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Capital Investment and Operational Decision Making in the Offshore Drilling Industry

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Drilling contractors new build or idle rigs based on market conditions and business strategies. In theory, contractors invest in new building when the expected net present value of adding a rig to the fleet is positive, and idle capacity when the costs of operation are expected to exceed the costs of idling. We developed models of capacity decision making in the offshore contract drilling industry and found that high combinations of day rates and utilization are required to justify new build investment and that idling capacity may be preferred even if daily operating costs exceed daily revenue.

Introduction

Mobile offshore drilling units (MODUs or rigs) are ocean-going vessels used to drill, complete, and workover wellbores in marine environments. MODUs are owned and operated by drilling contractors and are leased to exploration and production (E&P) companies on a day rate basis. Offshore contract drilling is big business, and in 2010, the industry received about $50 billion in worldwide revenue (Rystad Energy 2011).

Contractors increase their fleet size or capability by new building, acquiring assets through the secondhand market, or upgrading their existing fleet. New building is the primary growth strategy for most companies, but the secondhand market is also active. Contractors invest in new building when the expected net present value (NPV) of adding a rig to the fleet is positive and the firm has sufficient cash flows or access to debt to fund investment (Cole 1995; DeLuca 2001). Fleet diversity and the maintenance of high-quality, new rigs enable operators to mitigate exposure to industry downturns because high-quality rigs generally continue operating in depressed markets, whereas older, lower quality units often cannot find work and are taken out of service (Speer et al. 2009).

The decision to invest in new building carries substantial risk because of the large capital expenditures and uncertain future markets (Conway and Will 2006; Cozzolino 1979; Jablonowski and Kleit 2011; Klausner 1969). Contractors reduce new build risk with initial contracts and price discounting. Under an initial contract strategy, the firm does not enter into a construction contract unless the rig has an initial work commitment, mitigating market uncertainty for the first few years of operation. Under a price discount strategy, the contractor builds during periods of low shipyard demand to take advantage of lower

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construction costs and favorable interest rates. Firms may also build under a speculative strategy in which the contractor orders a rig without an initial contract with the expectation that the rig will receive work prior to delivery.

Contract drilling is cyclic and rigs may be idled for significant periods of time. Contractors stack (idle) capacity when the net costs of maintaining an active rig exceed the costs of maintaining a stacked rig. The stacking decision is complex because of the high carrying costs associated with spare capacity, and operating may be preferred to keep the rig active and available for future work even if the firm is losing money by operating the rig. Stacking a rig also removes a unit from the marketable supply and may act to support day rates for the other units in an operator's fleet (Corts 2008).

The purpose of this article is to model capital investment and operational decision making in the offshore contract drilling industry. Inventory management at the firm level amounts to deciding when to increase (new build) and decrease (stack) fleet capacity. The decision is framed by the capital intensity of new building and complicated by the uncertainty governing market conditions. Capacity expansion and idling decisions have a large and significant impact on firm profitability (Karri 2000), and with the exception of Corts (2008), have not been examined in the academic literature.

We begin with an overview of rig classifications and provide background information on the current fleet, new build costs, day rates, and utilization trends in the market. We develop and parameterize a NPV model of the new building decision and examine the effects of a variable utilization rate and an initial contract strategy on break-even day rates and utilization. Sensitivity analysis is performed and the limitations of the analysis are described. A cost–benefit model of the stacking decision is developed and parameterized with market data. Results are presented in graphical form and limitations described. Conclusions complete the article.

Rig Categorization

Rig Class

Mobile offshore drilling units include jack-ups, drillships, and semisubmersibles (Figure 1). A jack-up is a bottom-supported unit 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. Jack-ups are the most commonly used offshore rig in the world and are capable of drilling in water depths up to 500 ft.

Semisubmersibles and drillships are floating rigs used for deepwater (>500 ft) drilling. The semisubmersible (semi) 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, and 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. They are the most advanced and expensive sector of the rig market.

Figure 1. Clockwise from top: the jack-up West Triton, the semisubmersible West Aquarius, and the drillship West Gemini. Source: Seadrill (2012) (color figure available online).

Specification

Rigs are classified as harsh or moderate environment units. Harsh environments are characterized by frequent and severe storms and large wave heights as occur during winter in the North Sea, eastern Canada, and the Arctic Ocean. Elsewhere, moderate environmental conditions predominate, but tropical storms may cause severe weather events, as in the Gulf of Mexico and South China Sea. Harsh environment units have a number of design modifications to decrease weather-related downtime, including increased variable load to reduce the need for resupply and increased air gap to increase wave clearance.

A rig is generally considered high-spec if it can drill in deeper water than other rigs of its class, operate in harsh environments, or drill high-pressure (greater than 10,000 psi), high-temperature (greater than 400°F) wells. In most cases, a jack-up capable of drilling in over 300 to 350 ft would be high-spec. Floaters are typically divided into midwater (less than 4,500 ft), deep (less than 7,500 ft), and ultra-deep (greater than 7,500 ft) categories, with rigs in the deep and ultra-deep categories considered high-spec.

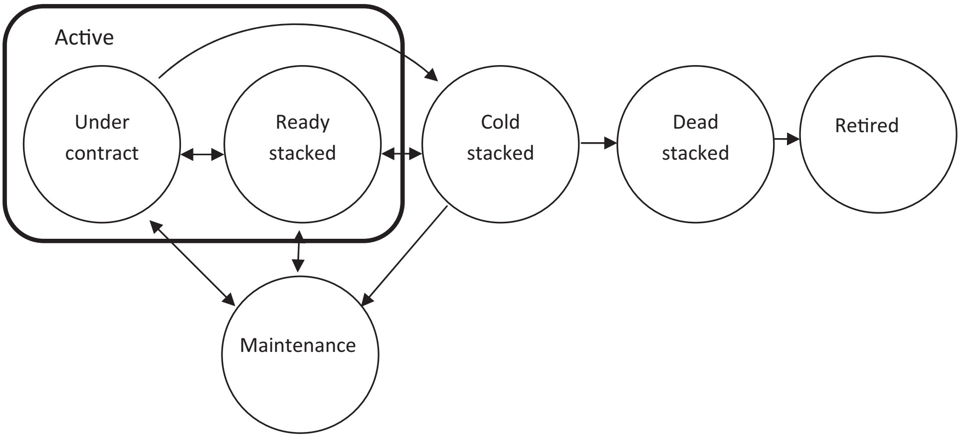

Figure 2. Rig activity states and transition pathways.

Activity States

MODUs transition through a number of activity states over their lifetime (Figure 2). Active rigs may be working under contract or ready-stacked. Ready-stacked rigs are not under contract but are available for immediate use with minor preparation. In a ready-stacked state, normal maintenance operations are performed, most of the crew is retained, and rigs are actively marketed and considered part of marketable supply.

Figure 3. Four cold-stacked rigs in Sabine Pass, Louisiana. Source: Microsoft (2012) (color figure available online).

Inactive rigs may be cold-stacked or dead-stacked. Cold-stacked rigs are not marketed and are stored in a wet dock (Figure 3) and require both capital and time to return to working condition (Mankins 1983). To bring back a cold-stacked rig into an active state, a crew must be rehired and a series of inspection and testing procedures is required, including power, load, and pressure testing; blowout preventer certification; riser and tensioner inspection; and a number of other service checks (Aird 2001). Reactivation expenses vary depending on how long the rig has been out of service. For jack-ups, 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.

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 a rig is dead-stacked. Dead-stacked rigs are used for parts before being retired and may remain in storage for many years before being dismantled and eliminated from the fleet.

Market Status

1Q2012 Fleet Inventory

During the first quarter of 2012, the global offshore drilling fleet consisted of 539 jack-ups and 329 floaters (Figures 4 and 5). The count represents a snapshot in time and includes both active and cold-stacked units. New building increases the count and retirements decrease the inventory. High-spec jack-ups dominate shallow water units, and the floater fleet is

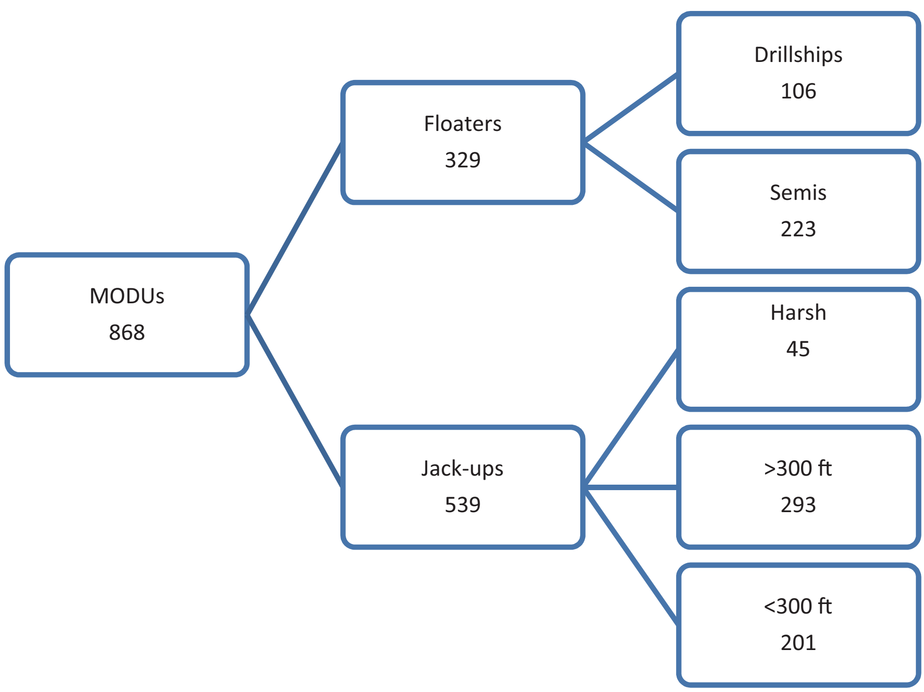

Figure 4. Global supply of MODUs during 1Q2012. Count includes active and stacked units. Source: Data from RigLogix (2011) (color figure available online).

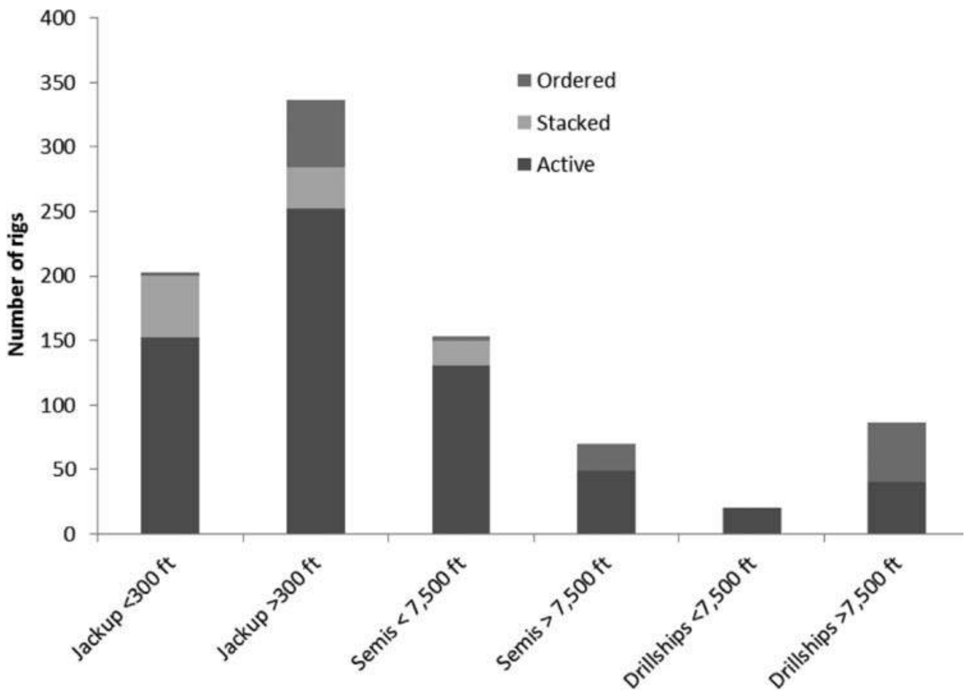

Figure 5. Global supply of MODUs in 1Q2012. Count includes active and stacked units. Source: Data from RigLogix (2011).

dominated by semis (223 semis versus 106 drillships). Drillships comprise the majority of the ultra-deepwater fleet.

New Build Market

Contractors enter into turnkey contracts with shipyards for the delivery of one or more units. In 2010, new builds supplied to the market were valued at $18 billion (Jefferies and Company, Inc. 2011–2012; RigLogix 2011). The major rig-building shipyards include Keppel and Sembcorp in Singapore; Hyundai, Samsung, and Daewoo in Korea; and China Ocean Shipping Company (COSCO) in China (Kaiser and Snyder 2013).

The demand for new build rigs is impacted by demand for drilling services, utilization and day rates, and the age of the fleet. High demand, utilization, day rates, and aging fleets increase new build orders. Historically, the new build industry is cyclic, and between 2000 and 2005 new build activity was low but expanded rapidly beginning in 2006 (Figure 6). Rig supply is relatively inelastic in the short run and demand for new build rigs is primarily impacted by oil and gas prices. As oil prices rise, the net income and capital budgets of E&P firms increase, and drilling demand responds, increasing day rates and utilization and providing a signal to contractors that additional capacity can be absorbed (Carter and Ghiselin 2003). The number of countries open to offshore exploration, geologic prospectivity, capital budgeting, and technological development are also important factors for drilling demand.

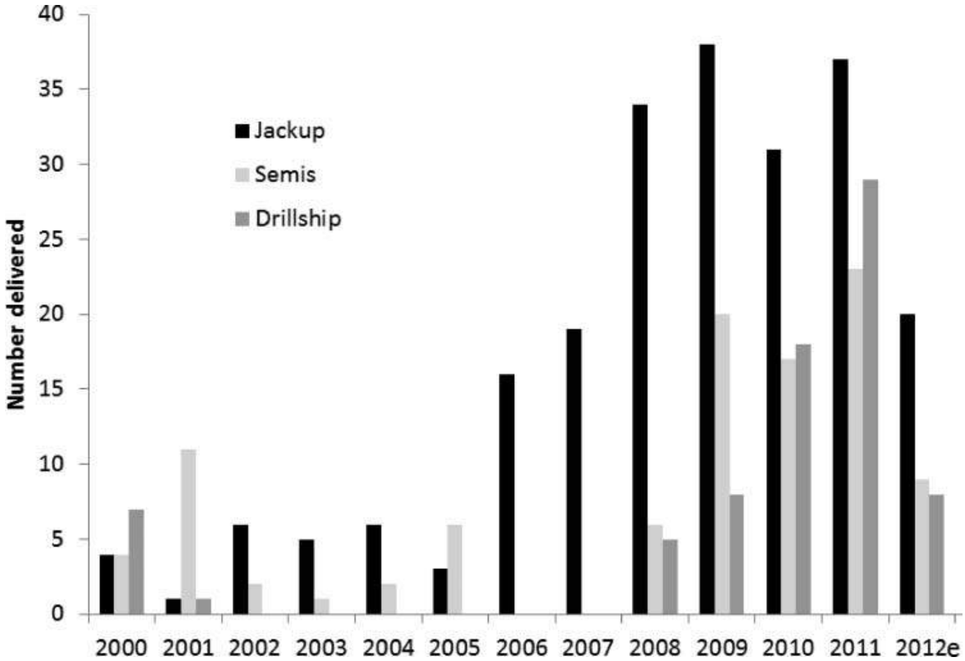

Figure 6. New build deliveries by rig class 2000–2012. Source: Data from RigLogix (2011).

New Build Costs

Rig costs depend on water depth and environmental capabilities, with the most expensive rigs in each class typically being capable of operating in harsh environments and the least expensive rigs typically having low water depth capabilities. In 2012, new build jack-ups cost on the order of $200 million, and semis and drillships cost approximately $600 million (Table 1), but there is wide variation and some jack-ups exceed the costs of some semis and some drillships cost over $1 billion. Construction costs vary over time due to changes in material and equipment costs, labor costs, and fluctuations in shipyard demand (Kaiser and Snyder 2010).

Table 1
Rig construction cost, 1Q2012

	Million $			
Rig class	Average	Minimum	Maximum	Sample size
Jack-ups	217 (73)	159	530	77
Semis	595 (96)	460	809	17
Drillships	634 (92)	550	1,150	47

Note: Standard deviation denoted in parentheses.
Source: Data from Jefferies and Company, Inc. (2011–2012).

Day Rates

Day rates are the primary descriptor of the status of the industry and a leading indicator of new build activity. The day rate is the daily fee charged to lease the rig and includes the cost of the crew but does not include most other costs associated with well construction. Rigs capable of drilling in deep water or harsh environments cost more to construct and operate and, because of their relative scarcity, command higher day rates. Day rates vary by region, class, and time due to the volatility of oil prices and local supply–demand conditions (Figure 7). From 2006 to 2010, average jack-up day rates ranged from $81,000/day in the U.S. Gulf of Mexico to $180,000/day in the North Sea, and average floater day rates ranged from $278,000/day in Southeast Asia to $374,000/day in West Africa. Regional day rates trend together because of the global impact of oil prices on market demand, and floater day rates are typically two to three times jack-up day rates, similar to the construction cost differences.

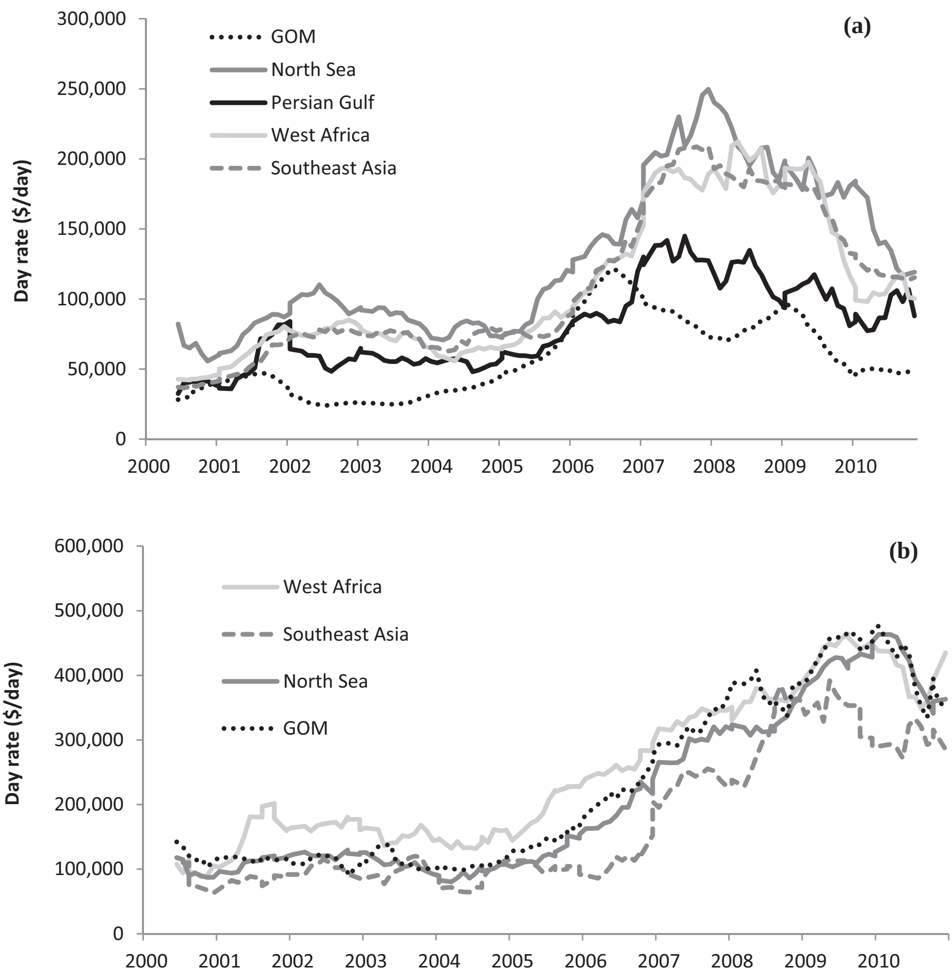

Figure 7. Regional (a) jack-up and (b) floater day rates, 2000–2011. Day rates computed as a 6-month moving average. Source: Data from RigLogix (2011).

Utilization

Utilization is the proportion of available rigs under contract at a given time and place and a measure of spare capacity in the market. At low utilization, spare capacity is high and contractors must offer low prices to win work. As utilization increases, bargaining power shifts from E&P firms to contractors and day rates rise. Contractors relocate rigs into high-utilization regions, reducing interregional utilization differences over the long-term. In general, lower utilization rates indicate a more competitive market, but utilization interacts with regional fleet size and specifications to determine the number of rigs capable of competing for a given contract. From 2000 to 2010, utilization rates in the U.S. Gulf of Mexico jack-up and Southeast Asian floater markets were highly variable and low on a relative basis, but in most other markets, utilization consistently exceeded 80% (Figure 8).

New Build Investment Decision

The economics of new building are conceptualized with an NPV model for a hypothetical rig. We select a jack-up for illustration, but the model works for floaters using a different parametrization. Prior to investment, contractors can reliably estimate the capital cost of the unit(s) and finance terms. Operating expenses are estimated based on historical performance of the rig class, and depreciation schedules are based on current regulations. The primary unknown variables are the future market conditions, specifically the day rate and utilization rate after any initial contract period.

Investment Model

A jack-up rig with an operational life of 25 years is built speculatively without an initial contract. Table 2 summarizes the model variables.

Net Present Value. The NPV of a new build rig is the discounted sum of cash flows over its lifecycle:

$$\mathrm{NPV} = \sum_{t=0}^{t=25} \frac{\text{Net cash flow}_t}{(1+D)^t},$$

where t is the year and D is the company discount rate. Cash flows consist of income generated by leasing the rig minus capital and operating costs and taxes:

$$\text{Net cash flow}_t = \text{Income}_t - \text{CAPEX}_t - \text{OPEX}_t - \text{Taxes}_t.$$

Income. Annual income is the product of the average day rate (DR_t) and utilization (U_t) normalized by the number of days in the year:

$$\text{Income}_t = DR_t^* U_t^* 365.$$

Capital Costs. Capital costs consist of the purchase price C of the rig and an upgrade at 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 $\text{CAPEX}_t = C^* I$, and at $t = T$, $\text{CAPEX}_t = C + C^* I$. When $t > T$, $\text{CAPEX}_\text{t} = 0$.

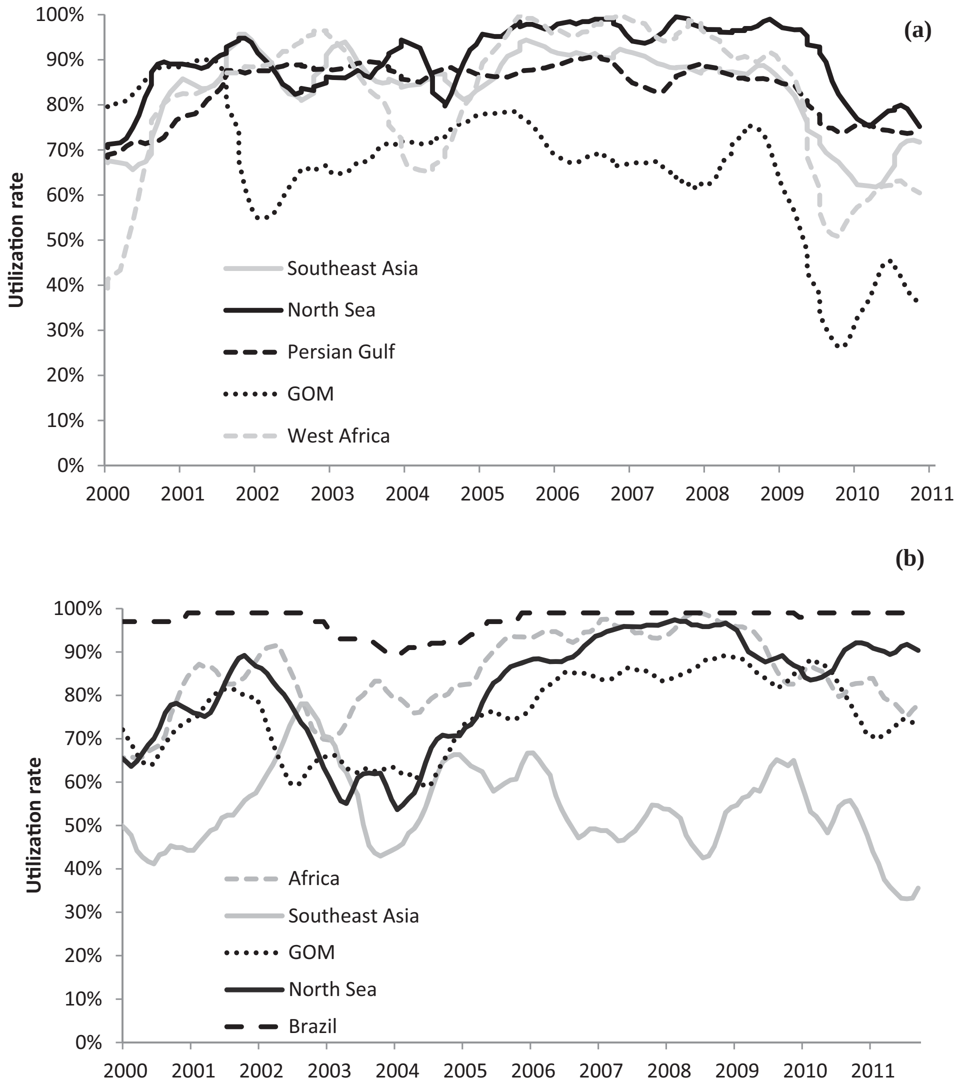

Figure 8. Regional (a) jack-up and (b) floater utilization rates, 2000–2011. Utilization computed as a 6-month moving average. Source: Data from RigLogix (2011).

Operating Expense. 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 we assume that 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). Operating costs in the active state usually range between 4 to 10 times the cost in the stacked mode. Annual operating costs are given by:

$$\mathrm{OPEX}_t = O_a^* 365 \text{ or } \mathrm{OPEX}_t = O_s^* 365$$

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

Table 2
NPV new build model variable definitions

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	Day rate in year t
A	year	Life time of the rig
U_t	%	Utilization rate in year t
U_e	%	Average utilization rate over t
X	%/year	Tax rate
D	%/year	Discount rate

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

$$\text{Taxes}_t = \left(\text{Income}_t - \left(\text{OPEX}_t + C^* I + \frac{C}{25}\right)\right)^* X.$$

After the 25-year life of the rig, the rig is assumed to have no residual value.

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 0 and income begins to be generated in year 1.

Utilization Rate

The offshore drilling market is cyclical, and during periods of low utilization, rigs are stacked to reduce operating costs and to help support day rates for the rest of the company's fleet. We present two models of capacity management referred to as *fixed utilization* and *variable utilization*. In fixed utilization, the rig is never cold-stacked and does not incur reactivation cost. In variable utilization, the rig is cold-stacked when market utilization falls below a given threshold and is brought back to ready status when utilization exceeds the threshold.

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

$$U_t = U_e.$$

Fixed utilization is a simplification of actual operation practices but requires few assumptions and reflects key features of industry models (Cole 1995; Kewo 2005).

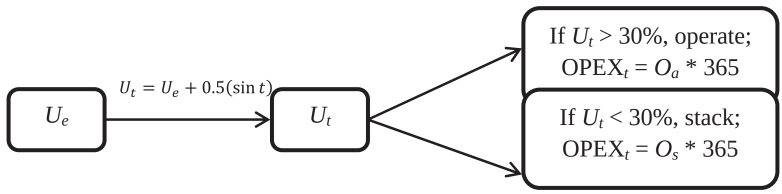

Figure 9. Variable utilization model and stacking decision.

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

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

where U_e is the fixed average rate and U_t is constrained between 0 and 1. The rig is cold-stacked in any year in which U_t falls below 30%. When stacked, utilization is set to 0 and operating costs are reduced (Figure 9). Initially, the rig enters a period of high utilization, consistent with market conditions during a new build cycle, and after the fourth year utilization falls below 30% and the rig is stacked. During the sixth year, the rig is active again and the cycle repeats (Figure 10). The period of the utilization is approximately 6 years and over the course of its 25-year life a rig cycles through four periods of high and low utilization.

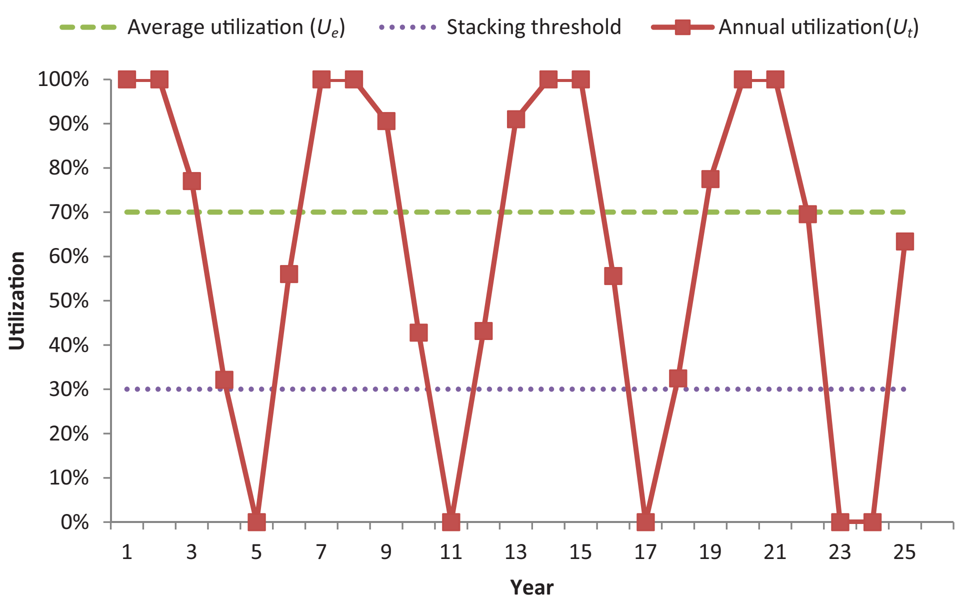

Figure 10. Utilization rate over the rig life cycle in the variable utilization model (color figure available online).

Table 3
New building model parameterizations

Variable	Unit	Expected	Optimistic
C	$	200,000,000	175,000,000
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

Parameterization

The model was parameterized under an expected and optimistic scenario. 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 7 years; and the tax and discount rates are 15% (Morris and Klett 2002). 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%. Additional assumptions are shown in Table 3.

Parameters were chosen based on public information and the annual reports of large firms. The purchase prices 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 4). In 2010–2011, operating costs for stacked jack-ups varied between $6,700 and $12,000/day for Transocean, Hercules, and Diamond, and operating expenses for active jack-ups varied from $32,000 to $58,000/day for standard units and $55,000 to $87,000/day for high-spec units. Stacked costs for floaters are comparable to jack-up units, whereas operating costs are significantly higher, ranging from $104,000 (midwater) to $150,000/day (ultra-deepwater).

Model Results

Break-Even Day Rates and Utilization. The break-even day rates and utilization in the fixed utilization model are depicted in Figure 11. Combinations of utilization and day rates above the lines yield a positive NPV, and values below the lines indicate a negative NPV. As the utilization rate increases, the day rate required to break even on the investment decreases because higher utilization rates translate into greater cash flows. 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 day rates between the optimistic and expected scenarios is $68,000/day; at 90% utilization the difference is $46,000/day. High utilization and day rates are required

Table 4
Stacked and active operating costs for jack-ups and floaters, 2010–2011

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

Source: Firm annual reports.

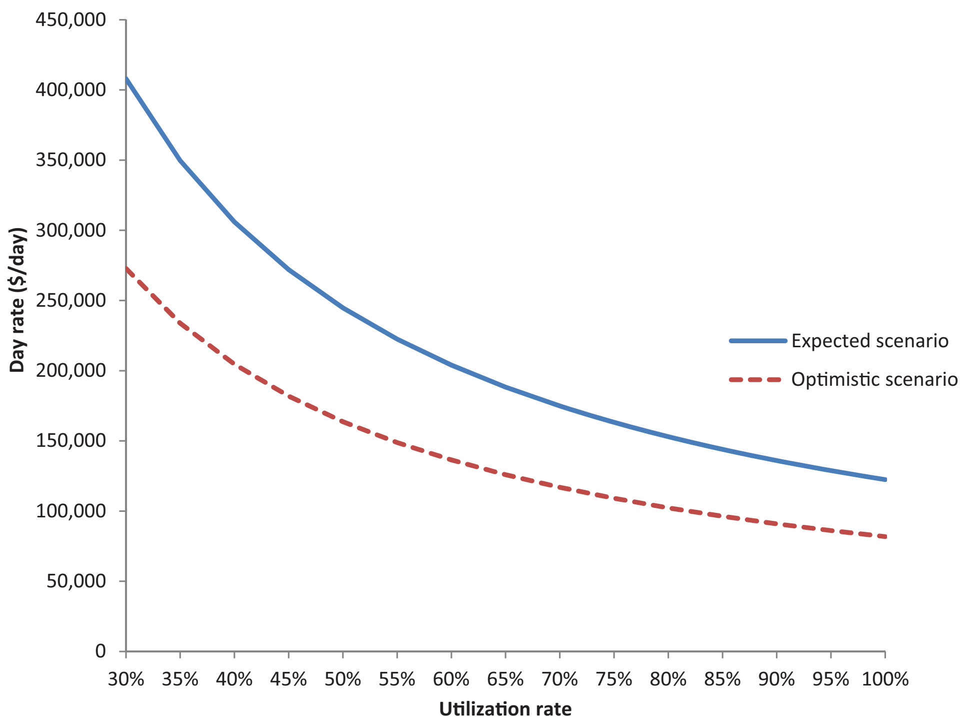

Figure 11. NPV break-even points of utilization and day rates under expected and optimistic assumptions for fixed utilization (color figure available online).

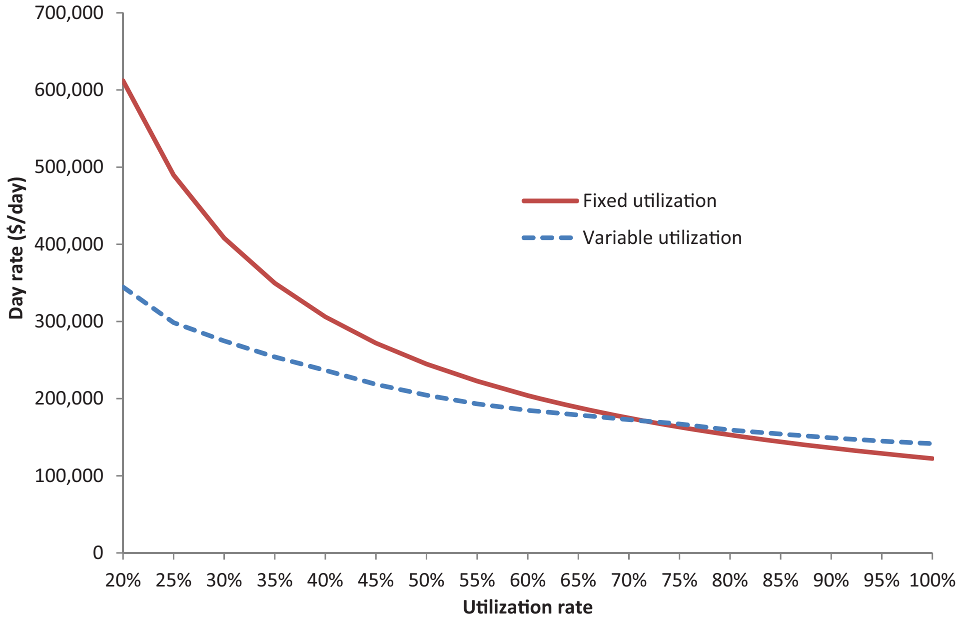

Figure 12. NPV break-even points of utilization and day rates with fixed and variable utilization rates under the expected scenario (color figure available online).

to justify investment. If market participants expect 90% utilization, the break-even day rate is $136,000/day in the expected scenario.

Fixed and Variable Utilization Assumptions. At low utilization, the fixed utilization model requires much higher day rates to justify investment, with the premium ranging from $191,000 to $70,000/day for utilization rates between 25 and 40% (Figure 12). As the utilization rate increases, the difference between the models decreases, and at utilization rates above 72%, the fixed utilization model has a lower break-even day rate than the variable utilization model. This occurs because annual utilization is constrained at 100%, and at high average utilization rates, the sine function in the variable utilization model cannot significantly increase the annual utilization above the average utilization.

Drilling contractors are unlikely to consider building if they believe that future utilization rates will be low, and the left part of Figure 12 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 has a utilization rate of 100%, followed by a fixed utilization for the remainder of its life cycle. At low utilization rates, an initial contract reduces the break-even day rates relative to the fixed and variable utilization models (Figure 13). Differences between the initial contract and fixed utilization models are significantly larger than differences with variable utilization because the variable utilization model implicitly assumes an initial period of high utilization similar to the initial contract.

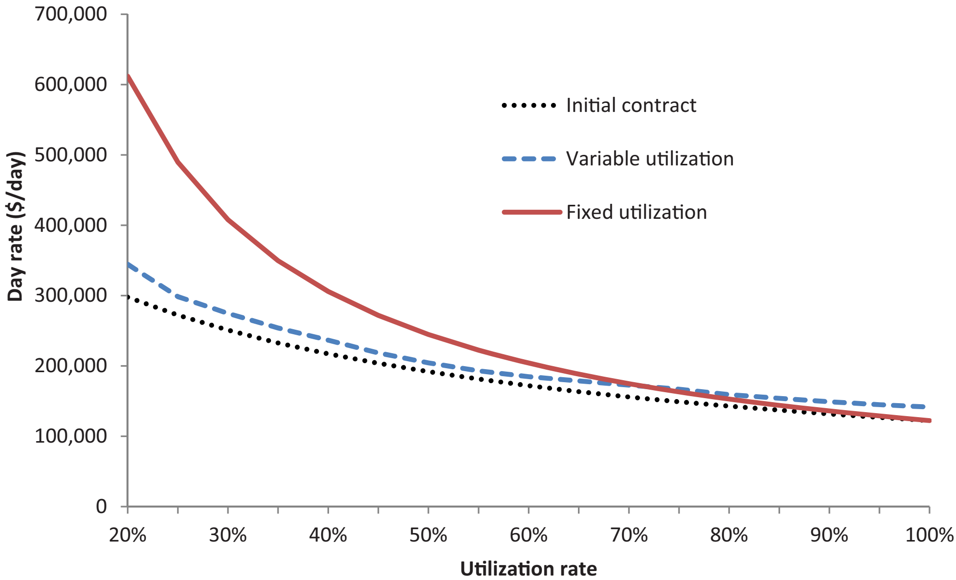

Figure 13. The impacts of an initial 2-year contract on break-even day rates and utilization rates (color figure available online).

At high utilization rates, the break-even day rates of all three models converge, reflecting the fact that initial conditions are less relevant in high utilization environments. At 70% utilization, the break-even day rate of the fixed utilization model is $19,000/day more than the initial contract model, whereas at 90% utilization, the difference is $4,000/day.

Sensitivity

Model sensitivity was assessed by varying a single parameter and holding all other conditions fixed (Figure 14). Results of the fixed utilization model under two utilization rates are shown. Break-even day rates were moderately sensitive to changes in operating and capital costs but relatively insensitive to changes in tax and discount rates.

Each $1,000 increase in the daily operating expenses increased the break-even day rate by $1,300/day at 75% utilization and $1,100/day at 90% utilization. Because operating expenses are a fraction of the day rate, each 10% change in the operating costs increased the day rate by 3–6% over the range examined. Each $10 million increase in the capital cost of the rig increased the break-even day rate 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 day rate.

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

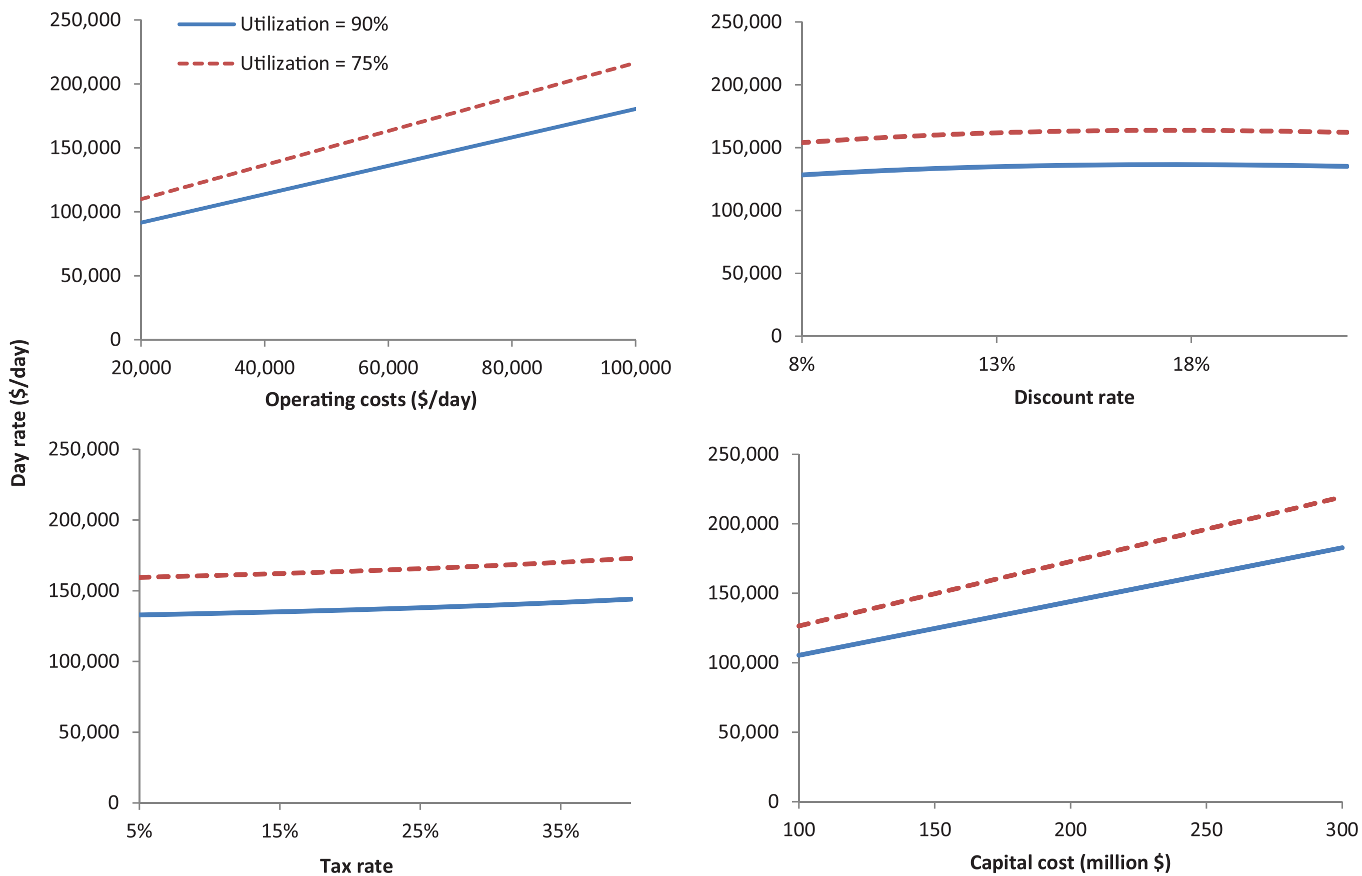

Figure 14. Sensitivity of fixed utilization model to changes in operating costs, discount rate, tax rate, and purchase price (color figure available online).

Limitations

All models are a simplification of reality and the objective of model development is to obtain insight into the business parameters and factors that impact the risk of the investment. Average day rates were employed in model development, but in the real world day rates are variable. In the new build investment model, average day rates were employed, but in reality day rates vary around a mean with a time-dependent variance. Future cash flows are discounted, so if day rates fall below the average early in the rig's lifetime but later exceed the mean, the NPV of the investment will decline. If the near-term future is more predictable than the distant future, and if realized day rates accurately reflect the mean during the first 5–10 years of service, the results of the model are likely to be similar to the actual NPV.

The decision to new build typically results in the net addition of a rig to the fleet, increasing regional supply, and potentially decreasing day rates for the other rigs in an operator's fleet. This is expected to make drilling contractors conservative when evaluating new building decisions. The effects of a small increase in fleet size on day rates and utilization is difficult to detect considering the volatile nature of the market, but the cumulative impact of a number of drilling contractors making similar investment decisions simultaneously is more significant.

Rigs are designed to have operational lives of around 25 years, but rigs often work for 30 years or more, and the oldest active rig in the current fleet is 54 years old. Therefore, significant value remains in the rig after the 25-year design life suggested in the model. No attempt was made to value the rig in the distant future.

The use of a sinusoidal function to model utilization does not incorporate stochasticity, and stochastic models are likely to yield different outcomes than deterministic ones. However, oil and gas markets have been historically cyclical, and a sinusoidal function may more closely represent future market conditions than a stochastic model. In any case, all futures are unknown, so model assumptions regarding future scenarios are all uncertain.

The financing structure of the model 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 day rates and utilization required to justify construction. Many bank loans used in the industry utilize balloon payments at the end of the term and would 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 NPV 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.

Stacking

During market downturns, firms choose to stack or maintain rigs in search of work. Cold-stacking results in lower daily operating costs but provides no opportunity to generate revenue and requires additional capital to return to ready status. Maintaining a rig in active status requires higher daily operating costs but allows contractors to potentially recoup cost through operating revenue when contract work is available. The most profitable strategy minimizes net cost and is a function of the operating costs in the cold-stacked and active condition, costs associated with stacking and reactivating a rig, the potential day rates and utilization rate if the rig is operated, and the time period considered.

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 (OPEX_s), and the costs to reactivate the rig to reenter the market (reactivation costs):

$$\text{Costs of stacking} = \text{Deactivation costs} + \text{Reactivation costs} + \mathrm{OPEX}_s.$$

Deactivation costs, reactivation costs, and operating costs are assumed to be positive.

The net costs of operating consist of the expected revenue received minus the active operating costs (OPEX_a):

$$\text{Net costs of operating} = \text{Expected revenue} - \mathrm{OPEX}_a.$$

Thus, a rig should be cold-stacked if

$$\text{Deactivation costs} + \text{Reactivation costs} + \mathrm{OPEX}_s < \text{Expected revenue} - \mathrm{OPEX}_a.$$

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

$$\text{Reactivation costs} = F + R^* y,$$

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

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

$$\mathrm{OPEX}_s = O_s^* y$$
$$\mathrm{OPEX}_a = O_a^* y$$

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 day rate multiplied by the expected utilization rate and the number of days the rig is idle:

$$\text{Expected revenue} = DR^* U_e^* y$$

where DR is the average day rate and U_e is the utilization rate. Table 5 summarizes the model variables.

Table 5
Stacking model variable definitions

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

Rig Stacking. The cost 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, we force the costs of stacking to be negative, and a rig should be stacked if the costs of stacking are less negative than the costs of operating:

$$-\,(\text{Deactivation costs} + \text{Reactivation costs} + \text{OPEX}_s) > \text{Expected income} - \text{OPEX}_a.$$

For example, if Deactivation costs + Reactivation costs + 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

$$-\,[1,000,000] < 3,000,000 - 3,000,000$$

Parameterization

The model is parameterized for a low-spec jack-up. Low-spec jack-ups are the most common cold-stacked rigs, and reliable 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 time period of analysis. Deactivation costs, the fixed component of reactivation (F), and operating costs (O_a and O_s) are fixed; day rate, utilization, and stacking duration are varied.

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 will be associated with lower direct and indirect costs. Deactivation costs are not typically reported in financial documents, and we assume a fixed cost of \$1,000,000. Reactivation costs for jack-ups 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 jack-ups, active operating expenses are assumed to be \$35,000/day; for a cold-stacked jack-up, operating expenses are assumed to be \$8,000/day (Hercules Offshore 2011).

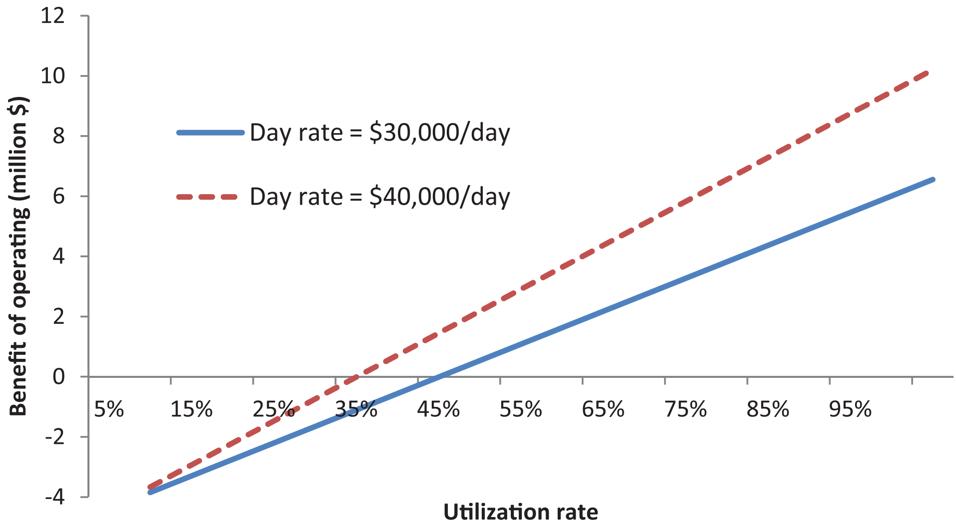

Figure 15. Effect of utilization on the benefit of stacking versus operating (color figure available online).

Model Results

The benefit of stacking a rig for one year at day rates above and below rig operating expense are depicted in Figure 15. Negative values indicate that stacking is the preferred strategy. When the expected day rate 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 day rate 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 day rate is greater than operating costs. Conversely, operating the rig may be preferred even if the day rate is less than the daily operating costs.

The effect of the duration of stacking is shown in Figure 16. Utilization is held constant at 50% for both day rates. At $40,000/day, the rig makes money and stacking is never the preferred option. At $30,000/day, operating the rig is the preferred strategy if adverse market conditions are expected for 500 days or less because of the high fixed costs associated with stacking. If adverse market conditions are expected for more than 500 days, stacking is the best strategy.

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 day rates higher for the rest of its fleet. Corts (2008) studied the stacking decisions of contractors from 1998 to 2000 and found that large firms stack and reactivate rigs more frequently than smaller firms. He attributed this observation to lower reactivation costs for large firms 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.

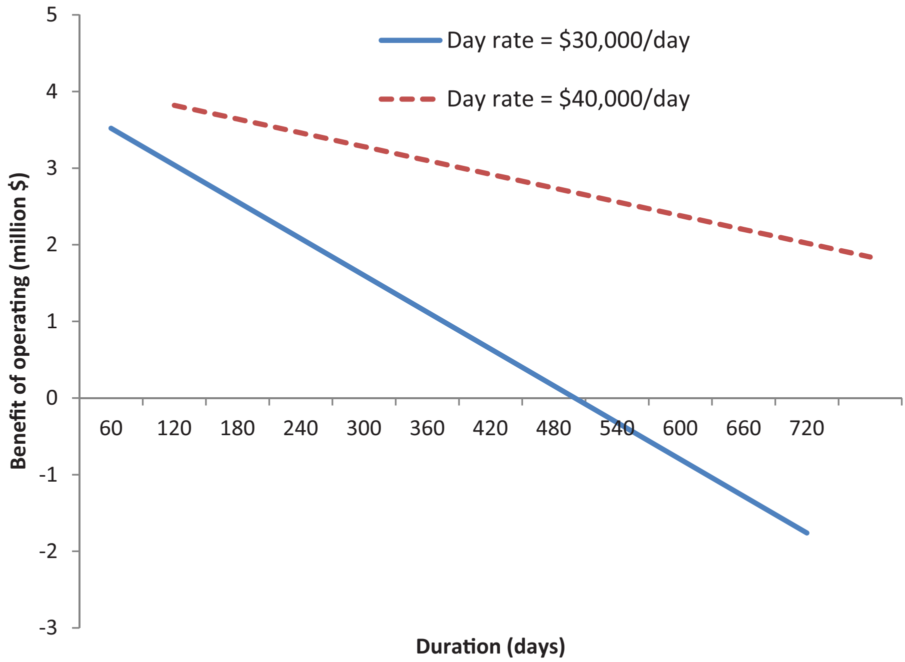

Figure 16. Effect of duration on the benefit of stacking versus operating (color figure available online).

Faced with an underutilized rig, firms have the option to continue to operate the rig, stack the rig, move the rig to another market to seek work, or sell the rig. The costs and benefits of moving or selling a rig were not examined. Moving an underutilized rig to a high-utilization region may result in improved cash flow but is complicated because contractors typically attempt to operate multiple rigs in a region to capitalize on economies of scale and build 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 underutilized asset in a depressed market.

The duration of the stacking decision was modeled by assuming that a firm evaluated a stacking decision over a specific period of time. That is, we addressed the question “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.

Conclusions

New building requires high day rates and utilization to justify construction; thus, new build activity is a direct reflection of management’s expectation of the future market conditions. In the model environment considered, a day rate of $136,000/day at 90% utilization is required to break even on a $200 million capital investment. The variable utilization model is more complex and requires more assumptions than the fixed utilization model, but for market conditions that lead to decision making the fixed utilization model may be adequate for modeling capital investment.

Stacking decisions are complex and depend upon future market conditions. Operating capacity may be the preferred strategy even if daily operating expenses exceed the day rate because of the high carrying costs of spare capacity.

Stacking and new build decision-making models were developed to illustrate the primary factors and the value of future conditions. Though quantitative models may aid in decision making, future market conditions are uncertain and impossible to predict with confidence. Therefore, the contractor's ability to divine future day rates and utilization remains the primary constraint in decision making and the ultimate source of risk.

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