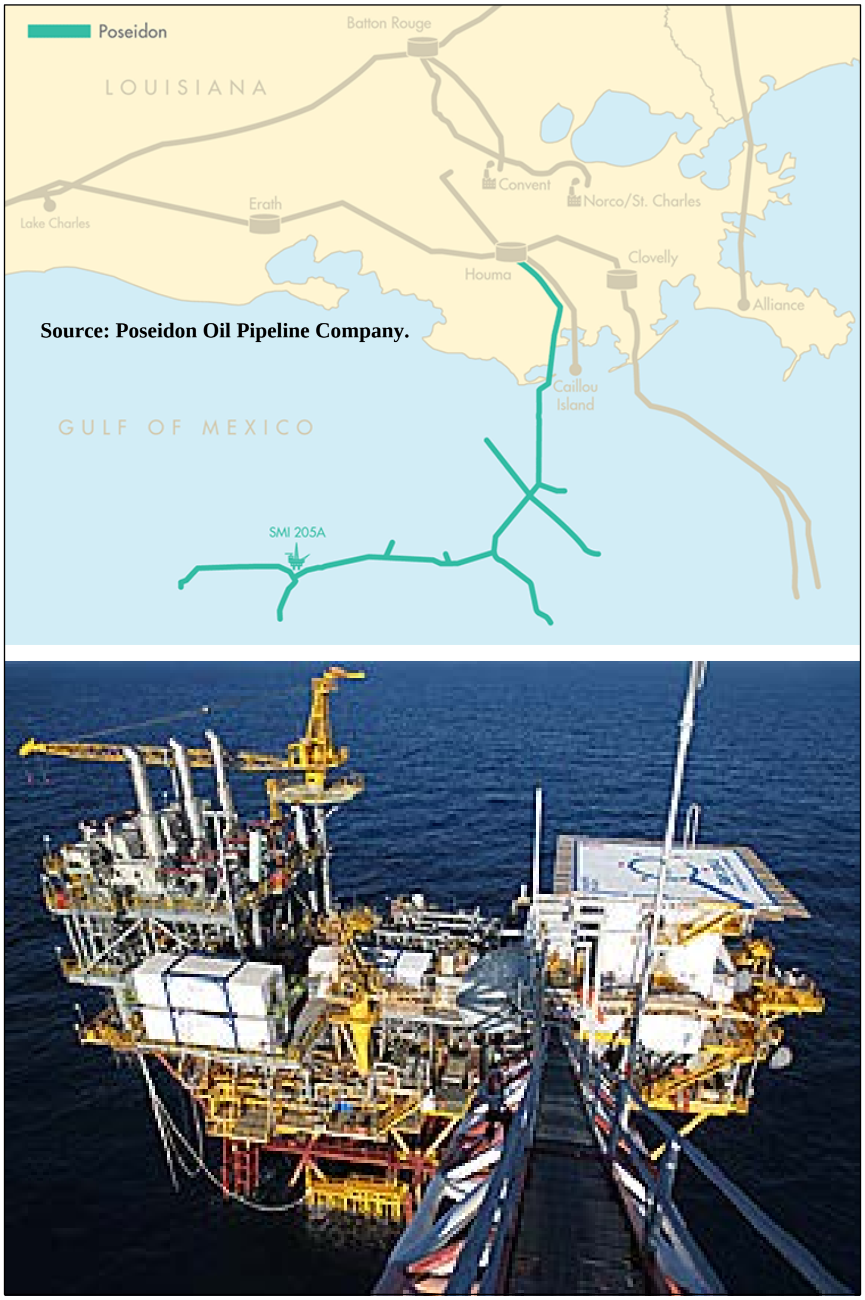



Figure N.17. Gulf of Mexico major oil pipelines.




Source: Poseidon Oil Pipeline Company.

Figure N.18. Poseidon oil pipeline network and South Marsh Island 205A junction platform.


Figure N.19. Shell's oil pipeline network and transportation platforms in yellow.

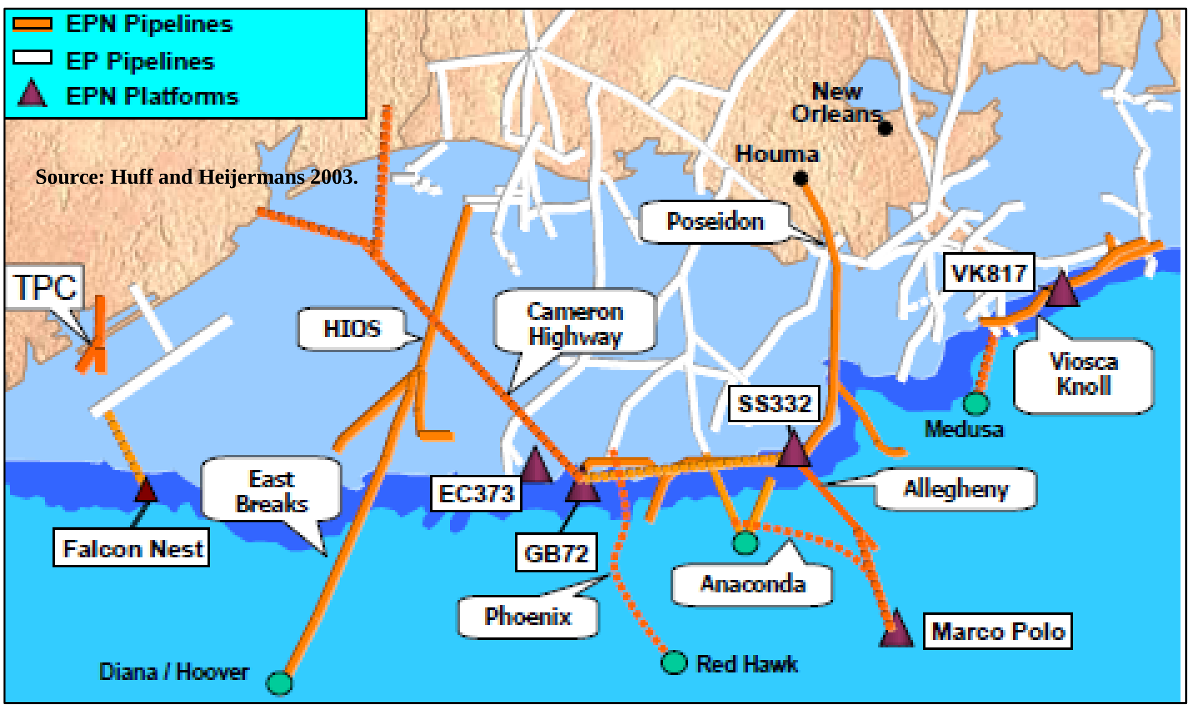



Figure N.20. El Paso's oil pipeline network and platforms circa 2003.

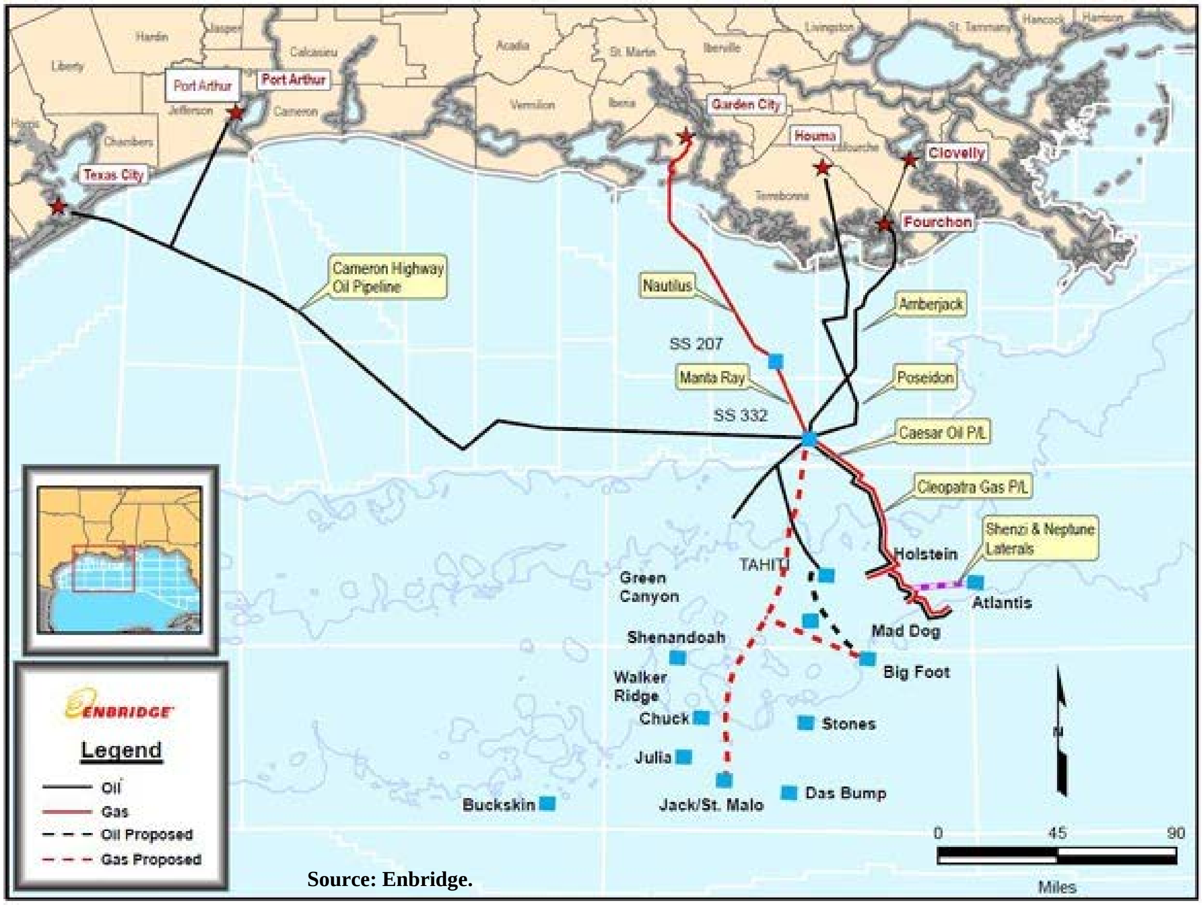



Figure N.21. The Walker Ridge Gathering System gas pipeline network.

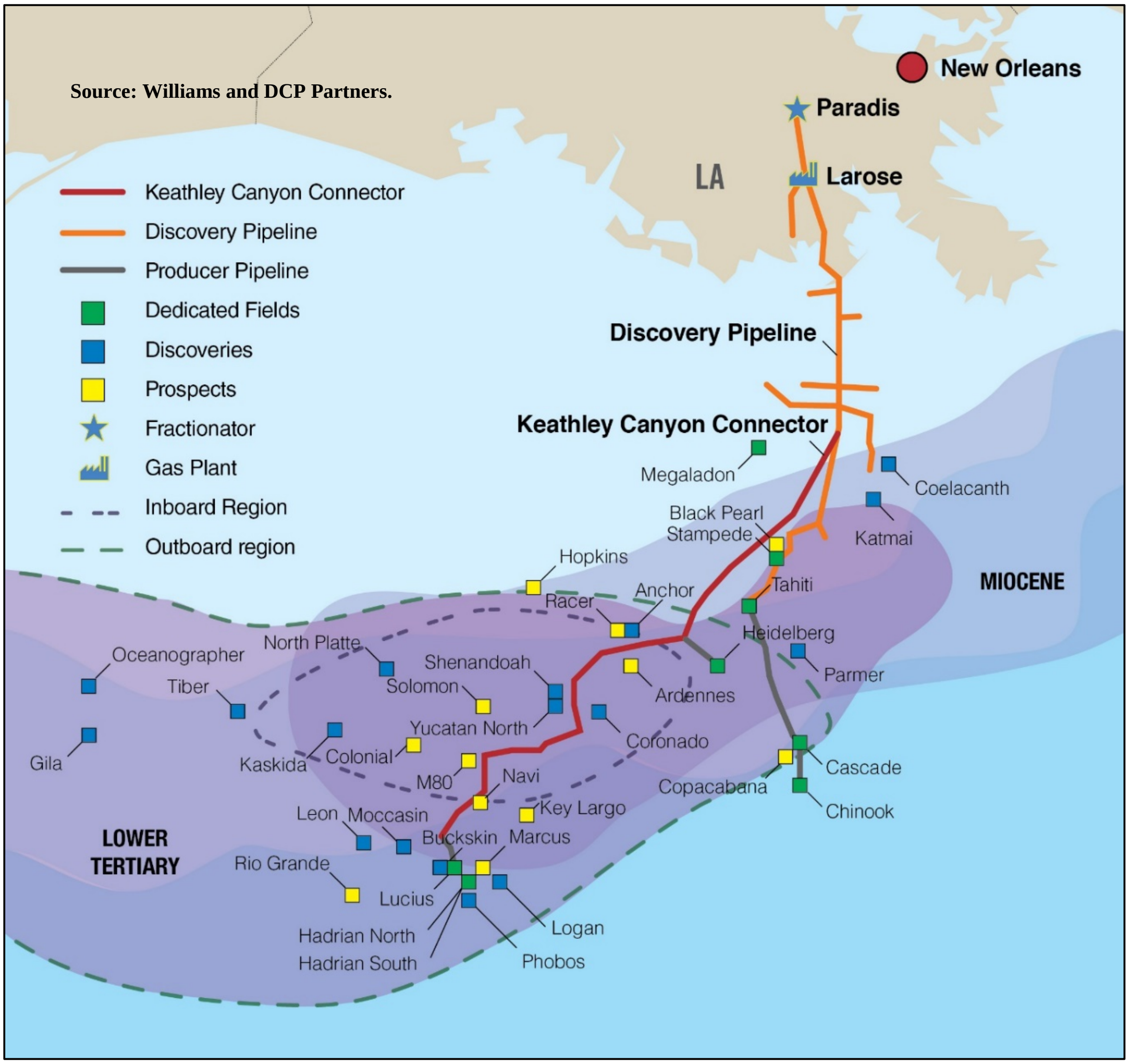



Figure N.22. The Keathley Canyon Connector gas pipeline corridor.

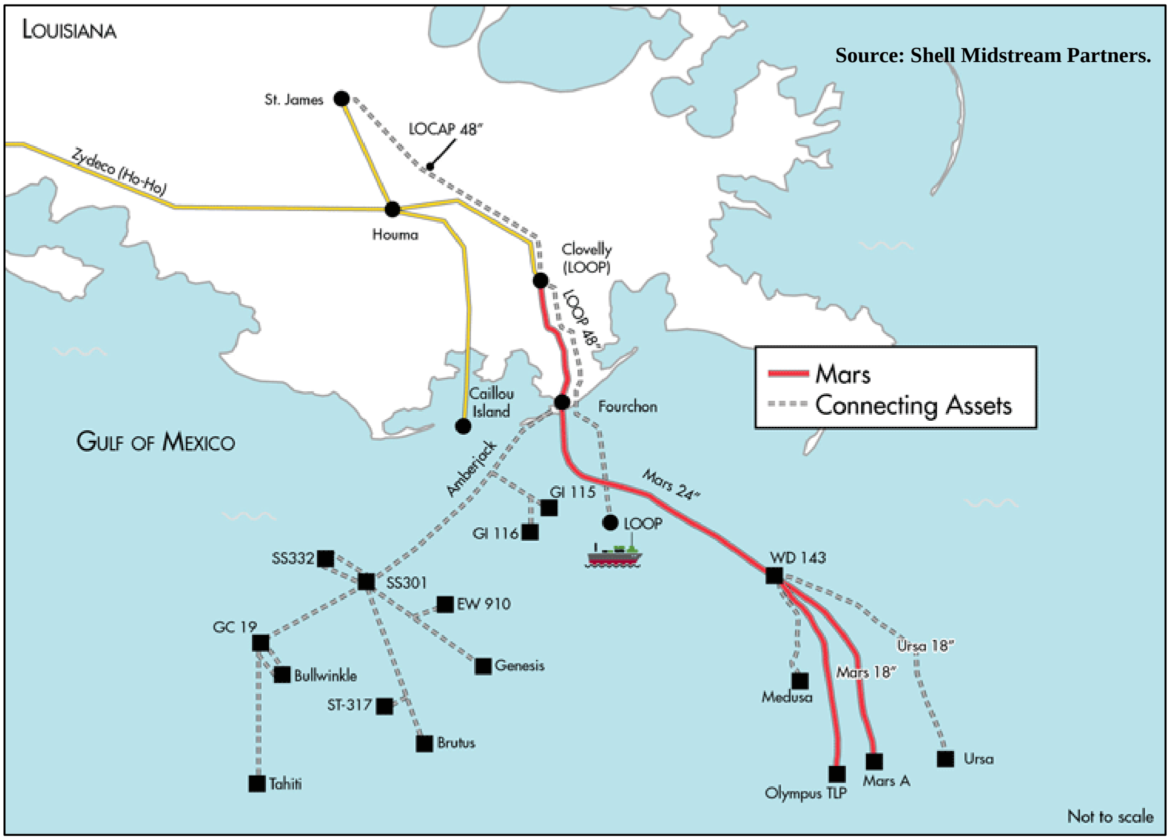



Figure N.23. A portion of Shell's central Gulf of Mexico oil pipeline network.

## Appendix O: Chapter 15 Tables and Figures

**Table O.1. Production codes for OCS pipelines**

| Product Code | Definition |
|---|---|
| ACID | Acid |
| AIR | Pneumatic |
| BLGH | Bulk gas with trace levels of hydrogen sulfide |
| BLKG | Full well stream production from gas well(s) prior to processing |
| BLKO | Full well stream production from oil well(s) prior to processing |
| BLOH | Bulk oil with trace levels of hydrogen sulfide |
| CBLC | A non-umbilical cable such as fiber optic/communications |
| CBLP | Power cable |
| CHEM | Corrosion inhibitor or other chemicals |
| CO2 | Carbon dioxide |
| COND | Condensate or distillate transported downstream of first processing |
| CSNG | Pipeline used as a protective casing for another pipeline |
| FLG | Flare gas |
| G/C | Gas and condensate service after first processing |
| G/CH | Gas and condensate with traces of H2S |
| G/O | Gas and oil service after first processing |
| G/OH | Gas and oil with traces of H2S |
| GAS | Gas transported after first processing |
| GASH | Processed gas with trace levels of hydrogen sulfide |
| H2O | Water |
| INJ | Gas injection |
| LGER | Liquid gas enhanced recovery |
| LIFT | Gas lift |
| LPRO | Liquid propane |
| METH | Methanol/glycol |
| NGER | Natural gas enhanced recovery |
| NGL | Natural gas liquids |
| O/W | Oil and water transported after first processing |
| OIL | Oil transported after first processing |
| OILH | Processed oil with trace levels of hydrogen sulfide |
| SERV | Service or utility line used for pigging and pipeline maintenance |
| SPLY | Supply gas |
| SPRE | Spare |
| SULF | Liquefied sulphur or slurried sulphur |
| TEST | Test |
| TOW | Tow route (not a pipeline) |
| UBEH | Electro/hydraulic umbilical |
| UMB | Umbilical line (usually pneumatic or hydraulic) |
| UMBC | Chemical umbilical |
| UMBE | Electrical umbilical |

Source: BOEM 2018c.

**Table O.2. Production group categories and subcategories**

| Product Group | Subcategories |
|---|---|
| Bulk Gas | BLGH, BLKG |
| Bulk Oil | BLKO, BLOH |
| Gas | G/C, G/CH, G/O, G/OH, GAS, GASH |
| Oil | O/W, OIL, OILH, COND |
| Umbilical | UBEH, UMB, UMBC, UMBE |
| Service | ACID, AIR, CBLC, CBLP, CBLR,CHEM, CO2, CSNG, FLG, H2O, INJ, LGER, LIFT, LPRO, METH, NGER, NGL, PWTR, SERV, SPLY, SPRE, SULF, TEST |

**Table O.3. Status codes for OCS pipelines**

| Status Code | Definition |
|---|---|
| A/C | Abandoned and combined |
| ABN | Abandoned |
| ACT | Active |
| CNCL | Cancelled |
| COMB | Combined |
| O/C | Out and combined |
| OUT | Out of service |
| PABN | Proposed abandonment |
| PREM | Proposed removal |
| PROP | Proposed |
| R/A | Relinquished and abandoned |
| R/C | Relinquished and combined |
| R/R | Relinquished and removed |
| RELQ | Relinquished |
| REM | Removed |

Source: BOEM 2018c.

**Table O.4. OCS pipeline status group categories**

| Status Group | Subcategories |
|---|---|
| Abandoned | A/C, ABN, R/A |
| Active | ACT |
| Idle | O/C, OUT |
| Removed | R/R, REM |
| Decommissioned | A/C, ABN, R/A, R/R, REM |

**Table O.5. Pipeline mileage installed in the GoM by product group and water depth circa 2016**

| Product Group | <400 ft (mi) | 401–1000 ft (mi) | >1000 ft (mi) | Total (mi) |
|---|---|---|---|---|
| Bulk Gas | 6046 | 410 | 1818 | 8332 |
| Bulk Oil | 2085 | 133 | 1841 | 4091 |
| Gas | 12,746 | 1391 | 2384 | 16,778 |
| Oil | 4138 | 1007 | 2183 | 7586 |
| Service | 1802 | 393 | 2521 | 4751 |
| Umbilicals | 293 | 295 | 2964 | 3770 |
| Total | 27,110 | 3,629 | 13,710 | 45,310 |

Source: BOEM 2018c.

**Table O.6. Pipeline mileage without installation date reported circa 2016**

| Product Group | No Installation Date (mi) | Total (mi) | Percentage (%) |
|---|---|---|---|
| Bulk Gas | 784 | 8332 | 9.4 |
| Bulk Oil | 464 | 4091 | 11.3 |
| Gas | 629 | 16,778 | 3.7 |
| Oil | 412 | 7586 | 5.4 |
| Service | 2658 | 4751 | 56.0 |
| Umbilicals | 3617 | 3770 | 96.0 |
| Total | 8564 | 45,310 | 18.9 |

Source: BOEM 2018c.

**Table O.7. Abandoned and removed pipeline mileage by product group circa 2016**

| Product Group | Abandoned (mi) | Removed (mi) | Total (mi) |
|---|---|---|---|
| Bulk Gas | 5802 | 144 | 5946 |
| Bulk Oil | 1443 | 124 | 1568 |
| Gas | 6881 | 53 | 6934 |
| Oil | 1665 | 23 | 1688 |
| Service | 1603 | 121 | 1724 |
| Umbilicals | 1354 | 21 | 1375 |
| Total | 18,749 | 486 | 19,236 |

Source: BOEM 2018c.

**Table O.8. Pipeline mileage without decommissioning date reported circa 2016**

| Product Group | No Decommissioning Date (mi) | Total (mi) | Percentage (%) |
|---|---|---|---|
| Bulk Gas | 684 | 5946 | 11.5 |
| Bulk Oil | 313 | 1568 | 20.0 |
| Gas | 467 | 6934 | 6.7 |
| Oil | 300 | 1688 | 17.8 |
| Service | 636 | 1724 | 36.9 |
| Umbilicals | 633 | 1375 | 46.0 |
| Total | 3033 | 19,235 | 15.8 |

Source: BOEM 2018c.

**Table O.9. Abandoned and removed pipeline mileage by water depth**

| Water Depth (ft) | Abandoned (mi) | Removed (mi) | Total (mi) |
|---|---|---|---|
| <400 | 14,493 | 381 | 14,874 |
| 401–1000 | 1136 | 33 | 1169 |
| >1000 | 2552 | 41 | 2593 |
| Total | 18,749 | 486 | 19,236 |

Source: BOEM 2018c.
Note: Total includes 599 miles of pipeline without water depth classification available.

**Table O.10. Active pipeline mileage by maximum water depth and product group circa 2016**

| Product Group | <400 ft (mi) | 401–1000 ft (mi) | >1000 ft (mi) | Total (mi) |
|---|---|---|---|---|
| Bulk Gas | 643 | 44 | 545 | 1236 |
| Bulk Oil | 705 | 70 | 1286 | 2074 |
| Gas | 5391 | 1137 | 2093 | 8690 |
| Oil | 2596 | 824 | 1987 | 5484 |
| Service | 549 | 151 | 1977 | 2686 |
| Umbilicals | 22 | 56 | 1574 | 1703 |
| Total | 9906 | 2281 | 9462 | 21,872 |

Source: BOEM 2018c.
Note: Total includes 233 miles of pipeline without product group classification available.

**Table O.11. Percentage of installed pipeline active circa 2016**

| Product Group | <400 ft (%) | 401–1000 ft (%) | >1000 ft (%) |
|---|---|---|---|
| Bulk Gas | 11 | 11 | 30 |
| Bulk Oil | 34 | 53 | 70 |
| Gas | 42 | 82 | 88 |
| Oil | 63 | 82 | 91 |
| Service | 30 | 38 | 78 |
| Umbilicals | 8 | 19 | 75 |
| Total | 37 | 63 | 69 |

Source: BOEM 2018c.

**Table O.12. Vintage of active pipeline mileage circa 2016**

| Installation Year | <400 ft (mi) | >400 ft (mi) |
|---|---|---|
| 1950–59 | 61 (1%) | - |
| 1960–69 | 648 (7%) | 22 (<1%) |
| 1970–79 | 2463 (26%) | 15 (<1%) |
| 1980–89 | 1289 (13%) | 320 (4%) |
| 1990–99 | 1789 (19%) | 1406 (17%) |
| 2000–09 | 2356 (24%) | 4112 (50%) |
| 2010–16 | 1045 (11%) | 2340 (28%) |
| Total | 9652 (100%) | 8215 (100%) |

Source: BOEM 2018c.

**Table O.13. Cumulative installed shallow water pipeline by product group, 2007 and 2016**

| Product Group | 2007 (mi) | 2016 (mi) | Difference (mi) |
|---|---|---|---|
| Gas | 11,435 | 12,260 | 825 |
| Oil | 3423 | 3869 | 446 |
| Bulk Gas | 4784 | 5400 | 616 |
| Bulk Oil | 1496 | 1780 | 284 |
| Total | 21,138 | 23,309 | 2171 |

Source: BOEM 2018c.

**Table O.14. Cumulative installed deepwater pipeline by product group, 2007 and 2016**

| Product Group | 2007 (mi) | 2016 (mi) | Difference (mi) |
|---|---|---|---|
| Gas | 2632 | 3706 | 1074 |
| Oil | 2520 | 3135 | 615 |
| Bulk Gas | 1620 | 2093 | 473 |
| Bulk Oil | 749 | 1784 | 1035 |
| Total | 7521 | 10,718 | 3197 |

Source: BOEM 2018c.

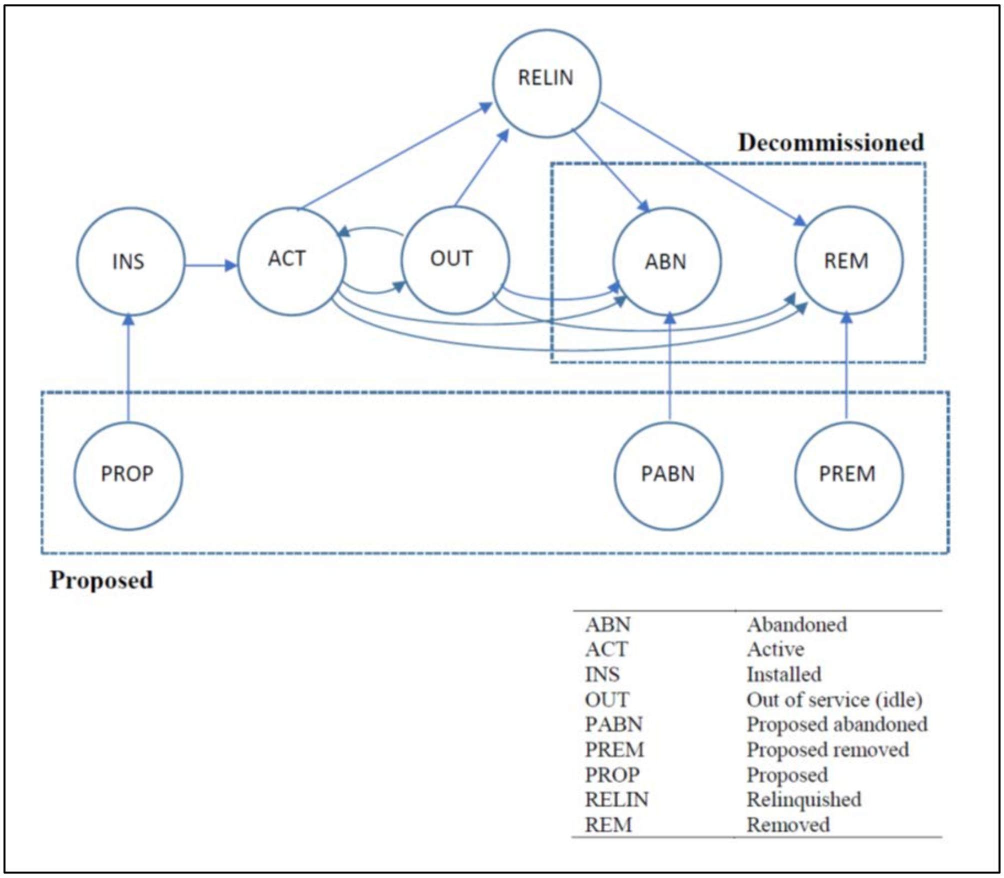



Figure O.1. Representation of transitions between pipeline states.

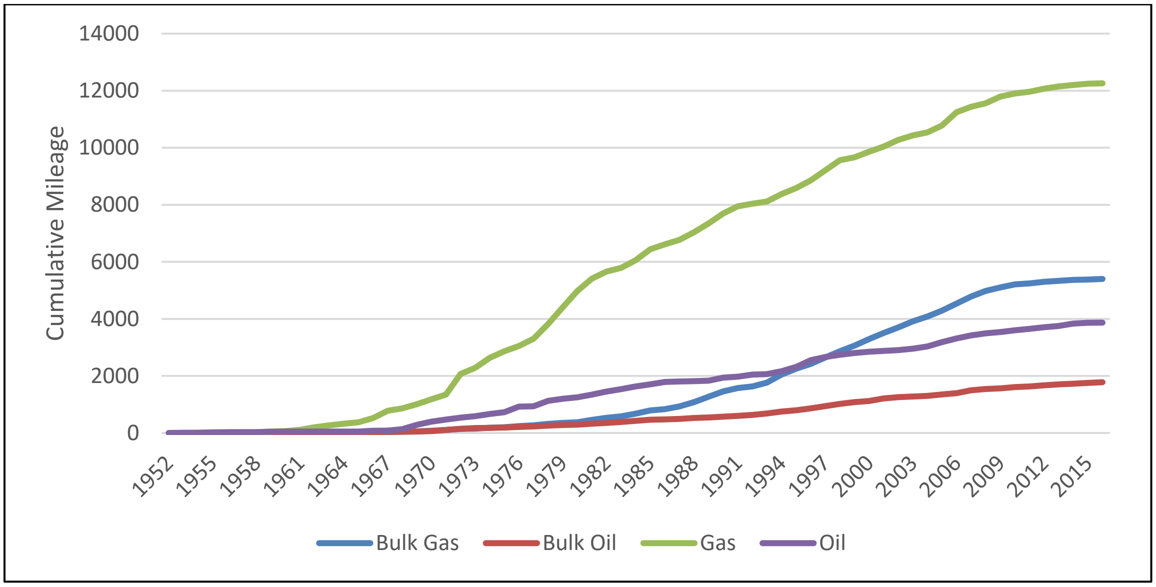



Figure O.2. Cumulative installed pipeline mileage by product group, shallow water.

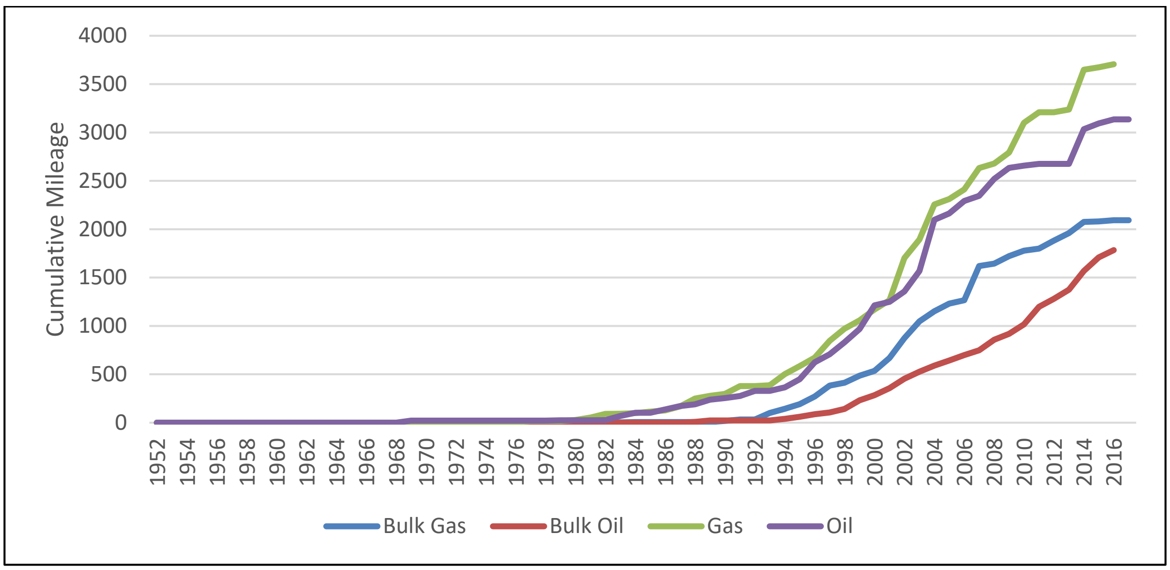



Figure O.3. Cumulative installed pipeline mileage by product group, deepwater.

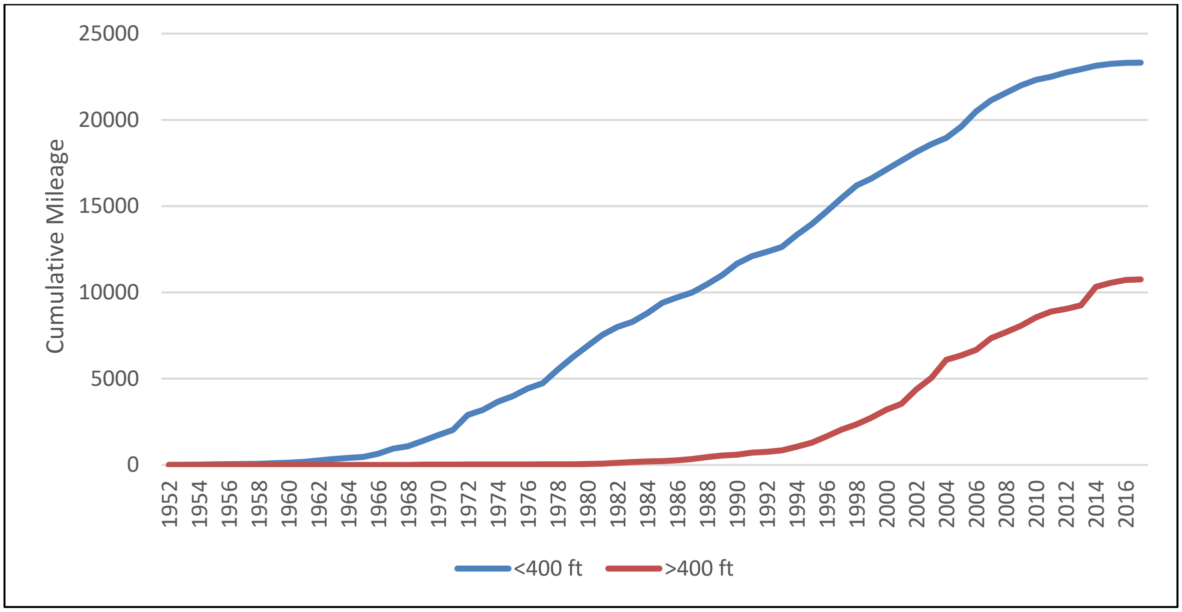



Figure O.4. Cumulative installed bulk and export pipeline mileage, shallow water and deepwater.

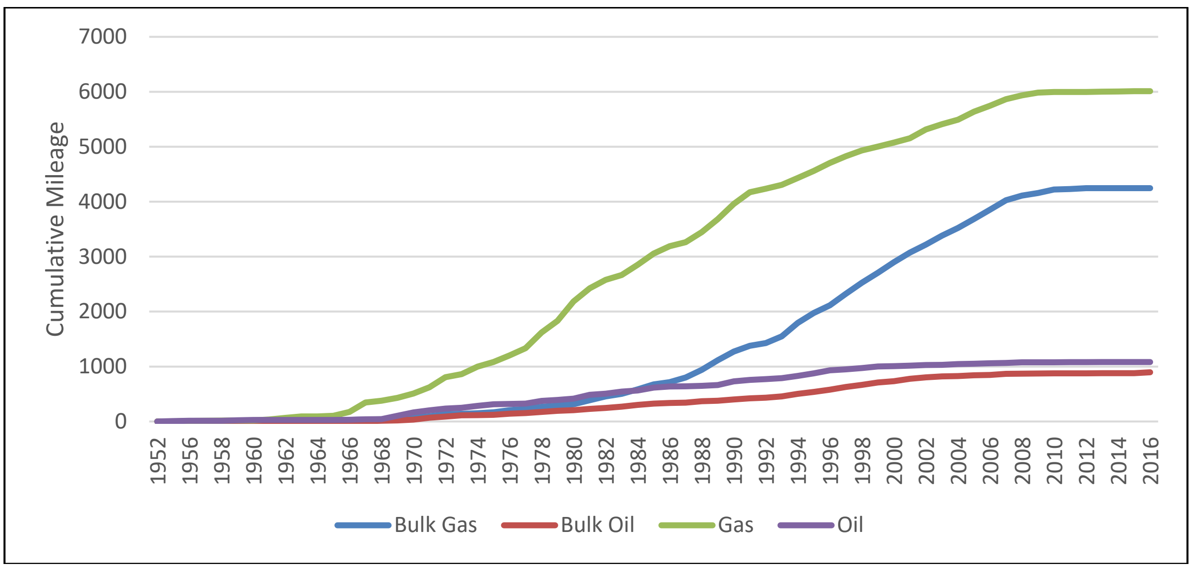



Figure O.5. Cumulative decommissioned pipelines by product group, shallow water.

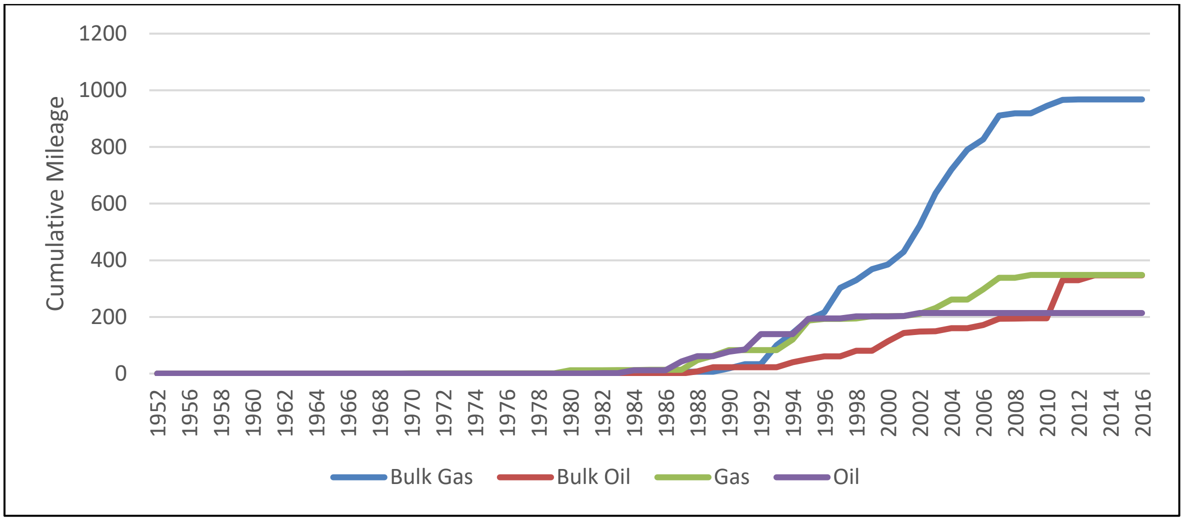



Figure O.6. Cumulative decommissioned pipelines by product group, deepwater.

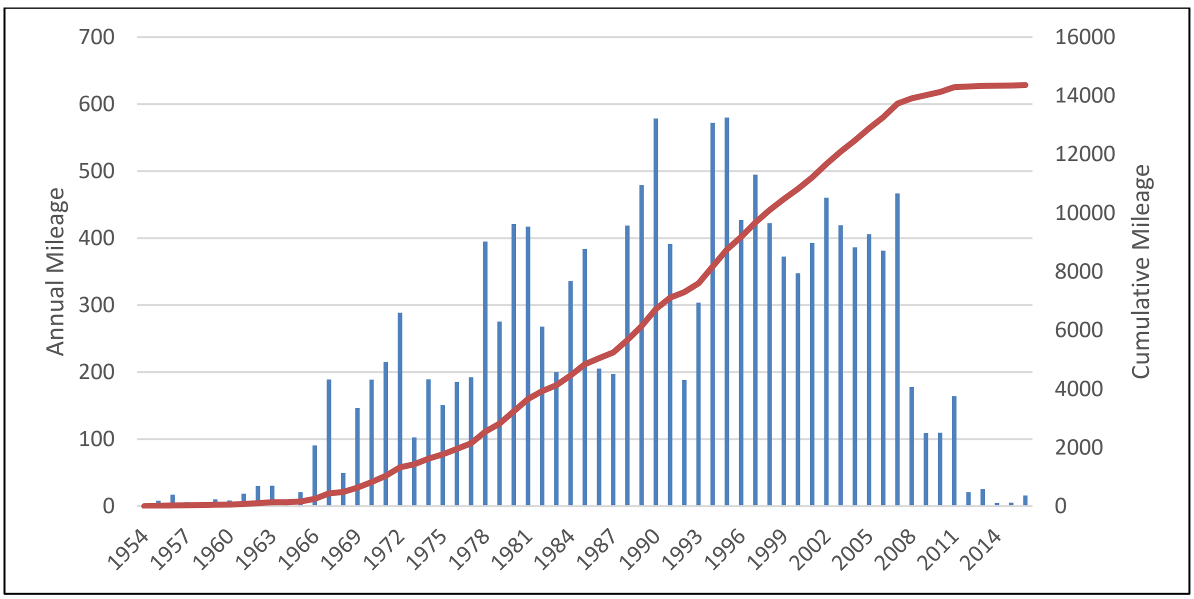



Figure O.7. Total decommissioned pipelines in the Gulf of Mexico.

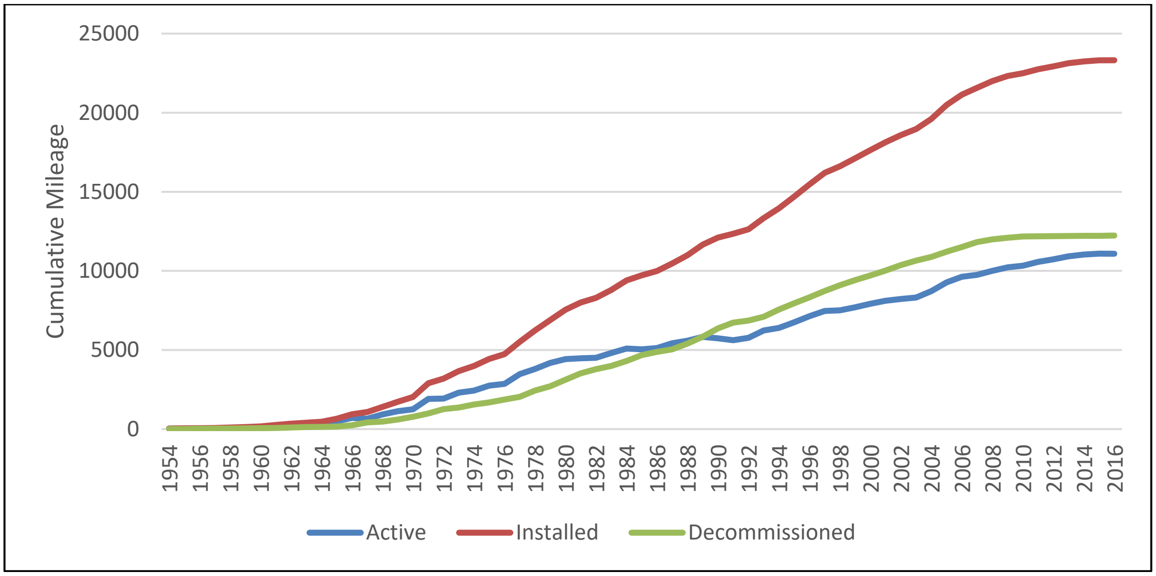



Figure O.8. Active bulk and export pipeline mileage, shallow water.

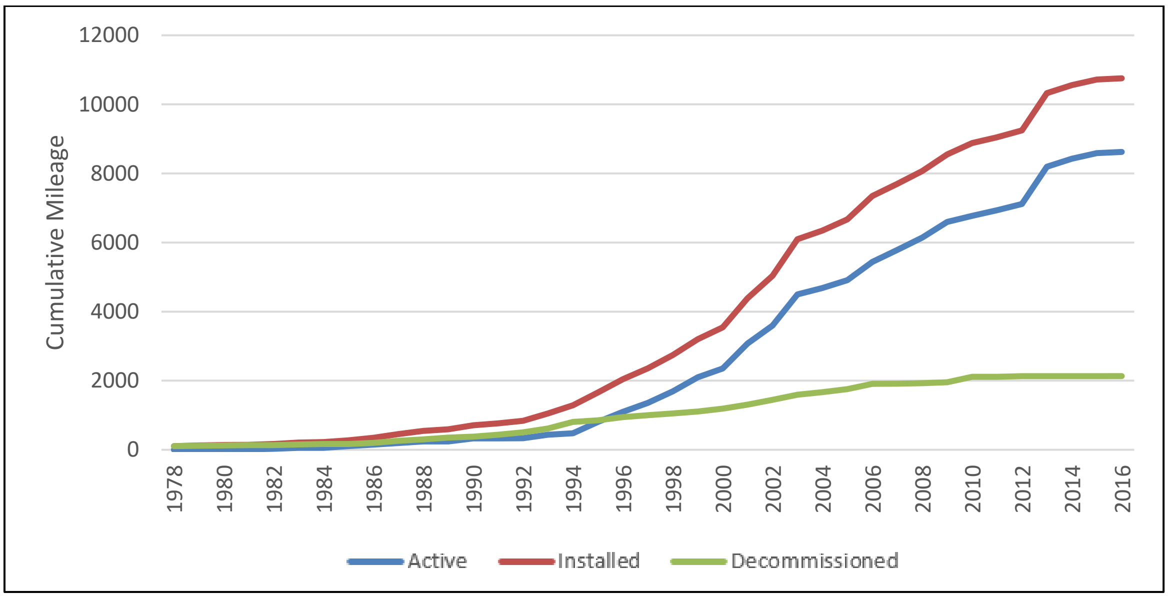



Figure O.9. Active bulk and export pipeline mileage, deepwater.

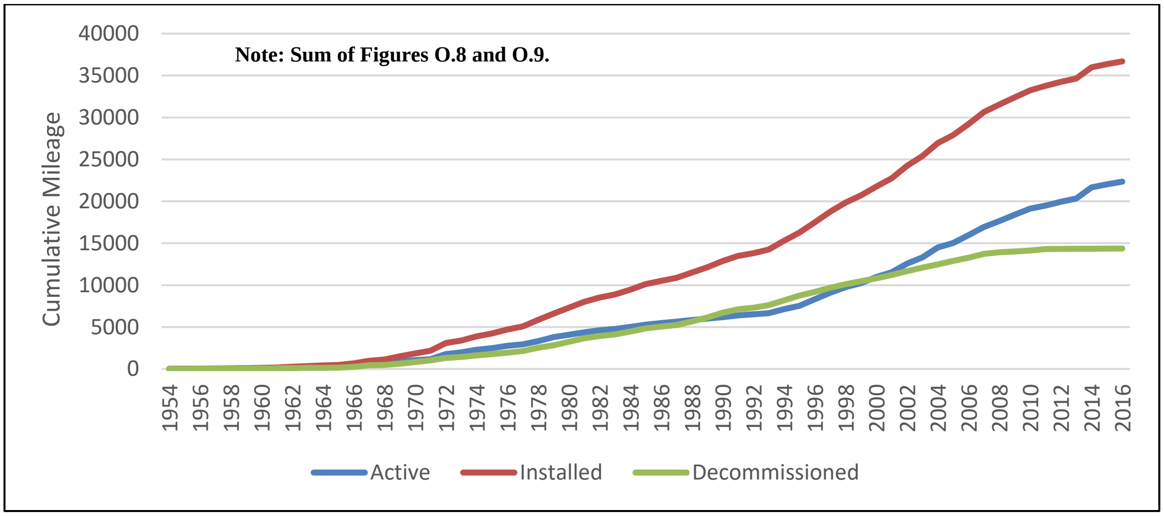



Figure O.10. Active bulk and export pipeline mileage, Gulf of Mexico.

# Appendix P: Chapter 16 Tables and Figures

**Table P.1. Relationship among pipelines, structures, and well types**

| Product Group | C/WP | Fixed platform | | | | Wet well | | DWS | |
|---|---|---|---|---|---|---|---|---|---|
| | | FP0 | FP1 | FP2 | FP3 | Remote | DVA | Dry Tree | Wet Tree |
| Bulk Oil | x | | x | | x | x | | | x |
| Bulk Gas | x | | x | | x | x | | | x |
| Oil | | | | x | x | | | x | x |
| Gas | | | | x | x | | | x | x |
| Service | x | | x | | x | x | x | | x |
| Umbilical | | | | | x | x | x | | x |

Note: Fixed platform subclasses include auxiliary platforms ($F_0$), minor platforms ($FP_1$), pipeline junctions ($FP_2$), and full processing platforms ($FP_3$). DWS denotes deepwater structure and DVA denotes direct vertical access wells.

**Table P.2. Structure classifications and associated pipeline requirements**

| Abbreviation | Type | Typical Pipelines |
|---|---|---|
| C/WP | Caisson/well protector | Bulk gas or bulk oil or both exit<br>Service line enter |
| $FP_0$ | Auxiliary | None |
| $FP_1$ | Fixed platform (minor) | Bulk gas or bulk oil or both exit<br>Service line enter |
| $FP_2$ | Fixed platform (pipeline junction) | Gas or oil or both enter and exit |
| $FP_{3a}$ | Fixed platform (major)<br>- Dry tree wells only | Bulk gas or bulk oil or both enter and exit<br>Gas or oil or both exit |
| $FP_{3b}$ | Fixed platform (major)<br>- Dry tree and wet wells | Bulk gas or bulk oil or both enter<br>Gas or oil or both exit<br>Service and umbilicals exit |
| DWS | Deepwater structure | Bulk gas or bulk oil or both enter<br>Gas or oil or both exit<br>Service and umbilicals exit |
| SS | Subsea (wet) well | Bulk gas or bulk oil or both exit<br>Service and umbilicals enter |
| M | Manifold | Bulk gas or bulk oil or both exit<br>Service and umbilicals enter |

Note: Corresponds to Figure P.1

**Table P.3. Pipeline installation factor relations–shallow water and deepwater**

| | Shallow water | | Deepwater | |
|---|---|---|---|---|
| **Output** | **Model** | **$R^2$** | **Model** | **$R^2$** |
| [BO + BG] | 2.8 C/WP + 71.5 | 0.66 | 2.4 SS + 20.3 | 0.64 |
| [O + G] | | | | |
| 1990–2016 | 3.0 FP + 114 | 0.42 | 54.8 DWS + 51.5 | 0.35 |
| 1990–2016, 5-yr TB | 2.3 FP + 160 | 0.40 | 61.1 DWS + 137 | 0.56 |
| 1995–2016, 5-yr TB | 2.9 FP + 140 | 0.53 | 80.1 DWS + 163 | 0.87 |

Note: TB = Time block

**Table P.4. Bulk pipeline two-factor model relations over different time periods**

| [BO + BG] = A + B · DWS + C · SS | | | | |
|---|---|---|---|---|
| **Time Period** | **A** | **B** | **C** | **$R^2$** |
| 1982–2016 | 19.1 (0.9) | 0.54 (0.1) | 2.4 (7.3) | 0.80 |
| 1988–2016 | 31.3 (1.2) | 0.21 (0.8) | 2.2 (5.5) | 0.73 |
| 1992–2016 | 43.2 (1.4) | 2.4 (0.4) | 1.9 (3.6) | 0.64 |
| 1997–2016 | 64.9 (1.4) | 3.7 (0.5) | 1.6 (2.0) | 0.50 |

Note: t-statistics denoted in parenthesis

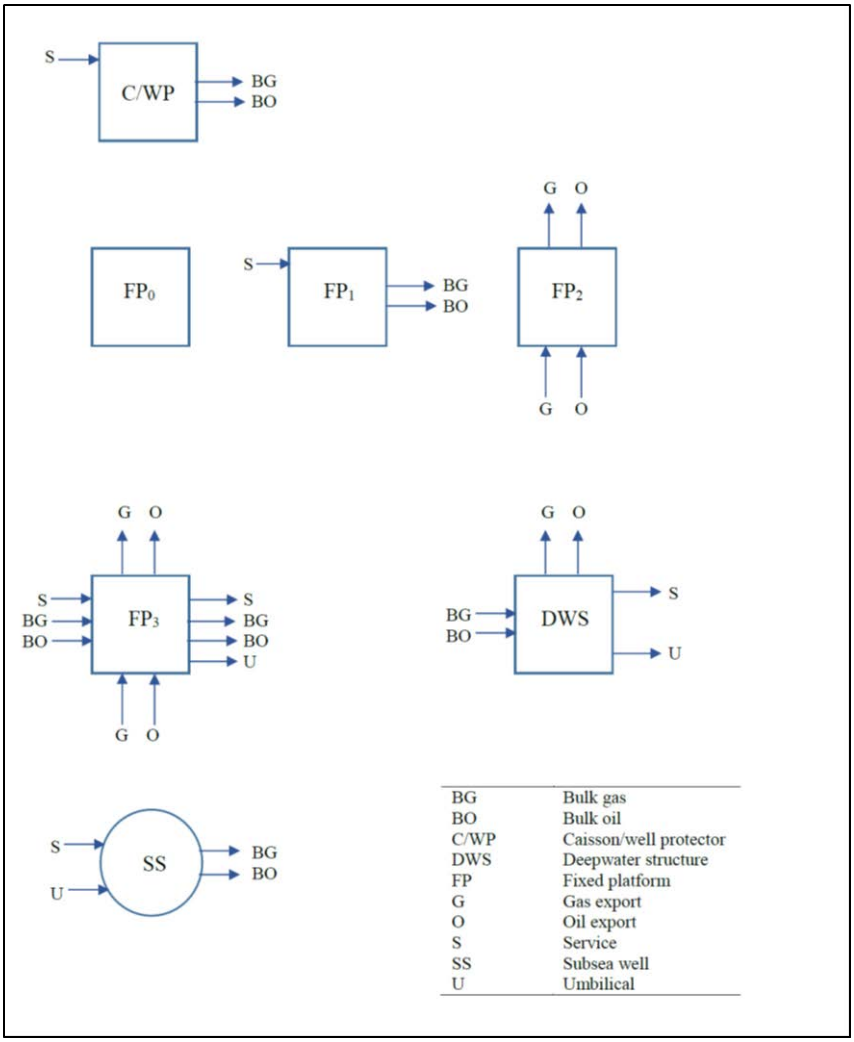



Figure P.1. Structure and subsea well configurations.

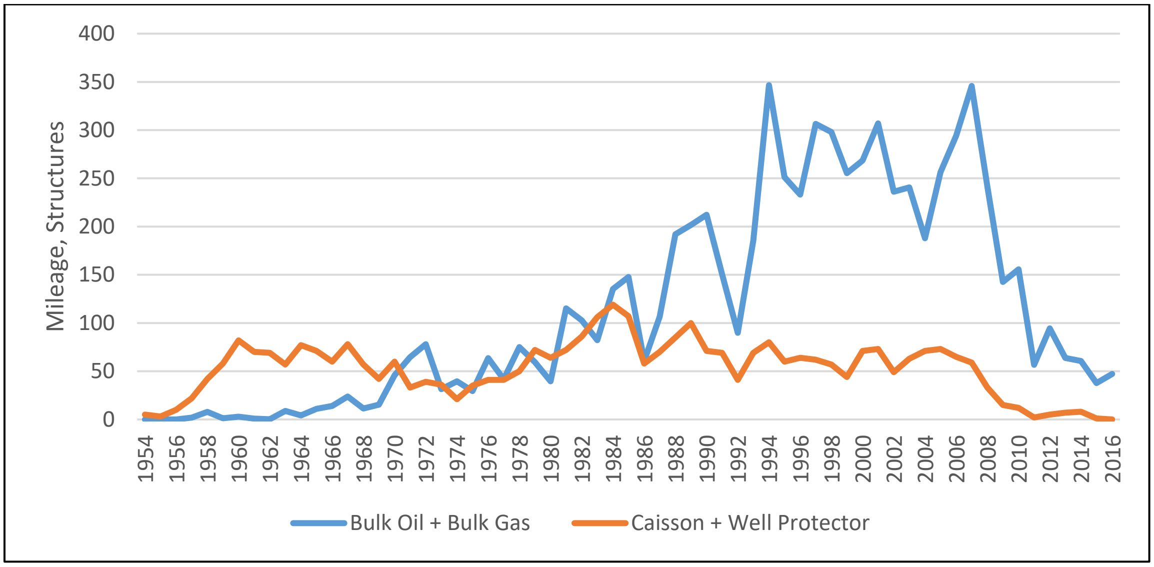



Figure P.2. Installed bulk pipelines, caissons and well protectors, shallow water, 1954–2016.

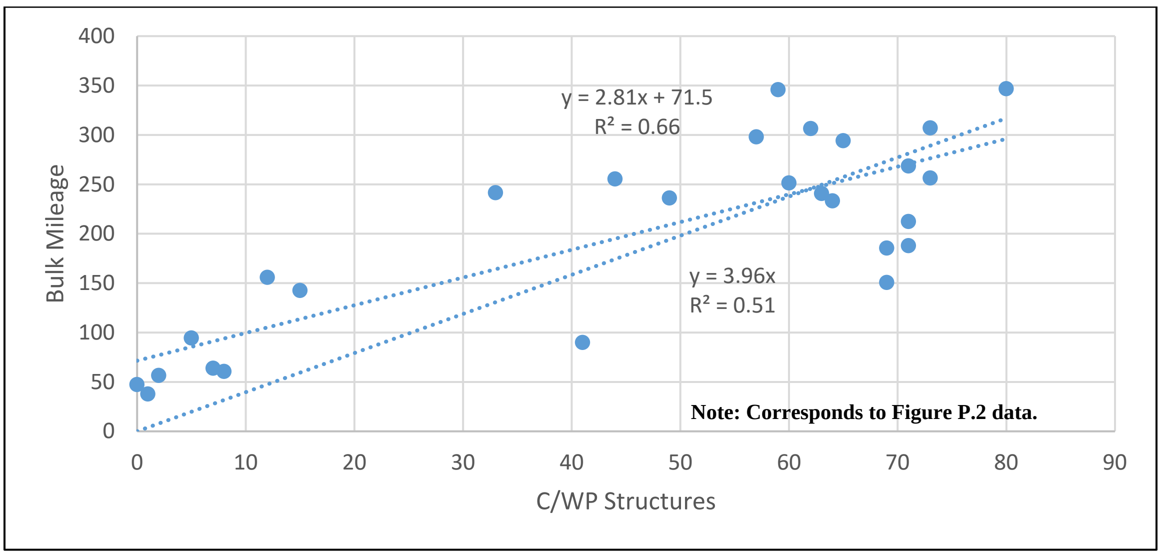



Figure P.3. Shallow water bulk pipeline mileage and installed caissons and well protectors, 1990–2016.

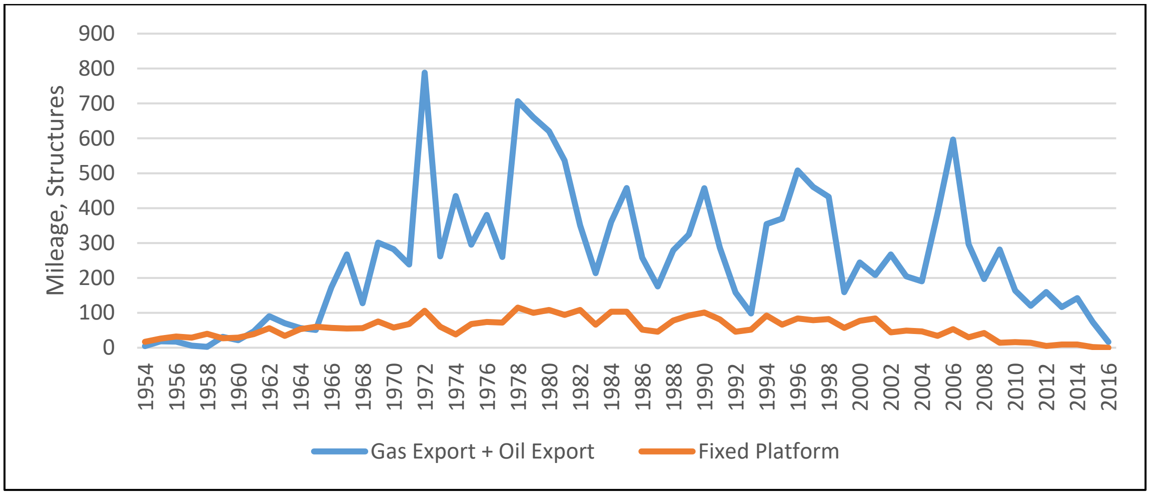



Figure P.4. Installed export pipelines and fixed platforms, shallow water, 1954–2016.

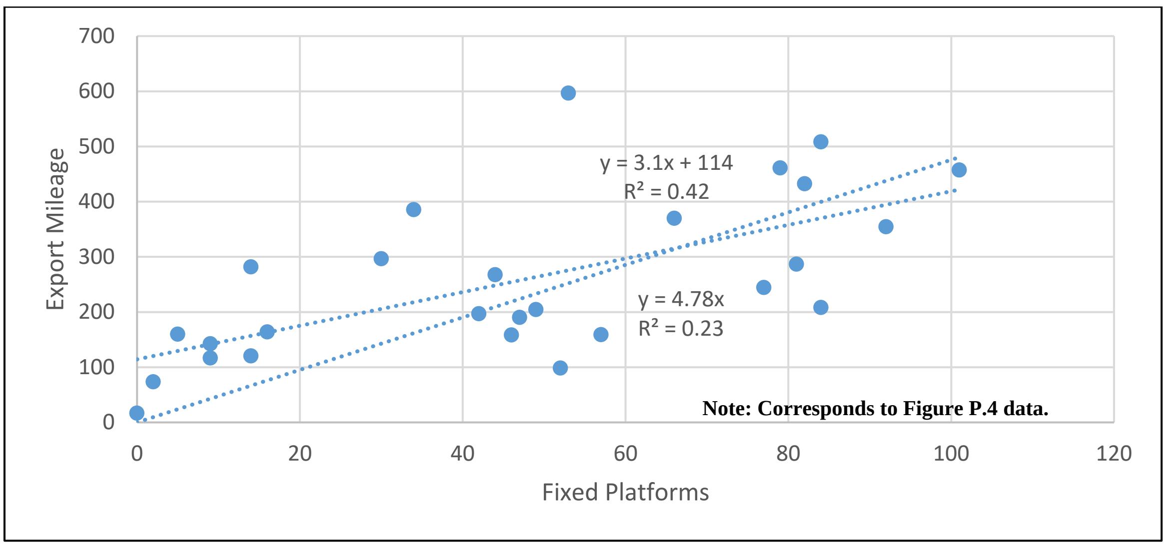



Figure P.5. Shallow water export mileage and installed fixed platforms, 1990–2016.

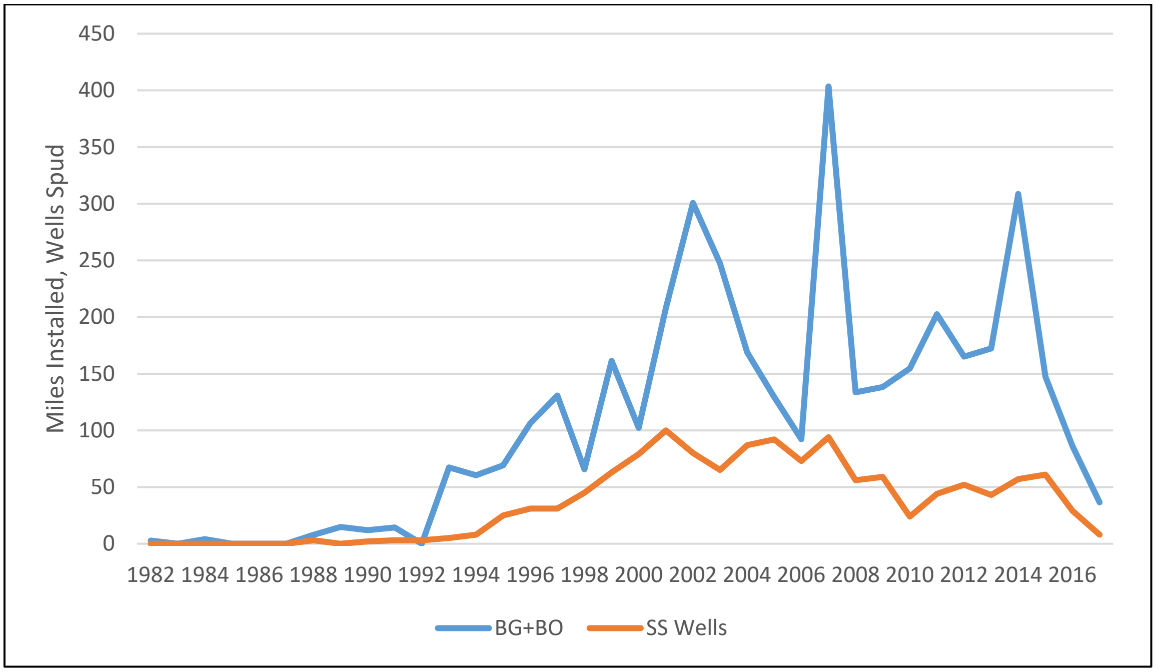



Figure P.6. Bulk flowline installed and subsea wells drilled, deepwater, 1982–2017.

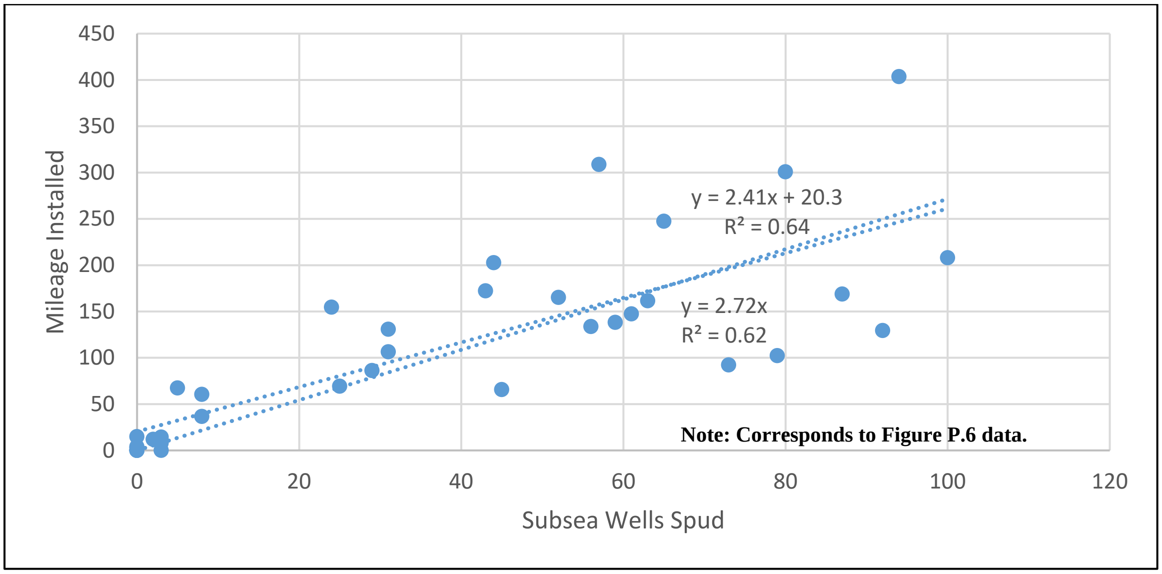



Figure P.7. Deepwater bulk flowline installed and subsea wells drilled, 1982–2017.

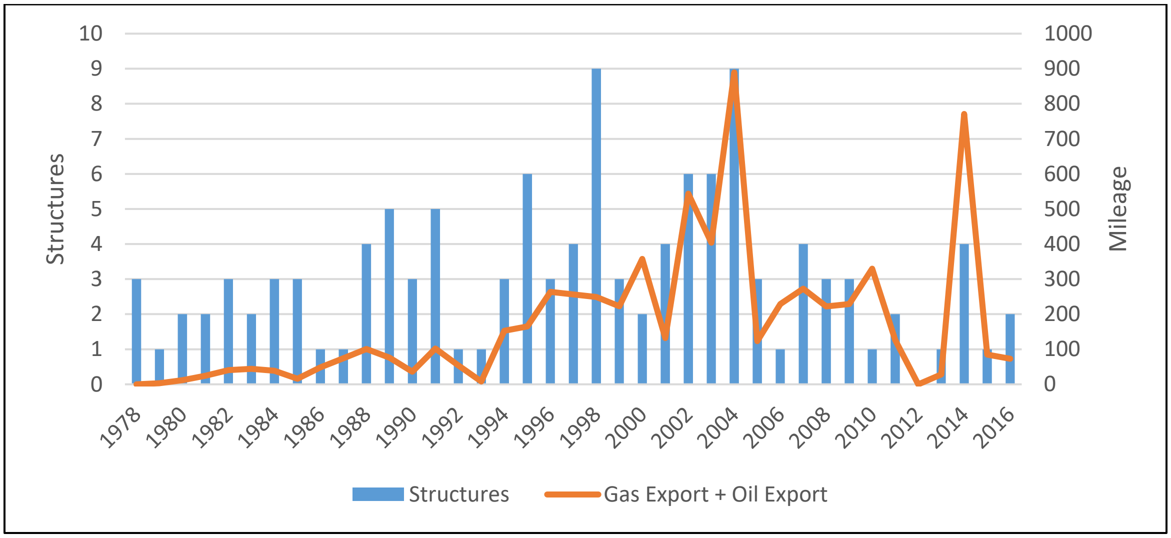



Figure P.8. Installed export pipelines and fixed platform and floater installations, deepwater, 1978–2016.

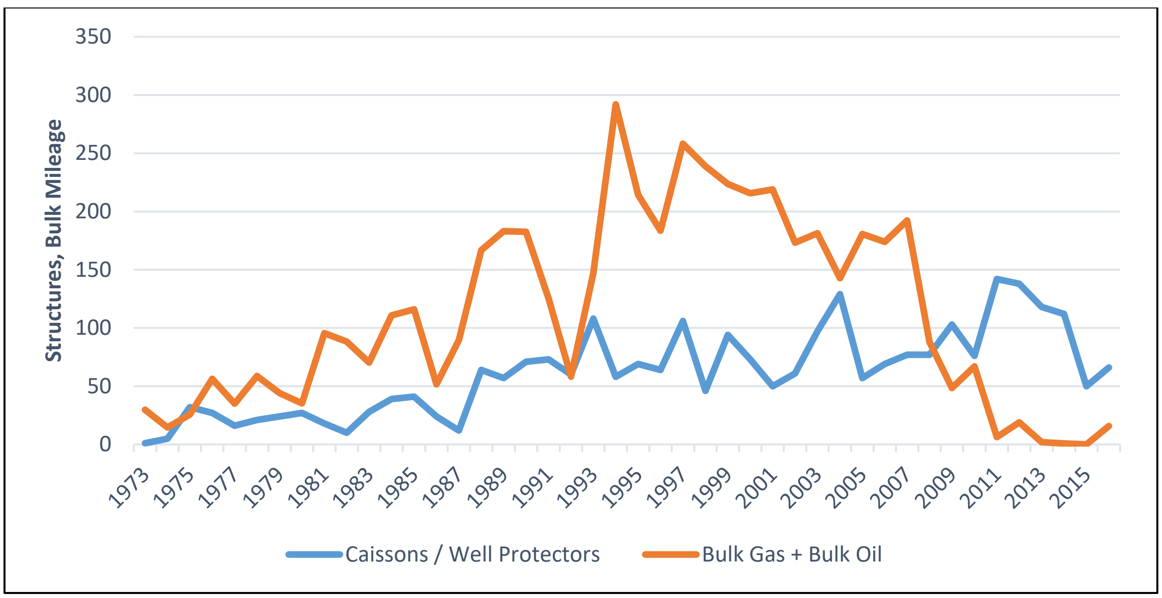



Figure P.9. Decommissioned bulk pipelines, caisson and well protector abandonments, shallow water, 1973–2016.

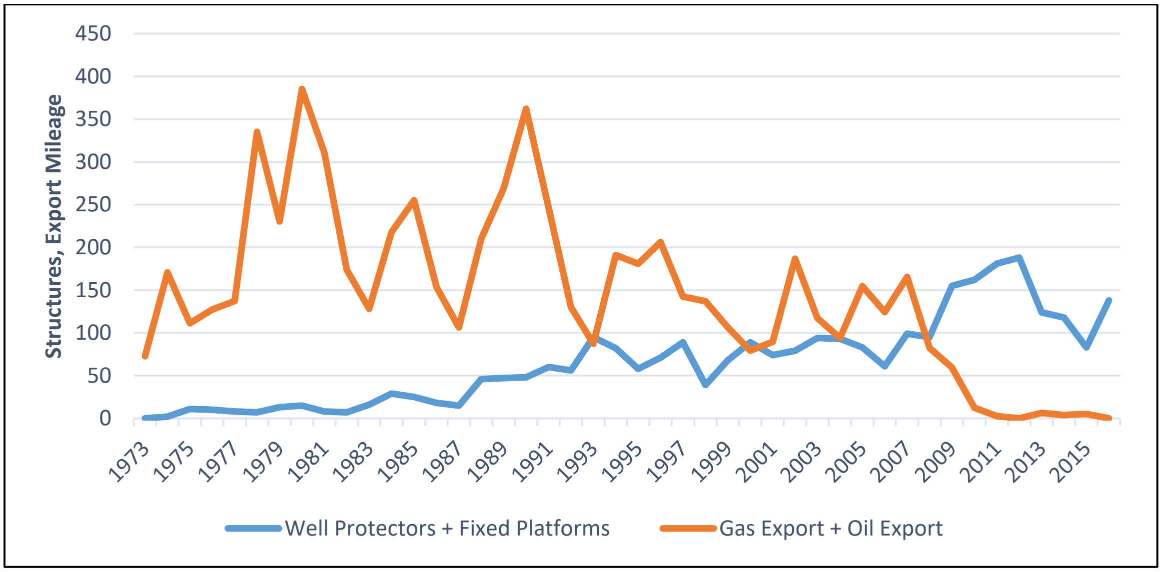



Figure P.10. Decommissioned export pipelines, fixed platforms and well protectors, shallow water, 1973–2016.

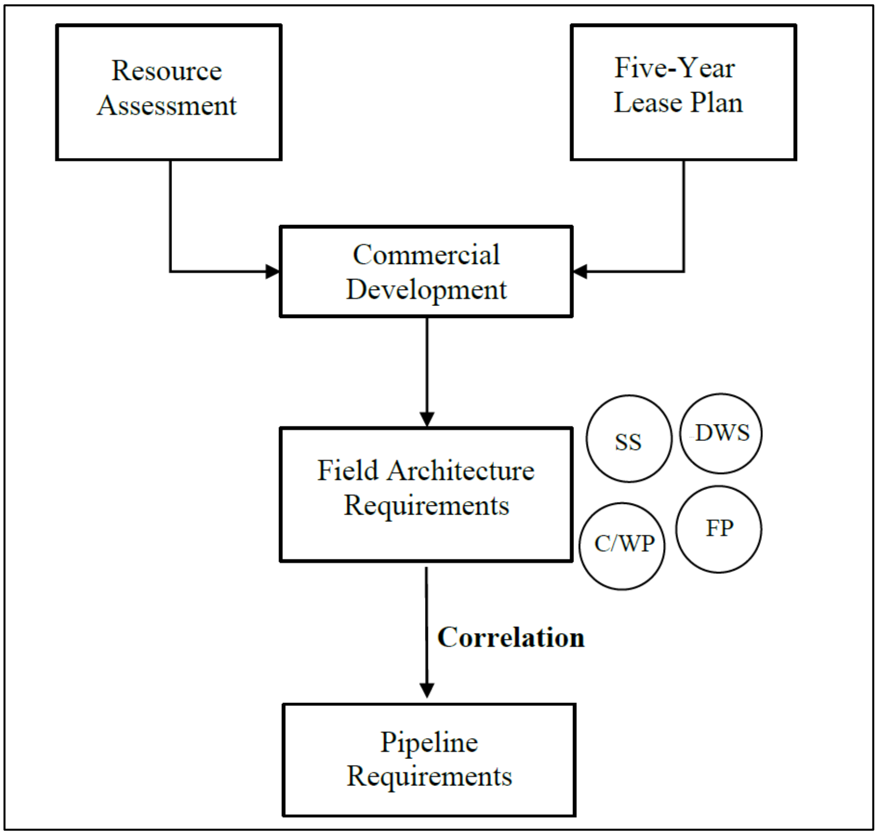



Figure P.11. Correlations are used with field architecture variables to assess pipeline requirements.

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