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Transaction Costs and the Value of a Good Reputation: Evidence from the Offshore Drilling Industry

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Executive Summary

This report investigates the role that reputation plays in the determination of transaction costs and contracting outcomes in the offshore oil and gas drilling rig market. The analysis specifies a novel economic model of drilling rig contracting, and estimates econometric models on an original data set to test hypotheses about the factors that determine contracting outcomes. The analysis and results indicate that oil companies capture benefits from drilling contractors with good reputations in the form of reduced transaction costs and lower total costs of transactions. Drilling contractors with good reputations enjoy benefits in the form of increased cost competitiveness which are anticipated to manifest as larger utilization rates for their respective rig fleets.

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INTRODUCTION

In the transaction cost literature, reputation has been shown to be an important factor in contracting outcomes. The purpose of this report is to examine the relationship between reputation and transaction costs in the offshore oil and gas drilling rig market. The investigation focuses on contracts between oil companies and drilling rig contractors, and the role of drilling contractor reputation on contracting outcomes. An economic model of rig contracting is specified which provides insight into the comparisons and choices made by oil companies, and what these choices indicate regarding transaction costs. An econometric model is estimated to test hypotheses about drilling contractor reputation, and other relevant variables, on actual market outcomes. This research provides new evidence on the existence of the reputation effect, the scale of the effect, and whether there are material differences between firms.

The report is organized as follows. The first two sections describe the structure of the offshore drilling industry and the subject market. The relevant transaction costs are then described, focusing on how they manifest in drilling rig contracting, and how reputation can play a moderating role. The following section specifies an economic model of rig contracting that describes the role of transaction costs in contracting outcomes. Dependent and independent variables are then defined, and the econometric models are specified and estimated. The final two sections present the results and conclusions.

OFFSHORE DRILLING RIG MARKET

Subsurface oil and gas deposits are developed in offshore hydrocarbon basins around the world by national oil companies, public or private oil companies, or some combination thereof. To develop these deposits, drilling rigs (rigs) are required to drill wells such that the oil and gas can be produced from the subsurface reservoir to the surface and be routed to subsequent stages of processing and refining. Some rigs are owned and operated by oil companies such as Petrobras of Brazil and the China National Offshore Oil Corporation. However, most rigs are owned and operated by specialized drilling contractors and marketed to oil companies.

In addition to rig ownership structure, the rig market is defined by a collection of sub-markets based on geography, physical environment, and rig type. For example, there are material differences between operating a rig in the North Sea versus West Africa (e.g. weather, support logistics, personnel). Also, within one geographic area, drilling operation environments can range from shallow water marshes to deep water exceeding 10,000 feet. Different types of rigs are used in each of these sub-markets. Given this market complexity, and given the purpose of this study, it is not necessary to analyze the entire global rig market to test transaction cost hypotheses. Thus, this study focuses on the Gulf of Mexico jackup rig sub-market. Constraining the scope in this way significantly reduces the analytical effort and data collection costs which would be incurred to identify and control for all the differences between sub-markets.

JACKUP RIGS AND PRICING

Jackup rigs are large barges equipped with vertically adjustable steel legs. All the equipment and storage capacity required to drill an offshore well are contained on or in the barge. During mobilization to a drilling location, the barge is in the water, and the legs are out of the water. The rig is towed by tugboats to the drilling location. Using a jacking mechanism, the legs are lowered until they contact the seafloor. The jacking process continues until the barge is elevated above the water's surface, and the rig can then act as a stable platform for drilling operations (Schempf, 2007).

Jackup rigs are differentiated from each other, technically and economically, primarily by operating limits with respect to water depth. Simply put, some rig designs are optimized and rated to drill in shallow water while other rigs are rated to drill in deeper water. While rigs rated for deeper water can drill in shallow water, rigs rated to drill in shallow water cannot drill in deeper water. The highest rated jackup rigs can work in water depths of up to ~550 feet while the lowest rated rigs may be constrained to 225 feet maximum water depth.

In the Gulf of Mexico, most rig contracts employ a "day rate" structure. In a day rate contract, the drilling contractor provides (to the oil company) a drilling rig and crew for a fixed fee per day of use. Typically, no other services or goods are included in these contracts. The market is made through competitive tendering processes or negotiation. Contract durations for jackup rigs can be for one well or multi-well campaigns. Day rates are directly related to a rig's water depth capability or rating. That is, rigs that are rated to drill in deeper water earn higher day rates (Kaiser and Snyder, 2012).

TRANSACTION COSTS AND REPUTATION IN DRILLING

Coase (1937) proposed that transaction costs such as discovery or information costs, contracting costs, and (implicitly) the costs of bounded rationality, contribute to the structural outcomes of markets and organizations. These outcomes were believed to depend on explicit managerial choices made after a comparison of the total costs of competing options. Coase's propositions were largely unattended until Williamson presented a refined perspective on vertical integration and the values of internal organization in a series of influential articles (Williamson: 1971, 1983, 1985, 1986). Williamson formalized the hypothesis that firms economize on transaction costs and explored the firm's organizational choices as institutional questions. Most importantly perhaps, he proposed a paradigm that treated the firm as a governance structure rather than a production function (Williamson, 1999). After Williamson, the field of transaction costs matured rapidly as investigators identified, categorized, and empirically examined transaction costs, including differences in production efficiency, contracting costs, monitoring costs, information costs, technology transfer costs, and internal coordination costs, *inter alia*. A full review of this literature is beyond the scope of this report (see Masten (1996), Shelanski and Klein (1999), and Macher and Richman (2008) for comprehensive summaries of the transaction cost literature).

The Reputation Effect

In the transaction cost literature, the definition of reputation can be summed up as *what one party believes about how another party will behave in a transaction*. Reputation has been shown to be an important factor in transactions when information about behaviors is good, when a long-term relationship is desired, or when there is an expectation of repeated interaction (Joskow, 1985; Williamson, 1986; Allen and Lueck, 1992; Besanko *et al.*, 1996), all conditions which typically hold in the offshore drilling industry (Corts and Singh, 2004; Jablonowski and Kleit, 2011). A “good” reputation would be characterized by traits such as trustworthiness, fairness, reliability, etc. Good reputations can reduce transaction costs, and this reduction is a source of competitive advantage and can affect buyers’ willingness to pay (Creyer, 1997; Burke, 1998; Bromiley and Harris, 2006; Rindova and Martins, 2012; Helm, 2013).

The remainder of this section describes the subset of the transaction costs that occur in offshore rig contracting, and the role that reputation can play in reducing these costs.

Monitoring Costs

A moral hazard exists when one party can act in its own interest to the detriment of the other and without the other party’s knowledge (asymmetric information in the form of hidden action) (Brickley and Dark, 1987; Besanko *et al.*, 1996). Under a day rate contract, the oil company designs the well and the drilling contractor executes the plan. The oil company provides general guidance during execution, makes all major decisions regarding the progress of the well, and holds all of the risk. The drilling contractor is not a residual claimant to any oil and gas revenue and thus its incentives are not necessarily aligned with the oil company’s goal of maximizing the net present value (NPV) of the well. For example, consider a case where the drilling contractor makes a mistake and causes reservoir damage, but does not report the mistake to the oil company and the oil company does not otherwise observe it. The primary potential consequence, that is, sub-optimal production and a reduction of NPV, will not be observed until the well is produced. In this case it would be practically impossible for the oil company to connect the consequence to the cause.

The existence of moral hazards in drilling operations creates an incentive for the oil company to monitor the drilling contractor's performance by placing one or more of its employees or agents on site, and/or by installing monitoring technology such as cameras and sensors. These monitoring resources are costly, and the magnitude of the oil company's investment in monitoring is expected to be related to the quality of the drilling contractor's reputation. That is, if the drilling contractor's reputation is good, less will be spent on monitoring. It is not expected that the operator's reputation would affect monitoring costs.

Contracting Costs

The oil company and drilling contractor incur costs to create a contract that documents the technical and economic terms of a transaction. Both parties have an incentive to write a detailed and complete project. However, because of uncertainty, information asymmetries, and bounded rationality, it is not possible to construct a complete contract that includes all relevant information and all possible contingencies. Contracts reduce the risk of transactional opportunism but do not eliminate it (Kronman, 1985). Therefore, in addition to the initial costs of creating a contract, the parties can expect to incur additional costs to renegotiate and resolve issues ex post that were not itemized in the contract ex ante (Williamson, 1985; Crocker and Reynolds, 1993; Burke, 1998; Jablonowski and Kleit, 2011).

If the parties have good reputations for fair dealing (e.g. following norms and precedents), the ex post issues can be expected to be resolved efficiently. A company's reputation for trustworthiness builds confidence and is important in situations with high levels of uncertainty (Shapiro, 1982, 1983; Gürhan-Canli and Batra, 2004). In fact, addressing some contingencies *after* they occur may be economically optimal when compared to the alternative of attempting to add detail ex ante. In this way, good reputations can reduce contracting costs on both sides of a transaction for both parties (Crocker and Reynolds, 1993). In other words, a good reputation acts as a form of performance bond, giving both parties some degree of confidence that a mutually agreeable solution will be identified (Dowling, 2016).

Information Costs

Adverse selection is a term that describes a case where one party possesses information that it can use to craft a contract in its favor (asymmetric information in the form of hidden information). Empirical analysis of the influence of information asymmetries on transaction costs can be found in Leffler and Rucker (1991) and Leffler *et al.* (2000). In the offshore drilling industry, the drilling contractor has intimate knowledge of the condition of its rig equipment and systems, the experience of its personnel (both office- and rig-based), the current and planned assignment of rig-based personnel across its fleet, and other information. The oil company desires this information because these factors can affect the performance of the rig, the ultimate cost of the well, and perhaps safety and environmental performance.

This case of asymmetric information in favor of the drilling contractor creates an incentive for the oil company to invest in collecting the aforementioned information prior to every well or multi-well contracting decision. But such a collection effort is a costly undertaking and requires skilled oil company and/or third-party personnel and adequate time to conduct the work. Therefore, in cases where the drilling contractor has a good reputation, the oil company will spend less cost and time collecting this kind of information prior to making contracting decisions.

Technology Transfer

Firms often possess proprietary technology and know-how that yield a competitive advantage. When firms interact, there can be potential for technology transfer depending on the quality of interaction between the parties. Any undesired technology transfer that does occur is itself a transaction cost (Teece, 1983; Oxley, 1997).

When an oil company drills a well, some of its proprietary technology and know-how may be deployed in the design of the well and/or in the operational procedures. For example, an oil company may have developed specialized techniques to efficiently design and drill wells with an unusual, complex characteristic. During the drilling of the well the drilling contractor will observe and learn about the oil company's techniques and then may share this knowledge, intentionally or unintentionally, with other oil companies on future projects and thus dissipate some or all of the oil company's competitive advantage.

An at-risk party will attempt to mitigate technology transfer risk contractually, and confidentiality agreements and non-disclosure agreements are often employed for this purpose. But compliance with these types of agreements is costly to monitor and enforce. In summary, if the drilling contractor has a good reputation, it will decrease the oil company's expected technology transfer costs, and its contracting and monitoring costs.

Productivity

Drilling contractors exhibit different productivities, and under a day rate contract the oil company obtains the benefits or costs of this productivity. This difference in productivity is a transaction cost and can be used by the oil company in its cost comparison of competing options (Teece: 1978, 1980; Joskow, 1985; Masten *et al.*, 1991). While differences in productivity are a transaction cost, the drilling contractor's reputation is unrelated to the oil company's expectation of this cost. Thus, it is possible that a particular contractor with a bad reputation (and large reputation-related transaction costs) could consistently win business if its productivity is large enough. Likewise, a driller with a good reputation and small productivity may not be consistently competitive. Unless this effect is controlled for, it may bias the estimation of the relationship between premiums and reputation-related transactions costs, and a result for a particular drilling contractor may reflect its productivity rather than its reputation.

CONTRACTING ECONOMICS

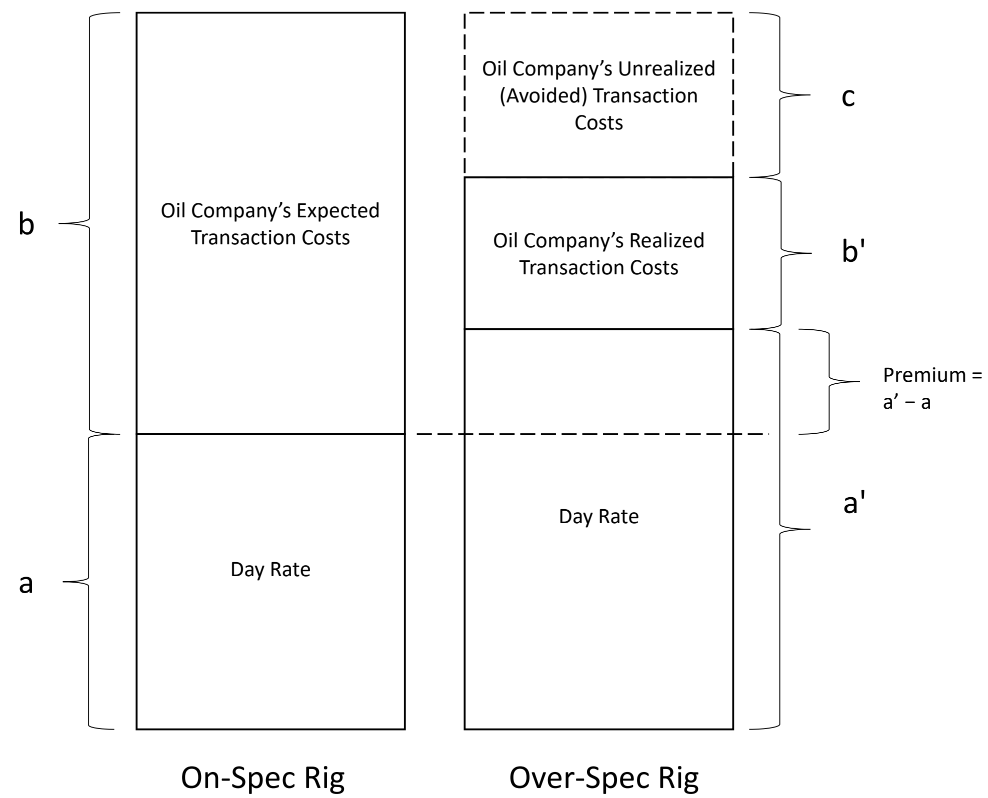
Oil companies desire to procure the least expensive rig that is physically capable of performing the work. When an oil company successfully contracts for the least expensive rig that can drill a well, based on the water depth at the well location, it is classified in this study as "On-Spec" which is short for "on specification." When an oil company contracts for a more expensive rig than is required to drill the well, it is classified as "Over-Spec" which is short for "over specification." There are other distinctions in functionality between rigs that can affect the day rate, but these day rate differences are typically small relative to the differences attributable to the water depth rating. Therefore, except for water depth rating, rig functionality is treated as homogenous.[1]

The major cost components of a rig contract incurred by an oil company when contracting with an On-Spec rig consist of the day rate and the oil company's internal transaction costs, and these are depicted on the left-hand side of Figure 1. When an oil company contracts with an Over-Spec rig as depicted on the right-hand side of Figure 1, it implies that the oil company's expected *total cost* of the transaction with the Over-Spec (larger day rate) rig is less than the expected *total cost* of the transaction with the On-Spec (smaller day rate) rig, i.e. when $a' + b' < a + b$ ($\rightarrow c > 0$). The oil company's expected transaction costs with the On-Spec rig decompose into three parts for the Over-Spec rig: (i) the difference in the day rate or "premium:" $a' - a$; (ii) the oil company's realized transaction costs: b'; and (iii) the oil company's unrealized (avoided) transaction costs: c. Under these conditions the oil company's realized transaction costs are necessarily decreased relative to the expected transaction costs. That is, the oil company chooses the Over-Spec rig when: $a' + b' < a + b$. Rearranging terms: $a' - a < b - b'$. Therefore, if $a' - a > 0$ (a premium is being paid), then $b - b' > 0$.[2]

[1] There is a subtle exception to this assumption that is addressed in the specification of the dependent and independent variables.

[2] Items such as consumables (e.g. fuel costs) and third-party costs (e.g. marine logistics) are not shown because they are assumed to be equal for the On-Spec and Over-Spec rigs.

Figure 1. Cost Components of a Day Rate Drilling Rig Contract



This structure also indicates that larger premiums are associated with larger decreases in the sum of realized and unrealized transaction costs. Therefore, the premium is an indicator of both the existence and the scale of impact on transaction costs when contracting with an Over-Spec rig. And as previous research indicates, and as argued above, a drilling contractor's reputation is hypothesized to be a primary factor in determining transaction costs. This indirect approach to transaction cost analysis is necessary because oil companies do not document or report these transaction costs for the selected option or the unselected options(s).[3]

To be clear, use of the word "premium" in this context reflects the oil company's perspective. The benefit to the oil company when using an Over-Spec rig is a lower total cost of the transaction. The drilling contractor that successfully contracts an Over-Spec rig obtains the day rate it would have obtained had the rig been contracted in an On-Spec application. Thus, the benefit to the drilling contractor (with a good reputation) is that it can compete its Over-Spec rigs against On-Spec rigs, essentially enlarging the size of its market, notwithstanding the disadvantage an Over-Spec rig carries with its larger day rate.

It is acknowledged that the day rate for a transaction also may depend on the drilling contractor's internal transaction costs when transacting with a specific oil company.

[3] The exception to this condition is productivity, which is observed and modeled directly.

That is, reputations may differ among oil companies in the same way they differ among drilling contractors. However, given the risk allocation in a drilling contract (i.e. almost all risks are held by the oil company), the oil company's transaction costs are assumed to dominate contracting outcomes. Therefore, no attempt is made to control for the oil company's reputation in this investigation.

This economic model is anticipated to govern most contracting decisions. That is, one should expect an oil company to choose the lower total cost alternative when possible. However, in a small number of cases, an oil company may have to choose a higher total cost alternative because of some market or operational constraint. That is, it is possible in some contracts that $b' \geq b$. Therefore, if one is to interpret the premium as an indicator of transaction cost phenomena as asserted here, then the potential for these constrained outcomes should be controlled for explicitly if possible.

THE PREMIUM

The premium is specified as the dependent variable and is derived as follows:

1. The water depth at the drill site is observed, along with the date that drilling began.
2. Based on the water depth and date, the rig type and day rate of the least expensive rig capable of drilling in the observed water depth is noted as the On-Spec day rate.
3. The rig type and day rate of the actual rig used to drill the well is noted as the actual day rate.
4. The premium is computed as the actual day rate minus the On-Spec day rate. By definition, the premium is greater than or equal to zero.

There are subtle implications of this derivation of the premium because some rig selection-relevant information about each well location is not readily observable in available databases. As described, the derivation selects the least expensive day rate *based on water depth alone*. However, there are other location-specific constraints that may force the oil company to select a rig with more expensive attributes than one that would have been selected based on water depth rating alone. The two most important of these attributes are whether a rig is a (i) slot or cantilever design, and the second is whether a rig has a (ii) mat or independent leg design. The technical description of each of these rig attributes, and the various rationale for why an attribute may be required for a specific well location, are beyond the scope of this report. Instead, it is sufficient to acknowledge that for any given water depth rating, cantilever designs and independent leg designs (i.e., higher functionality rigs) earn larger day rates than slot or mat designs, *ceteris paribus* (Kaiser and Snyder, 2012).

The implication of this aspect of rig selection and the available data is that when the actual rig used on a well exhibits one or both of the more expensive attributes that is not already captured in the On-Spec day rate, it is not possible to say whether that attribute was required because of location-specific constraints, or whether the rig was selected for another reason (e.g., reputation and lower total costs). In other words, if the more expensive attribute was in fact required, then the premium as derived above would be biased upward. To the degree that such instances are randomly distributed across all drilling contractors, they would not affect the relative ranking of the drilling contractors in terms of the estimated magnitude of premiums earned, although they would affect the magnitude of the coefficient estimates. One option to deal with this potential bias in the premium is to assume that when a rig with a more expensive attribute is used, that it was required for the well in question. However, this approach only changes the direction of the potential bias from upward to downward. Another treatment is required to control for this potential observational bias in the premium and is described in the definition of market and operational hypotheses.

HYPOTHESES AND INDEPENDENT VARIABLES

Reputation and Transaction Costs

Reputation Effect. As previously stated, an indirect approach is necessary to test transaction cost hypotheses because oil companies do not document or report transaction costs. Also, drilling contractor reputations are not observable. Therefore, the strategy employed here is to model the impact of reputation on transaction costs using a proxy variable. There are seven drilling contractors represented in the data set, and each one is represented with a binary variable. These drilling contractor variables are intended to provide evidence on the reputation effect on transaction costs and thus on premiums. The purpose is to discover which drilling contractors provide a transaction cost-reducing impact, and which drilling contractors provide more (or less) impact than others.[4]

This specification for estimating reputation effects is robust to cases where (i) there is some type of availability constraint, that is, when there are no or few On-Spec rigs available, and (ii) for cases where a drilling contractor's fleet is weighted toward deeper water rated rigs. In such cases, the oil company must choose between two or more Over-Spec rigs (and likely two or more drilling contractors) and the prevailing model holds—the drilling contractor with the better reputation (lower transaction costs) will earn premiums more frequently. Also, the effect of availability-related factors on premiums is controlled for separately as described below, thus the binary variable is construed to estimate the (residual) marginal effect of reputation on premiums.

[4] The drilling contractor company names are masked to protect the competitive value of this research to a client organization.

Productivity. As previously stated, drilling contractors exhibit different productivities and this transaction cost may influence contracting outcomes. To control for this effect, productivity is modeled using the rate of penetration (ROP), which is defined as the average number of feet drilled per day (for activities that involved drilling). For drilling activities where the footage was not reported, and for activities that did not involve drilling, the value is null. It is assumed that the ex post productivity is an unbiased proxy for the estimated productivity used in oil company decision-making (exogenous). Table 1 provides a summary of the productivity of each drilling contractor.

Table 1. Productivity of Drilling Contractors Measured by Rate of Penetration (ROP)

Drilling Contractor	Mean Feet per Day (Standard Deviation)	Sample Size
V	226 (35)	12
N	292 (30)	23
B	312 (27)	37
R	348 (40)	36
C	465 (67)	37
H	501 (93)	33
J	370 (40)	23

Market and Operational Hypotheses (Controls)

As previously stated, there can be cases when an oil company chooses to use an Over-Spec rig because of some market or operational constraint, rather than because of the drilling contractor's reputation and smaller transaction costs. Four of these cases and the associated hypotheses and independent variables are described in this section.

Timing. Oil companies occasionally experience emergencies, unexpected well intervention activity, competitive drainage situations, or other situations that prioritize speed over economy. But collecting and controlling for this type of detailed information at the individual activity level is not practicable. In addition, it is not believed to be necessary to explicitly control for this effect because these events are known to constitute a small proportion of rig activity, and these events can be assumed to be randomly distributed across oil companies and drilling contractors. For these reasons, the lack of an explicit control for this effect is anticipated to introduce only an immaterial upward bias in the premium estimates.

Rig Utilization. It is believed that in periods with large utilization rates (small excess capacity), it is less likely that oil companies succeed in their search for an On-Spec rig and thus are forced to contract with an Over-Spec rig. It is also expected that in periods with large utilization rates, where drilling contractor bargaining power is relatively large, drilling contractors take actions to maximize premiums. This could take the form of strategic deactivation and reactivation of specific rig types (and the timing thereof), limiting what rig types are offered to different operators, limiting what time periods are offered, etc. To control for these potential effects on premiums, the utilization rate for the Gulf of Mexico jackup drilling rig fleet is specified as an independent variable.[5]

It is acknowledged that timing and utilization effects may impose a joint effect on premiums. For example, it is probably more likely to be constrained to use an Over-Spec rig if a timing-related event occurs in a period of large utilization. To the degree that this overlap exists, the utilization variable will capture some of the (uncontrolled-for) timing effect and thus mitigate some of the upward bias in the premium estimates.

Multi-Well Campaigns. Oil companies can obtain benefits by contracting with one rig for multi-well campaigns. These benefits accrue from, for example, establishment of engineering norms, improvements in communication, and learning curves for wells with similar attributes. When an oil company desires to contract a rig for a multi-well campaign, the selected rig must be rated to operate on the well in the campaign with the deepest water depth. This requirement may cause the rig to be classified as Over-Spec for campaign wells in shallower water (i.e., a premium will be observed). Thus, when considering a multi-well campaign, the oil company will compare the aforementioned benefits to the costs of some of its wells being serviced by an Over-Spec rig, and in some case the benefits may exceed the costs. Therefore, it is anticipated that premiums are more likely to be observed in multi-well campaigns. This variable is defined as the total count of consecutive activities on a rig for each oil company-drilling contractor engagement.

Market Power. Economic theory suggests that an increase in market concentration can result in market power and higher prices. When markets are concentrated, the more likely it is that firms can coordinate their activities and maintain prices above competitive levels. It is also theorized that prices can exceed competitive levels without explicit coordination, for example, in a Cournot equilibrium.

The Herfindahl-Hirschman Index (HHI) is often used as a measure of market concentration.[6] The effect of market concentration on day rates in the offshore drilling rig market has been demonstrated in Lee and Jablonowski (2010) and Onwuka *et al*. (2014). A premium, if one exists, constitutes part of the day rate and thus the concentration effect should be modeled explicitly. However, the data set

[5] See Lee and Jablonowski (2010), Kaiser and Snyder (2012), and Onwuka *et al*. (2014) for evidence on the effect of utilization rates on day rates.

[6] HHI is defined as the sum of the squares of market shares of all participants in the market, $HHI = \sum_{i=1}^{N} x_i^2$, where x_i denotes the market share, in percent units, held by firm i and N denotes the total number of firms in the market. HHI is the most widely used measure of market concentration in research and governmental regulatory agencies (for examples see Calkins (1983), Rhoades (1995), Hannan (1997), Pilloff and Rhoades (2002), Lee and Jablonowski (2010), and Onwuka *et al*. (2014)).

organized for this study represents only a sample of the market and thus it is not possible to construct an accurate HHI index. As a second-best alternative, the water depth (in feet) of the drilling location is employed as a quasi-HHI. This is a plausible alternative in this context because there is a monotonic relationship between water depth and the number of firms and rigs that can compete for any well or campaign (see Table 2). Also, binary variables are defined and used to investigate the discrete impacts of water depth thresholds at 250, 300, and 350 feet where significant changes are observed in the number of firms and/or rigs.

Observational Bias in the Premium

Two variables are defined to control for potential bias in the dependent variable previously discussed. Consider a case where the On-Spec rig (least expensive based on water depth alone) is a slot rig, but the operator is observed to use a more expensive cantilever rig with the same water depth rating. As explained above, it is ambiguous whether the more expensive rig was required because of a location-specific constraint at the drill site, or if it was selected because of lower total costs. A binary variable CANT is defined that takes a value of 1 when there is a difference in the slot/cantilever attribute between the On-Spec rig and the actual rig, and 0 otherwise. Likewise, a binary variable IND is defined that takes a value of 1 when there is a difference in the mat/independent attribute between the On-Spec rig and the actual rig, and 0 otherwise. The coefficient estimates of these variables represent the average marginal impacts of these attributes on premiums.

Table 2: Number of Rigs and Contractors in Market based on Water Depth Rating

Required Water Depth Rating (feet)	Number of Capable Rigs (39 max)	Number of Drilling Contractors in Market (7 max)
50	39	7
150	36	7
250	27	6
300	14	4
350	8	4

ECONOMETRIC MODELS AND DATA SET

As described in the development of the economic model, the premium is an indicator of both the existence and the scale of impact on transaction costs of contracting with an Over-Spec rig. The purpose of the econometric analysis is to test hypotheses about the relationship between premiums and variables that represent drilling contractor reputations and transaction costs, while controlling for other potentially relevant factors.

Each observation in the data set represents an activity i on one well where a jackup drilling rig was used. y_i is the observed premium. $\boldsymbol{X}_i$ is a $1 \times k$ vector of independent variables believed to affect the premium. $\boldsymbol{\beta}$ is defined as a $k \times 1$ vector of coefficients to be estimated. An ordinary least squares (OLS) model is specified and estimated per Equation (1), where ε_i is a random error term, $\sim N(0, \sigma^2)$. A second model specifies the relationship as Poisson to accommodate the right skew in y, and independent variables are included in the parameter estimate using $ln(\mu_i) = \boldsymbol{X}_i\boldsymbol{\beta}$. The probability of y_i is represented as shown in Equation (2), and the model is estimated via maximum likelihood. Robust (Huber-White) standard errors are computed to provide valid inference despite potential overdispersion or other forms of variance misspecification.[7] Finally, a third model specifies a negative binomial relationship where a random error term ω is included in the parameter estimate to capture unobserved randomness in the data-generating process: $ln(\mu_i) = \boldsymbol{X}_i\boldsymbol{\beta} + \omega_i$.[8]

$$y_i = \boldsymbol{X}_i\boldsymbol{\beta} + \varepsilon_i \tag{1}$$

$$Pr(Y_i = y_i) = \pi(y_i; \mu_i) = e^{-\mu_i}\frac{\mu_i^{y_i}}{y_i!} \tag{2}$$

Data were collected on seven drilling contractors operating in the Gulf of Mexico over a 24-month period. Five rigs were selected from each contractor based on water depth rating, roughly in proportion to the distribution of water depth capability for each contractor's marketed fleet. The final data set contains 467 observations of individual drilling, completion or well intervention activities, although some fields are null, and this reduces the number of observations in any regression depending on the specification. Day rates ($/day) are available each month for multiple rig types and are provided as a range (Max/Min). For this study, the average of the Max and Min values is used as the day rate for each month. Day rates are adjusted to a constant dollar basis to reflect changes in labor and capital costs that are assumed to be amortized in the day rates. Most data were taken from market surveys conducted by Petrodata™ and was supplemented using proprietary databases. The distribution of observations by drilling contractor, along with the respective number of oil company clients, is provided in Table 3.

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[7] The standard Poisson model imposes the constraint that the variance equals the mean, $Var(y_i) = \mu_i$, a property known as equidispersion. When the variance exceeds the mean (overdispersion), this assumption is violated, which would bias standard errors downward if uncorrected. The robust standard errors address this concern and ensure asymptotically valid inference under potential variance misspecification.

[8] The negative binomial model also relaxes the constraint on the mean-variance relationship and specifies the variance as $Var(y_i) = \mu_i(1 + \alpha\mu_i)$, and the overdispersion parameter α is estimated simultaneously with $\boldsymbol{\beta}$. This parametric approach can yield more efficient estimates when the quadratic variance form approximates the data well. Robust standard errors are also applied to the negative binomial model to ensure robustness against potential misspecification of the variance function. See Hausman *et al*. (1984), Blossfeld *et al*. (1989), Lancaster (1990), Vermunt (1996), Cameron and Trivedi (1990, 1998), and Nakashima (1997) for a full development of negative binomial models.

Table 3. Distribution of Observations by Drilling Contractor

Drilling Contractor	Number of Activities	Number of Unique Operators
V	68	15
N	47	12
B	57	13
R	84	25
C	78	17
H	58	15
J	75	29

RESULTS AND CONCLUSIONS

The results from the three regression analyses are reported in Tables 4, 5, and 6. In each Table, Model A includes all the independent variables except one of the drilling contractor reputation variables and the productivity variable. Because there is a binary variable defined for each drilling contractor represented in the study, one variable must be omitted to prevent linear dependence with the intercept term in the ***X*** matrix. The productivity variable is excluded from Model A because nulls in this field significantly reduce the number of observations. Model B omits two statistically insignificant variables observed in Model A. The productivity variable is tested in Model C on a subset of the data.

Ordinary Least Squares

The reputation variables were studied extensively to discover the relative ranking of drilling contractors. The results for these variables are reported in descending order in Table 4 based on the magnitude of the coefficient estimate to facilitate comparison (this analysis was also used to select the omitted variable). The statistical evidence indicates that reputation plays a statistically significant and material role in the determination of premiums. In this data set, the average day rate for the rig used is ~$47,000, and the coefficient estimates for the reputation effect on premiums across all three Models (A-C) range from -$5,987 to +$9,783, which equates to -16%/+23% on a percentage basis. These differences in the reputation coefficients for each drilling contractor reflect differences in the respective impacts on transaction costs. Note that these binary variable coefficients are interpreted as *relative to* the premiums earned by the omitted drilling contractor(s).

The utilization rate is statistically significant and positively signed as anticipated. This result supports the hypothesis that during periods of large utilization rates, it is more likely that oil companies are forced to contract with Over-Spec rigs. The coefficient estimates from Models A and B indicate that a 10% increase in utilization rate has a positive marginal impact of almost $2,000 per day on the premium. Note that this estimate only applies for utilization values in the range observed in this data set which was ~70-85%.

The multi-well campaign variable was not statistically significant. This result suggests that on average, the expected benefits of multi-well campaigns do not outweigh the (premium) costs of using an Over-Spec rig. It is believed that the primary reason for this result is that oil companies organize their campaigns to avoid premiums. In some cases, paying a premium may be part of an optimal contracting strategy, but (apparently) the number of these cases are not large enough to enable a precise measurement of the effect of this variable on premiums. It has been suggested to the authors that this effect could be a result of risk aversion on the part of the oil company. Previous studies of oil company decision-making have examined risk preferences in hedging decisions (Haushalter, 2000), oil and gas lease auctions (Smith, 1982), capital allocation (Walls and Dyer, 1996), and drilling rig evacuations (Jablonowski, 2007), and have provided evidence that decision-makers are not always risk-neutral. That is, the decision between using an Over-Spec rig for a multi-well campaign would depend on the relative magnitudes of the premium and expected benefits, the probability distribution of benefits, and the degree of risk aversion, *inter alia*. This is a plausible explanation regarding this aspect of rig contracting given the uncertainty in estimates of the expected benefits.

The quasi-HHI (continuous) variable was statistically significant and positively signed as anticipated. This result supports the hypothesis that a concentrated market yields larger premiums. The coefficient estimate from Models A and B indicate that an increase in water depth from 150 feet to 300 feet (which represents a reduction in the number of capable rigs from 36 to 14 and the number of associated drilling contractors from 7 to 4) would have a positive marginal impact of $2,100 per day on the premium (see Table 2). Binary variables were defined to investigate the discrete changes in the number of capable rigs and the number of associated drilling contractors at thresholds of 250, 300, and 350 feet. Only the 350 feet variable was significant at the 95% confidence level, and the coefficient estimate was ~$4,600. This structure of results suggests that the impact of market concentration on premiums manifests in a non-linear manner.

Two variables were defined to control for an observational bias in the premium related to rig functionality, IND (independent leg) and CANT (cantilever). The IND variable was statistically significant and positively signed as anticipated. The CANT variable was not statistically significant at a 95% confidence level, although it is positively signed as anticipated across all three Models and significant at 80-90% confidence levels.

Model C estimates Model B with the addition of the productivity variable. Because of nulls in this variable, the number of observations is reduced by more than half from 429 to 198. The productivity variable was not statistically significant. This result suggests that the differences in productivity observed in Table 1 are not large enough to be a material factor in premium determination, relative to other variables. Results for other variables were largely unaffected by the smaller sample size with the exception of the quasi-HHI and IND variables.

Table 4. Ordinary Least Squares (OLS) Regression Results

		Model A		Model B		Model C	
Variable	Expected Sign	Coefficient	Standard Error	Coefficient	Standard Error	Coefficient	Standard Error
Reputation							
H	n/a	9397.28	1773.68	9542.50	1675.48	9783.14	2564.53
N	n/a	5948.02	1765.81	6176.26	1623.61	9558.13	2387.87
V	n/a	4565.49	1661.57	4663.40	1446.70	6829.02	3026.10
B	n/a	---	---	---	---	---	---
C	n/a	-281.82	2236.20	---	---	---	---
R	n/a	-5104.68	2047.51	-4926.02	1358.09	-5927.01	2123.59
J	n/a	-5824.73	1929.36	-5480.43	1272.11	-5986.59	2279.30
Productivity							
ROP	+	---	---	---	---	0.71	2.09
Market / Operational							
Utilization	+	19766.67	9688.03	19347.65	9611.63	42315.38	15834.74
Multi-Well	+	-33.17	82.38	---	---	---	---
quasi-HHI	+	14.09	5.78	14.35	5.73	10.43	8.68
Independent	+	4928.36	1542.87	5046.04	1131.07	3385.96	1851.42
Cantilever	+	2052.74	1567.24	2242.55	1497.33	3415.48	2237.77
Constant		-8643.40	7858.93	-8974.79	7592.32	-27270.74	12505.12
Number of observations		429		429		198	
R2		0.48		0.48		0.45	

Poisson and Negative Binomial

The coefficient estimates from the Poisson and negative binomial regressions are very similar to the results from the OLS regressions with respect to statistical significance and sign. Tables 5 and 6 report the regression results, and Table 7 reports the estimated average marginal impacts (using coefficient estimates from Model B) to facilitate direct comparison with the OLS results.[9] The coefficient estimates for the reputation effect on premiums across the Poisson and negative

[9] The average marginal impacts in Table 7 are computed as follows: $\frac{\partial y}{\partial x_k} = \beta_k e^{\bar{\boldsymbol{X}}\boldsymbol{\beta}}$, where $\bar{\boldsymbol{X}}$ is a $1 \times k$ vector of the means of the independent variables. An alternate method computes the marginal impacts as follows: $\frac{\partial y}{\partial x_k} = \beta_k \left(\sum_{i=1}^{n} e^{\boldsymbol{X}_i \boldsymbol{\beta}}\right)/n$. In this case, the two computations deliver similar magnitudes of marginal impacts and thus the outputs from the alternate method are not reported.

binomial regressions for all three Models (A-C) range from -\$5,764 to +\$8,504, which equates to -18%/+17% on a percentage basis. Unless otherwise noted, the observations in this section apply to results from both the Poisson and the negative binomial models.

Tests for overdispersion indicated that the Poisson model is overdispersed. The estimates for the overdispersion parameter α are reported in Table 6 along with the respective p-values. Also, a second negative binomial model was estimated with a simpler specification of the variance of y_i: $Var(y_i) = \mu_i(1 + \delta)$. The overdispersion parameter δ is estimated simultaneously with $\boldsymbol{\beta}$. The results were consistent with the results in Table 6 and are not reported here.

The statistical evidence again indicates that reputation plays a statistically significant and material role in the determination of premiums. The average marginal impact estimates for the reputation effect on premiums are notably smaller for the positively signed coefficients and somewhat more negative for the negatively signed coefficients in comparison to the OLS estimates.

The utilization rate was statistically significant and positively signed as anticipated. The average marginal impact estimate is similar in magnitude to the OLS estimate. As before, the multi-well campaign variable was not statistically significant at a 95% confidence level.

The quasi-HHI (continuous) variable was statistically significant and positively signed in the Poisson model as anticipated. In the negative binomial model, the statistical significance decreased slightly to a 92% confidence level. The average marginal impact estimate is about half the magnitude relative to the OLS estimate. Again, binary variables were defined to investigate the discrete changes in the number of capable rigs and the number of associated drilling contractors at thresholds of 250, 300, and 350 feet. In the Poisson models, both the 300 and 350 feet variables were significant at the 95% confidence level, with average marginal impact estimates of ~\$1,200 to ~\$2100, somewhat less than half of the OLS estimate. In the negative binomial models, the 350 feet variable is significant at an 83% confidence level, with an average marginal impact estimate of ~\$2,300. This structure of results provides some reinforcement of the conclusion from the OLS results that the effect of market concentration on premiums manifests in a non-linear manner, in other words, this effect only becomes relevant at higher levels of market concentration.

In the Poisson model, the results for two variables defined to control for an observational bias in the premium related to rig functionality, IND (independent leg) and CANT (cantilever), were mixed. The IND variable was statistically significant and positively signed as anticipated, whereas the CANT variable was statistically significant at 90-93% confidence levels and positively signed. In the negative binomial model, the IND variable was statistically significant and positively signed as anticipated, whereas the CANT variable was statistically significant at 79-81% confidence levels and positively signed. In both the Poisson and negative binomial models, the average marginal impact estimates were very similar in magnitude to the OLS estimates.

As before, because of nulls in the productivity variable, the number of observations in Model C is reduced by more than half from 429 to 198. The productivity variable was not statistically significant. Results for other variables in the Poisson and negative binomial models were largely unaffected by the smaller sample size, with the exception of the quasi-HHI variable which was no longer statistically significant.

Table 5. Poisson Regression Results

		Model A		Model B		Model C	
Variable	Expected Sign	Coefficient	Standard Error	Coefficient	Standard Error	Coefficient	Standard Error
Reputation							
H	n/a	0.464	0.101	0.451	0.101	0.516	0.133
N	n/a	0.347	0.132	0.340	0.130	0.563	0.182
V	n/a	0.314	0.080	0.278	0.075	0.411	0.149
B	n/a	---	---	---	---	---	---
C	n/a	0.139	0.152	---	---	---	---
R	n/a	-0.635	0.127	-0.724	0.099	-0.761	0.133
J	n/a	-0.701	0.113	-0.760	0.092	-0.776	0.140
Productivity							
ROP	+	---	---	---	---	0.000	0.000
Market / Operational							
Utilization	+	1.687	0.655	1.629	0.641	3.269	1.028
Multi-Well	+	-0.005	0.007	---	---	---	---
quasi-HHI	+	0.000670	0.000356	0.000688	0.000357	0.000489	0.000537
Independent	+	0.572	0.108	0.493	0.078	0.342	0.115
Cantilever	+	0.238	0.144	0.240	0.133	0.301	0.186
Constant		7.444	0.542	7.556	0.517	6.281	0.828
Number of observations		429		429		198	

Table 6. Negative Binomial Regression Results

Variable	Expected Sign	Model A Coefficient	Model A Standard Error	Model B Coefficient	Model B Standard Error	Model C Coefficient	Model C Standard Error
Reputation							
H	n/a	0.473	0.108	0.497	0.110	0.614	0.152
N	n/a	0.356	0.132	0.374	0.130	0.530	0.165
V	n/a	0.230	0.084	0.272	0.088	0.395	0.158
B	n/a	---	---	---	---	---	---
C	n/a	-0.159	0.180	---	---	---	---
R	n/a	-0.820	0.163	-0.703	0.104	-0.779	0.144
J	n/a	-0.809	0.145	-0.718	0.096	-0.767	0.146
Productivity							
ROP	+	---	---	---	---	0.000	0.000
Market / Operational							
Utilization	+	1.750	0.577	1.766	0.579	3.341	0.812
Multi-Well	+	0.004	0.006	---	---	---	---
quasi-HHI	+	0.000702	0.000398	0.000691	0.000391	0.000257	0.000570
Independent	+	0.349	0.146	0.437	0.089	0.297	0.115
Cantilever	+	0.163	0.131	0.164	0.124	0.255	0.167
Constant		7.644	0.513	7.535	0.489	6.361	0.669
alpha		0.8745 (p<0.001)		0.8753 (p<0.001)		0.6033 (p<0.001)	
Number of observations		429		429		198	

Table 7. Average Marginal Impact Estimates
(using coefficient estimates from Model B)

	Average Marginal Effect		
Variable	OLS	Poisson	Negative Binomial
Reputation			
H	9542.50	5449.377	6176.309
N	6176.26	3979.824	4484.294
V	4663.40	3136.907	3092.505
B	---	---	---
C	---	---	---
R	-4926.02	-5979.235	-5883.944
J	-5480.43	-6160.732	-5937.708
Productivity			
ROP	---	---	---
Market / Operational			
Utilization	19347.65	16542.76	18091.59
Multi-Well	---	---	---
pseudo-HHI	14.35	6.983298	7.073691
Independent	5046.04	5014.71	4476.391
Cantilever	2242.55	2219.61	1578.093

Conclusions

The economic model and statistical evidence regarding premiums support several conclusions. For drilling contractors, the results indicate that their reputations are valuable assets that can affect the bottom line. Oil companies are willing to pay material premiums to work with drilling contractors with good reputations to capture the benefits of smaller transaction costs and smaller total costs of transactions. A drilling contractor with a good reputation would be expected to benefit from a higher utilization rate of its fleet relative to a similarly situated competitor with a lesser reputation. That is, a drilling contractor with a good reputation can compete its Over-Spec rigs against On-Spec rigs, enlarging the size of the market for each rig in its fleet. Also, the differences between drilling contractors in the respective magnitude of the impact on transaction costs indicate that reputation can be viewed as existing along a spectrum. An incremental improvement in reputation would translate into an incremental increase in benefits. In summary, the results on the reputation variables militate against sharp business practices by drilling contractors, and likewise motivate management consideration of reputation-improving practices. Finally, for activity planned in periods when the utilization rate is expected to be relatively large, and for projects in water depths where the number of competitive rigs or drilling contractors will be relatively small, oil companies should identify and pursue strategies to mitigate the potential impact on premiums.

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