Lecture Notes in Energy 8

Mark J. Kaiser
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The Offshore Drilling Industry and Rig Construction in the Gulf of Mexico

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Preface

Wells are the only means to produce reserves, and the only way to create a well is to hire a rig and drill. The first offshore wells were drilled from wharfs off the California coast in 1898, and during the next half century, drilling moved into swamps, lakes, and coastal zones throughout the world. In 1947, the first well out of sight of land was drilled 9 miles off the coast of Louisiana. Today, about one-third of the world's 85 million barrels per day oil production is sourced offshore, and rig chartering is big business. Over the past decade, the contract drilling market spud about 39,000 offshore wells at a total estimated rig hire cost of $372 billion.

Jackups, semisubmersibles, and drillships are the marine vessels used to drill offshore wells and are referred to collectively as mobile offshore drilling units or MODUs. The fleet has grown and evolved over time into larger, more sophisticated rigs in response to operator's movement into deeper and more challenging environments. MODUs are supplied through newbuild construction primarily in Asian shipyards, and because rigs are long-lived assets, the legacy fleet contains a number of old rigs constructed in the U.S. and elsewhere. Offshore drilling is highly competitive, but the sector has consolidated over the past several decades through an active secondhand market.

The purpose of this monograph is to describe the structure of the offshore contract drilling market and the newbuild construction industry during the decade 2000–2010. We begin with background information on rig types and market organization in Chaps. 1 and 2. The rest of the monograph divides into two parts, covering the contract drilling market in Chaps. 3 through 8 and the newbuild market in Chaps. 9 through 15. In the newbuild market, our focus is on jackup construction in the United States.

Chapter 1 describes the types of rigs employed in the industry and their technical specifications. The fleet that exists today consists of both old and new technologies built to wide-ranging specifications. Contractors diversify by rig class and specification, and specialization plays an important role in determining dayrates and utilization. The activity states through which all rigs transition during their life cycle concludes the discussion.

In Chap. 2, the five markets that make up the MODU industry are described. Mobile offshore drilling units are owned and operated in the contract drilling market, constructed in the newbuild market, exchanged in the secondhand market, enhanced and maintained in the upgrade market, and end their life in the scrap market. For each market, the players, prices, size, and market values circa 2010–2011 are summarized. The newbuild and contract drilling markets are the largest and most transparent sectors of the industry.

Chapters 3 and 4 introduce the contract drilling industry and market structure. In Chap. 3, supply, utilization, and dayrates are summarized over the decade 2000–2010. A regional categorization of the market is employed with an emphasis on the largest competitive sectors. Dayrates are the mechanism by which contractors generate cash flow, and utilization reflects excess capacity in the market and provides signals to the industry on dayrate and investment trends. A summary of contracts used in the industry concludes the chapter.

In Chap. 4, we describe the ownership structure and specialization of drilling contractors and the degree of concentration in the market. A cash flow model of net asset value is introduced and compared to industry algorithms. In 2012, the contract drilling market was dominated by a small number of publicly traded firms, most notably Transocean, Seadrill, Noble, Ensco, and Diamond. Ensco, Noble, and Transocean are generalists with assets in all rig classes, both the high and low specification segments, across a broad range of geographic markets. We show that a company's degree of diversification is a good indicator of its business strategy. Markets appear competitive despite significant barriers to entry and consolidation trends over the past two decades.

In Chap. 5, the factors that impact MODU dayrates are quantified. A body of "common knowledge" has developed over the years, and the purpose of our evaluation is to review these expectations to support/refute selected claims. We show that oil prices explain a large proportion of the variation in the number of active rigs and average dayrates, while utilization is a weak predictor of dayrates. We find no evidence that large contractors are able to use their market power to capture higher dayrates than would be expected by the quality of their fleet. State-owned exploration and production companies, however, tend to pay higher dayrates than other oil companies, which suggests that ownership plays a role in investment decisions and negotiation strategies.

In Chap. 6, we describe newbuild strategies and develop conceptual models of firm stacking and newbuild decision-making to gain insight into the relationship between market drivers and investment criteria. A net present value model of newbuilding shows that relatively high combinations of dayrates and utilization are needed to justify investment. A simple stacking model is presented to show why operating a rig may be preferred over stacking even if operating expenses exceed the dayrate.

In Chap. 7, factors that impact contractor value, including fleet value and diversity, operating margin, financial structure, and business strategies are discussed. In Chap. 8, models of market valuation are developed for a cross-section of publicly owned drilling contractors. Fleet value is the single best predictor of market capitalization and enterprise value.

The second part of the monograph examines the newbuild market and begins in Chap. 9 with a historical overview of construction trends. Through the mid-1980s, the U.S. was the dominant player in newbuild construction, but comparative advantages change as technologies and experience evolve and governments support labor intensive industries. Today, U.S. yards represent a small fraction of the global market and the majority of rig construction is concentrated in Asia. In the U.S., only two shipyards build jackups – the LeTourneau shipyard in Vicksburg, Mississippi, and the Keppel AmFELS shipyard in Brownsville, Texas. The LeTourneau shipyard was sold twice in 2011 and, barring any major change, is unlikely to deliver future rigs.

In Chaps. 10 and 11, the technical aspects of jackup design and construction are presented. Chapter 10 describes the designs used in jackup construction and the trade-offs that arise between technical and economic factors. The most frequently built jackup designs are highlighted. Chapter 11 describes the workflows and stages of construction in U.S. shipyards.

In Chaps. 12 and 13, the factors that influence construction and replacement costs are discussed and cost functions of jackups, semisubmersibles, and drillships are derived. Many factors impact newbuild and replacement costs, including market conditions, design type and class, shipyard, rig specifications, and time of construction. Cost functions combine these variables to identify the relative importance of individual factors when evaluating newbuild programs and the value and insurance liability of fleets. Water depth is shown to be the single best predictor of rig cost.

In Chap. 14, an algorithm of jackup lightship displacement is presented. The weight of a rig is an important variable in cost estimation and in determining the amount of steel required in construction. In the marine construction industry, lightship displacements are widely reported, but in jackup construction, information on the weight of the unit is protected because weights are an indicator of the strength of a rig's legs which is an important distinguishing feature among designs. Using primary and secondary data, a regression model of jackup lightship displacement is derived.

Chapter 15 concludes the monograph with an analysis of the labor and market requirements of jackup rig construction in the United States. Rig deliveries in the U.S. peaked in 2008 at $1 billion and averaged $700 million annually from 1997 to 2011. We show that labor and drilling equipment are the largest cost components of rig construction and account for over half of the total cost of a rig. Future newbuild activity in the U.S. is contingent on regional demand and is expected to remain depressed.

Baton Rouge, Louisiana
July 10, 2013

Mark J. Kaiser

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Contents

Chapter 1
Mobile Offshore Drilling Units

Abstract Mobile offshore drilling units are ocean-going vessels used to drill, complete and workover wellbores in marine environments. The fleet has grown and evolved over time into larger more sophisticated rigs in response to operator's movement into deeper water and more challenging environments. The fleet that exists today includes both old and new technologies built to wide ranging specifications. The purpose of this introductory chapter is to describe rig classifications and their technical specifications. We conclude with a description of the activity states through which a rig transitions over its lifecycle.

1.1 Rig Function

1.1.1 Drilling

The primary function of a mobile offshore drilling unit (MODU or rig) is to drill a well in the earth. During drilling, the MODU's topdrive turns a steel pipe (the drillstring) which is connected to the drillbit. Drilling fluids are circulated down the well to regulate the pressure inside the wellbore, prevent formation fluids from entering the well, and transport the drill cuttings to the surface for disposal. Periodically, drilling is suspended to case the borehole with steel pipe (Fig. 1.1). Casing forms a barrier between drilling operations and the formation and is used to stabilize the borehole and minimize the loss of drilling fluids [15].

1.1.2 Well Type

Wells are drilled for exploration, appraisal or production. Exploration wells are used to find and confirm the presence of hydrocarbons, appraisal wells delineate and define the boundaries of the reservoir, and development wells are used for production.

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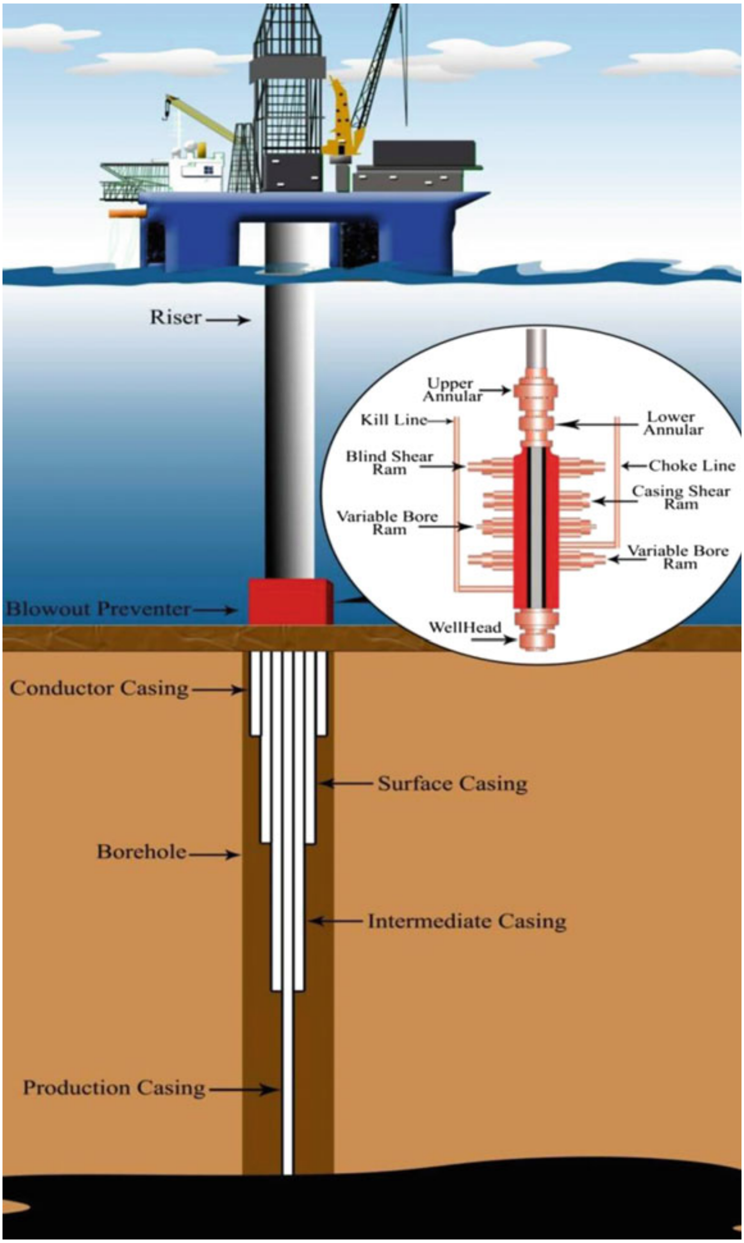


Fig. 1.1 Offshore well casing program (Source: BOEM)

Development drilling differs from exploration and appraisal drilling in that data acquisition is no longer the primary function of the well, and instead the objective is to drill targets as efficiently as possible. MODUs are used for all well types but are the only economic option for exploration and appraisal drilling. Development wells may be drilled from MODUs or a platform rig. The time to drill in both cases are about the same, but the cost of a MODU well is significantly higher than a platform well. In deepwater, the top portions of wells are often drilled ("top holes") from a MODU, and after infrastructure is installed, the remaining portion is drilled and completed from a platform rig to minimize construction cost.

1.1.3 Completions and Workovers

During completion, production casing is set across the reservoir interval and the blowout preventer is removed and replaced with a dry tree or subsea wellhead. Production tubing is suspended from the wellhead and a packer is used to isolate the annulus. The production casing is perforated to make contact with the reservoir, and the well is often gravel packed or frac packed [18]. Development wells are completed immediately if successful, while for exploratory wells, the well may be held in suspension and completed later or plugged and abandoned if not useful in field development. MODU's and platform rigs also perform workovers to repair or stimulate a well to restore, enhance, or prolong production. Replacement of production tubing, well cleanout and stimulation treatment are examples of workovers.

1.1.4 Well Configuration

Wells may be drilled vertical, directional or horizontal. Branches spurred off from the original wellbore called sidetracks are often drilled to target different areas of a reservoir. Exploration wells are almost always drilled vertically with the target directly below the rig. Most developmental wells are drilled directionally because several wells targeting different zones and traps are drilled from a central location, or the target lies under salt or an environmentally sensitive area. Long horizontal sections may be required to tap thin beds far from the rig or heavy oils that require greater contact with the reservoir. The distance along the wellbore is referred to as measured or total depth while true vertical depth is measured from the surface straight down to the target.

1.1.5 Pressure and Temperature

Temperature and pressure increase with depth. The temperature gradient averages 2 °F/100 ft and varies between 0.5 and 5 °F/100 ft worldwide. The pressure on the rock is called geostatic or lithostatic pressure and increases at an average rate of 100 psi/100 ft. The pressure on the fluids in the pores of the rock is reservoir or fluid pressure, and depends on the density of the overlying water; average fluid pressure worldwide is 45 psi/100 ft [9].

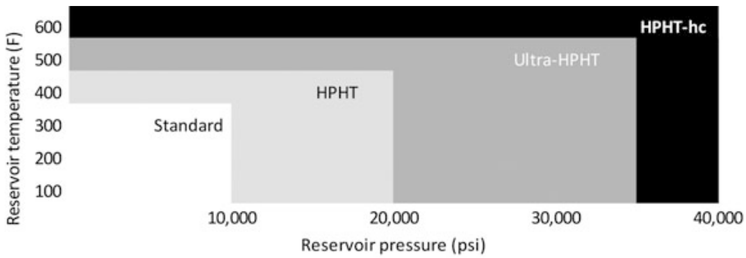


Fig. 1.2 High pressure-high temperature reservoir classification (Source: De Brunijn et al. [4])

High pressures and temperatures (above 300 °F and 0.8 psi/ft) are common in deep (>10,000 ft) and ultradeep (>25,000 ft) wells [13]. High pressure-high temperature (HPHT), ultra-HPHT and HPHT-hc[1] categories (Fig. 1.2) are based on technological thresholds associated with the elastomeric seals and electronic equipment used in downhole tools. HPHT wells stress many rig components and are more difficult to control relative to normal wells. Equipment and systems must be certified to operate at elevated temperatures and pressures. Upgraded equipment includes blowout preventers (BOPs) rated at 10,000–15,000 psi, enhanced mud systems including mud cooling, glycol injection units, high pressure choke and kill lines, pressure and temperature sensors, and high pressure risers [3].

1.2 Rig Classification

Rigs are classified according to type (bottom supported, floating), environmental capacity (harsh, moderate), water depth, and specification (standard, premium).

1.2.1 Rig Type

MODUs are classified as bottom-supported or floating rigs (Fig. 1.3). In bottom-supported units, the rig is in contact with the seafloor during drilling, while a floating rig floats over the site while it drills, held in position by anchors or equipped with thrusters using dynamic positioning. Bottom supported units are used for shallow-water drilling and include barges, submersibles and jackups (Fig. 1.4). Floaters are used for deepwater drilling and include semisubmersibles and drillships (Fig. 1.5). Jackups, drillships and semisubmersibles comprise the majority of the offshore fleet.

[1] Hors categorie or beyond categorization.

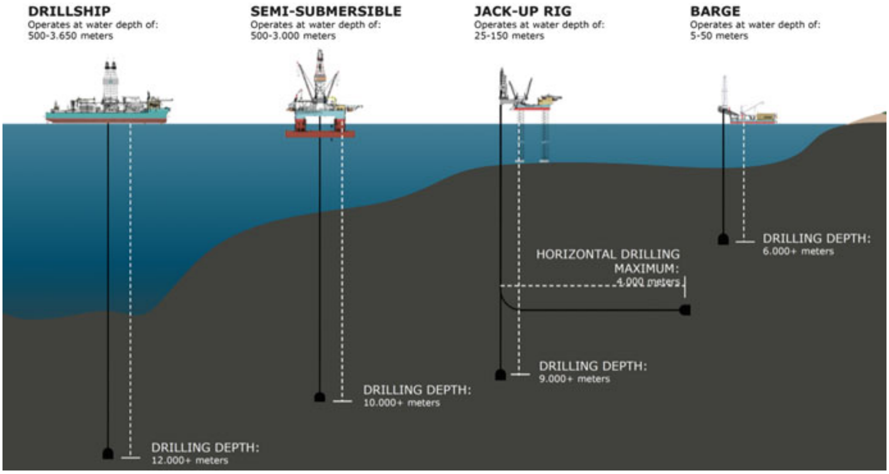


Fig. 1.3 Bottom supported versus floating rigs (Source: Maersk)

Bottom-Supported. A drilling barge is composed of a superstructure installed on a submersible hull. Once on location, the hull is flooded and sinks to the bottom while the superstructure remains above the surface. In "posted" barges, the superstructure and hull are connected by columns, increasing the water depth capability of the barge. Drilling barges are limited to approximately 30 ft water depths and are only used for inland areas such as Lake Maracaibo or the Mississippi River delta.

A jackup is composed of a triangular box-type hull and three legs. Once in position, the legs are lowered to the seabed, hoisting the hull out of the water, and creating a stable platform for drilling. Jackups are the most commonly used offshore rig in the world and are capable of drilling in water depths up to 500 ft.

Floaters. Floaters operate in 500–10,000 ft water depth and are usually self-propelled. Motion compensation systems are an essential element of all floating rigs to ensure that drilling can be performed during the vertical heaves arising from ocean waves.

The semisubmersible (semi or semisub) consists of an elevated deck supported by several large columns connected to submerged pontoons. By varying the amount of ballast, the unit can be raised or lowered. The lower the pontoons lie beneath the surface, the less the rig is affected by wave and current action. Semis may be held on location by mooring spreads or dynamic positioning.

A drillship is a self-propelled ship-shaped vessel. The rig derrick is mounted in the middle of the vessel and drilling is conducted through a large aperture known as a "moon pool." Drillships are more mobile than semisubmersibles, typically dynamically positioned, and can operate for long periods without resupply. Drillships are the most advanced and expensive sector of the rig market.

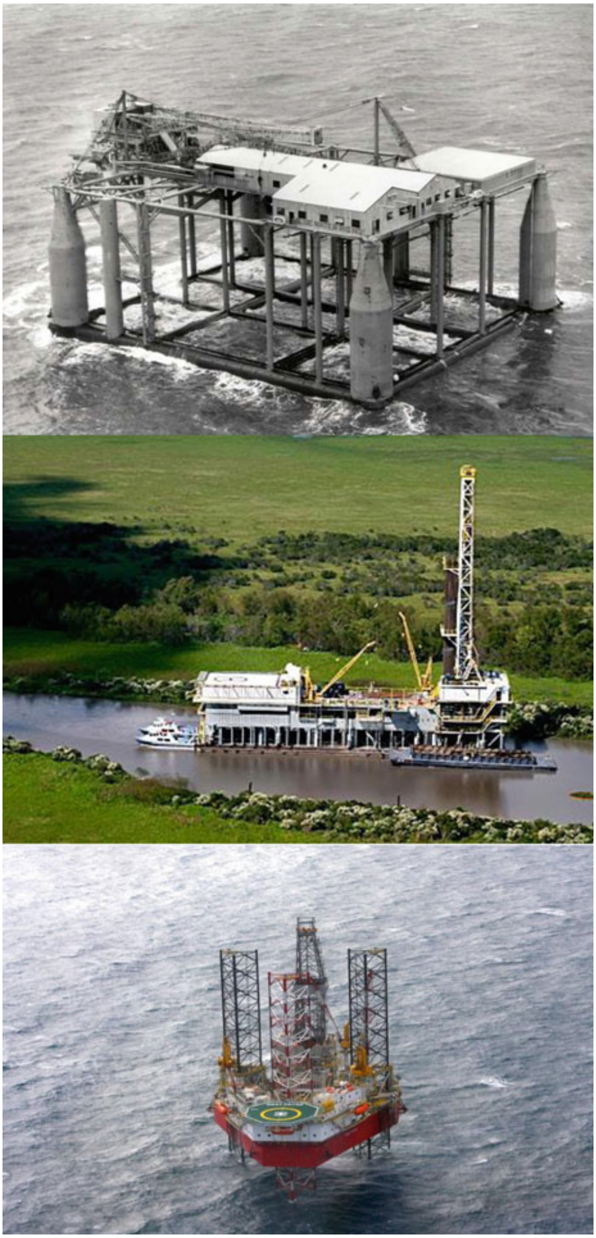


Fig. 1.4 An old submersible, a drilling barge, and a cantilevered jackup drilling rig (Sources: GNU License, Seadrill, DOE)

Fig. 1.5 The *West Aquarius* semisubmersible and the *West Polaris* drillship (Source: Seadrill)

1.2.2 Environmental Capacity

Rigs are classified as harsh or moderate environment units. Harsh environments are characterized by frequent and severe storms as occur during winter in the Northern Hemisphere (North Sea, Norwegian Sea, North Pacific, Eastern Canada). In the Gulf of Mexico and much of Asia, moderate environmental conditions predominate for most of the year, but tropical storms may cause severe weather events. In Brazil, Australia, West Africa and the Persian Gulf, severe weather is rare.

In order to work efficiently in a region, a rig must be capable of operating during average 1 year storm conditions and surviving 100 year storm conditions [6]. Due to tropical storms, the 100 year storm conditions in the North Sea are similar to conditions in the Gulf of Mexico and Asia; however, 1 year storm conditions are far more severe in the North Sea (Table 1.1). As a result, harsh and moderate environment rigs differ in maximum operating conditions but do not differ in maximum survival conditions.

Harsh environment units have a number of design modifications to decrease weather related downtime, including increased variable load to reduce the need for resupply, increased airgap to increase wave clearance, and changes in the geometry and spacing of the legs and columns to decrease wind and wave loads. Harsh environment rigs are larger, heavier and more expensive to construct and operate than moderate units (Fig. 1.6).

Table 1.1 Environmental criteria used in rig design

	North Atlantic	Gulf of Mexico	Asia/Pacific
100 year			
Wave height (ft)	46–52	52	18–45
Wind velocity (kn)	66–79	93	45–109
Surface current (kn)	1.1–2.9	3.5	3.7–3.9
1 year			
Wave height (ft)	42	13	16–20
Wind velocity (kn)	57	30	33
Surface current (kn)	1.7	0.8	3.5

Source: DNV [5]

Fig. 1.6 The harsh environment *Bob Palmer* and a moderate environment unit (Source: Sharples [16])

1.2.3 Water Depth

Rigs are defined in terms of their maximum water depth capability and are classified into water depth classes. Jackups are usually delineated into <250, 250–350 and >350 ft water depth categories, but other depth categories are sometimes employed. Floaters are typically divided into midwater (3,000–4,500 ft), deep (<7,500 ft) and ultradeep (>7,500 ft) categories. Water depth capabilities are frequently related to rig specifications and age.

1.2.4 Specification

High-spec premium rigs typically have more powerful mud pumps, a higher hook load and a greater variable load than standard rigs. Generally speaking, a rig is considered high-spec if it can drill in deeper water than other rigs of its class,

Table 1.2 Standard and high-spec jackup comparison – *Rowan Juneau* versus *Rowan EXL III*

	Rowan Juneau	*Rowan EXL III*
Water depth (ft)	210	350
Drill depth (ft)	25,000	35,000
Year built	1977	2010
Mud pumps (number × hp)	2 × 1,600	3 × 2,200
Hook load (million lbs)	1.25	2
Variable load (million lbs)	5.5	6.5
Construction cost[a] (million $)	76	175
Replacement cost[b] (million $)	146	210
Dayrate[b] ($1,000/day)	Stacked	140–150

Source: Rowan specification sheets; Jefferies and Company, Inc. [10]
[a]Adjusted to 2010 dollars
[b]Replacement cost and dayrate circa Jan 2012

operate in harsh environments or drill HPHT wells. Rowan defines a high-spec jackup as any rig with a hook load greater than two million pounds. In most cases, a jackup capable of drilling in >350 ft would be high-spec, while a jackup limited to <300 ft would be considered standard. Floaters are usually classified by water depth categories rather than specification, but the typical demarcation for high-spec units occurs at approximately 5,000 ft.

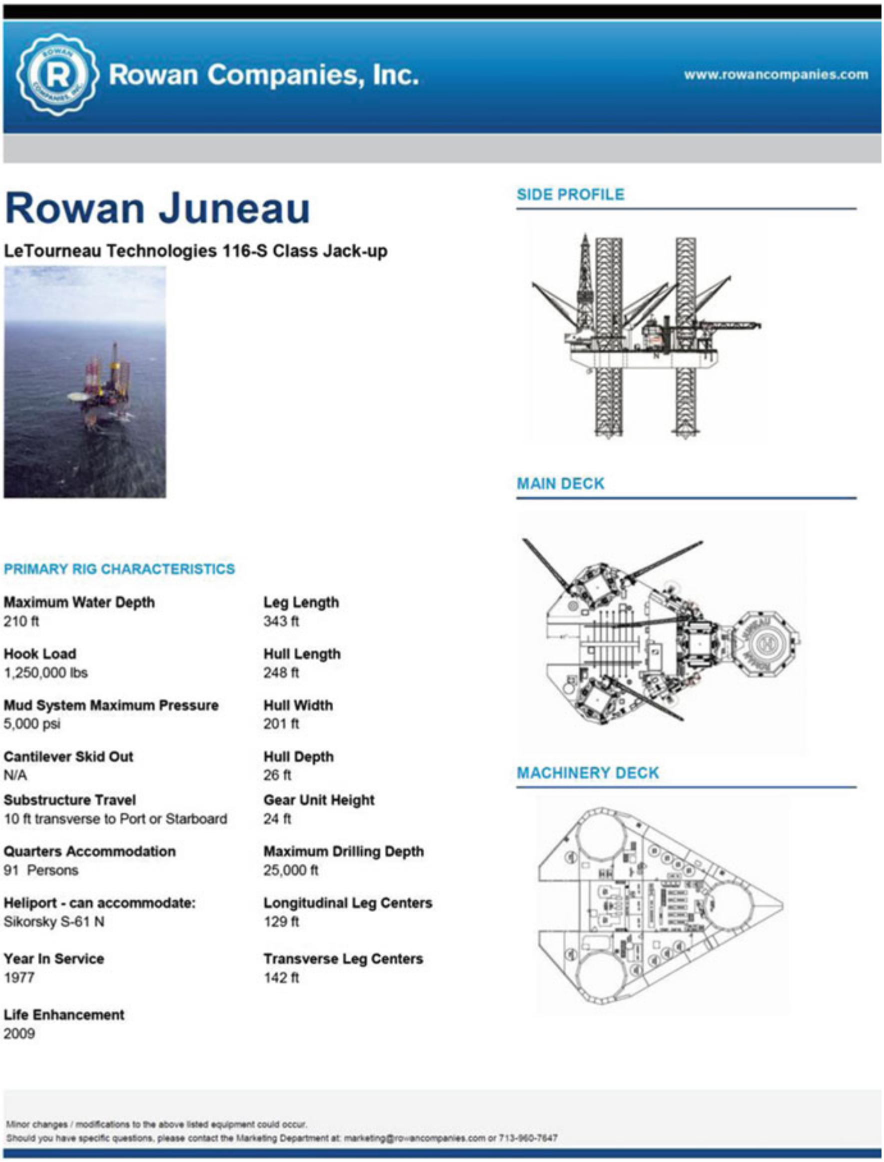
1.2.5 Standard Versus High-Spec

High-spec rigs are more capable than standard rigs and cost more to construct and operate, and as one would expect, high-spec rigs command premium pricing relative to standard units. In Table 1.2, a standard jackup (*Rowan Juneau*) is contrasted with a high-spec (*Rowan EXL III*) unit. The *Rowan Juneau* is rated at 210 ft water depth and can drill wells up to 25,000 ft deep (Fig. 1.7). The *Rowan EXL III* has longer legs, greater storage capacities, more advanced drilling equipment, a more powerful mud system, and a larger BOP stack than the standard rig (Fig. 1.8). The high spec unit cost more to construct and operate, but can drill deeper, more complex wells in 350 ft water depth.

1.3 Jackups

1.3.1 Design Elements

Jackups are composed of a triangular box-type hull supported by three or more legs. The hull contains all of the equipment required to operate the rig and provides displacement in the afloat condition. Hull dimensions typically range from 20 to 30 ft deep, 200 to 300 ft long, and 200 to 300 ft wide. Larger hulls identify harsh environment units and increase stability while elevated, allowing for larger drilling equipment, accommodations and storage.


Rowan Companies, Inc.
www.rowancompanies.com

Rowan Juneau

LeTourneau Technologies 116-S Class Jack-up

SIDE PROFILE

MAIN DECK

MACHINERY DECK

PRIMARY RIG CHARACTERISTICS

Maximum Water Depth 210 ft	**Leg Length** 343 ft
Hook Load 1,250,000 lbs	**Hull Length** 248 ft
Mud System Maximum Pressure 5,000 psi	**Hull Width** 201 ft
Cantilever Skid Out N/A	**Hull Depth** 26 ft
Substructure Travel 10 ft transverse to Port or Starboard	**Gear Unit Height** 24 ft
Quarters Accommodation 91 Persons	**Maximum Drilling Depth** 25,000 ft
Heliport - can accommodate: Sikorsky S-61 N	**Longitudinal Leg Centers** 129 ft
Year In Service 1977	**Transverse Leg Centers** 142 ft
Life Enhancement 2009	

Minor changes / modifications to the above listed equipment could occur.
Should you have specific questions, please contact the Marketing Department at: marketing@rowancompanies.com or 713-960-7647

Fig. 1.7 Specification sheet of the *Rowan Juneau* (Source: Rowan)

Legs support the weight of the jackup and provide lateral stability when elevated, and are composed of three or four vertical chords connected by a lattice-work of tubular braces. Chord design and number varies with the rig architect. Legs are raised and lowered by rack and pinion jacking systems. The pinions are

Rowan Juneau www.rowancompanies.com

CAPACITIES

Maximum Drilling Payload	5,538,000 lbs
Hook Load	1,250,000 lbs
Rotary Load	1,000,000 lbs
Setback load	450,000 lbs
Liquid Mud	1,465 bbls
Sand Traps	165 bbls
Pipe Storage (main)	2000 sqft x 7 ft high
Pipe Storage (cantilever)	N/A
Covered Sack Storage	1,500 sq ft
Bulk Cement	5,440 cu ft
Bulk Barite	5,440 cu ft
Potable Water	1,127 bbls
Drill Water	6,676 bbls (incl. combo tanks)
Diesel Fuel	3,768 bbls
Base Oil	700

WELL CONTROL

Diverter	21-1/4" 2000psi Hydril
Annular	(1) 13-5/8" 5K Hydril
BOP	(1) 13-5/8" 10K Type U Single, (1) 13 -5/8" 10K Type U Double with Blind Shear, w/ 4-1/16" 10K outlets
Choke Manifold	(18) Cameron 2 1/16" Type F 10K psi, H2S trimmed, (6) Cameron 4 1/16" Type F 10K psi H2S trimmed
Control Unit	Stewart and Stevenson ssb2-3S11

DRILLING EQUIPMENT

Derrick	167ft Lee C. Moore 30ft x 30ft
Top Drive / Power Swivel	Varco TDS-4H
Traveling Block	National 660H500
Crown Block	National 760 FA
Drawworks	National 1625-DE
Auxiliary Brake	Baylor 7838
Drill Line	1-1/2"
Rotary	National C-375
Prime Movers	5 - Caterpillar D-399 TA @ 1325 hp
Emergency Generator	1 - Caterpillar D-398 @ 860 hp
Cementing Equipment	Halliburton HCS-25D Twin HT400
Torque Wrench / Spinner	TW61 Wrench / Varco SSW30 Spinner
Cranes	(4) LeTourneau PCM 120AS

MUD SYSTEM

Mud Pumps	(2) National 12-P-160 Triplex. 1600 hp each
Mud Pits	1467 bbls total - 3 mud pits and 1 slug pit
Mud Mixing Pumps	(2) Mission Magnum
Shale Shakers	(3) Derrick Flo Line Cleaners, 2 Brandt Dual Tandem
Desanders	DEMCO 3 CONE
Desilters	Derrick FLC-503, 20 CONE W/3 Screen Mud Cleaner
Degasser	1- Swaco Total Mud Degasser
Mud Processing Pumps	(2) Mission Magnum
Maximum Pressure	5,000 psi

Minor changes / modifications to the above listed equipment could occur.
Should you have specific questions, please contact the Marketing Department at: marketing@rowancompanies.com or 713-960-7647

Fig. 1.7 Specification sheet of the *Rowan Juneau* (Source: Rowan) (continued)

contained in the jacking mechanism in the hull and interact with racks on the leg chords (Fig. 1.9).

1.3.2 Independent Versus Mat

Foundations are classified as independent-leg or mats. Independent-leg jackups have legs that can be jacked up independently of each other and are attached to a spudcan footing (Fig. 1.10). Spudcans are designed to penetrate the seafloor and transfer vertical loads from the legs to the ground; spudcan penetration also provides resistance to lateral forces acting on the legs. Mats are a rigid plate

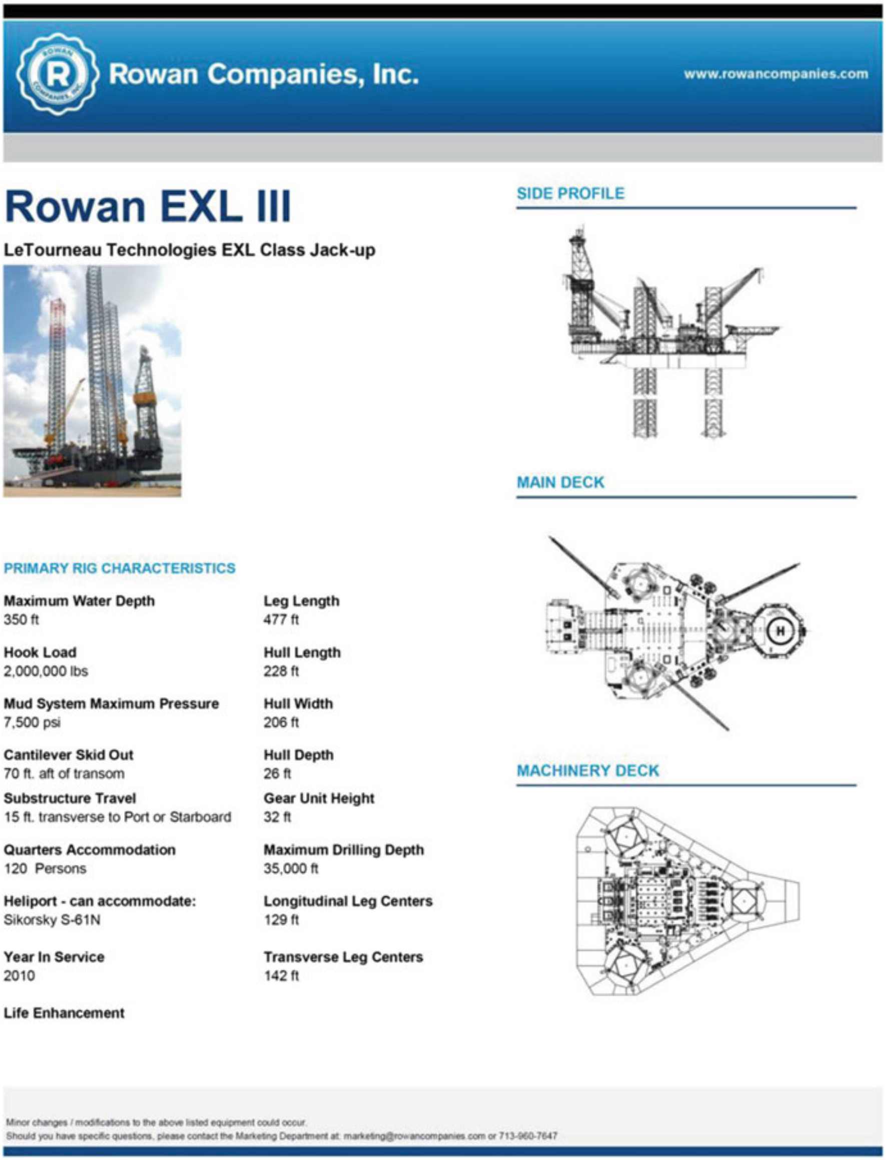


Fig. 1.8 Specification sheet of the high-spec *Rowan EXL III* (Source: Rowan)

structure which connects to the bottom of each leg (Fig. 1.11). Mat supported rigs are employed where the bottom conditions would cause spud cans to over-penetrate the seabed, as with soft muddy soil near the mouths of large rivers, or under-penetrate the seabed as with hard rock substrate.

Rowan EXL III www.rowancompanies.com

CAPACITIES

Maximum Drilling Payload	6,491,000 lbs
Hook Load	2,000,000 lbs
Rotary Load	2,000,000 lbs
Setback load	900,000 lbs
Liquid Mud	3,668 bbls
Sand Traps	350 bbls
Pipe Storage (main)	2,000 sq. ft. x 7 ft. high
Pipe Storage (cantilever)	2,000 sq. ft. x 7 ft. high
Covered Sack Storage	1,600 sq ft
Bulk Cement	6,805 cu ft
Bulk Barite	6,805 cu ft
Potable Water	1,762 bbls
Drill Water	13,882 bbls (incl. combo tanks)
Diesel Fuel	3,704 bbls
Base Oil	934

WELL CONTROL

Diverter	Vetco Gray 36-1/2" , 500 psi WP
Annular	13-5/8" Hydrill GX 10k psi
BOP	2 x 13-5/8" 15k Cameron type U, doubles, 4 x 3-1/16" 15k outlets. H2S trim
Choke Manifold	30 x Cameron 3-1/16" Type FLS Manual 15K PSI, H2S Trim 1 x Cameron 3-1/16" Type FLS Hydraulic 15K PSI, H2S Trim 4 x Cameron 4-1/16" Type FLS Manual 10K PSI, H2S Trim 2 x 3-1/16"15,000 PSI Adjustable Chokes, H2S Trim 2 x 3-1/16"15,000 PSI Hydraulic Drilling Chokes, H2S Trim 2 x 3-1/16"15,000 PSI Positive Chokes, H2S Trim
Control Unit	Cameron 3,000 PSI BOP Control Unit, 80-15 Gallon Bottles with 1,100 Gallon Reservoir Tank

DRILLING EQUIPMENT

Derrick	Loadmaster Model 2000 KIP, 32'x 35'Base, 170'High, 2,000,00 lbs. on 14 Lines
Top Drive / Power Swivel	Lewco 750 ton , OEM 1,500 HP AC Motor Output Torque 72,000 ft. lbs. continuous / 100,000 ft. lbs intermittent
Traveling Block	Lewco Model LBLK-1000, 2,000,000 lbs.
Crown Block	Loadmaster, Cap: 2,000,000 lbs.
Drawworks	Lewco Model 3000 HD Driven by 2 x 1,500 HP AC Motors
Auxiliary Brake	Baylor 15050W
Drill Line	1-3/4"
Rotary	Lewco Model D495 Driven by 1 x OEM 1,150 HP AC Motor
Prime Movers	5 x Cat 3516 CHD each Driving 1 x Kato 1525 KW Gen.
Emergency Generator	1 x Cat 3516 CHD each Driving 1 x Kato 1525 KW Gen.
Cementing Equipment	AC Drive provided (for Operator supplied unit)
Torque Wrench / Spinner	NOV IR 30120 Iron Roughneck-100,000 ft lbs make / 120,000 ft lbs break
Cranes	2 x LeTourneau PCM-220 SS Pedestal Cranes With 140' Booms, 1 x LeTourneau PCM-120 SS Pedestal Cranes With 100' Boom

MUD SYSTEM

Mud Pumps	3 x Lewco W-2215 2,200 HP, Driven by 2 x OEM 1,150 HP AC motors
Mud Pits	3668 bbls total, (6 mud pits + 2 slugging pits)
Mud Mixing Pumps	2 x Badger 8 x 6 x 14 pumps / 125 HP motor
Shale Shakers	4 Derrick DP-628 Box/Top feed shakers
Desanders	3 x 10" cones
Desilters	20 x 4" cones
Degasser	Derrick Vacu-Flow 1,200 GPM
Mud Processing Pumps	2 x Badger 8 x 6 x 14 pumps / 125 HP motor
Maximum Pressure	7,500 psi

Minor changes / modifications to the above listed equipment could occur.
Should you have specific questions, please contact the Marketing Department at: marketing@rowancompanies.com or 713-960-7647

Fig. 1.8 Specification sheet of the high-spec *Rowan EXL III* (Source: Rowan) (continued)

1.3.3 Cantilevered Versus Slot

The drilling rig on a jackup can be cantilevered or slot. A cantilevered jackup mounts the rig on cantilevers that extend outward from the hull of the unit. A slot jackup mounts the drilling unit over a slot in the deck. Cantilever designs are more versatile than slot designs since they can be used to drill and workover wells on

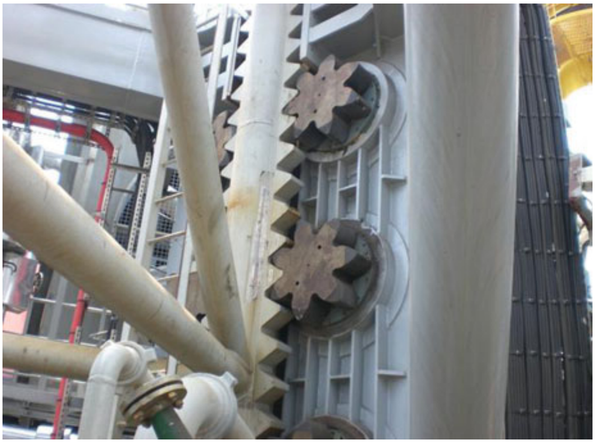


Fig. 1.9 Rack and pinion elevating system of a F&G Super M2 rig (Source: Remedial Offshore)

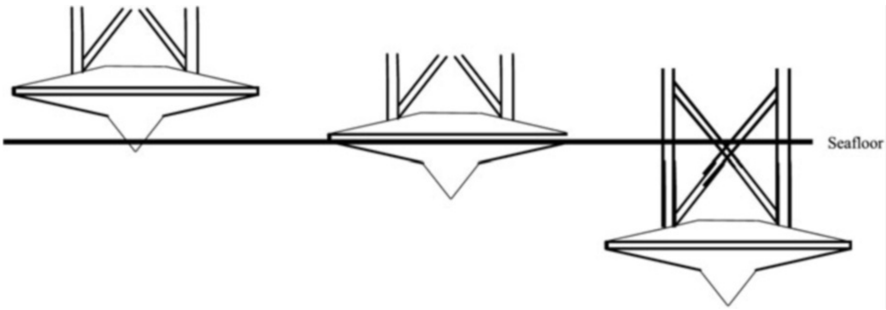


Fig. 1.10 Spudcan penetrating the seafloor during jackup operation

fixed platforms (Fig. 1.12) and to drill closely spaced wells without repositioning the rig. All rigs built over the past decade have been cantilevered but slot jackups are common in the legacy fleet.

1.4 Semisubmersibles

1.4.1 Station Keeping

Semis are held in position by anchors or are dynamically positioned [2]. In dynamic positioning, propellers (thrusters) mounted on the vessel's hull are controlled by an on-board computer that receives information from satellite positioning, wind sensors and hydrophones about wind, waves, and current to maintain position.

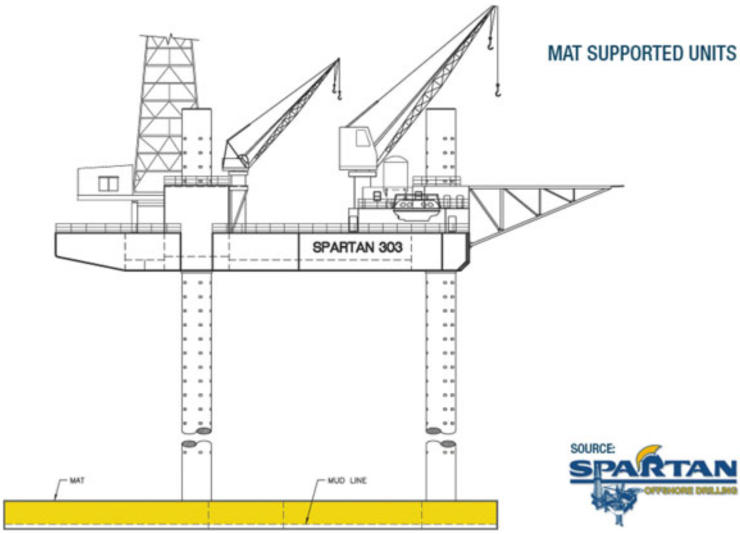


Fig. 1.11 Mat foundation (Source: Spartan Offshore)

Fig. 1.12 A cantilevered jackup positioned over platform wells shown in the foreground (Source: Seadrill)

1.4.2 Motion Compensation

Floating rigs require motion compensation systems to correct for vertical movement of the rig due to waves. Two separate motion compensation systems are required to control the tension on the marine riser and the drill string. A drill string

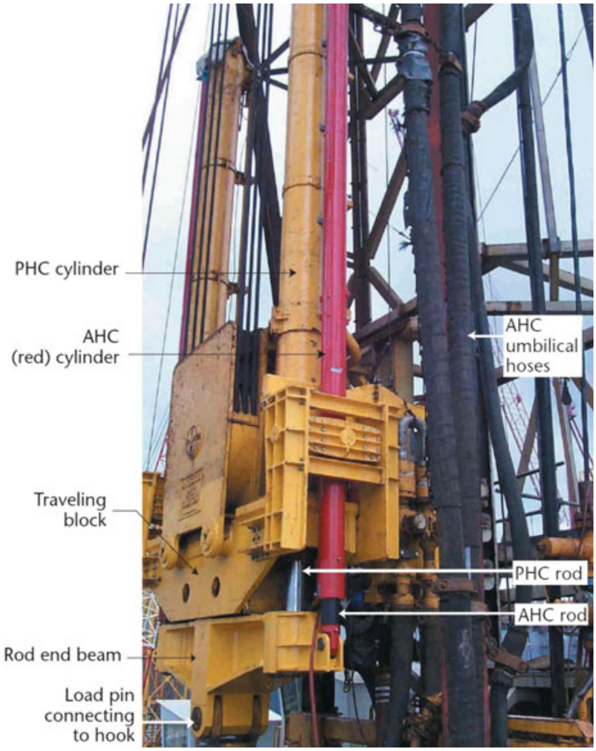


Fig. 1.13 Diagram of a drill string compensator (Source: NOV)

compensator (DSC) keeps the drillbit on the bottom of the hole and within the weight limits established by the driller while a riser tensioner is used to maintain the tension on the drilling riser. Both systems utilize pneumatic cylinders to push or pull the drill string or riser up or down relative to the rig.

A DSC is composed of a pneumatic cylinder placed between the travelling block and the hook and connected to an air pressure system placed on the deck (Fig. 1.13). As the rig heaves upward, a working fluid flows out of the compensator cylinder which allows the rod inside the cylinder to fall, moving the hook downward relative to the drill floor, but keeping it at a constant level relative to the earth. As the rig heaves downward, air flows from the pressure vessels to the cylinder, forcing the rod inside the cylinder and the attached hook upward relative to the drill floor. A riser tensioner is composed of several hydraulic cylinders with wire line sheaves at both ends and operates in the same basic fashion.

1.4.3 Displacement

The weight and capacity of marine vessels are measured by lightship (empty) and loadline (loaded) displacement [17] and are closely related to the weight of the vessel. Semisubmersibles are designed to have a variable displacement, and are

Table 1.3 Displacement and size of modern semisubmersibles

Design	Operating displacement (tons)	VDL (tons)	Deck dimensions (ft × ft)
Aker H-6e	64,500	7,000	295 × 230
F&G EXD	58,000	9,900	379 × 259
F&G Millennium	40,000	6,800	344 × 240
Gusto MSC DSS 20	33,500	4,400	208 × 211
Gusto MSC DSS 38	43,000	5,200	228 × 228
Gusto MSC DSS 51	58,000	8,800	254 × 256
GVA 7500	61,000	8,200	389 × 317

Source: Industry press

Table 1.4 Semisubmersible rig generations and technology development

Generation	Construction period	Water depth (ft)	Variable load (tons)	Technology implementation
I	1962–1969	600–800	1,000–2,000	2 × 1,250 hp mud pumps, kelly, manual derrick
II	1970–1981	1,000–1,500	2,300–3,300	2 × 1,600 hp mud pumps, kelly, manual derrick
III	1982–1986	1,500–2,500	3,800–4,500	2 × 1,600 hp mud pumps, kelly, automatic pipe handling
IV	1987–1998	3,500–7,000	3,800–5,000	3 × 1,600 hp mud pumps, top drive, automatic pipe handling, DP
V	1999–2005	7,500–10,000	5,000–8,000	4 × 2,200 hp mud pumps, top drive, dual activity, DP
VI	2005–2011	10,000	7,000–8,500	4–5 × 2,200 hp mud pumps, modular derrick drilling machine, DP3, dual activity

Source: PETEX [15]; Keener et al. [11]

specified by their transit, operating and survival displacements [8]. Transit displacement is the displacement while in transit, operating displacement is the displacement while drilling, and survival displacement is the displacement under storm conditions.[2] There is significant variation in the size of semis (Table 1.3) with the smallest commonly built rig (the Gusto DSS 20) approximately half the displacement of the largest (the Aker H-6e).

1.4.4 Generations

Semisubmersibles are classified into generations based on the year of construction and the technology of equipment, environmental specification, variable deck load and water depth capability (Table 1.4). As with all classifications, the delineation is approximate and is meant to serve as a general guideline. Variable deck load comprises all the weight beyond the lightship and ballast to be carried by the vessel.

[2] Transit displacement usually ranges from 70 % to 80 % of the operating displacement.

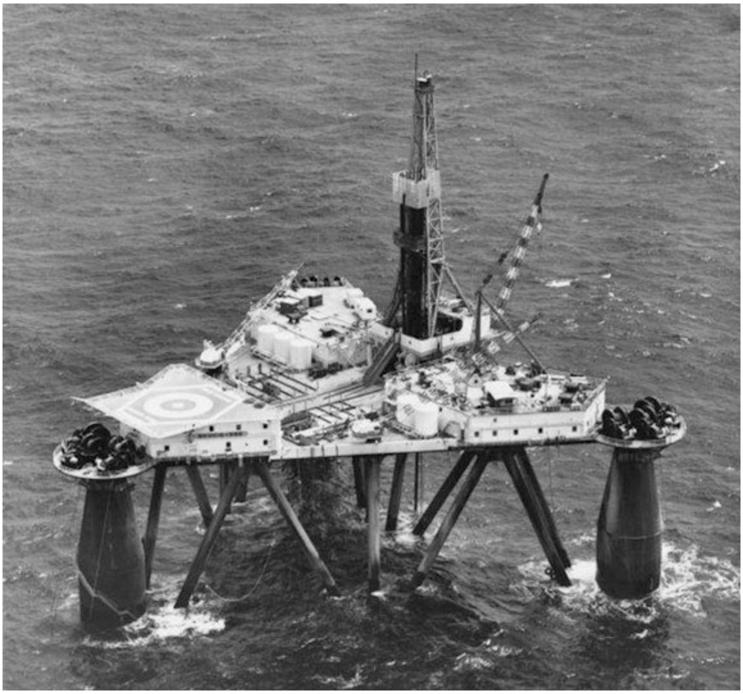


Fig. 1.14 The *SEDCO 135-E*, a first generation semisubmersible built in 1967 (Source: National Library of Australia)

The first generation of semis were built between 1962 and 1969 and were generally limited to water depths less than 800 ft (Fig. 1.14), while second generation semis were built between 1970 and 1981 for water depth up to 1,000–1,500 ft. Most of the first and second generation semis have now been retired, upgraded or converted to other uses such as floating production systems and accommodation vessels [12].

Third generation rigs were built from 1982 to 1986 and increased the size, payload and standards of redundancy [8]. Third generation rigs were designed to operate in water depths up to 2,500 ft, and many were upgraded in the late 1990s and early 2000s to increase their water depth capability and are still in service [7].

Fourth generation rigs are large units (30,000–53,000 tons displacement) capable of handling high variable deck loads (4,000–6,200 tons) and mud volumes ($3 \times 1{,}600$ hp). Pipe handling on fourth generation semis is automated and enhanced BOP controls are standard. Dynamic positioning was incorporated in some second generation rigs, but by the fourth generation, is more common. Due to the low oil prices and reduced demand for drilling in the late 1980s and 1990s, only 13 fourth generation units were built. In Fig. 1.15, the fourth generation rig *West Alpha* is depicted.

By the late 1990s and early 2000s, technology had matured so that deepwater and ultradeepwater drilling in 7,500–10,000 ft water depths was possible. In fifth generation rigs, drill floor systems, power management, dynamic positioning, and

Fig. 1.15 The *West Alpha*, a fourth generation semisubmersible built in 1986 (Source: Seadrill)

BOP controls are integrated and computer controlled. Fifth generation units often have triply redundant dynamic positioning (DP3), powerful mud systems, and automated pipe handling.

Sixth generation rigs have water depth capability of 10,000 ft and use modular top drive systems (Fig. 1.16). Top drives increase trip efficiency and drill speed, improve well control, allow for back reaming and improve the safety of the work environment. All sixth generation semis are dynamically positioned and are more mobile than their predecessors and capable of speeds up to 8 knots. New designs frequently have two fully functional derricks and may incorporate a multi-purpose drilling tower instead of a conventional derrick.

1.4.5 Upgrading

MODUs are frequently upgraded after being in service for a decade or more. A semisubmersible that is upgraded to drill in deeper water would be classified either as an upgraded or as an "equivalent" higher generation unit. For example, if a second generation rig was upgraded to drill in 3,500 ft water depth, with mud pump capacity 3 $\times$ 1,600 hp, variable displacement load of 4,300 tons, top drive and automatic pipe handling, the rig would be classified as a fourth generation unit.

Fig. 1.16 The *West Eminence*, a sixth generation semisubmersible built in 2009 (Source: Seadrill)

1.5 Drillships

1.5.1 Early Drillships

The first drillships were built in the late 1950s and 1960s and were structurally and functionally diverse. Some first generation vessels used early dynamic positioning systems, but most were moored (Fig. 1.17). By the late 1960s the basic layout of drillships was standardized and a typical design from this period is the Glomar III class (Fig. 1.18). In the early 1970s, the first modern dynamically positioned drillships were built, including the Gusto Pelican class and SEDCO 445 class. These vessels were generally capable of operating in 2,000–3,500 ft water depths, approximately twice the depth of contemporary semisubmersibles, and were capable of drilling 20,000 ft wells. Moored drillships continued to be built and some moored vessels had capabilities that matched or exceeded dynamically positioned drillships. Between the mid 1980s and late 1990s, no new drillships were ordered.

Fig. 1.17 The *E.W. Thornton*, an early drillship built in 1965 (Source: University of North Texas)

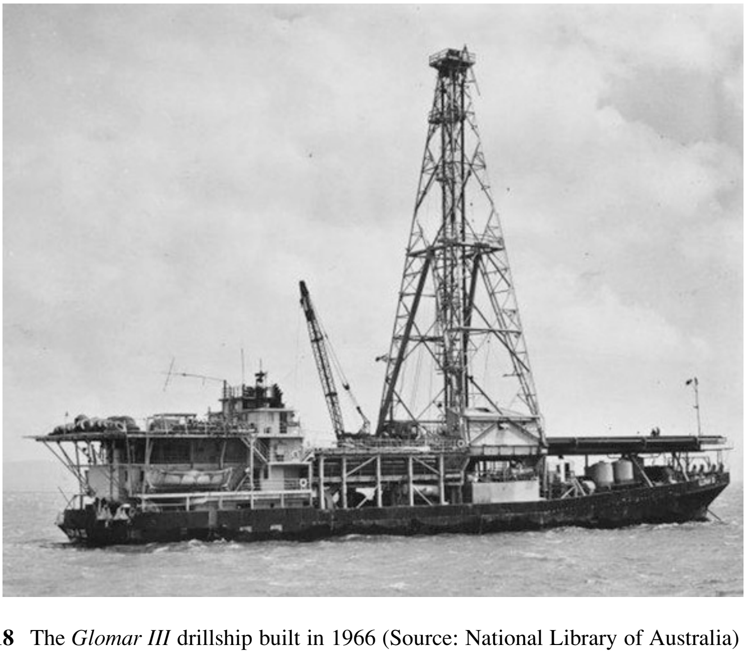


Fig. 1.18 The *Glomar III* drillship built in 1966 (Source: National Library of Australia)

Fig. 1.19 A modern drillship, the fifth generation *West Navigator* built in 2000 (Source: Seadrill)

Table 1.5 Specifications of modern sixth generation drillships

Design	Displacement (tons)	Variable load (tons)	Hook load (tons)	Mud pumps (number × hp)
Gusto P10000	75,000	20,000	1,250	4 × 2,200
Gusto PRD10000	54,000	15,000	1,000	4 × 2,200
Samsung 12000	105,000	22,000	1,250	4–6 × 2,200

Source: Industry press

1.5.2 Modern Drillships

Prior to the late 1990s, generations were generally not used to describe drillship construction, but when the *Discoverer Enterprise* was delivered in 1999 it was described as a fifth generation vessel, analogous to the fifth generation semis that were being built at the time (Fig. 1.19). Fifth generation drillships were significantly larger than previous designs (45,000–100,000 tons displacements) and capable of drilling in 7,500–10,000 ft water depths.

In the mid 2000s contractors began to refer to newbuilds as sixth generation vessels (Table 1.5). Sixth generation designs increased water depth capability to 12,000 ft and dual activity derricks became standard (Fig. 1.20). In some cases, surface BOP capabilities were included in addition to the standard subsurface BOP. Contractors began ordering seventh generation units in 2011, but the improved capabilities of these units are not yet clear.

Fig. 1.20 Dual activity derrick on the sixth generation *West Polaris* drillship built in 2008 (Source: Seadrill)

1.5.3 Displacement

Drillships vary in size from 50,000 to 100,000 ton displacements (Table 1.5). Smaller drillships (e.g. the Gusto PRD10000) sacrifice some functionality to reduce costs, but large designs such as the Samsung 12000 are the most popular. The *Discoverer Enterprise*, a 100,000 ton drillship, the 22,000 ton *Discoverer 534* drillship, and the 37,000 ton *Transocean Richardson*, a fourth generation semi are compared[3] (Fig. 1.21).

1.5.4 Competition with Semis

Drillships and semis compete for many of the same drilling programs with selection based on availability, cost, and technical factors. Drillships can operate for up to three months without resupply, which reduces the spread requirements and allows for efficient work in frontier regions or far from shorebases. Drillships are also able to mobilize rapidly to destination, and in some cases, have more

[3] For scale, a Nimitz class aircraft carrier is approximately 100,000 tons.

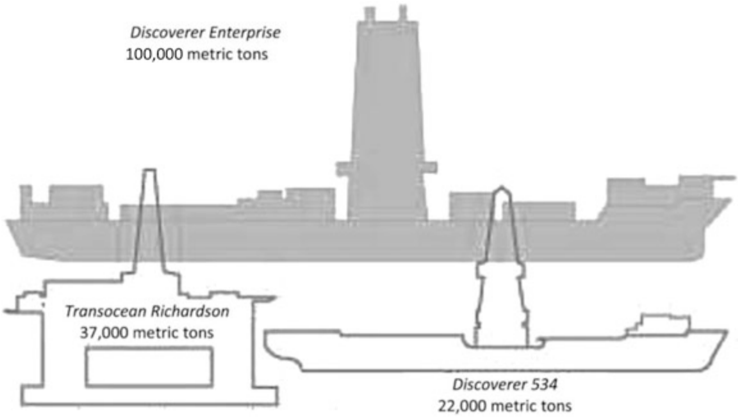


Fig. 1.21 Size comparison of the *Discoverer Enterprise*, *Discoverer 534*, and *Transocean Richardson*, a fourth generation semi (Source: Oil and Gas Journal)

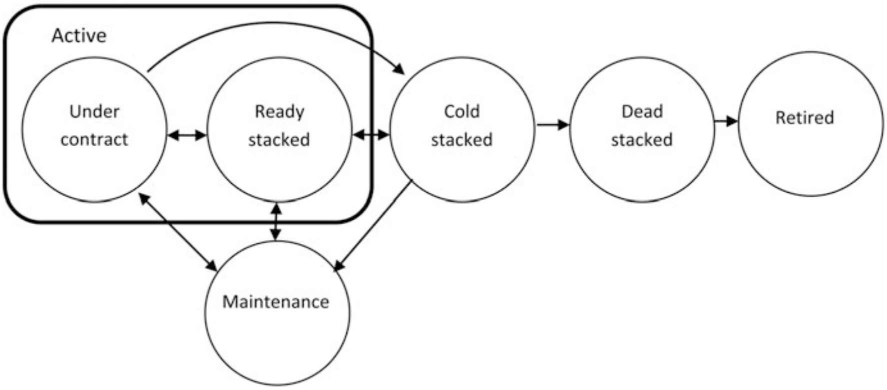


Fig. 1.22 Transitions among rig activity states

advanced drilling equipment, but the ship-shape layout also limits space for operations relative to the semisubmersible's square-shaped deck. Drillships are usually employed for exploratory and appraisal drilling in deepwater frontier regions. However, semis have more favorable motion characteristics than drillships and are favored for most harsh environments and if the drilling program requires closely spaced wells.

1.6 Activity States

MODUs transition through several distinct stages over their lifetime (Fig. 1.22).

Fig. 1.23 Four cold-stacked rigs in Sabine Pass, Louisiana (Source: Microsoft)

1.6.1 Active

Active rigs are working under contract and are the only state in which a rig is generating revenue. Active rigs may be drilling, waiting on location, in transit, or in a mobilization/demobilization status. Active rigs become inactive when their drilling contract (work obligation) expires.

1.6.2 Ready-Stacked

If a rig is to be idled for a short period of time, the rig is typically maintained in a prepared or ready-stacked (warm) state. Ready-stacked rigs are not under contract but are available for immediate use with minor preparation. In a ready-stacked state, normal maintenance operations similar to those performed when the rig is active are continued so the rig remains work ready, most of the crew is retained, and rigs are actively marketed and considered part of marketable supply.

1.6.3 Cold-Stacked

If operators do not expect a rig to be utilized in the near term, the rig is cold-stacked to reduce operating cost and support fleet dayrates. Cold-stacked rigs are frequently inactive for a period of several months to one or more years and are stored in a wet dock (Fig. 1.23). Cold-stacked rigs are generally not considered part of the marketable supply and are usually not counted in supply and utilization statistics. Capital and time are required to return a cold-stacked rig to working condition [14].

Fig. 1.24 The dead-stacked jackup rig *Zeus* being dismantled in Freeport, Texas (Source: Texas General Land Office)

A crew must be rehired and a series of inspection and testing procedures are required, including power, load, and pressure testing; BOP certification; riser and tensioner inspection; and a number of other service checks [1].

Reactivation expenses vary depending on how long the rig has been out of service. For jackups, reactivation can range from $4 to $20 million and take up to 9 months. For semis, reactivation can cost up to $50 million and take 12 months. Drillships are rarely cold-stacked due to high demand. The upgrade and maintenance markets are responsible for reactivating cold-stacked units. Cold-stacked units are frequently sold into the secondhand market.

1.6.4 Dead-Stacked

A rig will transition between activity states many times throughout its life, and as a rig ages, it will spend an increasing portion of its time cold-stacked. After being cold-stacked for several years, reactivation costs become prohibitive and the rig is used for parts in a dead-stacked state before being retired. Units may remain dead-stacked for many years before being retired from the fleet (Fig. 1.24).

1.6.5 Retired

A rig is removed from the fleet when it is converted to another use, lost due to a catastrophic event, or sold for scrap. Conversion to workover rigs and accommodation units are alternative uses for jackups; the most common alternative use for semisubmersibles are as floating production units. Rigs destroyed by hurricanes are scrapped or may form part of an approved reef site. Scrap sales occur in the secondhand market.

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Chapter 2
The Five Offshore Drilling Rig Markets

Abstract The offshore drilling industry is composed of five markets engaged in the trade of a unique service or good. Mobile offshore drilling units are owned and operated in the contract drilling services market, supplied by the newbuild and secondhand markets, maintained and enhanced in the upgrade market, and complete their lifecycle in the scrap market. The purpose of this chapter is to describe the players, prices, activity and cash flows in each of the five offshore rig markets circa 2010–2011. Contract drilling and newbuilding are large transparent markets and activity is closely followed throughout the industry. From 2005 to 2012, contract drilling and newbuilding generated between \$25–\$50 billion and \$10–\$20 billion in transactions per year, respectively. Maintenance and upgrade activities are performed by a number of shipyards throughout the world, but because of the sporadic nature of the activities and limited record keeping, the market is difficult to track. The secondhand and upgrade markets are estimated to be worth between \$2–\$10 billion and \$1–\$5 billion annually. The scrap market is the smallest of the five markets and is poorly documented and worth less than \$50 million during most years.

2.1 Offshore Rig Markets

The offshore rig industry is composed of five markets (Fig. 2.1). Cash enters the contract drilling services market when exploration and production (E&P) firms lease rigs from contractors. Contractors use this cash to operate their units, acquire new rigs, and upgrade and maintain their fleet. The newbuild and upgrade markets are the primary mechanisms by which capital leaves the service market.

In the contract drilling market, rigs owned and operated by contractors are leased to E&P firms on a dayrate basis to drill or service wells. The dayrate is the daily price to lease a rig and includes the use of the rig and its crew but does not include most of the other costs associated with drilling and completing a well (e.g., casing, drilling fluids, logistics, well evaluation, etc.). The drilling service industry is the largest and

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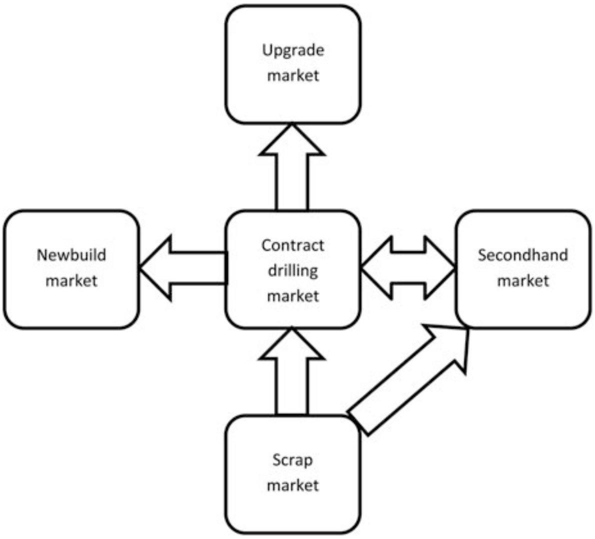

Fig. 2.1 Direction of cash flow through offshore rig markets

most closely followed of the five markets and drives the activities of investors in the other markets.

The newbuild market uses shipyard labor and capital to convert steel and third party equipment into rigs. Drilling contractors enter into turnkey contracts with shipyards for the construction and delivery of one or more rigs, or yards may build on speculation. The newbuild market is primarily Asian with major shipyards in Singapore, South Korea, and China.

Rigs operate offshore in a corrosive and hostile environment, and steel and equipment needs to be replaced for safe and efficient operations. As a rig ages, its technology also becomes obsolete and upgrades are required to sustain competitiveness and market value. The upgrade market is a ship repair market which both upgrades and maintains rigs. Upgrades improve and modernize rig technology and represent significant capital expenditures.

In the secondhand market, rigs are sold among and between contractors and other market participants. Rigs may be sold for use in the service market, may be converted to another use by the buyer, or sold into the scrap market. Transactions include corporate mergers where all the assets of the firm are purchased, liquidations during bankruptcy where one or more units may be purchased, or conventional sales.

In the scrap market, shipbreaking firms buy rigs on the secondhand market, either directly from contractors or via brokers. Equipment is removed and reused or sold as market conditions and demand permit. Following sale, dismantling occurs and the steel is sold for scrap to steel mills. Rigs in the U.S. may be stored for years until the price of scrap steel is adequate to make dismantling economic, while in international yards, rigs are broken down quickly along with beached ships [14].

The financial value of individual sales in the scrap market is low, and companies do not frequently report income from scrap sales leading to the smallest and least transparent of the five markets.

2.2 Contract Drilling Market

2.2.1 Measures

The contract drilling service market is described by dayrates, utilization and fleet size. Dayrates behave according to demand and supply conditions, and as regional demand approaches available supply, dayrates generally rise. Demand for drilling is driven by the capital spending patterns of E&P companies, which in turn, is based on operator's expectations of future oil and gas prices, the availability of acreage, and many other factors [11, 15]. Dayrates are an indicator of market conditions and the same drivers that impact dayrates tend to influence the rest of the offshore service industry.

Utilization is a system measure defined by the proportion of rigs working at a point in time to the available fleet within a specific region. Industry capacity is not a fixed resource because companies can add rigs through newbuilding and relocation to respond to higher demand and stack rigs when demand declines. While adding new capacity takes several years, rigs have very long lives (25+ years), and when demand weakens, overcapacity in the market may lead to prolonged declines in utilization. Stacking units removes capacity from the market and can be performed relatively quickly to help support prices, but stacking, like newbuilding decisions, are firm specific and are not performed in unison. High utilization cause dayrates to rise and provide a signal to operators that additional capacity can be absorbed in the market [4].

Fleet size describes the total number of rigs of a given water depth or class. Fleet size is described by firm, and when reported regionally, is an indicator of the total capacity in the drilling market at a given point in time. The scale and quality of a contractor's asset base is correlated with its revenue base. A large asset base implies a platform for sustainable earnings and cash flows and is related to a company's market position, its ability to compete in terms of cost structure, and the ability to obtain financing for capital projects.

2.2.2 Players

The number of offshore drilling companies varies over time, and in 2012 there were approximately 100 offshore drilling contractors and the market was dominated by a small number of firms, including Transocean, Ensco, Diamond Offshore and Seadrill (Table 2.1). The top four firms owned 36 % of the 868 rigs in the world

Table 2.1 Distribution of rigs by class and operator circa 2Q2011

Company	Jackups	Semis	Drillships	Total	Ownership
Transocean	68	50	23	141	Public
Ensco	49	20	7	76	Public
Noble Drilling	45	14	13	72	Public
Hercules Offshore	53	0	0	53	Public
Diamond Offshore	13	32	3	48	Public
Seadrill	21	12	6	39	Public
COSL	27	6	0	33	State
Rowan	31	0	0	31	Public
Maersk Drilling	14	6	0	20	Subsidiary
Aban Offshore	15	0	3	18	Public
Saipem	7	7	2	16	Public
Nabors Offshore	16	0	0	16	Public
Atwood Oceanics	6	6	1	13	Public
National Drilling	13	0	0	13	State
ONGC	8	0	2	10	State
Petrobras	6	4	0	10	State
All others (87 firms)	147	66	46	259	
Top 4 firms	205	116	46	367	
Top 8 firms	337	134	52	523	
Total	539	223	106	868	

Source: Data from RigLogix [16]
Note: Count includes cold-stacked rigs and rigs under construction

fleet circa 2011 and the top eight firms owned over half of the marketable rigs. Fleet size changes over time with changing market conditions, but the changes are often slow and represent a small portion of the world's asset base. Asset transactions and additions are common but new firm entrants are infrequent. Most large firms are publicly owned and all but one of the major players in the market (National Drilling) are listed on stock exchanges. Contractors not listed in Table 2.1 own on average three rigs per firm.

2.2.3 Prices

Dayrates are the primary contract specification during the bidding process and are frequently announced by contractors and assembled by commercial data providers such as RigLogix, ODS-Petrodata, and RigData. Contract durations are often less than a year so there is a steady stream of new contracts that provide a large number of transparent and reliable data.

Jackup and floater dayrates were relatively stable from 2000 to 2005 in most regional markets before increasing sharply from 2005 to 2007 as oil prices rose (Fig. 2.2). Following the 2008 global recession, dayrates fell rapidly, especially in the over-supplied and volatile jackup market. Regional prices tend to move together and follow oil prices but not all markets respond in the same manner.

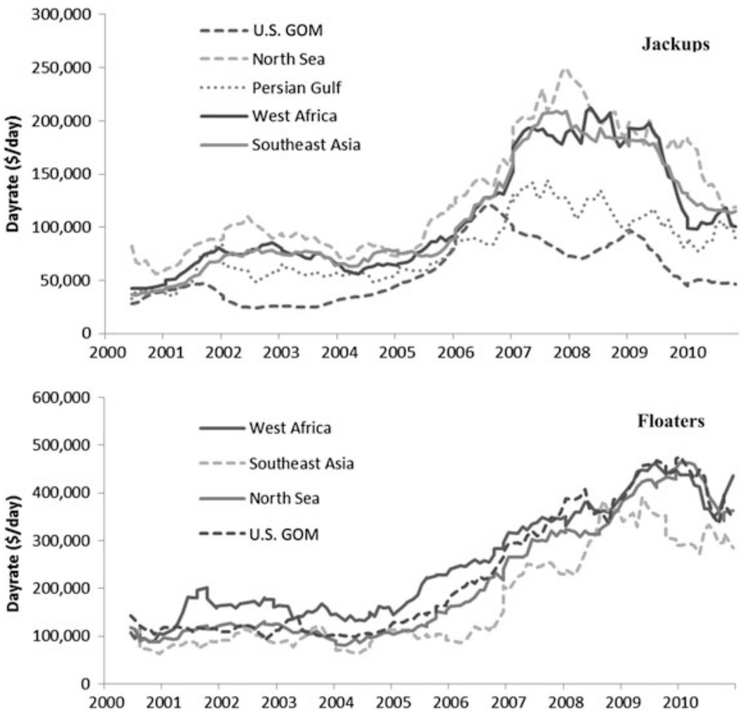

Fig. 2.2 Dayrates in the contract drilling market, 2000–2010 (Source: Data from RigLogix [16])

In the jackup market, there are significant price differences between regions, ranging from 50,000 to 100,000 $/day in the U.S. GOM during 2009–2011 compared with 100,000–175,000 $/day in the North Sea. In the floater market, there is less variation between regions due to patterns of supply and demand, technical requirements, and the greater similarity in deepwater rig specifications. In the 2009–2011 period, floater dayrates ranged between 300,000 and 500,000 $/day with slightly lower dayrates in Southeast Asia than in the Atlantic basins.

2.2.4 Size

In 2011, approximately 85 % of the active fleet was operating in the Persian Gulf, U.S. GOM, Brazil, North Sea, Southeast Asia, West Africa, India and China (Table 2.2). Smaller markets include the Mexican GOM, Mediterranean, the Red Sea, Black Sea, Caspian Sea, the Caribbean and Australia. Frontier regions typically have less than five working rigs and include the Arctic Ocean, East Africa, Ghana, and the Philippines.

Table 2.2 Geographic distribution of active rigs by region in 2011

Region	Jackups	Semis	Drillships	Total
Persian Gulf	85	0	0	85
U.S. GOM	51	20	10	81
Brazil	3	52	15	70
North Sea	32	36	2	57
Southeast Asia	42	9	2	53
India	34	2	9	45
West Africa	17	13	9	39
China	28	4	0	32
Mexico	24	3	0	27
Egypt	20	2	2	24
All others	55	33	13	101
Top 4	171	108	27	306
Top 8	292	136	47	475
Total	394	175	57	626

Source: Data from RigLogix [16]

The number of offshore wells drilled since 1994 has ranged between 2,500 and 3,700 per year (Fig. 2.3). All exploratory wells are drilled using MODUs, but development drilling may occur from either MODUs or platform rigs, and in many instances, both mobile and platform rigs are responsible for well construction. Deepwater drilling activity has grown over the past 15 years and is the more lucrative business segment, but about 80 % of well construction still occurs in shallow water throughout the world. Asia has accounted for nearly half of drilling activity in recent years. North American activity is dominated by drilling in the U.S. GOM, but after the Macondo blowout on April 20, 2010 and subsequent drilling moratorium, activity levels remain depressed through 2012, before returning to historic levels.

2.2.5 *Value*

To estimate market value, the number of rigs of each class under contract in each month and region were counted and multiplied by the average regional dayrates. Over the past decade, the revenue in the contract drilling market ranged from $21 billion in 2004 to over $50 billion in 2009 (Fig. 2.4; Table 2.3). Although deepwater drilling makes up a relatively small proportion (about 20 %) of the number of wells drilled each year, the deepwater market accounted for approximately two-thirds of total revenue throughout the decade. In 2010, the North Sea and Brazil were the largest floater markets and the largest overall, while the Persian Gulf was the largest jackup market.

Market valuations are performed by a number of industry consultancies (e.g. Douglas-Westwood, GBI Research, IHS, R.S. Platou, Rystad Energy, Wood Mackenzie). Comparisons across firms depend on the assumptions and methods

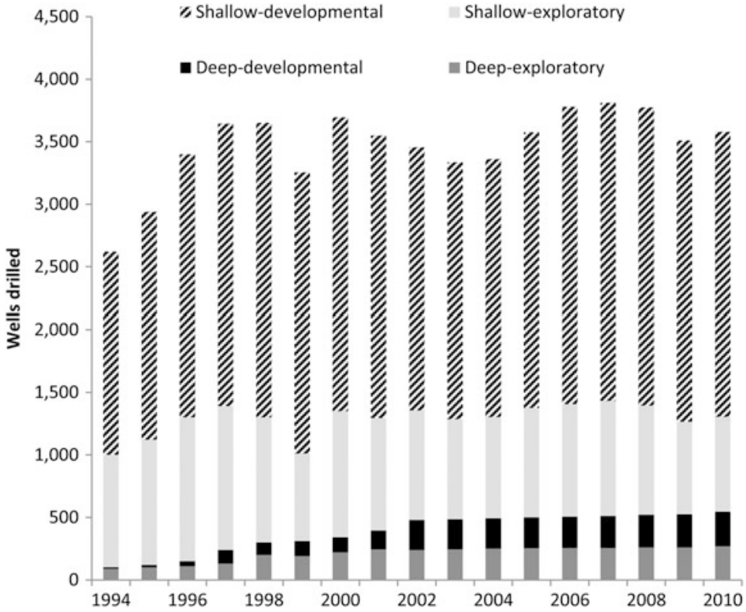

Fig. 2.3 Number of wells drilled per year, 1994–2010. Deepwater defined as greater than 400 m (Source: Data from Douglas-Westwood [5])

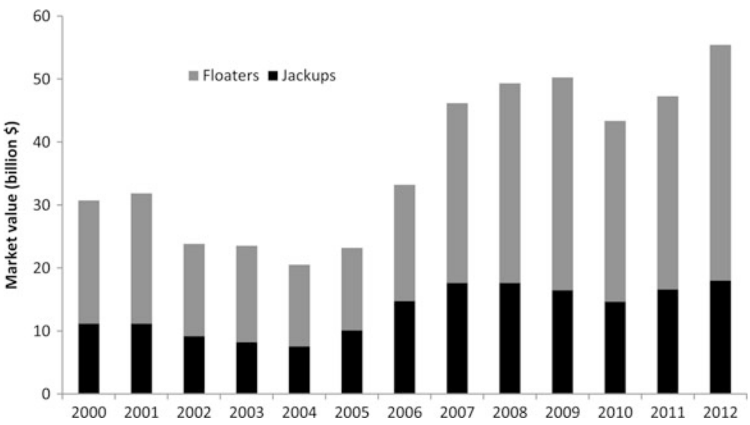

Fig. 2.4 Annual revenue of the offshore contract drilling market, 2000–2012 (Source: Data from RigLogix [16])

and the definition of the market employed [7, 18]. Large markets with a high degree of involvement by public E&P companies and drilling contractors are transparent and may be estimated with confidence. For small markets or those dominated by National Oil Companies and state-owned drilling contractors, more uncertainty

Table 2.3 Regional contract drilling markets in 2010

	Jackups (million $)	Floaters (million $)	Total (million $)
North Sea	1,865	6,436	8,302
Brazil	72	7,615	7,688
West Africa	994	4,314	5,307
U.S. GOM	983	3,781	4,765
Southeast Asia	1,931	2,092	4,023
Persian Gulf	3,253		3,253
India	1,263	1,369	2,632
China	1,377	526	1,903
Mediterranean	509	1,291	1,799
Mexico GOM	1,075	256	1,331
Australia	57	1,022	1,079
Venezuela & Caribbean	296	292	588
Red Sea	511		511
Total	14,187	28,588	42,775

Source: Data from RigLogix [16]; Authors calculations

arises in the valuation estimates. The Chinese market is particularly difficult to reliably estimate due to the large number of state-owned rigs.

2.3 Newbuild Market

2.3.1 Measures

The newbuild market is specified by deliveries and prices. The market is transparent because newbuilding is a significant capital expenditure for contractors and a significant source of revenue for rig-building shipyards. Prices are widely reported and tracked by the same firms that survey rig dayrates.

Drilling contractors order rigs when the expected rate of return from operating a new rig exceeds company investment criteria. The benefit of investment depends on dayrates and utilization over the life of the rig [2, 4], and since these are unknown and uncertain, management employ their own expectations relative to their business strategy [10]. The newbuild market is linked to conditions in the service market, and the cyclical nature of contract drilling causes similar cycles in the newbuild market.

Prices in the newbuild market are a function of demand and shipyard labor, equipment and steel costs. As shipyard demand increases, backlogs develop and yards are able to command higher prices for services. In addition, demand at rig-building shipyards is generally associated with demand across the drilling supply chain. Therefore, demand and prices for drilling equipment typically increase along with demand at shipyards, which leads to further price increases.

Table 2.4 Number of newbuild rigs on order by shipyard in 2011

Shipyard	Jackups	Semis	Drillships
Keppel FELS	17	4	1
Samsung		2	16
Daewoo		3	11
Jurong[a]	5	3	
Hyundai			6
PPL[a]	6		
COSCO		3	1
Dalian	4		
ABG	4		
Lamprell	4		

Source: Data from RigLogix [16]
[a]Part of Sembcorp Marine

Table 2.5 Worldwide distribution of rig construction in 2011

Country	Jackups	Semis	Drillships	Total	Value (million $)
South Korea	0	5	38	43	27,125
Singapore	33	7	2	42	13,402
China	9	6	3	18	6,979
Brazil	2	0	7	9	5,088
UAE	6	1	0	7	1,585
India	5	0	0	5	1,048
Norway	0	1	0	1	614
U.S.	2	0	0	2	375
Malaysia	1	0	0	1	227
Vietnam	1	0	0	1	180
Russia	1	0	0	1	100
Total	60	20	50	130	56,723

Source: Data from RigLogix [16]; Authors calculations

2.3.2 Players

In 2011, the jackup market was dominated by Keppel and its subsidiaries, while the drillship market was dominated by Daewoo and Samsung (Table 2.4). Keppel has shipyards located throughout the world, while the Daewoo and Samsung yards are located in Korea. Semi construction is spread across five Asian shipyards. There were 130 rigs under construction in 2011 worth an estimated $57 billion (Table 2.5). Measured by capital flows, rig building in South Korea is about twice as large as the Singaporean industry, but this is due to the current boom in drillship construction which may not continue after the current round of drillships are delivered. Singapore is a major supplier of jackups to the world market while the U.S. plays a niche role in jackup supply to the GOM market.

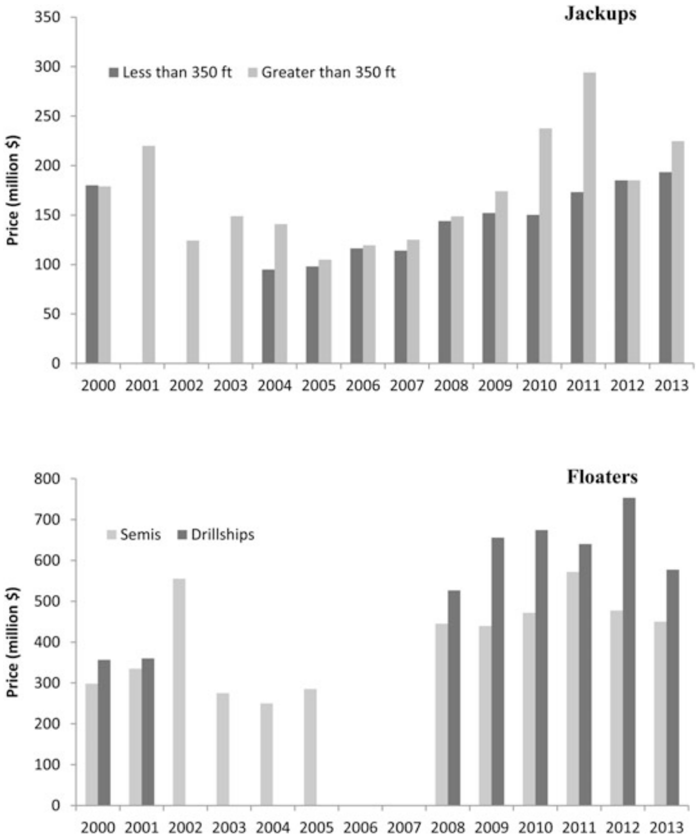

Fig. 2.5 Average cost of jackup and floater deliveries, 2000–2013 (Source: Data from RigLogix [16])

2.3.3 *Prices*

The average cost of jackup rigs increased from approximately \$100 million in 2004–2005 to approximately \$200 million for rigs delivered in 2012–2013 (Fig. 2.5). Price differences between high-spec (>350 ft) and standard (<350 ft) jackups varied only slightly over most of the cycle, except in 2010–2011 when several harsh environment high-spec units were delivered. Both ends of the jackup newbuild market respond to the same market stimuli due to similarities in the rigs and the firms engaged in construction.

Semis and floaters are two to three times more expensive than jackups and usually command dayrate premiums of similar magnitude. Drillships are more expensive to construct than semisubmersibles with average premiums ranging between \$70 to \$275 million.

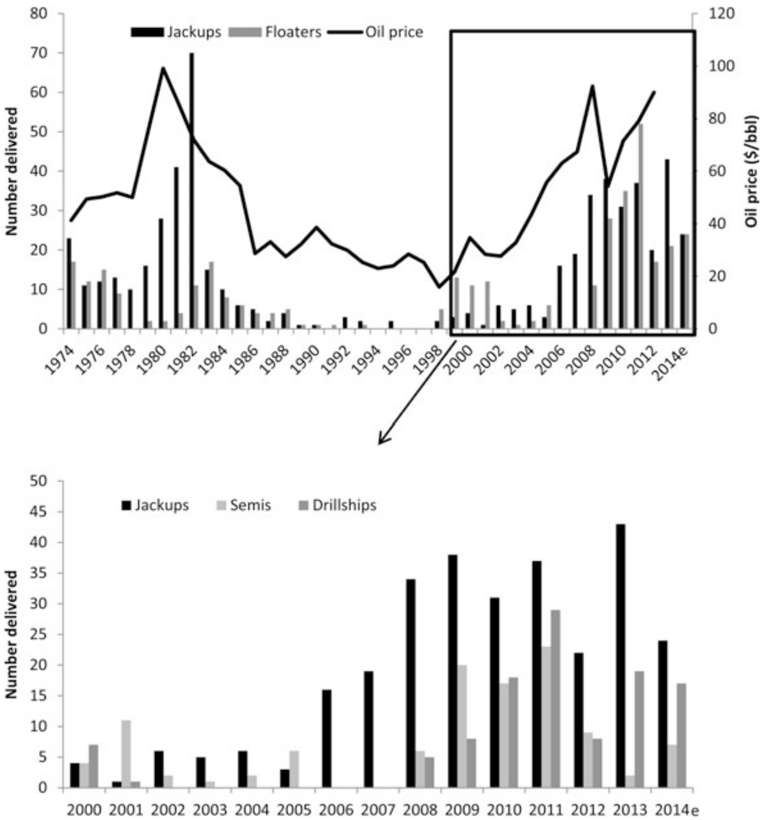

Fig. 2.6 Deliveries of newbuild rigs by class and oil prices, 1974–2014 (Source: Data from RigLogix [16])

2.3.4 Size

Newbuild deliveries have exhibited several cycles over the past half century (Fig. 2.6). The jackup industry began in the U.S. in the late 1950s and spread to Europe and Asia through the mid-1970s as exploration worldwide increased [1]. Prior to 1974, about 200 MODUs had been delivered. In the late 1970s and early 1980s, oil prices rose and the market grew rapidly, peaking in 1982 with 70 jackup and 11 floater deliveries.

Oil prices declined in the mid 1980s and demand collapsed, and during the decade 1986–1997, only 37 rigs were delivered. By the late 1990s, deepwater drilling technology had advanced, but few rigs were capable of drilling in water depths greater than 1,500 ft. Contractors responded by upgrading and ordering a small number of floaters. New jackup orders also began in this period due to concerns about the age of the fleet and operator interest in more challenging reservoirs and harsh environments.

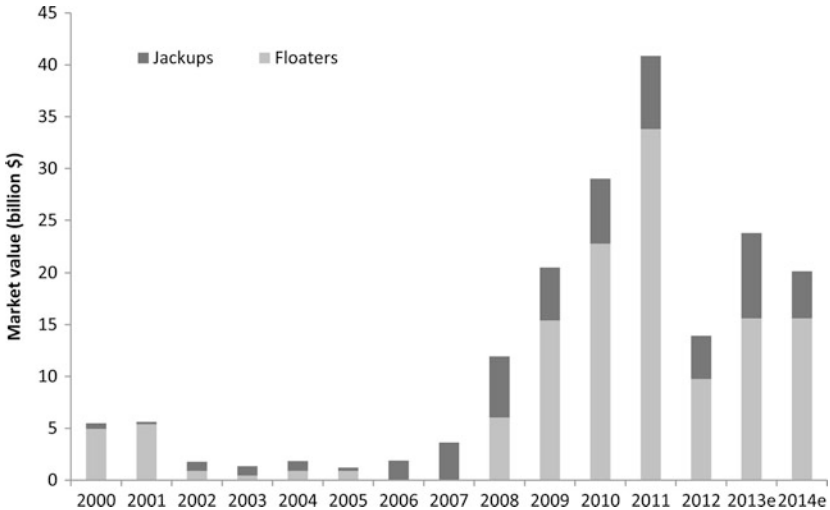

Fig. 2.7 Newbuild market size by delivery year, 2000–2014 (Source: Data from RigLogix [16])

During 2000–2005, about five jackups and five floaters were delivered each year. In 2005, the number of jackup orders increased dramatically followed by an increase in floater orders, due in large part to increasing oil and gas prices and contractors expectations of future demand. Jackup deliveries peaked in 2009 with 38 rigs delivered, and floater deliveries peaked in 2011 with 52 units. In every year since 2000, high-spec jackup deliveries have outnumbered standard jackups, and in 2011 only three standard jackups were delivered compared to 33 high-spec rigs.

2.3.5 Value

The value of the newbuild market is estimated[1] by tabulating the reported prices of rig deliveries. Market value peaked in 2010 at approximately $18 billion, and in most years floaters made up the majority of the market value, while jackups made up the majority of deliveries (Fig. 2.7). Market revenue peaked in 2009–2011 due to high demand in the 2007–2009 period. Orders declined in 2009 and 2010 due to the recession, and as a result, market revenue in 2012 was low before subsequently rebounding.

[1] Cost information is not available for a small number of rigs built by state-owned shipyards for state-owned drilling contractors, and cost data may not be reported similarly in all cases, but these sources of bias are believed to be small both on an absolute and relative basis.

2.4 Upgrade Market

2.4.1 Measures

Rigs require routine maintenance and periodically undergo upgrades. Periodic maintenance occurs over a 3–10 year period and typically consists of painting, replacing corroded or worn components, upgrading living quarters, and changing out machinery and equipment. Maintenance is performed to repair defects, accommodate customer demands, and maintain the useful life and value of the rig.

In addition to periodic maintenance, rigs are generally upgraded and refurbished at least once over the course of their lifetime to improve technology and maintain competitiveness. Upgrades involve significant capital expenditures and often involve structural changes to the rig, such as adding dynamic positioning, increasing leg length, adding cantilever capability and increasing variable load [6, 21]. Installation of new drilling equipment is also common. Upgrades increase the value of the rig and its replacement cost and require several months to perform [17].

In some cases, E&P companies require modifications to a rig before commencement of a drilling program. These typically do not significantly alter rig specifications and are charged to the E&P company, either as a lump sum payment or amortized over the duration of the contract. Money spent to maintain a rig in an acceptable state are considered operating expenditures. Costs incurred to upgrade the specifications of the rig or extend its life are considered capital costs.

2.4.2 Players

For most repairs and maintenance, work can be performed at local ports without shipbuilding or drydocking facilities [23]. More intensive upgrades are conducted at specialized facilities. Lamprell and Keppel are dominant players most years and no other shipyard upgraded more than one rig during 2009–2010 (Table 2.6). Other firms active in the upgrade market include Signal International and Gulf Cooper in the U.S., Drydocks World in the U.A.E., Larsen and Toubro in Oman, Malaysia Marine and Heavy Engineering in Malaysia, Maua Shipyard in Brazil, PD&MS in the U.K., Rijeka Shipyard in Croatia, and Remontowa in Poland.

2.4.3 Prices

The scale of upgrades varies widely and only by reviewing the scope of work can the variation in cost be understood. Recent jackup upgrades have ranged between

Table 2.6 Major rig upgrades by shipyard, 2009–2010

Shipyard	Nation	2009	2010
Lamprel	UAE	3	8
Keppel	Singapore	2	2
Keppel	Brazil	3	
Keppel	Netherlands	1	2
Hindustan	India		1
Keppel	Philippines		1
L&T	Oman		1
Aker	Norway		1
Sembawang	Singapore	1	
Others		3	
Total		13	16

Source: Offshore Magazine [13]

Table 2.7 Jackup upgrade contracts

Customer	Shipyard	Year	Cost (million $)	Scope
Ensco	Lamprell	2008	14.8	Steel renewal, leg repairs, accommodation upgrade, piping renewal, painting
National Drilling	Drydocks	2010	20	Life extension
GSP	Lamprell	2010	12	Upgrade electrical, drilling equipment, accommodation refurbishment
Japan Drilling	Lamprell	2010	11.8	Refurbishment
Aban Offshore	ABG	2011	13.2	Steel renewal, replacement of equipment
Gulf Drilling	Keppel-Qatar	2011	16.2	Major upgrade
Millennium	Lamprell	2011	27.5	Conversion to accommodation unit

Source: Industry press

$10 and $30 million and include painting, drilling equipment change-outs, new accommodations, piping and electrical system replacement, and leg and spudcan repair work (Table 2.7). Upgrade costs can exceed $50 million but at higher prices many firms choose to newbuild rather than upgrade [12].

Floater upgrades vary significantly in price depending on the type of upgrade (Tables 2.8 and 2.9). Complete rebuilds using the existing hull cost $300–$350 million and replace nearly all other components. Minor upgrades costing $10–$50 million include survey work, helideck addition, quarters replacement, piping installation, and structural modifications. At the mid-range, $75–$150 million will buy increased variable load, new accommodations and equipment. The 2010 upgrades of Noble's drillships *Roger Eason* and *Leo Segerius* are representative. For $152 million, new stern blocks were added to both vessels, over 85 % of the marine operating systems were replaced, derricks were refurbished, top drives and cranes were replaced, and the dynamic positioning system power was increased.

Table 2.8 Semisubmersible upgrade contracts

Customer	Shipyard	Year	Cost (million $)	Scope
Diamond	Keppel	2008	310	Complete rebuild
Noble	Signal	2010	15	Addition of helideck, quarters upgrade
Awilco	Remontowa	2010	75	Increase variable load, quarters
Fred Olsen	Keppel	2010	160	Survey, renewal and upgrade
Awilco	Remontowa	2010	15	Survey
Transocean	Semco	2011	20	Piping installation
Diamond	Keppel	2012	300	Complete rebuild

Source: Industry press

Table 2.9 Drillship upgrade contracts

Customer	Shipyard	Year	Cost (million $)	Scope
Neptune	Sembawang	2009	340	Increase water depth capacity, add dynamic positioning, upgrade drilling equipment
Transocean	Signal	2010	32.4	Living quarters upgrade, equipment replacement, painting, hull and tank repair
Noble	Keppel	2010	152	Replacement of accommodations and heliport modifications to stern

Source: Industry press

2.4.4 Size

A total of 287 rigs had major upgrades between 2001 and 2010 (Table 2.10). On average, 17 jackups and 13 floaters were upgraded each year, with peaks in 2004 and 2007 approximately coinciding with the timing of newbuild orders and suggesting that firms invest in upgrading under roughly the same conditions in which they invest in newbuilding. Upgrade activity is firm and rig specific and depends on factors such as the age of the fleet, the capital budgets of firms, and market demand.

2.4.5 Value

Estimating market revenue is complicated by the wide range of costs and the definition of what constitutes an upgrade. Shipyards generally do not breakout rig upgrade cost in their financial reports, and for private shipyards, no financial data is reported at all, therefore, a range of market values is provided by enumerating major upgrades and assuming a minimum and maximum upgrade cost per rig.

Table 2.10 Number of major upgrades and estimated market value, 2001–2010

	Jackups	Floaters	Total	Value (billion $)
2001	8	7	15	0.6–1.9
2002	32	10	42	1.0–3.3
2003	15	12	27	1.0–3.3
2004	22	15	37	1.3–4.3
2005	9		9	0.1–0.2
2006	13	20	33	1.6–5.3
2007	36	29	65	2.5–8.1
2008	18	18	36	1.5–4.9
2009	9	4	13	0.4–1.2
2010	11	5	16	0.5–1.5
Total	172	115	287	10.1–34.3

Source: Offshore Magazine [13]; Authors calculations

Jackup upgrades are estimated to cost at least $10 million and floater upgrades at least $75 million; at a maximum, jackup and floater upgrade costs are estimated as $25 and $250 million. Upgrade costs for individual rigs may fall outside of this range. Under these assumptions, the upgrade market is estimated to have an average value between $1 and $3.4 billion per year.

2.5 Secondhand Market

2.5.1 Measures

The secondhand market is measured by the number, value and type of transactions that occur. Rigs sold on the secondhand market may be part of the legacy fleet or newbuilds; units may be sold through mergers, liquidations, or private transactions; rigs may be sold with or without an existing contract backlog; and buyers may continue to use the vessel as a rig or may convert it to another use.

Transactions are conducted for a wide variety of reasons. In some cases, firms sell rigs due to bankruptcy. For example, Hercules purchased 20 rigs from Seahawk in 2011 for $105 million. Another example is Seadrill's purchase of a Petroprod rig from Sembcorp in 2010. In this case, Petroprod ordered a rig from Sembcorp, but entered bankruptcy before construction was finished. Sembcorp completed construction and sold the rig to Seadrill. In other cases, firms sell rigs to eliminate non-core assets which frequently involves a large drilling contractor selling older rigs to a low-spec specialist. For example, in September 2012, Transocean agreed to sell 38 shallow water rigs to Shelf Drilling International Holdings for $1.05 billion as part of its strategy to focus on the high-end market.

Rigs may be obtained through merger activity such as Seadrill's purchase of Scorpion in 2010, Transocean's purchase of Aker Drilling in 2011, and Noble's purchase of Frontier in 2010. However, the distinction between a secondhand transaction and a merger is ambiguous. For example, Ensco's purchase of Pride

Table 2.11 Number of transactions in the secondhand market for select firms, 2005–2010

Firm	Buyer	Seller
Hercules	7	4
Seadrill	8	3
Transocean		10
Songa	4	4
Noble	6	
Ensco	1	4
Rowan	3	2
Diamond Offshore	1	4
Maersk	2	3
Aban	3	1
Saipem	4	

Source: Data from RigLogix [16]
Note: Transactions frequently involve multiple rigs of different quality and classes

in 2010 and Transocean's purchase of Global Santé Fe in 2007 are typically considered mergers by market tracking services and are not included in secondhand market data. Mergers of similarly sized companies are not considered secondhand transactions, while mergers between a larger and smaller firm are often considered secondhand transactions.

2.5.2 Players

Hercules and Seadrill have been the most frequent buyers in the secondhand market in recent years, while Transocean has been the most frequent seller (Table 2.11). Seadrill has targeted newbuild and high-spec rig purchases, while Hercules has focused on less expensive, low-spec units as an alternative to newbuilding. Transocean has been active in divesting older rigs, particularly jackups.

The newbuild market allows firms to add capacity, but the secondhand market is critical to matching fleets to business strategies. For firms focused on the high specification market, the secondhand market provides a means to divest older assets. For firms focused on lower specification rigs, the secondhand market is an economic way to increase fleet size and gain market share.

2.5.3 Prices

Secondhand prices range widely due to differences in rig age and factors related to the buyer and seller and market conditions at the time of sale (Table 2.12). The minimum value of a rig on the secondhand market is \$5 million which is approximately equal to the scrap value of a unit. Low-priced transactions are frequently scrap sales or conversions.

Table 2.12 Secondhand market prices by year, 2005–2010

Year	Jackups (million $)	Floaters (million $)
2005	42 (22–60)	37 (13–60)
2006	67 (17–210)	102 (14–270)
2007	148 (26–212)	321 (211–675)
2008	106 (9–200)	294 (5–676)
2009	84 (5–199)	475 (460–490)
2010	188 (26–356)	288 (102–560)

Source: Data from RigLogix [16]
Note: Average price depicted. Price range shown in parentheses

Prices on the secondhand market are determined by market conditions and the net asset value (NAV) of the rig which is an estimate of its net revenue generation potential over its remaining life. Factors that influence NAV include rig design class, operational water depth, drilling depth and equipment specifications, age and condition, location, and participants expectations of future market conditions.

In the absence of market constraints the secondhand price should approximate the NAV, however, imperfect information, supply–demand imbalances, a limited number of players, and financial pressure (e.g. bankruptcy) may cause NAV and secondhand market prices to differ. For example, when Seahawk declared bankruptcy in 2011, it owned a fleet of 20 low specification jackup rigs valued at approximately $397 million. Hercules was the only interested buyer and paid $105 million to acquire the fleet.

The maximum price for a secondhand marine vessel can exceed the price of a newbuild if sold with a contract backlog, and this is particularly common in company acquisitions [22]. Sale with a contract backlog will increase the asset value. Secondhand rigs may also be more valuable because they are available immediately while rigs under construction may only be delivered after a multiyear delay. In recent years, secondhand prices for recently built rigs have been approximately equal to newbuild prices.

2.5.4 Size

From 2005 to 2010 about 20 rigs were sold each year with the majority being jackups (Table 2.13). Jackups transacted the most, followed by semis and drillships. Approximately 2–5 % of the global fleet is transferred each year.

2.5.5 Value

The secondhand market is valued on the order of $2–$4 billion per year. When cost data for a particular transaction was not available, the value of the transactions was

Table 2.13 Rigs sold and market valuation in the secondhand market, 2005–2010

Year	Jackups	Semis	Drillships	Total	Value (billion $)
2005	9	5	1	15	0.5
2006	20	10	1	31	2.1
2007	13	6	3	22	3.7
2008	10	3	1	14	2.2
2009	10	3	0	13	2.0
2010	20	4	7	31	6.8
Total	82	31	13	126	17.3

Source: Data from RigLogix [16]; Authors calculations

estimated based on the age of the rig, its water depth capability, and the average cost of similar transactions during the year. High market value in 2010 was due to three transactions: the purchase of Skeie Drilling by Rowan, the purchase of Scorpion by Seadrill, and the purchase of Frontier by Noble. Each of these transactions exceeded $1 billion.

2.6 Scrap Market

2.6.1 Measures

The scrap market is characterized by the annual number of transactions and their prices. Cold- and dead-stacked rigs are sold to specialized shipbreaking firms for dismantling and recycling [8]. Rigs may be scrapped after being damaged in a hurricane if toppled offshore, or may be economic to repair and re-enter the fleet (Fig. 2.8). When rigs are scrapped following damage, a marine salvage firm is contracted to remove the rig to the owner's shipyard.

2.6.2 Players

Rig scrapping is a small part of the larger ship breaking industry concentrated in India, Pakistan, China, Turkey and Bangladesh [14, 19]. Shipbreaking in the U.S. is primarily driven by disposal of U.S. Navy ships and other federal vessels and very little rig hull deconstruction occurs domestically [20]. The firms most likely to process scrapped rigs in the U.S. are located along the Brownsville, Texas ship channel: Esco Marine, International Shipbreaking, Marine Metals and All-Star Metals.

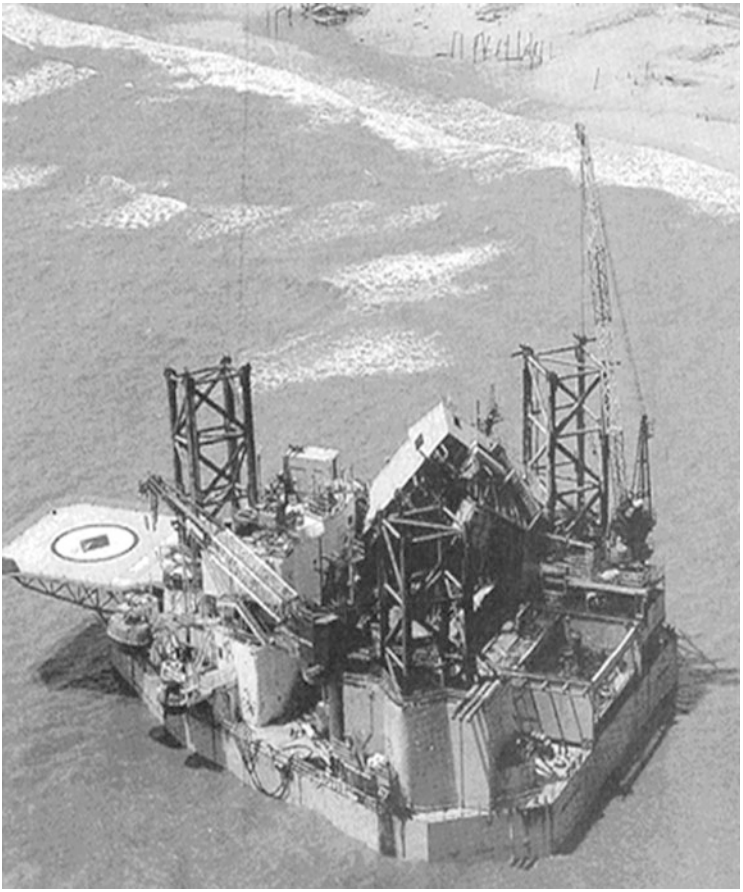

Fig. 2.8 The *Ocean Warwick* grounded near Dauphin Island, Alabama following Hurricane Katrina was repaired and re-entered the fleet (Source: Smit)

2.6.3 Prices

Vessels are sold to ship breaking firms directly or via brokers on a per ton basis and the value of a vessel will principally depend on its weight, the scrap metal price at the time of sale, the labor required to dismantle the unit, and the transport cost [9]. Most of the value in an obsolete rig lies in the drilling equipment which is removed and sold before the rig is scrapped [3].

In 2010 and 2011, Hercules sold five jackups for scrap ranging between $1 and $5 million with an average price of $2.5 million, consistent with scrap steel prices in the range of $300–$550 per ton. In some cases, scrapping may result in a net cost for contractors. In 2008, for example, the Texas General Land Office contracted Cleveland Wrecking Company to remove the jackup rig *Zeus* in the Freeport Ship

Channel. The Cleveland Wrecking Company was paid $1.75 million in addition to the value of the scrap steel.

2.6.4 Size

Rigs are removed from the fleet when converted to another use, when lost due to accidents or catastrophic events, or when sold into the scrap market. Conversion to another use is usually more profitable than scrapping, but the option may only be available sporadically. In addition, because storage costs are relatively low, there is little incentive for contractors to retire rigs from the fleet and a large number of dead-stacked rigs are in storage awaiting final disposition. As a result, rigs are rarely scrapped unless they have sustained significant damage from storms, blowouts or other accidents. Between 2005 and 2011, just seven rigs in the U.S. were sold for scrap [16].

2.6.5 Value

Given the small number of rigs scrapped each year and their low value, the size of the scrap market is for all practical purposes negligible relative to the other rig markets. In many years, no rigs are scrapped, and when rigs are scrapped the value of transactions are based on the rig weight and scrap metal price at the time of sale, rarely exceeding $5 million per unit. The average size of the market is estimated to be less than $50 million annually.

As the legacy fleet continues to age, scrapping activity will increase and the market may grow, and since many aging rigs are in the GOM, most of these rigs are likely to be processed by U.S. ship recyclers. While costs at U.S. ship recyclers are high relative to world costs, they will likely be sustained by the high costs to transport a rig from the GOM to Asia.

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Chapter 3
Rig Dayrates and Utilization

Abstract The contract drilling market is characterized by three interrelated measures: utilization, dayrates, and fleet size. Utilization describes the proportion of rigs working to the available fleet at a specific time and place, while dayrates represent the average daily rental charged by rigs of a given class operating in a specific water depth category and region over a specific period. Contractors build rigs to generate cash flow and capture market share. Rig movements between regions are usually not rapid enough to create strong interregional correlations in dayrates and utilization. Rig demand is associated with oil prices which vary dramatically over time, and dayrates are highly variable. When rig supply exceeds demand, low prices result. We characterize global and regional supply, utilization and dayrate trends over the 2000–2010 period. The U.S. Gulf of Mexico was the least expensive jackup market during the decade, followed by the Persian Gulf, while the North Sea was the most expensive jackup market. The chapter concludes with a brief discussion of the contracts used in the industry and the primary customers in each regional market.

3.1 Supply

The global supply of marketable rigs varies over time, increasing with newbuild construction and reactivation and decreasing when units are dead-stacked and retired. Newbuilds far outpace retirements and the total fleet size has grown 35 % over the past decade from 645 active and cold-stacked rigs in 2000 to 868 active and cold-stacked rigs in 2012 (Fig. 3.1).

In January 2012, the world fleet consisted of 539 jackups and 329 floaters (Fig. 3.2). The jackup inventory was composed of 201 low-spec (<300 ft, non-harsh environment) units and 336 high-spec units (>300 ft or harsh environment). The floater fleet was dominated by semisubmersibles (223 semis versus 106 drillships).

The jackup and drillship fleets are dominated by high-specification, deepwater newbuilds (>300 ft for jackups; >7,500 ft for drillships), while the semi fleet is dominated by midwater (<7,500 ft) units (Fig. 3.3). Semis comprise the majority of

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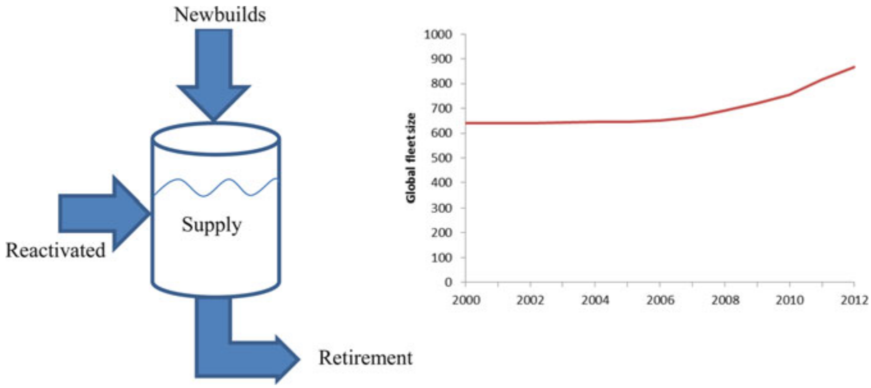

Fig. 3.1 Bathtub analogy for MODU supply (Source: Data from RigLogix [9])

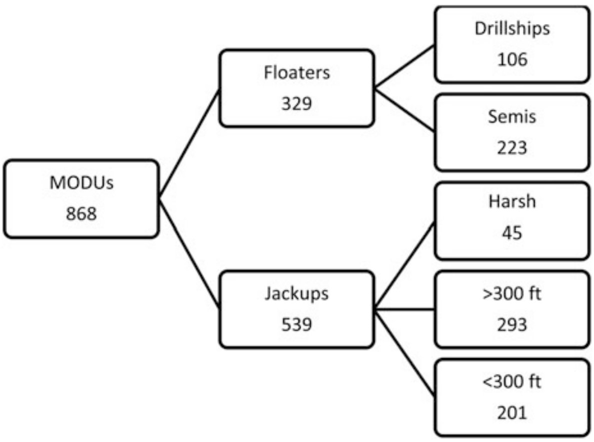

Fig. 3.2 Global supply of newbuild and existing MODUs in the 1Q2012 (Source: Data from RigLogix [9])

the floater fleet, but after the delivery of drillships currently under construction, drillships are expected to comprise the majority of the high-spec floater fleet from 2013–2018. Most new construction is occurring in the drillship and jackup markets with relatively few semis under construction.

3.2 Geographic Distribution

3.2.1 Regional Characteristics

Contract drillers service oil and gas companies throughout the world wherever hydrocarbon resources are found or are believed to occur. The Persian Gulf,

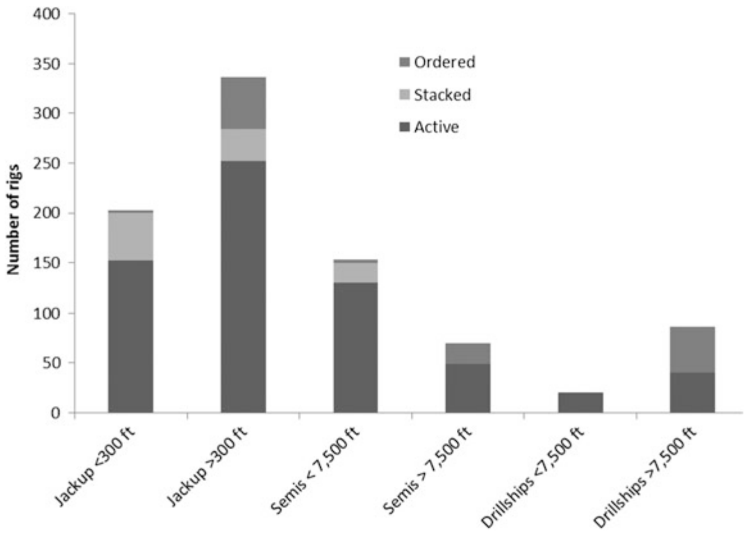

Fig. 3.3 Global supply of MODUs in the 1Q2012 (Source: Data from RigLogix [9])

U.S. Gulf of Mexico, Brazil, the North Sea, Southeast Asia, and West Africa were the largest offshore markets in 2011 accounting for approximately 80 % of the supply with over 50 contracted rigs per region (Table 3.1, Fig. 3.4). India and China were also significant markets with 77 contracted rigs.

The U.S. GOM and North Sea were the first offshore regions to be explored, and production in the shallow water areas of these basins have been in decline for over a decade. New discoveries in the deepwater GOM and Norwegian Continental Shelf have maintained capital investment, and both regions provide a stable and predictable business environment, a well-developed, reliable supply chain, and good geologic prospectivity (Table 3.2).

West African offshore markets are dominated by Nigeria and Angola. Investment and operation in West Africa is complicated by a tenuous security situation in Nigeria, limited infrastructure in Angola and Ghana, widespread corruption, and a lack of skilled labor throughout the region.

Southeast Asian markets are primarily composed of Indonesia and Malaysia, with Vietnam and the Philippines promising developing regions. The first offshore well in the region was drilled offshore Brunei territorial waters in 1958, and development intensified in the 1970s. Shallow water drilling dominates the region with significant midwater activity. Territorial disputes with China over the Spratley and Paracel Islands remain unresolved and have hindered capital investment in the region.

Brazil is a rapidly developing deepwater market dominated by the state-owned oil company Petrobras. Brazil has made a concerted effort to increase the domestic content across the supply chain and in 2011 Petrobras announced that it will build 33 drillships in newly established Brazilian shipyards by 2020.

The Persian Gulf is a shallow water market that has developed steadily over the last two decades. The region includes Saudi Arabia, Qatar, the UAE, Iran, Kuwait,

Table 3.1 Distribution of active rigs by nation in 2011

Country	Jackups	Semis	Drillships	Total	Region
U.S.	51	20	10	81	U.S. GOM
Brazil	3	52	15	70	Brazil
India	34	2	9	45	India
China	28	4	0	32	China
Norway	7	22	1	30	North Sea
U.K.	12	14	1	27	North Sea
Mexico	24	3	0	27	Mexican GOM
Egypt	20	2	2	24	Red Sea/Mediterranean
UAE	24	0	0	24	Persian Gulf
Saudi Arabia	21	0	0	21	Persian Gulf
Iran	19	1	0	20	Persian Gulf
Qatar	20	0	0	20	Persian Gulf
Malaysia	12	6	1	19	Southeast Asia
Nigeria	9	4	4	17	West Africa
Angola	4	7	5	16	West Africa
Vietnam	13	2	0	15	Southeast Asia
Indonesia	11	1	1	13	Southeast Asia
Singapore	2	6	3	11	Southeast Asia
Australia	1	7	1	9	Australia
Netherlands	8	0	0	8	North Sea
Gabon	4	2	0	6	West Africa
Thailand	6	0	0	6	Southeast Asia
Ghana	0	3	2	5	West Africa
Azerbaijan	2	3	0	5	Caspian Sea
Denmark	5	0	0	5	North Sea
Venezuela	3	0	2	5	Caribbean
All others	48	14	5	67	
Total	394	175	57	626	

Source: Data from RigLogix [9]

and Bahrain, and is dominated by National Oil Companies. The Persian Gulf includes Saudi Arabia's Safaniya field, the world's largest offshore oil field, and Qatar's North Field and adjacent South Pars field in Iran, the world's largest natural gas reservoir [5].

Mexico, India and China are mid-sized markets. India and China are developing markets with shallow and deepwater sectors. Mexico is a mature region dominated by production at the shallow water Cantarell field. Cantarell peaked in 2004 and production declined by 70 % through 2011. Only 15 deepwater wells were drilled in the Mexican GOM between 2004 and 2010 [5, 11].

Smaller markets with less than 25 active rigs in 2011 include the Mediterranean Sea, Black Sea, Caspian Sea, Eastern Canada, the Caribbean and Western Australia. Frontier regions defined as having fewer than five rigs include the Arctic Ocean and

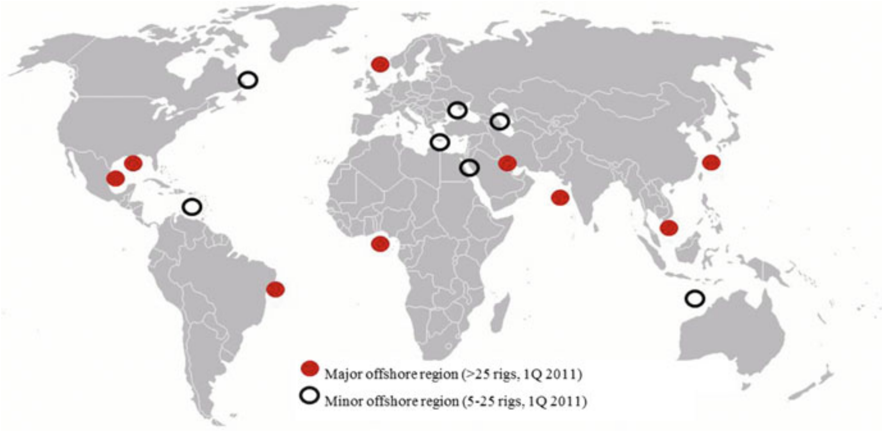

Fig. 3.4 Offshore drilling regions and 1Q2011 drilling activity (Source: Data from RigLogix [9])

East Africa, as well as previously unexplored regions such as Ghana in West Africa and the Philippines in Southeast Asia [2].

3.2.2 Active Rigs

Baker Hughes maintains a database on active rig counts that is widely referenced in the industry [1]. In North America, Baker Hughes defines a rig to be active from the time a well is spud until it reaches target depth; internationally, a rig must be drilling 15 days a month to be counted as active. Worldwide, the number of active rigs has varied from 150 to 300 per year over the past quarter century (Fig. 3.5).

Active rigs in the U.S. GOM peaked at 160 in 2001, while the North Sea rig count peaked at 85 in 1988. In 2012, about 40 rigs were active in each region. Southeast Asia and Persian Gulf markets have seen increasing trends and twice as many rigs working the regions since the late 1980s. West Africa has seen significant swings, peaking in the late 1990s at 35 rigs, declining to about half that level in the mid 2000s before returning to historic peak levels.

In the North Sea, a declining U.K. sector has been partially offset by growth in Norway (Fig. 3.6). In the Persian Gulf, the UAE, Qatar and Saudi Arabia have all been dominant at different times. Since 2005, most growth has occurred in Saudi Arabia while Iranian offshore activity has diminished. Nigeria has been the dominant player in West Africa since the early 1990s, but in 2009 there was significant growth offshore Congo, Gabon, Ghana, Liberia, Sierra Leone and Cameroon, in part due to the end of several civil wars and large discoveries in the region. In Southeast Asia, activity levels in Indonesia and Malaysia have been relatively stable over the past two decades with growth arising from Vietnam and Thailand.

Table 3.2 Major features of offshore regions

Region	2010 Production (million boe/day)	Features
Persian Gulf[a]	6.7	NOCs are primary players. Between 1990 and 2010 rig count increased fourfold from approximately 20 to 80
North Sea[b]	6.1	Mature region with harsh and moderate conditions. There has been a modest decline in rig count since 2000. Statoil and IOCs are major players
West Africa[c]	3.9	Nations vary in maturity with Nigeria well developed and Cameroon and Ghana frontier regions. Nearly all production is from Nigeria and Angola; growth is in the deepwater market, especially in Angola, but the shallow water market accounts for most production. IOCs are major players
SE Asia[d]	3.1	Strong shallow and deepwater segments subject to typhoons. Rig count has approximately doubled since 1990. Offshore production accounts for half of production in Indonesia and over 90 % of production in Malaysia. Vietnam and the Philippines have territorial disputes with China
U.S. GOM	2.7	Mature offshore region. Shallow water region in decline; deepwater market growing. Accounted for 23 % of domestic oil production in 2012. Periodically impacted by hurricanes and significant destruction
Mexico GOM	2.5	Primarily a declining shallow water market with little deepwater activity. Developed rapidly in the early 1990s and again in the early 2000s. Deepwater exploration slated for the future
Brazil	2.1	Large deepwater market with little shallow water activity. Offshore accounts for 90 % of national production. Growth in production due to pre-salt discoveries. Petrobras is the NOC and major player
India	1.1	Growing market with a strong gas sector. Offshore accounts for two-thirds of national production. ONGC and public firm Reliance are major players
China	1.0	Major development began in the 1980s and 1990s. CNOOC and subsidiary COSL are major players in the region. Offshore activity accounts for 20 % of national production

Source: Data from Rystad Energy [10, 11], Energy Information Administration [5], Industry press
[a]Composed of Saudi Arabia, Kuwait, Qatar, UAE, Bahrain and Iran
[b]Composed of the UK, Norway, the Netherlands, Germany and Denmark
[c]Composed of Nigeria, Angola, Cameroon, Ghana, Gabon, and Equatorial Guinea
[d]Composed of Indonesia, Thailand, Singapore, Malaysia, Vietnam, Brunei and the Philippines

3.2.3 Contracted Rigs

Contracted rigs refer to any rig under contract and are distinguished according to jackup and floater categories. A contracted rig may be drilling, performing a

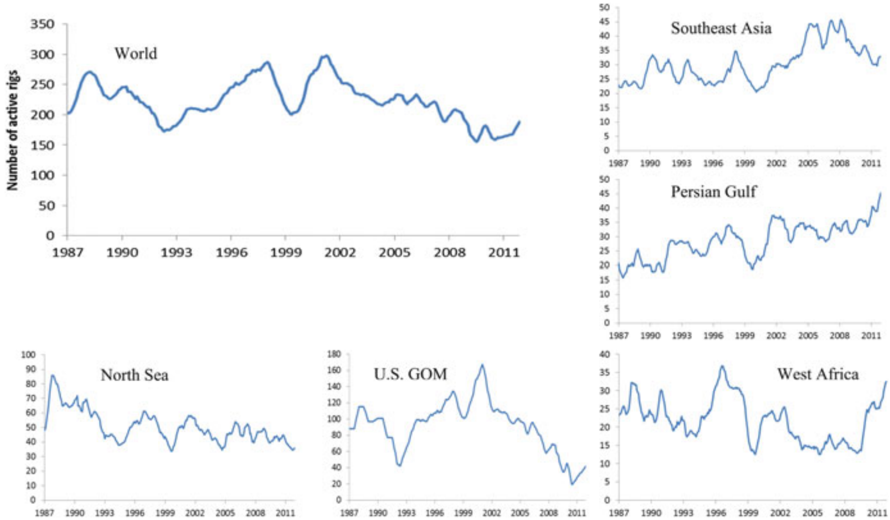

Fig. 3.5 Number of active rigs by region, 1987–2012 (Source: Data from Baker Hughes [1])

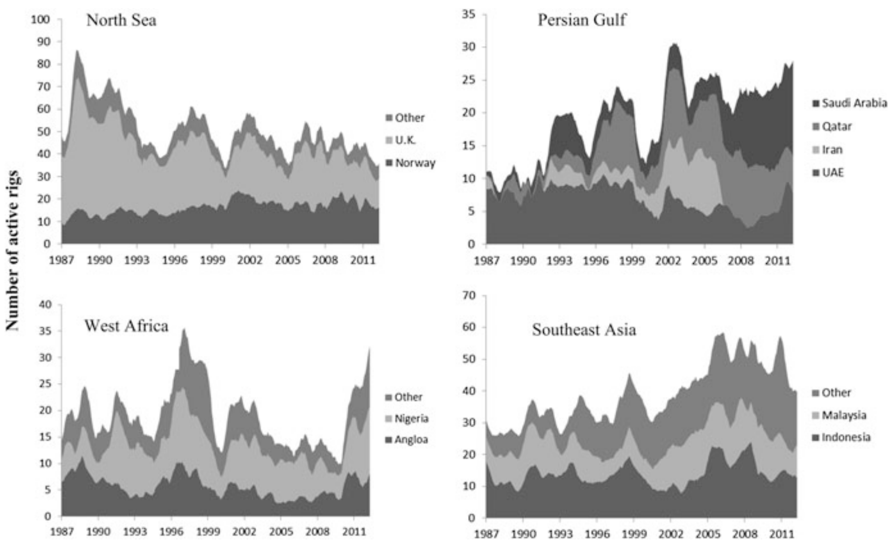

Fig. 3.6 Active rig trends by country, 1987–2012 (Source: Data from Baker Hughes [1])

workover, waiting on location, mobilizing, or under modification. RigLogix was the commercial service provider and data on 7,123 contracts written between 2000 and 2010 were analyzed.

Contracted rigs follow patterns similar to active rigs in the U.S. GOM because most contracts in the region are short-term and mobilization distances are small, but elsewhere in the world, correlations are not as strong and reflect differences in the manner in which rigs are counted.

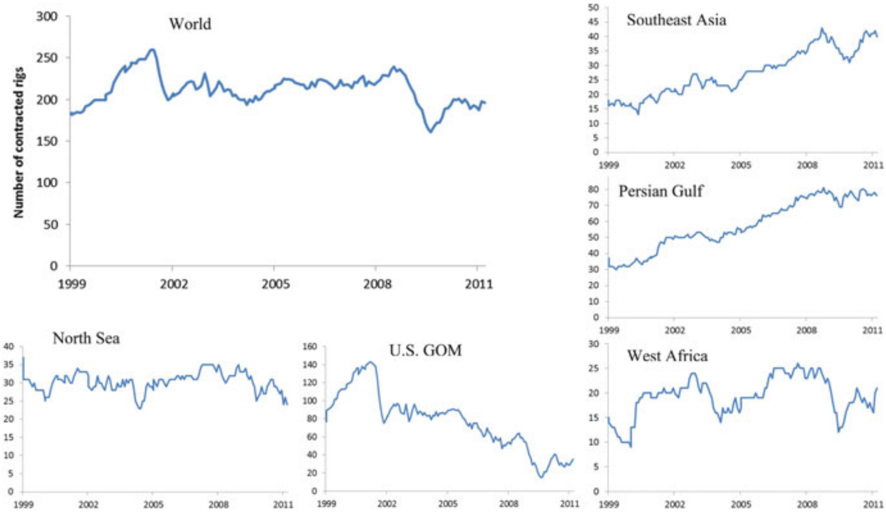

Fig. 3.7 Number of contracted jackups by region, 1999–2011 (Source: Data from RigLogix [9])

Southeast Asian and Persian Gulf jackup markets grew over the decade similar to the trends of active rig counts, while the North Sea market remained relatively stable (Fig. 3.7). West Africa exhibited the greatest volatility over the period similar to Baker Hughes trends. The U.S. GOM jackup market has seen a significant decline in contracted rigs due to the maturity of shelf drilling and economic recessions in 2001 and 2009. In the floater market, West Africa and Southeast Asia were generally increasing, while the U.S. GOM and North Sea have remained relatively constant (Fig. 3.8).

3.2.4 Working Water Depth

Average working water depth is a general indicator of the rig specification levels employed in each region and provides evidence of the requirements and variation of drilling activity (Fig. 3.9).

China, the U.S. GOM and Persian Gulf are the shallowest jackup markets and older, low-specification rigs are common in each region. Southeast Asia and the North Sea are among the deepest jackup markets and high-spec units are frequently required. The North Sea is a particularly shallow floater market, however, because of the harsh environmental conditions, high-specification floaters are typical. The U.S. GOM, Brazil, India and West Africa are the deepest floater markets, and have high maximum water depths.

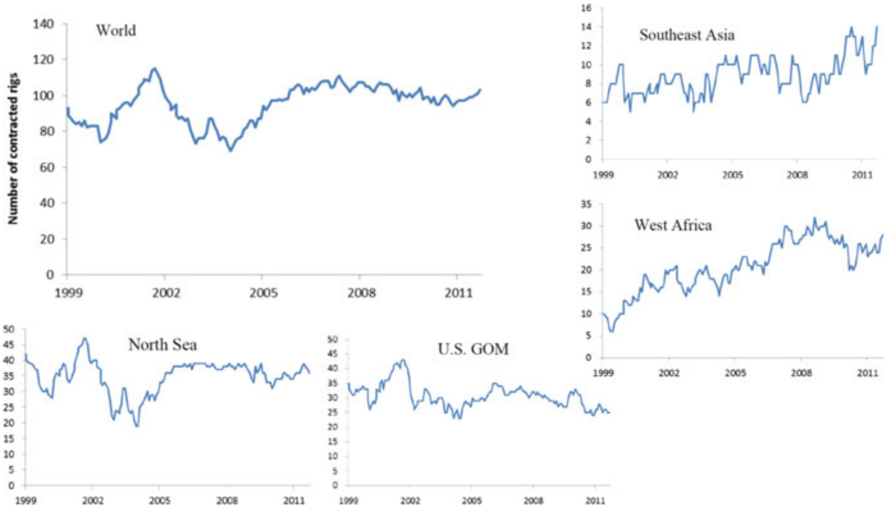

Fig. 3.8 Number of contracted floaters by region, 1999–2011 (Source: Data from RigLogix [9])

3.3 Utilization

3.3.1 *Definition*

Utilization is the ratio of the number of working rigs in a region to the number of rigs available to work at a specific point in time. If cold-stacked rigs are included in the count of available rigs as is most often the case, rigs which have little prospect of ever returning to service will bias the utilization measure downward and regional utilization rates will appear lower than actual performance. On the other hand, if cold-stacked rigs are not included in the metric, utilization rates would appear inflated and may not accurately reflect the number of rigs available to work. Utilization rates are a derived measure based on imprecise rig counts, and they are best presented on a moving-average basis to include data over a given period to smooth out and reduce short term variation.

3.3.2 *World Trends*

At the beginning of the decade, world jackup utilization rates exceeded floater rates, but since 2006 floaters have been more heavily utilized and more resilient against the economic recession during the period (Fig. 3.10). Jackup and floater utilization respond to different market stimuli and reflect differences in regional development, contract duration, newbuild orders and deliveries, and other factors. There is no significant correlation between global jackup and floater utilization rates suggesting that the two markets are largely independent.

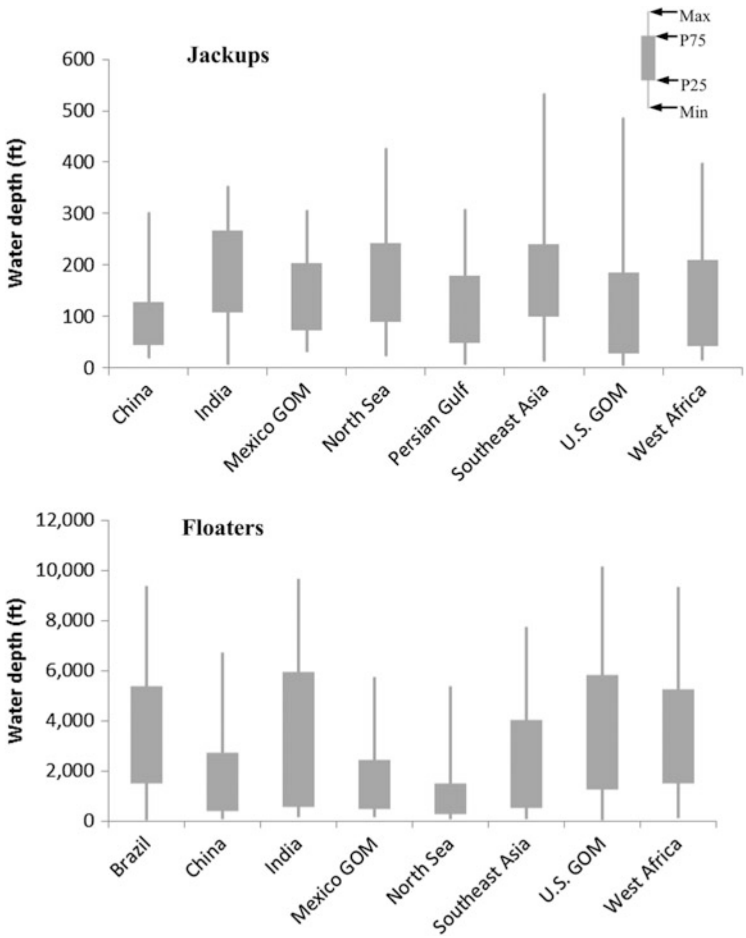

Fig. 3.9 Working water depths statistics of jackup and floater contracts by region, 2000–2011 (Source: Data from RigLogix [9])

3.3.3 Regional Trends

In the jackup market, utilization trends in Southeast Asia, the North Sea, and the Persian Gulf have tracked each other closely over the past decade, while the U.S. GOM and West Africa have exhibited more variable trends and lower utilization rates over the period (Fig. 3.11). In recent years, the U.S. GOM has had consistently lower utilization rates than other regions due to oversupply and low domestic gas prices (Table 3.3).

In the floater market, West Africa, the North Sea and the U.S. GOM have generally similar utilization patterns, but in the U.S. GOM, the post-2009 decline in utilization rates has been negatively impacted by the Macondo oil spill

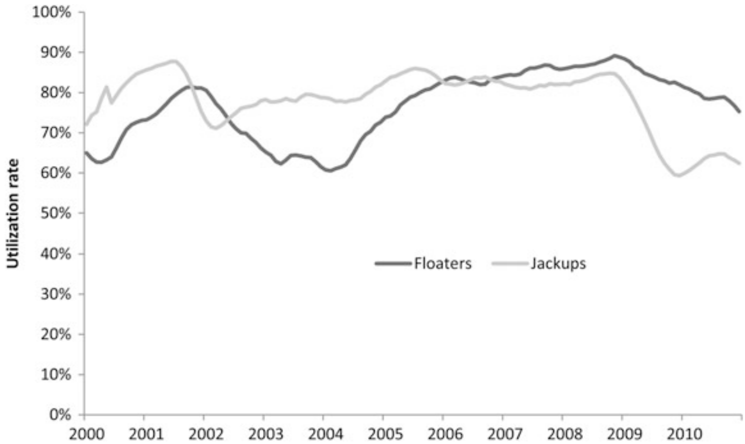

Fig. 3.10 World utilization rates for jackups and floaters, 2000–2010. Utilization computed as a 6-month moving average (Source: Data from RigLogix [9])

(Fig. 3.12). Southeast Asia exhibited the lowest utilization rates throughout the decade, while Brazil maintained high utilization with sustained periods of full utilization due to Petrobras' near monopoly[1] in the region.

3.3.4 Interregional Correlations

To the extent that global factors impact supply and demand conditions, utilization rates are expected to be correlated across regions. Conversely, if local factors predominate, regional utilization rates may not be associated and interregional correlations would be expected to be poor. For example, oil prices form in the world market and provide similar signals to E&P firms worldwide. If oil prices are a major driver of utilization rates, high correlations would likely occur. By contrast, if gas prices are a major driver of utilization in a regional market, or if the local mix of E&P firms is dominated by NOCs, low correlations are expected.

In the jackup market, utilization in the U.S. GOM has the lowest correlation with all other world regions indicating that region-specific factors are impacting utilization (Table 3.4). Growth in the Persian Gulf and declining U.S. GOM and North Sea markets during the evaluation period mean that the Persian Gulf will be poorly correlated with the U.S. GOM and North Sea. Utilization rates in most other regions are moderately correlated indicating that global factors (e.g., oil prices) effect the regions similarly but that intra-regional factors are also significant.

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[1] Petrobras' role as the E&P monopolist allows drilling contractors to better match demand and supply from a central decision-making firm. Private oil companies also operate offshore Brazil, but about 90 % of the fleet is typically contracted to Petrobras.

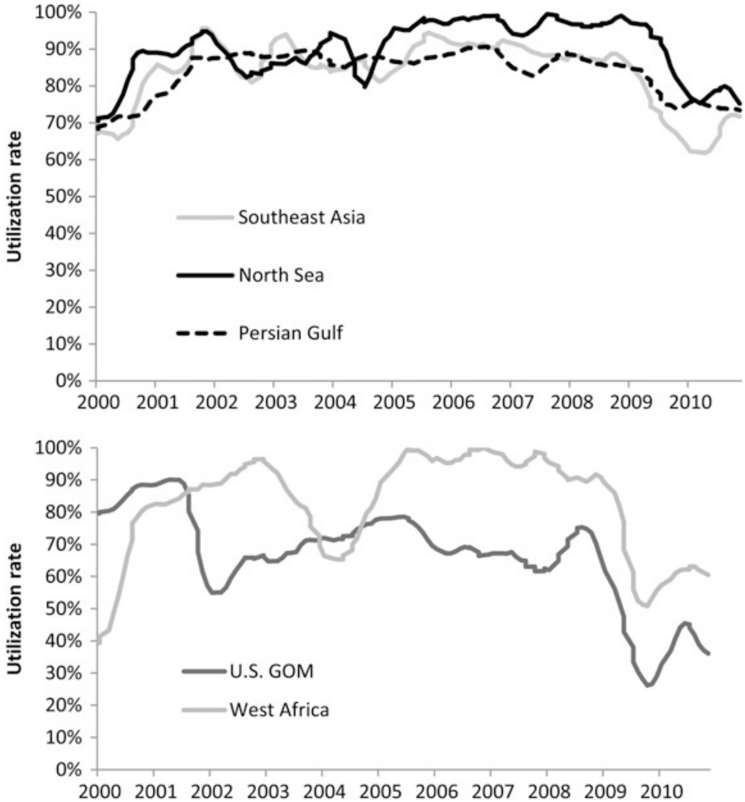

Fig. 3.11 Jackup utilization by region, 2000–2010. Utilization rate computed as a 6-month moving average (Source: Data from RigLogix [9])

Table 3.3 Average utilization rates by region and time period, 2000–2010

	Jackups			Floaters		
	2000–2005	2006–2010	2000–2010	2000–2005	2006–2010	2000–2010
North Sea	89	91	90	73	91	82
Persian Gulf	85	82	84			
Southeast Asia	86	81	84	57	50	54
U.S. GOM	74	55	65	69	82	76
West Africa	84	81	83	82	90	86

Source: Data from RigLogix [9]

In the floater market, Southeast Asia is poorly correlated with all other regions, suggesting that regional factors dominate market dynamics (Table 3.5). Correlations are slightly lower than in the jackup market, and the U.S. GOM and North Sea, and North Sea and Brazil, are the only regions with strong correlative structure. Low correlations among the floater fleet are believed to be partially due to

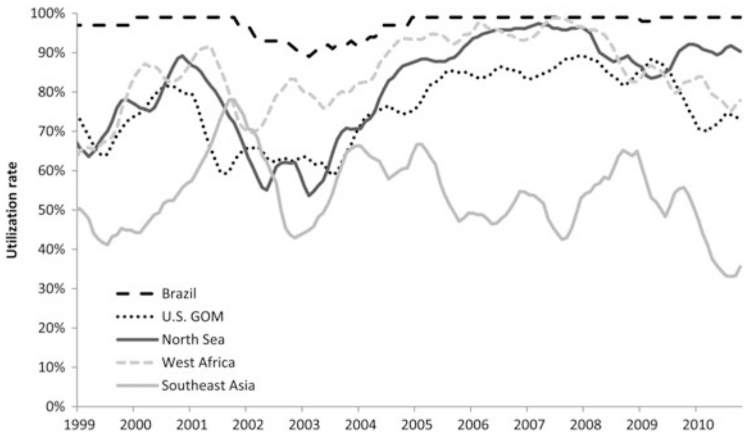

Fig. 3.12 Floater utilization rates by regions, 2000–2010. Utilization rate computed as a 6-month moving average (Source: Data from RigLogix [9])

Table 3.4 Jackup utilization regional correlation matrix, 2000–2010

	North Sea	Persian Gulf	Southeast Asia	U.S. GOM	West Africa
North Sea	1				
Persian Gulf	0.56	1			
Southeast Asia	0.71	0.83	1		
U.S. GOM	0.37	0.33	0.55	1	
West Africa	0.70	0.73	0.84	0.50	1
Average	0.59	0.61	0.73	0.44	0.70

Source: Data from RigLogix [9]

Table 3.5 Floater utilization regional correlation matrix, 2000–2010

	Brazil	North Sea	Southeast Asia	U.S. GOM	West Africa
Brazil	1				
North Sea	0.82	1			
Southeast Asia	−0.05	−0.14	1		
U.S. GOM	0.68	0.82	−0.14	1	
West Africa	0.39	0.66	0.15	0.62	1
Average	0.46	0.54	−0.05	0.50	0.46

Source: Data from RigLogix [9]

the high utilization rates for floaters. Variation in utilization in one region are unlikely to resolve small changes in variation in another region. Rig movements between regions are usually not large or rapid enough to create strong interregional correlations.

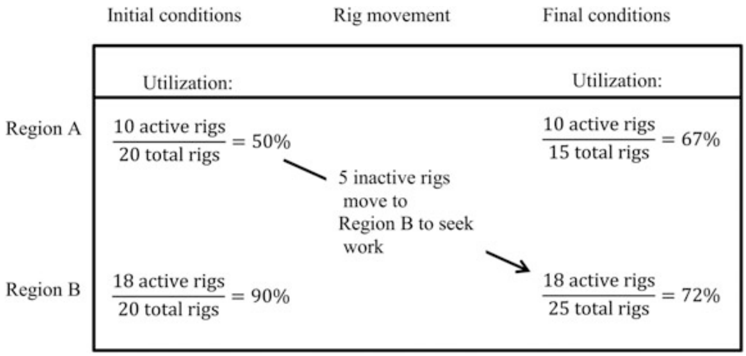

Fig. 3.13 Illustration of the movement of rigs in response to high utilization rates

3.3.5 High Utilization Creates Market Opportunities

When a regional fleet is highly utilized, contractors respond by marketing inactive rigs from other regions or building new rigs for the high utilization market (Fig. 3.13). As these rigs win contracts, they are moved into the high utilization region, increasing regional fleet size and capturing market share. Over time, if the market cannot sustain the larger fleet size, utilization rates will decline and the process of redistributing and stacking rigs will repeat.

The Persian Gulf and Southeast Asian jackup markets have expanded their inventories in response to high utilization over the past decade (Fig. 3.14). In both markets, utilization rates were high for several years, and during this time contractors responded by building new rigs and moving rigs into the region doubling (Persian Gulf) and tripling (Southeast Asia) capacity. Utilization rates eventually declined, but the momentum of rig movements into the regions persisted. Similar patterns may not exist elsewhere or at different times. For example, in the North Sea jackup market utilization rates were high for an extended period without an increase in rig count, likely reflecting a limited supply of harsh environment jackups capable of moving into the region (Fig. 3.15).

3.4 Dayrates

3.4.1 Definition

Operators request bids from contractors whose rigs in the area have the specifications and capacity to drill the target well. Contractors specify dayrates in the bidding process and the operator selects the preferred contractor based on the bid dayrate, technical capacity, scheduling availability, safety record, crew experience, and prior working relationships. Under most dayrate contracts, the contractor

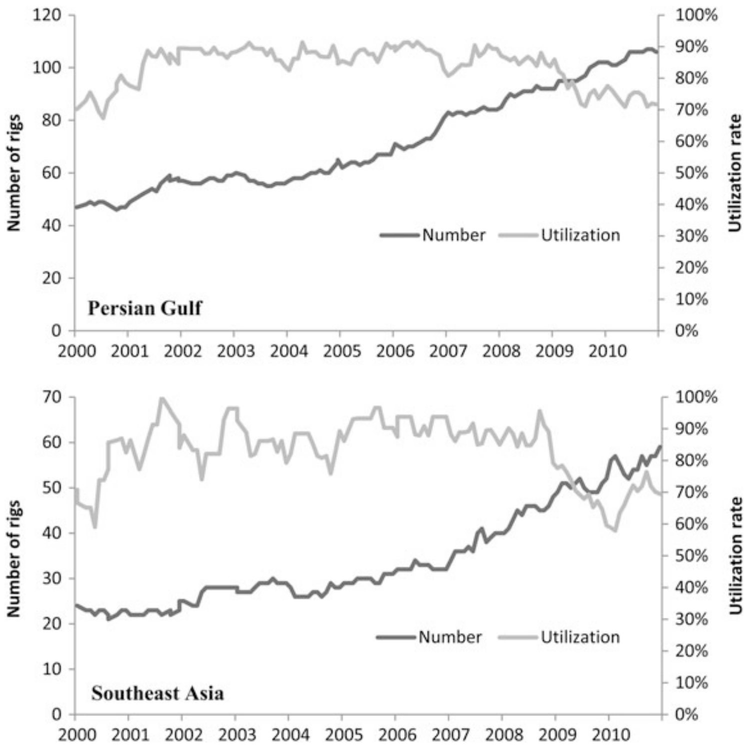

Fig. 3.14 Relationship between utilization rate and the increase in market capacity in the Persian Gulf and Southeast Asia, 2000–2010 (Source: Data from RigLogix [9])

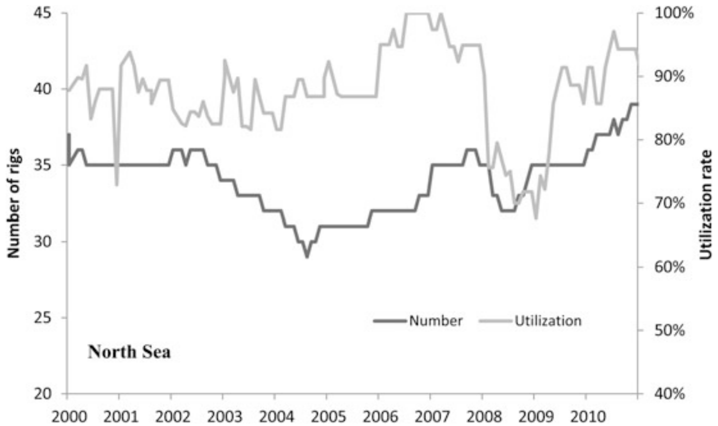

Fig. 3.15 Relationship between utilization rate and rig movement in the North Sea, 2000–2010 (Source: Data from RigLogix [9])

Fig. 3.16 Method used to compute average dayrates

receives a fixed amount per day for drilling the well with higher rates while the unit is operating and lower rates or a lump sum payment for periods of mobilization or when operations are interrupted or restricted by equipment breakdowns, adverse weather conditions or other factors [7, 8].

3.4.2 Normalization

Monthly average dayrates were computed for jackups, drillships and semisubmersibles based on 7,123 contracts between 2000 and 2010 using the average dayrates of all contracts where drilling began in that month (Fig. 3.16). Daryrates were inflation adjusted for comparisons across time using the U.S. Bureau of Labor Statistics (BLS) annual producer price index for all finished goods and the start year of the contract. Industry specific currency inflators are also available for data normalization (e.g., CERA Upstream Index).

3.4.3 Market Dynamics

Dayrates are determined by the supply and demand balance of rigs in the marketplace along with a number of factors that are more difficult to track. Supply and demand is proxied by utilization rate, and dayrates and utilization are expected to be correlated with respect to region, time period, and rig class. For a given supply of rigs available to work in a given region, as utilization rates increase, the number of rigs available to bid declines and pricing power shifts to the drilling contractor, eventually leading to higher dayrates, for all things equal. High dayrates provide signals to the market that the region is capable of absorbing additional rigs, and contractors may move units into the region, begin newbuilding, and/or bring back stacked units into service. As dayrates decline and competition increases for work, contractors stack units or move rigs out of the market to help support prices.

3.4.4 Regional Trends

Regional dayrates generally trend together (Fig. 3.17). From 2000 to 2005, stable dayrates prevailed throughout the world, followed by a sharp increase through

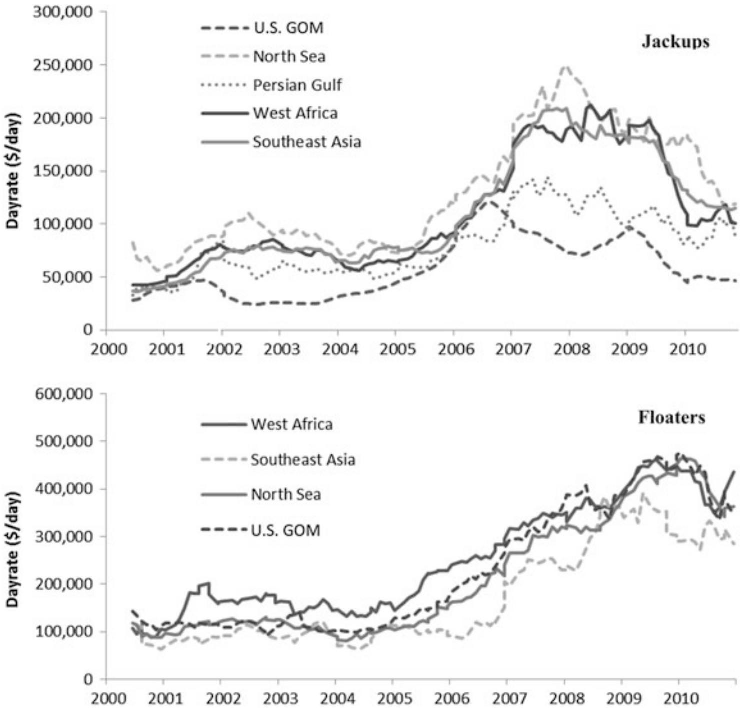

Fig. 3.17 Regional jackup and floater dayrates, 2000–2011. Dayrates computed as a 6-month moving average (Source: Data from RigLogix [9])

Table 3.6 Average dayrates by region and time period, 2000–2010

	Jackups			Floaters		
	2000–2005 ($/day)	2006–2010 ($/day)	Change (%)	2000–2005 ($/day)	2006–2010 ($/day)	Change (%)
North Sea	86,927	180,657	108	113,330	337,589	198
Persian Gulf	58,126	106,541	83			
SE Asia	67,846	159,731	135	92,229	278,060	201
U.S. GOM	48,776	81,865	68	122,530	361,995	195
West Africa	69,379	154,488	123	163,534	374,130	129

Source: Data from RigLogix [9]

2007, price stabilization, and declining rates starting in 2009. As a result, dayrates were significantly higher in the 2006–2010 period than during 2000–2005 (Table 3.6)

The U.S. GOM was the least expensive jackup market in both the 2000–2005 and 2006–2010 periods, followed by the Persian Gulf. West Africa and Southeast Asia experienced similar dayrates in both periods while the North Sea was consistently the most expensive jackup market, reflecting the regional supply and demand conditions and different environmental characteristics. In the floater market, Southeast Asia was the least expensive in both time periods while West Africa was the most expensive market.

Dayrates in the floater market are about two to three times jackup dayrates and reflect the higher capital expenditures of construction and higher operating expenses. West Africa, the North Sea and the U.S. GOM experienced similar dayrates over the decade, while Southeast Asian dayrates have been generally lower than the industry average. The North Sea, U.S. GOM and West Africa experience high dayrates because of the harsh environmental conditions and the ultra-deepwater exploration programs which require high-spec units. In contrast, high-spec ultra-deepwater rigs are not yet required in Southeast Asia.

3.4.5 Interregional Correlations

Regions differ in their development costs, fiscal regimes, geologic prospectivity, political risk, and strategic value. As oil prices rise, E&P firms demand drilling, which lead to increases in utilization and dayrates. The rate of increase in utilization and dayrate is not constant across regions, but the direction of the relationship is expected to be broadly consistent which creates interregional correlations. If regions are market oriented they will generally respond to the same market stimuli; whereas if regions are dominated by one or more NOCs or local conditions predominate, market stimuli are expected to play a less significant role in determining dayrates.

For most regions, there is a modest correspondence in dayrates, and while dayrates do tend to trend together, significant interregional variation remains. The U.S. GOM jackup market is the least regionally correlated market which suggests that local supply and demand conditions, high levels of competition, and related factors play important roles in the pricing environment (Table 3.7). Both West Africa and Southeast Asia are highly correlated suggesting similar market dynamics in each region. Moderate correlations[2] support the regional categorization of the market.

Regional correlations are higher in the floater market than in the jackup market (Table 3.8), which is at least partially due to the faster mobility of floaters which allow them to be rapidly moved among regions, balancing supply and demand. Correlations between the three Atlantic basin regions are also higher than the correlations between any of these regions and the Southeast Asian market, suggesting that these three markets interact with each other more than they do with Southeast Asia because of their geographic proximity.

[2] If correlations between markets were close to one, it would be more reasonable to consider the regional markets a single global market rather than a set of interacting regional markets.

Table 3.7 Jackup dayrate regional correlation matrix, 2000–2010

	North Sea	Persian Gulf	Southeast Asia	U.S. GOM	West Africa
North Sea	1				
Persian Gulf	0.64	1			
Southeast Asia	0.78	0.77	1		
U.S. GOM	0.49	0.51	0.58	1	
West Africa	0.73	0.72	0.90	0.54	1
Average	0.66	0.66	0.76	0.53	0.72

Source: Data from RigLogix [9]

Table 3.8 Floater dayrate regional correlation matrix, 2000–2010

	North Sea	Southeast Asia	U.S. GOM	West Africa
North Sea	1			
Southeast Asia	0.79	1		
U.S. GOM	0.88	0.77	1	
West Africa	0.87	0.77	0.84	1
Average	0.85	0.78	0.83	0.83

Source: Data from RigLogix [9]

Table 3.9 Quarterly volatility in the shallow and deepwater rig markets, 2000–2010

	Shallow (%)	Deepwater (%)
North Sea	18.3	18.2
Persian Gulf	23.4	
Southeast Asia	12.6	37.5
U.S. GOM	15.0	17.2
West Africa	15.7	28.7
Average	17.0	25.4

Source: Data from RigLogix [9]
Note: Volatility is defined as the standard deviation of the percent change in dayrates between quarters

3.4.6 Dayrate Volatility

Dayrate volatility measures dayrate changes over time analogous to the volatility metrics used in financial markets [4], and was calculated as the standard deviation of the percentage change in dayrates between quarters. Volatility reflects the nature of contracts and the levels of competition but a number of other factors also impact the computed measures such as the time period of evaluation.

The Persian Gulf jackup market is the most volatile shallow water market while the floater market is the most volatile in Southeast Asia (Table 3.9, Fig. 3.18).

In geographic regions with a small number of contracts negotiated in a given quarter, the effect of outliers is magnified and high volatility may arise because of the sample size. Regions that have a large variation in the specifications of rigs required (for example, harsh and non-harsh environments, or broad variation in

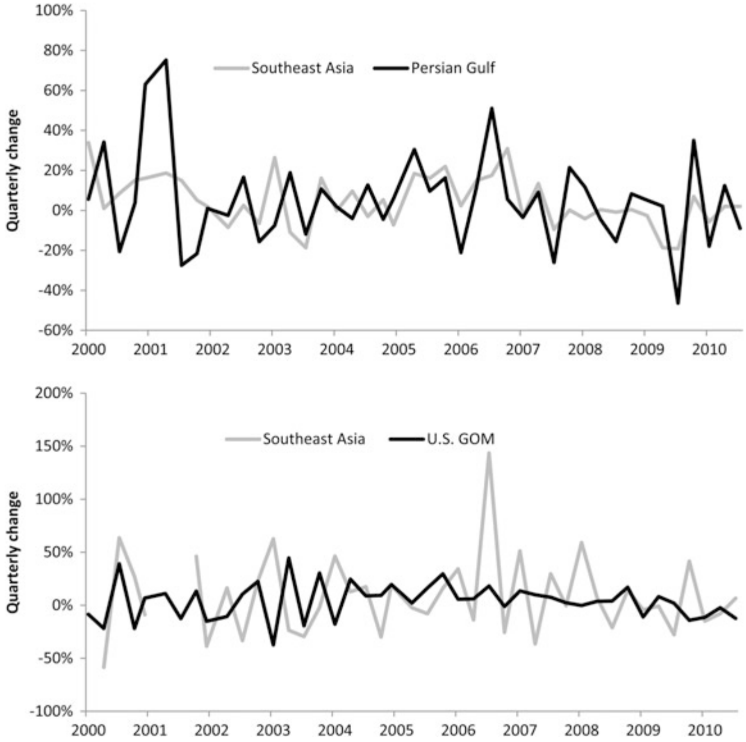

Fig. 3.18 Quarterly change in average dayrates in selected regions, 2000–2011 (Source: Data from RigLogix [9])

water depths) may also experience higher volatility. Floater markets appear more volatile than jackup markets which is counterintuitive considering the longer contract durations of deepwater drilling.

3.5 Contracts

3.5.1 Dayrate Versus Turnkey

Most drilling contracts are written on a dayrate basis, but turnkey contracts are occasionally employed by small E&P companies with limited financial and technical expertise [3, 7]. In a turnkey well, the E&P company defines the well specifications (e.g., total depth and target, minimum hole size at total depth, formation evaluation requirements) and retains a turnkey company to plan and supervise the well on a lump-sum basis [6]. The turnkey company retains a contractor under a dayrate contract and holds the risk of cost overruns.

Table 3.10 Contract type by rig market and region, 2000–2010

	Shallow water		Deepwater	
	Fixed well (%)	Term (%)	Fixed well (%)	Term (%)
North Sea	47	53	40	60
Persian Gulf	22	78		
Southeast Asia	40	60	64	36
U.S. GOM	76	24	45	55
West Africa	39	61	38	62
World	52	48	43	57

Source: Data from RigLogix [9]

Table 3.11 Average contract duration in days, 2000–2010

	North Sea	Persian Gulf	Southeast Asia	U.S. GOM	West Africa	World
Jackups	190	511	248	77	260	148
Floaters	233		213	173	261	212

Source: Data from RigLogix [9]

3.5.2 Term Versus Well

Term contracts specify contract duration, whereas fixed well contracts specify the number of wells to be drilled. Term contracts are more common in most regions and markets, except in the U.S. GOM jackup market and Southeast Asia floater market where fixed well contracts dominate (Table 3.10). Fixed well contracts are typically used for short term drilling programs while term contracts are used for longer exploration projects and field development. Worldwide, the average duration of fixed well contracts over the period 2000–2010 was 106 days, while the average for term contracts was 456 days.

In the U.S. GOM, jackups frequently work on a one-well basis and contractors have to find a new job at the completion of every well they drill. The average duration of jackup contracts in the U.S. GOM is significantly shorter than in other regions, but elsewhere deepwater and shallow water rigs operate under similar contracts (Table 3.11).

3.6 Customers

From 2000 to 2010, Chevron contracted more drilling days in the U.S. GOM and West Africa than any other operator; Maersk was the primary customer in the North Sea; Petronas and Saudi Aramco were dominant in Southeast Asia and the Persian Gulf (Table 3.12). In the floater market, BP, Shell and Total dominated the U.S. GOM, Southeast Asia, and West Africa, respectively. Statoil and Petrobras

Table 3.12 Largest E&P customers by region, 2000–2010

	Region	First	Second	Third	Fourth	Top four
Jackups	North Sea	Maersk (18)	Shell (9)	Conoco (9)	BP (6)	43
	Persian Gulf	Aramco (22)	ADMA (9)	Rasgas (6)	Maersk (5)	43
	Southeast Asia	Petronas (12)	Shell (11)	Total (7)	Chevron (6)	37
	U.S. GOM	Chevron (8)	Apache (6)	BP (4)	ADTI (3)	21
	West Africa	Chevron (29)	Exxon (18)	Total (11)	Addax (6)	65
Floaters	North Sea	Statoil (30)	Shell (11)	Hydro (10)	BP (7)	58
	Southeast Asia	Shell (18)	Petronas (12)	Exxon (8)	Murphy (8)	46
	U.S. GOM	BP (16)	Shell (10)	Anadarko (9)	Chevron (6)	40
	West Africa	Total (23)	Exxon (16)	Chevron (10)	Shell (5)	55

Note: Market share as a percent of total contracted days in parenthesis

dominated the North Sea and Brazil. Counting each contract day as one unit of market share, the top four firms controlled 21 % of the U.S. jackup market, whereas in every other market, the top four firms were responsible for at least 37 % of the contracted days. The West African jackup market is the most concentrated with the top four firms controlling 65 % of the market.

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Chapter 4
Players and Market Structure

Abstract The offshore drilling industry is composed of publicly owned, privately held, and state-owned firms. Large-cap firms diversify their risk by operating in a large number of markets and segments, while firms with smaller fleets specialize and compete in regional markets. In this chapter we describe the contractors, strategies, and market structure of the industry circa 2012, and begin by describing how rigs are valued by the market and compare a cash flow model of net asset value to industry algorithms. The ownership structure of the major players are introduced along with their specialization. A discussion of competition and market concentration concludes the chapter.

4.1 Fleet Value

Contractors hold a portfolio of rigs of different classes, ages and specifications. Each rig has a different revenue generation potential depending on its current and projected future dayrates, utilization, operating cost, contract backlog, and market conditions. The net asset value NAV of a rig is an estimate of the rig's discounted expected future net earnings and is a forward-looking indicator. Since contractual and market conditions change over time, NAV assessments are performed frequently, usually on a monthly or quarterly basis.

4.1.1 Definition

Fleet value is calculated as sum of the net asset values of each rig in a firm's fleet:

$$\text{Fleet Value} = \sum_{\text{i}} \text{NAV}(\text{Rig}_{\text{i}}), \tag{4.1}$$

Fleet value represents the price a hypothetical buyer would be willing to pay for all of the rigs in a firm's fleet, and is thus a primary determinant of the value of a contractor.

M.J. Kaiser and B.F. Snyder, *The Offshore Drilling Industry and Rig Construction in the Gulf of Mexico*, Lecture Notes in Energy 8, DOI 10.1007/978-1-4471-5152-4_4,

Fleet value correlates to fleet size because of the commodity-like nature of rigs and the algorithmic manner in which fleet values are assessed by industry. A strong correspondence exists between fleet value and contractor revenue because rigs that are worth more usually generate greater cash flows. Jefferies, Standard and Poor's, ODS-Petrodata, and other investment and market intelligence firms develop NAV estimates based on proprietary models and their data is widely referenced [7, 14].

4.1.2 NAV Estimation

Net Asset Value. The net asset value of a rig is estimated from the future net cash flow generated by leasing the rig over its remaining life:

$$\mathrm{NAV} = \sum_{t=0}^{t=L} \frac{\mathrm{NCF_t}}{(1+\mathrm{D})^t}, \tag{4.2}$$

where $\mathrm{NCF_t}$ is the net cash flow in year t, D is the company discount rate, and L is the remaining life of the rig.

Net Cash Flow. Net cash flow is determined as income minus operating expenses and taxes:

$$\mathrm{NCF_t} = \mathrm{Income_t} - (\mathrm{OPEX_t} + \mathrm{Taxes_t}). \tag{4.3}$$

Income. Income is based on current and projected future dayrates $\mathrm{DR_t}$ negotiated by the contractor and utilization rates $\mathrm{U_t}$, the portion of the year the rig is earning income, normalized by the number of days per year:

$$\mathrm{Income_t} = \mathrm{DR_t} * \mathrm{U_t} * 365. \tag{4.4}$$

Operating Expenses. Operating expenses are the direct and indirect costs incurred to operate the rig, and include labor, fuel, chemicals, maintenance, insurance, administration, and related costs parameterized on an average daily basis by $\mathrm{O_t}$:

$$\mathrm{OPEX_t} = \mathrm{O_t} * 365. \tag{4.5}$$

Operating expenses depend on the rigs working condition, and if it is stacked or active, and on regional market conditions that impact labor, fuel, and logistics costs.

Taxes. Net income is taxed at rate X and discounted for depreciation. Straight-line depreciation is assumed based on the initial capital costs C of the rig:

$$\mathrm{Taxes_t} = \left(\mathrm{Income_t} - \left(\mathrm{OPEX_t} + \frac{\mathrm{C}}{25}\right)\right) * \mathrm{X}. \tag{4.6}$$

Table 4.1 Net asset value parameterization for a $200 million hypothetical jackup rig

Variable	Unit	Description	Value
O_t	$/day	Operating costs	60,000
DR_t	$/day	Dayrate	Variable
L	year	Remaining life of the rig	25-A
U_t	%	Utilization rate	Variable
X	%/year	Tax rate	15
D	%/year	Discount rate	15
A	year	Age of the rig	5, 10 or 20
C	million $	Construction cost	200

Discount Rate. If the cash flows are known with certainty, the discount rate only needs to account for the opportunity cost of capital. However, future cash flows are uncertain, and the discount rate is the sum of the cost of capital and the premium required to compensate the investor for risk. The risk adjustment will vary with company practice and rig type [1, 2].

4.1.3 Illustration

Consider a $200 million jackup rig with $60,000/day operating expenses and a 25 year design life. The discount and tax rate is assumed to be 15 % and dayrate and utilization is assumed independent[1] of the age of the rig (Table 4.1). Net asset value is computed holding utilization constant at 90 % and varying dayrate, and by holding dayrate constant at $120,000/day and varying utilization, for a 5, 10 and 20 year old rig (Fig. 4.1).

Net asset value increases with increasing dayrates, utilization, and remaining life. At low dayrates and utilization ($80,000/day, 55 %), NAV is less than $20 million, and the difference in asset values between old and newer rigs is negligible. As dayrate and utilization increase, the difference in NAV increases depending on the remaining life of the rig. For 5 and 10 year old rigs, the difference in NAV is small, but for 20 year old rigs, the time remaining to generate income is limited and NAVs are steeply discounted. At 90 % utilization and $120,000/day, NAVs range from $60 million (A = 20 year) to $100 million (A = 5, 10 year).

4.1.4 Industry Comparison

Net asset value calculations for Transocean's *Galaxy II* and *Galaxy III* jackups are parameterized following Table 4.1 with the exception of age and dayrates which reflect the actual age and contract dayrates of the rigs circa 2011. The *Galaxy II* and

[1] In reality, the age of the rig influences dayrates and utilization since old rigs typically realize lower dayrates and utilization than newer rigs.

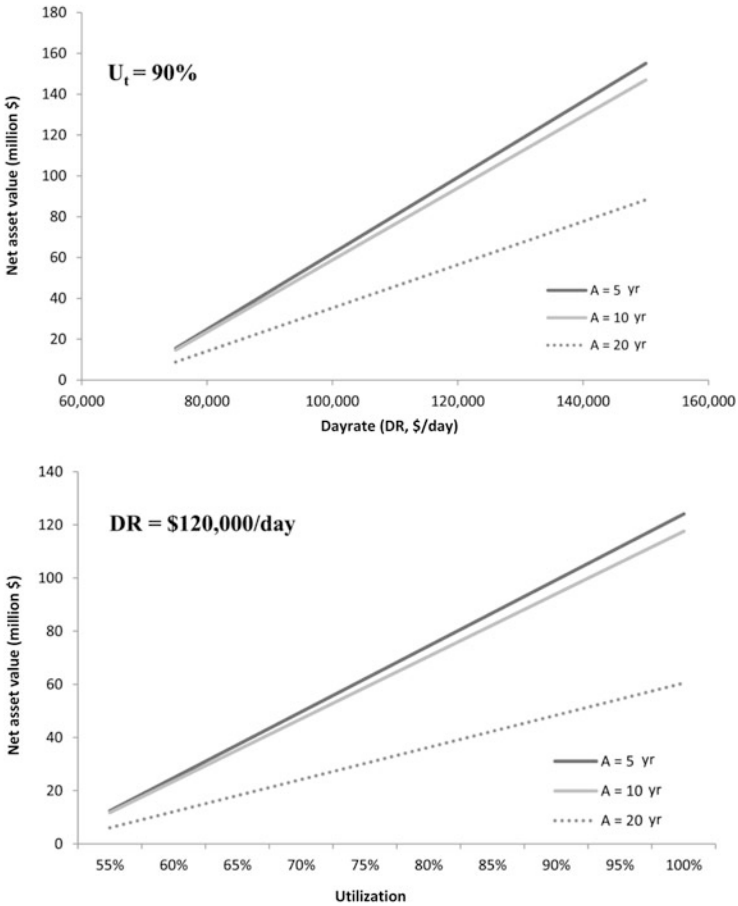


Fig. 4.1 Net asset value, dayrates and utilization relationships for jackups of different ages

Galaxy III were delivered by Keppel in 1998 and 1999, and are rated at 400 ft water depth and 30,000 ft drilling depth. In 4Q2011, the rigs were operating in the North Sea under dayrate contracts of $167,000/day and $144,000/day.

The net asset value of the *Galaxy II* and *Galaxy III* are estimated to be $166 million and $131 million, respectively (Table 4.2). These valuations match relatively closely with Jefferies, but our values are slightly lower reflecting differences in model assumptions. Jefferies' historic NAV estimates follow similar but not identical trends (Fig. 4.2). Rigs of the same specification and class operating in the same region typically have closely correlated NAVs, and the durability of NAV estimates depends upon the length of the contract and market conditions. When regional dayrates or utilization are depressed, net asset value will generally decline, and conversely, when market conditions improve, NAV will increase.

Table 4.2 Comparison of NAV estimates for two 400 ft jackup rigs in 4Q2011

	Age	Dayrate ($/day)	Utilization rate (%)	Discount rate (%)	Model NAV (million $)	Jefferies NAV (million $)
Galaxy II	14	167,000	90	15	166	170
Galaxy III	13	144,000	90	15	131	156

Source: Jefferies and Company, Inc. [4], Authors calculations

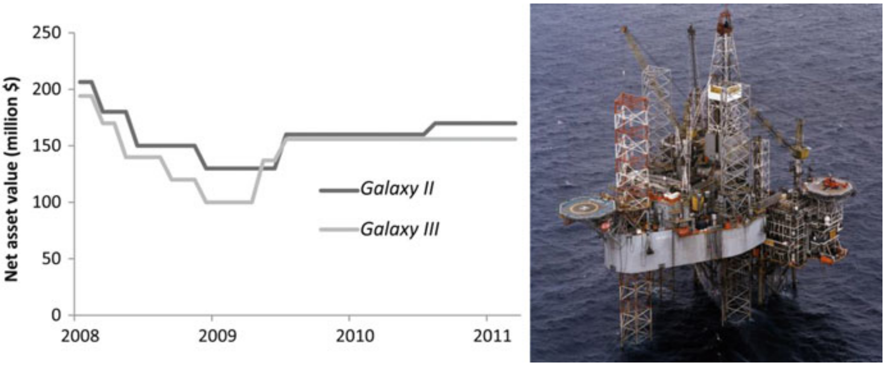


Fig. 4.2 Net asset value of the *Galaxy II* and *III* jackups, 2008–2011. *Galaxy II* is depicted (Source: Jefferies and Company, Inc. [4], Drilling Contractor)

4.2 Ownership

Drilling contractors are corporate entities that may be owned by investors or a government agency. Investor-owned drilling contractors may be publicly traded or privately held. Publicly traded corporations have a large number of shareholders, whereas private firms are owned by a small number of shareholders and do not report financial or operational data. State-owned drilling contractors may be entirely owned by a state, or a fraction of the shares may be traded on a financial exchange. Ownership structure is important because it impacts business strategies, governance, access to debt and transparency.

4.2.1 Public Firms

The 14 largest publicly traded drilling contractors realized $26.4 billion in revenues in 2011 from an inventory of 501 drilling rigs (289 jackups, 148 semis, and 64 drillships) and generated more than half of the industry revenue (Table 4.3).

Table 4.3 The largest publicly traded drilling contractors in 2011

Firm	Enterprise value[a] (billion \$)	Fleet value[a] (billion \$)	Revenue (billion \$)	Jackups	Semis	Drillships	Total	Headquarters
Transocean	25.4	32.1	9.1	68	50	23	141	U.S.
Seadrill	27.1	15.6	4.0	21	12	6	39	Norway
Diamond Offshore	8.9	8.7	3.3	13	32	3	48	U.S.
Ensco	16.7	14.5	2.8	42	18	5	65	U.S.
Noble	13.3	11.7	2.7	45	14	13	72	U.S.
Saipem	26[b]	4.5	1.0[c]	7	7	2	16	Italy
Rowan	4.5	5.7	0.9	31	0	0	31	U.S.
Songa Offshore	1.7	1.9	0.7	0	5	0	5	Norway
Ocean Rig	3.6	3.0	0.7	0	2	4	6	Norway
Atwood Oceanics	3.2	2.7	0.6	6	6	1	13	U.S.
Aban	2.9	2.4	0.6	15	0	3	18	India
Hercules Offshore	1.3	1.1	0.5[c]	33	0	0	33	U.S.
Vantage	1.5	1.7	0.3	4	0	4	8	U.S.
Japan Drilling	0.4	1.2	0.3	4	2	0	6	Japan
Total	110.5	106.8	26.4	289	148	64	501	
Percentage of world fleet				54 %	66 %	60 %	58 %	

Source: Data from Jefferies and Company, Inc. [4]; financial reports; RigLogix [12]
[a]Enterprise and fleet value evaluated on December 21, 2011
[b]Most of Saipem's enterprise value is associated with non-offshore drilling activities and is not included in the total
[c]Only includes offshore drilling revenues

Total fleet value is estimated at $107 billion, and collectively, the companies had an enterprise value[2] of $111 billion.

Transocean is the largest firm in terms of fleet size and revenue, and owned 141 rigs, or 16 % of the total fleet, including 22 % of the total floater fleet. In September 2012, Transocean agreed to sell 38 shallow water rigs to Shelf Drilling International Holdings Ltd for $1.05 billion as part of its strategy to unload older assets and focus on the high end market [13].

Seadrill, Diamond, Ensco and Noble are the next largest firms by fleet value and together own 209 rigs, including 88 floaters, and account for 24 % of the total fleet and 27 % of the floater fleet. Along with Transocean, these five firms are significantly larger than their nearest competitors and are categorized as "large-cap", while the nine smaller public firms are considered "mid-market" players.

All large cap firms except Seadrill are headquartered in the U.S., as are the mid–market firms Hercules, Rowan, Atwood and Vantage. Seadrill, Songa and Ocean Rig are headquartered in Norway. Most firms are incorporated in Switzerland, Cypress, and the Cayman Islands for tax purposes.

4.2.2 State-Owned Firms

China Oilfield Services Ltd (COSL) is the largest state-owned drilling contractor and owns as many rigs as UAE's National Drilling, India's Oil and Natural Gas Company (ONGC) and Brazil's Petrobras combined (Table 4.4). In total, state-owned firms own 127 drilling rigs, or about 15 % of the world fleet circa 2011. Most state-owned firms are jackup-oriented, but COSL, Petrobras and Socar own semisubmersibles and ONGC owns two drillships.

State-owned drilling contractors usually work exclusively in their home countries and are typically important players. They may be a subsidiary of a National Oil Company (e.g. COSL is owned by CNOOC) or the NOC may directly own and operate the drilling fleet. The largest state-owned drilling contractors are publicly traded firms in which the government is the majority shareholder; most other state-owned contractors are not publicly traded and are small players similar to small private firms.

4.2.3 Private Firms

Private firms own about a third of the world's fleet and deepwater rigs and play an important role in the floater markets in the North Sea and Brazil (Table 4.5). Maersk

[2] Enterprise value is a firm's market capitalization plus its debt, minority interest and preferred equity, minus cash. Market capitalization is the total value of tradable shares of a company at a given point in time, determined by the product of stock price and the number of outstanding shares [11].

Table 4.4 The largest state-owned drilling contractors in 2011

Firm	Market	Jackups	Semis	Drillships	Total	Publicly traded
China Oilfield Services Ltd.	China	27	6	0	33	Y
National Drilling	UAE	13	0	0	13	N
ONGC	India	8	0	2	10	Y
Petrobras	Brazil	6	4	0	10	Y
Socar	Azerbaijan	6	3	0	9	N
Egyptian Drilling	Egypt	7	0	0	7	N
Gulf Drilling International	Qatar	6	0	0	6	N
CNPC	China	4	0	0	4	Y
Gazflot	Russia	2	2	0	4	N
NIDC	Iran	4	0	0	4	N
Subtotal		83	15	2	100	
Percentage of world fleet		20 %	8 %	2 %	15 %	

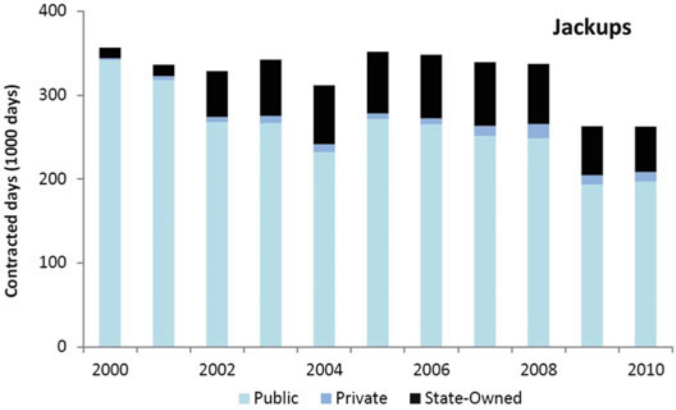
Source: Data from RigLogix [12]

Table 4.5 The largest privately-held drilling contractors in 2011

Firm	Market	Jackups	Semis	Drillships	Total
Maersk Drilling[a]	North Sea	14	6	0	20
Stena Drilling	North Sea	0	4	4	8
Dolphin A/S[b]	North Sea	0	7	1	8
Schahin	Brazil	1	2	4	7
Odfjell	North Sea	0	4	2	6
Queiroz Galvao	Brazil	0	6	0	6
Odebrecht	Brazil	0	2	3	5
Perforadora Central	Mexico	5	0	0	5
GSP	Black Sea	5	0	0	5
Jagson	India	4	0	0	4
Spartan Offshore	GOM	4	0	0	4
SeaWolf	Africa	3	0	0	3
Subtotal		36	31	14	81
All others		107	36	31	174
Total		143	67	45	255
Percentage of world fleet		27 %	30 %	42 %	29 %

Source: Data from RigLogix [12]
[a]Subsidiary of A.P. Moller-Maersk
[b]Subsidiary of Fred Olsen Energy

Drilling, Stena Drilling, Dolphin, Schahin, and Odfjeld are the largest private contractors and controlled about 20 % of the private fleet circa 2011. Maersk Drilling is a subsidiary of A.P Moller-Maersk and Dolphin is a subsidiary of Fred Olsen Energy. The only privately held firm frequently operating in the U.S. GOM is Spartan Offshore, which is owned by a private equity firm and operates four low-spec jackups. About 50 firms own less than three rigs, and are either privately held or traded on the over the counter market.



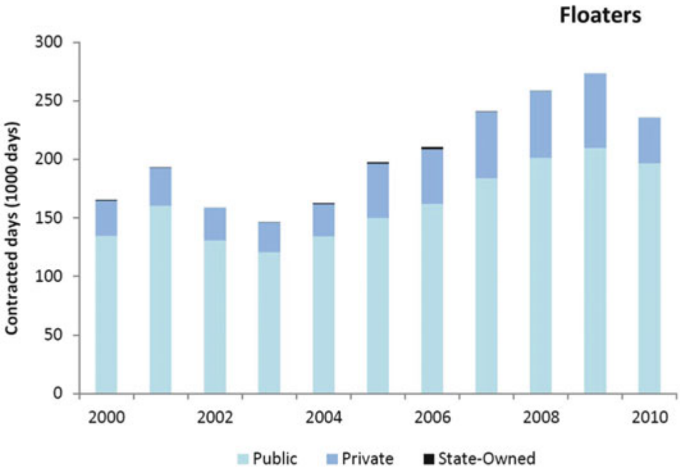


Fig. 4.3 Contracted days in the world drilling market by company ownership, 2000–2010 (Source: Data from RigLogix [12])

4.2.4 Market Share

The number of contracted days across all regional markets is used to measure market share. Over the decade 2000–2010, jackups were contracted between 250,000–350,000 days and floaters 150,000–275,000 days per year (Fig. 4.3). Publicly traded firms dominate the market because of their larger fleet sizes, but state-owned contractors are important in the jackup market, constituting about 20 % of days on contract, and in the floater market, private firms share of contracted days has historically ranged between 10 % to 20 %.

4.3 Firm Size

Firm size can be measured by fleet size, fleet value, revenue, enterprise value, and market capitalization. The scale and quality of a contractor's assets are correlated with its revenue base, and thus, firm size is an important predictive indicator. A large asset base implies a platform for sustainable earnings and cash flows and is related to a company's market position, cost structure, and ability to obtain financing for capital projects. Fleet sizes vary over time with newbuild programs and retirements and can change dramatically with merger and acquisition activity.

4.3.1 Large-Cap Firms

Transocean, Seadrill, Diamond Offshore, Ensco, and Noble realized revenue of $22 billion and total enterprise value of $91 billion in 2011 (Table 4.3). Transocean used its larger fleet size and value to generate more than twice the revenue of its nearest competitor (Fig. 4.4). After the 2010 Macondo oil spill, Transocean's share price declined because of uncertainty associated with its liability[3] and in 2013 activist investor Carl Icahn lost his fight to increase Transocean's dividend [16]. Seadrill was the largest firm by enterprise value in 2011 with only half the revenue and one-third the fleet size of Transocean.

Large-cap firms operate floaters and jackups in multiple geographic regions and all but Seadrill operate both high and low-specification units. All large-cap firms are focused almost exclusively on offshore drilling reflecting confidence in their ability to compete. Large-cap firms use internally generated cash flows and capital markets to undertake newbuild campaigns, build and operate expensive deepwater rigs, and expand their fleets through acquisition of smaller firms.

4.3.2 Mid-Market Firms

Mid-market players include both publicly traded firms such as Hercules, Rowan, Nabors, Vantage, and Atwood, as well as state-owned firms such as COSL, ONGC, and Petrobras. Market capitalizations of publicly traded firms in 2011 range from $337 million for Vantage to $3.7 billion for Rowan, and enterprise values range from $1.5 billion (Vantage) to $4.5 billion (Rowan).

Mid-market players utilize a broader array of business strategies than large-cap firms, and exhibit greater diversity in terms of fleet size and firm value. Several players such as Hercules, Saipem, COSL, Maersk and Nabors generate a substantial fraction of earnings from other activities.

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[3] In January 2013, Transocean agreed to pay $1.4 billion to settle all federal civil and criminal claims related to the oil spill [6].

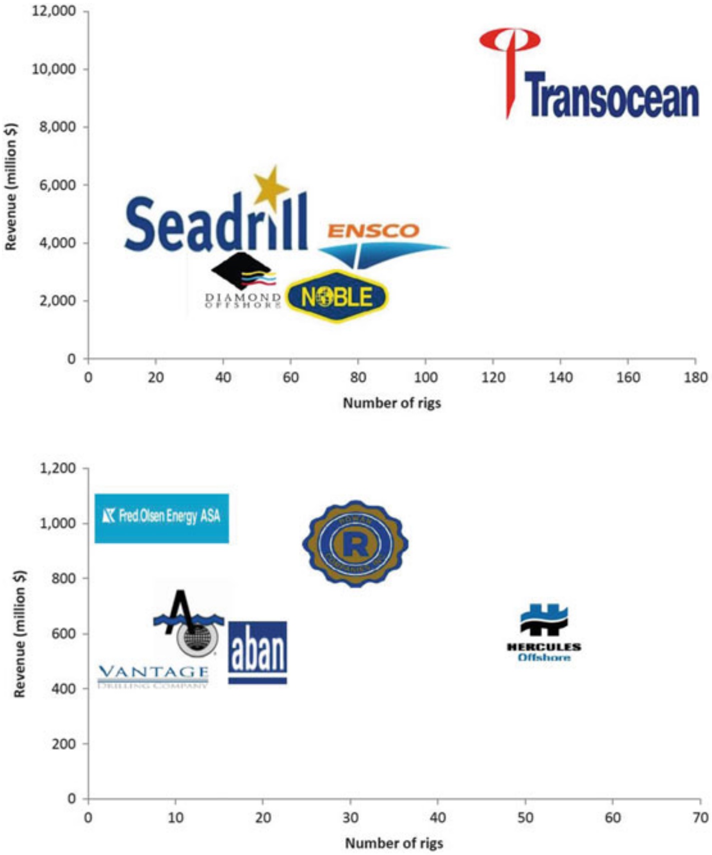

Fig. 4.4 Fleet size and revenue of large-cap and selected mid-market firms in 2011. The size of the firm insignia approximates enterprise value per chart (Source: Data from financial reports, Jefferies and Company, Inc. [4])

4.3.3 Small Firms

Firms that own less than eight rigs are regionally specialized and typically work in one or two markets. Most small players are privately held, but some small firms, especially those that specialize in high-spec floaters, may be publicly traded and have large market capitalizations. Ocean Rig and Songa, for example, had market caps greater than $1 billion in 2011. Unlike mid-market firms, small firms are not major players in large markets but may be important players in small markets. GSP, for example, is a major player in the Black Sea and Egyptian Drilling is a major player in the Red Sea.

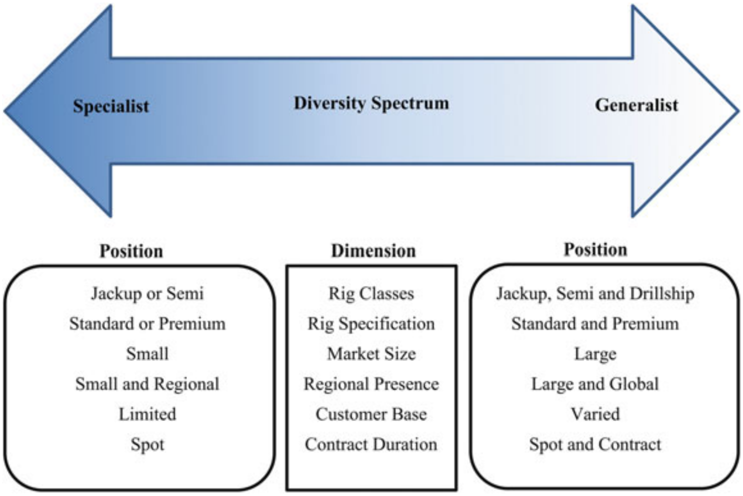

Fig. 4.5 Diversity spectrum of offshore drilling contractors

4.4 Diversification

Firms are classified according to their degree of diversification across one or more dimensions (Fig. 4.5). Diversity is usually an indicator of market strength since it insulates contractors from downturns experienced in specific business segments and provides upside potential when market conditions improve. A diverse fleet also allows contractors to respond quickly to changing industry conditions by matching demand trends across geographic region and water depth, and a market presence in several regions diversifies risk and reduces political exposure.

4.4.1 Generalists

Generalists maintain a geographically and technically diverse fleet across several regions and water depths with both bottom-supported and floating units. Generalists also tend to have a broad customer base and maintain a mix of short and long-term contracts.

The five large-cap firms operate significant fleets in both water depth classes (Fig. 4.6). Ensco, Noble and Transocean are generalists with assets in all rig classes, both the high and low specification segments, across a broad range of geographic markets. Seadrill operates high specification units across all rig classes and geographic markets. Diamond is a generalist but is not as geographically diverse as Noble, Ensco and Transocean.

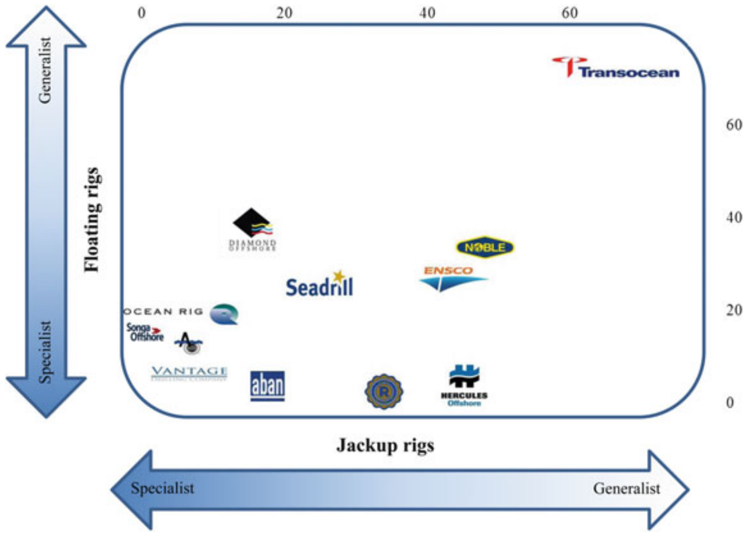

Fig. 4.6 Jackup and floater fleet sizes for selected firms in 2011 (Source: Data from financial reports, Jefferies and Company, Inc. [4])

4.4.2 Specialists

Specialization allows contractors to deliver on expectations but the downside is that specialization makes it harder to adapt to changes within markets by competitors and market decline. Specialists focus on one rig class or specification and fewer operating regions, and because they tend to be smaller firms with smaller fleets, they cannot simultaneously compete in more than a few regions and markets. Specialists tend to generate a greater percentage of their revenue from fewer customers which is generally a result of limited fleet size and diversity.

All mid-market firms are active in multiple national markets, but are more regionally specialized than large-cap firms. For example, COSL is focused on the Chinese market, Rowan and Hercules on the U.S. Gulf of Mexico and Persian Gulf, Aban on the Indian Ocean, Maersk and Fred Olsen Energy on the North Sea, Nabors and National Drilling on the Persian Gulf, and Saipem on Africa and the Middle East. Atwood and Vantage operate both jackups and floating units, but most other mid-market firms are specialized by class. Aban, Rowan and Hercules are jackup specialists, while Ocean Rig and Songa are floater specialists.

4.5 Business Strategies

A company's degree of diversification is usually a good indicator of its business strategy (Table 4.6). Large-cap firms diversify their risk by operating in a large number of markets and segments. Firms with smaller fleets specialize along at least one dimension and compete in specific market niches. Songa and Fred Olsen, for

Table 4.6 Specializations and business strategies of offshore drilling contractors circa 2011–2012

	Rig class	Specification	Region	Business strategies
Atwood	Generalist	Generalist	Global	Operates a small but diverse fleet including floaters and jackups
Diamond	Jackups and semis	Standard	Global	Operates an old but upgraded fleet and is entering high-spec drillship market
Ensco	Generalist	Generalist	Global	Formerly a jackup-specialist, but acquired Pride in 2011, adding floaters and diversifying fleet
Fred Olsen	Semis	Generalist	North Sea	Operates a fleet of mostly older floaters, but includes several harsh units
Hercules	Jackups	Standard	GOM/Persian Gulf	Buys inexpensive secondhand rigs and usually does not participate in newbuilding
Noble	Generalist	Generalist	Global	Operates a diverse fleet in a number of regional markets
Ocean Rig	Floaters	High-spec	Global	Frequently operates in small and emerging markets (e.g. Ghana, Greenland, Tanzania, the Falklands)
Rowan	Jackups	Generalist	GOM/Persian Gulf	Traditional jackup operator moving into deepwater market; operates primarily in high-spec shallow water markets
Seadrill	Generalist	High-spec	Global	Operates only high spec rigs; active in newbuilding and maintains aggressive growth strategy
Songa	Semis	High-spec	North Sea	Operates small fleet of semis
Transocean	Generalist	Generalist	Global	Active in all major regions and water depths

Source: Financial reports

example, operate mostly harsh-environment semis in the North Sea. Hercules is focused on the standard jackup market in the Gulf of Mexico and Persian Gulf and rarely engages in newbuilding, while Ocean Rig is a high-spec, floating rig specialist that frequently repositions its rigs to take advantage of local supply and demand imbalances.

Business strategies and specialization evolve and change with changing market conditions. Jackup specialist Rowan, for example, placed orders for several drillships in 2011–2012 while Maersk has been expanding its portfolio with 6th generation semis [10] as new entrants into the floater market; COSL, a Chinese specialist, is expanding its geographic base into Africa and the North Sea; and Transocean, a generalist, is in the process of selling most of its standard jackup fleet to focus on high-specification and deepwater business segments [13]. Dynamic strategies are necessary to maintain competitive advantage and seek out new opportunities to grow revenue.

4.6 Market Structure

Market structure characterizes the level and type of competition among contractors and determines their power to influence prices for their service. If contract drilling is perfectly competitive, contractors would not be able to raise prices above the marginal cost of operation without losing market share to their competition. According to basic microeconomic theory, perfectly competitive industries are characterized by unrestricted entry and exit of firms, large numbers of firms, and undifferentiated (homogenous) services being offered. The offshore drilling industry satisfy the conditions to varying degree.

4.6.1 Barriers to Entry

Significant barriers to entry exist in the offshore drilling market. From 2000–2012, newbuilt jackups cost between $150 and $300 million per unit and floaters cost between $500 million and $1 billion. Firms entering the industry typically build three or more rigs to take advantage of economies in the construction process and administration. It is difficult to raise this amount of capital to enter a mature and competitive industry. New market entrants that are not financed by a government entity raise capital from private sources and institutional investors (e.g. hedge funds or private equity firms) and may issue an initial public offering.

Successful entry also requires significant human capital. A high degree of specialized knowledge is necessary in management and operations positions which are only available to those already in the industry or recently retired. Drilling is an intangible service and contractors are difficult to evaluate without prior experience, which creates customer loyalty and may make operators unwilling to hire new contractors.

4.6.2 Number of Firms

Mergers and Acquisitions. Mergers and acquisitions continually shape and consolidate the industry (Fig. 4.7). Recent mergers and acquisitions include Ensco and Pride in 2011, Global Sante Fe and Transocean in 2007, Transocean and Aker in 2011, Noble and Frontier in 2010, and Seadrill and Scorpion in 2010.

Competititve Advantage. Much of the impetus behind industry consolidation is the competitive advantage associated with a larger capital base and greater asset diversification [9]. Size implicitly incorporates a degree of diversification by geography, rig class, rig quality, contract duration and customer base. Large companies benefit from greater asset diversification, financial resources and liquidity, and economics of scale, and can withstand shocks or market downturns better than smaller firms. Large companies also tend to be correlated with other characteristics such as market power and diversification [3]. Mergers are a critical

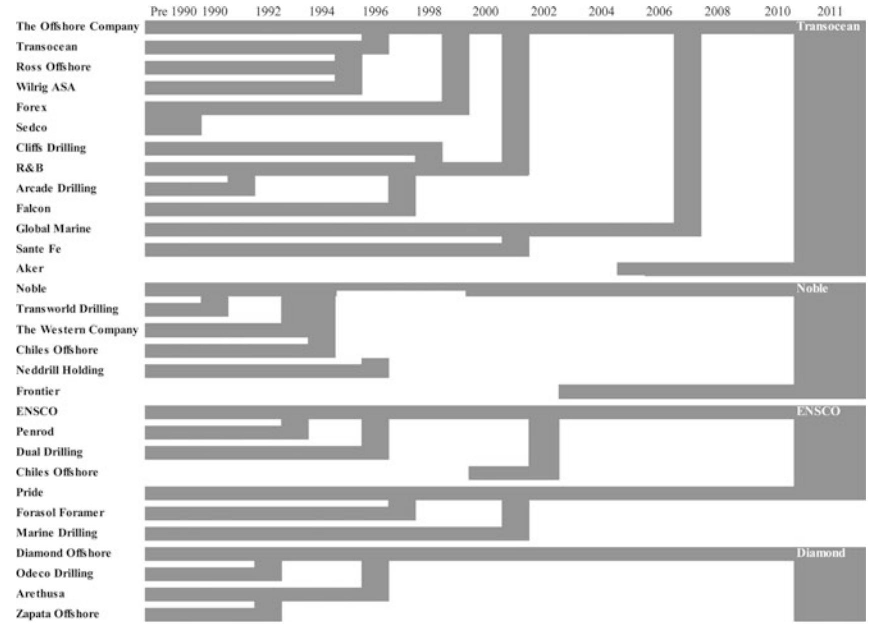

Fig. 4.7 Selected mergers among major players in the offshore drilling market, 1990–2010 (Source: Modified from Lee and Jablonowski [8])

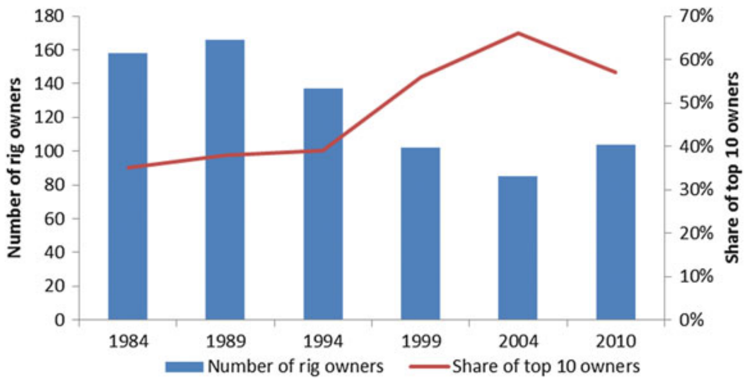

Fig. 4.8 Consolidation in the offshore contract drilling industry, 1984–2010 (Source: Data from Feyling [5]; RigLogix [12])

growth strategy for all large-cap drilling contractors and are a means to renew and upgrade their fleets without requiring new construction.

Consolidation and New Entrants. In the 1980s, there were approximately 160 drilling contractors and the top ten firms owned about 35–40 % of the total rig fleet (Fig. 4.8). Between 1989 and 2004, the industry experienced a prolonged downturn and consolidation eliminated nearly half of the contractors. Since 2004, the number

Table 4.7 Market concentration of the world MODU fleet circa 2010

	Jackups	Semis	Drillships	Floaters
CR4 (%)	53	68	69	54
CR8 (%)	79	85	88	67
HHI	940	1,628	2,511	1,692

Source: Data from RigLogix [12]

of firms has increased and new entrants have emerged to take advantage of high dayrates and greater access in regional markets. The top ten drilling contractors in 2010 own slightly more than half of the world fleet.

4.6.3 *Measures of Industry Concentration*

Industry concentration measures the ability of firms to influence prices. Economists use a variety of measures to assess the concentration of a given industry. Common measures include four firm concentration ratios (CR4), eight firm concentration ratios (CR8), and Herfindahl-Hirschmann indices (HHI). CR4 and CR8 measure the percentage of sales accounted by the top four and eight firms in the industry. The HHI is the sum of the squared market shares of firms in the industry [15].

Industry concentration measures for the offshore drilling market in 2010 were computed using contracts as the evaluation unit (Table 4.7). Each contract was considered one unit of market share. The top four firms accounted for over half of the jackup market and nearly 70 % of the semi and drillship market at the time of the assessment. The eight largest firms accounted for approximately 80–90 % of the industry in all three markets.

Using the HHI measure of concentration, industries with HHI below 1,000 are considered unconcentrated (i.e. more competitive); industries with HHIs between 1,000 and 1,800 are considered moderately concentrated (i.e. moderately competitive); and industries with higher HHIs are considered heavily concentrated. Based on these criteria, the offshore drilling jackup market was unconcentrated in 2010 even after recent merger activity, while the floater market is moderately concentrated (Table 4.7).

Concentration in the U.S. GOM jackup market has varied over time, but in South East Asia and the Persian Gulf concentration has declined as new firms entered the market in response to growing demand (Fig. 4.9). In the floater market, concentration declined in West Africa and Southeast Asia, but remained relatively stable in the North Sea, U.S. GOM and global markets over the decade. Regional markets exhibit a higher degree of concentration relative to global markets because of the definition of the metric.

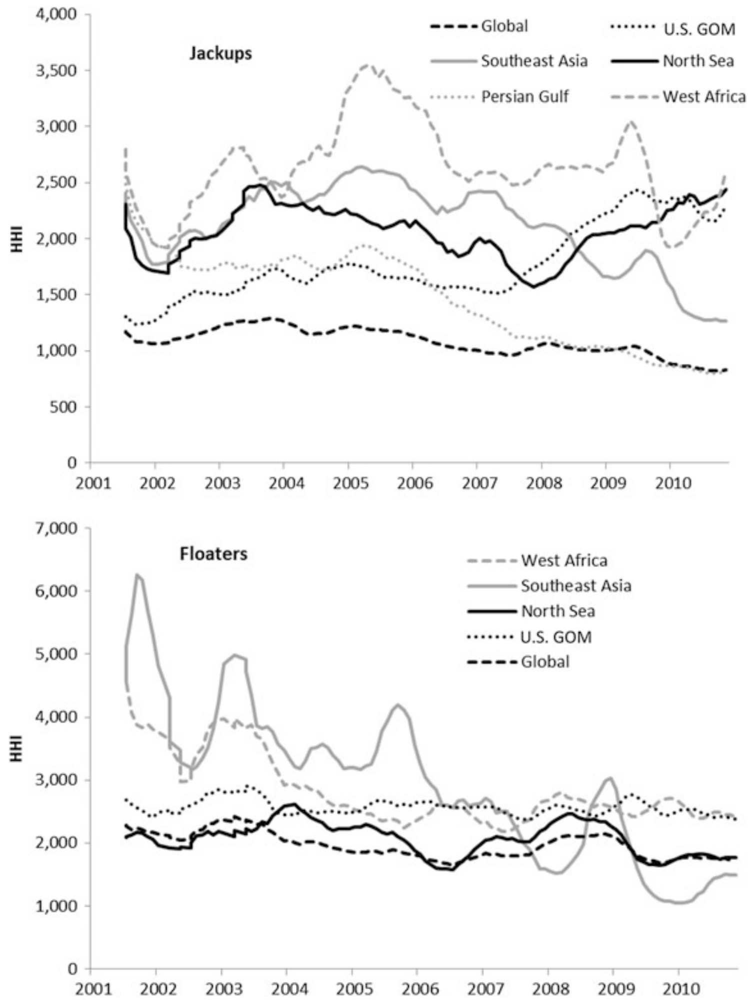

Fig. 4.9 Herfindahl–Hirschman index of jackup and floater regional markets, 2001–2010 (Source: Data from RigLogix [12])

4.6.4 Product Differentiation

Drilling contractors can influence prices for their services by differentiation through technology, safety record and crew experience. However, by the nature of their operations, drilling rigs are relatively homogenous, and there is little substantive difference between rigs of the same generation. While there may be some instances where service and safety differentiation is important, these are expected to be isolated. Overall, the market is commodity-like in nature which impedes the ability of firms to differentiate their products.

Barriers to entry, market size and product differentiation all impact competition among firms, but it is difficult to quantify the magnitude of these effects and it seems unlikely that individual companies are able to significantly influence market prices. The market is considered competitive with potentially transitory non-competitive periods in certain concentrated regions or specialized markets.

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Chapter 5
Empirical Analysis of Dayrate Factors

Abstract A large number of factors have the potential to influence dayrates and a body of "common knowledge" has developed over the years regarding their impact. The purpose of this chapter is to critically review these expectations and the empirical evidence to support/refute selected claims. Some of the claims can be tested, but many cannot, and our evaluation is limited by the availability and reliability of data and factor analysis. We examine the effects of oil prices on rig demand and evaluate the relationship between dayrates and oil prices, utilization, rig specifications, contract length, E&P ownership, contractor size and well type. We show that oil prices explain a large proportion of the variation in the number of active rigs and average dayrates, while utilization is a weaker predictor of dayrates with effects varying by region and time period. We find no evidence that large contractors are able to use their market power to capture higher dayrates than would be expected by their fleet specification. State-owned oil companies, however, tend to pay higher dayrates than private oil companies, and appraisal drilling is found to be more expensive than developmental or exploratory drilling.

5.1 Hypotheses

Eight hypotheses are examined by time period, rig class, and spatial region to assess their generality:

H1: Demand for drilling services is positively associated with oil prices.
H2: Dayrates increase with increasing oil prices.
H3: Dayrates and utilization are positively correlated.
H4: High specification rigs charge higher dayrates than low specification rigs.
H5: Long term contracts are priced at a premium to short term contracts.
H6: National oil companies pay higher dayrates than other companies.
H7: Large drilling contractors command higher dayrates than smaller contractors.
H8: Appraisal drilling programs pay higher dayrates than exploratory or developmental drilling.

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Hypotheses H1 to H4 evaluate basic assumptions widely reported in the industry. In hypothesis H1, rig demand is the dependent variable, and in all other hypotheses, the dayrate is the dependent variable. Hypotheses H5 to H8 identify factors that may contribute to the variation in dayrates between and within regions. These hypotheses are less obvious and require greater scrutiny.

Drilling contractors frequently seek a mix of long and short term contracts to balance opportunity and risk, and hypothesis H5 evaluates the costs of this strategy. For political reasons, national oil companies are expected to overinvest in drilling relative to other companies and this is evaluated in hypothesis H6. Hypothesis H7 examines the ability of firms to use market power to influence prices. Appraisal drilling is more technically challenging than exploratory or developmental drilling and may be associated with a dayrate premium which is tested in hypothesis H8.

5.2 Methodology

5.2.1 Data Source

Data from 7,123 rig contracts between January 1, 2000 and December 31, 2010 were obtained from RigLogix (Table 5.1). RigLogix assembles information on contract variables (dayrate, contract start date, contract duration, region, contract type) and rig variables (rig class, delivery date, water depth capability, rig maximum drilling depth) using surveys and contact with industry personnel. Dayrates are the primary bid variable, but contracts are negotiated individually with a number of terms and conditions (e.g. risk terms, mobilization costs, modifications, cost adjustment terms) that are not reported. Brent oil prices were obtained from the U.S. EIA and is the benchmark price for waterborne crude.

5.2.2 Categorization

The U.S. Gulf of Mexico, North Sea, Persian Gulf, West Africa and Southeast Asia regions were subdivided into jackup and floater classes, and no distinction was made between semisubmersibles and drillships. Jackup and floater classes were delineated by water depth, ownership, customer, and time period. The U.S. GOM had the largest number of contracts in the jackup market by a wide margin during 2000–2010 and, along with the North Sea, was the largest floater market. Note that the Persian Gulf does not have a deepwater segment.

Table 5.1 Offshore drilling contracts by region, 2000–2010

	Jackups	Drillships	Semis	Total
North Sea	600	14	615	1,229
Persian Gulf	341	0	2	343
Southeast Asia	465	25	149	639
U.S. GOM	3,441	91	709	4,241
West Africa	314	114	243	671
Total	5,161	244	1,718	7,123

Source: Data from RigLogix [9]

5.2.3 Evaluation Periods

From 2004 through 2006, oil prices and demand for drilling services rose significantly and, as a result of these changes, market conditions in the 2000–2005 and 2006–2010 periods differ in significant ways that require separate analysis (See Fig. 3.17). In the jackup market, the increase in dayrates pre- and post-2006 varied from 68 % in the U.S. GOM to 135 % in Southeast Asia. The change in dayrates in the floater market was more pronounced and three of the four floater markets increased by 200 % (See Table 3.6).

5.2.4 Approach

Individual contract records were treated as independent data points, and monthly average dayrates were computed as the average of the dayrates of all contracts for which drilling began in that month (See Fig. 3.16). Dayrates and Brent oil prices were inflation adjusted to 2010 using the U.S. BLS annual producer price index for all finished goods and the start year of the contract. The inflation adjustment allows for comparison across the decade but may introduce bias since the U.S. producer price index does not capture all inflationary pressures worldwide. Industry specific currency inflators (e.g. CERA Upstream Index) could be employed but are also limited in their application.

Linear regression and analysis of variance were used to test hypotheses. When multiple comparisons were performed, the Tukey-Kramer method was used [7]. Ordinary least squares regression was applied when data was not serially correlated. All variables were tested for serial correlation and when present, the AUTOREG procedure in SAS 9.2 was used. The order of the autocorrelation[1] varied depending on the results of a stepwise autocorrelation. Models were evaluated with and without logarithmic transformation. Transformed models generally performed

[1] The order of an autocorrelation is the number of previous periods used for the prediction of the error term. In a first order autocorrelation, the error term μ_t in the standard linear regression model ($Y_t = \beta_0 + \beta_1 X_t + \mu_t$) is dependent on the error in the previous period (μ_{t-1}). In a second order autocorrelation, the error term is dependent on the error in the two previous periods.

better than non-transformed models and were adopted, consistent with standard econometric techniques.

5.3 Demand Elasticity

Oil prices are a widely recognized driver of activity in the upstream sector since drilling is the only means to increase supply and capture the economic benefit of high prices. As oil prices increase, the net income and capital budgets of E&P firms increase and drilling activity responds. Increasing oil prices increase demand for drilling services which lead to increases in dayrates, for all other things equal. Studies have generally found a positive relationship between measures of drilling effort and oil prices with elasticity often greater than one [1, 2, 10]

To estimate the elasticity of demand with respect to oil prices, regression models were built using the average monthly oil price and the 3, 6, 9, 12, 18 and 24 month moving average oil price as predictors of the total number of rigs under contract per month. All active rigs in all offshore basins were considered and jackups and floaters were evaluated separately from 2000 through 2010 (Fig. 5.1). Models with logarithmic transformations provided the best fit.

For jackups, the best model was given by:

$$\ln(\mathrm{N_t}) = 4.2 + 0.23 * \ln(\mathrm{Oil_{12}}). \tag{5.1}$$

For floaters, the best model was given by:

$$\ln(\mathrm{N_t}) = 2 + 0.64 * \ln(\mathrm{Oil_{24}}), \tag{5.2}$$

where N_t is the number of active rigs in month t and Oil_k is the moving average of the oil price over the previous k months. Both models are first order autoregressive and yield high model fits ($R^2 = 0.92$, 0.97), and the coefficients are statistically significant ($p < 0.05$) and positive.

For jackups, the 12 month moving average oil price provides the best fit, and for floaters, the 24 month moving average is a better predictor than any shorter duration moving average. Rig activity responds slowly to changes in oil prices, consistent with the long periods required for offshore development and drilling programs.

The elasticity of rig activity suggests that for every 1 % increase in the moving average of oil prices, the number of working rigs increases by less than 1 %. Low elasticities are expected due to the capital intensity and long development cycles involved. Since deepwater is associated with longer and significantly more expensive development than shallow water regions, this same rationale at least partially explains why active floaters are correlated with a longer period of oil prices than jackups.

The trends remained the same when regions were considered separately, but the strength of the relationships declined for both rig classes, and in most cases, were no

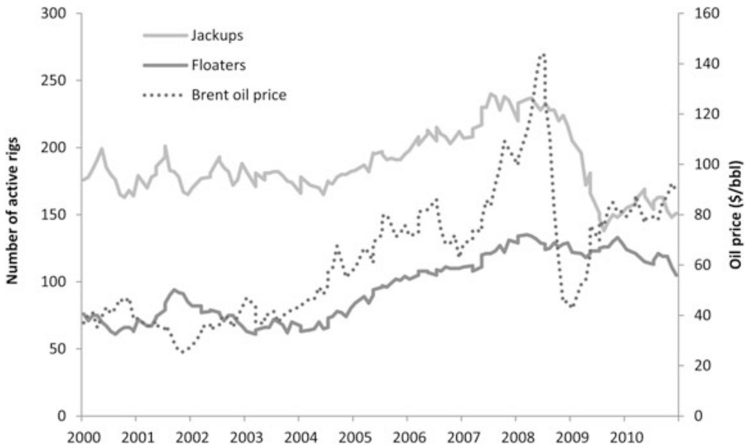

Fig. 5.1 Global active rig count and oil prices, 2000–2011 (Source: Data from RigLogix [9])

longer significant. This suggests that at the global level, oil prices are adequate predictors of demand, but at the regional level, local factors such as licensing rounds, customer base, geologic prospectivity, gas prices, etc. play important roles in regulating demand. Oil prices are a global indicator of demand, and when oil prices rise, global demand is stimulated, but the regional distribution of that demand is determined by local factors.

5.4 Dayrates and Oil Prices

Global monthly average jackup and floater dayrates were correlated against monthly average Brent oil prices between 2000 and 2010 (Fig. 5.2). The correspondence is noisy because of the high level of aggregation and the significant market changes that occurred during the period. As prices increase, jackup and floater dayrates exhibit a general upward trend, and for both rig classes, data clusters correspond to the oil price declines of mid-to-late 2008. During this period, dayrates did not change as quickly as the commodity price fluctuations, and rapid shifts in the markets were not immediately reflected in dayrates.

Autoregressive models were used to estimate price elasticity in dayrates. Oil price and 3, 6, 9, 12, 18 and 24 month moving averages were used as predictor variables over the 2000–2010 period.

For jackups, a second order autoregressive model was the best fit:

$$\ln(\mathrm{DR_t}) = 7.8 + 0.87 * \ln(\mathrm{Oil_{12}}), \tag{5.3}$$

Fig. 5.2 Jackup and floater dayrates and oil prices, 2000–2010 (Source: Data from RigLogix [9])

and for floaters, the best model was first order autoregressive:

$$\ln(\mathrm{DR_t}) = 6.8 + 1.4 * \ln(\mathrm{Oil}_{24}), \tag{5.4}$$

where $\mathrm{DR_t}$ is the average dayrate in month t and $\mathrm{Oil_k}$ is the moving average of the oil price over the previous k months. Both models were best described with logarithmic transformations and yielded high model fits.

Dayrates are positively related to oil prices and the model coefficients are positive regardless of the length of the moving average. The 12 month moving average oil price was the best predictor for jackup dayrates and the 24 month moving average was the best predictor of floater dayrates. Jackup dayrates respond rapidly to changes in oil price because of shorter drilling campaigns and the integrative effects of the moving average statistic.

Dayrate elasticity was 0.87 for jackups and 1.4 for floaters, but the elasticities are not directly comparable because oil prices in the two models are averaged over different periods. In the floater model, oil prices are averaged over a longer period and tend to be more stable; e.g., a 1 % increase in the 24 month moving average signifies a greater shift in market conditions than a 1 % increase in the 12 month moving average.

Model coefficients were similar when regions were compared separately. For jackups, elasticity varied from 0.7 in the Persian Gulf to 0.95 in the U.S. GOM. For floaters, regional elasticity varied from 1.0 in West Africa to 1.2 in Southeast Asia. Therefore, while oil prices are not a good predictor of regional demand, they are an adequate predictor of dayrates at the regional level reflecting the fact that dayrates are more strongly correlated between regions than the number of active rigs.

5.5 Dayrates and Utilization

When regional utilization is low, the supply of stacked units is large relative to demand and contractors bid aggressively to win work, increasing competition and lowering dayrates [8]. When utilization rates are high, there is more competition among E&P firms for access to drilling, and contractors can negotiate more favorable terms, increasing dayrates and providing signals to the market that additional capacity can be absorbed.

Over long time periods, contractors react to market conditions and order new rigs, reposition their fleet to attract high dayrates, or take capacity offline, and so dayrate and utilization may not correlate over specific time horizons. From 2000 to 2010, no statistically significant relationship was found between utilization and dayrate in any market or region, but in the post-2006 period, utilization and dayrates were correlated across all regions (Fig. 5.3).

Dayrates and the 3, 6, 9, 12, 18, and 24 month moving average utilization rates were regressed across five regional jackup markets and four floater markets in the 2006–2010 period using the functional specification:

$$\ln(\mathrm{DR}_t) = \beta_0 + \beta_1 \ln(\mathrm{U}_x), \tag{5.5}$$

where DR_t is the average dayrate in month t and U_x is the x-month moving average of the utilization rate.

In most cases, statistically significant models were constructed, however, the North Sea and Persian Gulf jackup models only explained a small proportion of the variation in dayrates, and no statistically meaningful relationship in the Southeast Asian floater market were obtained (Table 5.2). All successful models contained a 12, 18 or 24 month moving average predictor, and the moving averages in the jackup models were usually of shorter duration than those in the floater models.

Utilization and dayrate relationships vary by region, rig class and time period. One factor models were adequate for explaining large changes in dayrates but were unable to resolve more subtle differences. The Persian Gulf and North Sea had the lowest variance in utilization and the models were not sensitive enough to pick up these differences. The Southeast Asian floater market is small and utilization rates consistently lower than the other floater markets due in part to its larger geographic range.

5.6 Dayrates and Specification

Differences in rig specification lead to product differentiation in the market [5]. A number of rig specifications exist, but water depth and drilling depth are the most critical in determining the ability of a rig to drill a given well [3, 11]. As water depth and target depth increases, the number of rigs capable of performing the operation declines, reducing competition and increasing prices. For wells drilled in shallow

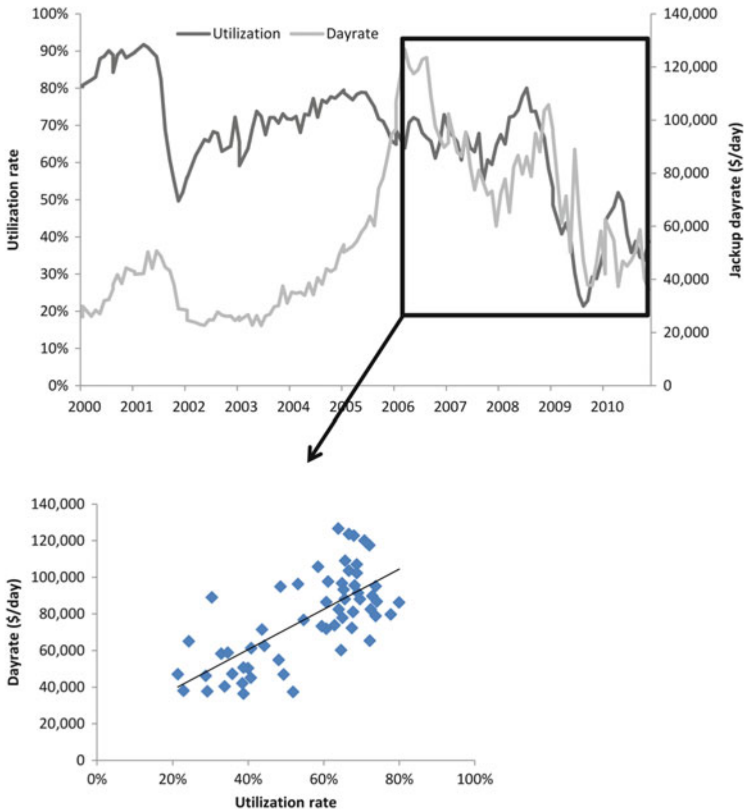

Fig. 5.3 Dayrates and utilization rate in the U.S. GOM jackup market. Other regional markets exhibit similar relations. (Source: Data from RigLogix [9])

Table 5.2 Models of the relationship between utilization rates and dayrates, 2006–2010

		β_0	β_1				
	Region		x = 12	x = 18	x = 24	R^2	Autoregressive order
Jackups	North Sea	12.2		3.0		0.27	None
	Persian Gulf	12.2		3.9		0.35	None
	Southeast Asia	12.3	1.7			0.80	None
	U.S. GOM	11.7	1.0			0.77	First
	West Africa	12.2	1.2			0.62	None
	World	12.0	1.5			0.67	None
Floaters	North Sea	12.8		2.4		0.99	Second
	Southeast Asia						NA
	U.S. GOM	13.3		3.5		0.99	Second
	West Africa	12.8			3.0	0.98	First
	World	13.4		3.9		0.99	Second

Source: Data from RigLogix [9]

water or targeting shallow formations more advanced capabilities are usually not necessary.

5.6.1 Drilling Depth

Dayrates increase with increasing drilling depth capability across both rig classes (Table 5.3). For jackups, rigs with drilling depth capabilities less than 15,000 ft did not have significantly different dayrates from rigs with maximum drilling depths of 15,000–20,000 ft, but all other drilling depth categories were significantly different.

For floaters, rigs with capabilities less than 20,000 ft charged dayrates that were indistinguishable from those with capabilities of 20,000–25,000 ft, and rigs with capabilities of 25,000–30,000 ft were indistinguishable from rigs with 30,000–35,000 ft drilling capacities. Rigs with drilling capabilities less than 25,000 ft, 25,000–35,000 ft and greater than 35,000 ft were significantly different and the direction of the differences matched expectations.

5.6.2 Water Depth

In both rig classes, deeper water depth capabilities are associated with dayrate premiums (Table 5.4). For jackups, the premium is largest ($30,000 per day) between the 300–350 ft and 350–400 ft water depth categories. There is no significant difference between the 350–400 ft and greater than 400 ft jackup categories which may reflect the small sample size of the later category.

For floaters, all four water depth categories are significantly different, but the biggest difference between categories is between the 5,000–7,500 ft and greater than 7,500 ft categories where the premium is $80,000 per day, while among the other water depth categories the premium ranges from $23,000–$34,000 per day.

5.6.3 Station Keeping

Dynamically positioned floaters and independent leg cantilever jackups are more flexible and versatile than moored floaters and mat or slot jackups, and this versatility is reflected in a premium in the market. Contractors received an average premium of $113,000 per day for dynamically positioned floaters and $35,000 per day for independent leg cantilever units across all of the regional markets and time period evaluated (Table 5.5). The value of these premiums over a 20 year

Table 5.3 Relationship between maximum drilling depth and dayrates, 2000–2010

	Drilling depth category (ft)	Dayrate ($/day)	Sample size	Standard error ($/day)	Significantly different[a]
Jackups	<15,000	53,804	41	4,299	A
	15,000–20,000	58,421	1,866	786	A
	20,000–25,000	86,580	1,632	1,257	B
	25,000–30,000	98,508	975	1,919	C
	>30,000	170,375	100	7,707	D
Floaters	<20,000	168,664	117	10,794	A
	20,000–25,000	176,570	1,099	3,885	A
	25,000–30,000	255,213	407	7,324	B
	30,000–35,000	264,882	212	9,020	B
	>35,000	409,058	35	23,104	C

Source: Data from RigLogix [9]
[a]Statistically significant differences between categories are denoted by letters (e.g. categories marked “A” do not differ from other A’s but do differ significantly from B’s, C’s, etc.)

Table 5.4 Relationship between maximum water depth and dayrates, 2000–2010

	Water depth category (ft)	Dayrate ($/day)	Sample size	Standard error ($/day)	Significantly different[a]
Jackups	<200	51,916	1,045	860	A
	200–250	69,241	1,520	1,089	B
	250–300	81,192	1,245	1,374	C
	300–350	88,616	726	2,005	D
	350–400	118,920	517	3,129	E
	>400	112,378	108	5,389	E
Floaters	<2,500	170,227	856	4,361	A
	2,500–5,000	193,760	426	6,515	B
	5,000–7,500	227,887	320	7,333	C
	>7,500	309,754	360	7,615	D

Source: Data from RigLogix [9]
[a]Statistically significant differences between categories are denoted by letters (e.g. categories marked “A” do not differ from other A’s but do differ significantly from B’s, C’s, etc.)

operational life assuming a constant premium, 75 % utilization, and a 10 % discount rate is $260 million for floaters and $80 million for jackups.

5.6.4 Regional Control

Dayrates are higher for rigs with greater drilling depth and water depth capabilities and more advanced station keeping abilities, however, these results could be associated with the regions in which these rigs work. We controlled for regional variation and calculated dayrates by drilling depth, water depth and station keeping

Table 5.5 Rig specifications and average dayrates, 2000–2010

	Station keeping	Average dayrate ($/day)	Sample size	Standard error ($/day)
Jackups	IC	87,746	3,480	940
	Mat or slot	53,125	1,134	820
Floaters	DP	295,775	408	6,923
	Moored	182,891	1,458	3,443

Source: Data from RigLogix [9]

Note: IC refers to independent leg cantilever; DP refers to dynamic positioning

Table 5.6 Rig specification and dayrates by region, 2000–2010

		Station keeping		Water depth		Drilling depth	
	Region	Mat or slot	IC	<300 ft	>300 ft	<25,000 ft	>25,000 ft
Jackups	North Sea	56,227	125,691	108,099	135,411[a]	108,011	153,195[a]
	Persian Gulf	72,192	88,758	77,617	98,785[a]	80,155	149,148[a]
	Southeast Asia	98,415	112,842	123,181	113,566	100,624	148,617[a]
	U.S. GOM	52,820	67,334[a]	53,035	72,342[a]	55,473	78,692[a]
	West Africa	63,401	106,436[a]	92,554	113,135[a]	101,833	151,267[a]
		Moored	DP	<5,000 ft	>5,000 ft	<25,000 ft	>25,000 ft
Floaters	North Sea	193,719	293,500[a]	199,186	302,776[a]	196,592	309,149[a]
	Southeast Asia	173,393	311,534[a]	157,737	236,094[a]	159,480	267,475[a]
	U.S. GOM	164,102	295,672[a]	109,536	249,683[a]	132,681	252,088[a]
	West Africa	225,577	295,959[a]	225,852	279,454[a]	226,167	300,893[a]

Source: Data from RigLogix [9]

[a]Indicates significant difference ($p < 0.05$)

Note: IC refers to independent leg cantilever; DP refers to dynamic positioning

ability (Table 5.6). To conserve sample size, rigs were divided into two water depth and drilling depth categories.

Independent leg cantilever units exhibited an average price premium of $15,000/day relative to mat or slot units in the U.S. GOM, and in West Africa the difference was $43,000/day. Dynamically positioned floater premiums ranged from $70,000/day in West Africa to $139,000/day in Southeast Asia. All regions experienced higher dayrates for deep water jackups, except Southeast Asia. The price difference in the Persian Gulf is unexpected because the vast majority of the Persian Gulf is less than 300 ft deep and E&P firms cannot use the increased water depth capacity of these rigs, but still pay a premium for this capacity.

Drilling depth was associated with increased dayrates in all regions, but the size of the premium varied among jackup markets from approximately $20,000/day in the U.S. GOM to nearly $70,000/day in the Persian Gulf. Low premiums in the U.S. GOM are due to depressed dayrates in the region, while the high price premium in the Persian Gulf is associated with the differences due to high and low-spec rig utilization. For floaters, high-spec rigs enjoyed a significant dayrate premium over low-spec rigs in every region and specification category. The premium in West Africa was always smaller than the premium in other regions.

Table 5.7 Contract duration and dayrates, 2000–2010

	Region	Average contract length (days)	Long-term dayrate ($/day)	Short-term dayrate ($/day)	Premium ($/day, %)
Jackups	North Sea	190	126,263	100,086	26,177 (26)
	Persian Gulf	511	100,421	69,345	31,076 (45)
	Southeast Asia	248	111,619	98,831	12,788 (13)
	U.S. GOM	77	59,385	48,465	10,920 (23)
	West Africa	260	111,273	85,986	25,287 (29)
Floaters	North Sea	233	257,595	192,843	64,752 (34)
	Southeast Asia	213	238,702	167,538	71,164 (42)
	U.S. GOM	173	295,625	159,880	135,745 (85)
	West Africa	261	297,852	237,797	60,055 (25)

Source: Data from RigLogix [9]
Note: Long-term and short-term contracts are defined relative to the regional mean duration. Premium is the difference between long and short term contracts as a percentage of long-term dayrate

5.7 Long-Term Contract Premium

Contractors generally seek a mix of long and short-term contracts to balance risk. Long-term contracts provide stable and durable cash flows, while short-term contracts provide upside exposure to improving markets and dayrate upswings [6].

Contracts were grouped by rig class and region into those greater than and less than the regional mean duration over the period 2000–2010. In every region and rig class, short-term contracts had lower dayrates than long-term contracts (Table 5.7). For jackups, the difference between contract types ranged from 13 % in Southeast Asia to 45 % in the Persian Gulf; for floaters, the premium was higher and ranged from 25 % to 85 %.

Contract duration premiums may vary temporally. If contractors expect future price and utilization to decline, they may accept lower dayrates for long-term contracts. To control for the effects of time, the data were separated into three periods: 2000–2004, 2005–2008 and 2009–2010, corresponding roughly to stable, improving, and declining market conditions. Observed price changes are assumed to reflect market participant expectations. If the dayrate premium for long-term contracts depends on market conditions, there will be no premium for long-term contracts in the 2009–2010 period.

Separating the data into three time periods, two rig classes and five regions provided 27 data sets for assessment. In 26 of 27 comparisons, longer-than-average contracts had higher dayrates than shorter-than-average contracts, although the trend was only significant in 14 comparisons. There is no evidence that higher dayrates for long-term contracts are affected by changing market conditions.

5.8 E&P Ownership Premium

Public oil companies and NOCs have different motivations for investing in drilling and may differ in their willingness to pay for drilling services. Public companies are responsive to shareholder concerns and driven to maximize return on investment.

Table 5.8 Dayrates by E&P firm type, 2000–2010

	E&P firm	Average dayrate ($/day)	Sample size
Jackups	NOC	114,608^{A}	261
	IOC	88,588^{B}	1,008
	Independent	71,788^{C}	3,893
Floaters	NOC	274,776^{A}	200
	IOC	226,757^{B}	610
	Independent	189,832^{C}	1,145

Source: Data from RigLogix [9]
Note: Letters indicate significant differences at $p = 0.05$

National Oil Companies are motivated by both economic and political factors which may increase their exploration investments and willingness to pay for drilling services, increasing the dayrates they negotiate relative to integrated companies and independents [4].

For jackups, NOCs paid approximately $25,000/day more than Integrated Oil Companies and $40,000/day more than independents over the past decade (Table 5.8). For floaters, NOCs paid $50,000/day more than IOCs and $85,000/day more than independents. All differences were statistically significant for both rig classes.

The trends observed could be influenced by regional or temporal factors. For example, if NOCs are more active in expensive markets such as the North Sea, differences in dayrates would reflect regional conditions rather than differences arising from ownership. National Oil Companies also became more active in the market after 2000, particularly the jackup segment, which coincided with an increase in dayrates. To control for these effects, a regression model was built for dayrates with the contract start year as a predictor variable and E&P firm type and region as indicator variables:

$$\begin{aligned} DR = \beta_0 + \beta_1 IND + \beta_2 IOC + \beta_3 YEAR + \beta_4 GOM + \beta_5 NSEA \\ + \beta_6 AFRICA + \beta_7 PGULF \end{aligned} \tag{5.6}$$

where IND is 1 if the E&P firm is an independent and 0 if otherwise; IOC is 1 if the E&P firm is an integrated oil company and 0 if otherwise; YEAR is the contract start year; and GOM, NSEA, AFRICA, and PGULF are indicator variables that take the value 1 if the region is selected and 0 otherwise. When the region was Southeast Asia, all regional indicator variables were zero. The Persian Gulf variable was not included in the floater model.

After controlling for year and region, NOCs paid higher dayrates than independents and IOCs in the jackup market and higher dayrates than independents in the floater market (Table 5.9). The difference between NOC and IOC rig hire in the floater market was not significant. NOCs paid a premium of $17,000/day for jackups relative to independents and $11,000/day relative to IOCs. For floaters, NOCs paid a premium of $30,000/day relative to independents. While significant, these premiums are much lower than observed globally, suggesting that time and regional differences are important factors in determining premiums.

Table 5.9 Models of the relationship between dayrates and E&P firm ownership, 2000–2010

$DR = \beta_0 + \beta_1 IND + \beta_2 IOC + \beta_3 YEAR + \beta_4 GOM + \beta_5 NSEA + \beta_6 AFRICA + \beta_7 PGULF$

Coefficient	Variable	Jackup model	Floater model
β_0	Intercept	−14,940,018	−67,703,588
β_1	IND	−16,914	−30,484
β_2	IOC	−10,962	−4,631^{NS}
β_3	YEAR	7,512	33,859
β_4	GOM	−37,064	6,1427
β_5	NSEA	16,058	49,386
β_6	AFRICA	−2,579^{NS}	84,499
β_7	PGULF	−29,575	

Source: Data from RigLogix [9]
Note: NS indicates the term is not significant

5.9 Market Power

Large drilling contractors may be able to use market power to achieve higher dayrates than their competitors. Transocean is the largest drilling contractor and was a market leader throughout the decade. The dayrates received by Transocean were compared to its competitors in each region and rig class from 2000 to 2010. Transocean received higher than average dayrates in the North Sea and U.S. GOM floater markets, however, when controlled for rig water depth, the dayrate difference became non-significant. Similar results were obtained when the five largest drilling contractors (e.g. Transocean, Diamond, Noble, Ensco, and Seadrill) were evaluated as a group. Thus, while large drilling contractors receive higher dayrates than their competitors in some regions and over some time periods, the effect appears to be due to the higher specifications of their fleets rather than the use of market power.

5.10 Appraisal Drilling Premium

In exploratory drilling, the primary goal is to find commercial quantities of hydrocarbons, while in development drilling, the goal is production. During appraisal and delineation, the primary goal is to define the characteristics of the reservoir, and as a result, appraisal drilling is considered more technically demanding than exploratory or developmental drilling. Information is a primary objective of drilling and because appraisal wells may later serve as production or injection wells, they are drilled with careful consideration of their future utility. High-spec rigs may be preferred for appraisal, and if such rigs are selected for drilling a dayrate premium is expected.

In jackup markets, there were no significant differences in dayrates by well type on a global or regional basis. In the floater market, appraisal drilling received a

Table 5.10 Floater dayrates by well type, 2000–2010

		Appraisal ($/day)	Development ($/day)	Exploratory ($/day)
Water depth	Midwater	271,624^{A}	202,623^{B}	237,740^{AB}
	Deepwater	430,455^{A}	325,031^{B}	291,286^{C}
	Ultra-deepwater	438,750^{A}	403,759^{AB}	357,191^{B}
Region	North Sea	344,632^{A}	240,501^{B}	307,938^{A}
	Southeast Asia	328,742^{A}	217,513^{A}	258,469^{A}
	U.S. GOM	378,404^{A}	331,684^{A}	258,624^{B}
	West Africa	433,974^{A}	366,197^{A}	338,087^{A}
	All floaters	362,727^{A}	286,758^{B}	289,567^{B}

Source: Data from RigLogix [9]
Note: Midwater refers to <3,000 ft, deepwater 3,000-7,500 ft and ultra-deepwater >7,500 ft. Letters indicate significant differences at $p = 0.05$

premium of approximately $80,000/day relative to development and exploratory drilling.

Appraisal wells may be drilled by more advanced rigs than development or exploratory wells, which could explain differences in rates. We used floater water depth ratings as a proxy for rig specification and separated floaters into mid-water (<3,000 ft), deepwater (3,000–7,500 ft), and ultra-deep (>7,500 ft) categories. The increased cost for appraisal drilling in floaters is robust across water depth (Table 5.10). Appraisal drilling is always significantly more expensive than development or exploratory drilling, or both.

It is also possible that appraisal drilling has been more common in high cost regions such as the North Sea. When regions were compared separately, appraisal drilling was always more expensive than developmental or exploratory drilling, but the difference was only significant in the U.S. GOM and North Sea where the sample sizes were the largest.

Higher dayrates for appraisal drilling suggest that contractors require a risk premium for appraisal wells. If a contractor damages a wellbore or otherwise provides inadequate well construction services, they are often contractually obligated to drill a replacement well at no additional cost to the E&P firm. If appraisal wells are associated with a higher risk of failure, contractors may require higher dayrates to undertake these drilling programs.

5.11 Limitations

Many factors impact rig dayrates, and the portion of the offshore drilling market available for quantitative analysis is limited. When data is aggregated and single factor trends are analyzed by time, region and class, the impact of interacting factors and other potential effects are not considered in the assessment, which if included, may bias or even negate the results obtained. For example, the analysis of contract duration did not account for rig specifications, and high-spec rigs may be more likely to negotiate long-term contracts than low-spec rigs, and this, rather than contract length, may account for the observation of higher dayrates for long-term contracts.

Sample size considerations limit the ability to make robust generalizations in multi-factor analyses. While the overall sample was large, only the U.S. GOM and North Sea had a large number of contracts in both the jackup and floater markets. Consequently, many comparisons within regions are statistically insignificant. For example, when comparing dayrates for appraisal, exploratory and development drilling within regions, the pattern of higher dayrates for appraisal drilling was consistent across regions, but significant differences were only observed in the U.S. GOM and North Sea.

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Chapter 6
Newbuild and Stacking Decision-Making

Abstract Drilling contractors newbuild or idle rigs based on market conditions and business strategies. In theory, contractors invest in newbuilding when the expected net present value of adding a rig to their fleet is positive (or the rate of return on the investment meets a minimum threshold), and idle capacity when the costs of operation exceed the costs of idling. The models employed by industry are confidential but the economics of decision-making are universal, which makes quantification of the problem meaningful. We develop and parameterize models of capacity decision-making and find that high combinations of dayrates and utilization are required to justify newbuild investment and that idling capacity may be preferred even if daily operating costs exceed daily revenue. The models presented are intended to reflect industry perspectives.

6.1 Newbuilding Strategies

Newbuilding is a high risk investment and contractors undertake various strategies to reduce the risk.

6.1.1 Initial Contract

Under an initial contract strategy, contractors require a firm committment from an E&P company before investment in order to secure cash flows during the early life of the rig. Bob Rose, former CEO of Global Marine, summarizes the strategy: "No newbuilds without a user contract in hand [3]." Without an initial contract, a drilling contractor may experience a negative net cash flow in the first years after a rig is delivered which can have a significant negative impact on the profitability of the investment.

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Proponents of an initial contract approach argue that building speculatively provides a signal to E&P firms that rig availability will increase in the future which reduces the motivation of E&P firms to commit to long-term contracts. Building without an initial contract adds supply that is not demanded, which may also lead to industry-wide reductions in dayrates. Transocean is the largest firm in the industry and the most likely to be impacted by fleet-wide reduction in utilization or dayrates and is the primary advocate of the initial contract approach.

E&P firms are only likely to engage in an initial contract when market conditions are so tight that they are unsure they will be able to contract capacity. As long as one or more contractors are willing to build without an initial contract, however, initial contracts will be rare. E&P firms may enter into a joint ownership arrangement for a newbuild rig to secure services for an extended period of time. State-owned drilling contractors and NOCs enter ownership arrangements more frequently than public and private firms.

6.1.2 Price Discount

Under a price discount strategy, firms invest counter-cyclically during periods of low newbuild prices. Stedman Garber, former CEO of Sante Fe, summarizes the position: "Counter-cyclical is the best time to build, contract or not [3]." The goal of a price discount strategy is to minimize cost rather than attempt to match supply and demand, and proponents of a price discount strategy argue that the benefits of an initial contract do not justify higher capital costs. Lower capital costs allow companies to be more competitive in the long run because the capital cost is locked in for the life of the rig. While there is a risk that the rig will be under-utilized after delivery, newbuild rigs are preferred in the market, but possibly at the cost of utilization and dayrates elsewhere in the fleet. Price discounting is a popular strategy at the beginning of a newbuild cycle.

6.1.3 Speculation

During periods of high utilization and dayrates, drilling contractors enter into newbuild contracts without an initial contract with the expectation that the rig will win work during the construction period. This is a high risk strategy because the rig may not be utilized or utilized at a low dayrate after delivery. During newbuild cycles, speculation is the dominant strategy, and since newbuild cycles are the primary source of fleet expansion, speculative newbuilding is an important source of new rigs. A price discount strategy is different from a speculative strategy in that proponents of a price discount strategy would not build speculatively during the peak of a newbuild cycle.

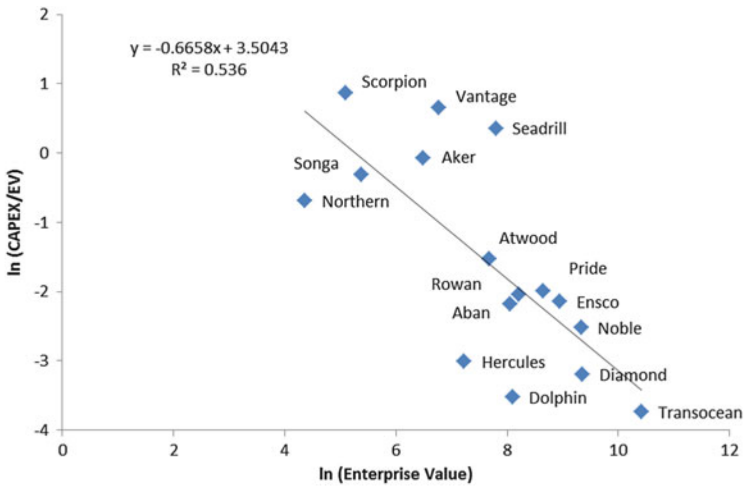

Fig. 6.1 Relationship between firm size and relative newbuilding expenditure, 2005–2011 (Source: Data from Bloomberg)

6.1.4 Firm Size

Firms differ in newbuilding strategies and smaller firms spend a larger proportion of their value on newbuilding than larger firms. Enterprise value was used to proxy company value, and the fraction of enterprise value invested in newbuilding was determined by dividing annual newbuild expenditures by total enterprise value over the 2005–2011 period (Fig. 6.1). This value was then plotted against the average enterprise value for each firm over the time period.

As the size of the firm increased, the proportion of firm value invested in newbuilding expenditures decreased. Over the recent newbuilding cycle, large firms such as Transocean and Diamond have invested relatively little in newbuilding while small and midsized firms such as Scorpion, Vantage, Seadrill and Aker have invested heavily.

6.2 Newbuild Investment

The economics of newbuilding are conceptualized with a net present value (NPV) model for a jackup rig built speculatively without an initial contract. A jackup is chosen for illustration, but the methodology applies to floaters as well as acquisition decisions. The effects of an initial contract are considered after the base model is developed. The capital cost of the drilling unit and finance terms are known at the time of evaluation, while operating expenses are estimated based on historical

Table 6.1 Newbuild model variable descriptions

Variable	Unit	Description
C	\$	Purchase price of the rig
T	year	Maturity of debt
I	%/year	Interest rate of debt
G	% of C	Upgrade cost
O_a	\$/day	Daily active operating costs
O_s	\$/day	Daily stacked operating costs
DR_t	\$/day	Dayrate in year t
A	year	Life of the rig
U_t	%	Utilization rate in year t
U_e	%	Average utilization rate
X	%/year	Tax rate
D	%/year	Discount rate

performance, and depreciation schedules are based on current regulations (Table 6.1). The primary unknown variables are the future market conditions, specifically dayrates and utilization, after the initial contract period.

6.2.1 Investment Model

Net Present Value. The NPV of a newbuild rig is the discounted sum of cash flows over the life of the rig:

$$\mathrm{NPV} = \sum_{t=0}^{t=A} \frac{\mathrm{NCF_t}}{(1+\mathrm{D})^t}, \tag{6.1}$$

where NCF_t represents the net cash flow in year t, D is the company discount rate, and A is the life of the rig assumed to be 25 years. Cash flows consist of income generated by leasing the rig minus capital and operating costs and taxes:

$$\mathrm{NCF_t} = \mathrm{Income_t} - \mathrm{CAPEX_t} - \mathrm{OPEX_t} - \mathrm{Taxes_t}. \tag{6.2}$$

Income. Income is the product of the average dayrate DR_t and utilization U_t normalized by the number of days in the year:

$$\mathrm{Income_t} = \mathrm{DR_t} * \mathrm{U_t} * 365. \tag{6.3}$$

The rig is assumed to have no residual value at the end of its life.

Capital Expenditures. Capital costs consist of the purchase price C of the rig, and an upgrade in year 10, assumed to be 25 % of the purchase price. The initial capital expenditure is financed through the issuance of bonds with an interest rate, I, and a date to maturity, T. When $t < T$, debt repayment is $CAPEX_t = C^*I$, and at $t = T$, $CAPEX_t = C + C^*I$. When $t > T$, $CAPEX_t = 0$.

Operating Expenses. Operating costs include labor, maintenance, insurance, administration, and related costs. Separate operating costs are accrued when the rig is active (O_a) and cold-stacked (O_s), and the rig may be in only one state in any given year (i.e. the rig cannot transition between active and cold-stacked states more than once per year). Annual operating costs are given by:

$$OPEX_t = O_a * 365 \text{ or } OPEX_t = O_s * 365, \tag{6.4}$$

depending on if the rig is active or stacked, respectively.

Reactivation and Finance Cost. A fixed $5 million capital expenditure is required in any year a rig is reactivated from a cold-stacked condition. To account for finance costs during construction, interest costs are accrued in year zero and income begins to be generated during the first year of operation.

Taxes. Net income is taxed at rate X and discounted for interest expense and rig depreciation. Interest expense is C*I when $t \leq T$, and zero otherwise. Straight line depreciation over a 25 year rig life is assumed:

$$Taxes_t = \left(Income_t - \left(OPEX_t + C * I + \frac{C}{25}\right)\right) * X. \tag{6.5}$$

6.2.2 Utilization Rate

The offshore drilling market is cyclical, and during periods of low utilization, contractors stack rigs to reduce fleet operating costs and to help support industry dayrates. Two models of capacity management are presented referred to as "fixed utilization" and "variable utilization". In fixed utilization, the rig is assumed to be utilized throughout its life cycle and is never cold-stacked. In variable utilization, the rig is cold-stacked when market utilization falls below a given threshold and is brought back to ready-status with a reactivation fee when utilization exceeds the threshold.

Fixed Utilization. In the fixed utilization model, utilization is equal to a fixed average rate U_e throughout the life of the rig:

$$U_t = U_e. \tag{6.6}$$

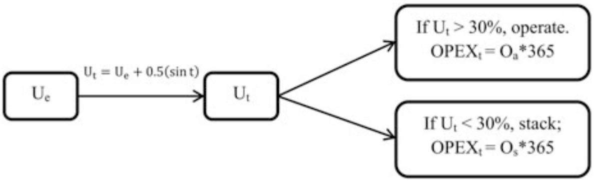

Fig. 6.2 Variable utilization model and stacking decision

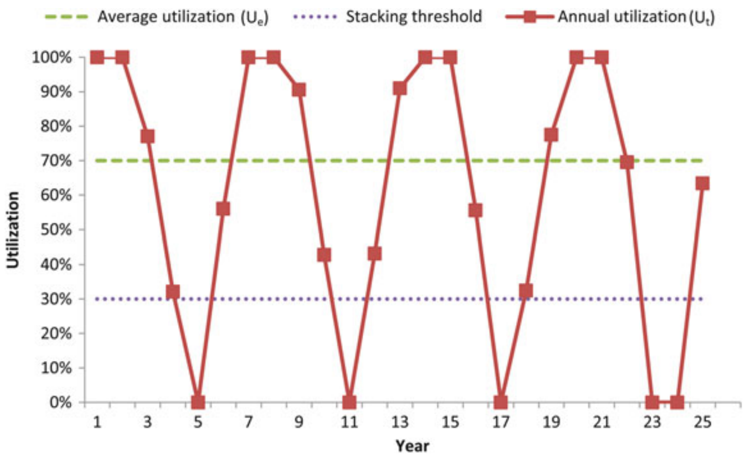

Fig. 6.3 Utilization rate over the rig lifecycle in the variable utilization model

Fixed utilization is a simplification of industry practice, but requires few assumptions and reflects key features of operational models [2].

Variable Utilization. In the variable utilization model, utilization is determined by a sinusoidal function varying around the fixed average rate:

$$U_t = U_e + 0.5(\sin t), \quad (6.7)$$

where U_e is the fixed average utilization rate and U_t is constrained between zero and one. In this model, the rig is cold-stacked in any year in which U_t falls below 30 %. When stacked, utilization is set to zero and operating costs are reduced (Fig. 6.2). Initially, the rig enters a period of high utilization, consistent with market conditions during a newbuild cycle, and after the fourth year utilization falls below 30 % and the rig is stacked. During the sixth year, market conditions improve to bring back the rig into service, which incurs a reactivation cost and the cycle repeats (Fig. 6.3).

Table 6.2 Newbuild model parameterizations

Variable	Unit	Expected	Optimistic
C	million $	200	175
T	year	7	15
I	%/year	4.5	3
G	% of C	25	25
O_a	$/day	60,000	50,000
O_s	$/day	10,000	6,000
DR_t	$/day	Variable	Variable
A	year	25	25
U_t	%	Variable	Variable
U_e	%	Variable	Variable
X	%/year	15	10
D	%/year	15	10

6.2.3 Parameterization

The model was parameterized under an expected and optimistic scenario (Table 6.2). Under the expected scenario, capital cost is $200 million, active and stacked operating cost is $60,000 and $10,000/day, bond interest rate is 4.5 %, bond maturity is seven years, and the tax and discount rates are 15 % [6]. Under the optimistic scenario, capital cost is $175 million, active and stacked operating cost is $50,000 and $6,000/day, bond interest rate is 3 %, bond maturity is 15 years, and the tax and discount rates are 10 %. Reactivation cost of $5 million is incurred in any year a rig is reactivated from a cold-stacked condition.

Parameters were chosen based on public information and the annual reports of large firms. The purchase price of rigs are widely reported and well known. Daily operating expenditures are not available for all contractors and regions, but some firms regularly report operating costs (Table 6.3). In 2010–2011, operating costs for stacked jackups varied between $6,700 and $12,000/day for Transocean, Hercules and Diamond, while operating expenses for active jackups varied from $32,000 to $58,000/day for standard units, and $55,000 to $87,000/day for high-spec units. Stacked cost for floaters are comparable to jackup units, while operating cost are significantly higher ranging from $104,000/day (midwater) to $150,000/day (ultra-deepwater). Operating cost change over time with market conditions, inflation, and region of operation.

6.2.4 Model Results

Break-Even Dayrates and Utilization. As the utilization rate increases, the dayrate required to break-even decreases since higher utilization rates translate into greater cash flows (Fig. 6.4). Combinations of utilization and dayrates above the scenario lines represent a positive NPV and values below the lines indicate a negative NPV.

Table 6.3 Stacked and active operating costs for jackups and floaters, 2010–2011

Rig type	Firm	Rig type	Status	OPEX ($/day)
Jackups	Diamond	High-spec	Operating	55,000
		Standard	Operating	45,000–58,000
	Hercules	Domestic	Operating	32,000
			Stacked	6,700
		International	Operating	47,000
			Stacked	8,000–12,000
	Transocean	High-spec	Operating	87,000
			Stacked	10,600
		Standard	Operating	46,000
			Stacked	6,900
Floaters	Transocean	Ultra-deepwater	Operating	150,000
		Deepwater	Operating	137,000
			Stacked	26,000
		Midwater	Operating	104,000
			Stacked	10,000

Source: Annual reports

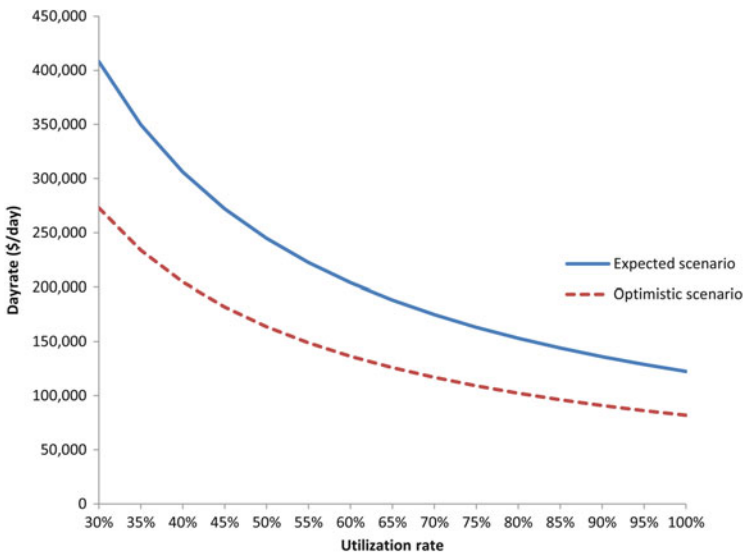

Fig. 6.4 NPV break-even curve under expected and optimistic assumptions for fixed utilization

The difference between the expected and optimistic scenarios decreases as utilization rates increase, but even at high utilization rates the difference between the scenarios is significant. At 60 % utilization, the difference in dayrates between the optimistic and expected scenarios is $68,000/day; at 90 % utilization, the difference

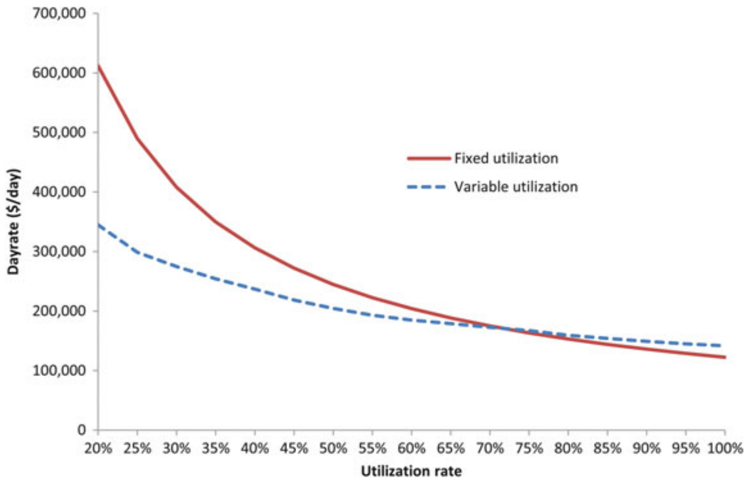

Fig. 6.5 NPV break-even curve under fixed and variable utilization rates for the expected scenario

is $46,000/day. If management expects a 90 % utilization rate, dayrates of $136,000/day are required to break-even on the investment in the expected scenario.

Fixed and Variable Utilization. At low utilization, the fixed utilization model requires much higher dayrates to justify investment with the premium ranging from $191,000 to $70,000/day for utilization rates between 25 % and 40 % (Fig. 6.5). As the utilization rate increases, the difference between the models decreases, and at utilization rates above 72 %, the fixed utilization model exhibits a lower break-even dayrate than the variable utilization model because the sine function is constrained by the average utilization.

Contractors are unlikely to consider building if they believe future utilization rates will be low, and the left part of Fig. 6.5 is not relevant to the investment decision. At average utilization rates above 60 %, the fixed and variable utilization models yield similar results and the fixed rate model is a good approximation to the variable rate model. Since the fixed utilization model requires fewer assumptions than the variable model, it may be preferred despite its relative simplicity.

Effects of an Initial Contract. The effects of a 2-year initial contract were examined. During the 2-year period, the rig is fully utilized, followed by a fixed utilization for the remainder of its lifecycle. At low utilization rates, an initial contract reduces the break-even dayrates relative to the fixed and variable utilization models (Fig. 6.6), but at higher utilization rates, the benefits of an initial contract diminish. At high utilization rates, the break-even dayrates of all three models converge because initial conditions become less relevant in high utilization environments. At 70 % utilization, for example, the break-even dayrate of the fixed utilization model is $19,000/day more than the initial contract model, while at 90 % utilization, the difference is $4,000/day.

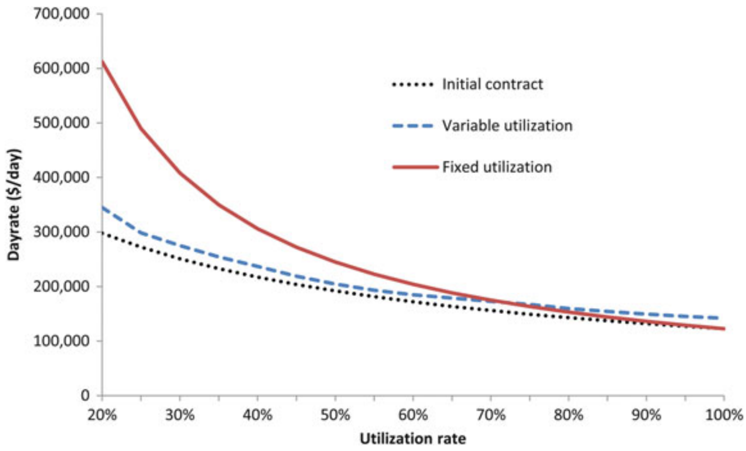

Fig. 6.6 Impact of an initial 2-year contract on break-even dayrates and utilization rates

6.2.5 Sensitivity

Break-even dayrates were moderately sensitive to changes in operating and capital costs, but mostly insensitive to changes in tax and discount rates (Fig. 6.7).

Each $1,000 increase in the daily operating expenses increased the break-even dayrate by $1,300/day at 75 % utilization and $1,100/day at 90 % utilization. Since operating expenses are a fraction of the dayrate, each 10 % change in the operating costs increased the dayrate by 3–6 % over the range examined. Each $10 million increase in the capital cost increased the break-even dayrate by $4,640/day at 75 % utilization and $3,860/day at 90 % utilization. A 10 % increase in the capital costs was associated with a 4–6 % increase in the break-even dayrate.

The effect of a 1 % change in tax and discount rates is not constant, but on average, a 1 % point increase in the tax rate (e.g. an increase from 10 % to 11 %) increased the break-even dayrate by $383/day at 75 % utilization and $319/day at 90 % utilization. A 1 % increase in the discount rate increased the break-even dayrate by $584/day at 75 % utilization and $487/day at 90 % utilization.

6.2.6 Limitations

All models are a simplification of reality and the objective of model development is to obtain insight into the business drivers and factors that impact investment risk and their relative importance. Average dayrates were employed in model development, but of course, in the real world dayrates change, and over extended periods of

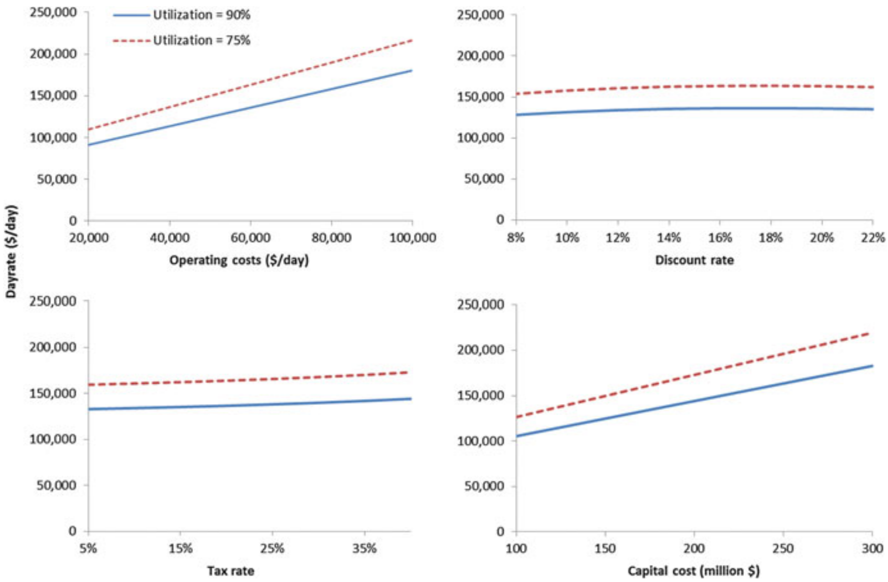

Fig. 6.7 Sensitivity of fixed utilization model to changes in operating costs, discount rate, tax rate and purchase price

time, may be highly volatile. Future cash flows are discounted, so if dayrates fall below the average early in the rig's lifetime but later exceed the mean, the present value of the investment will decline. If the near term future is more predictable than the distant future, and if realized dayrates accurately reflect the mean during the first decade of service, the results of the model are likely to be similar to the actual net present value.

Discounted cash flow analysis applies a single discount rate to both revenue and expenditure cash flows, and the use of a single discount rate assumes that the risk structure is stationary over time, which is unlikely the case for long-life assets such as newbuilds.

The decision to build results in the net addition of a rig to the fleet, increasing regional supply, and potentially decreasing dayrates and utilization for the other rigs in an operator's fleet, for all other things equal [1]. Contractors should therefore be conservative when evaluating newbuilding decisions. The effects of a small increase in fleet size on dayrates and utilization is difficult to detect relative to the volatile nature of the market, but the cumulative impact of a number of contractors making similar investment decisions simultaneously is more significant and a recognized problem facing the industry, since newbuild decisions are in part based on competitor actions [5].

Rigs are designed to have operational lives of 25 to 30 years, but often work as long as 40 to 50 years. Therefore, value remains in a rig after its design life is reached, but no attempt was made to value rigs in the distant future.

The utilization models applied did not incorporate random effects and stochastic models are likely to yield different outcomes. However, offshore markets have been historically cyclical and a sinusoidal function may more closely represent future market conditions than a stochastic model [4]. In any case, all futures are unknown so model assumptions regarding future scenarios are likely to be equally uncertain.

The assumed financial structure of the investment may be inappropriate for smaller firms and firms with high debt loads. We assumed that firms would raise capital through the issuance of bonds which is a major source of capital for large firms. In many cases, firms use more traditional loans to finance construction. Loans have higher interest rates and require repayment of principal earlier than bonds, and both of these factors would increase the dayrates and utilization required to justify construction. Many bank loans used in the industry utilize balloon payments at the end of the term and have a financing structure similar to bonds.

When bonds mature, firms may acquire new debt to pay off the principal rather than using available cash which would delay the principal repayment at the cost of additional interest payments. The effects on present value would depend on the terms of the new credit facility, but would generally be expected to be positive. Firms with low debt ratios may pursue such a strategy, but it is unlikely to be an option for firms with high debt ratios.

6.3 Stacking

During market downturns, firms may either stack or maintain rigs when searching for new contracts. Cold-stacking results in lower daily operating costs but provides no opportunity to generate revenue and requires capital to return to ready status. Maintaining a rig in a ready-stacked state imposes higher daily operating costs but allows contractors to recoup cost through faster deployment when work is available. The most profitable strategy minimizes net cost and is a function of the operating costs in the cold-stacked and active state, costs associated with stacking and reactivation, the potential dayrates and utilization rate if the rig is operated, and the time period considered.

6.3.1 Decision Model

Stacking Criteria. Firms cold stack rigs when the costs of stacking are less than the net costs of operating. The costs of cold stacking include the costs to prepare the rig for storage (deactivation costs), the operating and maintenance costs during storage ($\mathrm{OPEX_s}$), and the costs to reactivate the rig when re-entering the market (reactivation costs):

$$\text{Cost of stacking} = \text{Deactivation cost} + \text{Reactivation cost} + \text{OPEX}_\text{s}. \quad (6.8)$$

Deactivation costs, reactivation costs and operating costs are positive. The net costs of operating consist of the expected revenue received minus the active operating costs OPEX_a:

$$\text{Net costs of operating} = \text{Expected revenue} - \text{OPEX}_\text{a}. \quad (6.9)$$

Thus, a rig should be cold-stacked if:

$$\text{Deactivation} + \text{Reactivation} + \text{OPEX}_\text{s} < \text{Expected revenue} - \text{OPEX}_\text{a}. \quad (6.10)$$

Deactivation and Reactivation Costs. Deactivation costs are fixed and all other costs are variable. Reactivation costs are assumed to include a fixed and variable component:

$$\text{Reactivation costs} = \text{F} + \text{R} * \text{y}, \quad (6.11)$$

where F is the fixed cost associated with rehiring and training workers; R includes the maintenance, inspection and upgrade costs needed to bring back a cold-stacked unit to an active state; and y is the number of days the rig is expected to be idle. The variable y is the period over which the operator bases their decision; e.g. if the rig is stacked for 6 months, then $\text{y} = 180$ days. As stacking time increases, reactivation costs usually increase.

Operating Costs. Operating costs are given by the daily operating cost times the number of days the rig is idle:

$$\text{OPEX}_\text{s} = \text{O}_\text{s} * \text{y or OPEX}_\text{s} = \text{O}_\text{a} * \text{y}, \quad (6.12)$$

where O_s and O_a are the daily operating costs in the stacked and active states, respectively.

Lost Income. The potential lost revenue is the expected dayrate multiplied by the expected utilization rate and the number of days the rig is idle:

$$\text{Expected revenue} = \text{DR} * \text{U}_\text{e} * \text{y}, \quad (6.13)$$

where DR is the average dayrate and U_e the utilization rate.

Rig Stacking. The costs of stacking is always positive, but the net costs of operating may be positive (if Expected revenue $>$ OPEX_a) or negative (if Expected revenue $<$ OPEX_a). Therefore, by forcing the costs of stacking to be negative, a rig should be stacked if the costs of stacking are less negative than the costs of operating:

$$-(\text{Deactivation} + \text{Reactivation} + \text{OPEX}_\text{s}) > \text{Income} - \text{OPEX}_\text{a}. \quad (6.14)$$

For example, if: Deactivation + Reactivation + $OPEX_s = \$1{,}000{,}000$, Expected income = \$1,000,000, and $OPEX_a = \$3{,}000{,}000$, then the inequality becomes: $-(1{,}000{,}000) > 1{,}000{,}000–3{,}000{,}000$, and the rig should be stacked. If the expected income increased to \$3,000,000, the rig would not be stacked because: $-(1{,}000{,}000) < 3{,}000{,}000–3{,}000{,}000$.

6.3.2 Parameterization

The model is parameterized for a low-spec jackup (Table 6.4). Low-spec jackups are the most common cold-stacked rigs and cost information is available from several contractors. Costs to deactivate and maintain the rig in a cold and ready-stacked condition are well defined, but the time the rig will be out of service and the potential lost income depend upon market conditions, contractor decisions, and the period of analysis. Deactivation costs, the fixed component of reactivation, and operating costs are fixed. Dayrate, utilization and stacking duration are variable.

The costs to deactivate a rig include costs to move the rig to a shipyard or wet dock and secure the rig for storage. Workforce reductions lead to lower direct and indirect costs. Deactivation costs are not typically reported in financial documents, and we assume a fixed cost of \$1 million. Reactivation costs for jackups typically range from \$5 to \$10 million depending on the condition of the rig. A fixed reactivation cost of \$3 million and variable costs of \$4,000/day is assumed. Operating expenses for an active rig depend on its size, age and replacement value. For older jackups, active operating expenses are assumed to be \$35,000/day; for a cold-stacked jackup, operating expenses are assumed to be \$8,000/day.

6.3.3 Model Results

The benefit of stacking a rig for one year at dayrates above and below rig operating expense provide operational guidance for decision makers. Stacking is the preferred strategy when values are negative (Fig. 6.8). When the expected dayrate is \$30,000/day (\$5,000/day below operating costs), the contractor must expect a utilization rate of approximately 45 % to justify operating the rig. For an expected dayrate of \$40,000/day (\$5,000/day above daily operating expenses), the contractor requires a utilization of at least 35 % to justify operation. Thus, depending on the utilization rate, stacking can be preferred even if the dayrate is greater than operating costs. Conversely, operating the rig may be preferred even if the dayrate is less than the daily operating costs.

The effect of the duration of stacking shows that at \$40,000/day the rig makes money and stacking is never the preferred option, while at \$30,000/day, operating the rig is the preferred strategy if adverse market conditions are expected for 500 days or

Table 6.4 Stacking model variable descriptions

Variable	Unit	Description
O_a	\$/day	Daily active operating costs
O_s	\$/day	Daily stacked operating costs
DR	\$/day	Average dayrate
U_e	%	Average utilization rate
y	days	Time rig is to be stacked
F	\$	Fixed reactivation costs
R	\$/day	Variable reactivation costs

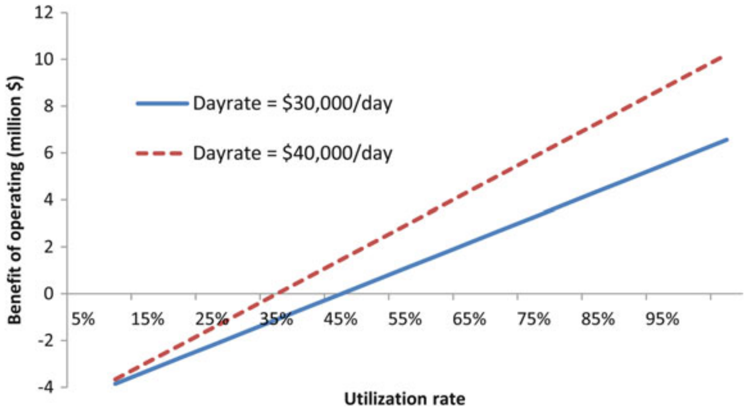

Fig. 6.8 Effect of utilization on the benefit of stacking for one year versus operating

less because of the high fixed costs associated with stacking (Fig. 6.9). If adverse market conditions are expected for more than 500 days, stacking is the best strategy.

6.3.4 Limitations

Stacking decisions are complex because firms typically operate several rigs in the same region, and the preferred strategy is the one that maximizes revenue for a firm's entire fleet of rigs. By stacking rigs, a firm may be able to improve utilization rates and keep dayrates higher for the rest of its fleet. Corts [2] studied the stacking decisions of contractors from 1998 to 2000 and found that large firms stack and reactivate rigs more frequently than smaller firms which he attributed to lower reactivation costs due to their greater ability to retain labor. As the costs of reactivation decline, firms are expected to stack and reactivate their rigs more rapidly in response to changing market conditions and business strategy.

Faced with an under-utilized rig, firms have the option to continue to operate the rig, stack the rig, move the rig to another market, or sell the rig. The costs and benefits of relocation and sales transactions were not examined. Moving an under-utilized rig to a high utilization region may result in improved cash flow if the rig can

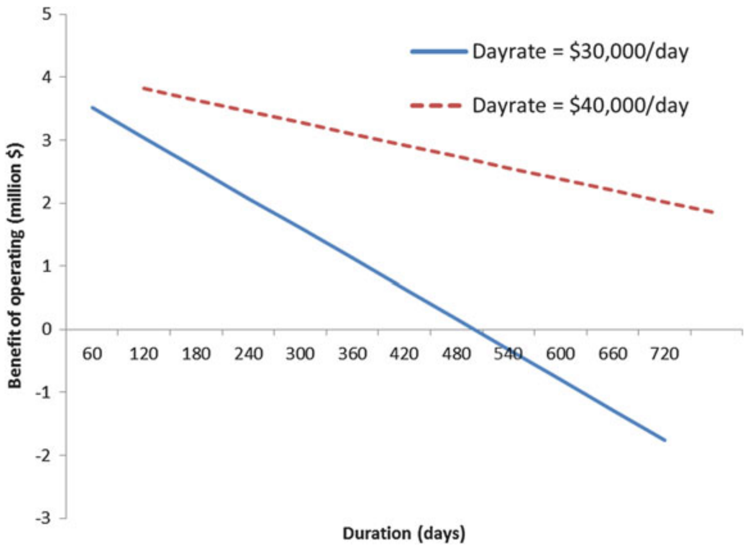

Fig. 6.9 Effect of duration on the benefit of stacking versus operating. Utilization is constant at 50% for both dayrates

find work, but is complicated by the delicate balance of operating multiple rigs in a region to capitalize on economies of scale while building customer and governmental relationships. Selling a rig may be more profitable than stacking or operating at a loss, but it may be difficult to find a buyer for an under-utilized asset in a depressed market, and when market conditions improve the opportunity to capture additional revenue will be lost.

The duration of the stacking decision was modeled by assuming a firm evaluated a stacking decision over a specific period of time. That is, the question addressed was "what is the most profitable strategy over the next *y* days". In reality, stacking decisions are undertaken without a fixed time period and a stacked rig will be reactivated when market conditions improve, not after an artificial time has elapsed.

The model addresses the question of when to cold-stack an active rig and does not address the question of when to reactivate a cold-stacked unit. A reactivation model would be similar to the deactivation model, however, in a reactivation decision, deactivation costs are sunk costs and would not be considered.

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Chapter 7
Factors That Impact Firm Value

Abstract The value of any company is derived from its cash flow and earnings, which are dependent upon the quantity of sales, sales price, and cost structure. The value of a drilling contractor is derived from the use of its fleet of rigs and the dayrates received, utilization, and operational cost in each region of the world in which it operates. The purpose of this chapter is to describe the primary factors that impact contractor value. Fleet size and value, age, and diversity, revenue, geographic and customer concentration, contract backlog, operating costs, operating margin, financial structure and business strategies are discussed.

7.1 Fleet Size and Value

Fleet size and value are closely correlated because of the commodity-like nature of rigs and the algorithmic manner in which fleet values are assessed (Fig. 7.1). Fleet value is expected to be a better predictor of firm value than fleet size because it incorporates variation associated with rig class, specifications, dayrates and contract status, while fleet size only measures the number of rigs. Fleet value is also more responsive to changing market conditions due to the nature of its evaluation.

7.2 Revenue

Revenue is a function of fleet size, dayrates and utilization rates. Firms with greater revenues will have greater earnings and value, and for all else equal, firms with more valuable fleets are expected to generate greater revenues (See Fig. 4.4). Revenue may vary considerably from year to year depending on market conditions and the firm's rig portfolio, and as a result, revenue tends to be a less stable measure than fleet or asset value.

M.J. Kaiser and B.F. Snyder, *The Offshore Drilling Industry and Rig Construction in the Gulf of Mexico*, Lecture Notes in Energy 8, DOI 10.1007/978-1-4471-5152-4_7,

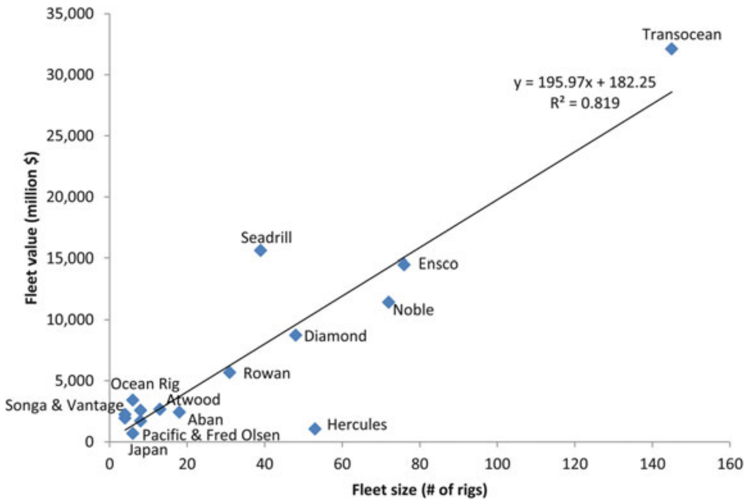

Fig. 7.1 Relationship between fleet size and fleet value in 2011 (Data from Jefferies and Company, Inc. [1])

7.3 Fleet Age

Old fleets are less valuable than new fleets because older rigs receive lower dayrates and utilization, and have fewer remaining years to generate earnings. Rigs in the 2010 world fleet were grouped by age into old (pre-1986 construction) and new (post-1986) classes[1] and the average dayrates per class were computed by region (Table 7.1). Older rigs received lower average dayrates than newer rigs in every regional market with a premium of 88 % in the jackup market, 71 % in the drillship market, and 25 % in the semi market. Newer rigs are also more heavily utilized than older rigs, and companies with older fleets stack their rigs a greater percentage of time (Fig. 7.2). Hercules and Diamond have particularly old fleets circa December 2010, while Seadrill has a younger fleet than the other large-cap firms.

7.4 Fleet Diversity

Fleet diversity is defined by rig class and specification. A diverse fleet mitigates risk to downturns and facilitates stable cash flows under changing market conditions.

[1] Few rigs were built between 1986 and 1999, and the majority of rigs in the post-1986 category were delivered after 2000.

Table 7.1 Regional dayrates for old and new rigs circa 2010

	Jackups ($/day)		Semis ($/day)		Drillships ($/day)	
	Pre-1986	Post-1986	Pre-1986	Post-1986	Pre-1986	Post-1986
North Sea	112,051	201,928	360,766	479,985		575,289
Persian Gulf	100,947	167,343				
Southeast Asia	128,924	137,440	305,715	470,781	252,846	455,113
U.S. GOM	45,282	117,805	330,793	418,301	205,054	512,333
West Africa	118,264	163,443	372,023	429,364	363,349	490,833
World	83,334	156,986	349,780	437,582	293,861	502,104

Source: Data from RigLogix [2]

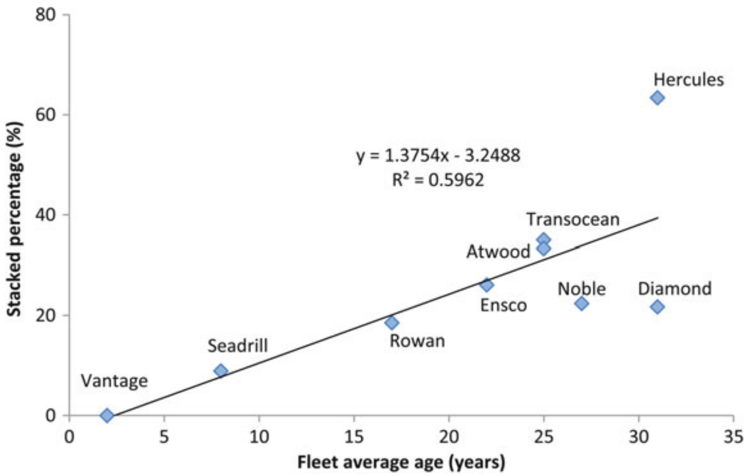

Fig. 7.2 Average fleet age and the proportion of the fleet stacked in December 2010. As rigs age and market conditions change, the slope will vary but is expected to remain positive. (Data from Jefferies and Company, Inc. [1])

7.4.1 Rig Class

Floaters generate larger net revenues than jackups in most regional markets and time periods, and drillers specialized in the floater market may have higher valuations than jackup contractors.

To illustrate, consider aggregate performance data for Diamond and Transocean by market segment in 2011 (Table 7.2). For jackups, average dayrates ranged between $82,000–$114,000/day, and for deepwater and ultra-deepwater floaters, $349,000–$533,000/day. Net revenue is the difference between dayrate and operating cost and varied from $33,000 to $68,000/day for jackups and $173,000 to $334,000/day for floaters.

Table 7.2 Diamond and Transocean performance measures by market segment in 2011

Firm	Rig class[a]	OPEX[b] (1,000 $/day)	Dayrates (1,000 $/day)	Net revenue (1,000 $/day)	Net revenue[c] (1,000 $/year)
Diamond	Ultra-deepwater	169	342	173	40,676
	Deepwater	119	416	297	99,295
	Midwater floaters	86	269	183	39,303
	Jackups	36	82	46	927
Transocean	Ultra-deepwater	199	533	334	81,056
	Deepwater	135	349	214	6,774
	Harsh floaters	171	450	279	93,623
	Midwater floaters	91	280	189	37,303
	High-spec jackups	81	114	33	–22
	Jackups	29	96.5	67.5	6,674

Source: Financial reports

[a]Diamond defines ultra-deepwater as >7,500 ft, deepwater as >5,000 ft and midwater as <5,000 ft. Transocean defines ultra-deepwater as >7,500 ft, deepwater as >4,500 ft, and midwater as <4,500 ft. High-spec jackups are capable of drilling in harsh environments, or have higher capacity derricks, drawworks, mud systems and storage

[b]Operating expenses include all of the costs associated with operating, maintenance and stacking

[c]Calculated as annual revenues (dayrate times utilization times 365) minus annual costs (daily operating costs times 365)

For Transocean, ultra-deepwater and harsh environment floaters were highly profitable due to high utilization and market conditions that commanded premium dayrates. High-specification shallow water jackups were the only market segment with negative net revenues. Diamond's deepwater fleet experienced higher dayrates than its ultra-deepwater fleet and was Diamond's most lucrative business segment. Floaters were more profitable than jackups in every segment, although the net earnings in Transocean's deepwater segment were relatively low due to low utilization and high maintenance costs. Rigs in the midwater market generated approximately $40 million per rig for both firms, while the jackup segment was only marginally profitable, and the deepwater segments generated between $7–$90 million and $40–$80 million per rig class.

7.4.2 *Specification*

Contractors diversify within a rig class by operating both high and low specification units (Fig. 7.3). In 2011, Transocean, Noble, Ensco, and Diamond were the only contractors to own units in every rig class. In contrast, all of Seadrill's units are high-spec, and nearly all of Hercules' units are standard jackups. In most market conditions, high specification rigs receive a dayrate premium, but high-spec rigs are also more expensive to operate, and may or may not be associated with higher net earnings. For example, Transocean's high-spec jackups were not associated with

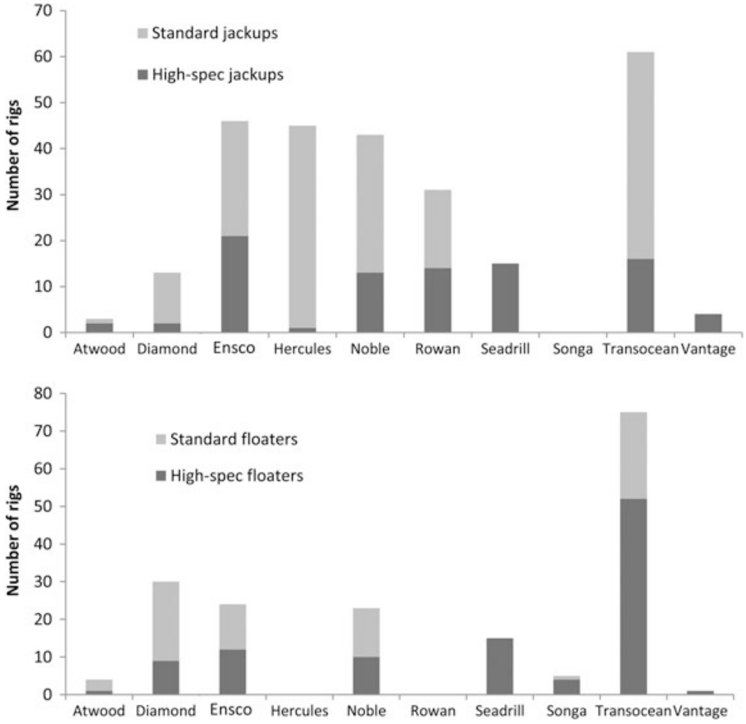

Fig. 7.3 Jackup and floater inventories in 2011. Active and stacked rigs are included in the count (Data from financial reports)

a net earnings premium relative to standard jackups in 2011, but high-spec floaters did have greater earnings than standard floaters.

7.5 Geographic Concentration

Contractors position rigs to capitalize on imbalances in supply and demand and achieve administrative cost reductions through economies of scale while building customer and governmental relationships. High concentration of assets in a few countries also subjects firms to increased political, regulatory and financial risk. Following the Macondo blowout in the Gulf of Mexico, for example, the U.S. government imposed a deepwater drilling moratorium which negatively impacted firms operating in the region. Firms with a high degree of concentration in the U.S. GOM in 2010–2011 were disproportionately impacted by the moratorium.

Drilling contractors involved in international operations are subject to additional risks not generally associated with domestic operations, such as terrorist acts; war and civil disturbance; expropriation or nationalization of assets; renegotiation or nullification of contracts; changes in law or interpretation of existing law; assaults on property or personnel; foreign and domestic monetary policies; and travel limitations or operational problems caused by public health threats. There is a tradeoff between fleet diversity and market position, and firms balance the desire for a strong market position in some regions and markets against geographic and market diversity. Firms with larger fleets are more geographically diverse than firms with smaller fleets (Fig. 7.4), and as the number of countries in which a company operates increases, the proportion of total revenue from the four largest regions generally declines indicating greater geographic diversification (Fig. 7.5).

Diamond Offshore was particularly dependent on the Brazilian market in 2011, and more than half of Hercules revenues were generated in the U.S. GOM (Table 7.3). Hercules and Rowan had the most concentrated geographic base in 2011 while Noble and Transocean had the most geographically diverse revenue base. Large firms are capable of balancing market position and diversity, while smaller firms are limited in the number of regions in which they can successfully compete. Firms that consistently rely on competitive or declining regions may be undervalued relative to their peers. Hercules, for example, has historically been concentrated in the U.S. GOM shallow water region, a declining market with low dayrates and utilization, while Seadrill has established itself as a significant presence in Brazil's deepwater region, a growing market with high utilization.

7.6 Contract Backlog

Contract backlog is the value of a firm's contract commitments. Backlog includes the contracts rigs are currently working under as well as any future contracts and is calculated as the contract dayrate multiplied by the remaining contract duration for all rigs in a company's fleet. High backlogs are associated with stable revenues in the near to mid-term which reduces risk for investors and increases firm value.

7.7 Customer Concentration

Contractors that derive the majority of their revenue from a small number of E&P firms can create risk because the loss of a single client may eliminate a major source of revenue. Transocean is particularly diverse and its largest customer in 2011 only accounted for 10 % of revenues (Table 7.4). Atwood, Diamond, Hercules, Noble and Rowan's major customer contributed between 25 % and 35 % of the firms' 2011 revenue and two customers comprised over half of total revenue for Atwood, Diamond, and Rowan. All else equal, firms with a diverse customer base are expected to be more valuable than firms with a limited customer base.

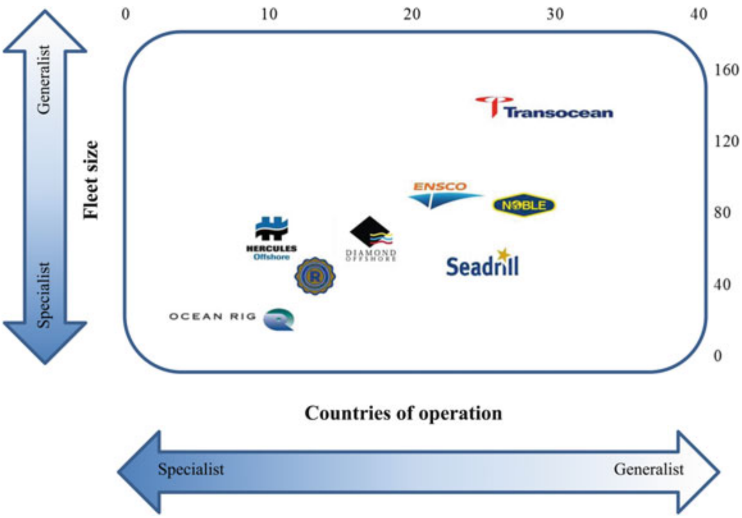

Fig. 7.4 Fleet size and the number of countries from which a contractor received revenue in 2011 (Data from financial reports, Jefferies and Company, Inc. [1])

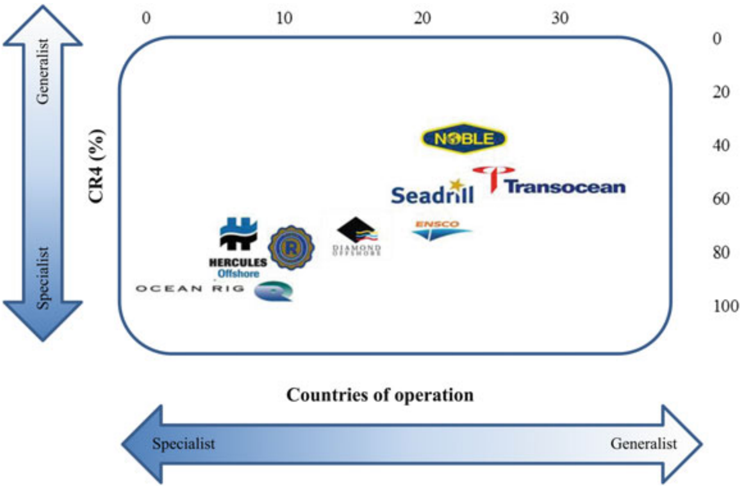

Fig. 7.5 Measure of geographic specialization for selected contractors. CR4 is defined as the proportion of revenue from the four largest countries (Data from financial reports, Jefferies and Company, Inc. [1])

Table 7.3 Drilling contractor revenues in million U.S. dollars by region in 2011

	Diamond	Ensco	Hercules	Noble	OceanRig	Rowan	Seadrill	Transocean
Angola	318	250					337	
Brazil	1,641	583		572			913	1,019
China							299	
India			61	102				
Mexico	62	148	16	402		28	49	
Nigeria			98				235	
Norway						74	966	
Qatar				132		60		
Saudi Arabia			93	96		204	127	
U.K.	152	240		164		230	56	1,211
U.S. GOM	323	753	302	524		264	202	1,975
Other	826	866	85	703	700	79	1,008	4,937
No. countries	14	21	8	23	5	10	22	27
CR4[a] (%)	71	64	85	42	93	82	60	55

Source: Financial reports

[a]CR4 is defined as the revenue from the four largest markets divided by the total revenue

Note: Blank values do not indicate that the contractor received no revenue from the region, only that the revenue was not considered significant enough to list separately

Table 7.4 Major customers of selected drilling contractors in 2011

	E&P customers (% of revenue)			
	First	Second	Third	Fourth
Atwood	Chevron (30 %)	Shell (21 %)	Kosmos (21 %)	
Diamond	Petrobras (35 %)	OGX (14 %)		
Ensco	Petrobras (16 %)			
Hercules	Chevron (25 %)	Saudi Aramco (13 %)	ONGC (9 %)	PEMEX (3 %)
Noble	Shell (24 %)	Petrobras (18 %)	Pemex (15 %)	
Rowan	Saudi Aramco (29 %)	McMoRan (21 %)	Total (11 %)	
Seadrill	Petrobras (17 %)	Statoil (15 %)	Total (10 %)	Shell (9 %)
Transocean	BP (10 %)			

Source: Financial reports

7.8 Operating Costs

Net profits associated with operating a rig are determined from the contract dayrate less the daily operating costs. Generally speaking, deepwater, high-spec, international rigs cost more to operate than shallow water, low-spec, domestic rigs (Table 7.5). Rig size and age, port infrastructure, scale economies related to a contractor's regional presence, market competition, and the availability of goods and services are primary factors that impact operating cost.

Table 7.5 Operating expenditures for jackups and floaters by contractor in 2011

Rig class	Firm	Rig type	OPEX ($/day)
Jackups	Atwood	High-spec	64,000
		Standard	44,000
	Diamond	High-spec	55,000
		Standard	52,000
	Hercules	Domestic	32,000
		International	47,000
	Transocean	High-spec	87,000
		Standard	46,000
Floaters	Atwood	Ultra-deepwater	191,000
		Deepwater	119,000
	Transocean	Ultra-deepwater	150,000
		Deepwater	137,000
		Midwater	104,000

Source: Financial reports

7.9 Operating Margin

Operating margin is the ratio of operating income (earnings before interest and taxes) to revenue and is an aggregate measure of the cost structure of the firm. Firms with higher operating margins have larger net earnings per dollar of revenue than firms with lower margins. Firms with older fleets or a large number of stacked rigs are expected to have lower operating margins than firms with younger or more active rigs. A statistically significant negative relationship exists between the percentage of the fleet that was stacked in 4Q2011 and operating margin (Fig. 7.6), but many other factors are responsible for operating margin and the relationship only explains a small proportion of the variation.

7.10 Financial Structure

Rig construction is capital intensive and fleet additions are financed through a combination of debt and equity. The use of debt to finance growth increases the risk of default and may lead to variation in earnings as firms service debt. However, the use of debt also allows a firm to leverage its equity, potentially increasing the yield to investors.

Seadrill and Songa were active in newbuilding and the secondhand market from 2008 to 2011 and maintained relatively high debt to capital ratios compared to the 37 % large-cap average (Fig. 7.7). Songa's 2008 earnings were approximately $200 million compared to a total debt of approximately $1 billion. With a limited cash flow at the time, Songa used debt to purchase six rigs between 2005 and 2008. By late 2010, Songa's debt level declined to about $500 million, and in 2011,

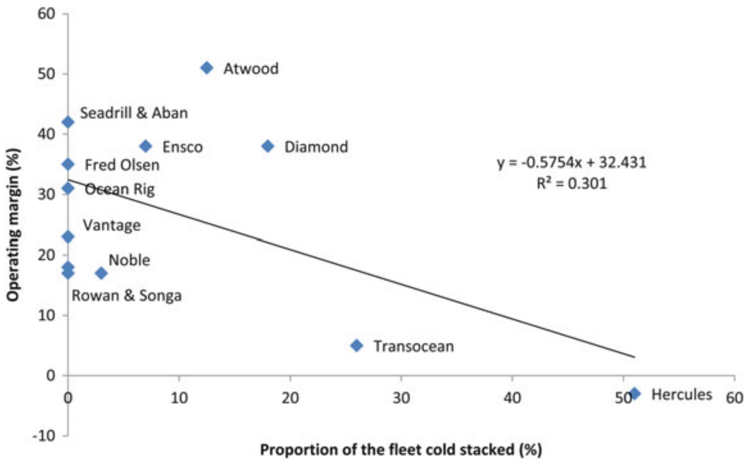

Fig. 7.6 Relationship between operating margins and the proportion of the fleet cold-stacked in 4Q2011 (Data from Jefferies and Company, Inc. [1])

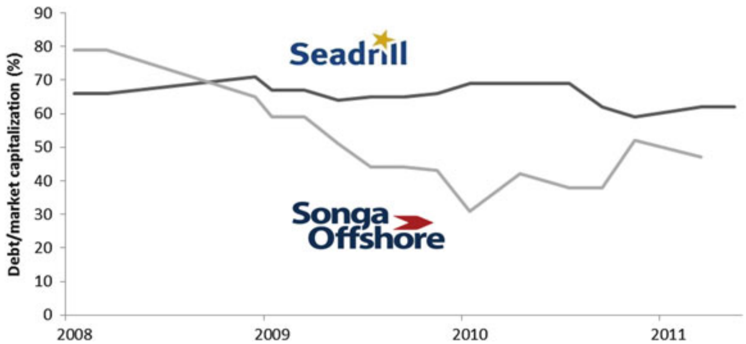

Fig. 7.7 Debt to capitalization ratio of Seadrill and Songa, 2008–2011 (Data from Jefferies and Company, Inc. [1])

it entered into a new credit facility to finance the construction of new rigs. By contrast, Seadrill's debt ratio remained relatively stable from 2008 to 2011, even as the firm's debt load grew from $6 billion in 2008 to $10 billion in 2011. Instead of using cash to pay off debt, Seadrill has spent cash on acquisitions, newbuilds, and shareholder dividends. Strong retained earnings have allowed Seadrill to maintain an acceptable debt to capital ratio, but its debt level remains high relative to its peers.

7.11 Business Segments

Several companies operate offshore rigs as a small, non-core part of their business operations. Saipem, Maersk Drilling, Nabors, Petrobras, and Oil and Natural Gas Corporation (ONGC) of India generate less than half of their revenues from offshore drilling. Saipem derives the majority of its revenue from offshore construction, Maersk Drilling is a subsidiary of the shipping conglomerate A.P. Moeller Maersk, Nabors is primarily an onshore drilling contractor, and Petrobras and ONGC are National Oil Companies. Other firms such as Aban, Fred Olsen Energy, COSL, and Hercules also have investments in other industries, but these investments do not generate more than 25 % of the firm's revenue. Aban has investments in wind energy, Fred Olsen Energy in offshore construction, COSL is an integrated offshore oilfield services company, and Hercules operates a liftboat division.

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Chapter 8
Offshore Driller Valuation Models

Abstract The value of publicly traded firms are characterized by their market capitalization and enterprise value. Market capitalization is the total value of tradable shares of a company at a specific point in time, determined by the product of its stock price and the number of outstanding shares. Enterprise value is the market capitalization plus debt, minority interest and preferred shares, minus total cash and cash equivalents. Models of market capitalization and enterprise value for a cross section of offshore drilling contractors circa 2011 is described. The valuation methodology is outlined and the results of regression models are presented along with a discussion of the limitations of analysis. Fleet value is the single best predictor of market capitalization and enterprise value.

8.1 Company Valuation

The value of any company is derived from its cash flow and earnings, which are dependent upon the quantity of sales, sales price, and cost structure [1]. For offshore drilling contractors, cash flow and earnings derive from the use of their fleet of rigs and the dayrates received, utilization, and operational cost in each region of the world in which they operate.

The market value of a firm reflects the worth of the company and its property on the open market at a specific point in time and is defined as "the estimated amount for which a property should exchange on the date of valuation between a willing buyer and a willing seller in an arms-length transaction after proper marketing wherein both parties had each acted knowledgably, prudently, and without compulsion... reflecting the collective perceptions and actions of a market..." [8]. Information on company valuation and its relationship to firm-specific data is useful in understanding industry structure [4], performing due diligence [3, 7, 10, 11], and revealing the relative value of companies [13, 14].

M.J. Kaiser and B.F. Snyder, *The Offshore Drilling Industry and Rig Construction in the Gulf of Mexico*, Lecture Notes in Energy 8, DOI 10.1007/978-1-4471-5152-4_8,

Table 8.1 Financial metrics of offshore drilling contractors circa December 31, 2011

Company	Fleet value (million $)	Backlog (million $)	Debt (million $)	Debt to equity (%)	Operating margin (%)	Dividends (million $)
Transocean	32,112	22,500	13,526	86	5	763
Seadrill	15,613	12,600	10,428	174	42	1,431
Ensco	14,496	9,666	5,050	46	38	269
Noble	11,433	13,683	4,071	55	17	151
Diamond	8,726	8,137	1,495	35	38	487
Rowan	5,680	3,065	1,134	26	17	0
Ocean Rig	3,420	2,335	2,735	92	31	0
Atwood	2,668	1,800	525	32	51	0
Fred Olsen Energy	2,575	2,900	962	59	35	236
Aban	2,436	1,900	2,296	507	42	0
Pacific Drilling	2,240	2,100	1,675	74	−19	0
Songa	1,946	7,100	1,096	98	18	0
Vantage	1,703	1,000	1,246	179	23	0
Hercules	1,065	432	845	93	−3	0
Japan Drilling	683	700	173	29	22	6

Source: Financial reports

8.2 Methodology

8.2.1 Sample

Market capitalization and enterprise value data from 15 publicly traded drilling contractors representing all large-cap firms and eight of the 10 largest firms in the industry was assembled along with fleet value, revenue, earnings, contract backlog, financial metrics and fleet specification for the year ending December 31, 2011 (Table 8.1). The sample represented 63 % of global drilling capacity in 2011 and all publicly traded firms where offshore drilling revenues accounted for a majority of total revenues. Annual reports, Bloomberg, Jefferies and Company [9], RigLogix [12] and Slorer et al. [13] were the primary data sources.

Maersk, Northern Offshore, Nabors, Saipem, COSL, Petrobras, ONGC and a number of other National Oil Companies with drilling subsidiaries were excluded from analysis because their drilling revenues accounted for less than 60 % of the total firm revenues. Drilling accounted for at least 95 % of total revenue for all firms except Hercules where drilling accounted for 74 % of revenues in 2011.

8.2.2 Valuation Model

Market capitalization (CAP) and enterprise value (EV) are hypothesized to follow linear relationships described by one or more combinations of fleet value (FLEET), revenue (REV), contract backlog (BL), floater and high-spec fleet proportions (PF, PH), debt to

Table 8.2 Variables used in the market valuation models

Variable	Definition	Unit	Data source
CAP	Market capitalization	million $	Bloomberg
EV	Enterprise value	million $	Bloomberg
FLEET	Fleet value	million $	Jefferies [9]
REV	Revenue	million $	Bloomberg
BL	Backlog	million $	Financial reports
PF	Proportion of floaters	%	Financial reports
PH	Prop. of high-spec rigs	%	Financial reports
DE	Debt to equity ratio	%	Bloomberg
OM	Operating margin	%	Bloomberg
SDR	Seadrill indicator	1 if Seadrill, 0 otherwise	
TRN	Transocean indicator	1 if Transocean, 0 otherwise	
EBIT	Earnings	million $	Bloomberg
DY	Dividend yield	%	Bloomberg

Note: All data reported on December 31, 2011

equity ratio (DE), operating margin (OM), earnings (EBIT) and dividend payments (DY). Seadrill (SDR) and Transocean (TRN) were identified separately using indicator variables.

The predictor variables were selected based on data availability and a subjective assessment of the variables most likely to impact company value (Table 8.2). The time of assessment coincides with the release of end-of-year financial data and ties the model results to a specific point in time, but it is easy to incorporate additional time variables into the analysis.

8.2.3 Expectations

Fleet Value. Fleet value is the sum of the net asset values of the individual rigs in a firm's fleet and is taken from Jefferies and Company [9] and Slorer et al. [13]. Fleet value is expected to be positively correlated with company valuation, revenue, earnings, and backlog.

Revenue. Company revenue is a function of regional dayrates, utilization and fleet size and was used as a proxy for all three variables. Aban and Japan Drilling revenues were converted to U.S. dollars using the exchange rate on December 31, 2011. Revenue is consistently reported and reliable and is expected to be positively correlated with company valuation, earnings, fleet value, and backlog.

Backlog. Information on the contract backlog was collected from annual reports at the time of the assessment. Backlog represents the future revenue potential of a company and is expected to be positively correlated with firm valuation.

Fleet Specification. The proportion of high-spec rigs and floaters was derived from financial reports. High-spec rigs usually achieve dayrate premiums over low-spec rigs, and floaters often realize higher utilization and dayrates than jackups. Measures of firm value are expected to be positively correlated with the proportion of the fleet that is composed of high-spec or floating rigs.

Debt. The debt to equity ratio was calculated as the total debt divided by shareholder equity using data from Bloomberg. Highly leveraged firms have higher fixed charges in the form of interest payments relative to discretionary outlays such as dividend payments. The higher the debt to equity ratio, the greater financial risk, and the lower the expected market cap and enterprise value.

Operating Margin. Operating margin is the ratio of operating income to revenue expressed as a percentage and was collected from Bloomberg. Operating margin is expected to be positively correlated with firm valuation.

Indicator Variables. Transocean drilled the Macondo well that blew out on April 20, 2010 and by December 31, 2011 its liabilities were not resolved. Seadrill has a young, high-spec fleet, high utilization rates and a low cost structure relative to its peers, and has been consistently rewarded by the market in its valuation. Indicator variables are employed to distinguish these companies from the other firms in the sample since they appear as outliers.

Earnings. Operating income is a function of firm revenue and expenses and was collected from Bloomberg. Earnings are expected to be positively correlated with fleet value, revenues, backlog and firm value.

Dividends. Drilling contractors often pay dividends to return cash to investors. Data on total cash dividend payments were collected from Bloomberg and normalized by the market capitalization to derive the dividend yield. High dividends may attract investors, potentially increasing the share price, but dividends and share price are often inversely related. The impact of dividends on contractor valuation is uncertain.

8.2.4 Correlation Matrix

Backlog, fleet value, and revenue were all strongly correlated and dividend yield was weakly correlated with earnings (Table 8.3). All other predictor variables were not correlated. Revenues and backlogs are measures of current and future income, and are expected to be related. Fleet value is determined in part by backlog and firms with more valuable fleets and strong customer relations are able to generate larger backlogs and revenues. Earnings and the other predictors of firm value do not demonstrate high correlations because several large firms (e.g., Noble, Transocean) had relatively low earnings while several smaller firms (e.g., Atwood, Fred Olsen) had high earnings relative to their revenues.

Table 8.3 Correlation matrix among predictor variables circa December 31, 2011

	FLEET	REV	BL	PF	PH	DE	OM	EBIT	DY
FLEET	1								
REV	0.98	1							
BL	0.95	0.93	1						
PF	−0.05	−0.02	0.06	1					
PH	0.03	−0.05	0.05	0.32	1				
DE	−0.10	−0.09	−0.12	−0.25	0.25	1			
OM	−0.03	−0.02	−0.04	−0.01	−0.06	0.22	1		
EBIT	0.49	0.51	0.51	0.05	−0.08	0.01	0.52	1	
DY	0.46	0.54	0.47	0.29	0.20	−0.12	0.30	0.71	1

8.3 Model Results

8.3.1 *Single Variable Models*

Fleet value, revenue, earnings, and backlog were significant predictors of enterprise value and market capitalization in single factor models (Figs. 8.1 and 8.2). Fleet value, revenue and backlog each predicted approximately 70–80 % of the variation in market capitalization and enterprise value; earnings predicted 55–65 % of the variation in firm value. Transocean and Seadrill are outliers in all the relationships, and with the exception of earnings, Transocean was undervalued and Seadrill overvalued relative to the industry average circa December 31, 2011. Operating margin, dividend yield, fleet specification, and debt to equity ratio were not useful predictors.

Offshore drilling contractors often have large debt loads and enterprise value is usually greater than market capitalization. Japan Drilling is the only company in the sample with an enterprise value less than its market cap. For each \$1 increase in fleet value, market capitalization on average increased \$0.55 and enterprise value increased \$0.90; for each \$1 increase in backlog, market capitalization increased by \$0.72 and enterprise value increased by \$1.17; for each \$1 increase in revenue, market capitalization increased by \$1.89 and enterprise value increased by \$3.11; and for each \$1 increase in earnings, market capitalization increased by \$8.3 and enterprise value increased by \$12.3.

8.3.2 *Multivariable Models*

Market Capitalization. All parameters of the multivariable market capitalization regression models are significant ($p < 0.05$) except the intercept terms (Table 8.4). Fleet specifications, operating margin and dividend yield did not add predictive power to the models and were not included. Model A yielded the best fit because indicator variables were used to eliminate the two “outlier” firms. When the debt to equity ratio and earning variables were removed, the model fit declined negligibly,

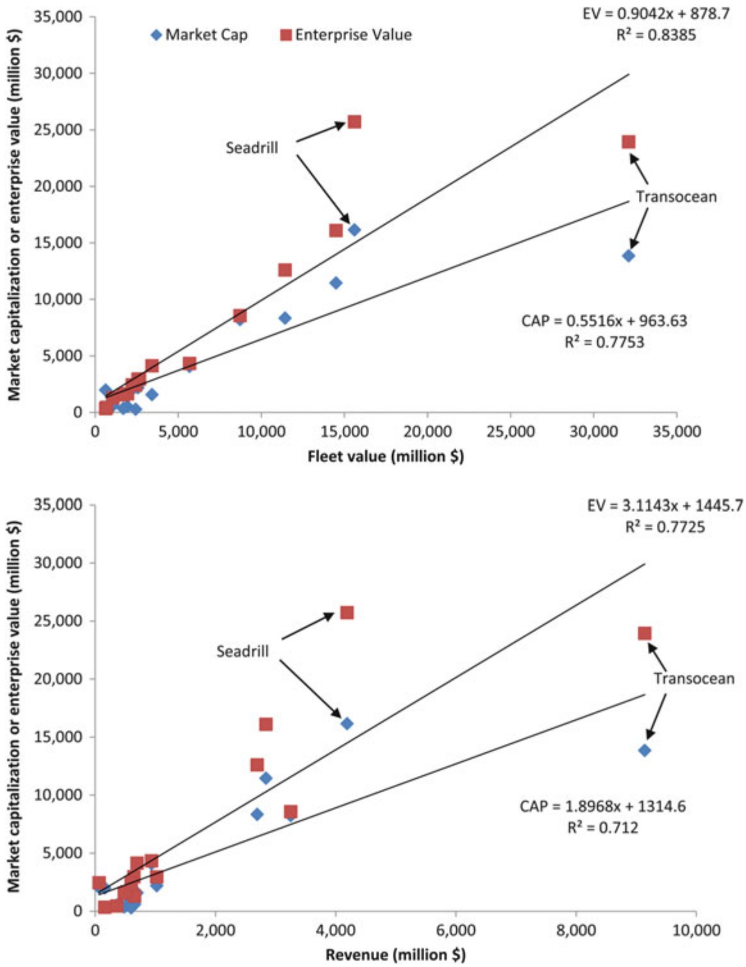

Fig. 8.1 Market capitalization and enterprise value relations for fleet value and revenue circa December 31, 2011 (Data from financial reports and Jefferies and Company, Inc. [9])

and since Model B explains essentially the same amount of variation in market cap as Model A with two less predictor variables, it may be preferred. Model B provides a superior description over single variable models because the outlier firms Seadrill and Transocean were controlled. Backlog (Model C) and revenue (Model D) were not as good predictors as fleet value, but relationships remained significant.

Enterprise Value. All parameters of the enterprise value regression models were also statistically significant ($p < 0.05$) except the intercept terms (Table 8.5). Fleet specifications, operating margin, debt to equity ratio, earnings and dividend yield did not add predictive power and were not included. As before, the inclusion of the Seadrill and Transocean indicator variables improved the model fits over the single

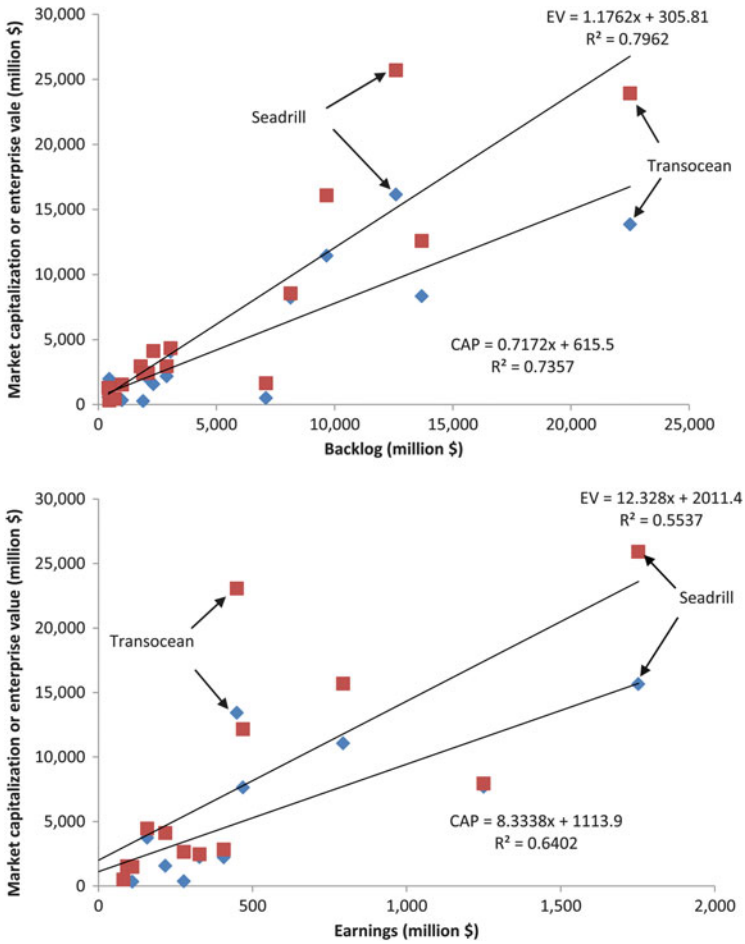

Fig. 8.2 Market capitalization and enterprise value relations for backlog and earnings circa December 31, 2011 (Data from financial reports and Jefferies and Company, Inc. [9])

Table 8.4 Selected models of market capitalization circa December 31, 2011

$CAP = a + b \cdot FLEET + c \cdot REV + d \cdot BL + g \cdot DE + i \cdot SDR + j \cdot TRN + k \cdot EBIT$

Model	a	b	c	d	g	i	j	k	R^2
A	−36.4	0.66			−3.5	3,117	−8,050	1.7	0.99
B	−439	0.78				3,858	−11,298		0.98
C	243			0.68		6,813	−2,168		0.83
D	−343		2.99			3,459	−13,571		0.92

Note: All variables are statistically significant ($p < 0.05$) except the intercept terms

Table 8.5 Selected models of enterprise value circa December 31, 2011

$EV = a + b \cdot FLEET + c \cdot REV + d \cdot BL + i \cdot SDR + j \cdot TRN + k \cdot EBIT$

Model	a	b	c	d	i	j	k	R^2
A	−205	1.05			9,663	−10,559		0.99
B	2,114		3.77		9,885	−11,619		0.92
C	466			0.98	13,037			0.91
D	955					16,618	12.2	0.80

Note: All variables are statistically significant ($p < 0.05$) except the intercept terms

variable relation. Fleet value was a better predictor than revenue (Model B), backlog (Model C) or earnings (Model D). In the backlog model, the Transocean indicator variable was not significant suggesting that Transocean is not undervalued with respect to its backlog. In the earnings model, the Seadrill indicator was not significant and the Transocean indicator was positive, suggesting that Seadrill is appropriately valued while Transocean is overvalued relative to their earnings.

8.3.3 Discussion

Fleet Value. Fleet value is the best predictor of firm value, and after controlling for Seadrill and Transocean, predicted essentially all of the variation in enterprise value and market capitalization. Fleet value is a better predictor than revenue, backlog or earnings. Market capitalization represented 78 % of the fleet value while enterprise value was 105 % of fleet value suggesting that the discounted value of the fleet most closely approximates enterprise value.

Debt to Equity. Debt to equity ratio was a significant predictor of market capitalization but not enterprise value. As expected, the sign of the debt to equity ratio was negative indicating that firm value decreases with increasing debt loads, however, the impact on model fit was small. The absence of debt to equity ratio as a useful predictor for enterprise value may partially reflect the fact that debt is already accounted for in its specification.

Transocean. Transocean's valuation discount is large but consistent with the market capitalization decline experienced after the Macondo blowout [2]. Prior to the blowout in early April 2010, Transocean's market capitalization was approximately $31.5 billion. By June 2010, Transocean's market capitalization was $16.4 billion, a decline of $15 billion. In 2011, Transocean recorded a loss of $6.2 billion related to the Macondo blowout, primarily due to goodwill impairment.[1] In January

[1] Goodwill impairment occurs when the fair market value of goodwill exceeds the carrying value. Under accounting rules, companies must review their goodwill annually by projecting profits and analyzing the market values of similar assets. If the profit outlook worsens or market value declines, a company is supposed to write down the value of the goodwill, booking an expense equal to the reduction. Since write downs don't involve cash flow or operations, they are often ignored by analysts and investors [15].

2013, Transocean agreed to plead guilty to one criminal misdemeanor violation of the Clean Water Act and pay a $100 million fine, pay $1 billion in fines for civil violations related to the Clean Water Act, and pay $300 million for oil-spill response and habitat rehabilitation [6].

Seadrill. Seadrill has a young, high specification fleet that has maintained high utilization rates and a low cost structure relative to its peers. Transocean, Diamond, Noble and Ensco all maintain larger, more diverse fleets with a mix of old and new units. In depressed markets, older units are frequently idle for a greater portion of time relative to new units, and may represent a net carrying cost to the firm. Seadrill has very few old units and realizes a higher operating margin than its large-cap peers. While the operating margin was not a significant predictor in the analysis, investors may still use operating margins as an indicator of firm value.

In 2011, Seadrill rigs were active in over 20 countries and every major market, and the U.S. GOM only accounted for 5 % of its revenue. By contrast, the U.S. GOM accounted for 26 % of Ensco, 22 % of Transocean, 19 % of Noble and 10 % of Diamond revenues and the stocks of these companies reacted less favorably to the drilling moratorium after the Macondo oil spill. Seadrill also has a higher debt load relative to its peers, and has used debt to fund an aggressive newbuild campaign which is in contrast to the more conservative large-cap peers [5]. In 2011, Seadrill paid a dividend yield of 9.1 % compared to 5.6 % for Transocean, 6.3 % for Diamond, 2.4 % for Ensco and 1.9 % for Noble. Dividend yield was not a significant predictor of firm value, and less than half of the firms in the sample paid dividends in 2011.

8.4 Limitations

The small size of the sample set and relative similarity of drilling contractors limit the ability to construct and robust multivariable models, but because we evaluated all publicly traded firms for which data was available the sample is considered representative of the industry. For private and state-owned firms or companies that generate a significant portion of their revenue from other business segments these models will not translate.

The contractor valuation models were constructed relative to a specific point in time and will not be representative of other time periods, however, the procedures are completely general and it is an easy exercise to extend the analysis to determine the relative positioning of firms and the importance of factors across time. As market conditions and fleet portfolios change, the slope of the linear relationships and coefficients of the valuation models will change, but we do not expect significant departures from the results described herein.

Market valuations are dynamic and it is unlikely that Seadrill will remain overvalued and Transocean undervalued relative to their fleet values for an extended period. Transocean's liability position should be resolved before 2015 which will reduce its market discount, and it will be interesting to watch the evolution of Seadrill's market premium and how long it will last. If Seadrill and Transocean regress towards the industry mean, single variable models will likely adequately reflect industry conditions and the use of indicator variables will not be necessary.

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Chapter 9
Construction Markets and Contracts

Abstract The rig construction industry began in the U.S. in the early 1950s and spread to Europe and Asia in the mid-1970s as offshore exploration increased. At its peak in 1983, 11 U.S. shipyards were engaged in rig construction. Shifts in exploration activity and the general decline in the competitiveness of the U.S. shipbuilding industry led to the entry of new market players, and today, Asia dominates all sectors of the newbuild industry. Since 2000, Asian shipyards have constructed 70 % of all jackups delivered in the world, and almost all semisubmersibles and drillships. The purpose of this chapter is to describe the demand factors and players in rig construction with an emphasis on jackups. We conclude with a brief review of the primary features of construction contracts.

9.1 Construction Trends

9.1.1 Jackups

From 1950 to 2012, 641 jackup rigs were constructed worldwide (Fig. 9.1) 37 % supplied from the Gulf of Mexico, 45 % from Asia, and 8 % from Western Europe. Since 2000, Asian shipyards have constructed 70 % of the rigs delivered, followed by 14 % in the U.S. and 16 % in all other countries.

Jackup construction began in the U.S. in the mid to late 1950s to support drilling in the Gulf of Mexico. The first jackup rig was Magnolia's DeLong Rig No. 1 built in 1950 and installed permanently at its first drill site in 1953. The first truly mobile jackup rig was the DeLong-McDermott No. 1 (also called the TODCO No. 51) built in 1954 [7]. Marathon LeTourneau, Bethlehem Steel and Levingston dominated the industry through the 1960s. In the early to mid-1970s U.S. firms invested in Singaporean shipyards to reduce transport costs for delivery in the region [2, 9, 11]. Western European, Canadian and Japanese firms were new entrants and the market grew significantly.

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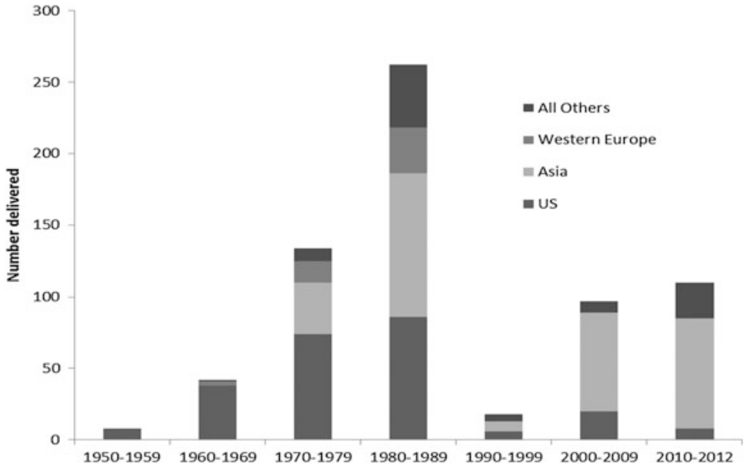

Fig. 9.1 Jackup rig construction by region, 1950–2012 (Data from Colton [5] and RigLogix [13])

The late 1970s and early 1980s saw significant increases in the price of oil, increased access to offshore acreage, and improvements in jackup technology which lead to strong demand growth and encouraged new market participants. By the mid 1980s, shipyards in 23 countries had delivered rigs, including Japan, Canada, France, the U.K., Singapore, Russia, Brazil, and Romania. At its height in the early 1980s, 11 U.S. shipyards were engaged in rig construction including six in Texas, three in Mississippi and one each in Maryland and South Carolina [5].

Oil prices dropped in the mid 1980s, and by 1986, new jackup orders had declined precipitously. Between 1980 and 1985, 244 jackups were delivered, but between 1986 and 2000, only 30 rigs were delivered. In early 2000, contractors began to replace their aging jackup fleet, and most new orders were placed in Singaporean yards (Fig. 9.2) due to the movement of exploration activity away from the Gulf of Mexico shelf and the general decline in the competitiveness of U.S. shipbuilding [10]. The pace of deliveries accelerated with the increasing price of oil, but new orders stopped in late 2008 following the economic recession, only to begin again in late 2010 with a new cycle of investment.

9.1.2 Semisubmersibles

The first semisubmersibles were delivered from Gulf Coast yards in Pascagoula, Mississippi and New Orleans, Louisiana in the late 1950s, and by 1970, eight semisubmersibles had been delivered from U.S. yards. Beginning in the early 1970s, semi construction expanded rapidly in the U.S. and spread to Japan, Norway, and Germany, and by the late 1970s to France, Korea, Finland, and several other countries had shipyards making semisubmersibles. Construction continued until the mid-to late-1980s, then largely stopped coincident with oil price declines and reduced demand.

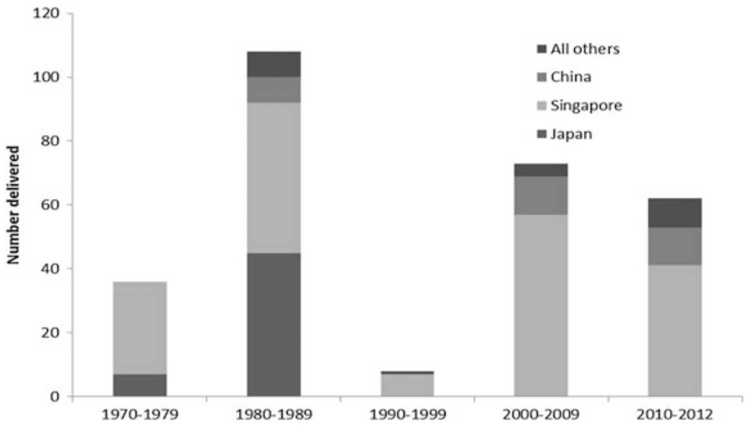

Fig. 9.2 Jackup rig construction in Asian countries, 1970–2012 (Data from Colton [5] and RigLogix [13])

Semi construction resumed in the late 1990s due to the maturation of deepwater technology and interest in exploration in the deepwater Gulf of Mexico, West Africa, Brazil and other regions. Construction occurred throughout Singapore, Korea, Japan, the U.S. and several Western European nations. However, by 2005, construction outside of Asia was mostly eliminated, and almost all deliveries have been from Korean, Singaporean or Chinese yards and this trend is expected to continue.

9.1.3 Drillships

The first drillships were built in U.S. yards in the mid-1960s. Through the 1970s and early 1980s, semisubmersibles were favored over drillships due to their superior motion characteristics and the few drillships that were built were constructed primarily in Japan, the U.S. and Western Europe. A short boom in drillship construction occurred between 1998 and 2001, with 16 drillships delivered, nine from Korean shipyards, five from European yards, and one each from Singaporean and U.S. yards. No new drillships were delivered from 2002 to 2007, and when the investment cycle began again in 2008, South Korean yards were dominant.

9.2 Demand Factors

The demand for drilling is impacted by the capital budgets of E&P firms and oil and gas prices. Utilization and dayrates send signals to the market of the need for additional supply, while technology and the number of countries open to exploration create new markets and demand. Trends in fleet age and construction cost also impact the demand for rigs.

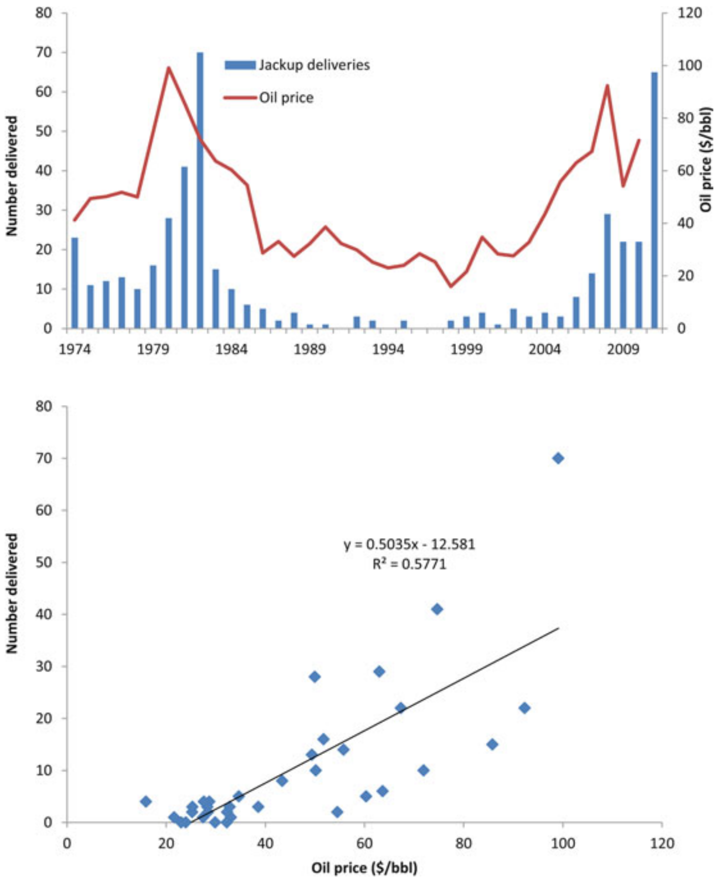

Fig. 9.3 Jackup deliveries and 2-year lagged oil price, 1974–2012 (Data from Colton [5])

9.2.1 Oil Prices

The number of jackups delivered worldwide from 1974 to 2012 is correlated with the 2-year lagged annual Brent oil[1] price (Fig. 9.3). The lag is roughly equal to the time to build a jackup and suggests that drilling contractors respond rapidly to changing oil prices by ordering rigs. Deliveries in floating rig construction follow a trend similar to the jackup market, but the statistical relationship is not significant.

[1] Natural gas prices also impact the demand for rig construction, but because gas prices are determined on a regional basis and outside the U.S. are often directly tied to the price of oil, Brent crude is considered the single best global indicator of world demand and waterborne production.

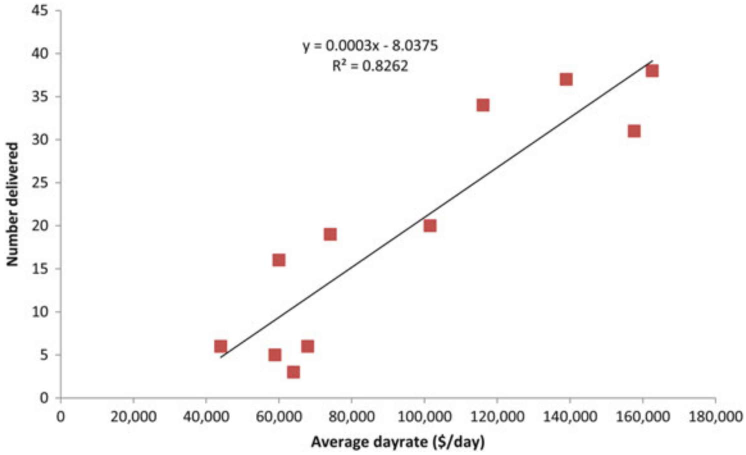

Fig. 9.4 Jackup deliveries and 2-year lagged average dayrate, 2000–2012 (Data from Colton [5], RigLogix [13])

9.2.2 Utilization and Dayrates

Utilization and dayrates send signals to the market on the need for additional supply. When utilization rates are high, spare capacity is limited which puts upward pressure on dayrates and signals to drilling contractors that additional capacity may be absorbed by the market. Average dayrates explain a significant portion of the variation in jackup deliveries between 2000–2012, and suggest an important link to investment decisions (Fig. 9.4). High dayrates and utilization encourage new contractors to enter the market and build which adds to construction demand during market upswings.

9.2.3 Technology and New Discoveries

Improved technology and the need to develop more technically challenging resources can also stimulate newbuild demand. From 1998–2002, oil price were at record lows, but deepwater drilling technology had matured and there was a brief period of high activity in floater construction [4]. Likewise, interest in high pressure high temperature shallow water drilling led Rowan to order several high-specification jackups in the early 2000s. In some cases, E&P firms order rigs to fulfill a specific exploratory or developmental role. For example, in 2009, Petrobras announced plans to build up to 28 drillships for the Brazilian market as part of a major investment in its pre-salt fields. As more countries open their offshore waters to exploration, the geographic distribution of rigs will change and increased demand may result.

9.2.4 Fleet Age

Rigs operate in a corrosive environment and over time steel in the hull and legs corrodes and must be replaced. Eventually, maintenance and refurbishment costs exceed the returns generated by operation, and the rig is sold for scrap, placed in long-term storage or converted to another use. Rigs are designed for a 25–30 year operational life, but many rigs remain operational beyond their design life because of upgrades and expansions. Fleet age provides a signal to investors that new rigs may be required in the future [16].

9.2.5 Construction Cost

During periods of low demand for drilling services, construction costs are typically low which may stimulate demand for newbuilds. By building during market downturns, drilling contractors increase the risk that the newbuilt rig will not be immediately utilized, but pay lower capital costs and lower the overall financial risk associated with newbuilding. Historically, construction cost has not been a major driver of demand and few firms take advantage of low prices to order rigs.

9.3 Players

In 2012, Singapore dominated jackup construction, Korea was building most of the world's drillships, and semisubmersible newbuilds were split between China, Mexico and Singapore (Table 9.1). From 2005 to 2012, Keppel and Sembcorp were dominant in jackup and semi construction, while Samsung and Daewoo was dominant in drillship construction (Table 9.2). Competitive advantages change over time and geographic redistribution will arise, but for the near-term future these players are expected to maintain a dominant position in the industry.

9.3.1 Singapore

Market Capitalization. Singapore is the largest producer of jackup rigs and is also active in semisubmersible construction. Keppel and Sembcorp are the major players, and together have the capacity to deliver approximately 25 jackups annually. From 2008 to 2011, Keppel and Sembcorp averaged 14 jackups and six semi deliveries per year. In 2011, the combined revenues of Keppel and Sembcorp accounted for approximately 2 % of Singapore's GDP [17].

Labor Cost Advantage. A primary advantage of Singaporean shipyards is their low labor costs relative to their competition. Over 75 % of the 20,000 people employed by Keppel and Sembcorp in 2011 were foreign workers which were paid approximately one-third as much as Korean shipyards [17]. Sembcorp and Keppel outsource

Table 9.1 Worldwide distribution of rig construction circa 2012

Country	Jackups	Semis	Drillships
Singapore	40	4	
Korea			37
China	18	6	3
Brazil	2	1	7
UAE	8		
Mexico	1	4	
India	5		
Vietnam	2		
Italy		1	
Russia	1		
Total	77	16	47

Source: Data from Jefferies and Company, Inc. [8]

Table 9.2 Rig deliveries by shipyard, 2005–2012

Shipyard	Nation	Jackups	Semis	Drillships
Keppel	Singapore	38	10	2
Sembcorp	Singapore	33	10	
Samsung	Korea		4	24
Daewoo	Korea		6	12
COSCO/Dalian	China	12	4	
AmFELS	U.S.	12		
Lamprell	UAE	12		
CIMC Raffles	China	3	6	
LeTourneau	U.S.	8		
ABG	India	4		
CNOOC	China	4		
IMAC	UAE		4	
Aker	Norway		2	
Severodvinsk	Russia	1	1	
Others		13	3	4

Source: Data from Jefferies and Company, Inc. [8]

work to company-owned yards in Indonesia, China and elsewhere to assemble hulls and other modular components to minimize production cost and achieve scale economies.

Keppel. From 2005 to 2012, Keppel delivered 38 jackups, 10 semis and two drillships from its Singaporean yards. Keppel owns rig building and repair shipyards in 11 countries, but most of their newbuilding is performed at one of four facilities at Keppel FELS shipyard in Singapore. The Pioneer yard is designed to accommodate three jackups and one semisubmersible in drydocks as well as several jackups, semis and drillships in quays (Fig. 9.5). Keppel also owns yards in the U.S., Brazil, Norway, Azerbaijan, Kazakhstan, UAE, Qatar, China, the Philippines and Indonesia. With the exception of Keppel AmFELS in the U.S., Keppel's international yards are primarily focused on repair and/or non-rig construction.

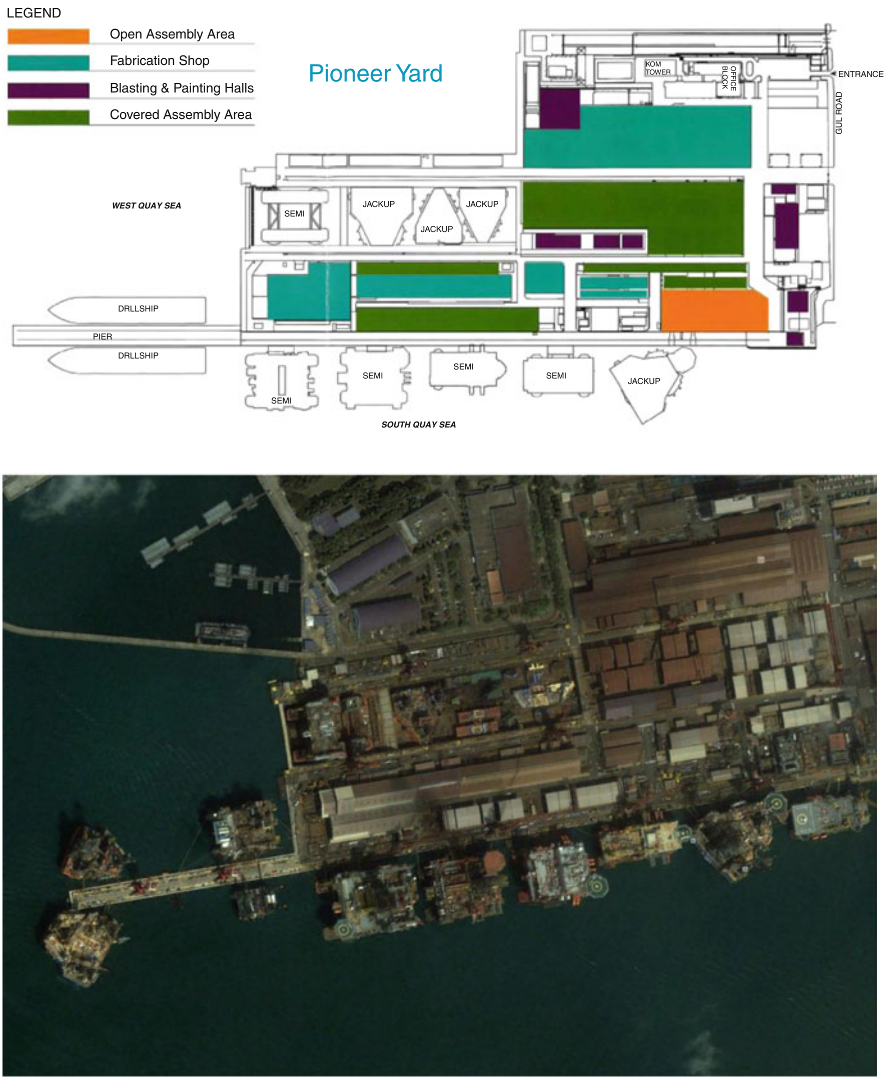

Fig. 9.5 Keppel's Pioneer shipyard layout and satellite view circa 2011. In the satellite view, three jackups, five semis, and one liftboat are in quays (Source: Keppel, Google)

Keppel's shipyards build a variety of rig designs, most of which are proprietary. Unlike other design firms, Keppel does not typically license its designs to other shipyards and their most important rig is the KFELS B Class. The use of proprietary designs increases efficiency through learning as shipyards can improve manufacturing processes and optimize purchasing and logistics. These factors, along with the elimination of the license fee, are estimated to reduce costs by 10–15 % [15].

Fig. 9.6 Sembcorp's Jurong and PPL shipyards circa 2012 (Source: Sembcorp)

Sembcorp. Sembcorp is the second largest firm in the jackup construction industry and between 2005 and 2012 delivered 33 jackups and 10 semisubmersibles. Sembcorp owns the PPL and Jurong rig building shipyards (Fig. 9.6). PPL owns the Pacific Class 375/400 design, and these rigs have made up most of the deliveries from the PPL yard. The Jurong yard has specialized in the F&G JU 2000/3000 class rigs but is also active in semi construction. In addition to its activities in rig construction, Sembcorp owns repair facilities in Sabine, Texas and Brazil, and operates additional yards in Singapore specializing in medium and large cargo vessels.

9.3.2 China

Rig construction in China has grown rapidly in recent years. In 2006, the first Chinese built jackup rig was delivered, and by 2011, China was the third largest builder with significant market share in both the jackup and semi segments. In 2011, six shipyards were building jackups in China with Dalian and Yantai Raffles being the largest players [8]. CIMC Raffles and COSCO are the largest Chinese players in the semi market. All of the major players in the Chinese market are state-owned but build rigs for both state-owned and international contractors.

9.3.3 South Korea

South Korean shipyards do not build jackups but are the dominant firms in drillship construction. South Korean players include Hyundai, Samsung and Daewoo. These three firms delivered 86 % of drillships and 20 % of semisubmersibles from 2005 to 2012. In January 2012, South Korea held over three-quarters of drillship orders. Samsung and Daewoo primarily build their own proprietary designs while Hyundai builds mostly Gusto MSC designed drillships.

9.3.4 United States

Jackup Deliveries. In the Southeastern U.S., shipbuilding in support of the offshore oil and gas industry is culturally and economically important [1], but on a worldwide basis is a small niche player. From 2000 to 2012, the LeTourneau yard in Vicksburg, Mississippi delivered 11 rigs, and the Keppel AmFELS yard in Brownsville, Texas delivered 14 rigs (Table 9.3). On average, approximately two jackups have been constructed each year over the past decade in Gulf Coast yards.

Vicksburg, Mississippi. The LeTourneau yard in Vicksburg, Mississippi was the first shipyard to build a jackup rig in the U.S. and between 1958–2010 delivered 87 rigs [12]. The yard is located on 90 acres adjacent to the Mississippi River about 400 miles from the Gulf of Mexico and exclusively builds LeTourneau designed rigs (Fig. 9.7).

Due to the height of the bridges along the Mississippi River, only the lower sections of legs are attached to the rig in Vicksburg with the upper sections fabricated in Vicksburg and attached at the company's shipyard in Sabine Pass, Texas. The Vicksburg shipyard does not have the ability to modify or repair rigs due to the bridges, nor does it have the infrastructure typically associated with large shipyards (drydocks or launching systems) and must instead "walk" the rig into the water. Despite its historical success, the Vicksburg shipyard has attracted smaller numbers of new orders and has apparently become uncompetitive.

From 2000 to 2011, LeTourneau was a wholly-owned subsidiary of the drilling contractor Rowan which was the shipyard's major customer. In 2011, LeTourneau was sold to Joy Global which subsequently resold LeTourneau's drilling equipment operations to Cameron for $375 million. After the delivery of the *Joe Douglas* in 2011, the shipyard has no newbuild work contracted, but it is likely that some work will continue in Vicksburg, primarily the construction of legs and elevating systems for LeTourneau designed rigs built elsewhere.

Table 9.3 Jackup construction in U.S. shipyards, 2000–2012

Name	Shipyard	Delivery	Design	Water depth (ft)
Rowan Gorilla VI	Vicksburg, MS	2000	LeT Super Gorilla 219-C	400
Rowan Gorilla VII	Vicksburg, MS	2001	LeT Super Gorilla 219-C	400
Seawork 1	New Iberia, LA	2002	Liftboat	140
ENSCO 105	Brownsville, TX	2002	KFELS B Class	375
Bob Palmer	Vicksburg, MS	2003	LeT Super Gorilla XL 224-C	550
Tonala	Brownsville, TX	2004	KFELS B Class	375
Scooter Yeargain	Vicksburg, MS	2004	LeT Tarzan Class 225-C	300
Bob Keller	Vicksburg, MS	2005	LeT Tarzan Class 225-C	300
Hank Boswell	Vicksburg, MS	2006	LeT Tarzan Class 225-C	300
Courageous	Brownsville, TX	2007	LeT Super 116	350
Panuco	Vicksburg, MS	2007	LeT Super 116E	350
Offshore Defender	Brownsville, TX	2007	LeT Super 116	350
Offshore Resolute	Brownsville, TX	2008	LeT Super 116	350
Ocean Scepter	Brownsville, TX	2008	KFELS B Class	350
Offshore Vigilant	Brownsville, TX	2008	LeT Super 116	350
Rowan Mississippi	Vicksburg, MS	2008	LeT Workhorse 240C	375
JP Bussell	Vicksburg, MS	2008	LeT Tarzan Class 225-C	300
Atwood Aurora	Brownsville, TX	2008	LeT Super 116E	350
Offshore Intrepid	Brownsville, TX	2009	LeT Super 116	350
Ralph Coffman	Vicksburg, MS	2009	LeT Workhorse 240C	400
Tuxpan	Brownsville, TX	2010	LeT Super 116E	375
Rowan EXL I	Brownsville, TX	2010	LeT Super 116E	350
Rowan EXL II	Brownsville, TX	2010	LeT Super 116E	350
Rowan EXL III	Brownsville, TX	2010	LeT Super 116E	350
Joe Douglas	Vicksburg, MS	2011	LeT Workhorse 240C	350
Rowan EXL IV	Brownsville, TX	2012	LeT Super 116E	350

Source: Data from RigLogix [13]
Note: LeT denotes LeTourneau. LeTourneau Super Gorilla designs are rated for harsh environments

Brownsville, Texas. The Brownsville shipyard is located on approximately 170 acres along the Brownsville Ship Channel east of Brownsville, Texas with easy access to the Gulf of Mexico (Fig. 9.8). The yard built its first rig in 1973 as the Marathon LeTourneau shipyard, and in 1991, it was bought by Keppel and renamed Keppel AmFELS.

Since reopening, AmFELS has primarily built jackup rigs, but has also built and upgraded a variety of other vessels, including a tension leg platform, accommodation platforms, semisubmersibles, drilling barges, and derrick barges. Since 2007, AmFELS has primarily built LeTourneau-designed Super 116E rigs for Rowan, Perforadora Central and Scorpion Offshore[2] (now part of Seadrill). AmFELS stands to benefit from any reduction in activity at the Vicksburg yard.

[2] Perforadora Central and Scorpion are both focused on the <350 ft water depth, moderate environment markets, and the LeTourneau Super 116 and 116E are typically the lowest cost designs for this market.

Fig. 9.7 The LeTourneau Vicksburg, Mississippi shipyard circa 2011 (Source: Pictometery)

Fig. 9.8 The AmFELS Brownsville, Texas shipyard circa 2011 (Source: Keppel)

9.4 Buyers

Drilling contractors purchase newbuild rigs to upgrade and expand their fleet to capture demand and compete using the latest technologies (Table 9.4). All rigs delivered from 2005–2012 and under construction in 1Q2012 are included in the

Table 9.4 Number of newbuild rigs in the fleets of drilling contractors circa 2012

Firm	Jackups	Semis	Drillships	Total
Seadrill	20	10	6	36
Transocean	4	5	11	20
COSL	15	5		20
Ensco	7	7	5	19
Noble	8		8	16
Rowan	13		3	16
Maersk	8	3	4	15
Diamond	1	4	4	9
Aban	9			9
Vantage	4		5	9
Atwood	4	2	2	8
National Drilling	5			5
Songa		4		4
Stena			4	4

Source: Data from RigLogix [13]
Note: Newbuild rigs delivered from 2005–2012 and under construction in 1Q2012

count, and the data are based on the number of newbuilt rigs in the fleet. Seadrill has been the major consumer of newbuilt rigs and has nearly twice as many newbuilt rigs as Transocean. COSL has also been a major consumer of newbuilt rigs, particularly relative to its smaller fleet size. Scorpion and Rowan have been the major buyers of U.S. built rigs and have purchased six and 14 rigs, respectively, since 2000.

9.5 Construction Contracts

9.5.1 Bidding Process

Contracts for rig construction are fixed-price turnkey contracts. Contracts are awarded in a competitive bidding process in which the buyer solicits bids from shipyards for the construction of a rig meeting certain specified criteria. The shipyard estimates the construction cost of the rig based on steel, labor and equipment prices, profit margins, and the rig design.

9.5.2 Contract Clauses

Contracts for rig construction contain a large number of clauses specifying all aspects of construction. Contracts are negotiated individually and clauses vary, but in general, contracts include three major categories of clauses: clauses that specify the product; clauses that specify the price; and clauses that detail responses to unforeseen events [3, 14].

9.5.3 Product Specification

The contract specifies a particular design to be built and detailed construction specifications are attached to the contract and binding to the parties. Construction practices are defined by classification society rules and the relevant classification society is identified. In many cases, the American Bureau of Shipping's Rules for Building and Classing Mobile Offshore Drilling Units are used and classification society decisions are considered binding on both parties.

Some product specifications are not known when the contract is written. Rig designs are finalized through a collaborative process between the builder and the buyer in which the builder submits finalized plans to the buyer and the buyer provides feedback. In other cases, the buyer may desire to make a significant change in product specifications, for example, increasing the water depth capability from 350 to 375 ft. In this case, an option for the increased capability is written into the contract and a date by which the option is to be invoked and option price is specified.

The builder is responsible for and warrants all work performed on the rig including subcontracted work, the rig design and builder furnished equipment. The duration of warranties may vary, but are typically on the order of 12 months. A provisional construction schedule is attached and a method by which the builder provides progress updates to the buyer is specified. The buyer is allowed to place a full-time technical representative at the yard to ensure compliance with contract specifications, and the representative's access to the construction site is described.

A delivery time and place is specified, typically at the builder's shipyard. Acceptance of the vessel is based on satisfactory performance in jacking, equipment certification, and other tests and classification society acceptance. Classification society acceptance depends on a detailed inspection of the rig by classification society personnel.

9.5.4 Payment Schedule

Payments are made in installments at the execution of the contract, delivery, and at one or more project milestones. The methods by which the builder demonstrates completion of a given project milestone are defined. A schedule of penalties and options are specified if either the buyer fails to make a payment on time or the builder fails to meet milestones. Late payments are often charged interest at the LIBOR rate plus a penalty. An impermissible delay in delivery is often charged at a set daily rate (e.g. $50,000 per day).

Rig construction contracts are long term agreements that specify delivery several years into the future. It is difficult for shipyards to accurately predict future price changes in supplies, and suppliers may be unwilling to provide firm quotes for products several years in advance [6]. This creates risk for shipyards which are managed with material cost escalation clauses linked to standard measures of inflation. Cost escalation clauses are common in option contracts.

9.5.5 Unforeseen Events

Force Majeure clauses are used to differentiate between permissible and impermissible delays. Permissible delays are explicitly specified and typically include war, riots, strikes, sabotage, epidemics, fire, hurricanes, floods and other acts of God. In the event of a Force Majeure event, the delivery date is extended without penalty to the builder. The builder is required to make all reasonable efforts to minimize the effects of Force Majeure events. If Force Majeure events cause extended delays (typically over 90–180 days), the buyer may be permitted to terminate the contract.

9.5.6 Performance Bonds and Mediation

Contracts stipulate that the builder must carry a performance bond and insurance equal to the contract price and the circumstances under which bonds may be invoked are defined. A method for the mediation of contract disputes is also described.

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Chapter 10
Jackup Design Primer

Abstract Jackup hulls provide the buoyancy to be towed to site, and once on location, the legs support the deck weight, which transfers the equipment and drilling rig loads into the seafloor. As drilling progressed into deeper and more challenging environments, rigs evolved based upon the experience of the builder and the demands of the market. In this chapter, we discuss the designs used in jackup construction and the tradeoffs between technical and economic factors. We summarize the design process and discuss the major design factors, highlighting the decisions made at the conceptual and preliminary stages. A discussion of the most popular jackup designs concludes the chapter.

10.1 Notable Features

The purpose of a jackup rig is to provide a stable platform to perform drilling operations. Today, there are about a dozen popular jackup designs which are, for the most part, structurally similar. Functionally, the designs differ in their water depth capability and storm environment, variable deck load, dimensions, and installed power. The BMC Pacific 375, KFELS N Class, LeTourneau 240C and LeTourneau Super 116E are four common design classes (Fig. 10.1). The KFELS N Class is a harsh environment rig while the other three rigs are designed for moderate environments.

10.1.1 Triangular Hulls, Independent Trussed Legs

Jackup hulls are triangular and the legs are located at the corners of the hull for maximum stability. Virtually all newbuilds use independent trussed legs that can be jacked up independently of each other and are attached to a spudcan footing which penetrates the seafloor and transfer vertical loads from the legs to the ground.

M.J. Kaiser and B.F. Snyder, *The Offshore Drilling Industry and Rig Construction in the Gulf of Mexico*, Lecture Notes in Energy 8, DOI 10.1007/978-1-4471-5152-4_10,

Fig. 10.1 Rig designs; clockwise from top left: BMC Pacific 375; KFELS N Class; LeTourneau 240C; LeTourneau Super 116E. (Source: Seadrill; Rowan)

10.1.2 Hull Dimensions

Hulls are approximately 20–30 ft deep and are comprised of several levels, including an inner-bottom, a machinery level and a mezzanine deck (Fig. 10.2). On the machinery deck, four or more large diesel engines are installed as well as pumps and other equipment. The main deck contains topside facilities including all the equipment for drilling, utilities, safety systems, accommodation and life support.

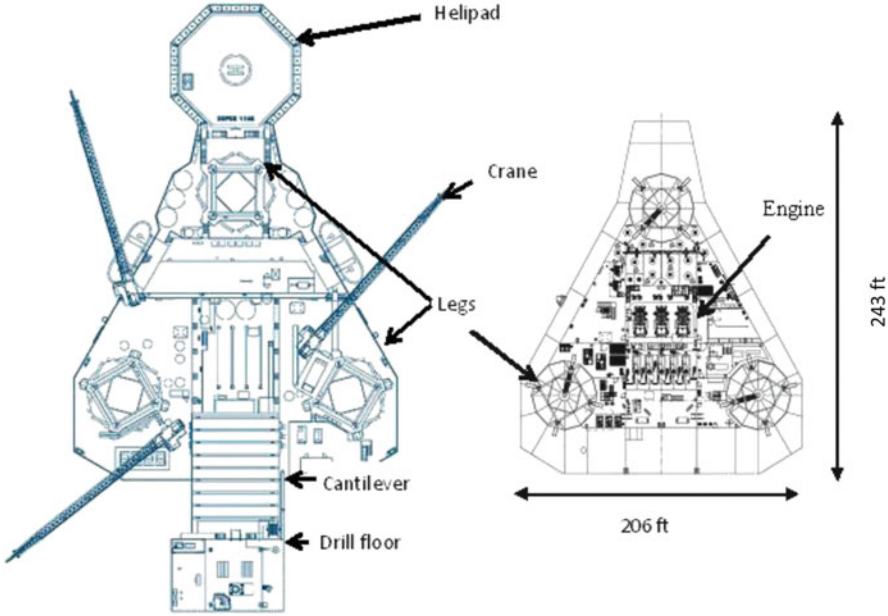

Fig. 10.2 Main deck (*left*) and machinery deck (*right*) layout of a LeTourneau Super 116E (Source: LeTourneau)

10.1.3 Cantilevered Derrick, Heliport, Cranes

The derrick is mounted on a cantilever system which can move in two dimensions both perpendicular and parallel to the hull. Cantilevers add weight and cost to the rig but allow jackups to work over platform structures, which increase the utility of the unit, and almost all jackup rigs delivered over the past decade were cantilever units. All offshore rigs have a heliport to transport offshore personnel and several cranes for heavy lifting. General practice is to separate hazardous and non-hazardous areas. The heliport is located opposite the derrick and extends outside the hull for safety reasons and to provide maximum clearance with drilling operations. Crew quarters is usually located below the heliport.

10.1.4 Harsh Versus Standard Design

Harsh environment rigs are larger and heavier than moderate environment rigs. Harsh environment rigs require longer legs to provide a greater air gap between the hull and sea level and larger hulls to increase the spacing between legs and improve stability. The legs and spudcans of harsh environment rigs are built to a more robust standard than moderate environment rigs and use higher quality and thicker steel.

Harsh environment units also frequently have greater variable loads than moderate units which requires a larger, heavier structure. Variable load on the deck is related to the mission function. The KFELS N Class harsh environment design has a hull 264 ft long by 289 ft wide; all the other rigs are approximately 200–240 ft long and 220–240 ft wide.

10.2 Specification Sheet

MODUs are equipped with marine and mission systems. Marine equipment is found on all marine vessels and is used to operate the vessel at sea (engines, pumps, electrical systems), while mission equipment is used to drill wells and systems specialized for the offshore environment. Critical systems include those used to position and elevate the rig above a well or platform; to provide mechanical force on the bit; to control the pressure inside the wellbore; to detect and control blowouts; to handle and assemble tubulars; and to handle and store liquid and bulk materials. The capabilities of these systems determine the hook load, maximum drilling depth, and other specifications (Fig. 10.3).

10.3 Design Process

Rig designers balance a number of technical and economic factors as they move through design stages (Fig. 10.4). The process is iterative and includes conceptual, preliminary and contract (detailed) phases [4]. Concept design includes the fundamental mission of the rig in terms of water depth, drilling capabilities, environmental capabilities and basic structure. Preliminary designs consist of the leg structure, spudcan, hull, deck diagrams, and basic information on electrical systems, piping systems and other systems. Detailed design work is done after a contract is written and plans are customized to the clients' needs.

10.4 Jackup Design Firms

The principal firms designing jackup rigs are Friede and Goldman, LeTourneau, Gusto MSC, Baker Marine, and Keppel. The KFELS B Class is the most common newbuilt rig, but the LeTourneau Super 116E and several Friede and Goldman designs are also popular (Table 10.1). None of the designs built today are common in the legacy (pre-2000) fleet, but several designs are based on rigs that were built in the 1980s, for example, the LeTourneau Super 116 is based on the LeTourneau 116.

Seadrill

West Ariel

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GENERAL	
Delivery	Q2, 2008
Hull ID	B-291
Major Upgrades	-
Design	KFELS 'B' Class
Previous Names	Seadrill 8
Flag	Bahamas
Classification Agency	ABS
Dimensions	234' x 208' x 25'
Transit draft	16'
Target VDL - Operating	7,500 kips
Target VDL – Survival	5,000 kips
Outfitted Max WD	400'
Min WD	55'
Leg Length	517' (incl spudcan tip)
- usable below hull	460' (incl spudcan tip)
Leg Spacing	142' transverse 129' longitudinal
Spudcan Diameter	47'
Max Drilling Depth	30,000'
Cantilever Envelope	70' aft 30' transverse
Max Combined Load	2,500 kips at 60' aft CL
Quarters	- 104 (Aust/NZ) - 112 (elsewhere)
Helideck Size	73' diameter
Helideck Capacity	S61N & S92
Helideck Compliance	CAP437
DRILLING PACKAGE	
Derrick (SWL)	1,500 kips
Racking Capacity	30,000' x 5-1/2" dp
Drawworks	Varco ADS-10T 3000 HP AC
Rotary Table	Varco RST-49,5
Top Drive	Varco TDS-8SA, 750T
- continuous torque	62,500 ft lbs @ 95 rpm
Pipehandling	Dolly retract system Varco AR-3200C Varco PS-21 powerslips Varco rotating mousehole
MUD SYSTEM	
Pressure Rating	7.5k psi
Pumps	3 x Lewco W-2215
Solids Control	1 x Dual gumbo box 5 x Brandt LCM-3D 1 x Brandt LCM-3D mud conditioner

CAPACITIES	
Diesel	2,630 bbls
Drillwater	3,825 bbls (dedicated tanks) 16,094 bbls (pre load tanks)
Potable Water	2,053 bbls
Bulk Product	11,100 ft³
Sack Storage	5,000 sx
Base Oil	662 bbls
Brine	855 bbls (dedicated tank) - 1,084 bbls (mud pits 5 & 6)
Liquid Mud	3,613 bbls
Mudpits (excl slug/mix)	6
WELL CONTROL	
Diverter	49.5" KFDJ 2,000 psi
High pressure BOP	1 x CIW 18-3/4" 10k psi annular preventer 2 x CIW 18-3/4" 15k psi double ram preventers
Choke & Kill Manifold	15k psi TechDrill
CRANES	
Pedestal Cranes	3 x Favco 7.5k / 10k
API SWL	50ST @ 40' / 11ST @ 120'
BOP Crane	2 x 75ST
POWER	
Main Engines	5 x CAT3516B-HD x 2,150 HP
Total Power	10,750 HP
Main Generators	5 x Kato 6P7-2650 x 2,306 HP
Emergency Power	1 x Cat 3508B x 915 HP
OTHER	
Mooring System	4 x 27.5ST mooring winches
Conductor Tensioner	500 kips vertical
TUBULARS	
Drillpipe	15,000' x 5-1/2"
FEATURES	Helo refuelling system Dual mud system Autodriller SBM modified

Fig. 10.3 Specification sheet for Seadrill's KFELS B Class jackup (Source: Seadrill)

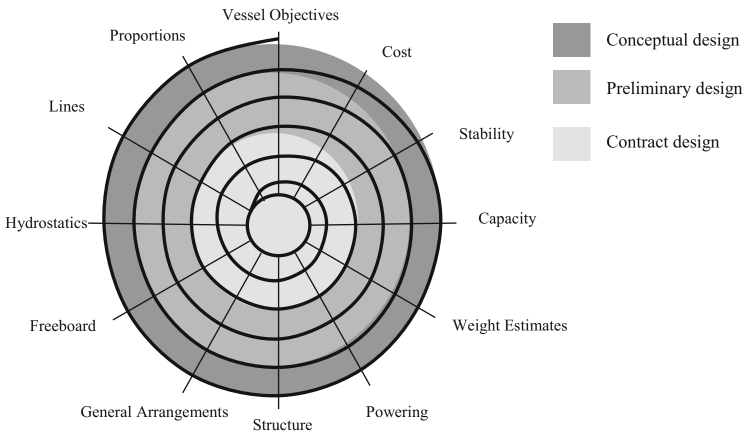

Fig. 10.4 Jackup rig design applies a process similar to the ship design spiral (Source: Eyers [4])

Table 10.1 Number of rigs delivered and under construction worldwide circa 1Q2012

Rig class	Number under build (1Q2012)	Number delivered (2000–2011)	Harsh design
CPLEC CP 300	2		
F&G 2000E/2000A	15	11	Y
F&G 3000N	6		Y
F&G L780		5	
F&G Super M2	5	11	
Gusto MSC CJ70	3	3	Y
Gusto MSC CJ46	2	8	
Gusto MSC CJ50		4	
KFELS B/Super B Class	19	30	
KFELS Super A Class	6	2	Y
KFELS N Class		3	Y
LeTourneau Super 116E	12	20	
LeTourneau 240C	2	3	
LeTourneau Super Gorilla		3	
LeTourneau Tarzan		4	
PPL Pacific 375/400	3	28	
Unknown/other	2	5	
Total	77	140	

Source: Data from RigLogix [14]

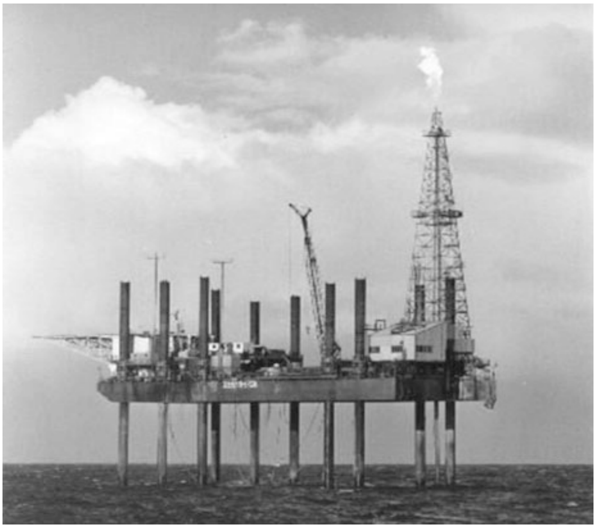

Fig. 10.5 Early jackup rig *Sea Gem* in 1964 (Source: O. Buggee)

10.5 Design Factors

10.5.1 Number of Legs

Early designs experimented with the number, placement, type and canter of legs until experience dictated the optimal configuration [6]. Some early jackups used ten or more legs to compensate for uncertain sea states and design considerations (Fig. 10.5). All modern jackup rigs in the oil and gas industry utilize three legs placed in a triangular arrangement at the corners of the hull.[1] Three leg units can carry more deck load while afloat than four leg units since they do not need to carry an extra leg and its associated jacking systems [5]. Three leg units also expose less area to wind, wave, and current loads and are less sensitive to environmental conditions and are less expensive due to the reductions in steel weight [12]. The primary advantages of four legged units are redundancy, greater stability, and a reduction in the elevating time due to a simplified preloading procedure.

[1] Other elevating vessels, including those used in offshore construction, offshore wind, and smaller workover rigs, may have four or more legs.

Table 10.2 Characteristics of selected Gusto MSC jackups

	CJ46	CJ50	CJ70
Hull dimensions (ft × ft)	203 × 213	223 × 230	292 × 319
Leg length (ft)	483	480	672
Water depth (ft)	350	350	492
Elevated weight (tons)	13,640	18,700	33,000

Source: Gusto MSC

10.5.2 Leg Length

Early jackups such as Zapata's Scorpion delivered in 1956 were limited to water depths under 100 ft, but by the 1970s, rigs capable of operating in 300 ft of water were common. In the late 1990s contractors began demanding newbuilds with 350 to 400 ft water depth capability to more efficiently drill on the margins of the continental shelf. As water depth capability increases, leg length must also increase, but many other rig parameters, including hull breadth, hull depth, and deck area are also affected. Water depth has a strong correlation with costs because of its broad influence on size-related parameters.

10.5.3 Environmental Conditions

Rigs are designed for harsh or moderate environments. Harsh environment rigs operate in high latitude areas such as the North Sea or Eastern Canada while moderate environment rigs operate in low latitude areas such as the Gulf of Mexico, Southeast Asia, and the Persian Gulf. Environmental conditions influence leg length, leg structure and hull size. Harsh environment rigs require longer legs to provide a greater air gap between the hull and sea level [3] and require larger hulls to increase the spacing between legs and improve stability. Jackups are particularly well suited to harsh environment operations, and contractors have built harsh environment jackups with 500 ft water depth capabilities to extend their use into waters typically limited to floating rigs. Ultra-high specification jackups are much heavier than moderate environment units. The Gusto MSC CJ70, for example, weighs 33,000 tons, approximately twice the weight of a typical moderate environment unit (Table 10.2; Fig. 10.6).

10.5.4 Leg Type

Early jackup rigs frequently used cylindrical legs, but as the water depth capabilities increased, the problem of bending stresses became more central and designers started using open-fabricated or truss-type legs and replaced the jacking

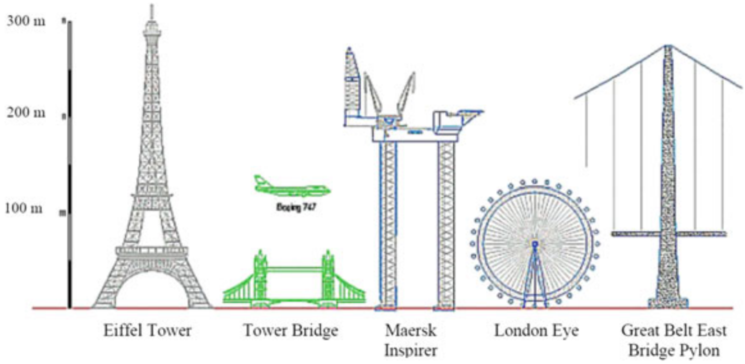

Fig. 10.6 Size comparison of the *Maersk Inspirer*, a Gusto MSC CJ70 rig (Source: Kellezi et al. [9])

devices with hydraulic pin or rack and pinion devices (Fig. 10.7). All contemporary newbuilt rigs are trussed structures. Cylindrical legs are still used on liftboats and other offshore construction vessels and continue to exist in the legacy fleet for mat supported rigs [11]. Trussed legs require a large number of welds and are more expensive to fabricate and take up more deck space than cylindrical legs, however, trussed legs are usually lighter than cylindrical legs for the same bearing capacity which decreases steel costs and provides better stability while afloat. Trussed legs also expose less area to wind and water currents which reduces the likelihood of loss during storms [12, 15].

10.5.5 Chord Number and Type

There are several basic arrangements for leg chords. The choice of chord shape is influenced by the required strength of the leg, but also by the way in which the racks of the chord interact with pinions in the elevating system and wind and wave loading considerations [13]. Tubular chords are typical of F&G, Gusto MSC, Keppel Baker Marine and some LeTourneau designed rigs, and generally utilize two "half rounds" welded to a rack to make up a single chord (Fig. 10.8). Teardrop chords simplify construction but result in heavier legs containing more steel [10]. Teardrop chords have a rack and elevating pinions on one side of each chord while tubular chords have elevating pinions on either side of each chord. Trussed legs may have either three or four chords. Most designs utilize three chords, but several popular models including the LeTourneau Super 116E use four chords. Four chorded legs are typically heavier and more susceptible to wind and wave loads than three chorded legs.

Fig. 10.7 Cylindrical and trussed legs on the Bethlehem MS-225 *Spartan 202* and Gusto MSC CJ 70 *Maersk Inspirer* (Source: Spartan Offshore; Maersk)

10.5.6 Rack Chocks

After jacking, the vertical load of the rig may either continue to be supported by the pinions in the jacking system, or rack chocks may be inserted below the jacks to support the load (Fig. 10.9). Without chocks, the fixity between the hull and the legs

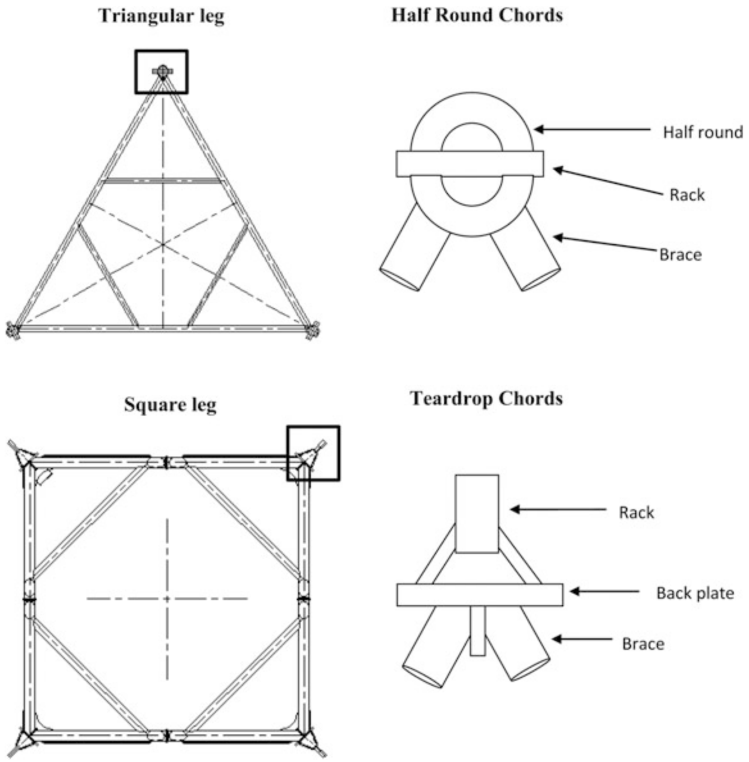

Fig. 10.8 Alternative leg and chord designs

Fig. 10.9 Rack chocks are inserted against the leg's racks to transfer the vertical load away from the pinions (Source: Remedial Offshore)

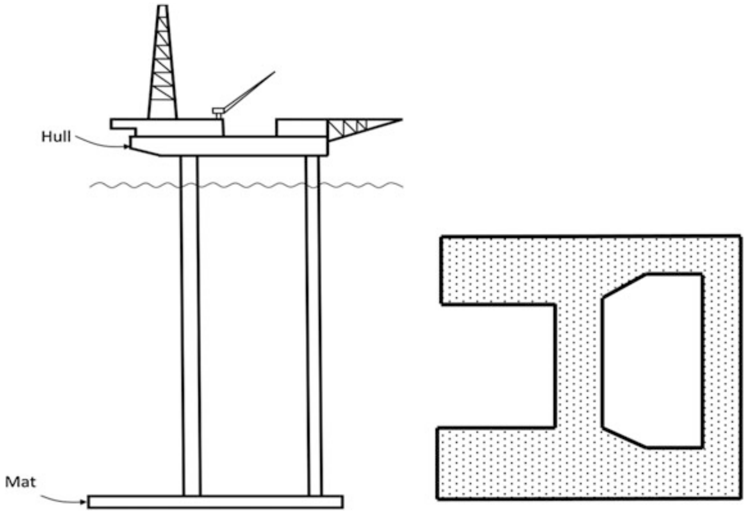

Fig. 10.10 Plan view of mat foundation (Source: Young et al. [16])

is less than 100 %, and movement between the hull and the legs will occur because the racks and pinions are not firmly connected. When chocks are inserted the fixity increases to 100 % which allows for a reduction in the bracing required in the legs and a decrease in weight [12]. Lighter legs are less expensive, reduce wind and wave loads, and increase variable loads by decreasing the lightship weight. However, smaller legs are more susceptible to breaking under uneven or increased loads, as in punch through [8]. Most F&G, Keppel, Baker Marine and Gusto MSC rigs utilize chocks.

10.5.7 Footing Structure

Rig legs are connected either to a large mat-like structure attached to all the legs that rest on the seafloor (Fig. 10.10) or to independent spudcans that penetrate the mudline during jackup operations (Fig. 10.11). One of the problems associated with early jackups was that of excessive leg penetration in soft soils, and a few early rigs tipped over while preparing to move off location because of soil failure. To counteract the difficulty, large diameter cans later known as spudcans were installed near the lower end of the cylindrical legs. Several mat-type jackups were built and continue to be used but spudcan footings came to dominate the fleet.

Mat foundations distribute weight over a larger area than spudcans and are superior to spudcans in soft sea beds but cannot be used on uneven or sloping terrain, nor can they be used near pipelines. Spudcan footings are capable of working in a wide variety of soil types and terrain and all modern newbuilds use spudcan foundations.

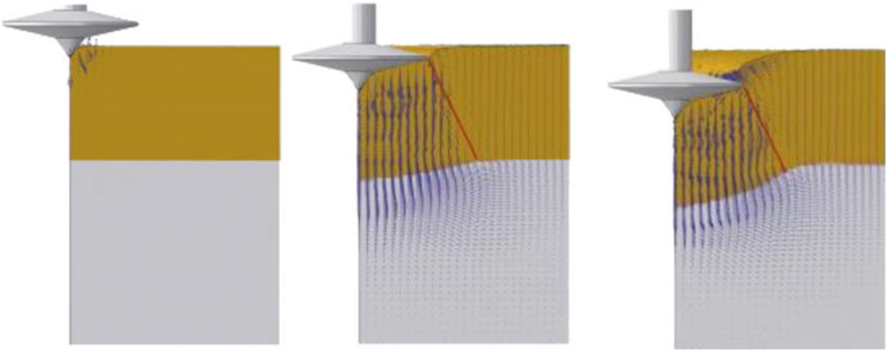

Fig. 10.11 Spudcan penetrating the seafloor during jackup operation

Fig. 10.12 Cantilever drilling rig operating over a fixed platform (Source: JDC)

10.5.8 Slot and Cantilevered Systems

Derricks are configured in a slot or cantilevered system. In a slot system, drilling occurs through a slot in the floor of the rig, whereas in a cantilevered system, the derrick extends off of one side of the rig (Fig. 10.12). Cantilevers are the most flexible derrick arrangement and allow jackups to work over caisson and platform structures and increase the number of closely spaced well patterns that may be drilled, especially in "Swiss-cheesed" seabeds.[2] Cantilever rigs are the most versatile and all newbuilds are cantilevered [1].

10.6 Jackup Design Classes

10.6.1 Worldwide Deliveries

From 2000–2011, 140 jackup rigs were delivered worldwide at an estimated value of $36 billion (Table 10.1). The KFELS B Class, F&G JU 2000 series, and LeTourneau Super 116E comprise the majority of recent orders and along with the PPL Pacific 375/400 and F&G Super M2, comprised over two-thirds of deliveries during the decade.

10.6.2 Common U.S. Built Designs

LeTounreau designed rigs are dominant at U.S. shipyards (Fig. 10.13). The Tarzan is the smallest class while the Super 116E and 240C are approximately the same size and the Super Gorilla is the largest class by a significant margin (Fig. 10.14; Table 10.3).

LeTourneau Tarzan. The Tarzan is specifically designed for shallow water (300 ft) HPHT deep drilling (35,000 ft) in moderate environments, but the design has not been internationally successful. Four Tarzan class rigs exist, all built between 2004 and 2008 at the Vicksburg, Mississippi shipyard and all owned by Rowan.

LeTourneau Super 116E. The LeTourneau Super 116E evolved from the LeTourneau 116C which was first built in 1978 and is considered one of the workhorses of the industry. The first Super 116E was delivered in 2007 and eight have been delivered through 2011. The Super 116E is designed for moderate locations and 350 ft water depths and is well suited to regions such as the Persian Gulf. In recent years, several Super 116Es have been assembled at the AmFELS shipyard in Texas, and worldwide, 12 Super 116E rigs were under construction in 2012. Prices are typically less than $200 million per rig and can be as low as $160 million for rigs designed for the Persian Gulf.

[2] A Swiss-cheesed seabed is an area in which jackup rigs have previously worked. In these areas, depressions in the seabed left by earlier rigs can constrain the areas where a rig may be positioned.

Fig. 10.13 Common U.S. built jackup designs; clockwise from top left: LeTourneau Super 116E, LeTourneau Tarzan, LeTourneau 240C, LeTourneau Super Gorilla XL (Source: Seadrill; Drilling Contractor; Offshore Magazine)

LeTourneau 240C Workhorse. Compared to the Super 116E, the LeTourneau 240C can work in deeper water with a greater variable load and a larger cantilever reach. The 240C is a relatively recent design and only three have been delivered and all of these were built at the LeTourneau shipyard for Rowan. In 2011, KS Energy ordered two 240Cs from a COSCO shipyard in China for $194 million each and these represent the first foreign sales of a 240C design license.

LeTourneau Super Gorilla XL. The LeTourneau Super Gorilla XL is among the largest jackups in the world and is capable of drilling 35,000 ft wells in 550 ft water depth in harsh environments (Fig. 10.15). The Super Gorilla XL is an upgraded

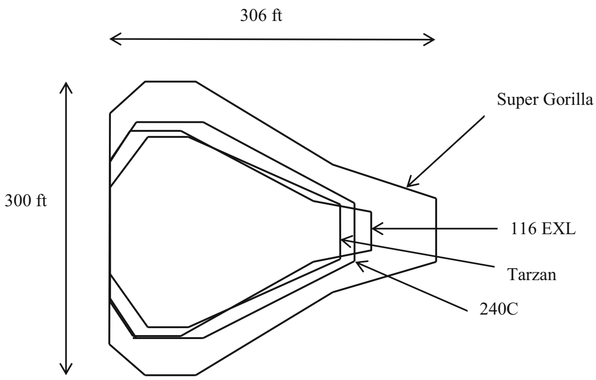

Fig. 10.14 Hull dimensions of common LeTourneau jackup designs (Source: Rowan)

Table 10.3 Characteristics of newbuilt jackup rigs

Design	Length (ft)	Width (ft)	Leg length (ft)	Variable load (tons)	Drilling depth (ft)
F&G 2000E	231	250	547	6,500	35,000
F&G Super M2	206	183	411	4,080	30,000
Gusto MSC CJ70	290	319	672	8,000	40,000
KFELS Super B Class	246	218	486	5,600	35,000
LeTourneau Tarzan	215	196	445	3,850	35,000
LeTourneau Super 116E	243	206	477	3,650	30,000
LeTourneau 240C	228	220	491	4,850	35,000
LeT Super Gorilla XL	306	300	713	5,950	35,000
PPL Pacific Class 375	236	224	506	3,750	30,000
PPL Pacific Class 400	236	224	532	3,750	30,000

Source: Rig specification sheets

version of the Super Gorilla and the *Bob Palmer* is the only rig of its class. The *Bob Palmer* cost $326 million to construct (in 2010 dollars) and has been let for nearly $300,000 a day on a long term contract with Saudi Aramco from 2011 to 2015.

10.6.3 Common Internationally Built Designs

The KFELS B Class, Gusto MSC CJ70, F&G JU 2000 series, and Pacific Class 375/400 are the most common international designs (Fig. 10.16). The KFELS Super B Class is the most popular rig design in the world, while the Gusto MSC CJ70 is one of the largest rigs ever built.

KFELS B Class/Super B Class. The KFELS Super B Class is the most popular rig design in recent years, and through 2012, 33 have been delivered and 18 are

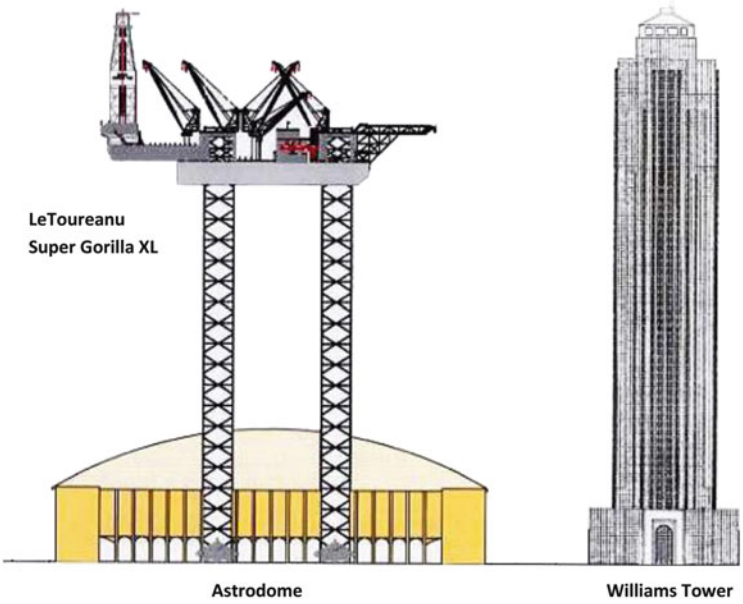

Fig. 10.15 LeTourneau Super Gorilla XL size comparison (Source: Offshore Shipping Online)

under construction. The B Class is only built at Keppel's yards and is a high specification unit approximately equivalent to the LeTourneau 240C in capabilities and cost. Newbuild prices in 2012 ranged from $180 to $210 million. The B Class is available with a number of design variations including large spudcans to increase the allowable operating conditions and 300–425 ft water depth capability.

Gusto MSC CJ70. The Gusto MSC CJ70 is the largest and most expensive jackup ever built capable of drilling 40,000 ft wells in 492 ft of water in harsh environments under 8,000 tons variable load. In 2011, Maersk ordered two CJ70's for $500 million each and a third is under construction for North Atlantic Drilling (a subsidiary of Seadrill) for $530 million. All three rigs have secured initial contracts of 3–5 years with dayrates exceeding $350,000.

F&G JU 2000 Series. The Friede and Goldman JU 2000A, JU 2000E and JU 3000N are the most popular series of harsh environment jackups. The 2000A is limited to 350 ft water depths while the 2000E and 3000N can drill in up to 400 ft of water. The 3000N is slightly more expensive (approximately $240 million in 2012) than moderate environment designs with similar drilling capabilities, but far less expensive than other harsh environment jackups like the Gusto MSC CJ70 or LeTourneau Super Gorilla XL.

Fig. 10.16 Commonly built international jackups; *clockwise* from *top left*: KFELS B Class, Gusto MSC CJ70, Pacific Class 375, F&G JU 2000E (Sources: Seadrill; Freide and Goldman)

PPL Pacific 375/400. The PPL Pacific Class 375 and 400 (also called the Baker Marine Pacific Class) are moderate environment proprietary designs owned by PPL shipyard where the class number specifies the water depth capability. The design is primarily built at shipyards owned by Sembcorp, but is also licensed to other shipyards. In 2012, three 400 ft units were under construction for Atwood for $190 million each.

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Chapter 11
Jackup Rig Construction

Abstract Shipyards use labor, materials and capital to turn steel and third party equipment into rigs. Major work activities include welding, material handling, pipe fitting, machinery installation, electrical systems, and outfit materials. Construction requirements include an experienced workforce, land adjacent to a waterway, several cranes, and a large enclosed space for performing high quality welds. Rigs may be built in drydocks or adjacent to a quay. In the U.S., drydocks are not used which necessitates some type of launching system to transfer the constructed rig to the waterway for transportation to market. In this chapter, a high-level narrative of jackup construction is provided with an emphasis on methods used in U.S. shipyards.

11.1 Workflow

The exact methods to assemble a jackup depend on the shipyard and rig specifications but there are many commonalities in requirements. Steel forms of different grades are received from one or more suppliers and are welded together to form the hull, legs, spudcans, liquid storage tanks, and quarters (Fig. 11.1). Components are built separately and modularly and combined at different locations in the yard.

11.2 Spudcans

Spudcans are hollow steel structures generally made of 50–100 ksi steel. Spudcans may be fabricated away from the hull and lifted into holes (yokes) built into the hull, or the hull may be built around existing spudcans (Fig. 11.2).

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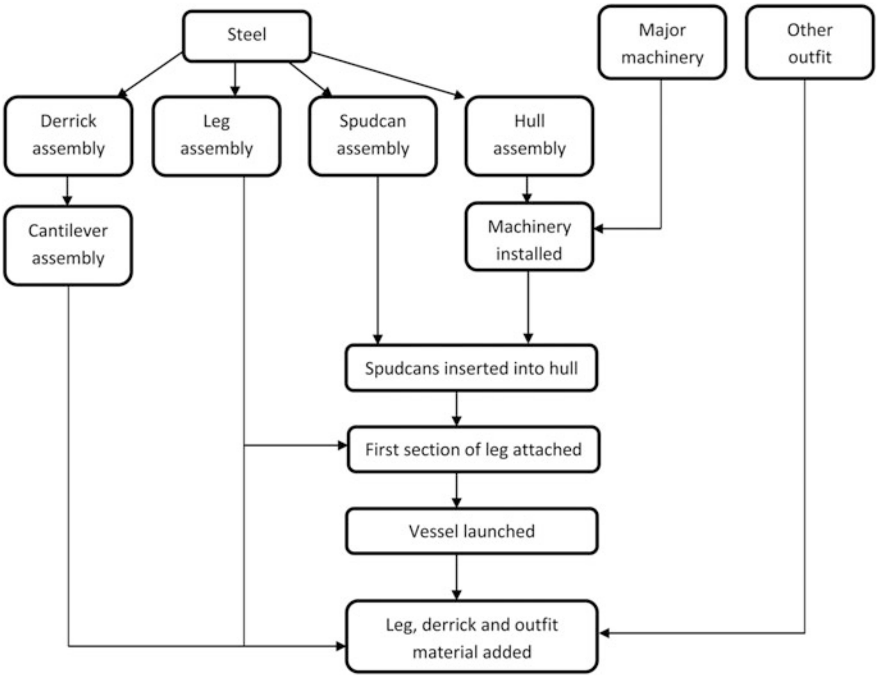

Fig. 11.1 Work processes in jackup assembly

11.3 Hull

The hull of the rig is composed of a flat bottom with sides constructed from stiffened plates which are supported by framing girders which span the bulkhead. The hull is generally made of 30–50 ksi steel, however, small sections of the hull, especially the area around the legs, are made from high strength steel. Horizontal steel plates (1) are stiffened with bulb flats placed 2–3 ft apart (Fig. 11.3). These sections (2) are supported by framing girders (3) that are spaced 6–9 ft apart and span between bulkheads (4) that are placed at areas of high loads [1]. The early to mid-construction stages of three rig hulls illustrate the process (Fig. 11.4).

Depending on the rig design and builder preference, the hull may be constructed modularly with different sections of the hull fabricated separately and assembled. Modules are designed to utilize similar steel shapes to increase the repetition involved in construction. Modular construction is common in shipbuilding and allows for parallel workflows, increasing shipyard output but is a relatively recent innovation in rig construction.

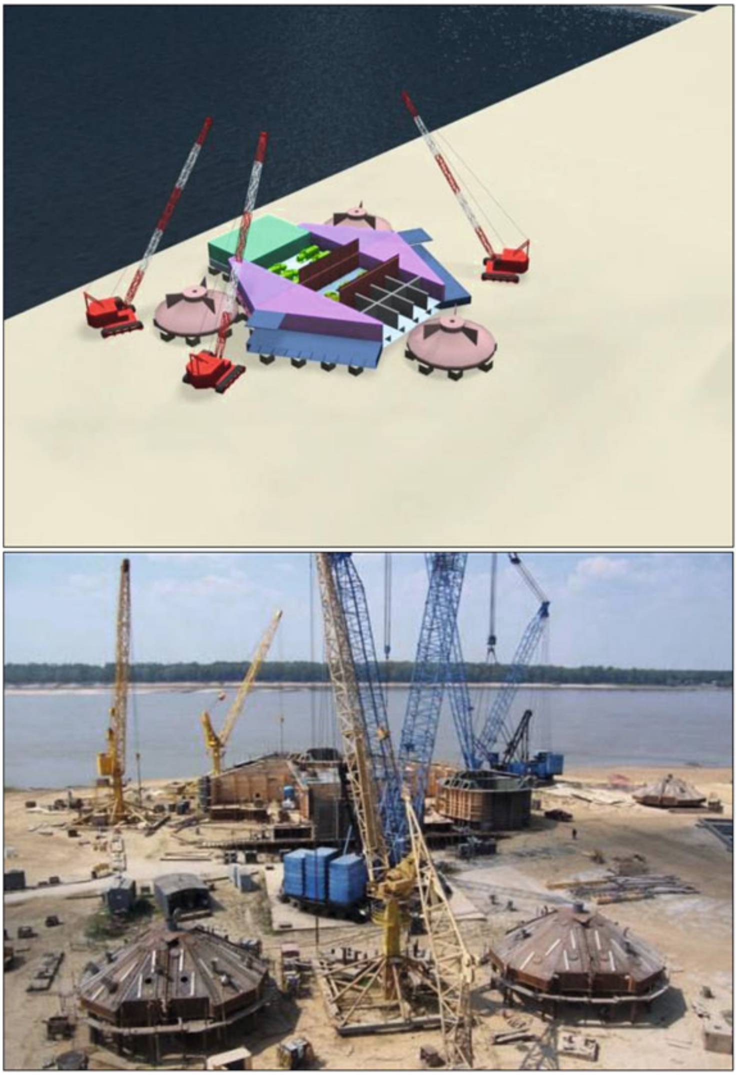

Fig. 11.2 Early construction stages of jackup rigs F&G JU 2000E (*top*) and *Hank Boswell* (*bottom*) at the LeTourneau Vicksburg, Mississippi yard. In the top image, the hull is being built around existing spudcans, while in the bottom image, three spudcans (two in the foreground and one on the left of the image) are visible and as the leg wells are completed the spudcans will be inserted. (Source: Freide and Goldman)

11.4 Topsides

After the spudcans are in place and the hull is built, the jacking system and topsides containing living quarters and offices are installed (Fig. 11.5). The components of the jacking system are typically supplied by the design firm and included as part of

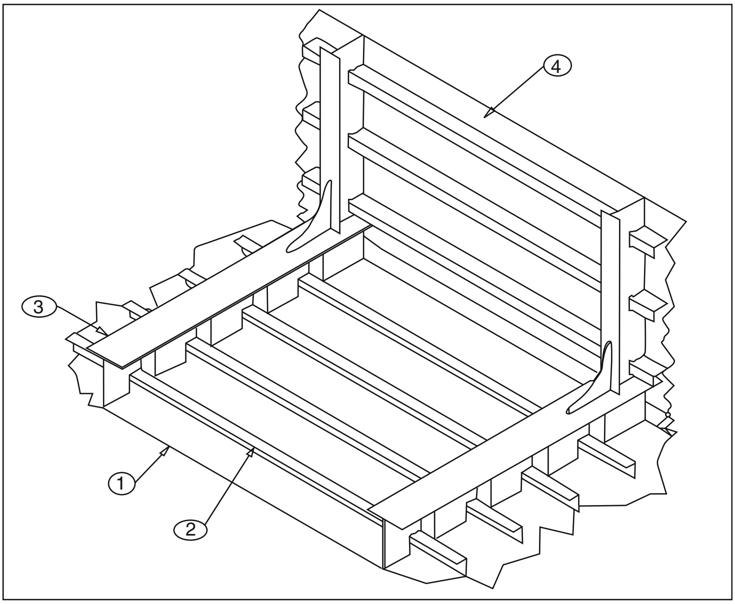

Fig. 11.3 Structural design of a jackup hull (Source: Rammohan [1])

the rig design package. Outfitting work and the installation of machinery and equipment may be carried out before or after launching, but is most efficient if conducted prior to launch.

11.5 Racks and Half-Rounds

Racks start as solid 5–7 inch plates of high grade quenched and tempered steel. The steel is flame cut to form teeth, making the rack and is the most expensive steel used on the rig (Fig. 11.6). Half-rounds start as flat plates of high grade steel which are cold pressed into half rounds (Fig. 11.7). After the racks and half-rounds are machined, they are placed in shipping containers and delivered to the shipyard.

11.6 Chord Assembly

Racks and half-rounds are delivered to the shipyard in 20–40 ft sections. A section of rack is welded to two slightly shorter half-round chords so that several feet of rack extends beyond the end of the half-round. The racks of these sections are welded together, and then adjoined to half-rounds. After individual chord sections are assembled, braces are welded to the chords and the chords are joined to form a 40–90 ft long section of leg.

Fig. 11.4 Hull construction of a F&G Super M2 rig (*top*) and two LeTourneau Super 116s at the AmFELS Brownsville, Texas yard. In the top image, much of the hull has been completed and machinery has been installed on the lower decks. In the bottom image, two hulls are under construction. (Source: Remedial Offshore; Microsoft)

The steel used on leg chords must be of extremely high quality because of the structural demands placed on rig legs, but the high quality steel can make welding difficult. The large number of alloys in high strength steel increases its hardness but decreases its weldability. The welding of the legs must be carried out in controlled shop conditions with submerged arc or gas metal arc welding techniques. Welding consumables must also be tightly controlled to ensure quality. The most notable problem in welding leg joints is hydrogen cracking (embrittlement) which can be caused by the marine environment. Therefore, every weld on a leg must be inspected for cracks either by x-ray, ultrasound or another method of non-destructive testing.

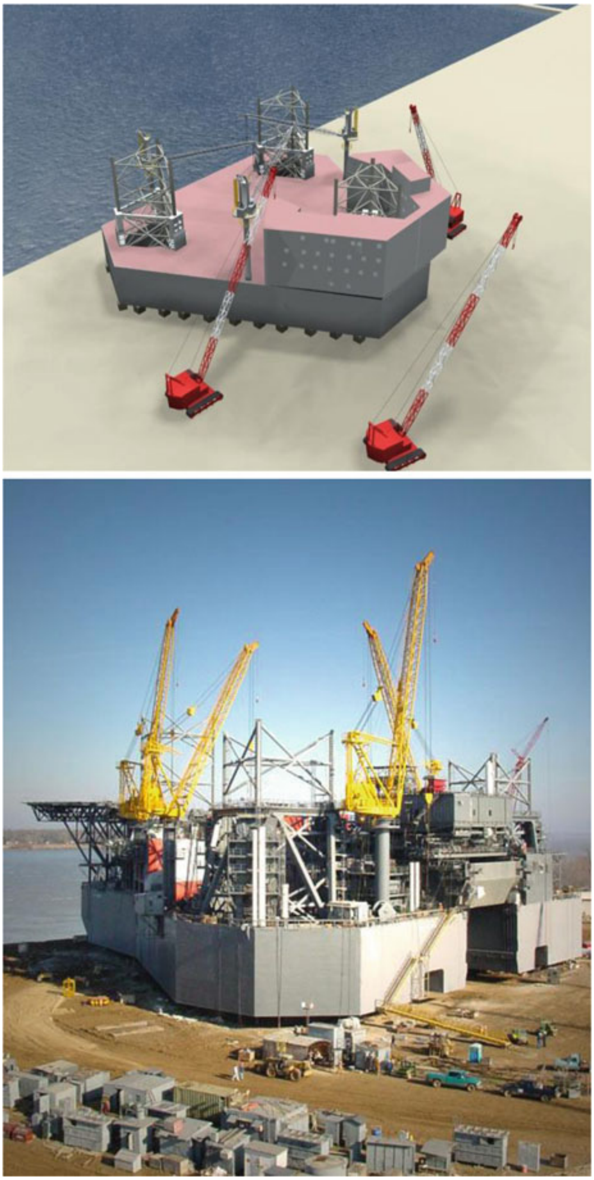

Fig. 11.5 Topside installation on F&G JU 2000E (*top*) and *Bob Palmer* (*bottom*) at the LeTourneau Vicksburg, Mississippi yard (Source: Freide and Goldman)

11.7 Launching

Rigs may be built in drydocks or adjacent to a quay. At the AmFELS shipyard in Brownsville, Texas, rigs are launched into the water via a slipway and at the LeTourneau shipyard in Vicksburg, Mississippi, rigs are "walked" into the water using a complicated and time consuming method of elevating the rig and moving dirt around the spudcans (Fig. 11.8).

Fig. 11.6 Principal components of leg chords (Source: Arcellor Mittal)

Fig. 11.7 Formed half chords (Source: Jackrabbit Steel)

11.8 Derrick and Cantilever

The cantilever and derrick are constructed separately and assembled and installed onto the rig following launching. The derrick is usually assembled by a specialized firm. Like the jacking system, prefabricated components of the cantilever may be supplied by the design firm and included as part of the rig design package.

11.9 Leg Assembly

Early in construction, the first sections of leg are attached to the spudcans and jacking systems. After launching, the remainder of the leg is added (Fig. 11.9). Depending on shipyard infrastructure, sections may be added directly to the top of the legs via an onshore crane, or sections may be added using the lift capacity of the jackup legs. After the legs are added, the jackup will be unable to pass under most bridges, thus, if the shipyard is located on a river (as is the case with the LeTourneau

Fig. 11.8 Launching rigs at the AmFELS shipyard (*top*) via slipway and the LeTourneau shipyard (*bottom*) via walking (Source: Keppel; Pitts)

shipyard in Vicksburg, Mississippi), the rig will be floated to a yard with direct ocean access before the final leg sections are added.

11.10 Delivery and Classification

Following final outfitting, the rig is delivered to the buyer, usually at the builder's shipyard. Acceptance of the rig is based on satisfactory sea trials and certification by a classification society. Classification societies are independent, third party organizations that serve as a verification system for parties such as regulatory

Fig. 11.9 Top section of F&G Super M2 leg installed (Source: Remedial Offshore)

authorities, insurance underwriters, owners, shipyards and subcontractors, finance institutions and charterers with a special interest in the safety and quality of marine vessels.

Classification societies provide a set of guidelines for design and construction and inspect shipyards during construction to ensure compliance and provide assurance that a set of requirements and standards are met during design and construction. Each classification society has its own rules for classification, however, many aspects of classification are similar and are meant to ensure the safety against hazards to the vessel, personnel and environment. The American Bureau of Shipping is the most common classification society in the U.S. and internationally, but Det Norsk Veritas is also used depending on customer preference.

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Chapter 12
Construction Cost Factors

Abstract Rigs are built under a wide variety of designs, specifications and contracts at shipyards throughout the world. Market conditions, material and labor, design class and rig specifications, shipyard, and the time of construction are the primary factors that impact newbuild costs. Contract type, shipyard productivity, and exchange rate fluctuations also influence cost, but their impacts are more difficult to observe. The purpose of this chapter is to describe the factors that impact construction cost and provide empirical evidence to quantify their influence.

12.1 Market Conditions

Drilling contractors demand newbuilt rigs when dayrates and utilization make investment criteria positive. Prices are determined by demand and shipyard supply, and since only a small number of shipyards around the world build rigs, the capacity of construction services saturates during periods of high demand, leading to backlogs and price increases.

Early in the 2000–2012 period, less than 10 jackups were ordered per year and for floaters, only three orders were made through 2004 (Fig. 12.1). As orders increased prices rose. The average cost of jackup rigs increased from approximately $125 million in 2004–2005 to $200 million after 2006. Floater prices doubled from $300 million in 2002 to $600 million in 2006. Following the 2008 recession, new orders declined significantly, but prices only fell marginally, reflecting long backlogs and the expectation that a decline in orders would be short lived.

M.J. Kaiser and B.F. Snyder, *The Offshore Drilling Industry and Rig Construction in the Gulf of Mexico*, Lecture Notes in Energy 8, DOI 10.1007/978-1-4471-5152-4_12,

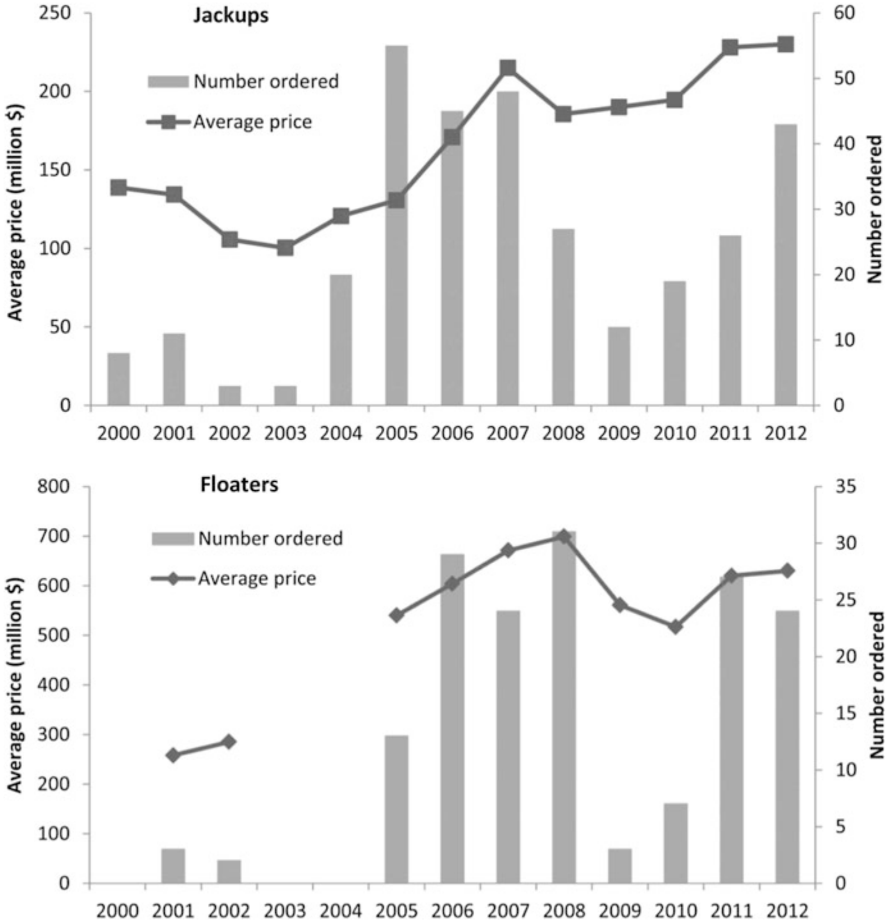

Fig. 12.1 Number and average price of worldwide jackup and floater orders, 2000–2012 (Source: Data from RigLogix [14])

12.2 Material and Labor

Rig construction requires steel, labor, and equipment. Steel costs are highly variable over time, depending on world demand and economic conditions, and when prices are high, steel will comprise a larger portion of the total cost (Table 12.1). Labor costs are highly variable geographically and fluctuate less over time. In China, labor costs are low and are likely to represent a small proportion of total costs. By contrast, U.S. labor costs may account for as much as 30 % of the total costs of construction. Drilling and equipment costs are influenced by steel prices to the extent that the majority of rig equipment is made from steel.

Table 12.1 Typical construction cost distribution for jackups and floaters

	Jackups		Floaters	
	Cost (million $)	Proportion (%)	Cost (million $)	Proportion (%)
Steel	15–40	10–20	25–60	<10
Labor	15–55	10–30	50–120	10–20
Drilling equipment	20–70	10–30	100–200	20–30
All other equipment	35–50	20–30	100–200	20–30
Profits	10–25	<10	50–75	<10
Total	175–225	100	500–700	100

Note: Estimates are for a generic $175–$225 million jackup and a $500–$750 million floater

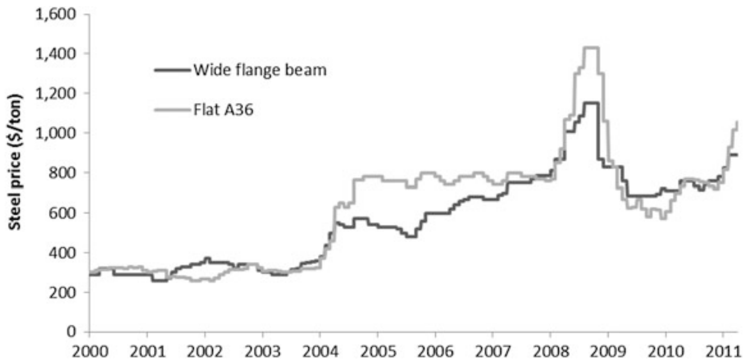

Fig. 12.2 Domestic U.S. steel prices, 2000–2011 (Source: Data from Steel Business Briefing [16])

12.2.1 Steel

Steel is the main component of rigs and jackup steel is usually a larger component of cost (10–20 %) than in floater construction (<10 %). Steel prices change dramatically with supply and demand conditions and impact the cost of rig construction (Fig. 12.2). Rigs are constructed using a variety of steel strengths and no single steel price reflects costs for all rigs. However, because the vast majority of rigs are built in Asia, the Asian steel price index[1] created by the steel industry tracking firm MEPS is considered a reasonable proxy for the rig construction market. Average jackup price and the steel index grew over the course of the decade at approximately the same rate, and the steel price index explains 70 % of the variation in average rig price during the period (Fig. 12.3). No significant relationship is observed between floater prices and steel prices indicating that other factors and market drivers impact the floater construction market.

[1] The Asian steel price index is the arithmetic average of steel plate prices in four Asian countries based on a survey of industry participants.

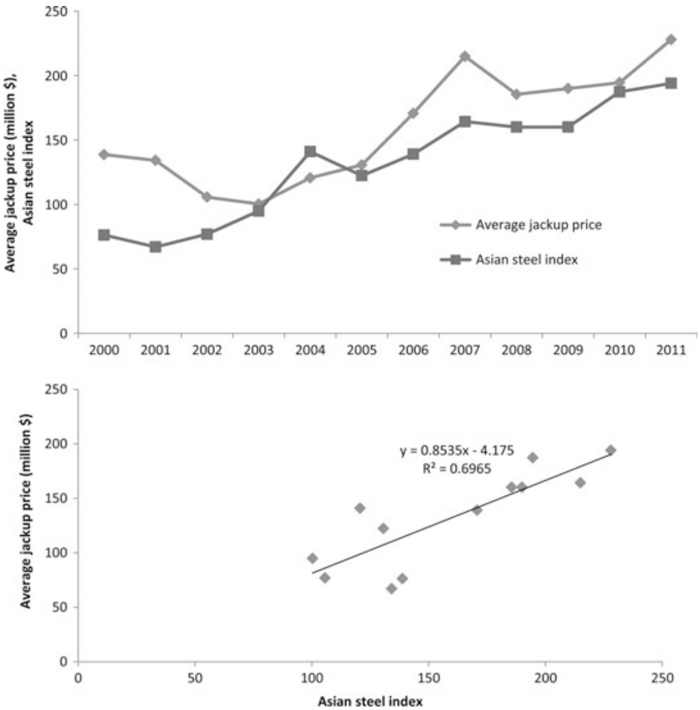

Fig. 12.3 Asian steel index and average world jackup prices and correlation, 2000–2011 (Source: Data from RigLogix [14] and Steel Business Briefing [16])

12.2.2 Labor

Labor costs and productivity are important drivers of shipyard costs [20]. The costs of shipbuilding labor in the U.S. and Korea are roughly similar and about three times the labor costs of Singaporean yards. South Korea compensates for relatively high labor costs with advantages in productivity. In the U.S., each dollar spent on labor generated approximately three dollars of revenue over the past decade, consistent with labor costs accounting for approximately one third of total costs (Fig. 12.4). In Singapore and South Korea, each dollar spent on labor generates approximately seven to ten dollars of revenue, suggesting labor costs make up on the order of 10–15 % of total costs for rigs built internationally.

12.2.3 Equipment

Engines, cranes, generators, drilling equipment, and dynamic positioning systems are third-party materials purchased by the rig builder. Drilling equipment is the

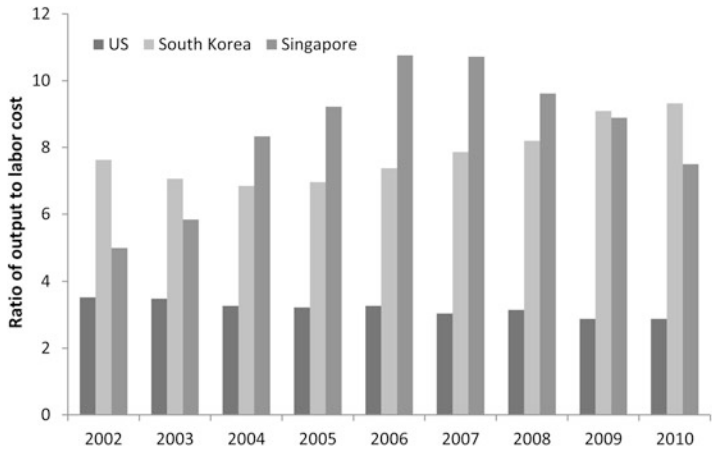

Fig. 12.4 Revenue generated per U.S. dollar spent on labor in U.S., Korean and Singaporean shipyards, 2002–2010 (Source: Data from USDOC [20] and Wong and Chang [18])

largest equipment expenditure, and typically costs between \$20–\$70 million for jackups and between \$100–\$200 million for floaters, or on the order of 10–30 % of total costs. Non-drilling related equipment range over similar cost intervals, and together, drilling and other equipment typically range from 30 % to 60 % of construction cost.

The Bureau of Labor Statistics (BLS) oil and gas field machinery equipment index[2] is used to proxy the costs of the drilling equipment installed on MODUs while the BLS finished goods index proxies the overall rate of inflation experienced by the manufacturing industry (Fig. 12.5). Both indices are based on U.S. products, but the oil equipment index is applicable to global MODU prices because much of the drilling equipment installed on MODUs is sourced from the United States. Throughout the 1990s the field equipment index grew gradually and in line with the finished goods index, but in the mid-2000s increased rapidly, outpacing the overall rate of inflation, suggesting that increasing rig prices was due in part to an increase in the costs of drilling equipment.

Average world jackup and floater prices correlate with the BLS equipment index suggesting that changes in equipment costs are a larger factor in overall prices than changes in steel costs for floaters (Fig. 12.6). The equipment and steel indices are themselves correlated and likely to be influenced by many of the same global factors, however, their influence on the costs of rigs is largely independent since each index impacts a separate budget category.

[2] The BLS oil and gas field machinery and equipment price index is based on a monthly survey of prices of a basket of onshore and offshore products including drawworks, blowout preventers, rotary equipment, drill bits, risers, production equipment, etc. [17].

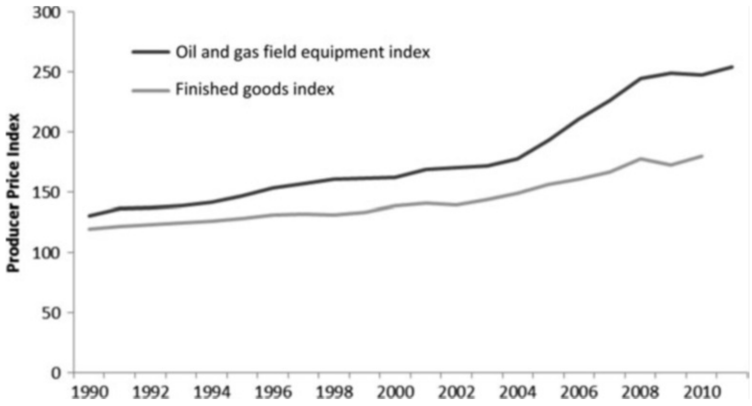

Fig. 12.5 BLS oil and gas field machinery equipment and finished goods producer price indices, 1990–2011 (Source: Data from BLS [1])

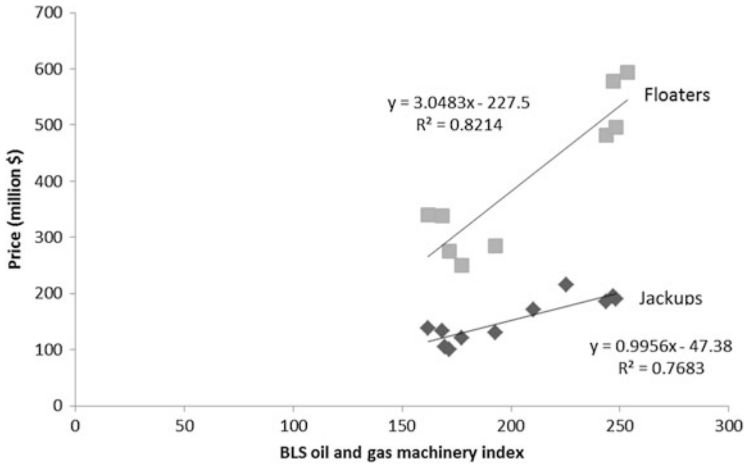

Fig. 12.6 Relationship between the BLS oil and gas machinery equipment index and global jackup and floater prices (Source: Data from BLS [1] and RigLogix [14])

12.3 Exchange Rates

Contracts for rig construction are denominated in U.S. dollars, but costs at international shipyards may be in another currency. For example, labor and steel costs at a South Korean shipyard may be in South Korean won while drilling equipment costs may be in U.S. dollars. For the rig builder, as the value of the U.S. dollar rises, the value of a contract increases. From the perspective of a rig buyer, a strong U.S. dollar lowers newbuild costs at international shipyards. Thus, when the dollar declines relative to a local currency, an increase in costs is expected.

Table 12.2 Jackup design class properties and prices circa 2011

Design	Number	Price (million $)	Water depth (ft)	Harsh	VDL (tons)
F&G JU-2000E	11	190–220	400	Y	7,000
F&G JU-2000A	4	220–229	350	Y	4,500
F&G JU-3000N	6	220–245	400	N	7,000
Gusto MSC CJ70	3	500–530	492	Y	7,000
KFELS B Class	20	180–210	350–400	N	4,500
KFELS Super A	5	230–260	400	Y	7,000
LeTourneau Super 116E	12	159–210	200–375	N	3,750
LeTourneau 240C	3	194–257	400	N	3,000
PPL Pacific 400	3	190	400	N	3,750

Source: Data from Jefferies and Company, Inc. [9]; Industry press

12.4 Design Class

Jackups under construction circa 2011 cost between $159 to $530 million for units capable of operating in 200–492 ft water depth with variable deck load (VDL) between 3,750–7,000 tons (Table 12.2). In general, there is relatively little variation in cost between rigs of the same design, but some designs such as the LeTourneau Super 116E class is especially variable because the design is suitable for both shallow and deeper water markets.

Semisubmersibles under construction in 2011 cost between $460 to $771 million for water depth capability ranging from 1,640 to 10,000 ft, VDLs between 5,000 and 22,000 tons, and operating displacements between 42,000 and 62,000 tons (Table 12.3). There is more variation in costs between rigs of the same design than for jackups which reflects increased customization. Most units are sixth generation ultra-deepwater rigs; however, the GM 4000 is designed for drilling in midwater regions and the GVA 4000 NCS is intended for harsh environments.

Drillships under construction in 2011 cost between $550 million to $1.2 billion (Table 12.4). Drillships are usually more expensive than semisubmersibles even though construction is typically easier because of the greater displacements and enhanced capabilities. The Samsung 10000 and 12000 and the Gusto P10000 are the most popular designs and are capable of storing small volumes of oil during well testing [4].

12.5 Rig Specifications

Rigs vary in drilling capabilities, variable deck load capacity, maximum water depths, and environmental criteria. As vessel specifications and capability increase, costs rise for all other factors held constant.

Table 12.3 Semisubmersible design class properties and prices circa 2011

Design	Number	Price (million $)	Water depth (ft)	Harsh	VDL (tons)	Displacement (tons)
CS-50 MkII (N)	2	510–526	9,843–10,000	Y	6,800	47,000
Ensco 8500	2	537–560	8,500	N	8,000	
F&G ExD	3	599–771	7,500–10,000	N	10,000	58,000
GM 4000	2	460–560	1,640–4,000	Y	5,000	42,000
GVA 4000 NCS	2	565	1,640	Y		60,000
GVA 7500-N	2	526–709	10,000	Y	8,250	62,000
Sevan Drilling 650	3	526–685	10,000	N	22,000	61,000

Source: Data from Jefferies and Company, Inc. [9]; Industry press

Table 12.4 Drillship design class properties and prices circa 2011

Design	Number	Price (million $)	Water depth (ft)	Harsh	VDL (tons)	Displacement (tons)
DSME 10000	2	579	10,000	N	24,000	112,000
DSME 12000	6	590–782	10,000–12,000	N	24,000	112,000
GustoMSC P10000	11	590–630	10,000–12,000	N	20,000	75,000
GustoMSC PRD12000	1	632	12,000	N	15,000	45,000
Huisman GT-10000	2	550–585	10,000	N	20,000	60,000
Samsung 10000	17	638–820	10,000–12,000	N	22,000	105,000
Samsung 12000	8	550–650	10,000–12,000	N	22,000	105,000
Stena/Samsung	1	1,150	7,500	Y	19,000	108,000

Source: Data from Jefferies and Company, Inc. [9]; Industry press

12.5.1 Structural Weight

Weight is a primary factor in determining the physical characteristics of a rig and fabrication costs [8]. Larger rigs have greater variable loads, can support more powerful drilling equipment and can operate in more severe conditions than smaller rigs. As more steel is added, material costs and fabrication expenses increase, and because so many complex tradeoffs and interdependent factors are involved, it is difficult to quantify the effects of weight on construction cost [5, 7, 12].

12.5.2 Water Depth

Water depth is a primary determinate of jackup costs. The legs of a jackup are made of expensive high grade steel, and as water depth capacity and environmental criteria increase, so will the costs of construction. Wind and wave forces act in proportion to leg length, and above a certain threshold, a rig cannot be extended to deeper water by simply extending its legs. Instead, a new and larger rig design is required [2, 11, 15]. For drillships and semisubmersibles, water depth capability is not expected to be as strongly correlated with costs because the rigs are floating units capable of working in a large water depth range, and with the exception of the risers and anchor handling systems, do not have structural components that pass through the water column.

12.5.3 Operating Environment

Rigs capable of operating in harsh environments are heavier and more expensive than moderate environment rigs. Harsh environment jackups have longer legs to increase the airgap, and as leg length increases, the distance between the legs and the size of the hull must also increase. Similarly, semisubmersibles built for harsh environments must have longer and thicker columns than moderate environment units which increases costs. Drillships are not typically designed for operation in harsh environments, but interest in Arctic exploration has led to harsh environment designs costing over $1 billion per drillship.

In harsh environments, jackups with 350–400 ft water depth capabilities cost 90 % more than jackups with 300–350 ft water depth capabilities; in moderate environments, the price premium is 23 % (Table 12.5). For semis, there is a significant water depth price premium in harsh environments, but a less notable premium in moderate environments. Small sample sizes influence these results, but in general, large cost differences are found in harsh environment rigs because of design variability and country of build differences.

12.5.4 Equipment Specifications

As the drilling depth capability of a rig increases, more robust pumping units and safety systems are required to handle the higher formation pressures and temperatures, increasing costs. Power, storage and VDL capacities determine the maximum drilling equipment that may be installed on the rig. Drilling depth proxies equipment specification, but it is the actual equipment capabilities and degree of automation that determine cost. Important specifications include the hook load, riser pressure, rated pressure and diameter of the blowout preventer, degree of offline capability, storage capabilities, number and power of mud pumps, mud tank capacity, number and flowrate of shale shakers, desilters, desanders, cementing unit operating pressure, and capacity of the BOP handling system.

Table 12.5 Newbuild average costs by water depth and environmental design circa 2012

	Water depth (ft)	Harsh (million $)	Moderate (million $)
Jackups	≤300	–	171 (7)
	300–350	240 (2)	173 (13)
	350–400	465 (1)	213 (12)
	≥400	530 (3)	–
Semis	≤2,500	375 (3)	–
	2,500–7,500	633 (1)	542 (3)
	≥7,500	585 (9)	563 (19)

Source: Data from Jefferies and Company, Inc. [9]
Note: Sample sizes in parenthesis

12.6 Country of Build

Large rig shipyards exist in Singapore, China, India, South Korea, Russia, the United States and the United Arab Emirates. These countries differ markedly in their labor practices and costs, tax structures, the importance of rig/shipbuilding to the overall economy, and the degree of government intervention which contributes to construction cost differences across countries [10]. Korea, Singapore, and China captured 80 % of the newbuild market in jackups, semis and drillships in 2012. Singapore is the primary jackup builder, China is dominant in semi construction, and Korea dominates drillship construction. In both the jackup and semi market, there is significant international competition, but nearly all drillships in recent years have been built in Korean yards. In every market in which Singaporean yards have market share, the average cost at Singaporean yards is less than in any other nation (Table 12.6). No other nation has a notable cost advantage.

12.7 Contract Type and Options

Rigs are built by drilling contractors with or without a firm contract commitment from an E&P company. When building a rig speculatively, contractors may approach negotiation with the shipyard more aggressively and be less willing to pay than when building a rig with an initial contract. Building a rig on speculation increases risk and the contractor may only be willing to accept this risk at a steep price discount.

For example, in 2011, Maersk Drilling ordered two MSC CJ70 jackups on speculation for $500 million each; two months later, Seadrill ordered the same rig for $530 million after receiving an initial contract. Similarly, in June 2008, Seadrill ordered a Pacific Class 375 rig on speculation from PPL shipyard for $215 million; the next month Egyptian Drilling received a contract and ordered the same rig from the same shipyard for $220 million. These data are anecdotal and the differences small, but the general concept is clear.

Table 12.6 Newbuild costs by country of shipyard in million U.S. dollars circa 2012

Rig type	Water depth (ft)	Harsh	India	U.S.	China	Singapore	UAE	Korea	Italy	Average
Jackups	≤350	Y	240 (2)							240
		N	182 (1)	178 (5)		163 (5)	174 (9)			172
	350–400	Y				465 (1)				465
		N		223 (2)		212 (10)				213
	≥400	Y			607 (1)	473 (2)				530
		N								
Semis	≤2,500	Y			375 (3)					375
		N								
	2,500–7,500	Y						633 (1)		633
		N			574 (2)	480 (1)				542
	≥7,500	Y			557 (5)			623 (3)	615 (1)	585
		N			604 (9)	517 (7)	547 (3)			563
Drillships	7,500	N						683 (5)		683
	10,000	Y						1,500 (1)		1,500
		N						676 (23)		676
	12,000	N			616 (2)			700 (6)		681

Source: Data from Jefferies and Company, Inc. [9]; Industry press
Note: Sample sizes in parentheses

Rigs ordered on option allow a contractor to purchase one or more additional rigs at a fixed price simultaneously with their initial order or at a later time. Typically, options must be exercised within a year of contract signing and the cost of optioned rigs is frequently higher to account for the risk of inflation and the value of locking in future newbuilding capacity.

12.8 Shipyard Characteristics

Shipyards vary in their rig building experience, labor costs, supply chain management, tax structure and government subsidies, construction methods, reputation and degree of integration [6]. Many major rig shipyards maintain their specialization with proprietary designs. Keppel-FELS and LeTourneau each have their own line of jackup rigs and while these yards can and do build other designs, they have gained significant experience by building specific rigs and may be able to do so at lower costs than other yards [19]. Similarly, many yards have long-term contractual relationships with rig operators who often prefer a particular design class or company and is likely to lead to cost reductions through learning.

Shipyards differ in the methods in which they construct rigs based on their level of automation, subcontracting, and the degree of serial production line usage. The particular method of fabrication and assembly is unique for each yard and rig and depends upon space and equipment availability. South Korean yards use a sophisticated "mega-block" method of ship construction in which very large ship sections are fabricated separately and then assembled in a floating dock [20]. A high degree of specialization will likely lead to reduced costs and enhanced quality control standards, but this is only feasible for yards with a constant supply of orders.

12.9 Backlogs

The amount of time between when a rig is ordered and delivered is important in determining costs and risks to both parties [3, 13]. The time to construct a rig depends on a number of factors but is typically 18–36 months; however, the time between contract finalization and rig delivery can significantly exceed the construction time due to shipyard backlogs. During construction, the buyer is required to make payments on the rig but does not receive income which can create cash flow problems for buyers. Additionally, as the time between ordering and delivery increases, market conditions may change, creating risk for the buyer and seller. For the buyer, rig utilization and dayrates may decline, while for the seller, steel, labor or material costs may increase. When there is a particularly long delay between contract finalization and the start of construction, a cost escalation clause is frequently included.

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Chapter 13
Newbuild and Replacement Cost Functions

Abstract Rigs are the primary assets of drilling contractors and their newbuild and replacement costs are frequently required in corporate planning and financial valuation. In this chapter, newbuild and replacement cost functions are derived based on rig class, age and upgrade status, water depth, and other factors using 2010 market data. A U.S. jackup newbuild cost function explained 77 % of the variance in construction cost using water depth, drilling depth and an environmental indicator variable. Water depth was the single best predictor across all models and rig classes. Replacement cost models explained larger proportions of variance than newbuild models but this is likely due to the manner in which replacement cost estimates are performed rather than superior methodologies. A brief discussion of the limitations of analysis concludes the chapter.

13.1 Data Sources

Construction costs are publicly reported because most drilling operators are public companies and rig construction represents significant investments. The use of public data is subject to reporting bias, however, because costs may not be reported similarly and may differ in the inclusion of owner-furnished equipment or finance charges. The replacement value of rigs is estimated by market intelligence firms, drilling contractors and insurance companies using specialized algorithms, and because model assumptions and parameterizations differ, replacement costs depend upon the firm performing the estimation.

Newbuild and replacement cost data from Jefferies [6] and RigLogix [8] was applied and inflation adjusted to 2010 dollars using the BLS shipyard producer price index [2]. The newbuild cost sample includes 39 jackups, 35 semis and 37 drillships and represented the majority of rigs under construction in 2010. The replacement cost sample includes 282 jackups, 149 semis and 35 drillships in active, ready- and cold-stacked status representing a significant portion of the world fleet at

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the time of analysis. Cost information on rigs owned by private companies and NOCs were not available for analysis, but should not be materially different from the sample evaluated.

13.2 Model Development

13.2.1 Function Specification

Newbuild and replacement cost models are specified using a multi-factor linear functional:

$$C = \alpha_0 + \sum \alpha_i X_i, \tag{13.1}$$

where C represents the cost of the rig type and the number and selection of the descriptor variables X_i is specific to the rig class, user preference, and data availability. The coefficients of the formulation are estimated through ordinary least-squares regression common in maritime cost assessments [1, 4, 9].

Several models are applied to highlight differences and compare predictors, and functionals are estimated with and without the fixed-term component because cost models without a fixed component allow for the determination of the relative contribution of each variable. Whenever the intercept term in a regression model is set to zero, however, the model fit R^2 and statistical significance improve due to the manner in which R^2 is calculated.[1] There is no meaningful way to interpret R^2 values in this case and they are not reported for regressions through the origin. Instead, the standard error (SE) is reported to allow for model comparisons.

13.2.2 Variable Description

For newbuilds, the following variables were evaluated: operating water depth, year of delivery, drilling depth, environmental design conditions (harsh or non-harsh environment), variable deck load, and country of build. For replacement cost, water depth, year of delivery, years since upgrade (effective age), upgrade status, and environmental design conditions were examined. Variable deck load was not considered in the replacement cost analysis due to data limitations. For jackup

[1] In a regression with an intercept, the R^2 is the proportion of variance explained by the regression: $R^2 = 1 - SSE/SST$, where SSE is the variance not explained by the regression and SST is the total variance. SST is determined by summing the squared differences between the observed values and the mean value: $SST = \sum (Y_i - \overline{Y})^2$, where Y_i is the ith observation and $\overline{Y}$ is the mean. However, when the regression is forced through the origin, the SST becomes the sum of the squared differences between the observed values and zero ($SST = \sum (Y_i - 0)^2$) while SSE does not change. This will increase SST and therefore R^2 [5].

replacement and newbuild costs, water depth squared was examined because higher-order terms of deadweight have previously been shown to be a reliable predictor [7] and because rig weight is better correlated with water depth squared (see Chap. 14).

Water depth, drilling depth and variable load are continuous variables. Delivery year is a discrete variable that enters the newbuild model as X rather than 200X, while for replacement costs, the actual year of delivery is used. When qualitative variables are used they are referred to as indicator or dummy variables and they take the value 0 or 1; e.g., rigs designed to operate in a harsh environment are categorized using an indicator variable 1 if harsh, 0 otherwise.

13.2.3 Expectations

Water depth and drilling depth are expected to be positively correlated with costs for all rig types. Water depth should have a pronounced impact on jackup costs because of the leg length correspondence and the increased material and time to build. Time enters the evaluation for newbuild costs because contracts made for late deliveries were finalized in early 2008, before credit markets tightened and shipyard demand was high. Harsh environment rigs are expected to cost more than non-harsh environment rigs, and newer rigs and more recently upgraded ones are expected to be more expensive to replace than older rigs that have not been upgraded.

13.3 Newbuild Cost Models

13.3.1 Single Variable Models

Single variable linear regression models using water depth, year of delivery and drilling depth capability were examined. In most cases, increases in water depth, drilling depth and build year have a positive influence on cost, however, most relations were not significant. The only statistically significant relationship involved water depth and jackup costs (Fig. 13.1).

13.3.2 Jackups

Multivariate newbuild cost models were specified using an environmental indicator (HARSH), water depth (WD, ft), and water depth squared terms. Variables for country of build, drill depth or delivery year did not add explanatory power and were excluded. The impact of variable deck load was minor and was not included in the best model which took the form:

$$\text{Newbuild cost} = \alpha_0 + \alpha_1\text{HARSH} + \alpha_2\text{WD} + \alpha_3(\text{WD})^2. \qquad (13.2)$$

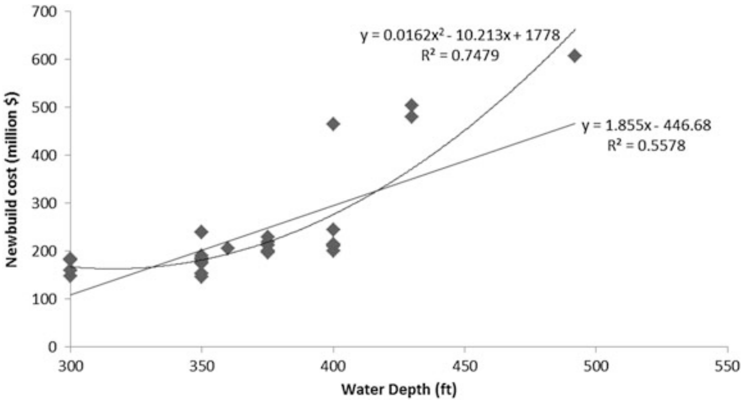

Fig. 13.1 Relationship between water depth and cost in jackup newbuilds (Source: Data from Jefferies and Company, Inc. [6])

Model A explained the largest portion of the variation in newbuild costs using water depth and water depth squared terms (Table 13.1) and is used to distinguish cost curves for harsh and moderate environment rigs (Fig. 13.2).

Models B and C compare the effects of the water depth and water depth squared terms and suggest that water depth squared is a slightly better predictor than water depth. In all three models, negative and large positive intercepts are inconsistent with a priori expectations and therefore we examined the effects of constraining the y-intercept to zero in Models D through F. When the y-intercept is set to zero, the magnitude of the coefficients changes, but the signs of the coefficients do not change, suggesting that the direction of the relationships between water depth and operating environments and costs are robust.

All of the models examined contain indicator variables for environmental conditions and the coefficients for these variables range from 140 to 202 suggesting that harsh-environment rigs are approximately $140 to $200 million more expensive than non-harsh environment rigs. Drilling depth was not a useful predictor because it is relatively invariant across the sample with most rigs capable of drilling either 30,000 or 35,000 ft wells. International competition limits geographic differences in pricing.

13.3.3 Semisubmersibles

Semisubmersibles did not yield robust newbuild models. The best model contained water depth and delivery year and results are depicted with and without the fixed cost component (Table 13.2). Both models had similar coefficients but poor

Table 13.1 Jackup newbuild cost models

Cost (million \$) = $\alpha_0 + \alpha_1 HARSH + \alpha_2 WD + \alpha_3 (WD)^2$

Model	α_0	α_1	α_2	α_3	R^2	SE
A	1248[a]	140.4[a]	−6.88[a]	0.011[a]	0.91	31.5[b]
B	−209.9[a]	171.7[a]	1.128[a]		0.83	42.9[b]
C	−16.0	163.38[a]		0.0016[a]	0.85	40.1[b]
D	0	159.9[a]	−0.146	0.002[a]		39.8
E	0	201.6[a]	0.54[a]			47.7
F	0	167.8[a]		0.0015[a]		39.7

[a]Parameter is statistically significant ($p < 0.05$)
[b]Model is statistically significant ($p < 0.05$)

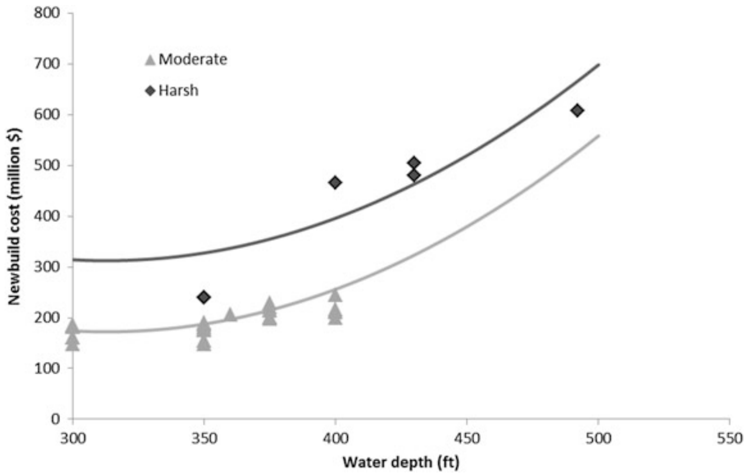

Fig. 13.2 Newbuild cost curves based on Model A

predictive ability. The model suggests that for each 1,000 foot increase in water depth capability, cost increases by \$25 million, and as the year of delivery increases over the period of the sample set, costs increase by \$38 million per year. Thus, a semi for delivery in 2012 should cost approximately \$100 million more than an identical semi delivered in 2009 because of changing market conditions.

For a semisubmersible capable of operating in 8,333 ft water depth and delivered in 2010, Model B estimates cost at \$535 million. Approximately 37 % of the cost is associated with water depth capability and 63 % is associated with the delivery year term. The influence of the delivery year on costs is time dependent and related to commodity prices and shipyard demand when the contract was written. Hence, these terms do not extrapolate outside the period of analysis and are generally not preferred in specification. Market conditions in the 2009–2012 period led to increasing price with time, however, if a different

Table 13.2 Semisubmersible newbuild cost models

Cost (million \$) = $\alpha_0 + \alpha_1$WD + α_2YEAR					
Model	α_0	α_1	α_2	R^2	SE
A	−50.3	0.025[a]	38.1[a]	0.39	81.2[b]
B	0	0.024[a]	33.6[a]		79.5

[a]Parameter is statistically significant ($p < 0.05$)
[b]Model is statistically significant ($p < 0.05$)

time period were selected, conditions are likely to be different.[2] Understanding the role of time is an important determinant when applying cost relations outside their sample window.

13.3.4 Drillships

No combination of variables were able to capture the distinguishing features of drillship costs. The vast majority of drillships were under construction in Korea at the time of analysis which eliminates the country of build variability inherent in the jackup and semi data sets. All orders in the sample occurred over an 18 month period reducing temporal differences due to market conditions. Additionally, many of the vessels under build were one of three similar designs further reducing the data variation.

13.3.5 Design Class

Design class was investigated for each rig type using the single-factor model:

$$\text{Newbuild cost} = \alpha_0 + \alpha_1\text{DESIGN}. \qquad (13.3)$$

For semisubmersibles and drillships, design class did not improve the model results, but for jackups, the variable was statistically significant (Table 13.3). Nine design classes were employed to categorize the sample data and each design class used its own indicator variable. The model predicted over 95 % of the variance in costs and suggests that there is more variation between rig classes than within rig classes. The LeTourneau Super 116, the F&G Super M2 and the Gusto MSC CJ46 are priced at a discount; the KFELS ModVB, LeTourneau 240C and Pacific Class 375 may be considered average; and the KFELS N Class, Gusto MSC CJ70 and F&G 2000A are priced at a premium. All three premium designs are for harsh environments.

[2] For example, the *Sevan Brasil*, was delivered in 2012 at a cost of \$685 million, but two identical rigs built at the same shipyard for delivery in 2014 each cost \$526 million.

Table 13.3 Jackup newbuild costs by design class

Cost (million \$) = 213[a] + α_1DESIGN	
Class	α_1
F&G 2000A	27.0[a]
F&G Super M2	−41.6[a]
KFELS ModVB	−11.3
KFELS N Class	270.0[a]
LeTourneau Super 116	−33.8[a]
LeTourneau 240	9.5
Gusto MSC CJ46	−55.0[a]
Gusto MSC CJ70	394.0[a]
Pacific Class 375	0.0[a]

[a]Parameter is statistically significant ($p < 0.05$)

13.4 U.S. Newbuild Cost Models

13.4.1 Sample Data

A total of 26 rigs were built in the U.S. between 2000 and 2012 (Table 13.4). All rigs are independent-leg cantilever units, and all but three were LeTourneau designs. Water depth capabilities range from 300 ft to 550 ft, and the 350 ft water depth class was the most common along with the Super 116E design class. Inflation-adjusted prices range from \$101 to \$326 million.

13.4.2 Summary Statistics

Costs generally increase with increasing water depth capacity, and within a water depth class, costs are reasonably similar because of similar build locations and contract execution dates (Table 13.5). In some cases, prices range widely for similar rigs due to differences in contract options and timing. For example, the *Offshore Defender*, *Resolute*, *Courageous*, *Intrepid* and *Vigilant* are all LeTourneau Super 116s built at the Brownsville, TX, shipyard and ordered in 2005 and 2006. The *Defender* and *Courageous* cost \$87 million each, while the *Resolute* and *Intrepid* cost \$143 million. *Defender* and *Courageous* were built as options executed in 2005 based on contracts written in 2004, while the other rigs were new contracts written in 2005 and 2006 at a time of higher demand. Cost variation by rig class is usually smaller than by water depth category.

13.4.3 Regression Model

Regression models using hull length, hull width, order date, drilling depth, maximum water depth, and environmental design were examined. Hull width was correlated with hull length, water depth, order date and harsh environment

Table 13.4 Construction costs of U.S. jackup rigs, 1996–2011

Rig	Construction cost (million $)	Order year	Inflated cost[a] (million $)
Rowan Gorilla VI	208	1996	305
Rowan Gorilla VII	220	1997	314
Bob Palmer	240	2000	326
Scooter Yeargain	95	2001	126
Ensco 105[b]	110	2002	142
Tonala[b]	117	2002	151
Bob Keller	100	2002	129
Hank Boswell	100	2002	129
JP Bussell	125	2004	149
Offshore Courageous	87	2005	101
Panuco	133	2005	154
Offshore Defender	87	2005	101
Offshore Resolute	143	2005	166
Ocean Scepter[b]	150	2005	174
Offshore Vigilant	93	2005	108
Rowan Mississippi	165	2005	191
Atwood Aurora	177	2006	198
Offshore Intrepid	143	2006	160
Ralph Coffman	165	2005	191
Tuxpan	190	2007	204
Rowan EXL I	175	2007	188
Rowan EXL II	175	2007	188
Rowan EXL III	175	2007	188
Joe Douglas	200	2007	215
Rowan EXL IV	175	2007	188
Perforadora Central I	195	2011	191

Source: Data from RigLogix [8] and Colton [3]
[a]Inflated using the BLS shipyard producer price index to 2010 U.S. dollars [2]
[b]Non-LeTourneau design

variables. Multicolinearity was also found between the harsh environment indicator and the hull length and order date variables. These variables were not allowed to enter the model together.

The best model was specified by:

$$\text{Newbuild cost} = -96 + 0.42\text{WD} + 0.003\text{DD} + 103\text{HARSH}, \qquad (13.4)$$

where newbuild cost is in million dollars, WD is water depth (ft), DD is drilling depth (ft), and HARSH is an environmental indicator variable. All the coefficients except the intercept are positive and statistically significant and the model explained 77 % of the cost variation. According to the generalized relation, every 100 ft of increased water depth capability increased construction cost by $42 million; each 1,000 ft of drilling depth capability increased cost by $3 million, and the premium for harsh environmental capacity was $103 million.

Table 13.5 U.S. jackup rig cost by water depth and rig class, 1996–2011

Water depth (ft)	Number	Average cost (million $)	Standard deviation (million $)
300	4	133	11
350	13	164	38
375	5	176	27
400	3	270	68
550	1	326	
Class			
KFELS B Class	2	147	6
KFELS Super B Class	1	174	
LeTourneau 240C	3	199	14
LeTourneau Super 116	5	127	33
LeTourneau Super 116E	8	188	15
LeTourneau Super Gorilla 219-C	2	309	6
LeTourneau Super Gorilla XL 224-C	1	326	
LeTourneau Tarzan Class 225-C	4	133	11

Source: Data from RigLogix [8] and Colton [3]

13.5 Replacement Cost Models

Replacement costs reflect the costs to replace a rig with a new asset of like quality assuming market conditions and comparable technology at the time of assessment. For a recently built rig, replacement cost are estimated by reference to the rig's original newbuild cost adjusted for market conditions, or the newbuild cost of similar rigs under construction. As the rig ages, replacement cost will depend on technology trends, labor and material cost, shipyard supply and demand conditions, and related factors (Fig. 13.3). If new technology and improved construction methods, high competition among shipyards, and low demand for steel prevail in the future, replacement costs will be lower. Conversely, when there is high demand for shipbuilding services and a high price environment, replacement costs are expected to increase. Since many of the factors that influence newbuild prices also impact replacement costs, and because most replacement cost require adjustment and estimation, we expect the results of empirical models will be broadly similar. Rig age and upgrade status are primary variables because of the large variation in these variables in the legacy fleet.

13.5.1 Single Variable Models

Single variable linear regression models were used to investigate factor impacts on replacement costs. Water depth was a significant factor for jackups (Fig. 13.4) and floaters (Fig. 13.5), and delivery year was a useful descriptor for drillships (Fig. 13.6). Drill depth was not a significant factor for any rig type.

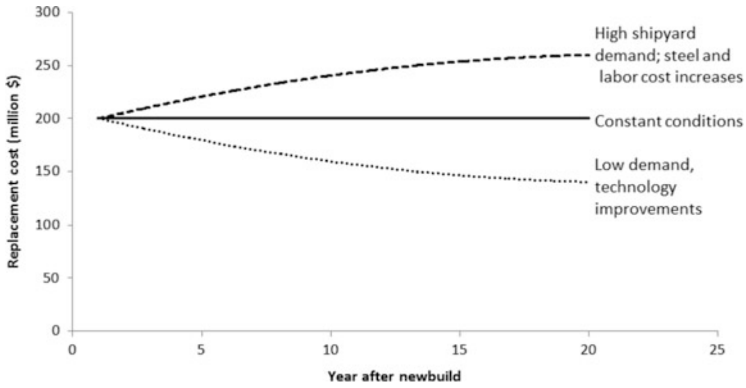

Fig. 13.3 Effects of time and market conditions on replacement costs

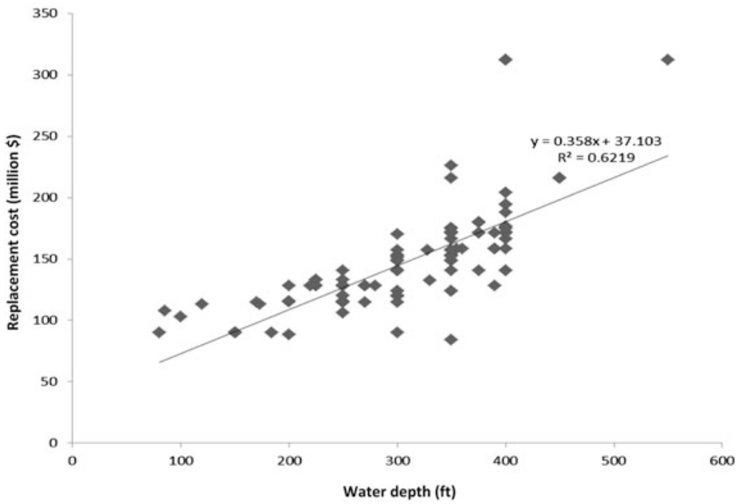

Fig. 13.4 Jackup replacement costs as a function of water depth (Source: Data from Jefferies and Company, Inc. [6])

13.5.2 Jackups

Multivariate replacement cost models were specified using water depth (WD, ft), water depth squared, environmental indicator (HARSH), and year of delivery (YEAR, yr):

$$\text{Replacement cost} = \alpha_0 + \alpha_1\text{WD} + \alpha_2(\text{WD})^2 + \alpha_3\text{HARSH} + \alpha_4\text{YEAR}. \quad (13.5)$$

Age and the environmental indicator were significant predictors in all models, and water depth squared performed better than water depth, similar to the newbuild cost

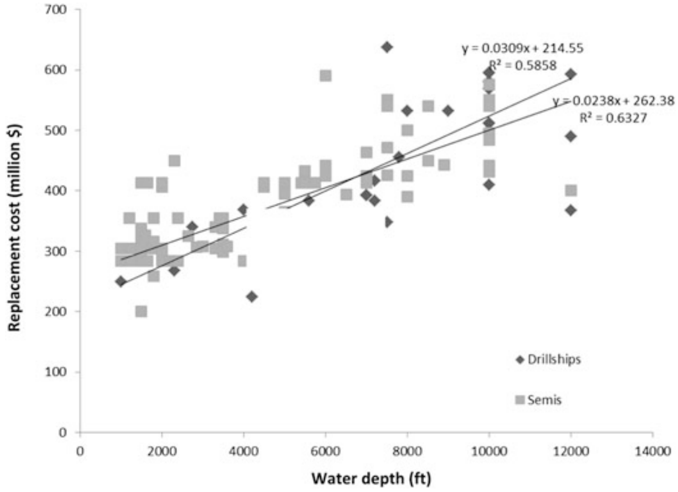

Fig. 13.5 Semisubmersible and drillship replacement costs as a function of water depth (Source: Data from Jefferies and Company, Inc. [6])

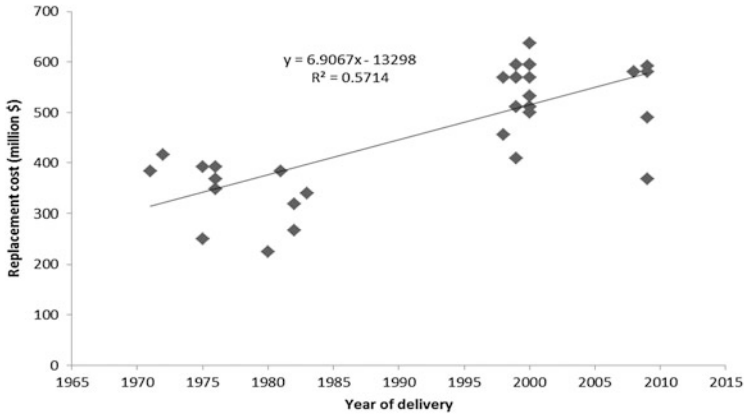

Fig. 13.6 Drillship replacement costs as a function of delivery year (Source: Data from Jefferies and Company, Inc. [6])

function (Table 13.6). Constraining the intercept to zero had little impact on parameter estimates.

Harsh environment rigs enjoy an $11 million premium over non-harsh rigs, which was significantly less than for newbuilds and likely due to the enhanced capabilities of the harsh environment rigs under build. Advanced capabilities make modern harsh environment rigs more expensive than those of the legacy fleet.

Table 13.6 Jackup replacement cost models

Cost (million \$) = $\alpha_0 + \alpha_1 WD + \alpha_2 (WD)^2 + \alpha_3 HARSH + \alpha_4 YEAR$

Model	α_0	α_1	α_2	α_3	α_4	R^2	SE
A	−1243.7[a]		0.0005[a]	10.6[a]	0.674[a]	0.70	17.5[b]
B	−1567[a]	0.282[a]		10.6[a]	0.818[a]	0.68	18.0[b]
C	0		0.0006[a]	10.6[a]	0.04[a]		18.2

[a]Parameter is statistically significant ($p < 0.05$)
[b]Model is statistically significant ($p < 0.05$)

Table 13.7 Semisubmersible replacement cost models

Cost (million \$) = $\alpha_0 + \alpha_1 WD + \alpha_2 YEAR + \alpha_3 HARSH$

Model	α_0	α_1	α_2	α_3	R^2	SE
A	−4121[a]	0.020[a]	2.2[a]	23.8[a]	0.69	48.3[b]
B	0	0.023[a]	0.13[a]			52.4

[a]Parameter is statistically significant ($p < 0.05$)
[b]Model is statistically significant ($p < 0.05$)

13.5.3 Semisubmersibles

Replacement cost models for semisubmersibles were specified using water depth (WD, ft), year of delivery (YEAR, yr), and environmental indicator (HARSH):

$$\text{Replacement cost} = \alpha_0 + \alpha_1 \text{WD} + \alpha_2 \text{YEAR} + \alpha_3 \text{HARSH}. \tag{13.6}$$

The water depth model coefficient 0.020 indicates that for every 1,000 foot increase in water depth, costs increase by \$20 million (Table 13.7). Newer rigs had higher replacement costs than older rigs, and each year increased cost by \$2.2 million. Harsh environment rigs cost \$23.8 million more than moderate environment rigs.

13.5.4 Drillships

Replacement cost models for drillships were specified using water depth (WD, ft) and environmental indicator (HARSH) variables:

$$\text{Replacement cost} = \alpha_0 + \alpha_2 \text{WD} + \alpha_1 \text{HARSH}. \tag{13.7}$$

The coefficient of the water depth term was positive and for every 1,000 ft increase in water depth replacement costs increased by \$31 million (Table 13.8). The harsh environment coefficient suggests that a harsh environment drillship costs \$196 million more than a moderate environment drillship. This is far more than the harsh environment premium in the jackup or semi cost models, and is partially the

Table 13.8 Drillship replacement cost models

Cost (million \$) = $\alpha_0 + \alpha_1$HARSH + α_2WD					
Model	α_0	α_1	α_2	R^2	SE
A	204.4[a]	196[a]	0.031[a]	0.65	67.2[b]
B	0	234.7[a]	0.053[a]		94.0

[a]Parameter is statistically significant ($p < 0.05$)
[b]Model is statistically significant ($p < 0.05$)

result of semis and jackups being more amenable to modification for harsh environments.

13.6 Limitations

Newbuild and replacement cost models are primarily limited by the ability of rig attributes to distinguish construction cost. The models treat the environmental design conditions as a simple binary variable. However, for jackup rigs, the environmental conditions which a rig can withstand depend in part on the water depth at that location. For example, a rig designed to operate in 350 ft in the Gulf of Mexico may only be able to operate in 200 ft in the North Sea. Water depth is believed to proxy structure weight, and if weight were included the model fits may improve.

Regression models were unable to capture the cost variation and distinguish the factors that make drillships unique because of the small dispersion among the sample data. Replacement cost variation is relatively uniform across rig types which reflect the manner in which replacement cost is estimated and similar lifecycle and upgrade regimes.

The cost assessment provides a snapshot of market conditions over a specific period of time. By fixing the time of assessment the effects of market fluctuations on cost data are eliminated which allows for a precise analysis of the physical factors that influence costs. While we suspect that the factors identified as influencing costs apply to the market generally, the value of individual coefficients and model output will change with changes in shipyard supply and demand. It is easy to adjust the cost functions for a future period using an appropriate index, or alternatively, if the sample sets are updated, new cost functions are readily derived.

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Chapter 14
Jackup Rig Weight Algorithm

Abstract Weight is an important design factor and a primary feature in determining the physical characteristics of a rig. In the marine construction industry, lightship displacements are widely reported, but in jackup construction, designers protect information on the weight of the vessel because weights are an indicator of the design and strength of a rig's legs which is an important distinguishing feature among designs. Methods for predicting ship weight based on physical attributes have been used for decades, but given the structural differences between jackups and ships, these techniques do not adequately predict rig weight. In this chapter we present an empirically derived lightship displacement function useful for first-order estimates.

14.1 Weight Factors

14.1.1 Water Depth

As the water depth capability of a rig increases, the length of the legs increase, but at some point, incremental leg length cannot be added to a given hull design and the hull must be enlarged. As a result, water depth is correlated with a number of physical descriptors including leg length, hull breadth, hull depth, deck area and hull volume [8].

14.1.2 Drilling Depth

Equipment weight is a product of functionality. In order to increase the drilling depth capability of a rig, designers make allowances for more powerful drilling equipment, stronger cantilevers and greater variable loads. Larger and heavier rigs are required to accommodate more numerous and powerful drilling systems and heavier loads.

M.J. Kaiser and B.F. Snyder, *The Offshore Drilling Industry and Rig Construction in the Gulf of Mexico*, Lecture Notes in Energy 8, DOI 10.1007/978-1-4471-5152-4_14,

14.1.3 Outfitting and Drilling Support Systems

Outfitting weight includes piping, wiring, ducting, corrosion protection, access items (ladders, walkways, gratings, rails, etc.) and helideck and usually composes less than 10% of hull weight. Cantilevers must be able to support the weight of the drill string (the hook load) and the weight of the cantilever system will depend on the distance from the hull it can be extended and the weight it can support. Most modern rigs are rated to at least 1.5 million pounds hook load.

14.1.4 Environmental Capability

Harsh environment rigs are heavier than moderate environment units. For the same water depth capability, harsh environment rigs must have longer legs than moderate environment units to increase the air gap. The legs and spudcans of harsh environment rigs are built to a more robust standard than moderate environment rigs and use higher quality and thicker steel [3, 4]. Harsh environment units also frequently have greater variable loads than moderate units which requires a larger, heavier rig.

14.1.5 Steel Quality and Quantity

The tradeoffs designers make between the grade and quantity of steel impact rig weight [5]. Either larger quantities of lower grade steel or smaller quantities of higher grade steel may be employed. For example, a rig designer may increase the number of braces in each leg, but decrease the yield strength of the steel. Using lower grade steel will increase weight but may result in lower costs. Leg density usually varies from 2 to 6 tons/ft and is greater in harsh environment rigs (Table 14.1).

14.1.6 Foundation Type

Mat foundations provide for nearly complete fixity of the legs which allows for legs to be lighter and smaller. However, as the water depth capacity increases, the distance between its footings must increase, which can lead to increasing weight [3]. Mat foundations are uncommon on rigs with greater than 300 ft operational water depths.

Table 14.1 Leg weights of alternative rig designs

Source	Rig type	Environmental design	Leg mass (tons)	Leg length (ft)	Leg density (tons/ft)
Massie and Liu [5]	Generic	Moderate	1,400	508	3
Cassidy et al. [1]	Generic	Harsh	3,141	558	6
Pers. Comm.	Generic	Moderate	971	482	2
William et al. [7]	Generic	Harsh	2,123	377	6
PetroProd [6]	CJ70	Harsh	2,255	672	3
Global Chimaks [2]	F&G L780	Moderate	585	338	2

14.2 Data Source

Weight data from 31 rigs built between 1980–2011 representing 21 designs was assembled, including the F&G L780 Mod II, the LeTourneau Super 116 and Super 116E, the Baker Marine 375 and the Gusto CJ70 (Table 14.2). All units were independent trussed leg moderate environment cantilevered rigs except one slot unit and three harsh environment units. Water depth, hull length, hull width, build year and designer data were collected from the academic and trade literature, specification sheets and industry personnel.

For six of 21 rig designs, lightship displacements were estimated as the transit displacement minus the transit variable load. Transit displacement is the weight of the rig when prepared for wet tow and transit variable load is the weight of material and ballast required during a wet tow. Transit displacement data introduces error in the estimation but increases sample size. When more than one data point was available from a single rig design, the displacements were averaged to ensure that the data points were independent.

14.3 Summary Statistics

Rig lightship displacement averaged 11,479 tons (range 5,569–28,600 tons) with an average water depth capability of 314 ft (range 250–450 ft). For harsh and moderate environment rigs, the average displacement was 17,575 and 10,195 tons, respectively. Ten of the 31 rigs were built after 2008, and the remaining units were built before 1985. The oldest rig in the sample is the *Diamond M*, a Levingston 111 design, built in 1976. The average age of the sample was 22 years.

14.4 Single Factor Models

Water depth explained 57 % of the variation in lightship weight, with water depth squared a slightly better predictor (Fig. 14.1). The three harsh environment designs weigh more than average moderate environment rigs for the same water depth capability. Another key issue is the relationship between hull dimensions and rig

Table 14.2 Jackup rig lightship displacements

Rig Name	Design	Weight (tons)	Water depth (ft)	Harsh	Build year	Length (ft)	Width (ft)
Ensco 97[a]	LeT 82 SDC	5,559	250	N	1980	207	176
Ensco 96[a]	Hitachi 250 C	5,969	250	N	1982	193	174
Ensco 94[a]	Hitachi 250 C	6,417	250	N	1981	193	174
Ensco 88[a]	LeT 82 SDC	6,745	250	N	1982	207	176
Ensco 53[a]	F&G L780 Mod II	7,172	300	N	1982	180	175
Diamond M	Levingston 111	7,263	300	N	1976	208	178
Ensco 54[a]	F&G L780 Mod II	7,747	300	N	1982	180	175
Amarnath[a]	F&G L780 Mod II	7,749	300	N	1982	180	175
DYVI Bet[a]	CFEM	8,030	350	N	1978	230	212
Ensco 95[a]	Hitachi 250 C	8,443	250	N	1982	193	174
Generic	CJ 40	8,525	300	N	2010	193	180
Sagadrill2	Mitsubishi T76J	8,720	300	N	1981	194	184
Sagadrill1	Mitsubishi T76J	9,228	300	N	1984	194	184
Soraya		9,350	225	N	1970	177	133
Vicksburg[a]	LeTourneau 84S	9,625	300	N	1976	238	213
Ensco 92[a]	LeT 116 C	9,711	250	N	1982	243	200
Ensco 87[a]	LeT 116 C	9,751	350	N	1982	243	200
Offshore Resolute	LeT Super 116	10,605	350	N	2008	243	206
Courageous	LeT Super 116	10,682	350	N	2008	243	206
Offshore Vigilant	LeT Super 116	10,698	350	N	2008	243	206
Offshore Freedom	LeT Super 116E	11,274	350	N	2009	243	206
Energy Exerter[a]	CFEM 2005	11,364	300	Y	1982	245	283
Energy Enhancer[a]	CFEM 2005	11,368	300	Y	1982	245	283
Generic	Generic	12,200	330	N	1990	255	295
Generic	CJ 46 × 100	12,210	375	N	2010	214	203
Murmanskay	CDB Corall	14,800	330	N	1991	357	252
Arcticheskaya	CDB Corall	15,200	330	Y	2011	357	252
Glomar Moray	CFEM T2600C	15,334	300	Y	1984	324	284
Hakuryu 10	BMC 375	17,500	375	N	2008	236	224
Generic	CJ 50 × 120	17,600	400	N	2010	230	223
Generic	CJ 70 × 150	28,600	450	Y	2010	291	318

Source: Industry press; rig specification sheets
[a]Estimated as transit displacement minus transit variable load
Note: LeT denotes LeTourneau

weight. Hull dimensions predict about half of the variation in rig weight, but there is no trend of harsh environment rigs being heavier than moderate environment rigs for a given hull dimension (Fig. 14.2).

14.5 Weight Relation

A linear regression model was developed to predict rig weight using hull length and breadth (width), water depth capability, designer, environmental class (harsh vs. moderate) and build year as predictor variables. Hull length and breadth entered

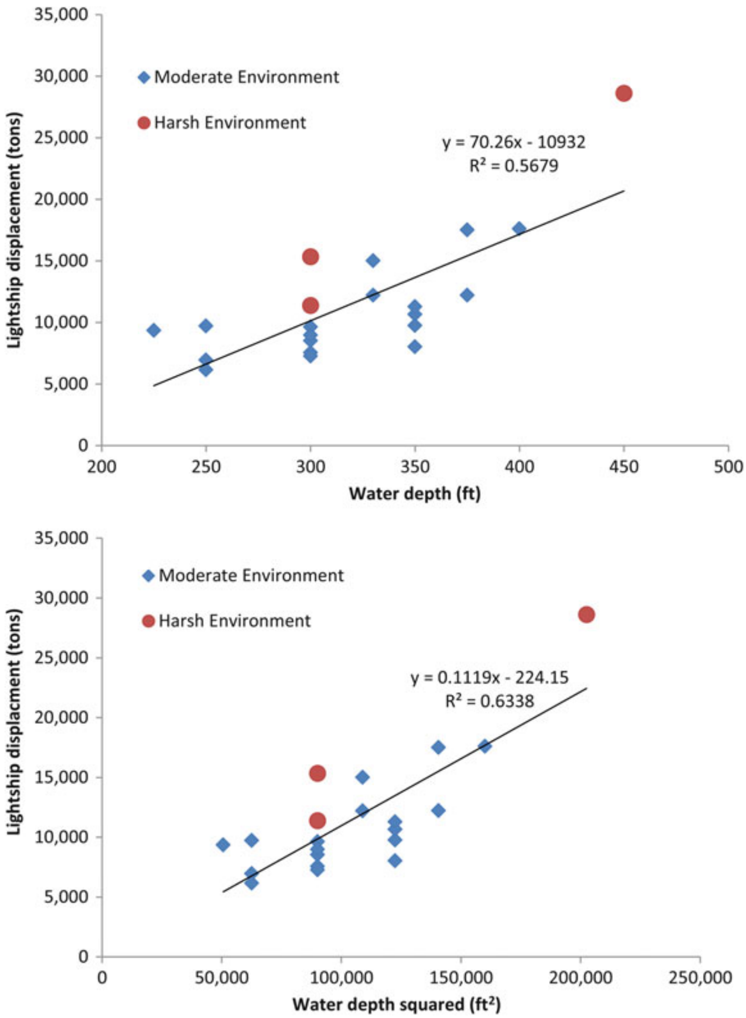

Fig. 14.1 Relationship between water depth and rig weight

the model as an interaction term to proxy the area of the hull. Designer and environmental class were modeled as indicator variables. Variables were checked for multicolinearity, and because breadth was correlated with length and environmental class, these variables were not permitted to enter the same model.

The best model included terms for water depth, water depth squared and hull length times hull width:

$$D = 49,316 - 323.3WD + 0.563(WD)^2 + 0.12LB \quad (14.1)$$

where D is lightship displacement (tons), WD is water depth capability (ft), and L and B are the length (ft) and breadth (ft) of the hull. Environmental class, designer and build year were not significant predictors.

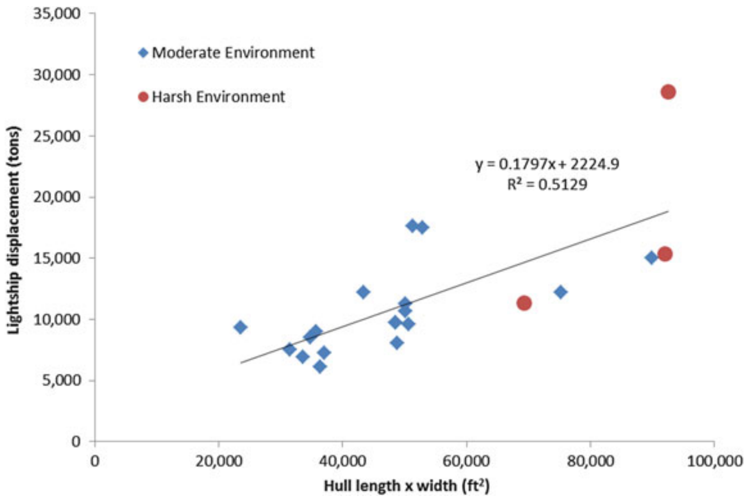

Fig. 14.2 Relationship between hull dimensions and rig weight

The model explained 91 % of the variation in displacement for the data sample and all terms were significant. The inclusion of the interaction term explained slightly more variation than either the length or width terms individually, and the coefficients were insignificant when the interaction term and the length or width terms were included together. Water depth is positively correlated with weight, and as water depth increases, the slope of the relationship increases (Fig. 14.3). In reality, width and breadth are not constant with increasing water depth.

The harsh environment indicator variable was not a significant predictor of weight which is likely due to the fact that only three of the 21 designs were harsh environment units. Data restrictions limit the ability of the model to accurately predict the weight of harsh environment rigs. Build year and designer were also not significant predictors, which could indicate physical similarity in rig designs over time and between designers.

14.6 Limitations

Small sample size reduces the confidence in the results and inflates model fit. However, because the total number of rig designs in the world is limited and our sample includes a broad assemblage of the most popular designs over a 30 year period, the relation is expected to be reasonably robust and adequate for general assessments. The impact of mat foundations and cylindrical legs were not examined, but rigs with these features are no longer commonly built and are of less relevance than the independent and trussed legged units that made up the sample.

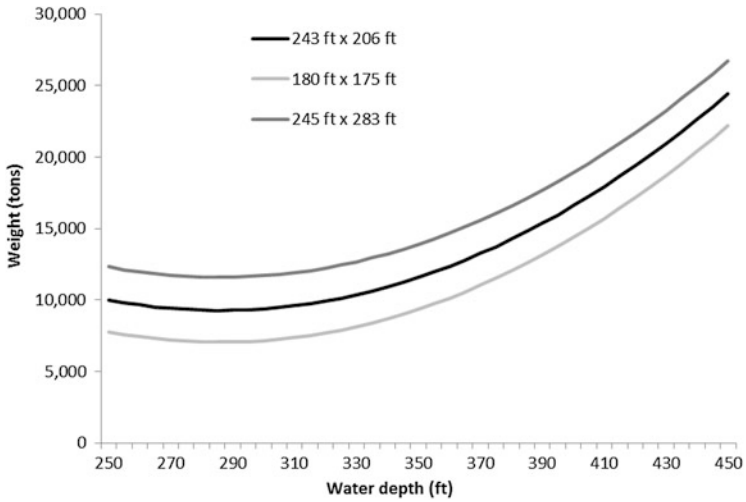

Fig. 14.3 Model relationship between water depth and predicted weight for rigs of different length and breadth

Notably, no designs from Keppel, among the most popular in the newbuild fleet, were included in the sample. While Keppel designs are generally similar to Gusto MSC, Baker Marine and Friede and Goldman designs, their absence from the dataset might limit application.

Additional error is introduced because the lightship displacement of some vessels was based on estimated values, and a number of different sources were utilized which may estimate lightship displacement differently. Deficiencies in weight reporting may be partly offset by the averaging of multiple records.

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Chapter 15
Labor and Material Requirements for U.S. Jackup Construction

Abstract Most of the shipbuilding activity in the U.S. in support of the offshore oil and gas industry occurs in the Gulf Coast states of Alabama, Mississippi, Louisiana and Texas. Between 2000 and 2012, two U.S. shipyards delivered a total of 26 jackup rigs worth $4.5 billion. In this final chapter, we quantify the labor and material requirements associated with jackup construction in the United States. Approximately $50–$70 million per rig is spent on labor at the shipyard and $60–$90 million per rig is spent on drilling equipment and the rig kit which flow to manufacturers throughout the region. The U.S. jackup industry competes with international markets with lower labor costs and higher productivity, and profit margins in the sector are expected to be low on a relative basis. Total annual employment is estimated between 800–3,900, and although small with respect to other offshore industries, is regionally and culturally important.

15.1 Cost Components

The cost to construct a rig is broken into five components: labor, drilling equipment, rig kit, material, and shipyard profit (Fig. 15.1). Labor is required to fit, weld, and assemble steel components and pumping systems, attach drilling equipment and outfitting, and certify, inspect and manage construction. Drilling equipment is frequently purchased as a package from integrated suppliers and includes the derrick, top drive, blowout preventer, mud and pipe handling systems, and other systems (Fig. 15.2). The rig kit includes the jacking systems, design license, and other components sold by the design firm. Materials include steel, engines, generators, and various other manufactured goods such as outfit material, piping, electrical system components, pumps, and safety equipment.

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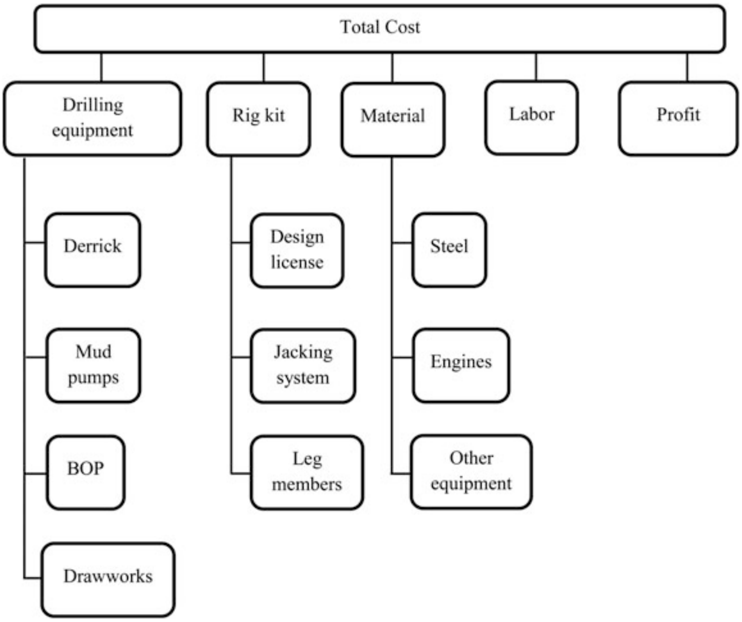

Fig. 15.1 Capital cost components for jackup rig construction

15.2 Supply Chain Distribution

Labor costs directly enter local economies, but material costs are distributed across a greater geographic region and represent a greater percentage of the total cost in rig construction (Fig. 15.3).

For LeTourneau designed rigs, leg steel is fabricated in Longview, Texas. Low strength 34 or 51 ksi steel is widely available throughout the shipbuilding industry and is typically ABS A, ABS AH36 or similar grades.[1] Globally, several hundred mills produce ABS certified products including 36 in the U.S., mostly in the Midwest, Southeast, Pennsylvania and West Virginia [2].

Much of the drilling equipment used in jackup rigs is assembled in and around Houston, Texas, and other locations in Texas and South Louisiana. Cameron operates manufacturing facilities in Ville Platte, Louisiana; National Oilwell Varco (NOV) operates manufacturing facilities in and around Houston and Pampa, Texas; Woolslayer (now Lee C. Moore, A Woolslayer company) operates a manufacturing facility in Tulsa, Oklahoma; Loadmaster operates a manufacturing facility in

[1] ABS steel is steel that is fabricated to ABS specifications. ABS A steel is 34 ksi and ABS AH36 is 51 ksi.

Fig. 15.2 Drilling equipment; Clockwise from upper left; mud pumps, top drive, shale shaker, drawworks

Broussard, Louisiana; and LeTourneau drilling systems operates manufacturing facilities in Longview and Houston, Texas.

Engines are typically sourced from Caterpillar and assembled at the Lafayette, Indiana and Griffin, Georgia manufacturing facilities (Table 15.1). Blowout preventers are sourced from Cameron, Hydril or NOV. Derricks are sourced from Woolslayer, Loadmaster or NOV, and most other drilling equipment from either Lewco (a division of LeTourneau) or NOV.

15.3 Cost Estimation

For each cost component, an estimation module is developed based on user input, model assumptions and time adjustment factors (Table 15.2).

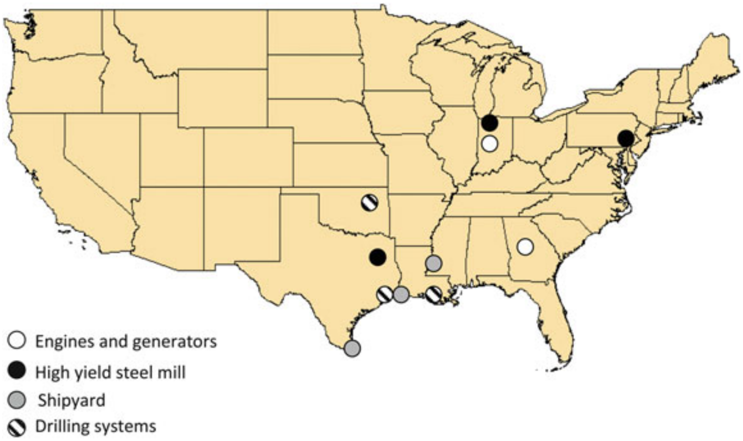

Fig. 15.3 Locations of major suppliers for the jackup rig industry in the United States

Table 15.1 Market share (in percent) of rig equipment suppliers in U.S. jackup rig construction, 2000–2010

Supplier	Engines	BOP	Topdrive	Rotary	Mudpumps	Derrick	Manufacturing locations
Caterpillar	95						Indiana, Georgia
NOV		17	50	50	15	34	Texas
Lewco			50	50	85		Texas
Cameron		66					Louisiana
Woolslayer						33	Oklahoma
Loadmaster						33	Louisiana
Hydril		15					Texas
Wartsilla	5						Europe

Source: Data from RigLogix [18]

For the labor and material modules, the output cost is a function of capital costs, lightship displacement, and installed power. Model parameters for the labor module include wages and productivity assumptions. Model parameters for the material module include the jackup weight distribution, steel prices, and the price per kilowatt for engines and generators. The drilling equipment and rig kit modules apply fixed prices and do not vary with other input. Profit margin is assumed to be a fixed percentage of capital costs.

All price assumptions and output costs are in 2010 dollars and reflect average market conditions in the 2005–2010 period. To apply the estimation procedure to a past or future time period, output is multiplied by the adjustment factor given by I_t/I_{2010}, where I_t is the year t BLS price index (Fig. 15.4).

Table 15.2 Rig construction cost estimation modules

Module	Sub-module	User input	Model assumptions	Adjustment factor
Labor		Capital costs	Productivity, hourly wages	Shipyard earnings index
Material	Steel	Lightship weight	Weight distribution, steel price	Steel mill products index
	Generators/ engines	Installed power	Price per kW	Machinery and equipment index
	Other material	Capital costs	Fixed percentage	All finished goods
Rig kit			Fixed price	Ship and boat building index
Equipment			Fixed price	Oil field equipment index
Profit		Capital costs	Fixed percentage	

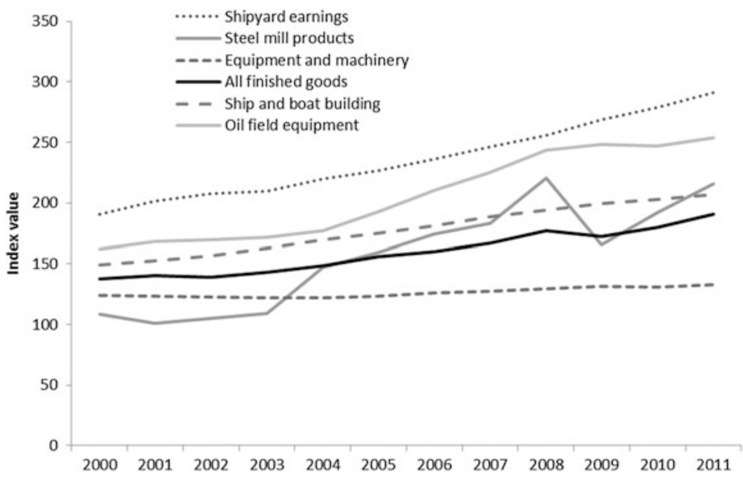

Fig. 15.4 BLS producer price indices related to jackup construction, 2000–2011

15.4 Capital Expenditures

Rig construction cost is user input for several component modules. In many cases, capital costs may be known and input directly; if unknown, capital cost are estimated based on rig specifications using Eq. 13.4:

$$\text{Newbuild cost} = -96 + 0.42\text{WD} + 0.003\text{DD} + 103\text{HARSH}, \qquad (15.1)$$

where Newbuild cost is in million dollars, WD is water depth (ft), DD is drilling depth (ft), and HARSH is an environmental indicator variable (1 if harsh, 0 otherwise).

15.5 Labor Cost Module

15.5.1 Labor Cost

Labor cost is determined as the product of the number of man-hours required and average hourly wage:

$$\text{Labor cost} = (\text{Capital costs}/\text{Productivity}) * \text{Wage}, \tag{15.2}$$

where capital costs are measured in dollars, productivity is measured in dollars of value produced per hour of labor (USD output/h labor), and wages are measured in dollars per hour ($/h). Capital cost is a user input. Wages and productivity are based on empirical data.

15.5.2 Wages

Hourly wages in rig building are expected to be broadly similar to ship building because of the commonalities in the work requirements. In 2009, shipbuilding in the U.S. employed 100,372 people and paid $7.6 billion in total compensation, or about $76,000 per employee (Table 15.3). Labor cost are adjusted using the BLS labor index [4], and the inflated dollars per hour is calculated under the assumption that all employees work an average of 2,000 h per year. Labor costs in U.S. shipyards have been relatively stable over time ranging from 35 to 38 $/h from 2002 to 2009.

15.5.3 Productivity

The number of man-hours required to construct a jackup rig depends on the rig design, nation of build, preassembly status, and shipyard. Because jackup productivity in U.S. yards is confidential, estimating the labor requirements in support of rig construction requires the use of a suitable proxy. Steel weight or compensated gross tonnage[2] is often used to proxy the man-hours required to construct a ship [5, 6, 13, 17], but jackup rigs are structurally different from other ship types and their compensated gross tonnage factors are not well defined [12].

The average revenue generated by one unit of labor for the entire U.S. shipbuilding industry is used to proxy the relationship between labor and revenue for the rig

[2] Compensated gross tonnage is a unit of measurement developed by the Organization for Economic Cooperation and Development that allows relative comparison of shipbuilding outputs across countries and vessel types. Compensated gross tonnage is defined by $A*GT^B$, where GT is a vessel's gross tonnage, and A and B are class-specific conversion factors.

Table 15.3 Cost of labor at U.S. shipyards, 2002–2009

Year	Number of employees	Total compensation ($1,000)	USD per employee	Inflated USD per employee	Inflated USD per h labor[a]
2002	87,152	4,694,721[b]	53,868	69,922	35.0
2003	86,155	4,799,634[b]	55,709	71,647	35.8
2004	87,111	4,904,367[b]	56,300	68,925	34.5
2005	84,407	5,028,646	59,576	70,769	35.4
2006	85,262	5,111,697	59,953	68,398	34.2
2007	96,955	6,186,983	63,813	69,795	34.9
2008	106,049	7,074,944	66,714	70,263	35.1
2009	100,372	7,597,040	75,689	75,689	37.8

Source: U.S. Census [20]
[a]Assumes employees work an average of 2,000 h per year
[b]Total compensation estimated as payroll plus 30 %

Table 15.4 Labor requirements per unit of shipment value, 2002–2009

Year	Shipment value ($1,000)[a]	Number of employees	USD per h labor[b]
2002	16,598,108	87,152	95
2003	16,659,085	86,155	97
2004	16,073,195	87,111	92
2005	16,225,604	84,407	96
2006	16,657,923	85,262	98
2007	18,833,866	96,955	97
2008	22,192,036	106,049	105
2009	21,801,484	100,372	109

Source: U.S. Census [20]
[a]Adjusted to 2009 using the BLS labor index [3, 4]
[b]Assumes employees work 2,000 h per year

building industry. This method assumes that productivity is similar between the U.S. rig and shipbuilding industries which is likely to be reasonable as long as the levels of competition are similar across industries and the technology employed in shipbuilding is roughly similar to that used in rig building [11]. This assumption is difficult to validate, but provides a consistent means to estimate market revenue and infer employment in support of rig construction.

In 2009, the shipment value from all U.S. shipyards was worth $21.8 billion, and when divided by the total number of hours worked, yields a productivity of $109 shipyard revenue per hour of labor (Table 15.4). From 2002 to 2009, one hour of labor generated between $92 and $109 of vessel value which is approximately the reported productivity in Keppel's Singaporean yards in 2010. The labor required to construct a vessel is estimated by multiplying vessel cost by the inverse of productivity. Thus, a $200 million jackup rig is expected to require approximately 2,000,000 man-hours of labor.

15.6 Material Cost Module

15.6.1 Steel Sub-Module

Categorization. Two grades of steel are typically used in rig construction: low-carbon steel for structural elements such as legs, decks, railings, walkways and deck plating; and high-strength steel for critical components and extreme conditions [14]. Three categories of steel components are considered for the steel sub-module: hull steel (typically 34–51 ksi), leg steel (typically 100 ksi), and miscellaneous steel (typically 72–90 ksi).

Steel Cost Relation. Steel costs for the leg, hull, and miscellaneous component are calculated as the weight of steel (in tons) multiplied by the price per ton. Each component is assumed to be a proportion of lightship displacement:

$$\text{Cost steel}_x = \text{Percent weight}_x * \text{ Lightship displacement } * \text{ Steel price}_x. \quad (15.3)$$

Weight Distribution. Lightship displacement is a user input. The proportion of lightship displacement attributable to the leg, hull and miscellaneous steel is estimated from the weight distributions of a sample of rigs (Table 15.5). Although the sample size is small and based on both generic and actual rigs, interval ranges are not expected to vary significantly across rigs or time. Approximately 20–30 % of rig weight is made up of steel in the legs and spudcans, while 40–60 % is made up of steel in the hull, jacking houses and cantilevers, and 5–10 % is miscellaneous steel.

Example. The weight distribution of a 300 ft water depth moderate environment rig built in the U.S. is shown for comparison (Table 15.6). Fifty-three percent of the rig weight is composed of 34–51 ksi steel in the hull, jackhouse and cantilever, 23 % is composed of 100 ksi steel in the legs, and 7 % is composed of miscellaneous 72–90 ksi steel. The total steel weight is 8,036 tons and the total weight of the rig is 9,700 tons.

Steel Price. Steel prices vary with changing market conditions and depend on yield strength, shape and quantity ordered. Deliveries are negotiated on a per-rig basis and are not publicly reported. Hull steel prices are expected to be similar to North American A36 plate which varied from 267 to 1,080 $/ton between 2001 and 2011. We assume that leg steel costs between 4,000 and 7,000 $/ton, hull steel costs 700–1,100 $/ton, and miscellaneous steel costs 1,000–1,500 $/ton. Hull steel costs are estimated with confidence because prices for shipbuilding steel are widely reported. Prices for leg steel are poorly known because they are not widely tracked. Miscellaneous steel is a minor cost component.

Table 15.5 Weight distribution of selected jackups

	Massie and Liu [15]	Cassidy et al. [7]	William et al. [21]	PetroProd [16]	Global Chimaks [9]
Rig type	Generic	Generic	Generic	CJ70	F&G L780
Environment	Moderate	Harsh	Harsh	Harsh	Moderate
Hull mass (tons)	5,000	17,577[a]	17,700[a]	11,221	4,219
Leg mass (tons)	1,400	3,141	2,123	2,255	585
Machinery (tons)	3,000			10,614	1,270
Lightship (tons)	12,200	27,000	24,069	28,600	7,267

[a]Includes machinery

Table 15.6 Steel grade distribution of a 300 ft moderate environment jackup built in the U.S.

Steel Grade (ksi)	Weight (tons)	Percent of total weight (%)	Use
34–51	5,130	53	Hull, jackhouse, cantilever
72–90	652	7	Hull, cantilever, legs, spudcans
100	2,254	23	Legs

Source: Industry personnel

Table 15.7 Installed power of selected jackup rig designs

	Installed power (kW)
Gusto MSC CJ70	10,500
Gusto MSC CJ46	8,600
KFELS Super B Class	9,145
KFELS N Class	9,600
LeTourneau Super 116E	8,015
LeTourneau 240C	9,150

Source: Specification sheets

15.6.2 Engine Sub-Module

Engines and generators are a large component of material costs. While most rigs use a version of the Caterpillar 3516, a number of versions and options are available and prices vary with market conditions. Generator prices are assumed to cost 400–600 \$/kW delivered based on a 2012 industry survey. If the actual power of the rig is known, it may be input (Table 15.7); otherwise, power is assumed to range from 8 to 10 MW.

15.6.3 Other Material Module

Other materials include piping, wiring and electrical equipment, pumps, heating and cooling systems, kitchen equipment, lifeboats and other safety equipment, capstans, cranes, navigational equipment, furniture and outfit materials. Consumables include

Table 15.8 LeTourneau Super 116E rig kit costs

Year	Kit cost (million $)	Number of kits	Rig cost (million $)	Kit percent of cost (%)	Inflated kit cost[b] (million $)	Builder
2005	26	5	90–150	18–30	33	Keppel
2007	40	1	168	24	44	Lamprell
2007	60[a]	4	175	33	66	Keppel
2009	92[a]	2			92	Petrobras
2009	40	1	180	22	40	Petro Vietnam

Source: Industry press
[a]Includes drilling equipment
[b]Adjusted to 2010 using the BLS oil field machinery equipment price index [3]

paint, electricity, fuel, and welding supplies. The costs of these supplies are difficult to generalize, but in the shipbuilding industry they typically account for 20–25 % of total vessel costs. Material costs for rigs are assumed to represent a similar proportion of total costs as ship construction.

15.7 Rig Kit Module

Rig kit costs depend on the rig design and the scope of the kit and are purchased separately. All kits include a design license and jacking systems and may also include leg components, anchor winches, cranes and certain components for the cantilever and spudcans. Between 2007 and 2009, LeTourneau reported income of $418 million for work on 15–18 rig kits, giving an average cost of $23–$29 million per kit during this time. LeTourneau Super 116E rig kits typically range between 18% to 33% total construction cost (Table 15.8). In this analysis, rig kits are assumed to cost between $25 and $45 million per rig. Rig kits are likely to scale in proportion to the size of the rig, and for rigs larger than the Super 116E, kits will be more expensive.

15.8 Drilling Equipment Module

Drilling equipment includes derricks, mudpumps, topdrives, BOPs, drawworks, automated pipe handling systems, and solids control systems. Drilling equipment costs vary with the drilling capabilities of the unit, and high specifications will cost more than standard capabilities. Costs for a complete drilling package typically range from $20 to $70 million (Table 15.9). The cost of specific drilling components can be acquired from equipment suppliers (Table 15.10).

Table 15.9 Contract costs of jackup drilling equipment

Supplier	Buyer	Contract year	Contract scope	Inflated cost[a] (million $)
Varco	Hyundai	2001		37
National Oilwell	COSL	2004		42
Varco	Gulf Drilling	2004	BOP, topdrive, drawworks, pipe handling, derrick, mud pumps, solids control, drilling control	22
Varco	Ensco	2004	BOP, topdrive, drawworks, solids control, pipe handling	20
Varco	Keppel	2004	Solids control, topdrive, drilling control	15
Aker	Maersk	2005	Derrick, BOP handling	18
TTS Energy	Jurong	2007	All drilling equipment	71
EMER	Yantai Raffles	2007	Drilling equipment, cantilever	33
TSC	Yantai Raffles	2010	Drilling and power systems	39
TTS Energy	DSIC	2010		38
TTS Energy	Jurong	2011	All drilling equipment	62
TSC	Yantai Raffles	2011	Drilling and power systems	29

Source: Industry press
[a]Adjusted to 2010 using the BLS oil field machinery equipment price index [3]

15.9 Profit Margin

From 2006 to 2010, Rowan's drilling products division (principally composed of the LeTourneau shipyard) received an average profit margin of −2.7 % and a maximum of 9.7 %. In contrast, Keppel's marine division (principally its Singaporean shipbuilding operations) averaged a 13.6 % profit margin over the same period. Low profit margins do not adequately protect a firm from the risks of cost overruns and we assume that profit margins below 5 % are unsustainable. Profit margins above 10 % are unlikely due to international competition. A profit range of 5–10 % is assumed representative of the U.S. industry.

15.10 Illustration

The cost estimation procedure is illustrated with a hypothetical moderate-environment LeTourneau Super 116E jackup rig. The rig is assumed to have an operational water depth of 375 ft, a drilling depth capability of 30,000 ft, and hull dimensions of 243 ft by 206 ft. Labor and material requirements and cost distribution are estimated for U.S. Gulf Coast construction in the year 2010.

Table 15.10 Costs of selected jackup rig drilling equipment in 2010

Equipment	Unit cost ($1,000)	Typical number	Total cost ($1,000)
Top drive	3,312	1	3,312
BOP	2,650	2	5,299
Mud pump	1,920	3	5,759
Choke manifold	1,332	1	1,332
BOP handler	814	2	1,627

Note: Modified from Robertson [19] using the BLS oil field machinery equipment price index [3]

Table 15.11 Labor cost estimates for a hypothetical LeTourneau 375 ft Super 116E jackup in million U.S. dollars

	Labor cost		
Productivity ($value/h)	34 ($/h)	36 ($/h)	38 ($/h)
90	62	66	69
100	56	59	62
110	51	54	57

15.10.1 Capital Expenditures

Application of the capital cost model Eq. 15.1 requires the user to substitute the operational water depth (375 ft) and drilling depth (30,000 ft) to estimate capital expenditures of $164 million. Capital cost is the primary input in the labor, material and profit modules.

15.10.2 Labor Costs

Labor requirements are determined by Eq. 15.2 through the product of the capital cost and the inverse productivity metric. For hourly compensation ranging between 34 and 38 $/h and productivity between 90 and 100 $/h, total labor costs to construct the rig range from $51 to $69 million (Table 15.11).

15.10.3 Rig Weight

Rig weight is estimated according to the water depth, length, and breadth specifications and the weight relation Eq. 14.1:

$$D = 49,316 - 323.3WD + 0.563(WD)^2 + 0.12LB. \qquad (15.4)$$

Substituting the input parameters of the rig specification yields a rig weight of 12,575 tons.

Table 15.12 Steel costs for a hypothetical LeTourneau 375 ft Super 116E jackup

Total weight (tons)	Component	Proportion of lightship weight (%)	Unit cost ($/ton)	Cost range (million $)
12,575	Legs	20–40	4,000–7,000	10–35
	Hull	40–80	700–1,100	4–11
	Misc. steel	5–15	1,000–1,500	1–3
	Total			15–49

15.10.4 Material Costs

Mass is partitioned among rig components based on an assumed distribution range for leg steel, hull steel, and miscellaneous steel. Unit price assumptions per component yield a total steel cost ranging between $15 and $49 million (Table 15.12). Steel costs are dominated by the costs of leg steel because of its high unit costs, even though the hull contributes the majority of the weight. Installed power is assumed to range from 8 to 10 MW and when multiplied by the unit price (400–600 $/kW) yields the generator costs of $3–$6 million. Additional material costs are assumed to range from 20 % to 25 % of capital costs, or $33–$41 million.

15.10.5 Rig Kit and Drilling Equipment Costs

Rig kits and drilling equipment are rig-specific. For LeTourneau rigs, rig kits are estimated to cost between $25 and $45 million. Drilling equipment is assumed to cost $20–$50 million.

15.10.6 Profit Margins

Profits are assumed to be 5–10 % of capital costs, or $8–$16 million.

15.10.7 Cost Distribution

The construction costs for a LeTourneanu 375 ft Super 116E jackup built in 2010 is expected to range from $145 to $237 million (Table 15.13). Approximately one third of total costs are associated with shipyard labor and over half of costs are associated with materials, mostly in the drilling equipment package and rig kit.

Table 15.13 Construction costs for a hypothetical LeTourneau 375 ft Super 116E jackup

Component	Cost range (million $)	Proportion of total costs (%)
Labor	51–69	31–42
Rig kit (including leg steel)	25–45	15–27
Drilling equipment	25–50	12–30
Hull and miscellaneous steel	4–10	2–5
Engines	4–6	2–4
All other material	33–41	20–25
Profit	8–16	5–10
Total	145–237	

Table 15.14 Jackup drilling rig market revenue in million U.S. dollars, 2000–2011

	Delivery value	Three-year average	Vicksburg	Brownsville
2000	305			
2001	314			
2002	142	254	206	47
2003	326	261	213	47
2004	277	248	151	98
2005	129	244	194	50
2006	129	178	128	50
2007	356	205	137	67
2008	986	490	208	283
2009	351	564	228	336
2010	768	702	177	525
2011	403	507	135	372
Average	374	365	168	194

15.11 U.S. Jackup Market Size

15.11.1 Market Revenue

The total value of jackup deliveries in the U.S. has ranged from $129 million to $986 million between 2000–2011 (Table 15.14). On average, the rig building industry generates $374 million in revenue each year. A 3-year moving average is the best measure of annual industry revenues because payments for shipbuilding are spread throughout the construction process. In the early part of the decade, the LeTourneau Vicksburg yard dominated rig construction, but by 2008, the AmFELS Brownsville yard had surpassed LeTourneau in revenue (Fig. 15.5).

In 2011, the Vicksburg shipyard was sold to Cameron, a flow equipment manufacturer, along with LeTourneau Technologies drilling equipment manufacturing division. The Vicksburg shipyard delivered the *Joe Douglas* to Rowan in late 2011,

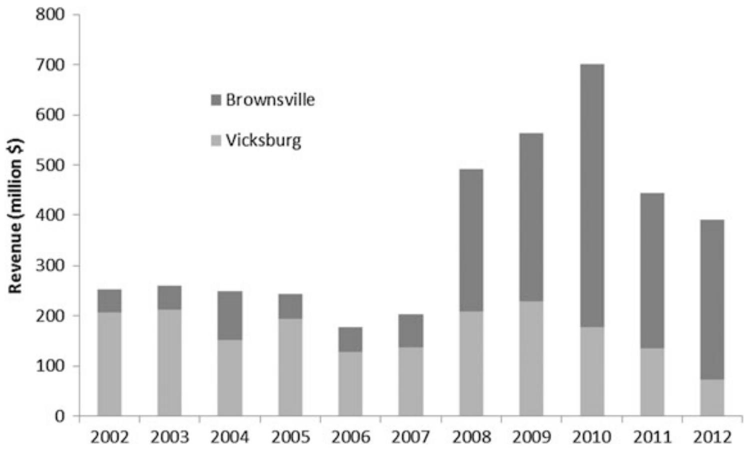

Fig. 15.5 Jackup construction revenue at the Brownsville and Vicksburg shipyards, 2002–2012

Table 15.15 Jackup construction full time equivalent employment, 2000–2010

Productivity	LeTourneau		AmFELS	
($/h)	90	110	90	110
2000	1,146	938	263	215
2001	1,185	970	263	215
2002	837	685	543	444
2003	1,076	880	280	229
2004	711	582	280	229
2005	763	624	374	306
2006	1,154	944	1,570	1,285
2007	1,269	1,038	1,867	1,527
2008	983	805	2,915	2,385
2009	752	615	1,719	1,406
2010	398	326	1,770	1,448

and barring a significant change in market conditions, newbuild work in the yard is unlikely to resume.

15.11.2 Labor Market

U.S. shipyard productivity varies between 90 and 110 $/h of revenue generated for each hour of input labor. Using this productivity range and the 3-year average value of revenue, the total annual employment in the U.S. rig building industry is estimated between 800 and 3,900 (Table 15.15). These employment estimates match anecdotal reports [8, 10], and although small relative to other offshore industries, remains regionally and culturally important [1].

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