UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

(Mark one)

☑ QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended June 30, 2010

OR

☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from _____ to _____.

Commission file number 000-53533

TRANSOCEAN LTD.

(Exact name of registrant as specified in its charter)

Zug, Switzerland (State or other jurisdiction of incorporation or organization)	**98-0599916** (I.R.S. Employer Identification No.)
Chemin de Blandonnet 10 **Vernier, Switzerland** (Address of principal executive offices)	**1214** (Zip Code)

+41 (22) 930-9000
(Registrant's telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☑ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☑ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.
Large accelerated filer ☑ Accelerated filer ☐ Non-accelerated filer (do not check if a smaller reporting company) ☐ Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☑

As of July 27, 2010, 318,993,839 shares were outstanding.

TRANSOCEAN LTD.
INDEX TO FORM 10-Q
QUARTER ENDED JUNE 30, 2010

PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

TRANSOCEAN LTD. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(In millions, except per share data)
(Unaudited)

	Three months ended June 30,		Six months ended June 30,	
	2010	2009	2010	2009
Operating revenues				
Contract drilling revenues	$ 2,290	$ 2,625	$ 4,731	$ 5,459
Contract drilling intangible revenues	29	75	62	179
Other revenues	186	182	314	362
	2,505	2,882	5,107	6,000
Costs and expenses				
Operating and maintenance	1,358	1,277	2,554	2,448
Depreciation, depletion and amortization	400	360	801	715
General and administrative	58	53	121	109
	1,816	1,690	3,476	3,272
Loss on impairment	—	(67)	(2)	(288)
Gain (loss) on disposal of assets, net	268	(4)	254	—
Operating income	957	1,121	1,883	2,440
Other income (expense), net				
Interest income	5	1	10	2
Interest expense, net of amounts capitalized	(141)	(114)	(273)	(250)
Gain (loss) on retirement of debt	—	(8)	2	(10)
Other, net	(3)	(8)	10	—
	(139)	(129)	(251)	(258)
Income before income tax expense	818	992	1,632	2,182
Income tax expense	98	184	227	435
Net income	720	808	1,405	1,747
Net income (loss) attributable to noncontrolling interest	5	2	13	(1)
Net income attributable to controlling interest	$ 715	$ 806	$ 1,392	$ 1,748
Earnings per share				
Basic	$ 2.23	$ 2.50	$ 4.32	$ 5.43
Diluted	$ 2.22	$ 2.49	$ 4.31	$ 5.42
Weighted average shares outstanding				
Basic	319	320	320	320
Diluted	320	321	321	321

See accompanying notes.

TRANSOCEAN LTD. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(In millions)
(Unaudited)

	Three months ended June 30,		Six months ended June 30,	
	2010	2009	2010	2009
Net income	$ 720	$ 808	$ 1,405	$ 1,747
Other comprehensive income (loss) before income taxes				
Unrecognized components of net periodic benefit cost	—	—	(10)	(39)
Recognized components of net periodic benefit cost	3	5	9	9
Unrealized gain (loss) on derivative instruments	(11)	10	(17)	9
Other, net	(3)	1	(3)	—
Other comprehensive income (loss) before income taxes	(11)	16	(21)	(21)
Income taxes related to other comprehensive income (loss)	(1)	(6)	(1)	3
Other comprehensive income (loss), net of income taxes	(12)	10	(22)	(18)
Total comprehensive income	708	818	1,383	1,729
Total comprehensive income (loss) attributable to noncontrolling interest	(9)	13	(8)	10
Total comprehensive income attributable to controlling interest	$ 717	$ 805	$ 1,391	$ 1,719

See accompanying notes.

TRANSOCEAN LTD. AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
(In millions, except share data)

	June 30, 2010 (Unaudited)	December 31, 2009
Assets		
Cash and cash equivalents	$ 2,888	$ 1,130
Accounts receivable, net of allowance for doubtful accounts of $41 and $65 at June 30, 2010 and December 31, 2009, respectively	2,254	2,385
Materials and supplies, net of allowance for obsolescence of $66 at June 30, 2010 and December 31, 2009	467	462
Deferred income taxes, net	121	104
Assets held for sale	—	186
Other current assets	184	209
Total current assets	5,914	4,476
Property and equipment	27,377	27,383
Property and equipment of consolidated variable interest entities	2,179	1,968
Less accumulated depreciation	7,034	6,333
Property and equipment, net	22,522	23,018
Goodwill	8,132	8,134
Other assets	984	808
Total assets	$ 37,552	$ 36,436
Liabilities and equity		
Accounts payable	$ 968	$ 780
Accrued income taxes	154	240
Debt due within one year	1,580	1,568
Debt of consolidated variable interest entities due within one year	82	300
Other current liabilities	1,884	730
Total current liabilities	4,668	3,618
Long-term debt	8,862	8,966
Long-term debt of consolidated variable interest entities	902	883
Deferred income taxes, net	710	726
Other long-term liabilities	1,683	1,684
Total long-term liabilities	12,157	12,259
Commitments and contingencies		
Shares, CHF 15.00 par value, 502,852,947 authorized, 167,617,649 conditionally authorized, 335,235,298 issued at June 30, 2010 and December 31, 2009; 318,916,207 and 321,223,882 outstanding at June 30, 2010 and December 31, 2009, respectively	4,479	4,472
Additional paid-in capital	6,421	7,407
Treasury shares, at cost, 2,863,267 and none held at June 30, 2010 and December 31, 2009, respectively	(240)	—
Retained earnings	10,400	9,008
Accumulated other comprehensive loss	(336)	(335)
Total controlling interest shareholders' equity	20,724	20,552
Noncontrolling interest	3	7
Total equity	20,727	20,559
Total liabilities and equity	$ 37,552	$ 36,436

See accompanying notes.

TRANSOCEAN LTD. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF EQUITY
(In millions)
(Unaudited)

	Six months ended June 30, 2010	Six months ended June 30, 2009
Shares outstanding		
Balance, beginning of period	321	319
Issuance of shares under share-based compensation plans	1	2
Purchases of shares held in treasury	(3)	—
Balance, end of period	319	321
Shares		
Balance, beginning of period	$ 4,472	$ 4,444
Issuance of shares under share-based compensation plans	7	24
Balance, end of period	$ 4,479	$ 4,468
Additional paid-in capital		
Balance, beginning of period	$ 7,407	$ 7,313
Share-based compensation expense	53	43
Issuance of shares under share-based compensation plans	(9)	16
Obligation for cash distribution	(1,024)	—
Repurchases of convertible senior notes	—	16
Changes in ownership of noncontrolling interest and other, net	(6)	—
Balance, end of period	$ 6,421	$ 7,388
Treasury shares, at cost		
Balance, beginning of period	$ —	$ —
Purchases of shares held in treasury	(240)	—
Balance, end of period	$ (240)	$ —
Retained earnings		
Balance, beginning of period	$ 9,008	$ 5,827
Net income attributable to controlling interest	1,392	1,748
Balance, end of period	$ 10,400	$ 7,575
Accumulated other comprehensive loss		
Balance, beginning of period	$ (335)	$ (420)
Other comprehensive loss attributable to controlling interest	(1)	(29)
Balance, end of period	$ (336)	$ (449)
Total controlling interest shareholders' equity		
Balance, beginning of period	$ 20,552	$ 17,164
Total comprehensive income attributable to controlling interest	1,391	1,719
Share-based compensation expense	53	43
Issuance of shares under share-based compensation plans	(2)	40
Purchases of shares held in treasury	(240)	—
Obligation for cash distribution	(1,024)	—
Repurchases of convertible senior notes	—	16
Changes in ownership of noncontrolling interest and other, net	(6)	—
Balance, end of period	$ 20,724	$ 18,982
Total noncontrolling interest		
Balance, beginning of period	$ 7	$ 3
Net income (loss) attributable to noncontrolling interest	13	(1)
Other comprehensive income (loss) attributable to noncontrolling interest	(21)	11
Changes in ownership of noncontrolling interest	4	—
Balance, end of period	$ 3	$ 13
Total equity		
Balance, beginning of period	$ 20,559	$ 17,167
Total comprehensive income	1,383	1,729
Share-based compensation expense	53	43
Issuance of shares under share-based compensation plans	(2)	40
Purchases of shares held in treasury	(240)	—
Obligation for cash distribution	(1,024)	—
Repurchases of convertible notes	—	16
Changes in ownership of noncontrolling interest and other, net	(2)	—
Balance, end of period	$ 20,727	$ 18,995

See accompanying notes.

TRANSOCEAN LTD. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(In millions)
(Unaudited)

	Three months ended June 30,		Six months ended June 30,	
	2010	2009	2010	2009
Cash flows from operating activities				
Net income	$ 720	$ 808	$ 1,405	$ 1,747
Adjustments to reconcile net income to net cash provided by operating activities				
Amortization of drilling contract intangibles	(29)	(75)	(62)	(179)
Depreciation, depletion and amortization	400	360	801	715
Share-based compensation expense	18	24	53	43
Excess tax benefit from share-based compensation plans	(1)	—	(1)	(1)
(Gain) loss on disposal of assets, net	(268)	4	(254)	—
Loss on impairment	—	67	2	288
(Gain) loss on retirement of debt	—	8	(2)	10
Amortization of debt issue costs, discounts and premiums, net	51	57	100	109
Deferred income taxes	(12)	20	(34)	26
Other, net	(6)	14	(1)	23
Deferred revenue, net	7	49	158	43
Deferred expenses, net	(23)	(37)	(37)	(35)
Changes in operating assets and liabilities	412	277	313	228
Net cash provided by operating activities	1,269	1,576	2,441	3,017
Cash flows from investing activities				
Capital expenditures	(300)	(947)	(679)	(1,655)
Proceeds from disposal of assets, net	10	—	51	8
Proceeds from insurance recoveries for loss of drilling unit	560	—	560	—
Proceeds from payments on notes receivable	11	—	21	—
Proceeds from short-term investments	—	172	5	393
Purchases of short-term investments	—	(234)	—	(234)
Joint ventures and other investments, net	(1)	—	(1)	—
Net cash provided by (used in) investing activities	280	(1,009)	(43)	(1,488)
Cash flows from financing activities				
Change in short-term borrowings, net	(46)	(476)	(177)	(500)
Proceeds from debt	—	231	54	319
Repayments of debt	(22)	(708)	(275)	(1,410)
Payments for warrant exercises, net	—	(13)	—	(13)
Purchases of shares held in treasury	(180)	—	(240)	—
Proceeds from (taxes paid for) share-based compensation plans, net	3	5	(1)	22
Excess tax benefit from share-based compensation plans	1	—	1	1
Other, net	(3)	(1)	(2)	(4)
Net cash used in financing activities	(247)	(962)	(640)	(1,585)
Net increase (decrease) in cash and cash equivalents	1,302	(395)	1,758	(56)
Cash and cash equivalents at beginning of period	1,586	1,302	1,130	963
Cash and cash equivalents at end of period	$ 2,888	$ 907	$ 2,888	$ 907

See accompanying notes.

Note 1—Nature of Business

Transocean Ltd. (together with its subsidiaries and predecessors, unless the context requires otherwise, "Transocean," the "Company," "we," "us" or "our") is a leading international provider of offshore contract drilling services for oil and gas wells. Our mobile offshore drilling fleet is considered one of the most modern and versatile fleets in the world. Specializing in technically demanding sectors of the offshore drilling business with a particular focus on deepwater and harsh environment drilling services, we contract our drilling rigs, related equipment and work crews predominantly on a dayrate basis to drill oil and gas wells. At June 30, 2010, we owned, had partial ownership interests in or operated 139 mobile offshore drilling units. As of this date, our fleet consisted of 45 High-Specification Floaters (Ultra-Deepwater, Deepwater and Harsh Environment semisubmersibles and drillships), 26 Midwater Floaters, 10 High-Specification Jackups, 55 Standard Jackups and three Other Rigs. We also have three Ultra-Deepwater Floaters under construction (see Note 8—Drilling Fleet).

We also provide oil and gas drilling management services, drilling engineering and drilling project management services, and we participate in oil and gas exploration and production activities. Drilling management services are provided through Applied Drilling Technology Inc., our wholly owned subsidiary, and through ADT International, a division of one of our U.K. subsidiaries (together, "ADTI"). ADTI conducts drilling management services primarily on either a dayrate or a completed-project, fixed-price (or "turnkey") basis. Oil and gas properties consist of exploration, development and production activities performed by Challenger Minerals Inc. and Challenger Minerals (North Sea) Limited (together, "CMI"), our oil and gas subsidiaries.

Note 2—Significant Accounting Policies

Basis of presentation—We have prepared our accompanying condensed consolidated financial statements without audit in accordance with accounting principles generally accepted in the United States ("U.S.") for interim financial information and with the instructions to Form 10-Q and Article 10 of Regulation S-X of the U.S. Securities and Exchange Commission ("SEC"). Pursuant to such rules and regulations, these financial statements do not include all disclosures required by accounting principles generally accepted in the U.S. for complete financial statements. The condensed consolidated financial statements reflect all adjustments, which are, in the opinion of management, necessary for a fair presentation of financial p osition, results of operations and cash flows for the interim periods. Such adjustments are considered to be of a normal recurring nature unless otherwise identified. Operating results for the three and six months ended June 30, 2010 are not necessarily indicative of the results that may be expected for the year ending December 31, 2010 or for any future period. The accompanying condensed consolidated financial statements and notes thereto should be read in conjunction with the audited consolidated financial statements and notes thereto included in our annual report on Form 10-K for the year ended December 31, 2009.

Accounting estimates—The preparation of financial statements in accordance with accounting principles generally accepted in the U.S. requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and the disclosures of contingent assets and liabilities. On an ongoing basis, we evaluate our estimates and assumptions, including those related to our allowance for doubtful accounts, materials and supplies obsolescence, property and equipment, investments, notes receivable, goodwill and other intangible assets, income taxes, share-based compensation, defined benefit pension plans and other postretirement benefits and contingencies. We base our estimates and assumptions on historical experience and o n various other factors we believe are reasonable under the circumstances, the results of which form the basis for making judgments about the carrying amounts of assets and liabilities that are not readily apparent from other sources. Actual results could differ from such estimates.

Fair value measurements—We estimate fair value at a price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants in the principal market for the asset or liability. Our valuation techniques require inputs that we categorize using a three-level hierarchy, from highest to lowest level of observable inputs, as follows: (1) unadjusted quoted prices for identical assets or liabilities in active markets ("Level 1"), (2) direct or indirect observable inputs, including quoted prices or other market data, for similar assets or liabilities in active markets or identical assets or liabilities in less active markets ("Level 2") and (3) unobservable inputs that require significant judgment for which there is little or no market data ("Level 3"). When multiple input levels are required for a valuation, we categorize the entire fair value measurement according to the lowest level of input that is significant to the measurement even though we may have also utilized significant inputs that are more readily observable.

Principles of consolidation—We consolidate those investments that meet the criteria of a variable interest entity where we are deemed to be the primary beneficiary for accounting purposes and for entities in which we have a majority voting interest. Intercompany transactions and accounts are eliminated in consolidation. We apply the equity method of accounting for investments in joint ventures and other entities when we have the ability to exercise significant influence over an entity that (a) does not meet the variable interest entity criteria or (b) meets the variable interest entity criteria, but for which we are not deemed to be the primary beneficiary. We apply the cost method of accounting for investments in joint ventures and o ther entities if we do not have the ability to exercise significant influence over the unconsolidated affiliate. See Note 4—Variable Interest Entities.

Share-based compensation—Share-based compensation expense was $18 million and $53 million for the three and six months ended June 30, 2010, respectively. Share-based compensation expense was $24 million and $43 million for the three and six months ended June 30, 2009, respectively.

Capitalized interest—We capitalize interest costs for qualifying construction and upgrade projects. We capitalized interest costs on construction work in progress of $19 million and $47 million for the three and six months ended June 30, 2010, respectively. We capitalized interest costs on construction work in progress of $49 million and $95 million for the three and six months ended June 30, 2009, respectively.

Reclassifications—We have made certain reclassifications to prior period amounts to conform with the current period's presentation. These reclassifications did not have a material effect on our condensed consolidated statement of financial position, results of operations or cash flows.

Subsequent events—We evaluate subsequent events through the time of our filing on the date we issue our financial statements. See Note 15—Subsequent Events.

Note 3—New Accounting Pronouncements

Recently adopted accounting standards

Consolidation—Effective January 1, 2010, we adopted the accounting standards update that requires enhanced transparency of our involvement with variable interest entities, which (a) amends certain guidance for determining whether an enterprise is a variable interest entity, (b) requires a qualitative rather than a quantitative analysis to determine the primary beneficiary, and (c) requires continuous assessments of whether an enterprise is the primary beneficiary of a variable interest entity. We evaluated these requirements, particularly with regard to our interests in Transocean Pacific Drilling Inc. ("TPDI") and Angola Deepwater Drilling Company Limited ("ADDCL") and our adoption did not have a material effect on our co ndensed consolidated statement of financial position, results of operations or cash flows. See Note 4—Variable Interest Entities.

Fair value measurements and disclosures—Effective January 1, 2010, we adopted the effective provisions of the accounting standards update that clarifies existing disclosure requirements and introduces additional disclosure requirements for fair value measurements. The update requires entities to disclose the amounts of and reasons for significant transfers between Level 1 and Level 2, the reasons for any transfers into or out of Level 3, and information about recurring Level 3 measurements of purchases, sales, issuances and settlements on a gross basis. The update also clarifies that entities must provide (a) fair value measurement disclosures for each class of assets and liabilities and (b) information about both the va luation techniques and inputs used in estimating Level 2 and Level 3 fair value measurements. We have applied the effective provisions of this accounting standards update in preparing the disclosures in our notes to condensed consolidated financial statements and our adoption did not have a material effect on such disclosures. See Note 2—Significant Accounting Policies.

Subsequent events—Effective for financial statements issued after February 2010, we adopted the accounting standards update regarding subsequent events, which clarifies that SEC filers are not required to disclose the date through which management evaluated subsequent events in the financial statements. Our adoption did not have a material effect on the disclosures contained within our notes to condensed consolidated financial statements. See Note 2—Significant Accounting Policies.

Recently issued accounting standards

Fair value measurements and disclosures—Effective January 1, 2011, we will adopt the remaining provisions of the accounting standards update that clarifies existing disclosure requirements and introduces additional disclosure requirements for fair value measurements. The update requires entities to separately disclose information about purchases, sales, issuances, and settlements in the reconciliation of recurring Level 3 measurements on a gross basis. The update is effective for interim and annual periods beginning after December 15, 2010. We do not expect that our adoption will have a material effect on the disclosures contained in our notes to consolidated financial statements.

Note 4—Variable Interest Entities

Consolidated variable interest entities—TPDI and ADDCL, two joint venture companies in which we hold interests, were formed to own and operate certain ultra-deepwater drillships. We have determined that each of these joint venture companies meets the criteria of a variable interest entity for accounting purposes because their equity at risk is insufficient to permit them to carry on their activities without additional subordinated financial support from us. We have also determined, in each case, that we are the primary beneficiary for accounting purposes since (a) we have the power to direct the construction, marketing and operating activities, which are the activities that most significantly impact each entity's economic performance, and (b) we have the obligation to absorb a majority of the losses or receive a majority of the benefits that could be potentially significant to the variable interest entity. As a result, we consolidate TPDI and ADDCL in our condensed consolidated financial statements, we eliminate intercompany transactions, and we present the interests that are not owned by us as noncontrolling interest on our condensed consolidated balance sheets. The carrying amounts associated with these two joint venture companies, after eliminating the effect of intercompany transactions, were as follows (in millions):

	June 30, 2010			December 31, 2009		
	Assets	Liabilities	Net carrying amount	Assets	Liabilities	Net carrying amount
Variable interest entity						
TPDI	$ 1,600	$ 806	$ 794	$ 1,500	$ 763	$ 737
ADDCL	825	319	506	582	482	100
Total	$ 2,425	$ 1,125	$ 1,300	$ 2,082	$ 1,245	$ 837

Unconsolidated variable interest entities—In January 2010, we completed the sale of two Midwater Floaters, *GSF Arctic II* and *GSF Arctic IV*, to subsidiaries of Awilco Drilling Limited, a U.K. company ("ADL"). See Note 8—Drilling Fleet. We have determined that ADL meets the criteria of a variable interest entity for accounting purposes because their equity at risk is insufficient to permit them to carry on their activities without additional subordinated financial support. We have also determined that we are not the primary beneficiary for accounting purposes since, although we hold a significant financial interest in the variable interest entity and have the obligation to absorb losses or receive benefits that could be potentially significant to the variable interest entity, we do not have the power to direct the marketing and operating activities that most significantly impact the entity's economic performance.

In connection with the sale, we accepted payment in the form of cash and two notes receivable, which are secured by the drilling units, with an aggregate principal amount of $165 million. The notes receivable have stated interest rates of 9 percent and are payable in scheduled quarterly installments of principal and interest through maturity in January 2015. We have also committed to provide ADL with a working capital loan, which is also secured by the drilling units, with a maximum borrowing amount of $35 million. Additionally, we continue to operate *GSF Arctic IV* under a short-term bareboat charter with ADL through October 2010. At June 30, 2010, the notes receivable and working capital loan receivable represented aggregate carrying amounts of $120 million and $1 million, respectively, which together represents our maximum exposure to loss.

Note 5—Impairments

Goodwill—During the six months ended June 30, 2010, we recognized a loss on impairment of goodwill associated with our oil and gas properties in the amount of $2 million ($0.01 per diluted share), which had no tax effect. The carrying amount of goodwill associated with our oil and gas properties reporting unit was $2 million at December 31, 2009.

Definite-lived intangible assets—During the six months ended June 30, 2009, we determined that the customer relationships intangible asset associated with our drilling management services was impaired due to market conditions in that reporting unit resulting from the global economic downturn and continued pressure on commodity prices. We estimated the fair value of the customer relationships intangible asset using the excess earnings method, a generally accepted valuation methodology that applies the income approach. Our valuation required us to project the future performance of the drilling management services unit based on unobservable inputs that require significant judgment for which there is little or no market data, including assumptions f or future commodity prices, projected demand for our services, rig availability and dayrates. As a result of our impairment testing, we determined that the carrying amount of the asset exceeded its fair value and recognized a loss on impairment of $9 million ($0.03 per diluted share), which had no tax effect, during the three and six months ended June 30, 2009. The carrying amount of the customer relationship intangible asset associated with our drilling management services, recorded in other assets on our condensed consolidated balance sheets, was $62 million and $64 million at June 30, 2010 and December 31, 2009, respectively.

Assets held for sale—During the six months ended June 30, 2009, we determined that *GSF Arctic II* and *GSF Arctic IV*, both previously classified as assets held for sale, were impaired due to the global economic downturn and pressure on commodity prices, both of which have had an adverse effect on our industry. We estimated the fair values of these rigs based on an exchange price that would be received for the assets in the principal or most advantageous market for the assets in an orderly transaction between market participants as of the measurement date and considering our undertakings to the Office of Fair Trading in the U.K. ("OFT") that required the sale of the rigs with certain limitations and in a limited amount of time. We based our estimates on unobservable inputs that require significant judgment, for which there is little or no market data, including non-binding price quotes from unaffiliated parties, considering the then-current market conditions and restrictions imposed by the OFT. As a result of our evaluation, we recognized losse s on impairment of $58 million ($0.18 per diluted share) and $279 million ($0.87 per diluted share), which had no tax effect, for the three and six months ended June 30, 2009, respectively. The carrying amount of assets held for sale was $186 million at December 31, 2009, and these assets were sold in the six months ended June 30, 2010. See Note 8—Drilling Fleet.

Note 6—Income Taxes

Overview—Transocean Ltd., a holding company and Swiss resident, is exempt from cantonal and communal income tax in Switzerland, but is subject to Swiss federal income tax. At the federal level, qualifying net dividend income and net capital gains on the sale of qualifying investments in subsidiaries are exempt from Swiss federal income tax. Consequently, Transocean Ltd. expects dividends from its subsidiaries and capital gains from sales of investments in its subsidiaries to be exempt from Swiss federal income tax.

Tax provision—We conduct operations through our various subsidiaries in a number of countries throughout the world, all of which have taxation regimes with varying nominal rates, deductions, credits and other tax attributes. Our provision for income taxes is based on the tax laws and rates applicable in the jurisdictions in which we operate and earn income. There is little to no expected relationship between the provision for or benefit from income taxes and income or loss before income taxes considering, among other factors, (a) changes in the blend of income that is taxed based on gross revenues versus income before taxes, (b) rig movements between taxing jurisdictions and (c) our rig operating structures.

Our estimated annual effective tax rates for the six months ended June 30, 2010 and June 30, 2009 were 15.5 percent and 15.4 percent, respectively. These rates were based on projected annual income before income taxes for each period after adjusting for certain items, such as impairment losses, the gain resulting from the insurance recoveries on the loss of *Deepwater Horizon* and various other discrete items.

We record a valuation allowance for deferred tax assets, including those resulting from net operating losses, when it is more likely than not that we will not realize some or all of the benefit from the deferred tax assets. At June 30, 2010 and December 31, 2009, the valuation allowance for non-current deferred tax assets was $70 million and $69 million, respectively.

Tax returns—We file federal and local tax returns in several jurisdictions throughout the world. With few exceptions, we are no longer subject to examinations of our U.S. and non-U.S. tax matters for years prior to 1999. For the six months ended June 30, 2010 and June 30, 2009, the amount of current tax benefit recognized from the settlement of disputes with tax authorities and from the expiration of statutes of limitations was insignificant.

The liabilities related to our unrecognized tax benefits, including related interest and penalties that we recognize as a component of income tax expense, were as follows (in millions):

	June 30, 2010	December 31, 2009
Unrecognized tax benefits, excluding interest and penalties	$ 457	$ 460
Interest and penalties	209	200
Unrecognized tax benefits, including interest and penalties	$ 666	$ 660

Our tax returns in the other major jurisdictions in which we operate are generally subject to examination for periods ranging from three to six years. We have agreed to extensions beyond the statute of limitations in three major jurisdictions for up to 15 years. Tax authorities in certain jurisdictions are examining our tax returns and in some cases have issued assessments. We are defending our tax positions in those jurisdictions. While we cannot predict or provide assurance as to the final outcome of these proceedings, we do not expect the ultimate liability to have a material adverse effect on our consolidated statement of financial position, or results of operations, although it may have a material adverse effect on our consolidated cash flows.

Tax positions—With respect to our 2004 and 2005 U.S. federal income tax returns, the U.S. tax authorities have withdrawn all of their previously proposed tax adjustments, except a claim regarding transfer pricing for certain charters of drilling rigs between our subsidiaries, reducing the total proposed adjustment to approximately $79 million, exclusive of interest. We believe an unfavorable outcome on this assessment with respect to 2004 and 2005 activities would not result in a material adverse effect on our consolidated financial position, results of operations or cash flows. Although we believe the transfer pricing for these charters is materially correct, we have been unable to reach a resolution with the tax authorities and we expect the matter to proceed to litigation.

In May 2010, we received an assessment from the U.S. tax authorities related to our 2006 and 2007 U.S. federal income tax returns. The significant issues raised in the assessment relate to transfer pricing for certain charters of drilling rigs between our subsidiaries and the creation of intangible assets resulting from the performance of engineering services between our subsidiaries. These two items would result in net adjustments of approximately $278 million of additional taxes, exclusive of interest. An unfavorable outcome on these adjustments could result in a material adverse effect on our consolidated financial position, results of operations or cash flows. We believe our returns are materially correct as file d, and we intend to continue to vigorously defend against all such claims.

In addition, the assessment included adjustments related to a series of restructuring transactions that occurred between 2001 and 2004. These restructuring transactions ultimately resulted in the disposition of our interests in our former subsidiary TODCO in 2004 and 2005. The authorities are disputing the amount of capital losses resulting from the disposition of TODCO. We utilized a portion of the capital losses to offset capital gains on the 2006, 2007, 2008 and 2009 tax returns. The majority of the capital losses expired on December 31, 2009. The adjustments would also impact the amount of certain net operating losses and other carryovers into 2006 and later years. The authorities are also contesting the characterization of certain amounts of income received in 20 06 and 2007 as capital gain and thus the availability of the capital gain for offset by the capital loss. Claims with respect to our U.S. federal income tax returns for 2006 through 2009 could result in net tax adjustments of approximately $320 million. An unfavorable outcome on these potential adjustments could result in a material adverse effect on our consolidated financial position, results of operations or cash flows. We believe that our tax returns are materially correct as filed, and we intend to vigorously defend against any potential claims.

The assessment also included certain claims with respect to withholding taxes and certain other items resulting in net tax adjustments of approximately $182 million, exclusive of interest. In addition, the tax authorities assessed penalties associated with the various tax adjustments in the aggregate amount of approximately $92 million, exclusive of interest. We believe that our tax returns are materially correct as filed, and we intend to vigorously defend against any potential claims.

Norwegian civil tax and criminal authorities are investigating various transactions undertaken by our subsidiaries in 2001 and 2002 as well as the actions of certain of our former external advisors on these transactions. The authorities issued tax assessments of (a) approximately $241 million plus interest, related to certain restructuring transactions, (b) approximately $105 million plus interest, related to the migration of a subsidiary that was previously subject to tax in Norway, (c) approximately $63 million plus interest, related to a 2001 dividend payment and (d) approximately $6 million plus interest, related to certain foreign exchange deductions and dividend withholding tax. We have filed or expect to file appeals to these tax assessments. We may be required to provide some form of financial security, in an amount up to $898 million, including interest and penalties, for these assessed amounts as this dispute is appealed and addressed by the Norwegian courts. The authorities have indicated that they plan to seek penalties of 60 percent on all matters. For these matters, we believe our returns are materially correct as filed, and we have and will continue to respond to all information requests from the Norwegian authorities. We intend to vigorously contest any assertions by the Norwegian authorities in connection with the various transactions being investigated.

During the six months ended June 30, 2010, our long-term liability for unrecognized tax benefits related to these Norwegian tax issues decreased $12 million to $169 million due to the accrual of interest being offset by favorable exchange rate fluctuations. An unfavorable outcome on these Norwegian civil tax matters could result in a material adverse effect on our consolidated financial position, results of operations or cash flows. While we cannot predict or provide assurance as to the final outcome of these proceedings, we do not expect the ultimate resolution of these matters to have a material adverse effect on our consolidated financial position or results of operations, although it may have a material adverse effect on our consolidated cash flows.

The Norwegian authorities issued notification of criminal charges against Transocean Ltd. and certain of its subsidiaries related to disclosures included in one of our Norwegian tax returns. This notification, however, does not itself constitute an indictment under Norwegian law nor does it initiate legal proceedings but represents a formal expression of suspicion and continued investigation. All income taxes, interest charges and penalties related to this Norwegian tax return have previously been settled. We believe that these charges are without merit and plan to vigorously defend Transocean Ltd. and its subsidiaries to the fullest extent.

Certain of our Brazilian income tax returns for the years 2000 through 2004 are currently under examination. The Brazilian tax authorities have issued tax assessments totaling $109 million, plus a 75 percent penalty of $82 million and $102 million of interest through June 30, 2010. An unfavorable outcome on these proposed assessments could result in a material adverse effect on our consolidated financial position, results of operations or cash flows. We believe our returns are materially correct as filed, and we are vigorously contesting these assessments. We filed a protest letter with the Brazilian tax authorities on January 25, 2008, and we are currently engaged in the appeals process.

Note 7—Earnings Per Share

The reconciliation of the numerator and denominator used for the computation of basic and diluted earnings per share is as follows (in millions, except per share data):

	Three months ended June 30,				Six months ended June 30,			
	2010		2009		2010		2009	
	Basic	Diluted	Basic	Diluted	Basic	Diluted	Basic	Diluted
Numerator for earnings per share								
Net income attributable to controlling interest	$ 715	$ 715	$ 806	$ 806	$ 1,392	$ 1,392	$ 1,748	$ 1,748
Undistributed earnings allocable to participating securities	(4)	(5)	(5)	(5)	(8)	(8)	(10)	(10)
Net income available to shareholders	$ 711	$ 710	$ 801	$ 801	$ 1,384	$ 1,384	$ 1,738	$ 1,738
Denominator for earnings per share								
Weighted-average shares outstanding	319	319	320	320	320	320	320	320
Effect of stock options and other share-based awards	—	1	—	1	—	1	—	1
Weighted-average shares for per share calculation	319	320	320	321	320	321	320	321
Earnings per share	$ 2.23	$ 2.22	$ 2.50	$ 2.49	$ 4.32	$ 4.31	$ 5.43	$ 5.42

For the three and six months ended June 30, 2010, 2.3 million and 1.6 million share-based awards, respectively, were excluded from the calculation since the effect would have been anti-dilutive. For the three and six months ended June 30, 2009, 1.9 million and 2.9 million share-based awards, respectively, were excluded from the calculation since the effect would have been anti-dilutive.

The 1.625% Series A, 1.50% Series B and 1.50% Series C Convertible Senior Notes did not have an effect on the calculation for the periods presented. See Note 9—Debt.

Note 8—Drilling Fleet

Expansion—Construction work in progress, recorded in property and equipment, was $2.6 billion and $3.7 billion at June 30, 2010 and December 31, 2009, respectively. The following table presents actual capital expenditures and other capital additions, including capitalized interest, for our remaining major construction projects (in millions):

	Six months ended June 30, 2010	Through December 31, 2009	Total costs
Discoverer Luanda (a)	$ 160	$ 535	$ 695
Deepwater Champion (b)	56	527	583
Discoverer India	50	541	591
Dhirubhai Deepwater KG2 (c) (d)	33	641	674
Discover Inspiration (c)	7	667	674
Capitalized interest	47	183	230
Mobilization costs	36	19	55
Total	$ 389	$ 3,113	$ 3,502

(a) The costs for *Discoverer Luanda* represent 100 percent of expenditures incurred since inception. ADDCL is responsible for all of these costs. We hold a 65 percent interest in ADDCL, and Angco Cayman Limited holds the remaining 35 percent interest.
(b) These costs include our initial investment in *Deepwater Champion* of $109 million, representing the estimated fair value of the rig at the time of our merger with GlobalSantaFe Corporation (“GlobalSantaFe”) in November 2007.
(c) The accumulated construction costs of these rigs are no longer included in construction work in progress, as their construction projects had been completed as of June 30, 2010.
(d) The cost for *Dhirubhai Deepwater KG2* represents 100 percent of TPDI’s expenditures, including those incurred prior to our investment in the joint venture. TPDI is responsible for all of these costs. We hold a 50 percent interest in TPDI, and Pacific Drilling Limited (“Pacific Drilling”) holds the remaining 50 percent interest.

During the six months ended June 30, 2010, we acquired *GSF Explorer*, an asset formerly held under capital lease, in exchange for a cash payment in the amount of $15 million, terminating the capital lease obligation. See Note 9—Debt.

Dispositions—During the six months ended June 30, 2010, we completed the sale of two Midwater Floaters, *GSF Arctic II* and *GSF Arctic IV.* In connection with the sale, we received net cash proceeds of $38 million and non-cash proceeds in the form of two notes receivable in the aggregate amount of $165 million. The notes receivable, which are secured by the drilling units, have stated interest rates of 9 percent and are payable in scheduled quarterly installments of principal and interest through maturity in January 2015. We estimated the fair values of the notes receivable ba sed on unobservable inputs that require significant judgment, for which there is little or no market data, including the credit rating of the buyer. We continue to operate *GSF Arctic IV* under a short-term bareboat charter with the new owner of the vessel through October 2010. As a result of the sale, we recognized a loss on disposal of assets in the amount of $15 million ($0.04 per diluted share), which had no tax effect for the six months ended June 30, 2010. For the three and six months ended June 30, 2010, we recognized gains on disposal of other unrelated assets in the amounts of $1 million and $2 million, respectively.

During the six months ended June 30, 2009, we received net proceeds of $8 million in connection with our sale of *Sedco 135-D* and disposals of other unrelated property and equipment, and these disposals had no net effect on income taxes or net income. During the three months ended June 30, 2009, we recognized a loss on disposal of assets of $4 million ($0.01 per diluted share), which had no tax effect.

Deepwater Horizon—On April 22, 2010, the Ultra-Deepwater Floater *Deepwater Horizon* sank after a blowout of the Macondo well caused a fire and explosion on the rig. The rig had an insured value of $560 million, which was not subject to a deductible, and our insurance underwriters have declared the vessel a total loss. During the three months ended June 30, 2010, we received $560 million in cash proceeds from insurance recoveries related to the loss of the drilling unit and, for the three and six months ended June 30, 2010, we recognized a gain on the loss of the rig in the amount of $267 million ($0.83 per diluted sh are), which had no tax effect. See Note 12—Contingencies.

Note 9—Debt

Our debt, net of unamortized discounts, premiums and fair value adjustments, was comprised of the following (in millions):

	June 30, 2010			December 31, 2009		
	Transocean Ltd. and subsidiaries	Consolidated variable interest entities	Consolidated total	Transocean Ltd. and subsidiaries	Consolidated variable interest entities	Consolidated total
ODL Loan Facility	$ 10	$ —	$ 10	$ 10	$ —	$ 10
Commercial paper program (a)	104	—	104	281	—	281
6.625% Notes due April 2011 (a)	168	—	168	170	—	170
5% Notes due February 2013	254	—	254	247	—	247
5.25% Senior Notes due March 2013 (a)	509	—	509	496	—	496
TPDI Credit Facilities due March 2015	—	595	595	—	581	581
ADDCL Credit Facilities due August 2017	—	241	241	—	454	454
TPDI Notes due October 2019	—	148	148	—	148	148
6.00% Senior Notes due March 2018 (a)	997	—	997	997	—	997
7.375% Senior Notes due April 2018 (a)	247	—	247	247	—	247
Capital lease obligation due July 2026	—	—	—	15	—	15
8% Debentures due April 2027 (a)	57	—	57	57	—	57
7.45% Notes due April 2027 (a)	96	—	96	96	—	96
7% Senior Notes due June 2028	312	—	312	313	—	313
Capital lease contract due August 2029	703	—	703	711	—	711
7.5% Notes due April 2031 (a)	598	—	598	598	—	598
1.625% Series A Convertible Senior Notes due December 2037 (a)	1,281	—	1,281	1,261	—	1,261
1.50% Series B Convertible Senior Notes due December 2037 (a)	2,093	—	2,093	2,057	—	2,057
1.50% Series C Convertible Senior Notes due December 2037 (a)	2,014	—	2,014	1,979	—	1,979
6.80% Senior Notes due March 2038 (a)	999	—	999	999	—	999
Total debt	10,442	984	11,426	10,534	1,183	11,717
Less debt due within one year						
ODL Loan Facility	10	—	10	10	—	10
Commercial paper program (a)	104	—	104	281	—	281
6.625% Notes due April 2011 (a)	168	—	168	—	—	—
TPDI Credit Facilities due March 2015	—	70	70	—	52	52
ADDCL Credit Facilities due August 2017	—	12	12	—	248	248
Capital lease contract due August 2029	17	—	17	16	—	16
1.625% Series A Convertible Senior Notes due December 2037 (a)	1,281	—	1,281	1,261	—	1,261
Total debt due within one year	1,580	82	1,662	1,568	300	1,868
Total long-term debt	$ 8,862	$ 902	$ 9,764	$ 8,966	$ 883	$ 9,849

(a) Transocean Inc., a wholly owned subsidiary of Transocean Ltd., is the issuer of the notes and debentures, which have been guaranteed by Transocean Ltd. Transocean Ltd. has also guaranteed borrowings under the commercial paper program and the Five-Year Revolving Credit Facility. Transocean Ltd. has no independent assets or operations, its guarantee of debt securities of Transocean Inc. is full and unconditional and its only other subsidiaries not owned indirectly through Transocean Inc. are minor. Transocean Ltd. is not subject to any significant restrictions on its ability to obtain funds from its consolidated subsidiaries or entities accounted for under the equity method by dividends, loans or return of capital distributions.

Scheduled maturities—In preparing the scheduled maturities of our debt, we assume the noteholders will exercise their options to require us to repurchase the 1.625% Series A, 1.50% Series B and 1.50% Series C Convertible Senior Notes (collectively, the "Convertible Senior Notes") in December 2010, 2011 and 2012, respectively. At June 30, 2010, the scheduled maturities of our debt were as follows (in millions):

	Transocean Ltd. and subsidiaries	Consolidated variable interest entities	Consolidated total
Twelve months ending June 30,			
2011	$ 1,595	$ 82	$ 1,677
2012	2,218	96	2,314
2013	2,969	98	3,067
2014	21	99	120
2015	23	346	369
Thereafter	3,909	263	4,172
Total debt, excluding unamortized discounts, premiums and fair value adjustments	10,735	984	11,719
Total unamortized discounts, premiums and fair value adjustments	(293)	—	(293)
Total debt	$ 10,442	$ 984	$ 11,426

Commercial paper program—We maintain a commercial paper program, which is supported by the Five-Year Revolving Credit Facility, under which we may issue privately placed, unsecured commercial paper notes for general corporate purposes up to a maximum aggregate outstanding amount of $1.5 billion. At June 30, 2010, $104 million in commercial paper was outstanding at a weighted-average interest rate of 0.5 percent, excluding commissions.

Five-Year Revolving Credit Facility—We have a $2.0 billion, five-year revolving credit facility under the Five-Year Revolving Credit Facility Agreement dated November 27, 2007, as amended (the "Five-Year Revolving Credit Facility"). Throughout the term of the Five-Year Revolving Credit Facility, we pay a facility fee on the daily amount of the underlying commitment, whether used or unused, which ranges from 0.10 percent to 0.30 percent and was 0.15 percent at June 30, 2010. At June 30, 2010, we had $81 million in letters of credit issued and outstanding and no borrowings outstanding under the Five-Year Revolving Credit Facility.

TPDI Credit Facilities—TPDI has a bank credit agreement for a $1.265 billion secured credit facility (the "TPDI Credit Facilities") comprised of a $1.0 billion senior term loan, a $190 million junior term loan and a $75 million revolving credit facility, which was established to finance the construction of and is secured by *Dhirubhai Deepwater KG1* and *Dhirubhai Deepwater KG2*. One of our subsidiaries participates in the secured term loan with an aggregate commitment of $595 million. At June 30, 2010, $1.2 billi on was outstanding under the TPDI Credit Facilities, of which $577 million was due to one of our subsidiaries and was eliminated in consolidation. The weighted-average interest rate on June 30, 2010 was 2.1 percent. See Note 10—Derivatives and Hedging.

In April 2010, we had a letter of credit issued in the amount of $60 million on behalf of TPDI to satisfy its liquidity requirements under the TPDI Credit Facilities.

TPDI Notes—TPDI has issued promissory notes (the "TPDI Notes") payable to its two shareholders, Pacific Drilling and one of our subsidiaries, which have maturities through October 2019. At June 30, 2010, the aggregate outstanding principal amount was $296 million, of which $148 million was due to one of our subsidiaries and has been eliminated in consolidation. The weighted-average interest rate on June 30, 2010 was 2.4 percent.

ADDCL Credit Facilities—ADDCL has a senior secured bank credit agreement for a credit facility (the "ADDCL Primary Loan Facility") comprised of Tranche A, Tranche B and Tranche C for $215 million, $270 million and $399 million, respectively, which was established to finance the construction of and is secured by *Discoverer Luanda*. Unaffiliated financial institutions provide the commitment for and the borrowings under Tranche A. One of our subsidiaries prov ides the commitment for and the borrowings under Tranche C. In March 2010, ADDCL terminated Tranche B, having repaid borrowings of $235 million under Tranche B using borrowings under Tranche C. At June 30, 2010, $215 million was outstanding under Tranche A at a weighted-average interest rate of 0.8 percent. At June 30, 2010, $399 million was outstanding under Tranche C, which was eliminated in consolidation.

Additionally, ADDCL has a secondary bank credit agreement for a $90 million credit facility (the "ADDCL Secondary Loan Facility"), for which one of our subsidiaries provides 65 percent of the total commitment. At June 30, 2010, $75 million was outstanding under the ADDCL Secondary Loan Facility, of which $49 million was provided by one of our subsidiaries and has been eliminated in consolidation. The weighted-average interest rate on June 30, 2010 was 3.7 percent.

Capital lease obligation—During the six months ended June 30, 2010, we acquired *GSF Explorer*, an asset formerly held under a capital lease, in exchange for a cash payment of $15 million, thereby terminating the capital lease obligation. In connection with the termination of the capital lease obligation, we recognized a gain on debt retirement of $2 million, which had no per diluted share or tax effect. See Note 8—Drilling Fleet.

1.625% Series A, 1.50% Series B and 1.50% Series C Convertible Senior Notes—The carrying amounts of the liability components of the Convertible Senior Notes were as follows (in millions):

	June 30, 2010			December 31, 2009		
	Principal amount	Unamortized discount	Carrying amount	Principal amount	Unamortized discount	Carrying amount
Carrying amount of liability component						
Series A Convertible Senior Notes due 2037	$ 1,299	$ (18)	$ 1,281	$ 1,299	$ (38)	$ 1,261
Series B Convertible Senior Notes due 2037	2,200	(107)	2,093	2,200	(143)	2,057
Series C Convertible Senior Notes due 2037	2,200	(186)	2,014	2,200	(221)	1,979

The carrying amounts of the equity components of the Convertible Senior Notes were as follows (in millions):

	June 30, 2010	December 31, 2009
Carrying amount of equity component		
Series A Convertible Senior Notes due 2037	$ 215	$ 215
Series B Convertible Senior Notes due 2037	275	275
Series C Convertible Senior Notes due 2037	352	352

Including the amortization of the unamortized discount, the effective interest rates were 4.88 percent for the Series A Notes, 5.08 percent for the Series B Notes, and 5.28 percent for the Series C Notes. At June 30, 2010, the remaining period over which the discount will be amortized was less than a year for the Series A Notes, 1.5 years for the Series B Notes and 2.5 years for the Series C Notes. Interest expense, excluding amortization of debt issue costs, was as follows (in millions):

	Three months ended June 30,		Six months ended June 30,	
	2010	2009	2010	2009
Interest expense				
Series A Convertible Senior Notes due 2037	$ 15	$ 22	$ 30	$ 47
Series B Convertible Senior Notes due 2037	26	25	52	50
Series C Convertible Senior Notes due 2037	26	25	52	50

Under certain conditions, holders have the right to convert the Convertible Senior Notes at the applicable conversion rate. As of June 30, 2010, the applicable conversion rate was 5.9310 shares per $1,000 note, equivalent to a conversion price of $168.61 per share. The conversion rate is subject to increase upon the occurrence of certain fundamental changes and adjustment for other corporate events, such as the distribution of cash to our shareholders (see Note 13—Equity).

During the six months ended June 30, 2010, we did not repurchase any of the Convertible Senior Notes. During the six months ended June 30, 2009, we repurchased an aggregate principal amount of $440 million of the 1.625% Series A Notes for an aggregate cash payment of $410 million. During the three and six months ended June 30, 2009, respectively, we recognized a loss on retirement of $8 million ($0.03 per diluted share), with no tax effect, and $10 million ($0.03 per diluted share), with no tax effect, associated with the debt component of the 1.625% Series A Notes and recorded additional paid-in capital of $10 million and $16 million associated with the equity component of the 1.625% Series A Notes.

Note 10—Derivatives and Hedging

Cash flow hedges—TPDI has entered into interest rate swaps, which have been designated and have qualified as a cash flow hedge, to reduce the variability of cash interest payments associated with the variable-rate borrowings under the TPDI Credit Facilities. The aggregate notional amount corresponds with the aggregate outstanding amount of the borrowings under the TPDI Credit Facilities. As of June 30, 2010, the aggregate notional amount was $1.2 billion, of which $577 million was attributable to the intercompany borrowings provided by one of our subsidiaries and the related balances have been eliminated in consolidation. At June 30, 2010, the weighted-average variable interest rate associated with the interest rate swa ps was 0.3 percent, and the weighted-average fixed interest rate was 2.3 percent. At June 30, 2010, the interest rate swaps represented a liability measured at a fair value of $13 million, recorded in other long-term liabilities, with a corresponding increase to accumulated other comprehensive loss. At December 31, 2009, the interest rate swaps represented an asset measured at a fair value of $5 million, recorded in other assets, and a liability measured at a fair value of less than $1 million, recorded in other long-term liabilities, with a corresponding net decrease to accumulated other comprehensive loss. The amount associated with the ineffective portion of the cash flow hedges was less than $1 million, recorded in interest expense for the three and six months ended June 30, 2010. There was no ineffectiveness for the three and six months ended June 30, 2009.

Fair value hedges—Two of our wholly owned subsidiaries have entered into interest rate swaps, which are designated and have qualified as fair value hedges, to reduce our exposure to changes in the fair values of the 5.25% Senior Notes and the 5.00% Notes. The interest rate swaps have aggregate notional amounts of $500 million and $250 million, respectively, equal to the face values of the hedged instruments and have stated maturities that coincide with those of the hedged instruments. We have determined that the hedging relationships qualify for, and we have applied, the shortcut method of accounting, under which the interest rate swaps are considered to have no ineffectiveness and no ongoing assessment of effectiveness is require d. At June 30, 2010, the weighted-average variable interest rate on the interest rate swaps was 3.7 percent, and the fixed interest rates matched those of the underlying debt instruments. At June 30, 2010, the interest rate swaps represented an asset measured at fair value of $14 million, recorded in other assets, with a corresponding increase to the carrying amounts of the underlying debt instruments. At December 31, 2009, the interest rate swaps represented a liability measured at a fair value of $4 million, recorded in other long-term liabilities, with a corresponding decrease to the carrying amount of the underlying debt instrument.

Note 11—Postemployment Benefit Plans

Defined benefit pension plans and other postretirement employee benefit plans—We have several defined benefit pension plans, both funded and unfunded, covering substantially all of our U.S. employees, including certain frozen plans, assumed in connection with our mergers, that cover certain current employees and certain former employees and directors of our predecessors (the “U.S. Plans”). We also have various defined benefit plans in the U.K., Norway, Nigeria, Egypt and Indonesia that cover our employees in those areas (the “Non-U.S. Plans”). Additionally, we offer several unfunded contributory and noncontributory other postretirement employee benefit plans (the “OPEB Plans”) covering substantially all of our U.S. employees. The components of net periodic benefit costs, before tax, and funding contributions were as follows (in millions):

	Three months ended June 30, 2010				Three months ended June 30, 2009			
	U.S. Plans	Non-U.S. Plans	OPEB Plans	Total	U.S. Plans	Non-U.S. Plans	OPEB Plans	Total
Net periodic benefit costs								
Service cost	$ 11	$ 4	$ 1	$ 16	$ 11	$ 4	$ 1	$ 16
Interest cost	14	5	—	19	13	4	—	17
Expected return on plan assets	(15)	(3)	—	(18)	(14)	(4)	—	(18)
Settlements and curtailments	2	—	—	2	—	—	—	—
Actuarial losses, net	3	1	—	4	5	—	—	5
Prior service cost, net	(1)	—	—	(1)	(1)	1	—	—
Net periodic benefit costs	$ 14	$ 7	$ 1	$ 22	$ 14	$ 5	$ 1	$ 20
Funding contributions	$ 49	$ 4	$ 1	$ 54	$ 45	$ —	$ 1	$ 46

	Six months ended June 30, 2010				Six months ended June 30, 2009			
	U.S. Plans	Non-U.S. Plans	OPEB Plans	Total	U.S. Plans	Non-U.S. Plans	OPEB Plans	Total
Net periodic benefit costs								
Service cost	$ 21	$ 10	$ 1	$ 32	$ 22	$ 8	$ 1	$ 31
Interest cost	27	8	1	36	25	8	1	34
Expected return on plan assets	(29)	(8)	—	(37)	(27)	(7)	—	(34)
Settlements and curtailments	2	1	—	3	2	—	—	2
Actuarial losses, net	7	4	—	11	9	—	—	9
Prior service cost, net	(1)	—	(1)	(2)	(1)	1	—	—
Net periodic benefit costs	$ 27	$ 15	$ 1	$ 43	$ 30	$ 10	$ 2	$ 42
Funding contributions	$ 51	$ 8	$ 3	$ 62	$ 47	$ 1	$ 2	$ 50

Severance plan—Following our merger with GlobalSantaFe in 2007, we established a plan to consolidate operations and administrative functions and identified 377 employees that were involuntarily terminated pursuant to this plan. We recognized $5 million and $8 million of severance expense, recorded in either operating and maintenance expense or general and administrative expense and paid $13 million and $9 million in severance payments under this plan in the six months ended June 30, 2010 and June 30, 2009, respectively. No additional expense will be recognized under the severance plan, which expired in January 2010. The liability associated with the severance plan, recorded in other current liabiliti es, was $9 million and $17 million at June 30, 2010 and December 31, 2009, respectively. Since the severance plan's inception in 2007, we have paid $66 million in termination benefits under the plan.

Note 12—Contingencies

Macondo well incident

Overview—On April 22, 2010, the Ultra-Deepwater Floater *Deepwater Horizon* sank after a blowout of the Macondo well caused a fire and explosion on the rig. Eleven persons have been declared dead and others were injured as a result of the incident. At the time of the explosion, *Deepwater Horizon* was located approxim ately 41 miles off the coast of Louisiana in Mississippi Canyon Block 252 and was contracted to BP America Production Co. ("BP").

As we continue to investigate the cause or causes of the incident, we are evaluating its consequences. Although we cannot predict the final outcome or estimate the reasonably possible range of loss with certainty, as of June 30, 2010, we have recognized a liability of approximately $80 million, recorded in other current liabilities on our condensed consolidated balance sheet based on estimated losses related to the incident that we believe are probable and for which a reasonable estimate can be made. We believe that a portion of this liability may be recoverable from insurance. New information or future developments could require us to adjust our disclosures and our estimated liabili ties and insurance recoveries. See "—Retained risk" and "—Contractual indemnity."

Litigation—As of June 30, 2010, 206 actions or claims have been filed against Transocean entities, along with other unaffiliated defendants, in state and federal courts. Additionally, government agencies have initiated investigations into the Macondo well incident. We have categorized below the nature of the legal actions or claims. We are evaluating all claims and intend to vigorously defend any claims and pursue any and all defenses available. In addition, we believe we are entitled to contractual defense and indemnity for all wrongful death and personal injury claims made by non-employees and third-party subcontractors' employees as well as all liabilities for pollution or contamination, other than for pollution or contamination originating on or above the surface of the water. See "—Contractual indemnity."

Wrongful death and personal injury—Since April 2010, we and one or more of our subsidiaries have been named, along with other unaffiliated defendants, in eight complaints that were filed in state and federal courts in Louisiana and Texas involving multiple plaintiffs that allege wrongful death and other personal injuries arising out of the Macondo well incident. The complaints generally allege negligence and seek awards of unspecified economic damages and punitive damages. BP p.l.c., MI-SWACO and Weatherford Ltd. have, based on contractual arrangements, also made indemnity demands upon us with respect to personal injury and wrongful death claims asserted by our employees or representatives of our employees against these entities. See "—Contractual indemnity."

Economic loss—Since April 2010, we and one or more of our subsidiaries have been named, along with other unaffiliated defendants, in 50 individual complaints as well as 139 putative class-action complaints filed in the federal and state courts in Louisiana, Texas, Mississippi, Alabama, Georgia, Kentucky, South Carolina, Tennessee, Colorado and possibly other courts. The complaints generally allege, among other things, potential economic losses as a result of environmental pollution arising out of the Macondo well incident and are based primarily on the Oil Pollution Act of 1990 ("OPA") and state OPA analogues. See "—Environmental matters." One complaint also alleges a violation of the Racketeer Influenced and Corrupt Organizations Act. The plaintiffs are generally seeking awards of unspecified economic, compensatory and punitive damages, as well as injunctive relief. See "—Contractual indemnity."

Federal securities claims—Since April 2010, three federal securities law class actions have been filed naming us and certain of our officers and directors as defendants, two of which were filed in the United States District Court, Southern District of New York, and one of which was filed in the United States District Court, Eastern District of Louisiana. These actions generally allege violations of Section 10(b) of the Securities Exchange Act of 1934 (the "Exchange Act"), Rule 10b 5 promulgated under the Exchange Act and Section 20(a) of the Exchange Act in connection with the Macondo well incident. The plaintiffs are generally seeking awards of unspecified economic damages, including damages resulting from the recent decline in our stock price.

Shareholder derivative claims—In June 2010, two shareholder derivative suits were filed naming us as a nominal defendant and certain of our officers and directors as defendants in the District Courts of the State of Texas. The first case generally alleges breach of fiduciary duty, unjust enrichment, abuse of control, gross mismanagement and waste of corporate assets in connection with the Macondo well incident and the other generally alleges breach of fiduciary duty, unjust enrichment and waste of corporate assets in connection with the Macondo well incident.& #160; The plaintiffs are generally seeking, on behalf of Transocean, restitution and disgorgement of all profits, benefits and other compensation from the defendants.

Environmental matters—Environmental claims under two different schemes, statutory and common law, and in two different regimes, federal and state, have been asserted against us. See "—Litigation—Economic loss." Liability under many statutes is imposed without fault, but such statutes often allow the amount of damages to be limited. In contrast, common law liability requires proof of fault and causation, but generally has no readily defined limitation on damages, other than the type of damages that may be redressed. We have described below certain significant applicable environmental statutes and matters relating to the Macondo well incident. As described below, we believe that we have limited statutory environmental liability and we are entitled to contractual defense and indemnity for all liabilities for pollution or contamination, other than for pollution or contamination originating on or above the surface of the water. See "—Contractual indemnity."

*Oil Pollution Act***—**OPA imposes strict liability on responsible parties of vessels or facilities from which oil is discharged into or upon navigable waters or adjoining shore lines. OPA defines the responsible parties with respect to the source of discharge. We believe that the owner or operator of a mobile offshore drilling unit ("MODU"), such as *Deepwater Horizon*, is only a responsible party with respect to discharges from the vessel that occur on or above the surfac e of the water. As the responsible party for *Deepwater Horizon*, we believe we are responsible only for the discharges of oil emanating from the rig. Therefore, we believe we are not responsible for the discharged hydrocarbons from the Macondo well.

Responsible parties for discharges are liable for: (1) removal and cleanup costs, (2) damages that result from the discharge, including natural resources damages, generally up to a statutorily defined limit, (3) reimbursement for government efforts and (4) certain other specified damages. For responsible parties of MODUs, the limitation on liability is determined based on the gross tonnage of the vessel. The statutory limits are not applicable, however, if the discharge is the result of gross negligence, willful misconduct, or violation of federal construction or permitting regulations by the responsible party or a party in a contractual relationship with the responsible party.

*Other federal statutes***—**Several of the claimants have made assertions under other statutes, including the Clean Water Act, the Endangered Species Act, the Migratory Bird Treaty Act and the Clean Air Act.

State environmental laws—As of June 30, 2010, claims have been asserted by private claimants under state environmental statutes in Florida, Louisiana and Mississippi. As described below, the only claim currently asserted by a state government is pending in Louisiana.

In June 2010, the Louisiana Department of Environmental Quality (the "LDEQ") issued a consolidated compliance order and notice of potential penalty to us and certain of our subsidiaries asking us to eliminate and remediate discharges of oil and other pollutants into waters and property located in the State of Louisiana, and to submit a plan and report in response to the order. We have requested that the LDEQ rescind the enforcement actions against us and our subsidiaries because the remediation actions that are the subject of such orders are actions that do not involve us or our subsidiaries, as we are not involved in the remediation or clean-up activities. Alternatively, if the LDEQ will not rescind the enforcement actions altogether, we have requested the LDEQ to dismiss the enforcement actions against us and certain of our subsidiaries as these entities are not proper parties to the enforcement actions and were improperly served. We have requested an administrative hearing on the charges alleged in these orders.

By letter dated May 5, 2010, the Attorneys General of the five Gulf Coast states of Alabama, Florida, Louisiana, Mississippi and Texas informed us that they intend to seek recovery of pollution clean up costs and related damages arising from the Macondo well incident. In addition, by letter dated June 21, 2010, the Attorneys General of the 11 Atlantic Coast states of Connecticut, Delaware, Georgia, Maine, Maryland, Massachusetts, New Hampshire, New York, North Carolina, Rhode Island and South Carolina informed us that their states have not sustained any damage from the Macondo 60;well incident but they would like assurances that we will be responsible financially if damages are sustained. We responded to each letter from the Attorneys General and indicated that we intend to fulfill our obligations as a responsible party for any discharge of oil from *Deepwater Horizon* on or above the surface of the water, and we assume that the operator will similarly fulfill its obligations under OPA for the ongoing discharge from the undersea well.

Wreck removal—We may be requested to remove the diesel fuel from the wreckage, if it is present, as well as various forms of debris from *Deepwater Horizon*. We have insurance coverage for wreck removal for up to 25 percent of *Deepwater Horizon's* insured value, or $140 million, with any excess wreck removal liability, generally covered to the extent of our excess liability coverage.

Contractual indemnity—Under our drilling contract for *Deepwater Horizon*, the operator has agreed, among other things, to assume full responsibility for and defend, release and indemnify us from any loss, expense, claim, fine, penalty or liability for pollution or contamination, including control and removal thereof, arising out of or connected with operations under the contract other than for pollution or contamination originating on or above the surface of the water from hydrocarbons or other specified substances within the control and poss ession of the contractor, as to which we agreed to assume responsibility and protect, release and indemnify the operator. Although we do not believe it is applicable to the Macondo well incident, we also agreed to indemnify and defend the operator up to a limit of $15 million for claims for loss or damage to third parties arising from pollution caused by the rig while it is off the drilling location, while the rig is underway or during drive off or drift off of the rig from the drilling location. The operator has also agreed, among other things, (1) to defend, release and indemnify us against loss or damage to the reservoir, and loss of property rights to oil, gas and minerals below the surface of the earth and (2) to defend, release and indemnify us and bear the cost of bringing the well under control in the event of a blowout or other loss of control. We agreed to defend , release and indemnify the operator for personal injury and death of our employees, invitees and the employees of our subcontractors while the operator agreed to defend, release and indemnify us for personal injury and death of its employees, invitees and the employees of its other subcontractors (other than us). We have also agreed to defend, release and indemnify the operator for damages to the rig and equipment, including salvage or removal costs.

Given the potential amounts involved in connection with the Macondo well incident, the operator may seek to avoid its indemnification obligations. In particular, the operator, in response to our request for indemnification, has generally reserved all of its rights and stated that it could not at this time conclude that it is obligated to indemnify us. In doing so, the operator has asserted that the facts are not sufficiently developed to determine who is responsible and has cited a variety of possible legal theories based upon the contract and facts still to be developed. We believe this reservation of rights is without justification and that the operator is required to honor its indemnification obligations contained in our con tract and described above.

Other legal proceedings

Asbestos litigation—In 2004, several of our subsidiaries were named, along with numerous other unaffiliated defendants, in 21 complaints filed on behalf of 769 plaintiffs in the Circuit Courts of the State of Mississippi and which claimed injuries arising out of exposure to asbestos allegedly contained in drilling mud during these plaintiffs' employment in drilling activities between 1965 and 1986. A Special Master, appointed to administer these cases pre-trial, subsequently required that each individual plaintiff file a separate lawsuit, and the original 21 multi-plaintiff complaints were then dismissed by th e Circuit Courts. The amended complaints resulted in one of our subsidiaries being named as a direct defendant in seven cases. We have or may have an indirect interest in an additional 17 cases. The complaints generally allege that the defendants used or manufactured asbestos-containing products in connection with drilling operations and have included allegations of negligence, products liability, strict liability and claims allowed under the Jones Act and general maritime law. The plaintiffs generally seek awards of unspecified compensatory and punitive damages. In each of these cases, the complaints have named other unaffiliated defendant companies, including companies that allegedly manufactured the drilling-related products that contained asbestos. None of the cases in which one of our subsidiaries is a named defendant has been scheduled for trial in 2010, and the preliminary information available on these claims is not sufficient to determine if there is an identifiable period for alleged exposure to asbestos, whether any asbestos exposure in fact occurred, the vessels potentially involved in the claims, or the basis on which the plaintiffs would support claims that their injuries were related to exposure to asbestos. However, the initial evidence available would suggest that we would have significant defenses to liability and damages. In 2009, two cases that were part of the original 2004 multi-plaintiff suits went to trial in Mississippi against unaffiliated defendant companies which allegedly manufactured drilling-related products containing asbestos. We were not a defendant in either of these cases. One of the cases resulted in a substantial jury verdict in favor of the plaintiff, and this verdict was subsequently vacated by the trial judge on the basis that the plaintiff failed to meet its burden of p roof. While the court's decision is consistent with our general evaluation of the strength of these cases, it has not been reviewed on appeal. The second case resulted in a verdict completely in favor of the defendants. There have been no other trials involving any of the parties to the original 21 complaints. We intend to defend these lawsuits vigorously, although there can be no assurance as to the ultimate outcome. We historically have maintained broad liability insurance, although we are not certain whether insurance will cover the liabilities, if any, arising out of these claims. Based on our evaluation of the exposure to date, we do not expect the liability, if any, resulting from these claims to have a material adverse effect on our consolidated statement of financial position, results of operations or cash flows.

One of our subsidiaries was involved in lawsuits arising out of the subsidiary's involvement in the design, construction and refurbishment of major industrial complexes. The operating assets of the subsidiary were sold and its operations discontinued in 1989, and the subsidiary has no remaining assets other than the insurance policies involved in its litigation, fundings from settlements with insurers, assigned rights from insurers and "coverage-in-place" settlement agreements with insurers, and funds received from the cancellation of certain insurance policies. The subsidiary has been named as a defendant, along with numerous other companies, in lawsuits alleging personal injury as a result of exposure to asbestos. ; As of June 30, 2010, the subsidiary was a defendant in approximately 1,062 lawsuits. Some of these lawsuits include multiple plaintiffs and we estimate that there are approximately 2,569 plaintiffs in these lawsuits. For many of these lawsuits, we have not been provided with sufficient information from the plaintiffs to determine whether all or some of the plaintiffs have claims against the subsidiary, the basis of any such claims, or the nature of their alleged injuries. The first of the asbestos-related lawsuits was filed against this subsidiary in 1990. Through June 30, 2010, the amounts expended to resolve claims, including both attorneys' fees and expenses and settlement costs, have not been material, and all deductibles with respect to the primary insurance have been satisfied. The subsidiary continues to be named as a defendant in additional lawsuits, and we cannot predict the number of additional cases in whi ch it may be named a defendant nor can we predict the potential costs to resolve such additional cases or to resolve the pending cases. However, the subsidiary has in excess of $1 billion in insurance limits potentially available to the subsidiary. Although not all of the policies may be fully available due to the insolvency of certain insurers, we believe that the subsidiary will have sufficient funding from settlements and claims payments from insurers, assigned rights from insurers and "coverage-in-place" settlement agreements with insurers to respond to these claims. While we cannot predict or provide assurance as to the final outcome of these matters, we do not believe that the current value of the claims where we have been identified will have a material impact on our consolidated statement of financial position, results of operations or cash flows.

Rio de Janeiro tax assessment—In the third quarter of 2006, we received tax assessments of approximately $164 million from the state tax authorities of Rio de Janeiro in Brazil against one of our Brazilian subsidiaries for taxes on equipment imported into the state in connection with our operations. The assessments resulted from a preliminary finding by these authorities that our subsidiary's record keeping practices were deficient. We currently believe that the substantial majority of these assessments are without merit. We filed an initial response with the Rio de Janeiro tax authorities on September 9, 2006 refuting these additional tax assessments. In September 2007, we received confirmation from the state tax authorities that they believe the additional tax assessments are valid, and as a result, we filed an appeal on September 27, 2007 to the state Taxpayer's Council contesting these assessments. While we cannot predict or provide assurance as to the final outcome of these proceedings, we do not expect it to have a material adverse effect on our consolidated statement of financial position, results of operations or cash flows.

Patent litigation—Several of our subsidiaries have been sued by Heerema Engineering Services ("Heerema") in the United States District Court for the Southern District of Texas for patent infringement, claiming that we infringe their U.S. patent entitled Method and Device for Drilling Oil and Gas. Heerema claims that our Enterprise class, advanced Enterprise class, Express class and Development Driller class of drilling rigs operating in the U.S. Gulf of Mexico infringe on this patent. Heerema seeks unspecified damages and injunctive relief. The court has held a hearing on constr uction of their patent but has not yet issued a decision. We deny liability for patent infringement, believe that their patent is invalid and intend to vigorously defend against the claim. We do not expect the liability, if any, resulting from this claim to have a material adverse effect on our consolidated statement of financial position, results of operations or cash flows.

Other matters—We are involved in various tax matters and various regulatory matters. We are also involved in lawsuits relating to damage claims arising out of hurricanes Katrina and Rita, all of which are insured and which are not material to us. In addition, as of June 30, 2010, we were involved in a number of other lawsuits, including a dispute for municipal tax payments in Brazil and a dispute involving customs procedures in India, neither of which is material to us, and all of which have arisen in the ordinary course of our business. We do not expect the liability, if any, resultin g from these other matters to have a material adverse effect on our consolidated statement of financial position, results of operations or cash flows. We cannot predict with certainty the outcome or effect of any of the litigation matters specifically described above or of any such other pending or threatened litigation. There can be no assurance that our beliefs or expectations as to the outcome or effect of any lawsuit or other litigation matter will prove correct and the eventual outcome of these matters could materially differ from management's current estimates.

Other environmental matters

Hazardous waste disposal sites—We have certain potential liabilities under the Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA") and similar state acts regulating cleanup of various hazardous waste disposal sites, including those described below. CERCLA is intended to expedite the remediation of hazardous substances without regard to fault. Potentially responsible parties ("PRPs") for each site include present and former owners and operators of, transporters to and generators of the substances at the site. Liability is strict and can be joint and several.

We have been named as a PRP in connection with a site located in Santa Fe Springs, California, known as the Waste Disposal, Inc. site. We and other PRPs have agreed with the U.S. Environmental Protection Agency ("EPA") and the U.S. Department of Justice ("DOJ") to settle our potential liabilities for this site by agreeing to perform the remaining remediation required by the EPA. The form of the agreement is a consent decree, which has been entered by the court. The parties to the settlement have entered into a participation agreement, which makes us liable for approximately eight percent of the remediation and related costs. The remediation is complete, and we believe our share of the future operation and maintenance costs of the site is not material. There are additional potential liabilities related to the site, but these cannot be quantified, and we have no reason at this time to believe that they will be material.

One of our subsidiaries has been ordered by the California Regional Water Quality Control Board ("CRWQCB") to develop a testing plan for a site known as Campus 1000 Fremont in Alhambra, California. This site was formerly owned and operated by certain of our subsidiaries. It is presently owned by an unrelated party, which has received an order to test the property. We have also been advised that one or more of our subsidiaries is likely to be named by the EPA as a PRP for the San Gabriel Valley, Area 3, Superfund site, which includes this property. Testing has been completed at the property but no contaminants of concern were d etected. In discussions with CRWQCB staff, we were advised of their intent to issue us a "no further action" letter but it has not yet been received. Based on the test results, we would contest any potential liability. We have no knowledge at this time of the potential cost of any remediation, who else will be named as PRPs, and whether in fact any of our subsidiaries is a responsible party. The subsidiaries in question do not own any operating assets and have limited ability to respond to any liabilities.

Resolutions of other claims by the EPA, the involved state agency or PRPs are at various stages of investigation. These investigations involve determinations of:

- § the actual responsibility attributed to us and the other PRPs at the site;
- § appropriate investigatory or remedial actions; and
- § allocation of the costs of such activities among the PRPs and other site users.

Our ultimate financial responsibility in connection with those sites may depend on many factors, including:

- § the volume and nature of material, if any, contributed to the site for which we are responsible;
- § the numbers of other PRPs and their financial viability; and
- § the remediation methods and technology to be used.

It is difficult to quantify with certainty the potential cost of these environmental matters, particularly in respect of remediation obligations. Nevertheless, based upon the information currently available, we believe that our ultimate liability arising from all environmental matters, including the liability for all other related pending legal proceedings, asserted legal claims and known potential legal claims which are likely to be asserted, is adequately accrued and should not have a material effect on our financial position, or ongoing results of operations. Estimated costs of future expenditures for environmental remediation obligations are not discounted to their present value.

Contamination litigation

On July 11, 2005, one of our subsidiaries was served with a lawsuit filed on behalf of three landowners in Louisiana in the 12th Judicial District Court for the Parish of Avoyelles, State of Louisiana. The lawsuit named 19 other defendants, all of which were alleged to have contaminated the plaintiffs' property with naturally occurring radioactive material, produced water, drilling fluids, chlorides, hydrocarbons, heavy metals and other contaminants as a result of oil and gas exploration activities. Experts retained by the plaintiffs issued a report suggesting significant contamination in the area operated by the subsidiary and another codefendant, a nd claimed that over $300 million would be required to properly remediate the contamination. The experts retained by the defendants conducted their own investigation and concluded that the remediation costs would amount to no more than $2.5 million.

The plaintiffs and the codefendant threatened to add GlobalSantaFe as a defendant in the lawsuit under the "single business enterprise" doctrine contained in Louisiana law. The single business enterprise doctrine is similar to corporate veil piercing doctrines. On August 16, 2006, our subsidiary and its immediate parent company, each of which is an entity that no longer conducts operations or holds assets, filed voluntary petitions for relief under Chapter 11 of the U.S. Bankruptcy Code in the U.S. Bankruptcy Court for the District of Delaware. Later that day, the plaintiffs dismissed our subsidiary from the lawsuit. Subsequently, the codefendant filed various motions in the lawsuit and in the Delawa re bankruptcies attempting to assert alter ego and single business enterprise claims against GlobalSantaFe and two other subsidiaries in the lawsuit. The efforts to assert alter ego and single business enterprise theory claims against GlobalSantaFe were rejected by the Court in Avoyelles Parish, and the lawsuit against the other defendant went to trial on February 19, 2007. This lawsuit was resolved at trial with a settlement by the codefendant that included a $20 million payment and certain cleanup activities to be conducted by the codefendant.

The codefendant sought to dismiss the bankruptcies. In addition, the codefendant filed proofs of claim against both our subsidiary and its parent with regard to its claims arising out of the settlement of the lawsuit. On February 15, 2008, the Bankruptcy Court denied the codefendant's request to dismiss the bankruptcy case but modified the automatic stay to allow the codefendant to proceed on its claims against the debtors, our subsidiary and its parent, and their insurance companies. The codefendant subsequently filed suit against the debtors and certain of its insurers in the Court of Avoyelles Parish to determine their liability for the settlement. The denial of the motion to dismiss the bankruptcies was app ealed. On appeal the bankruptcy cases were ordered to be dismissed, and the bankruptcies were dismissed on June 14, 2010.

On March 10, 2010, GlobalSantaFe and the two subsidiaries filed a declaratory judgment action in State District Court in Houston, Texas against the codefendant and the debtors seeking a declaration that GlobalSantaFe and the two subsidiaries had no liability under legal theories advanced by the codefendant. On March 11, 2010, the codefendant filed a motion for leave to amend the pending litigation in Avoyelles Parish to add GlobalSantaFe, Transocean Worldwide Inc., its successor and our wholly owned subsidiary, and one of the subsidiaries as well as various additional insurers. Leave to amend was granted and the amended petition was filed. An extension to respond for all purposes was agreed until April& #160;28, 2010 for the debtors, GlobalSantaFe, Transocean Worldwide Inc. and the subsidiary. On April 28, 2010, GlobalSantaFe and its two subsidiaries filed various exceptions seeking dismissal of the Avoyelles Parish lawsuit, which have been denied.

We believe that these legal theories should not be applied against GlobalSantaFe or Transocean Worldwide Inc. Our subsidiary, its parent and GlobalSantaFe intend to continue to vigorously defend against any action taken in an attempt to impose liability against them under the theories discussed above or otherwise and believe they have good and valid defenses thereto. We do not believe that these claims will have a material impact on our consolidated statement of financial position, results of operations or cash flows.

Retained risk

Our hull and machinery and excess liability insurance program consists of commercial market and captive insurance policies primarily with 12-month and 11-month policy periods beginning on May 1, 2010 and June 1, 2010, respectively.

Under the hull and machinery program, we generally maintain a $125 million per occurrence deductible, limited to a maximum of $250 million per policy period. Subject to the same shared deductible, we also have coverage for costs incurred to mitigate damage to a rig up to an amount equal to 25 percent of a rig's insured value. Also subject to the same shared deductible, we have coverage for wreck removal for an amount up to 25 percent of a rig's insured value, with any excess generally covered to the extent of our excess liability coverage described below. However, the shared deductible is $0 in the event of a total loss or a constru ctive total loss of a drilling unit.

We carry $950 million of commercial market excess liability coverage, exclusive of deductibles and self-insured retention, noted below, which generally covers offshore risks such as personal injury, third-party property claims, and third-party non-crew claims, including wreck removal and pollution. Our excess liability coverage has separate (1) $10 million per occurrence deductibles on crew personal injury liability and on collision liability claims and (2) a separate $5 million per occurrence deductible on other third-party non-crew claims. These types of excess liability coverages are subjec t to an additional aggregate self-insured retention of $50 million that is applied to any occurrence in excess of the per occurrence deductible until the $50 million is exhausted. We generally retain the risk for any liability losses in excess of $1.0 billion.

We also carry $100 million of additional insurance that generally covers expenses that would otherwise be assumed by the well owner, such as costs to control the well, redrill expenses and pollution from the well. This additional insurance provides coverage for such expenses in circumstances in which we have legal or contractual liability arising from our gross negligence or willful misconduct. As of June 30, 2010, the insured value of our drilling rig fleet was approximately $36.9 billion in the aggregate, excluding rigs under construction.

We have elected to self-insure operators extra expense coverage for ADTI and CMI. This coverage provides protection against expenses related to well control, pollution and redrill liability associated with blowouts. ADTI's customers assume, and indemnify ADTI for, liability associated with blowouts in excess of a contractually agreed amount, generally $50 million.

We generally do not have commercial market insurance coverage for physical damage losses, including liability for wreck removal expenses, to our fleet caused by named windstorms in the U.S. Gulf of Mexico and war perils worldwide. Except with respect to *Dhirubhai Deepwater KG1* and *Dhirubhai Deepwater KG2*, we generally do not carry insurance for loss of revenue unless contractually required.

Letters of credit and surety bonds

We had letters of credit outstanding totaling $479 million and $567 million at June 30, 2010 and December 31, 2009, respectively. These letters of credit guarantee various contract bidding and performance activities under various committed and uncommitted credit lines provided by several banks. In April 2010, we had a letter of credit issued in the amount of $60 million on behalf of TPDI to satisfy its liquidity requirements under the TPDI Credit Facilities, which is included in the total as of June 30, 2010 (see Note 9—Debt).

As is customary in the contract drilling business, we also have various surety bonds in place that secure customs obligations relating to the importation of our rigs and certain performance and other obligations. Surety bonds outstanding totaled $24 million and $31 million at June 30, 2010 and December 31, 2009, respectively.

Note 13—Equity

Shares held by subsidiary—In December 2008, we issued 16 million of our shares to one of our subsidiaries for future use to satisfy our obligations to deliver shares in connection with awards granted under our incentive plans or other rights to acquire our shares. At June 30, 2010 and December 31, 2009, our subsidiary held 13,455,824 shares and 14,011,416 shares, respectively.

Share repurchase program—In May 2009, at our annual general meeting, our shareholders approved and authorized our board of directors, at its discretion, to repurchase an amount of our shares for cancellation with an aggregate purchase price of up to CHF 3.5 billion, which is equivalent to approximately U.S. $3.2 billion, using an exchange rate of USD 1.00 to CHF 1.08 as of the close of trading on June 30, 2010. On February 12, 2010, our board of directors authorized our management to implement the share repurchase program.

During the three months ended June 30, 2010, following the authorization by our board of directors, we repurchased 2,146,267 of our shares under our share repurchase program for an aggregate purchase price of CHF 193 million, equivalent to $180 million. During the six months ended June 30, 2010, following the authorization by our board of directors, we repurchased 2,863,267 of our shares under our share repurchase program for an aggregate purchase price of CHF 257 million, equivalent to $240 million. At June 30, 2010, we held 2,863,267 treasury shares purchased under our share repurchase program, recorded at cost.< /div>

Distribution—In May 2010, at our annual general meeting, our shareholders approved a cash distribution in the form of a par value reduction in the aggregate amount of CHF 3.44 per issued share, equal to approximately $3.19, using an exchange rate of USD 1.00 to CHF 1.08 as of the close of trading on June 30, 2010. We expect the cash distribution to be calculated and paid in four quarterly installments. Under Swi ss law, upon satisfaction of all legal requirements, we must submit an application to the commercial register in the Canton of Zug to register the applicable par value reduction.

We intend to fund any installments using our available cash balances and our cash flows from operations. Shareholders are expected to be paid in U.S. dollars, converted using an exchange rate determined by us approximately two business days prior to the payment date, unless shareholders elect to receive the payment in Swiss francs. Distributions to shareholders in the form of a reduction in par value of our shares are not subject to the 35 percent Swiss withholding tax. In May 2010, we recognized a distribution payable in the amount of approximately $1.0 billion, recorded in other current liabilities, with a corresponding entry to additional paid-in capital. Upon registration of an installment with the commercia l register of the Canton of Zug, we expect to reduce our par value and reclassify from additional paid-in capital to shares the portion of the distribution associated with the respective installment. At June 30, 2010, the carrying amount of the unpaid distribution payable was $1.0 billion.

Note 14—Fair Value of Financial Instruments

We estimate the fair value of each class of financial instruments, for which estimating fair value is practicable, by applying the following methods and assumptions:

Cash and cash equivalents—The carrying amount approximates fair value because of the short maturities of those instruments.

Accounts receivable—The carrying amount, net of valuation allowance, approximates fair value because of the short maturities of those instruments.

Short-term investments—The carrying amount of our short-term investments approximates fair value and represents our estimate of the amount we expect to recover. Our short-term investments primarily include our investment in The Reserve International Liquidity Fund Ltd. At June 30, 2010 and December 31, 2009, the carrying amount of our short-term investments was $32 million and $38 million, respectively, recorded in other current assets on our condensed consolidated balance sheets.

Notes receivable and working capital loan receivable—The carrying amount represents the estimated fair value, measured using unobservable inputs that require significant judgment, for which there is little or no market data, including the credit rating of the borrower. At June 30, 2010, the aggregate carrying amount of our notes receivable and working capital loan receivable was $121 million, including $10 million and $111 million recorded in other current assets and other assets, respectively. We did not hold notes receivable as of December 31, 2009.

Debt—The fair value of our fixed-rate debt is measured using quoted prices for identical instruments in active markets. Our variable-rate debt is included in the fair values stated below at its carrying amount since the short-term interest rates cause the face value to approximate its fair value. The TPDI Notes and ODL Loan Facility are included in the fair values stated below at their aggregate carrying amount of $158 million at June 30, 2010 and December 31, 2009, since there is no available market price for such related-party debt. The carrying amounts and estimated fair values of our long-term debt, including debt due within one year, were as follows (in millions):

	June 30, 2010		December 31, 2009	
	Carrying amount	Fair value	Carrying amount	Fair value
Long-term debt, including current maturities	$ 10,442	$ 9,751	$ 10,534	$ 11,218
Long-term debt of consolidated variable interest entities, including current maturities	984	997	1,183	1,178

Derivative instruments—The carrying amount of our derivative instruments represents the estimated fair value, measured using direct or indirect observable inputs, including quoted prices or other market data for similar assets or liabilities in active markets or identical assets or liabilities in less active markets. At June 30, 2010, the carrying amounts of our derivative instruments were $14 million and $13 million recorded in other assets and other long-term liabilities, respectively, on our condensed consolidated balance sheets. At December 31, 2009, the carrying amounts of our derivative instruments were $5 million and $5 million recorded in other assets and other long-term liabilities, respectively, on our condensed consolidated balan ce sheets.

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

Forward-Looking Information

The statements included in this quarterly report regarding future financial performance and results of operations and other statements that are not historical facts are forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Forward-looking statements in this quarterly report include, but are not limited to, statements about the following subjects:

- § the impact of the Macondo well incident and related matters,
- § the offshore drilling market, including the impact of the drilling moratorium in the United States ("U.S.") Gulf of Mexico, supply and demand, utilization rates, dayrates, customer drilling programs, commodity prices, stacking of rigs, reactivation of rigs, effects of new rigs on the market and effects of declines in commodity prices and the downturn in the global economy or market outlook for our various geographical operating sectors and classes of rigs,
- § customer contracts, including contract backlog, force majeure provisions, contract commencements, contract extensions, contract terminations, contract option exercises, contract revenues, contract awards and rig mobilizations,
- § newbuild, upgrade, shipyard and other capital projects, including completion, delivery and commencement of operation dates, expected downtime and lost revenue, the level of expected capital expenditures and the timing and cost of completion of capital projects,
- § liquidity and adequacy of cash flow for our obligations, including our ability and the expected timing to access certain investments in highly liquid instruments,
- § our results of operations and cash flow from operations, including revenues and expenses,
- § uses of excess cash, including the payment of dividends and other distributions, debt retirement and share repurchases under our share repurchase program,
- § the cost and timing of acquisitions and the proceeds and timing of dispositions,
- § tax matters, including our effective tax rate, changes in tax laws, treaties and regulations, tax assessments and liabilities for tax issues, including those associated with our activities in Brazil, Norway and the U.S.,
- § legal and regulatory matters, including results and effects of legal proceedings and governmental audits and assessments, outcomes and effects of internal and governmental investigations, customs and environmental matters,
- § insurance matters, including adequacy of insurance, renewal of insurance, insurance proceeds and cash investments of our wholly owned captive insurance company,
- § debt levels, including impacts of the financial and economic downturn,
- § effects of accounting changes and adoption of accounting policies, and
- § investments in recruitment, retention and personnel development initiatives, pension plan and other postretirement benefit plan contributions, the timing of severance payments and benefit payments.

Forward-looking statements in this quarterly report are identifiable by use of the following words and other similar expressions:

§ "anticipates"	§ "estimates"	§ "may"	§ "projects"
§ "believes"	§ "expects"	§ "might"	§ "scheduled"
§ "budgets"	§ "forecasts"	§ "plans"	§ "should"
§ "could"	§ "intends"	§ "predicts"	

Such statements are subject to numerous risks, uncertainties and assumptions, including, but not limited to:

- § those described under "Item 1A. Risk Factors" included herein and in our annual report on Form 10-K for the year ended December 31, 2009,
- § the adequacy of and access to sources of liquidity,
- § our inability to obtain contracts for our rigs that do not have contracts,
- § the cancellation of contracts currently included in our reported contract backlog,
- § the effect and results of litigation, tax audits and contingencies, and
- § other factors discussed in this quarterly report and in our other filings with the U.S. Securities and Exchange Commission ("SEC"), which are available free of charge on the SEC website at www.sec.gov.

The foregoing risks and uncertainties are beyond our ability to control, and in many cases, we cannot predict the risks and uncertainties that could cause our actual results to differ materially from those indicated by the forward-looking statements. Should one or more of these risks or uncertainties materialize, or should underlying assumptions prove incorrect, actual results may vary materially from those indicated.

All subsequent written and oral forward-looking statements attributable to us or to persons acting on our behalf are expressly qualified in their entirety by reference to these risks and uncertainties. You should not place undue reliance on forward-looking statements. Each forward-looking statement speaks only as of the date of the particular statement, and we undertake no obligation to publicly update or revise any forward-looking statements, except as required by law.

Business

Transocean Ltd. (together with its subsidiaries and predecessors, unless the context requires otherwise, “Transocean,” the “Company,” “we,” “us” or “our”) is a leading international provider of offshore contract drilling services for oil and gas wells. As of July 15, 2010, we owned, had partial ownership interests in or operated 139 mobile offshore drilling units. As of this date, our fleet consisted of 45 High-Specification Floaters (Ultra-Deepwater, Deepwater and Harsh Environment semisubmersibles and drillships), 26 Midwater Floaters, 10 0;High-Specification Jackups, 55 Standard Jackups and three Other Rigs. In addition, we had three Ultra-Deepwater Floaters under construction.

We have two reportable segments: (1) contract drilling services and (2) other operations. Contract drilling services, our primary business, involves contracting our mobile offshore drilling fleet, related equipment and work crews primarily on a dayrate basis to drill oil and gas wells. We believe our drilling fleet is one of the most modern and versatile fleets in the world, consisting of floaters, jackups and other rigs used in support of offshore drilling activities and offshore support services on a worldwide basis. We specialize in technically demanding regions of the offshore drilling business with a particular focus on deepwater and harsh environment drilling services.

Our contract drilling operations are geographically dispersed in oil and gas exploration and development areas throughout the world. Although rigs can be moved from one region to another, the cost of moving rigs and the availability of rig-moving vessels may cause the supply and demand balance to fluctuate somewhat between regions. Still, significant variations between regions do not tend to persist long term because of rig mobility. Our fleet operates in a single, global market for the provision of contract drilling services. The location of our rigs and the allocation of resources to build or upgrade rigs are determined by the activities and needs of our customers.

Our other operations segment includes drilling management services and oil and gas properties. We provide drilling management services through Applied Drilling Technology Inc., our wholly owned subsidiary, and through ADT International, a division of one of our U.K. subsidiaries (together, “ADTI”). ADTI provides oil and gas drilling management services on either a dayrate basis or a completed-project, fixed-price (or “turnkey”) basis, as well as drilling engineering and drilling project management services. Our oil and gas properties consist of exploration, development and production activities carried out through Challenger Minerals Inc. and Challenger Minerals (North Sea) Limited (together, “CMI”), our oil and gas subsidiaries.

Significant Events

Macondo well incident—On April 22, 2010, the Ultra-Deepwater Floater *Deepwater Horizon* sank after a blowout of the Macondo well caused a fire and explosion on the rig, and the rig has been declared a total loss. Eleven persons have been declared dead and others were injured as a result of the incident. As investigations pertaining to the cause or causes of the incident continue, we are evaluating its consequences, which could ultimately have a material adverse effect on our consolidated statement of financial position, results of operations or cash flows. Although the rig was operating under a contrac t which was to extend through September 2013, the total loss of the rig resulted in an automatic termination of the agreement. The backlog associated with the *Deepwater Horizon* drilling contract was approximately $590 million. See “—Contingencies—Macondo well incident.”

Fleet expansion—In the six months ended June 30, 2010, we completed construction of three Ultra-Deepwater newbuilds and each has commenced its respective contract. See “—Outlook.”

Exchange listing—Effective April 20, 2010, our shares began trading on the SIX Swiss Exchange under the symbol “RIGN.” Our shares also continue to be listed on the New York Stock Exchange under the symbol “RIG.”

Share repurchase program—As of June 30, 2010, we had repurchased a total of 2,863,267 of our shares under our share repurchase program for an aggregate purchase price of CHF 257 million, equivalent to $240 million. We have agreed not to repurchase any additional shares under our share repurchase program without 30 days written notice to the U.S. Department of Justice (the “DOJ”). See “—Liquidity and Capital Resources—Sources and Uses of Liquidity.”

Distribution—In May 2010, at our annual general meeting, our shareholders approved a cash distribution in the form of a par value reduction in the aggregate amount of CHF 3.44 per issued share, equal to approximately $3.19, using an exchange rate of USD 1.00 to CHF 1.08 as of the close of trading on June 30, 2010. We expect the cash distribution to be calculated and paid in four quarterly installments, following registration with the commercial register of the Canton of Zug. At June 30, 2010, the carrying amount of the unpaid distribution payable was $1.0 billion. See “—Liquidity and Capital Resources—Sources and Uses of Liquidity.”

Outlook

Drilling market—We expect market utilization to remain steady over the next few quarters for the jackup and midwater floater markets due to continued stability in oil and gas prices. Additionally, we expect this stability to result in contracting opportunities for all classes within our drilling fleet during 2010. However, considering the potential impact of the uncontracted capacity in 2010 and 2011 from newbuilds and existing units in the market, coupled with the uncertainties of the drilling moratorium in the U.S. Gulf of Mexico, we cannot be certain of projections for utilization for our High-Specification Floater fleet. Consequently, we do not believe that the increased tendering activity that we are currently experiencing will foster a co rresponding increase in dayrates in the near term.

As of July 15, 2010, our contract backlog had declined to $27.6 billion. As of April 13, 2010, our contract backlog was $28.6 billion, as adjusted for the $590 million lost backlog associated with the *Deepwater Horizon* drilling contract. The depletion of backlog from drilling activity was partially offset by the execution of new contracts with approximately $1.4 billion of associated backlog during the second quarter of 2010. Although we are currently engaged in advanced discussions with customers on several additional opportunities, our backlog may continue to decline if we are unable to obtain new contracts for our rigs that sufficiently replace exis ting backlog as it is consumed over time or if any contracts are terminated.

On May 30, 2010, the U.S. government implemented a six-month moratorium on certain drilling activities in the U.S. Gulf of Mexico. This initial moratorium has been challenged in the U.S. courts; on July 12, 2010, the U.S. government implemented a revised drilling moratorium that is scheduled to be in effect until November 30, 2010. The U.S. government, however, may elect to shorten or extend the duration of the moratorium. We have 14 rigs under contract in the U.S. Gulf of Mexico, and we are unable to predict, with certainty, the full impact that the moratorium will have on our operations. The backlog associated with the contracts relating to these rigs was approximately $7.6 billion as of July 15, 2010, of which $2.1 billion could be lost if our customers are legally permitted to and choose to exercise their termination rights under certain contracts. Our customers may elect to move rigs to locations outside of the U.S. Gulf of Mexico, perform activities permitted under the moratorium or attempt to terminate our contracts pursuant to their respective force majeure provisions.

Several customers have either declared force majeure or indicated that they may declare force majeure under their respective contracts. We do not believe that a force majeure event exists as a result of the drilling moratorium under the drilling contracts for the rigs in the U.S. Gulf of Mexico, and we are working closely with our customers to assess each situation. If an actual force majeure event occurs, as determined under the applicable drilling contract, these agreements generally allow for a period of 30 to 60 days during which the rig will earn a force majeure rate, which is generally between 85 percent and 100 percent of the contracted dayrate. Following this period, and in some cases subject to a notice or waiting period, e ither we or the customer may terminate the contract. In some contracts, we have the right to further extend the contract for a period of time by electing to continue the contract at a zero dayrate, thereby retaining the backlog associated with the contract for possible recognition in a later period. Some drilling contracts for rigs in the U.S. Gulf of Mexico include early termination provisions that require the payment of the contractual dayrate for the remaining term of the contract upon termination for force majeure either in a lump sum or over an extended term. We have, in some instances, negotiated, and may continue to negotiate, special standby rates with some of our customers under our drilling contracts for rigs in the U.S. Gulf of Mexico. These special standby rates are lower than the regular contract dayrate and apply during periods when the customer is prevented from performing drilling operations. For every day on special standby rate, the con tract term of the applicable contract is extended by an equal number of days.

Fleet status—The uncommitted fleet rate is the number of uncommitted days as a percentage of the total number of available rig calendar days in the period. As of July 15, 2010, the uncommitted fleet rates for the remainder of 2010, 2011, 2012 and 2013 are as follows:

	2010	2011	2012	2013
Uncommitted fleet rate				
High-Specification Floaters	8%	20%	36%	48%
Midwater Floaters	30%	60%	80%	95%
High-Specification Jackups	46%	52%	81%	100%
Standard Jackups	52%	72%	87%	95%

We have 11 existing contracts with fixed-price or capped options, and given current market conditions, we expect that a number of these options will not be exercised by our customers in 2010. Well-in-progress or similar provisions of our existing contracts may delay the start of higher dayrates in subsequent contracts, and some of the delays could be significant.

High-Specification Floaters—Our Ultra-Deepwater Floater fleet is fully contracted for 2010, and we are in advanced discussions with customers to contract the two remaining Ultra-Deepwater Floaters with availability in 2011. We recently extended a Deepwater Floater available in 2010 for a four-month period and expect to contract the remaining active and available 2010 Deepwater Floater. Recent subletting of our High-Specification Floater fleet has had minimal impact on our operations in 2010 thus far, but we cannot be certain of the impact on our operations in 2011 and beyond. As of July 15, 2010, we had 43 of our 48 current and future High-Specification Fl oaters contracted through the end of 2010, with 36, including all of our newbuilds, contracted beyond 2011. These 43 units also include all of our Ultra-Deepwater Floaters. We believe the continued exploration successes in the deepwater offshore provinces will foster significant demand and should support our long-term positive outlook for our High-Specification Floater fleet.

Midwater Floaters—For our Midwater Floater fleet, which includes 26 semisubmersible rigs, near-term customer interest has remained steady and in line with the previous quarter. Although we stacked an additional unit in West Africa due to the lack of opportunities in that region, we also executed several contracts for our Midwater Floater fleet on short-term work during the second quarter of 2010. Fifty percent of our Midwater Floater fleet is committed to contracts that extend beyond 2010. We believe the recent tendering activity may result in our active rigs working beyond their current contracts. Market utilization for this fleet, however, may face challenge s from the moored Deepwater Floaters coming available in 2010 and potentially competing in the midwater market due to the lack of current opportunities in the deepwater market and further pressure resulting from the moratorium in the U.S. Gulf of Mexico. Tenders for our Midwater Floaters are generally shorter in duration, resulting in these units working on well-to-well programs.

High-Specification Jackups—The High-Specification Jackup fleet is experiencing rising utilization and dayrates, and we expect this fleet to remain attractive to customers throughout 2010. Tendering activity has remained steady during the second quarter of 2010, which has resulted in extensions of several existing contracts. As of July 15, 2010, we had three of our 10 High-Specification Jackups stacked. Although we have two High-Specification Jackups completing their current contracts in the third quarter of 2010, the continued increase in tendering activity could result in the extension of some of these contracts.

Standard Jackups—Considering the number of units currently stacked, and the number of newbuild units expected to enter the market without customer contracts and the absence of a corresponding increase in customer demand, we expect near-term dayrates for our Standard Jackup fleet to remain flat or slightly decrease as contracts are renewed or completed. As of July 15, 2010, we had 22 of our 55 Standard Jackups stacked. We expect a few more of our Standard Jackups to be stacked in the second half of 2010.

Key measures—Key measures of our results of operations and financial condition are as follows:

	Three months ended June 30, 2010	Three months ended June 30, 2009	Change	Six months ended June 30, 2010	Six months ended June 30, 2009
Performance indicators					
Average daily revenue (a) (b)	$ 284,200	$ 255,900	$ 28,300	$ 291,300	$ 256,200
Utilization (b)(c)	64%	84%	n/a	65%	87%
Statement of operations data					
Operating revenues	$ 2,505	$ 2,882	$ (377)	$ 5,107	$ 6,000
Operating and maintenance expense	1,358	1,277	81	2,554	2,448
Operating income	957	1,121	(164)	1,883	2,440
Net income attributable to controlling interest	715	806	(91)	1,392	1,748

	June 30, 2010	December 31, 2009	Change
Balance sheet data			
Cash and cash equivalents	$ 2,888	$ 1,130	$ 1,758
Total assets	37,552	36,436	1,116
Total debt	11,426	11,717	(291)

"n/a" means not applicable.

(a) Average daily revenue is defined as contract drilling revenue earned per revenue earning day. A revenue earning day is defined as a day for which a rig earns dayrate after commencement of operations. Stacking rigs, such as Midwater Floaters, High-Specification Jackups and Standard Jackups, has the effect of increasing the average daily revenue since these rig types are typically contracted at lower dayrates compared to the High-Specification Floaters. Average daily revenue includes our rigs that are operating on standby rates located in the U.S. Gulf of Mexico.

(b) Calculation excludes results for *Joides Resolution*, a drillship engaged in scientific geological coring activities that is owned by an unconsolidated joint venture in which we have a 50 percent interest and for which we apply the equity method of accounting.

(c) Utilization is the total actual number of revenue earning days as a percentage of the total number of calendar days in the period. Idle and stacked rigs are included in the calculation and reduce the utilization rate to the extent these rigs are not earning revenues. Newbuilds are included in the calculation upon acceptance by the customer.

Resulting from the market pressures experienced in the six months ended June 30, 2010, our revenues declined relative to those recognized in the six months ended June 30, 2009. The decline was primarily due to lower utilization, mostly related to 36 stacked and idle rigs as of June 30, 2010, as compared to 18 stacked and idle rigs during the same period in 2009. This decline was partially offset by revenues from the commencement of operations of our newbuild rigs. The lower utilization also resulted in a decrease in our operating and maintenance expenses compared to the prior year period, which was more than offset by increased operating and maintenance expenses associated with the commencement of operations of our newbuild rigs, increased maintenance and shipyard expenses an d costs associated with the Macondo well incident, primarily related to insurance deductibles. As of June 30, 2010, we had reduced our total debt compared to December 31, 2009, primarily due to net repayments under our commercial paper program (see "—Liquidity and Capital Resources—Sources and Uses of Liquidity").

For the year ending December 31, 2010, we expect our total revenues to decline compared to our total revenues for the year ended December 31, 2009. We expect this reduction to result from reduced drilling activity associated with stacked and idle rigs, lost revenues from the *Deepwater Horizon* contract termination and reduced operating activity associated with our integrated services. However, we expect the decrease in revenues to be partially offset by a full year of drilling operations of our five newbuilds delivered in 2009, the commencement of drilling operations of four additional newbuilds in 2010, and increased activity in our other operations segment. ; We are unable to ascertain, with certainty, the effect the moratorium will have on our operations in the U.S. Gulf of Mexico in 2010.

We expect our total operating and maintenance expenses for the year ending December 31, 2010 to increase compared to operating and maintenance expenses for the year ended December 31, 2009, primarily due to a full year of drilling operations for our five newbuilds delivered in 2009, the commencement of drilling operations of four additional newbuilds in 2010, an increase in maintenance and shipyard expenses, an increase in activity in our other operations segment and additional costs associated with the Macondo well incident as further discussed below. We expect these increases will be partially offset by reduced costs associated with stacked and idle rigs and reduced integrated services activity. Our projected operating and maintenance expenses for the year ending December 31, 201 0 remain uncertain and could be affected by actual activity levels, rig reactivations, the Macondo well incident and related contingencies, exchange rates and cost inflation as well as other factors.

Although we are currently unable to estimate the full impact of the Macondo well incident on our business, the incident could ultimately have a material adverse effect on our consolidated statement of financial position, results of operations or cash flows. We expect an increase of approximately $180 million in operating and maintenance expenses in 2010 comprised primarily of approximately $70 million of insurance deductibles, approximately $30 million of higher insurance premiums, approximately $36 million of additional legal expenses related to lawsuits and investigations, net of insurance recoveries, and approximately $44 million of additional costs primarily related to our internal investigation of the Macondo well incident, in cluding consultant costs, travel costs and other miscellaneous costs. See “—Contingencies—Insurance matters” and “Part II. Other Information, Item 1A. Risk Factors.”

At June 30, 2010, the carrying amount of our property and equipment was $22.5 billion, representing 60 percent of our total assets, and the carrying amount of our goodwill was $8.1 billion, representing 22 percent of our total assets. In accordance with our critical accounting policies, we review our property and equipment for impairment when events or changes in circumstances indicate that the carrying amounts of our assets held and used may not be recoverable, and we conduct impairment testing for our goodwill when events and circumstances indicate that the fair value of a reporting unit falls below its carrying amount. If we are unable to secure new or extended contracts for our active units or the reactivation of any of our stacked units, or if we experience further declines in actual or anticipated dayrates, especially those in our Standard Jackup fleet, we may be required to recognize losses on impairment of the carrying amount of one or more of our asset groups. Additionally, we may be required to recognize losses on impairment of goodwill if we determine that the fair value of our contract drilling services reporting unit declines below its carrying amount. See “—Critical Accounting Policies and Estimates” and “Part II. Other Information, Item 1A. Risk Factors.”

Performance and Other Key Indicators

Contract backlog—The following table presents our contract backlog, including firm commitments only, for our contract drilling services segment as of July 15, 2010, March 31, 2010 and June 30, 2009. Firm commitments are represented by signed drilling contracts or, in some cases, by other definitive agreements awaiting contract execution. Our contract backlog is calculated by multiplying the full contractual operating dayrate by the number of days remaining in the firm contract period, excluding revenues for mobilization, demobilization and contract preparation or other incentive provisions, which are not expected to be significant to our contract drilling revenues. The contractual operating dayrate may be higher than certain othe r rates included in the contract, such as a waiting-on-weather rate, repair rate, standby rate or force majeure rate. In certain contracts, the dayrate may be reduced to zero if, for example, repairs extend beyond a stated period of time.

Contract backlog	July 15, 2010	March 31, 2010 (in millions)	June 30, 2009
High-Specification Floaters	$ 22,969	$ 24,293	$ 27,022
Midwater Floaters	2,767	2,933	4,272
High-Specification Jackups	391	315	356
Standard Jackups	1,374	1,323	2,234
Other Rigs	62	72	91
Total	$ 27,563	$ 28,936	$ 33,975

We have 14 rigs under contract in the U.S. Gulf of Mexico. The backlog associated with the contracts relating to these rigs was approximately $7.6 billion as of July 15, 2010, of which $2.1 billion could be lost if our customers are legally permitted to and choose to exercise their termination rights under certain contracts. The backlog associated with the *Deepwater Horizon* drilling contract represented approximately $590 million of the High-Specification Floaters backlog and total backlog for March 31, 2010 and June 30, 2009. Although the rig was operating under a contract which was to extend through September 2013, the total loss of the rig resulted in an automatic termination of the agreement.

Fleet average daily revenue—The following table presents the average daily revenue for our contract drilling services segment for each of the quarters ended June 30, 2010, March 31, 2010 and June 30, 2009. See "—Outlook—Key measures" for a definition of average daily revenue.

	Three months ended		
	June 30, 2010	March 31, 2010	June 30, 2009
Average daily revenue			
High-Specification Floaters			
Ultra-Deepwater Floaters	$ 482,100	$ 486,000	$ 450,500
Deepwater Floaters	395,800	383,800	339,600
Harsh Environment Floaters	428,500	400,100	374,500
Total High-Specification Floaters	447,800	443,200	397,600
Midwater Floaters	319,000	331,600	302,700
High-Specification Jackups	146,100	166,000	161,400
Standard Jackups	117,100	133,100	149,200
Other Rigs	72,000	72,700	48,300
Total fleet average daily revenue	284,200	298,300	255,900

Fleet utilization—The following table presents the utilization rates for our contract drilling services segment for each of the quarters ended June 30, 2010, March 31, 2010 and June 30, 2009. See "—Outlook—Key measures" for a definition of utilization.

	Three months ended		
	June 30, 2010	March 31, 2010	June 30, 2009
Utilization			
High-Specification Floaters			
Ultra-Deepwater Floaters	76%	88%	91%
Deepwater Floaters	66%	71%	82%
Harsh Environment Floaters	85%	98%	93%
Total High-Specification Floaters	74%	83%	88%
Midwater Floaters	69%	67%	84%
High-Specification Jackups	70%	63%	87%
Standard Jackups	53%	53%	82%
Other Rigs	50%	50%	59%
Total fleet average utilization	64%	66%	84%

Operating Results

Three months ended June 30, 2010 compared to three months ended June 30, 2009

Following is an analysis of our operating results. See "—Outlook—Key measures" for a definition of revenue earning days, utilization and average daily revenue.

	Three months ended June 30, 2010	2009	Change	% Change
		(In millions, except day amounts and percentages)		
Revenue earning days	8,057	10,261	(2,204)	(21)%
Utilization	64%	84%	n/a	n/m
Average daily revenue	$ 284,200	$ 255,900	$ 28,300	11%
Contract drilling revenues	$ 2,290	$ 2,625	$ (335)	(13)%
Contract drilling intangible revenues	29	75	(46)	(61)%
Other revenues	186	182	4	2%
	2,505	2,882	(377)	(13)%
Operating and maintenance expense	1,358	1,277	81	6%
Depreciation, depletion and amortization	400	360	40	11%
General and administrative expense	58	53	5	9%
	1,816	1,690	126	7%
Loss on impairment	—	(67)	67	n/m
Gain (loss) on disposal of assets, net	268	(4)	272	n/m
Operating income	957	1,121	(164)	(15)%
Other income (expense), net				
Interest income	5	1	4	n/m
Interest expense, net of amounts capitalized	(141)	(114)	(27)	24%
Gain (loss) on retirement of debt	—	(8)	8	n/m
Other, net	(3)	(8)	5	63%
Income before income taxes	818	992	(174)	(18)%
Income tax expense	98	184	(86)	(47)%
Net income	720	808	(88)	(11)%
Net income attributable to noncontrolling interest	5	2	3	n/m
Net income attributable to controlling interest	$ 715	$ 806	$ (91)	(11)%

"n/a" means not applicable

"n/m" means not meaningful

Operating revenues—Contract drilling revenues decreased $335 million for the three months ended June 30, 2010 compared to revenues for the three months ended June 30, 2009, primarily due to lower utilization and partially offset by higher average daily revenue. The lower utilization during the three months ended June 30, 2010, as compared to the three months ended June 30, 2009, was primarily due to (a) approximately $345 million in reduced drilling activity as 36 rigs were stacked or idle at June 30, 2010, compared to 18 rigs that were stacked or idle, including one held for sale, at June 30, 2009, (b) approximately $170 million due to higher out-of-service time for shipyard, mobilization, maintenance and repair projects in the three months ended June 30, 2010, as compared to the same period in 2009, (c) approximately $40 million due to the loss of revenues associated with the *Deepwater Horizon* contract and (d) approximately $25 million due to rig sales or rigs in which we sold our interest. These decreases were partially offset by revenues of approximately $270 million associated with our newbuilds, which commenced operations during 2009 and 2010. Our average daily revenue increases as we stack rigs in our Midwater Floater fleet and jackup fleets, since rigs in these classes are typically contracted at lower dayrates compared to those in our High-Specification Floater fleet.

Contract drilling intangible revenues declined $46 million for the three months ended June 30, 2010, compared to the three months ended June 30, 2009, due to the timing of the contracts with which they were associated. Contract drilling intangible revenues represent the amortization of the fair value of drilling contracts in effect at the time of our merger with GlobalSantaFe Corporation ("GlobalSantaFe"). We recognize contract drilling intangible revenues over the respective contract period using the straight-line method of amortization.

Costs and expenses—Operating and maintenance expenses increased $81 million, or six percent, for the three months ended June 30, 2010 compared to the three months ended June 30, 2009. The increase was due to (a) approximately $80 million of expenses primarily related to insurance deductibles and legal costs associated with the Macondo well incident, (b) approximately $75 million of expenses due to our newbuilds, which commenced operations during 2009 and 2010 and (c) approximately $60 million of expenses due to increased activity in our other operations segment. These increases were partially offset by an approximate $115 million reduction resulting from lower utilization and approximately $ 30 million due to reduced activity in our integrated services operations.

Depreciation, depletion and amortization increased for the three months ended June 30, 2010, primarily due to $39 million of additional expense related to the commencement of operations of seven newbuilds subsequent to June 30, 2009.

During the three months ended June 30, 2009, *GSF Arctic II* and *GSF Arctic IV*, both previously classified as assets held for sale, were impaired due to the global economic downturn and pressure on commodity prices, both of which have had an adverse effect on our industry. We recognized a $58 million loss on impairment of these rigs during the three months ended June 30, 2009. We also recognized a $9 million loss on impairment of the customer relationships intangible asset associated with our drilling management services during the three months ended June 30, 2009 with no comparable activity during the three months ended June 30, 2010.

During the three months ended June 30, 2010, we recognized a net gain on disposal of assets of $268 million, including a $267 million gain on the loss of *Deepwater Horizon*, which resulted from insurance recoveries received during the three months ended June 30, 2010 that exceeded the carrying amount of the rig at the date of the incident. During the three months ended June 30, 2009, we recognized a net loss on disposal of other unrelated assets of $4 million.

The increase in interest expense for the three months ended June 30, 2010 was primarily attributable to a $30 million reduction of capitalized interest, compared to the three months ended June 30, 2009, and $14 million of interest expense associated with the *Petrobras 10000* capital lease. Partially offsetting the increase was $18 million associated with debt repaid or repurchased subsequent to June 30, 2009.

Income tax expense—We operate internationally and provide for income taxes based on the tax laws and rates in the countries in which we operate and earn income. There is little to no expected relationship between the provision for income taxes and income before income taxes considering, among other factors, (a) changes in the blend of income that is taxed based on gross revenues versus income before taxes, (b) rig movements between taxing jurisdictions and (c) our rig operating structures. The estimated annual effective tax rates at June 30, 2010 and 2009 were 15.5 percent and 15.4 percent, respectively, based on projected 2010 and 2009 annual income before incom e taxes, after excluding certain items, such as losses on impairment, the gain resulting from insurance recoveries on the loss of *Deepwater Horizon* and prior period adjustments. The tax effect, if any, of the excluded items as well as settlements of prior year tax liabilities and changes in prior year tax estimates are all treated as discrete period tax expenses or benefits. For the three months ended June 30, 2010, the impact of the various discrete period tax items was a net tax expense of $6 million, resulting in a tax rate of 12.0 percent on income before income tax expense. For the three months ended June 30, 2009, the impact of the various discrete items was a net expense of $16 million, resulting in a tax rate of 18.5 percent on income before income tax expense.

Six months ended June 30, 2010 compared to six months ended June 30, 2009

Following is an analysis of our operating results. See "—Outlook—Key measures" for a definition of revenue earning days, utilization and average daily revenue.

	Six months ended June 30, 2010	Six months ended June 30, 2009	Change	% Change
	(In millions, except day amounts and percentages)			
Revenue earning days	16,241	21,311	(5,070)	(24)%
Utilization	65%	87%	n/a	n/m
Average daily revenue	$ 291,300	$ 256,200	$ 35,100	14%
Contract drilling revenues	$ 4,731	$ 5,459	$ (728)	(13)%
Contract drilling intangible revenues	62	179	(117)	(65)%
Other revenues	314	362	(48)	(13)%
	5,107	6,000	(893)	(15)%
Operating and maintenance expense	2,554	2,448	106	4%
Depreciation, depletion and amortization	801	715	86	12%
General and administrative expense	121	109	12	11%
	3,476	1,690	126	6%
Loss on impairment	(2	(288)	286	(99)
Gain on disposal of assets, net	254	—	254	n/m
Operating income	1,883	2,440	(557)	(23)%
Other income (expense), net				
Interest income	10	2	8	n/m
Interest expense, net of amounts capitalized	(273)	(250)	(23)	9%
Gain (loss) on retirement of debt	2	(10)	12	n/m
Other, net	10	—	10	n/m%
Income before income taxes	1,632	2,182	(550)	(25)%
Income tax expense	227	435	(208)	(48)%
Net income	1,405	1,747	(342)	(20)%
Net income (loss) attributable to noncontrolling interest	13	(1)	14	n/m
Net income attributable to controlling interest	$ 1,392	$ 1,748	$ (356)	(20)%

"n/a" means not applicable

"n/m" means not meaningful

Operating revenues—Contract drilling revenues decreased $728 million for the six months ended June 30, 2010 compared to the six months ended June 30, 2009 primarily due to lower utilization and partially offset by higher average daily revenue. The lower utilization during the six months ended June 30, 2010, as compared to the six months ended June 30, 2009, was primarily due to (a) approximately $780 million in reduced drilling activity as 36 rigs were stacked or idle at June 30, 2010 compared to 18 rigs that were stacked or idle, including one held for sale, at June 30, 2009, (b) approximately $375 million due to higher out-of-service time for shipyard, mobilization, maintena nce and repair projects in the six months ended June 30, 2010, as compared to the same period in 2009 and (c) approximately $40 million due to the loss of revenues associated with the *Deepwater Horizon* contract. This reduced activity was partially offset by revenue of approximately $480 million associated with our newbuilds, which commenced operations during 2009 and 2010. Our average daily revenue increases as we stack rigs in our Midwater Floater fleet and jackup fleets, since rigs in these classes are typically contracted at lower dayrates compared to those in our High-Specification Floater fleet.

Contract drilling intangible revenues declined $117 million for the six months ended June 30, 2010, compared to the six months ended June 30, 2009, due to timing of the contracts with which they were associated. Contract drilling intangible revenues represent the amortization of the fair value of drilling contracts in effect at the time of our merger with GlobalSantaFe. We recognize contract drilling intangible revenues over the respective contract period using the straight-line method of amortization.

Other revenues decreased $48 million for the six months ended June 30, 2010 compared to the six months ended June 30, 2009, primarily due to reduced integrated services activity of $57 million and lower reimbursable revenues of $20 million. These decreases were partially offset by increased activity of $36 million associated with our other operations segment.

Costs and expenses—Operating and maintenance expenses increased $106 million, or four percent for the six months ended June 30, 2010 compared to the six months ended June 30, 2009. The increase was due to (a) approximately $140 million of expenses resulting from our newbuilds, which commenced operations during 2009 and 2010, (b) approximately $80 million of expenses related to insurance deductibles and legal costs associated with the Macondo well incident, (c) approximately $100 million of expenses due to increased shipyard and maintenance expense and (d) approximately $40 million of expenses due to increased activity in our othe r operations segment. These increases were partially offset by an approximate $205 million reduction of expenses resulting from lower utilization and an approximate $45 million reduction due to our integrated services operations.

Depreciation, depletion and amortization increased primarily due to $63 million of additional expense related to the commencement of operations of seven newbuilds subsequent to June 30, 2009 and $21 million of accelerated depletion of our oil and gas properties during the six months ended June 30, 2010.

During the six months ended June 30, 2009, *GSF Arctic II* and *GSF Arctic IV*, both previously classified as assets held for sale, were impaired due to the global economic downturn and pressure on commodity prices, both of which have had an adverse effect on our industry. We recognized a $279 million loss on impairment of these rigs during the six months ended June 30, 2009. We also rec ognized a $9 million loss on impairment of the customer relationships intangible asset associated with our drilling management services during the six months ended June 30, 2009 with no comparable activity during the six months ended June 30, 2010.

During the six months ended June 30, 2010, we recognized a net gain on disposal of assets of $254 million, including a $267 million gain on the loss of *Deepwater Horizon*, which resulted from insurance recoveries received during the six months ended June 30, 2010 that exceeded the carrying amount of the rig at the date of the incident. Partially offsetting the gain was a loss of $15 million related to the sale of *GSF Arctic II* and *GSF Arctic IV.* There was no comparable activity during the six months ended June 30, 2009.

The increase in interest expense for the six months ended June 30, 2010 was primarily attributable to a $48 million reduction of capitalized interest, compared to the six months ended June 30, 2009, and $28 million of interest expense associated with the *Petrobras 10000* capital lease. Partially offsetting the increase was $54 million associated with debt repaid or repurchased subsequent to June 30, 2009.

Income tax expense—We operate internationally and provide for income taxes based on the tax laws and rates in the countries in which we operate and earn income. There is little to no expected relationship between the provision for income taxes and income before income taxes considering, among other factors, (a) changes in the blend of income that is taxed based on gross revenues versus income before taxes, (b) rig movements between taxing jurisdictions and (c) our rig operating structures. The estimated annual effective tax rates at June 30, 2010 and 2009 were 15.5 percent and 15.4 percent, respectively, based on projected 2010 and 2009 annual income before income taxes, after excluding certain items, such as losses on impairment, net gains on disposal of assets, the gain on the loss of *Deepwater Horizon* and prior period adjustments. The tax effect, if any, of the excluded items as well as settlements of prior year tax liabilities and changes in prior year tax estimates are all treated as discrete period tax expenses or benefits. For the six months ended June 30, 2010, the impact of the various discrete period tax items was a net tax expense of $7 million, resulting in a tax rate of 13.9 percent on income before income tax expense. For the six months ended June 30, 2009, the impact of the various discrete items was a net tax expense of $51 million resulting in a tax rate of 19.9 percent on income before income tax expense.

Liquidity and Capital Resources

Sources and uses of cash

Our primary sources of cash during the six months ended June 30, 2010 were our cash flows from operating activities and the receipt of insurance proceeds of $560 million following the loss on *Deepwater Horizon*. Our primary uses of cash were capital expenditures (including for newbuild construction), repayments of borrowings under our credit facilities and commercial paper program and repurchases of shares under our share repurchase program. At June 30, 2010, we had $2.9 billion in cash and cash equivalents.

	Six months ended June 30, 2010	Six months ended June 30, 2009	Change
Cash flows from operating activities		(In millions)	
Net income	$ 1,405	$ 1,747	$ (342)
Amortization of drilling contract intangibles	(62)	(179)	117
Depreciation, depletion and amortization	801	715	86
Loss on impairment	2	288	(286)
Gain on disposal of assets, net	(254)	—	(254)
Other non-cash items	236	218	18
Changes in operating assets and liabilities	313	228	85
	$ 2,441	$ 3,017	$ (576)

Net cash provided by operating activities decreased primarily due to less cash generated from net income, after adjusting for non-cash items primarily related to a gain on the loss of *Deepwater Horizon* during the six months ended June 30, 2010 and a loss on impairment primarily related to two rigs previously held for sale during the six months ended June 30, 2009.

	Six months ended June 30, 2010	Six months ended June 30, 2009	Change
Cash flows from investing activities		(In millions)	
Capital expenditures	$ (679)	$ (1,655)	$ 976
Proceeds from disposal of assets, net	51	8	43
Proceeds from insurance recoveries for loss of drilling unit	560	—	560
Proceeds from payments on notes receivable	21	—	21
Proceeds from short-term investments	5	393	(388)
Purchases of short-term investments	—	(234)	234
Joint ventures and other investments, net	(1)	—	(1)
	$ (43)	$ (1,488)	$ 1,445

Net cash used in investing activities decreased primarily due to reduced capital expenditures for the construction of five of our Ultra-Deepwater Floaters during the six months ended June 30, 2010 compared to capital expenditures for the construction of 10 of our Ultra-Deepwater Floaters during the six months ended June 30, 2009. In addition, net cash used in investing activities declined as a result of the proceeds from insurance recoveries for the loss of *Deepwater Horizon* in the six months ended June 30, 2010 and purchases of short-term investments in the six months ended June 30, 2009, with no comparable activity in the current period. These reductions of cash used in investing activities were partiall y offset by reduced proceeds from short-term investments resulting from diminished investing activity in marketable securities and reduced recoveries from The Reserve International Liquidity Fund and The Reserve Primary Fund during the six months ended June 30, 2010 compared to the six months ended June 30, 2009.

	Six months ended June 30, 2010	2009	Change
Cash flows from financing activities		(In millions)	
Change in short-term borrowings, net	$ (177)	$ (500)	$ 323
Proceeds from debt	54	319	(265)
Repayments of debt	(275)	(1,410)	1,135
Payments for warrant exercise, net	—	(13)	13
Purchases of shares held in treasury	(240)	—	(240)
Proceeds from (taxes paid for) share-based compensation plans, net	(1)	22	(23)
Excess tax benefit from share-based compensation plans	1	1	—
Other, net	(2)	(4)	2
	$ (640)	$ (1,585)	$ 945

Net cash used in financing activities decreased primarily because of reduced repayments or repurchases of debt and short-term borrowings during the six months ended June 30, 2010 relative to the six months ended June 30, 2009, including repurchases of $440 million aggregate principal amount of our convertible senior notes and the repayment of $1 billion of borrowings under a term loan in the six months ended June 30, 2009 with no comparable activity during the six months ended June 30, 2010. Partially offsetting the reduced repayment and repurchases were decreased borrowings drawn under the TPDI Credit Facilities and ADDCL Credit Facilities in the six months ended June 30, 2010 as we completed construction of the rigs for which those credit facilities were established . Additionally, we repurchased $240 million of our shares in the six months ended June 30, 2010 with no comparable activity in the prior year period.

Drilling fleet expansion and dispositions

Expansion—Capital expenditures, including capitalized interest of $47 million, totaled $679 million during the six months ended June 30, 2010, substantially all of which related to our contract drilling services segment. Having completed five of our 10 newbuild projects in the year ended December 31, 2009, the following table presents the historical and projected capital expenditures and other capital additions, including capitalized interest, for our remaining major construction projects (in millions):

	Total costs through June 30, 2010	Expected costs for the remainder of 2010	Estimated costs thereafter	Total estimated cost at completion
Discoverer Luanda (a)	$ 695	$ 10	$ —	$ 705
Discoverer Inspiration (b)	674	4	—	678
Dhirubhai Deepwater KG2 (b) (c)	674	5	—	679
Discoverer India	591	139	—	730
Deepwater Champion (d)	583	167	5	755
Capitalized interest	230	37	16	283
Mobilization costs	55	56	3	114
Total	$ 3,502	$ 418	$ 24	$ 3,944

(a) The costs for *Discoverer Luanda* represent 100 percent of expenditures incurred since inception. Angola Deepwater Drilling Company Limited ("ADDCL") is responsible for all of these costs. We hold a 65 percent interest in ADDCL, and Angco Cayman Limited holds the remaining 35 percent interest.

(b) The accumulated construction costs of these rigs are no longer included in construction work in progress, as their construction projects had been completed as of June 30, 2010.

(c) The cost for *Dhirubhai Deepwater KG2* represents 100 percent of TPDI's expenditures, including those incurred prior to our investment in the joint venture. TPDI is responsible for all of these costs. We hold a 50 percent interest in Transocean Pacific Drilling Inc. ("TPDI"), and Pacific Drilling holds the remaining 50 percent interest.

(d) These costs include our initial investment in *Deepwater Champion* of $109 million, representing the estimated fair value of the rig at the time of our merger with GlobalSantaFe in November 2007.

During 2010, we expect capital expenditures to be approximately $1.4 billion, including approximately $777 million of cash capital costs for our major construction and conversion projects. The level of our capital expenditures is partly dependent upon financial market conditions, the actual level of operational and contracting activity and the level of capital expenditures requested by our customers for which they agree to reimburse us.

As with any major shipyard project that takes place over an extended period of time, the actual costs, the timing of expenditures and the project completion date may vary from estimates based on numerous factors, including actual contract terms, weather, exchange rates, shipyard labor conditions and the market demand for components and resources required for drilling unit construction.

We intend to fund the cash requirements relating to our capital expenditures through available cash balances, cash generated from operations and asset sales. We also have available credit under the Five-Year Revolving Credit Facility (see "—Sources and Uses of Liquidity") and may utilize other commercial bank or capital market financings. We intend to fund the cash requirements of our joint ventures for capital expenditures in connection with newbuild construction through their respective credit facilities.

From time to time, we review possible acquisitions of businesses and drilling rigs and may, in the future, make significant capital commitments for such purposes. We may also consider investments related to major rig upgrades or new rig construction. Any such acquisition, upgrade or new rig construction could involve the payment by us of a substantial amount of cash or the issuance of a substantial number of additional shares or other securities. During the six months ended June 30, 2010, we acquired *GSF Explorer*, an asset formerly held under capital lease, in exchange for a cash payment of $15 million, thereby terminating the capital lease obligation.

Dispositions—From time to time, we may review possible dispositions of drilling units. During the six months ended June 30, 2010, we completed the sale of two Midwater Floaters, *GSF Arctic II* and *GSF Arctic IV*. In connection with the sale, we received net cash proceeds of $38 million and non-cash proceeds in the form of two notes receivable in the aggregate amount of $165 million. The notes receivable, which are secured by the drilling units, have stated interest rates of 9 percent and are payable in scheduled quarterly installments of principal and interest through maturity in January 2015. We estimated the fair values of the notes receivable based on unobservable inputs that require significant judgment, for which there is little or no market data, including the credit rating of the buyer. We continue to operate *GSF Arctic IV* under a short-term bareboat charter with the new owner of the vessel through October 2010. As a result of the sale, we recognized a loss on disposal of assets in the amount of $15 million for the six months ended June 30, 2010.

Deepwater Horizon—On April 22, 2010, our Ultra-Deepwater Floater *Deepwater Horizon* sank after an explosion and fire onboard the rig. The rig had an insured value of $560 million, which was not subject to a deductible, and our insurance underwriters have declared the vessel a total loss. During the three months ended June 30, 2010, we received $560 million in cash proceeds from insurance recoveries related to the loss of the drilling unit and, for the three and six months ended June 30, 2010, we recognized a gain on the loss of the rig in the amount of $267 million.

Sources and uses of liquidity

Overview—We expect to use existing cash balances, internally generated cash flows, bank credit agreements, proceeds from other debt issuances and proceeds from asset sales to fulfill anticipated obligations such as scheduled debt maturities or other payments, repayment of debt due within one year (including the repurchase of 1.625% Series A Notes at the option of the noteholders), capital expenditures, shareholder-approved distributions and working capital needs. Subject in each case to then existing market conditions and to our then expected liquidity needs, among other factors, we may continue to use a portion of our internally generated cash flows and proceeds from asset sales to reduce debt prior to scheduled maturities through debt repurchases, either in t he open market or in privately negotiated transactions, through debt redemptions or tender offers, or through repayments of bank borrowings. From time to time, we may also use borrowings under bank lines of credit and under our commercial paper program to maintain liquidity for short-term cash needs.

In May 2010, at our annual general meeting, our shareholders approved a cash distribution in the form of a par value reduction in the aggregate amount of CHF 3.44 per issued share, equal to approximately $3.19, using an exchange rate of USD 1.00 to CHF 1.08 as of the close of trading on June 30, 2010. See "—Distribution." In May 2009, our shareholders approved, and our board of directors subsequently authorized management to implement, a program to repurchase an amount of our shares for cancellation with an aggregate purchase price of up to CHF 3.5 billion, which is equivalent to approximately $3.3 billion at an exchange rate as of the close of business on July 27, 2010 of USD 1.00 to CHF 1.06. See "—Share repurchase program.& #8221;

On June 28, 2010, we received a letter from the DOJ asking us to meet with them to discuss our financial responsibilities in connection with the Macondo well incident and requesting that we provide them certain financial and organizational information. The letter also requested that we provide the DOJ advance notice of certain corporate actions involving the transfer of cash or other assets outside the ordinary course of business. After preliminary discussions with the DOJ, we have voluntarily agreed to provide them with 30 days notice prior to repurchasing any additional shares under our share repurchase program and prior to making substantial cash payments out of our U.S. entities, other than in the ordinary course of business. We expect to engage in further discussions with the DOJ in th e future. We can give no assurance that the DOJ investigation and other matters arising out of the Macondo well incident will not adversely affect our liquidity in the future.

Our access to debt and equity markets may be limited due to a variety of events, including among others, credit rating agency downgrades of our debt, industry conditions, general economic conditions, market conditions and market perceptions of us and our industry. The economic downturn and related financial market instability, as well as uncertainty related to our potential liabilities from the Macondo well incident, have had, and could continue to have, an impact on our business and our financial condition. Our ability to access such markets may be severely restricted at a time when we would like, or need, to access such markets, which could have an impact on our flexibility to react to changing economic and business conditions. The economic downturn could have an impact on the lenders participating in our credit facilities or on our customers, causing them to fail to meet their obligations to us. Uncertainty related to our potential liabilities from the Macondo well incident has impacted our share price and could impact our ability to access capital markets in the future.

Our internally generated cash flow is directly related to our business and the market sectors in which we operate. Should the drilling market deteriorate, or should we experience poor results in our operations, cash flow from operations may be reduced. We have, however, continued to generate positive cash flow from operating activities over recent years and expect that cash flow will continue to be positive over the next year.

Bank credit agreements—We have a $2.0 billion five-year revolving credit facility under the Five-Year Revolving Credit Facility Agreement dated November 27, 2007 (the “Five-Year Revolving Credit Facility”). The Five-Year Revolving Credit Facility includes limitations on creating liens, incurring subsidiary debt, transactions with affiliates, sale/leaseback transactions, mergers and the sale of substantially all assets. The Five-Year Revolving Credit Facility also includes a covenant imposing a maximum debt to tangible capitalization ratio of 0.6 to 1.0. As of June 30, 2010, our debt to tangible capitalization ratio was 0.48 to 1.0. In order to borrow under the Five-Year Revolving Credit Facility, we must, at the time of the borrowing request, not be in default under the bank credit agreement and make certain representations and warranties, including with respect to compliance with laws and solvency, to the lenders. We are not required to make any representation to the lenders as to the absence of a material adverse effect. Borrowings under the Five-Year Revolving Credit Facility are subject to acceleration upon the occurrence of an event of default. We are also subject to various covenants under the indentures pursuant to which our public debt was issued, including restrictions on creating liens, engaging in sale/leaseback transactions and engaging in certain merger, consolidation or reorganization transactions. Although credit rating downgrades below investment grade do not constitute an event of default under the Five-Year Revolving Credit Facility, our commitment fee and lending margin are subject to change based on our credit rating. A default under our public debt indentures could trigger a default under the Five-Year Revolving Credit Facility and, if not waived by the lenders, could cause us to lose access to the Five-Year Revolving Credit Facility and the commercial paper program for which it provides liquidity. As of July 27, 2010, we had $81 million in letters of credit issued and outstanding and no borrowings outstanding under the Five-Year Revolving Credit Facility.

Commercial paper program—We maintain a commercial paper program, which is supported by the Five-Year Revolving Credit Facility, under which we may issue privately placed, unsecured commercial paper notes up to a maximum aggregate outstanding amount of $1.5 billion. At July 27, 2010, $105 million in commercial paper was outstanding at a weighted-average interest rate of 0.5 percent, excluding commissions.

TPDI Credit Facilities—TPDI has a bank credit agreement for a $1.265 billion secured credit facility (the “TPDI Credit Facilities”), comprised of a $1.0 billion senior term loan, a $190 million junior term loan and a $75 million revolving credit facility, which was established to finance the construction of and is secured by *Dhirubhai Deepwater KG1* and *Dhirubhai Deepwater KG2*. One of our subsidiaries participates in the term loan with an aggregate commitment of $595 million. The senior term loan requires quarterly payme nts with a final payment in March 2015. The junior term loan and the revolving credit facility are due in full in March 2015. The TPDI Credit Facilities may be prepaid in whole or in part without premium or penalty. The TPDI Credit Facilities have covenants that require TPDI to maintain a minimum cash balance and available liquidity, a minimum debt service ratio and a maximum leverage ratio. At July 27, 2010, $1.2 billion was outstanding under the TPDI Credit Facilities, of which $577 million was due to one of our subsidiaries and was eliminated in consolidation. The weighted-average interest rate on July 27, 2010 was 2.1 percent.

In April 2010, we had a letter of credit issued in the amount of $60 million on behalf of TPDI to satisfy its liquidity requirements under the TPDI Credit Facilities.

TPDI Notes—TPDI has issued promissory notes payable to Pacific Drilling and one of our subsidiaries (the “TPDI Notes”). The TPDI Notes bear interest at London Interbank Offered Rate (“LIBOR”) plus the applicable margin of 2 percent and have maturities through October 2019. As of July 27, 2010, $296 million in promissory notes remained outstanding, $148 million of which was due to one of our subsidiaries and has been eliminated in consolidation. The weighted-average interest rate on July 27, 2010 was 2.4 percent.

ADDCL Credit Facilities—ADDCL has a senior secured bank credit agreement for a credit facility (the “ADDCL Primary Loan Facility”) comprised of Tranche A, Tranche B and Tranche C for $215 million, $270 million and $399 million, respectively, which was established to finance the construction of and is secured by *Discoverer Luanda*. Unaffil iated financial institutions provide the commitment for and borrowings under Tranche A. Tranche A bears interest at LIBOR plus the applicable margin of 0.725 percent. Tranche A requires semi-annual payments beginning in February 2011 and matures in August 2017. One of our subsidiaries provides the commitment for Tranche C. In March 2010, ADDCL terminated Tranche B, having repaid borrowings of $235 million under Tranche B using borrowings under Tranche C. The ADDCL Primary Loan Facility contains covenants that require ADDCL to maintain certain cash balances to service the debt and also limits ADDCL’s ability to incur additional indebtedness, to acquire assets, or to make distributions or other payments. At July 27, 2010, $215 million was outstanding under Tranche A at a weighted-average interest rate o f 0.7 percent. At July 27, 2010, $399 million was outstanding under Tranche C, which was eliminated in consolidation.

Additionally, ADDCL has a secondary bank credit agreement for a $90 million credit facility (the “ADDCL Secondary Loan Facility”), for which one of our subsidiaries provides 65 percent of the total commitment. The facility bears interest at LIBOR plus the applicable margin, ranging from 3.125 percent to 5.125 percent, depending on certain milestones. The ADDCL Secondary Loan Facility is payable in full on the earlier of (1) 90 days after the fifth anniversary of the first well commencement or (2) Decemb er 2015, and it may be prepaid in whole or in part without premium or penalty. Borrowings under the ADDCL Secondary Loan Facility are subject to acceleration by the unaffiliated financial institution upon the occurrence of certain events of default, including the occurrence of a credit rating assignment of less than Baa3 or BBB- by Moody’s Investors Service or Standard & Poor’s Ratings Services, respectively, for Transocean Inc.’s long-term, unsecured, unguaranteed and unsubordinated indebtedness. At July 27, 2010, $75 million was outstanding under the ADDCL Secondary Loan Facility, of which $49 million was provided by one of our subsidiaries and was eliminated in consolidation. The weighted-average interest rate on July 27, 2010 was 3.7 percent.

Capital lease contract—*Petrobras 10000* is held by one of our subsidiaries under a capital lease contract that requires scheduled monthly payments of $6.0 million through its stated maturity on August 4, 2029, at which time our subsidiary will have the right and obligation to acquire *Petrobras 10000* from the lessor for one dollar. Upon the occurrence of certain termination events, our subsidiary is also required to purchase *Petrobras 10000* and pay a termination amount determined by a formula based upon the total cost of the drillship. As of July 27, 2010, $702 0;million was outstanding under the capital lease contract.

The capital lease contract includes limitations on creating liens on *Petrobras 10000* and requires our subsidiary to make certain representations in connection with each monthly payment, including with respect to the absence of pending or threatened litigation or other proceedings against our subsidiary or any of its affiliates, which could, if determined adversely, have a material adverse effect on our subsidiary’s ability to perform its obligations under the capital lease contract. Additionally, another subsidiary of ours has guaranteed the obligations under the capital lease contract, and this guarantor subsidiary is required to maintain an adjusted net worth, as defined, of at least $5.0 billion as of the end of each fiscal quarter. In the e vent the guarantor subsidiary does not satisfy this covenant at the end of any fiscal quarter, it is required to deposit the deficit amount, determined as the difference between $5.0 billion and the adjusted net worth for such fiscal quarter, into an escrow account for the benefit of the lessor.

Convertible Senior Notes—Holders of the 1.625% Series A Notes and 1.50% Series B Notes have the right to require us to repurchase their notes on December 15, 2010 and December 15, 2011, respectively. In addition, holders of any series of the Convertible Senior Notes will have the right to require us to repurchase their notes on December 14, 2012, December 15, 2017, December 15, 2022, December 15, 2027 and December 15, 2032, and upon the occurrence of a fundamental change, at a repurchase price in cash equal to 100 percent of the principal amount of the notes to be repurchased plus accrued and unpaid interest, if any. As of July 27, 2010, $5.4 billion of the Convertible Senior Notes remained outstanding.

Our 1.625% Series A Convertible Senior Notes due 2037, 1.50% Series B Convertible Senior Notes due 2037 and 1.50% Series C Convertible Senior Notes due 2037 (the “Convertible Senior Notes”), may be converted at a rate of 5.9310 shares per $1,000 note, equivalent to a conversion price of $168.61 per share. Upon conversion, we will deliver, in lieu of shares, cash up to the aggregate principal amount of notes to be converted and shares in respect of the remainder, if any, of our conversion obligation in excess of the aggregate principal amount of the notes being converted. The conversion rate is subject to increase upon the occurrence of certain fundamental changes and adjustment upon certain other corporate events, such as the distribution of cash to our shareholders as described below.

Distribution—In May 2010, at our annual general meeting, our shareholders approved a cash distribution in the form of a par value reduction in the aggregate amount of CHF 3.44 per issued share, equal to approximately $3.19, using an exchange rate of USD 1.00 to CHF 1.08 as of the close of trading on June 30, 2010. We expect the cash distribution to be calculated and paid in four quarterly installments. Under Swiss law, upon satisfaction of all legal requirements, we must submit an application to the commercial register in the Canton of Zug to register the applicable par value reduction. We have submitted to the commercial register of the Canton of Zug our application for registration of the initial installment. 60;The cantonal commercial register is currently reviewing our application, and although we believe that all registration requirements have been met, the Swiss authorities have indicated to us that the process will take longer than customary in light of lawsuits filed in the U.S. and served on the Company in Switzerland. They have indicated that they will seek guidance from the Swiss Federal Office of the Commercial Register on whether the requirements for the registration of the first installment have been met. Given the expected extended review of our application by the Swiss authorities, the payment of the first installment will be delayed. If the Swiss authorities disagree with our view that all registration requirements have been met, our ability to pay the distribution installments could be further delayed or restricted indefinitely. A delay of the first installment will likely also result in a delay of the remaining three installments, which were expected to be paid in October 2010, January 2011 and April 2011, subject to the satisfaction of the applicable Swiss legal requirements.

We intend to fund any installments using our available cash balances and our cash flows from operations. Shareholders are expected to be paid in U.S. dollars, converted using an exchange rate determined by us approximately two business days prior to the payment date, unless shareholders elect to receive the payment in Swiss francs. Distributions to shareholders in the form of a reduction in par value of our shares are not subject to the 35 percent Swiss withholding tax. In May 2010, we recognized a distribution payable in the amount of approximately $1.0 billion, recorded in other current liabilities, with a corresponding entry to additional paid-in capital. Upon registration of an installment with the commercial register of the Canton of Zug, we expect to reduce our pa r value and reclassify from additional paid-in capital to shares the portion of the distribution associated with the respective installment. At June 30, 2010, the carrying amount of the unpaid distribution payable was $1.0 billion.

Share repurchase program—In May 2009, at our annual general meeting, our shareholders approved and authorized our board of directors, at its discretion, to repurchase an amount of our shares for cancellation with an aggregate purchase price of up to CHF 3.5 billion, which is equivalent to approximately $3.3 billion at an exchange rate as of the close of trading on July 27, 2010 of USD 1.00 to CHF 1.06. On February 12, 2010, our board of directors authorized our management to implement the share repurchase program. We intend to fund any repurchases using available cash balances and cash from operating activities. As of July 27, 2010, we have repurchased 2,863,267 of our shares under our share repurcha se program for an aggregate purchase price of CHF 257 million, equivalent to $240 million. We have agreed not to repurchase any additional shares under our share repurchase program without 30 days notice to the DOJ. See "—Overview."

We may decide, based upon our ongoing capital requirements, the price of our shares, matters relating to the Macondo well incident, regulatory and tax considerations, cash flow generation, the relationship between our contract backlog and our debt, general market conditions and other factors, that we should retain cash, reduce debt, make capital investments or otherwise use cash for general corporate purposes, and consequently, repurchase fewer or no incremental shares under this program. Decisions regarding the amount, if any, and timing of any share repurchases would be made from time to time based upon these factors.

Any shares repurchased under this program are expected to be purchased from time to time either, with respect to the U.S. market, from market participants that have acquired those shares on the open market and that can fully recover Swiss withholding tax resulting from the share repurchase or, with respect to the Swiss market, on the second trading line for our shares on the SIX Swiss Exchange. Repurchases could also be made by tender offer, in privately negotiated transactions or by any other share repurchase method. Any repurchased shares would be held by us for cancellation by the shareholders at a future annual general meeting. The share repurchase program could be suspended or discontinued by our board of directors or company management, as applicable, at any time.

Under Swiss corporate law, the right of a company and its subsidiaries to repurchase and hold its own shares is limited. A company may repurchase such company's shares to the extent it has freely distributable reserves as shown on its Swiss statutory balance sheet in the amount of the purchase price and the aggregate par value of all shares held by the company as treasury shares does not exceed 10 percent of the company's share capital recorded in the Swiss commercial register, whereby for purposes of determining whether the 10 percent threshold has been reached, shares repurchased under a share repurchase program for cancellation purposes authorized by the company's shareholders are disregarded. As of July 27, 2010, Transocean Inc., our wholly owned subsidiary, held as treasury shares approximately four percent of our issued shares. At the annual general meeting in May 2009, the shareholders approved the release of 3.5 billion Swiss francs of additional paid-in capital to other reserves, or freely available reserves as presented on our Swiss statutory balance sheet, to create the freely available reserve necessary for the 3.5 billion Swiss franc share repurchase program for the purpose of the cancellation of shares (the "Currently Approved Program"). We may only repurchase shares to the extent freely distributable reserves are available. Our board of directors could, to the extent freely distributable reserves are available, authorize the repurchase of additional shares for purposes other than cancellation, such as to retain treasury shares for use in satisfying our obligations in connection with incentive plans or other rights to acquire our shares. Based on the current amount of shares held as treasury s hares, approximately six percent of our issued shares could be repurchased for purposes of retention as additional treasury shares. Although our board of directors has not approved such a share repurchase program for the purpose of retaining repurchased shares as treasury shares, if it did so, any such shares repurchased would be in addition to any shares repurchased under the Currently Approved Program.

Contractual obligations—As of June 30, 2010, there have been no material changes from the contractual obligations as previously disclosed in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" of our annual report on Form 10-K for the year ended December 31, 2009, except as noted below.

For the year ending December 31, 2010, the minimum funding requirement for our U.S. defined benefit pension plans is approximately $48 million, and in April 2010, we contributed $48 million to satisfy this funding requirement. For the year ending December 31, 2010, the minimum funding requirement for our non-U.S. defined benefit plans is approximately $39 million.

As of June 30, 2010, the total liability for unrecognized tax benefit related to uncertain tax positions was $666 million. Due to the high degree of uncertainty regarding the timing of future cash outflows associated with the liabilities recognized in this balance, we are unable to make reasonably reliable estimates of the period of cash settlement with the respective taxing authorities.

In May 2010, at our annual general meeting, our shareholders approved a cash distribution in the form of a par value reduction in the aggregate amount of CHF 3.44 per issued share, equal to approximately $3.19, using an exchange rate of USD 1.00 to CHF 1.08 as of the close of trading on June 30, 2010. We expect the cash distribution to be calculated and paid in four quarterly installments, following registration with the commercial register of the Canton of Zug. We expect to pay the four installments within the next 12 months, although due to the uncertainty regarding the extended review by the Swiss authorities, we are unable to estimate, with certainty, the timing of each installment. At June 30, 2010, the carrying amount of the unpaid distribution payable was $1.0 0;billion. See "—Distribution."

Commercial commitments—As of June 30, 2010, there have been no material changes from the commercial commitments as previously disclosed in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" of our annual report on Form 10-K for the year ended December 31, 2009.

Derivative instruments

We have established policies and procedures for derivative instruments approved by our board of directors that provide for the approval of our Chief Financial Officer prior to entering into any derivative instruments. From time to time, we may enter into a variety of derivative instruments in connection with the management of our exposure to fluctuations in interest rates and foreign exchange rates. We do not enter into derivative transactions for speculative purposes; however, we may enter into certain transactions that do not meet the criteria for hedge accounting. See Notes to Condensed Consolidated Financial Statements—Note 10—Derivatives and Hedging.

Contingencies

Macondo well incident

On April 22, 2010, the Ultra-Deepwater Floater *Deepwater Horizon* sank after a blowout of the Macondo well caused a fire and explosion on the rig. Eleven persons have been declared dead and others were injured as a result of the incident. At the time of the explosion, *Deepwater Horizon* was located approximately 41 miles off the coast of Louisiana in Mississippi Canyon Block 252 and was contracted to BP America Production Co. ("BP").

The rig has been declared a total loss. Although the rig was operating under a contract, which was to extend through September 2013, the total loss of the rig resulted in an automatic termination of the agreement. The backlog associated with the *Deepwater Horizon* drilling contract was approximately $590 million. As we continue to investigate the cause or causes of the incident, we are evaluating its consequences, which could ultimately have a material adverse effect on our consolidated statement of financial position, results of operations or cash flows.

Litigation—As of August 2, 2010, 249 legal actions or claims have been filed against Transocean entities, along with other unaffiliated defendants, in state and federal courts. Additionally, government agencies have initiated investigations into the Macondo well incident. We have categorized below the nature of the legal actions or claims. We are evaluating all claims and intend to pursue any and all defenses available. In addition, we believe we are entitled to contractual defense and indemnity for all wrongful death and personal injury claims made by non-employees and third-party subcontractors' employees as well as all liabilities for pollution or contamination, other than for pollution or contamination origin ating on or above the surface of the water. See "—Contractual indemnity."

Wrongful death and personal injury—Since April 2010, we and one or more of our subsidiaries have been named, along with other unaffiliated defendants, in 12 complaints that were filed in state and federal courts in Louisiana and Texas involving multiple plaintiffs that allege wrongful death and other personal injuries arising out of the Macondo well incident. The complaints generally allege negligence and seek awards of unspecified economic damages and punitive damages. BP p.l.c., MI-SWACO and Weatherford Ltd. have, based on contractual arrangements, also made indemnity demands upon us with respect to personal injury and wrongful death claims asserted by our employees or representatives of our employees against these entities. S ee "—Contractual indemnity."

Economic loss—Since April 2010, we and one or more of our subsidiaries have been named, along with other unaffiliated defendants, in 60 individual complaints as well as 160 putative class-action complaints filed in the federal and state courts in Louisiana, Texas, Mississippi, Alabama, Georgia, Kentucky, South Carolina, Tennessee, Colorado and possibly other courts. The complaints generally allege, among other things, potential economic losses as a result of environmental pollution arising out of the Macondo well incident and are based primarily on the Oil Pollution Act of 1990 ("OPA") and state OPA analogues. See "—Environmental matters." One complaint also alleges a violation of the Racketeer Influenced and Corrupt Organizations Act. The plaintiffs are generally seeking awards of unspecified economic, compensatory and punitive damages, as well as injunctive relief. See "—Contractual indemnity."

Federal securities claims—Since April 2010, three federal securities law class actions have been filed naming us and certain of our officers and directors as defendants, two of which were filed in the United States District Court, Southern District of New York, and one of which was filed in the United States District Court, Eastern District of Louisiana. These actions generally allege violations of Section 10(b) of the Securities Exchange Act of 1934 (the "Exchange Act"), Rule 10b5 promulgated under the Exchange Act and Section 20(a) of the Exchange Act in connection with the Macondo well incident. The plaintiffs are generally seeking awards of unspecified economic damages, including damages r esulting from the recent decline in our stock price.

Shareholder derivative claims—In June 2010, two shareholder derivative suits were filed naming us as a nominal defendant and certain of our officers and directors as defendants in the District Courts of the State of Texas. The first case generally alleges breach of fiduciary duty, unjust enrichment, abuse of control, gross mismanagement and waste of corporate assets in connection with the Macondo well incident and the other generally alleges breach of fiduciary duty, unjust enrichment and waste of corporate assets in connection with the Macondo well incident. The plaintiffs are generally seeking, on behalf of Transocean, restitution and disgorgement of all profits, benefits and other compensation from the defendants.

Environmental matters—Environmental claims under two different schemes, statutory and common law, and in two different regimes, federal and state, have been asserted against us. See "—Litigation—Economic loss." Liability under many statutes is imposed without fault, but such statutes often allow the amount of damages to be limited. In contrast, common law liability requires proof of fault and causation but generally has no readily defined limitation on damages, other than the type of damages that may be redressed. We have described below certain significant applicable enviro nmental statutes and matters relating to the Macondo well incident. As described below, we believe that we have limited statutory environmental liability, and we are entitled to contractual defense and indemnity for all liabilities for pollution or contamination, other than for pollution or contamination originating on or above the surface of the water. See"—Contractual indemnity."

Oil Pollution Act—OPA imposes strict liability on responsible parties of vessels or facilities from which oil is discharged into or upon navigable waters or adjoining shore lines. OPA defines the responsible parties with respect to the source of discharge. We believe that the owner or operator of a mobile offshore drilling unit ("MODU"), such as *Deepwater Horizon*, is only a responsible party with respect to discharges from the vessel that occur on or above the surface of the water. As the responsible party for *Deepwater Horizon*, we believe we are responsible only for the discharges of oil emanating from the ri g. Therefore, we believe we are not responsible for the discharged hydrocarbons from the Macondo well.

Responsible parties for discharges are liable for: (1) removal and cleanup costs, (2) damages that result from the discharge, including natural resources damages, generally up to a statutorily defined limit, (3) reimbursement for government efforts and (4) certain other specified damages. For responsible parties of MODUs, the limitation on liability is determined based on the gross tonnage of the vessel. The statutory limits are not applicable, however, if the discharge is the result of gross negligence, willful misconduct, or violation of federal construction or permitting regulations by the responsible party or a party in a contractual relationship with the responsible party.

Other federal statutes—Several of the claimants have made assertions under other statutes, including the Clean Water Act, the Endangered Species Act, the Migratory Bird Treaty Act and the Clean Air Act.

State environmental laws—As of July 27, 2010, claims have been asserted by private claimants under state environmental statutes in Florida, Louisiana and Mississippi. As described below, the only claim currently asserted by a state government is pending in Louisiana.

In June 2010, the Louisiana Department of Environmental Quality (the "LDEQ") issued a consolidated compliance order and notice of potential penalty to us and certain of our subsidiaries asking us to eliminate and remediate discharges of oil and other pollutants into waters and property located in the State of Louisiana, and to submit a plan and report in response to the order. We have requested that the LDEQ rescind the enforcement actions against us and our subsidiaries because the remediation actions that are the subject of such orders are actions that do not involve us or our subsidiaries, as we are not involved in the remediation or clean-up activities. Alternatively, if the LDEQ will not rescind the enforcement actions altogether, we have requested the LDEQ to dismiss the enforcement actions ag ainst us and certain of our subsidiaries as these entities are not proper parties to the enforcement actions and were improperly served. We have requested an administrative hearing on the charges alleged in these orders.

By letter dated May 5, 2010, the Attorneys General of the five Gulf Coast states of Alabama, Florida, Louisiana, Mississippi and Texas informed us that they intend to seek recovery of pollution clean up costs and related damages arising from the Macondo well incident. In addition, by letter dated June 21, 2010, the Attorneys General of the 11 Atlantic Coast states of Connecticut, Delaware, Georgia, Maine, Maryland, Massachusetts, New Hampshire, New York, North Carolina, Rhode Island and South Carolina informed us that their states have not sustained any damage from the Macondo well incident but they would like assurances that we will be responsible financially if damages are sustained. We responded to each letter from the Att orneys General and indicated that we intend to fulfill our obligations as a responsible party for any discharge of oil from *Deepwater Horizon* on or above the surface of the water, and we assume that the operator will similarly fulfill its obligations under OPA for the ongoing discharge from the undersea well.

Wreck removal—We may be requested to remove the diesel fuel from the wreckage, if it is present, as well as various forms of debris from *Deepwater Horizon*. We have insurance coverage for wreck removal for up to 25 percent of *Deepwater Horizon's* insured value, or $140 million, with any excess wreck removal liability generally covered to the extent of our excess liability coverage.

Contractual indemnity—Under our drilling contract for *Deepwater Horizon*, the operator has agreed, among other things, to assume full responsibility for and defend, release and indemnify us from any loss, expense, claim, fine, penalty or liability for pollution or contamination, including control and removal thereof, arising out of or connected with operations under the contract other than for pollution or contamination originating on or above the surface of the water from fuels, lubricants, motor oils and hydrocarbons or other specified substances within our control and possession, as to which we agreed to assume responsibility and protect, release and indemnify the operator. Although we do not believe it is applicable to the Macondo well incident, we also agreed to indemnify and defend the operator up to a limit of $15 million for claims for loss or damage to third parties arising from pollution caused by the rig while it is off the drilling location, while the rig is underway or during drive off or drift off of the rig from the drilling location. The operator has also agreed, among other things, (1) to defend, release and indemnify us against loss or damage to the reservoir, and loss of property rights to oil, gas and minerals below the surface of the earth and (2) to defend, release and indemnify us and bear the cost of bringing the well under control in the event of a blowout or other loss of control. We agreed to defend, release and indemnify the operator for personal injury and death of our employees, invitees and the employees of our subcontractors while the operator agreed to defend, release and indemnify us for personal injury and death of its employees, invitees and the employees of its other subcontractors (other than us). We have also agreed to defend, release and indemnify the operator for damages to the rig and equipment (including salvage or removal costs). We understand that indemnification agreements are generally in place between the operator and its other subcontractors for their personnel and property.

Given the potential amounts involved in connection with the Macondo well incident, the operator may seek to avoid its indemnification obligations. In particular, the operator, in response to our request for indemnification, has generally reserved all of its rights and stated that it could not at this time conclude that it is obligated to indemnify us. In doing so, the operator has asserted that the facts are not sufficiently developed to determine who is responsible and has cited a variety of possible legal theories based upon the contract and facts still to be developed. We believe this reservation of rights is without justification and that the operator is required to honor its indemnification obligations contained in our contract and described above.

Insurance coverage—We expect certain costs resulting from the Macondo well incident to be recoverable under insurance policies as described below.

Hull and machinery coverage—*Deepwater Horizon* had an insured value of $560 million, and there is no deductible for the total loss of the unit. During the six months ended June 30, 2010, we received $560 million of cash proceeds from insurance recoveries for the loss of the drilling unit. For the three and six months ended June 30, 2010, we recognized a gain on the disposal of the rig in the amount of $267 million. We also have coverage for costs incurred in our attempt to mitigate or minimize damage to *Deepwater Horizon* up to an amount equal to 25 percent of the rig's insured value, or $140 million. We also have coverage for wreck removal, which includes coverage for removal of diesel, for up to 25 percent of *Deepwater Horizon*'s insured value, or $140 million, with any excess wreck removal liability generally covered to the extent of our excess liability coverage described below, in the event wreck removal is required. As *Deepwater Horizon* was a total loss, there was no deductible for any applicable costs incurred to mitigate damages or for wreck removal, provided the costs are within the limits mentioned above.

Excess liability coverage—We carry $950 million of commercial market excess liability coverage, exclusive of deductibles and self-insured retention, noted below, which generally covers offshore risks such as personal injury, third-party property claims and third-party non-crew claims, including wreck removal and pollution. This $950 million excess liability limit is an annual aggregate limit covering the entire Transocean worldwide fleet, including *Deepwater Horizon*. Prior to the April 20, 2010 Macondo well incident, there were no known incidents or occurrences that would have eroded the $950 million aggregate excess liability limit. We generally retain the risk for any liability losses with respect to the Macondo well incident and any other incidents or occurrences in excess of $1.0 billion. In the case of the Macondo well incident, we expect to pay $65 million in deductible costs prior to any insurance reimbursements from the excess liability insurance. We expect liability costs from the Macondo well incident in excess of the $65 million deductible costs to be covered up to the $950 million excess liability limit.

In May 2010, we received notice from the operator under the drilling contract for *Deepwater Horizon* maintaining that it believes that it is entitled to additional insured status as provided for under the drilling contract. In response, many of our insurers filed declaratory judgment actions in the Houston Division of the U.S. District Court for the Southern District of Texas in May 2010, seeking a judgment declaring that they have no, or limited, additional-insured obligation to the operator. In the actions, our insurers maintain that, although the drilling contract requires additional insured protection for certain entities related to the operator, the protection is limited to the liabilities assumed by us under the terms of the drilling contract, which includes above land or water surface pollution emanating from substances in our possession, such as fuels, lubricants, motor oils, and bilge. Our insurers maintain that, under the drilling contract, the operator accepted full responsibility and indemnified us for any pollution not assumed by us. Further, our insurers contend that the liabilities the operator currently faces arise from pollution originating from the operator's well, below the surface and not within the scope of the additional insured protection.

Specifically, our insurers seek declarations that: (1) the operator assumed full responsibility in the drilling contract for any and all liabilities arising out of or in any way related to the release of oil originating from its well; (2) the additional insured status in the drilling contract therefore does not extend to the pollution liabilities the operator has incurred and will incur with respect to oil originating from its well; (3) our insurers have no additional obligation to the operator under any of the policies for the pollution liabilities it has incurred and will incur with respect to the oil originating from its well; and (4) the operator is not entitled to coverage under any of the policies for pollution liabilities it has incurred and will incur with respect to the oil originating from its well.

Any such claim, if paid to the operator, could limit the amount of coverage otherwise available to us. We can provide no assurances as to the estimated costs, insurance recoveries, or other actions that will result from this incident. See "Part II. Other Information, Item 1A. Risk Factors."

Other insurance—We also carry $100 million of additional insurance that generally covers expenses that would otherwise be assumed by the well owner, such as costs to control the well, redrill expenses and pollution from the well. This additional insurance provides coverage for such expenses in circumstances in which we have legal or contractual liability arising from our gross negligence or willful misconduct.

Limitation of liability action—At the instruction of our insurers and to preserve our insurance coverage, pursuant to the federal Limitation of a Shipowner's Liability Act (the "Limitation Act"), we filed a complaint in the Houston Division of the Southern District of Texas on May 13, 2010 regarding the casualty of the *Deepwater Horizon* rig. Under the Limitation Act, a vessel owner is generally liable only for the post-accident value of the vessel and cargo as long as the vessel owner can show that it had no knowledge of or privity of knowledge with entities that were negligent. Claims limited under the Limitation Act include personal injury, wrongful death, and damage to property contained on the rig. Statutory claims that may be asserted by the U.S. government or individuals under OPA, the Parks Systems Resource Protection Act, the National Marine Sanctuaries Act (the "NMSA"), the Rivers and Harbors Act or CERCLA and claims by the U.S. government for fines and penalties under the Clean Water Act, the NMSA, the Marine Mammal Protection Act, the Endangered Species Act, the Shipping Act, the Ports and Waterways Safety Act, the Act to Prevent Pollution from Ships, the Clean Air Act, the Resource Conservation and Recovery Act and the Outer Continental Shelf and Lands Act are not covered by the limitation proceeding. In addition, a number of similar state statutory environmental claims are not covered by the limitation proceeding.

Pursuant to the Limitation Act, we are seeking an injunction staying certain lawsuits underway in jurisdictions other than the Southern District of Texas. In addition, we are seeking to limit our liability for personal injury, wrongful death and damage to property contained on the rig to $26,764,083, the value of the rig and its freight, including the accounts receivable and accrued accounts receivable, as of April 28, 2010. One objective of the filing is to consolidate lawsuits relating to the *Deepwater Horizon* casualty and to process these lawsuit s and claims in an orderly fashion, before a single federal judge. The filing also seeks to establish a single fund from which legitimate claims may be paid.

The presiding judge issued an order staying all pending applicable claims and directing claimants to file notice of their claims against us with the court no later than November 2010. The order has been amended to address the exclusion of claims made under OPA. Specifically, claims filed under OPA or state OPA analogue statutes enacted to impose liability for the discharge of oil or relating to any removal activities in connection with such a discharge are excluded from the limitation proceeding. If a lawsuit is filed under OPA by another party held responsible for the accident, such as the operator, the action could potentially be included in the limitation proceeding.

We expect that the order will be modified in the future, as necessary and appropriate, based on the review and assessment of newly filed claims.

The U.S. House of Representatives has recently passed legislation to repeal retroactively the Limitation Act. We can provide no assurance of the final form of such legislation, if enacted, or its anticipated impact on us.

Investigations—As a result of the Macondo well incident, the Department of Homeland Security and the Department of Interior have announced a joint investigation into the cause or causes of the incident and its effects. The U.S. Coast Guard and the Bureau of Ocean Energy Management, Regulation, and Enforcement (the "BOE"), formerly the Minerals Management Service, share jurisdiction over the investigation into the incident. In connection with the investigation, we have received a subpoena from the Office of Inspector General of the Department of Interior for certain information. In addition, an investigation has been commenced by the Chemical Safety Board, and the President of the United States has established the National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling to, among other things, examine the relevant facts and circumstances concerning the cause or causes of the Macondo well incident and develop options for guarding against future oil spills associated with offshore drilling. Further, we have participated in hearings related to the incident before various committees and subcommittees of the House of Representatives and the Senate of the United States, and the DOJ has publicly announced that it has opened criminal and civil investigations of the Macondo well incident. The DOJ announced that it is reviewing, among other traditional criminal statutes, The Clean Water Act, The Oil Pollution Act of 1990, The Migratory Bird Treaty Act of 1918 and Endangered Species Act of 1973. We cannot predict the ultimate outcome of these investigations, the total costs to be incurred in completing the investigations, the potential impact on personnel and the effect of implement ing measures that may result from these investigations or to what extent, if any, we could be subject to fines, sanctions or other penalties.

U.S. Department of Justice—On June 28, 2010, we received a letter from the DOJ asking us to meet with them to discuss our financial responsibilities in connection with the Macondo well incident and requesting that we provide them certain financial and organizational information. The letter also requested that we provide the DOJ advance notice of certain corporate actions involving the transfer of cash or other assets outside the ordinary course of business. After preliminary discussions with the DOJ, we have voluntarily agreed to provide them with 30 days notice prior to repurchasing any additional shares under our share repurchase program and prior to making substantial cash payments out of our U.S. entities, other than in the ordinary course o f business. We expect to engage in further discussions with the DOJ in the future.

Drilling moratorium—On May 30, 2010, the BOE issued a notice to lessees and operators implementing a six-month moratorium on drilling activities with respect to new wells in water depths greater than 500 feet in the U.S. Gulf of Mexico. The notice also stated that the BOE would not consider for the six-month moratorium period drilling permits for wells and related activities for those water depths. In addition, the notice ordered the operators of 33 wells covered by the moratorium that were being drilled to halt drilling and take steps to secure the affected wells. The notice provided for certain exceptions to the moratorium, including, among others, operations necessary to sustain reservoir pressure from production wells and wor kover operations. Subsequently, on June 22, 2010, a United States District Court in the Eastern District of Louisiana granted a preliminary injunction that effectively lifted the moratorium. The U.S. government appealed the decision to the Fifth Circuit, and the Fifth Circuit upheld the injunction. On July 12, 2010, the U.S. Department of the Interior issued a revised moratorium that is scheduled to end on November 30, 2010 and that applies to deepwater drilling configurations and technologies rather then specific water depths. See "Outlook—Drilling market."

On June 8, 2010, the BOE issued a directive to lessees and operators implementing new governmental safety and environmental requirements applicable to both deepwater and shallow water operations. Among other things, this directive requires each operator to conduct a specific review of its operations and to certify to the BOE that it is in compliance with the new requirements and current regulations. This directive also requires operators to submit independent third-party reports on the design and operation of certain pieces of drilling equipment, including blowout preventers and other well control systems, and instructs operators to conduct tests on the functionality of various rig parts and to submit the results of those tests to the BOE. With respect to operations subject to the moratorium, the rep orts and certifications are required to be provided to the BOE prior to commencement of operations following expiration of the moratorium. We are not certain what requirements these new regulations will impose on us or how our operations will ultimately be impacted.

Insurance matters

Our hull and machinery and excess liability insurance program is comprised of commercial market and captive insurance policies. We periodically evaluate our insurance limits and self-insured retentions. Although our existing insurance policies were scheduled to expire May 1, 2010, we negotiated with our underwriters a one-month extension on some of our insurance policies as we assessed the incident involving the loss of the Ultra-Deepwater Floater *Deepwater Horizon*. As a result, our current insurance program consists of insurance policies primarily with 12-month and 11-month policy periods beginning on May 1, 2010 and June 1, 2010, respectively.

Hull and machinery—We completed the renewal of our hull and machinery insurance coverage, effective June 1, 2010, with updated rig insured values, primarily based on fair market value appraisals, and with similar terms as previous policies. Under the hull and machinery program, we generally maintain a $125 million per occurrence deductible, limited to a maximum of $250 million per policy period. Subject to the same shared deductible, we also have coverage for costs incurred to mitigate damage to a rig up to an amount equal to 25 percent of a rig's insured value. Also subject to the same shared deductible, we have additional coverage for wreck removal for up to 25 percent of a rig's insured value, with any excess generally covered to the extent of our remaining excess liability coverage. The above shared deductible is $0 in the event of a total loss or a constructive total loss of a drilling unit.

Excess liability coverage—We completed the renewal of our excess liability insurance coverage with some policies effective May 1, 2010 and others effective June 1, 2010. These policies were renewed with substantially the same terms and conditions except for additional provisions to address the Macondo well incident. We renewed $950 million of commercial market excess liability coverage, exclusive of deductibles and self-insured retention, noted below, which generally covers offshore risks such as personal injury, third-party property claims, and third-party non-crew claims, including wreck removal and pollution. Our excess liability coverage has (1) separa te $10 million per occurrence deductibles on crew personal injury liability and on collision liability claims and (2) a separate $5 million per occurrence deductible on other third-party non-crew claims. These types of excess liability coverages are subject to an additional aggregate self-insured retention of $50 million that is applied to any occurrence in excess of the per occurrence deductible until the $50 million is exhausted. We generally retain the risk for any liability losses in excess of $1.0 billion.

Other insurance—We also carry $100 million of additional insurance that generally covers expenses that would otherwise be assumed by the well owner, such as costs to control the well, redrill expenses and pollution from the well. This additional insurance provides coverage for such expenses in circumstances in which we have legal or contractual liability arising from our gross negligence or willful misconduct.

We have elected to self-insure operators extra expense coverage for ADTI and CMI. This coverage provides protection against expenses related to well control, pollution and redrill liability associated with blowouts. ADTI's customers assume, and indemnify ADTI for, liability associated with blowouts in excess of a contractually agreed amount, generally $50 million.

We generally do not have commercial market insurance coverage for physical damage losses, including liability for wreck removal expenses, to our fleet caused by named windstorms in the U.S. Gulf of Mexico and war perils worldwide. Except with respect to *Dhirubhai Deepwater KG1* and *Dhirubhai Deepwater KG2*, we generally do not carry insurance for loss of revenue unless contractually required.

See Notes to Condensed Consolidated Financial Statements Note 12—Contingencies—Retained risk "—Macondo well incident" and "Part II. Other Information, Item 1A. Risk Factors."

Tax matters

We are a Swiss corporation and we operate through our various subsidiaries in a number of countries throughout the world. Our tax provision is based upon and subject to changes in the tax laws, regulations and treaties in effect in and between the countries in which our operations are conducted and income is earned. Our effective tax rate for financial reporting purposes fluctuates from year to year considering, among other factors, (a) changes in the blend of income that is taxed based on gross revenues versus income before taxes, (b) rig movements between taxing jurisdictions and (c) our rig operating structures. A change in the tax laws, treaties or regulations in any of the countries in which we operate, or in which we are incorporated or resident, could result in a higher or lower effe ctive tax rate on our worldwide earnings and, as a result, could have a material effect on our financial results.

The Senate Finance Committee and the Senate Permanent Subcommittee on Investigations have launched separate investigations into our tax practices, specifically including but not limited to the U.S. tax implications of our change of jurisdiction of incorporation to the Cayman Islands in 1999 and to Switzerland in 2008. We are cooperating with the committees and responding to their inquiries. We cannot predict the outcome of these investigations.

With respect to our 2004 and 2005 U.S. federal income tax returns, the U.S. tax authorities have withdrawn all of their previously proposed tax adjustments, except a claim regarding transfer pricing for certain charters of drilling rigs between our subsidiaries, reducing the total proposed adjustment to approximately $79 million, exclusive of interest. We believe an unfavorable outcome on this assessment with respect to 2004 and 2005 activities would not result in a material adverse effect on our consolidated financial position, results of operations or cash flows. If the authorities were to continue to pursue this transfer pricing position with respect to subsequent years and were successful in such assertion, our effective tax rate on worldwide earnings with respect to years following 2005 could increase subs tantially, and our earnings and cash flows from operations could be materially and adversely affected. Although we believe the transfer pricing for these charters is materially correct, we have been unable to reach a resolution with the tax authorities and we expect the matter to proceed to litigation.

The U.S. tax authorities' original assessment against our 2004 and 2005 activities also asserted that one of our key subsidiaries maintains a permanent establishment in the U.S. and is, therefore, subject to U.S. taxation on certain earnings effectively connected to such U.S. business. In November 2009, we were notified that this position was withdrawn by the U.S. tax authorities. If the authorities were to pursue this permanent establishment position with respect to years following 2005 and were successful in such assertion, our effective tax rate on worldwide earnings with respect to those years could increase substantially, and our earnings and cash flows from operations could be materially and adversely affected. We believe our returns are materially correct as filed, and we inten d to continue to vigorously defend against any such claim.

In May 2010, we received an assessment from the U.S. tax authorities related to our 2006 and 2007 U.S. federal income tax returns. The significant issues raised in the assessment relate to transfer pricing for certain charters of drilling rigs between our subsidiaries and the creation of intangible assets resulting from the performance of engineering services between our subsidiaries. These two items would result in net adjustments of approximately $278 million of additional taxes, exclusive of interest. An unfavorable outcome on these adjustments could result in a material adverse effect on our consolidated financial position, results of operations or cash flows. Furthermore, if the authorities were to continue to p ursue these positions with respect to subsequent years and were successful in such assertions, our effective tax rate on worldwide earnings with respect to years following 2007 could increase substantially, and our earnings and cash flows from operations could be materially and adversely affected. We believe our returns are materially correct as filed, and we intend to continue to vigorously defend against all such claims.

In addition, the assessment included adjustments related to a series of restructuring transactions that occurred between 2001 and 2004. These restructuring transactions ultimately resulted in the disposition of our interests in our former subsidiary TODCO in 2004 and 2005. The authorities are disputing the amount of capital losses resulting from the disposition of TODCO. We utilized a portion of the capital losses to offset capital gains on the 2006, 2007, 2008 and 2009 tax returns. The majority of the capital losses expired on December 31, 2009. The adjustments would also impact the amount of certain net operating losses and other carryovers into 2006 and later years. The authorities are also contesting the characterization of certain amounts of income received in 20 06 and 2007 as capital gain and thus the availability of the capital gain for offset by the capital loss. Claims with respect to our U.S. federal income tax returns for 2006 through 2009 could result in net tax adjustments of approximately $320 million. An unfavorable outcome on these potential adjustments could result in a material adverse effect on our consolidated financial position, results of operations or cash flows. We believe that our tax returns are materially correct as filed, and we intend to vigorously defend against any potential claims.

The assessment also included certain claims with respect to withholding taxes and certain other items resulting in net tax adjustments of approximately $182 million, exclusive of interest. In addition, the tax authorities assessed penalties associated with the various tax adjustments in the aggregate amount of approximately $92 million, exclusive of interest. We believe that our tax returns are materially correct as filed, and we intend to vigorously defend against any potential claims.

Norwegian civil tax and criminal authorities are investigating various transactions undertaken by our subsidiaries in 2001 and 2002 as well as the actions of certain of our former external advisors on these transactions. The authorities issued tax assessments of approximately $241 million, plus interest, related to certain restructuring transactions, approximately $105 million, plus interest, related to the migration of a subsidiary that was previously subject to tax in Norway, approximately $63 million, plus interest, related to a 2001 dividend payment, and approximately $6 million, plus interest, related to certain foreign exchange deductions and dividend withholding tax. We have filed or expect to file appeals to these tax assessments. We may be required to provide some form of fina ncial security, in an amount up to $898 million, including interest and penalties, for these assessed amounts as this dispute is appealed and addressed by the Norwegian courts. The authorities have indicated that they plan to seek penalties of 60 percent on all matters. For these matters, we believe our returns are materially correct as filed, and we have and will continue to respond to all information requests from the Norwegian authorities. We intend to vigorously contest any assertions by the Norwegian authorities in connection with the various transactions being investigated.

During the six months ended June 30, 2010, our long-term liability for unrecognized tax benefits related to these Norwegian tax issues decreased $12 million to $169 million due to the accrual of interest being offset by favorable exchange rate fluctuations. An unfavorable outcome on the Norwegian civil tax matters could result in a material adverse effect on our consolidated financial position, results of operations or cash flows. While we cannot predict or provide assurance as to the final outcome of these proceedings, we do not expect the ultimate resolution of these matters to have a material adverse effect on our consolidated financial position or results of operations, although it may have a material adverse effect on our consolidated cash flows.

Certain of our Brazilian income tax returns for the years 2000 through 2004 are currently under examination. The Brazil tax authorities have issued tax assessments totaling $109 million, plus a 75 percent penalty of $82 million and interest of $102 million through June 30, 2010. An unfavorable outcome on these assessments could result in a material adverse effect on our consolidated financial position, results of operations or cash flows. We believe our returns are materially correct as filed, and we are vigorously contesting these assessments. We filed a protest letter with the Brazilian tax authorities on January 25, 2008, and we are currently engaged in the appeals process.

See Notes to Condensed Consolidated Financial Statements—Note 6—Income Taxes.

Regulatory matters

In June 2007, GlobalSantaFe's management retained outside counsel to conduct an internal investigation of its Nigerian and West African operations, focusing on brokers who handled customs matters with respect to its affiliates operating in those jurisdictions and whether those brokers have fully complied with the U.S. Foreign Corrupt Practices Act ("FCPA") and local laws. GlobalSantaFe commenced its investigation following announcements by other oilfield service companies that they were independently investigating the FCPA implications of certain actions taken by third parties in respect of customs matters in connection with their operations in Nigeria, as well as another company's announced settlement implicating a third party handling customs matters in Nigeria. In each case, the custo ms broker was reported to be Panalpina Inc., which GlobalSantaFe used to obtain temporary import permits for its rigs operating offshore Nigeria. GlobalSantaFe voluntarily disclosed its internal investigation to the DOJ and the SEC and, at their request, expanded its investigation to include the activities of its customs brokers in certain other African countries. The investigation is focusing on whether the brokers have fully complied with the requirements of their contracts, local laws and the FCPA and GlobalSantaFe's possible involvement in any inappropriate or illegal conduct in connection with such brokers. In late November 2007, GlobalSantaFe received a subpoena from the SEC for documents related to its investigation. In addition, the SEC advised GlobalSantaFe that it had issued a formal order of investigation. After the completion of the merger with GlobalSantaFe, outside counsel began formally reporting directly to the audit committee of our board of directors. Our legal representatives are keeping the DOJ and SEC apprised of the scope and details of their investigation and producing relevant information in response to their requests.

On July 25, 2007, our legal representatives met with the DOJ in response to a notice we received requesting such a meeting regarding our engagement of Panalpina Inc. for freight forwarding and other services in the U.S. and abroad. The DOJ informed us that it was conducting an investigation of alleged FCPA violations by oil service companies who used Panalpina Inc. and other brokers in Nigeria and other parts of the world. We developed an investigative plan which has continued to be amended and which would allow us to review and produce relevant and responsive information requested by the DOJ and SEC. The investigation was expanded to include one of our agents for Nigeria. This investigation and the legacy GlobalSantaFe investigation are being conducted by outside counsel who reports directly to the audit committee of our board of directors. The investigation has focused on whether the agent and the customs brokers have fully complied with the terms of their respective agreements, the FCPA and local laws and the company's and its employees' possible involvement in any inappropriate or illegal conduct in connection with such brokers and agent. Our outside counsel has coordinated their efforts with the DOJ and the SEC with respect to the implementation of our investigative plan, including keeping the DOJ and SEC apprised of the scope and details of the investigation and producing relevant information in response to their requests. The SEC has also now issued a formal order of investigation in this case and issued a subpoena for further information, including information related to the U.S. Treasury Department' ;s Office of Foreign Assets Control ("OFAC") investigation described below.

Our internal compliance program has detected a potential violation of U.S. sanctions regulations in connection with the shipment of goods to our operations in Turkmenistan. Goods bound for our rig in Turkmenistan were shipped through Iran by a freight forwarder. Iran is subject to a number of economic regulations, including sanctions administered by OFAC, and comprehensive restrictions on the export and re-export of U.S.-origin items to Iran. Iran has been designated as a state sponsor of terrorism by the U.S. State Department. Failure to comply with applicable laws and regulations relating to sanctions and export restrictions may subject us to criminal sanctions and civil remedies, including fines, denial of export privileges, injunctions or seizures of our assets. We have self-repo rted the potential violation to OFAC and retained outside counsel who conducted an investigation of the matter and submitted a report to OFAC.

We are continuing to cooperate with the DOJ, SEC and OFAC and are in discussions with the SEC and DOJ with respect to resolution of the matter. There can be no assurance that these discussions will lead to a final settlement. We may still continue to incur significant legal fees and related expenses, and the investigations may continue to involve significant management time. We cannot predict the ultimate outcome of these investigations, the total costs to be incurred in completing the investigations, the potential impact on personnel, the effect of implementing any further measures that may be necessary to ensure full compliance with applicable laws or to what extent, if at all, we could be subject to fines, sanctions or other penalties. In response to these investigations, we have implemented meas ures to strengthen and expand our compliance program and training.

For a description of regulatory and environmental matters relating to the Macondo well incident, please see "—Macondo well incident."

Other matters

In addition, from time to time, we receive inquiries from governmental regulatory agencies regarding our operations around the world, including inquiries with respect to various tax, environmental, regulatory and compliance matters. To the extent appropriate under the circumstances, we investigate such matters, respond to such inquiries and cooperate with the regulatory agencies. We recently received an administrative subpoena from OFAC concerning our operations in Myanmar. We are cooperating with OFAC and believe that all of our operations fully comply with applicable laws. Although we are unable to predict the outcome of any of these matters, we do not expect the liability, if any, resulting from these inquiries to have a material adverse effect on our consolidated statement of financial posi tion, results of operations or cash flows.

Critical Accounting Policies and Estimates

Our discussion and analysis of our financial condition and results of operations are based upon our condensed consolidated financial statements. This discussion should be read in conjunction with disclosures included in the notes to our condensed consolidated financial statements related to estimates, contingencies and new accounting pronouncements. Significant accounting policies are discussed in Note 2 to our condensed consolidated financial statements in this quarterly report on Form 10-Q and in Note 2 to our consolidated financial statements in our annual report on Form 10-K for the year ended December 31, 2009.

The preparation of our financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues, expenses and related disclosure of contingent assets and liabilities. On an ongoing basis, we evaluate our estimates, including those related to our allowance for doubtful accounts, materials and supplies obsolescence, investments, property and equipment, goodwill and other intangible assets, income taxes, share-based compensation, defined benefit pension plans and other postretirement benefits and contingent liabilities. We base our estimates on historical experience and on various other assumptions that we believe are reasonable under the circumstances, the results of which form the basis for making judgments about the carrying amounts of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates.

For a discussion of the critical accounting policies and estimates that we use in the preparation of our condensed consolidated financial statements, see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" in our annual report on Form 10-K for the year ended December 31, 2009. These estimates require significant judgments, assumptions and estimates. We have discussed the development, selection and disclosure of these critical accounting policies and estimates with the audit committee of our board of directors. During the six months ended June 30, 2010, there have been no material changes to the judgments, assumptions and estimates, upon which our critical accounting estimates are based.

New Accounting Pronouncements

For a discussion of the new accounting pronouncements that have had or are expected to have an effect on our consolidated financial statements, see Notes to Condensed Consolidated Financial Statements—Note 3—New Accounting Pronouncements.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Interest Rate Risk

We are exposed to interest rate risk, primarily associated with our long-term and short-term debt. For our debt obligations, including obligations of our consolidated variable interest entities, as of June 30, 2010, the following table presents our scheduled debt maturities in U.S. dollars and related weighted-average stated interest rates for the twelve months ending June 30 (in millions, except interest rate percentages):

	Scheduled Maturity Date (a)							Fair Value
	2011	2012	2013	2014	2015	Thereafter	Total	6/30/10
Total debt								
Fixed rate	$1,561	$ 2,288	$ 2,289	$ 91	$ 320	$ 3,909	$ 10,458	$9,547
Average interest rate	2.2%	1.6%	1.2%	3.6%	2.7%	6.9%	3.5%	
Variable rate	$ 116	$ 26	$ 778	$ 29	$ 49	$ 263	$1,261	$1,201
Average interest rate	1.0%	1.4%	3.4%	1.4%	1.8%	2.0%	2.5%	

(a) Expected maturity amounts are based on the face value of debt.

In preparing the scheduled maturities of our debt, we assume the noteholders will exercise their options to require us to repurchase the 1.625% Series A Convertible Senior Notes, 1.50% Series B Convertible Senior Notes and 1.50% Series C Convertible Senior Notes in December 2010, 2011 and 2012, respectively.

We have engaged in certain hedging activities designed to reduce our exposure to interest rate risk, and the effect of our derivative instruments is included in the table above (see Notes to Condensed Consolidated Financial Statements—Note 10—Derivatives and Hedging).

At June 30, 2010, the face value of our variable-rate debt was approximately $1.3 billion, which represented 11 percent of the face value of our total debt, including the effect of our hedging activities. At June 30, 2010, our variable-rate debt, excluding the effect of our hedging activities, primarily consisted of borrowings under the ADDCL Credit Facilities and the TPDI Credit Facilities. At December 31, 2009, the face value of our variable-rate debt was approximately $1.7 billion, which represented 14 percent of the face value of our total debt, including the effect of our hedging activities. At December 31, 2009, our variable-rate debt, excluding the effect of our hedging activities, primarily cons isted of notes issued under our commercial paper program and borrowings under the ADDCL Credit Facilities and the TPDI Credit Facilities. Based upon variable-rate debt amounts outstanding as of June 30, 2010 and December 31, 2009, a one percentage point change in annual interest rates would result in a corresponding change in annual interest expense of approximately $13 million and $17 million, respectively.

The fair value of our debt was $10.7 billion and $12.4 billion at June 30, 2010 and December 31, 2009, respectively. The $1.7 billion decrease was primarily due to our repayment of debt during the six months ended June 30, 2010 and changes in market rates for corporate bonds.

A large portion of our cash investments is subject to variable interest rates and would earn commensurately higher rates of return if interest rates increase. Based upon our cash investments as of June 30, 2010 and December 31, 2009, a one percentage point change in interest rates would result in a corresponding change in annual interest income of approximately $29 million and $11 million, respectively.

Foreign Exchange Risk

We are exposed to foreign exchange risk associated with our international operations. For a discussion of our foreign exchange risk, see "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" in our annual report on Form 10-K for the year ended December 31, 2009. There have been no material changes to these previously reported matters during the six months ended June 30, 2010.

Item 4. Controls and Procedures

Disclosure controls and procedures—In accordance with Exchange Act Rules 13a-15 and 15d-15, we carried out an evaluation, under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of June 30, 2010 to provide reasonable assurance tha t information required to be disclosed in our reports filed or submitted under the Exchange Act was (1) accumulated and communicated to our management, including our Chief Executive Officer and our Chief Financial Officer, to allow timely decisions regarding required disclosure and (2) recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's rules and forms.

Internal controls over financial reporting—There were no changes to our internal controls during the quarter ended June 30, 2010 that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

Other matters—In April 2010, we implemented a new global Enterprise Resource Planning ("ERP") system, a fully integrated software environment, designed to optimize and standardize processes in treasury, accounting, supply chain management, asset management and information technology. Although we are updating our internal controls that have been affected by the ERP implementation, we do not believe that the ERP implementation has had an adverse effect on our internal controls over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

We have certain actions, claims and other matters pending as discussed and reported in Notes to Condensed Consolidated Financial Statements Note 12—Contingencies and "Part I. Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations—Contingencies—Macondo well incident." We are also involved in various tax matters as described in Notes to Condensed Consolidated Financial Statements Note 6—Income Taxes. As of June 30, 2010, we were also involved in a number of lawsuits which have arisen in the ordinary course of our business and for which we do not expect the liability, if any, resulting from these lawsuits to have a material adverse effect on our curren t consolidated financial position, results of operations or cash flows. We cannot predict with certainty the outcome or effect of any of the matters specifically described above or of any such other pending or threatened litigation or legal proceedings. There can be no assurance that our beliefs or expectations as to the outcome or effect of any lawsuit or other matters will prove correct and the eventual outcome of these matters could materially differ from management's current estimates.

Item 1A. Risk Factors

In addition to the risk factors set forth below and the other information set forth in this quarterly report on Form 10-Q, careful consideration should be given to factors described in "Item 1A. Risk Factors" in our annual report on Form 10-K for the year ended December 31, 2009 that could materially affect our business, financial condition or future results.

The Macondo well incident could result in increased expenses and decreased revenues, which could ultimately have a material adverse effect on us.

Numerous lawsuits have been filed against us and unaffiliated defendants related to the Macondo well incident, and we expect additional lawsuits to be filed. We may be subject to claims alleging that we are jointly and severally liable, along with BP and others, for damages arising from the Macondo well incident. We expect to incur significant legal fees and costs in responding to these matters. We may also be subject to governmental fines or penalties. Although we have excess liability insurance coverage, our personal injury and other third party liability insurance coverage is subject to deductibles and overall aggregate policy limits. In addition, we have also been placed on notice by the operator that it intends to make a claim on our excess liability coverage. Such a claim, if paid, could limit the amount of coverage otherwise available to us. There can be no assurance that our insurance will ultimately be adequate to cover all of our potential liabilities in connection with these matters. For a discussion of the potential impact of the failure of the Macondo well operator to honor its indemnification obligations to us, see "We could experience a material adverse effect on our consolidated statement of financial position, results of operations and cash flows to the extent any of the operator's indemnification obligations to us are not enforceable or the operator does not indemnify us" below. If we ultimately incur substantial liabilities in connection with these matters with respect to which we are neither insured nor indemnified, those liabilities could have a material adverse effect on us.

As a result of the incident, our business will be negatively impacted by the loss of revenue from the rig. The backlog associated with the *Deepwater Horizon* drilling contract was approximately $590 million through the end of the contract term in 2013. We do not carry insurance for loss of revenue. In addition, we expect an increase of approximately $180 million in operating and maintenance expenses in 2010 comprised primarily of approximately $70 million of insurance deductibles, approximately $30 million of higher insurance premiums, approximately $36 million of additional legal expenses related to lawsuits and investigations, net of insurance recoveries, and approximately $44 million of additional costs primarily related to our internal investigation of the Macondo well incident, including consultant costs, travel costs and other miscellaneous costs. The uncertainties and contingencies resulting from the incident could also result in a reduction of our credit ratings by the rating agencies, or have a material adverse effect on our ability to access the debt and equity markets, either of which could ultimately have an adverse impact on our liquidity in the future.

Our relationship with BP p.l.c. and its affiliates (collectively, "BP"), one of which was the operator on the Macondo well, could also be negatively impacted by the Macondo well incident. For 2009, BP was our most significant customer. As of July 15, 2010, the contract backlog associated with our contracts with BP and its affiliates was $3.4 billion.

Our business may also be adversely impacted by any negative publicity relating to the incident and us, any negative perceptions about us by customers, the skilled personnel that we require to support our operations or others, any further increases in premiums for insurance or difficulty in obtaining coverage and the diversion of management's attention from our other operations to focus on matters relating to the incident. Ultimately, these factors could have a material adverse effect on our statement of financial position, results of operations or cash flows.

We could experience a material adverse effect on our consolidated statement of financial position, results of operations and cash flows to the extent any of the operator's indemnification obligations to us are not enforceable or the operator does not indemnify us.

The combined response team was unable to stem the flow of hydrocarbons from the well prior to the sinking of the rig. The resulting spill of hydrocarbons has been the most extensive in U.S. history. According to its public filings, as of June 30, 2010, the operator had already recognized a pre-tax charge of $32.2 billion in relation to the spill, and we expect the operator will continue to incur substantial costs related to the spill for the foreseeable future. As described under "Part I. Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations—Contingencies—Macondo well incident—Contractual indemnity," under the drilling contract for *Deepwater Horizon, the operator of Deepwater Horizon has agreed to indemnify us with respect to certain matters, and we have agreed to indemnify the operator with respect to certain matters. We could ultimately experience a material adverse effect on our consolidated statement of financial position, results of operations and cash flows to the extent that BP does not honor its indemnification obligations, including by reason of financial or legal restrictions, or our insurance policies do not fully cover these amounts. In response to our demand to BP to honor its indemnity obligations, BP's outside counsel has stated that BP could not yet determine that it was obligated to defend or indemnify us under the contract and that BP has reserved its rights in that regard. The letter also claims that the operator may not be obligated to defend or indemnify us based on v arious arguments, including alleged breach of contract and gross negligence or other factors, such as in the event our actions materially increased the risks to, or prejudiced the rights of, BP. The interpretation and enforceability of this contractual indemnity depends upon the specific facts and circumstances involved in this case, as governed by applicable laws. The question may ultimately need to be decided by a court or other proceeding which will need to consider the specific contract language, the facts and applicable laws.*

The moratorium on drilling operations in the U.S Gulf of Mexico and potential new related regulations could materially and adversely affect our business.

The U.S. government has implemented a six-month moratorium on certain drilling activities in the U.S. Gulf of Mexico. Some operators have claimed that the moratorium is a force majeure event under their drilling contracts that allow them to terminate these contracts. We do not believe that a force majeure event exists and are in discussions with our customers. In some instances, we have negotiated special lower standby dayrates with our customers for rigs in the U.S. Gulf of Mexico for the period in which the moratorium is in effect but have also agreed to extend the terms of these contracts. The moratorium may result in a number of rigs being moved, or becoming available for movement to locations outside of the U.S. Gulf of Mexico, which could potentially reduce dayrates worldwide and negative ly affect our ability to contract our rigs that are currently uncontracted or coming off contract. The moratorium may also decrease the demand for drilling services and negatively affect dayrates, which could ultimately have a material adverse affect on our revenue and profitability. There can be no assurance that the moratorium will not be extended beyond the current time period.

Following the issuance of the moratorium, new governmental safety and environmental requirements applicable to both deepwater and shallow water operations have been adopted. The new safety and environmental guidelines and regulations for drilling in the U.S. Gulf of Mexico that the U.S. government has already issued, and any further new guidelines or regulations the U.S. government may issue or any other steps the U.S. government may take, could disrupt or delay operations, increase the cost of operations or reduce the area of operations for drilling rigs in U.S. offshore areas. Other governments could adopt similar moratoria and take similar actions relating to implementing new safety and environmental regulations. Additional governmental regulations and requirements concerning licensing, taxation, equip ment specifications and training requirements could increase the costs of our operations, increase certification and permitting requirements, increase review periods and impose increased liability on offshore operations. Legislation pending before the U.S. Congress would impose some of these regulations and requirements. Additionally, increased costs for our customers' operations in the U.S. Gulf of Mexico, along with permitting delays, could affect the economics of currently planned exploration and development activity in the area and reduce demand for our services, which could ultimately have a material adverse affect on our revenue and profitability.

Many investigations are ongoing in connection with the Macondo well incident, the outcome of which is unknown and could have a material adverse effect on us.

The Departments of Homeland Security and Interior have begun a joint investigation into the cause or causes of the Macondo well incident. The U.S. Coast Guard and the Bureau of Ocean Energy Management, Regulation, and Enforcement share jurisdiction over the investigation into the incident. In connection with the investigation, we have received a subpoena from the Office of Inspector General of the Department of Interior for certain information. In addition, an investigation has been commenced by the Chemical Safety Board, and the President of the United States has established the National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling to, among other things, examine the relevant facts and circumstances concerning the cause or causes of the Macondo well incident and develop options f or guarding against future oil spills associated with offshore drilling. In addition, we have participated in hearings related to the incident before various committees and subcommittees of the House of Representatives and the Senate of the United States. These hearings may result in changes in laws and regulations, such as the Consolidated Land, Energy, and Aquatic Resources Act of 2010 recently passed by the House of Representatives, that may have a material adverse effect on the level of liability that we expect in connection with the Macondo well incident.

On June 28, 2010, we received a letter from the DOJ asking us to meet with them to discuss our financial responsibilities in connection with the Macondo well incident and requesting that we provide them certain financial and organizational information. The letter also requested that we provide the DOJ advance notice of certain corporate actions involving the transfer of cash or other assets outside the ordinary course of business. After preliminary discussions with the DOJ, we have voluntarily agreed to provide them with 30 days notice prior to repurchasing any additional shares under our share repurchase program and prior to making substantial cash payments out of our U.S. entities, other than in the ordinary course of business. We expect to engage in further discussions with the DOJ in th e future.

We have significant carrying amounts of goodwill and long-lived assets that are subject to impairment testing.

At June 30, 2010, the carrying amount of our property and equipment was $22.5 billion, representing 60 percent of our total assets, and the carrying amount of our goodwill was $8.1 billion, representing 22 percent of our total assets. In accordance with our critical accounting policies, we review our property and equipment for impairment when events or changes in circumstances indicate that carrying amounts of our assets held and used may not be recoverable, and we conduct impairment testing for our goodwill when events and circumstances indicate that the fair value of a reporting unit may have fallen below its carrying amount.

Our industry has historically been cyclical and is impacted by oil and gas price levels and volatility. There have been periods of high demand, short rig supply and high dayrates, followed by periods of low demand, excess rig supply and low dayrates. Changes in commodity prices can have a dramatic effect on rig demand, and periods of excess rig supply intensify the competition in the industry and often result in rigs being idle for long periods of time. We have previously experienced weakness in our Midwater Floater, High Specification Jackup and Standard Jackup markets. Additionally, uncertainties have recently developed, particularly with regard to our High-Specification Floater fleet, as a result of the drilling moratorium in the U.S. Gulf of Mexico. We have idled and stacked rigs in several classes of our fleet, and may in the future, idle or stack additional rigs or enter into lower dayrate contracts in response to market conditions.

During prior periods of high utilization and dayrates, industry participants have increased the supply of rigs by ordering the construction of new units. This has typically resulted in an oversupply of drilling units and has caused a subsequent decline in utilization and dayrates, sometimes for extended periods of time. There are numerous high specification rigs and jackups under contract for construction. The entry into service of these new units will increase supply and could curtail a strengthening or trigger a reduction in dayrates as these rigs are absorbed into the active fleet. Any further increase in construction of new drilling units would likely exacerbate the negative impact on utilization and dayrates. Lower utilization and dayrates could adversely affect our revenues and profitability. Prolonged periods of low utilization and dayrates could also result in the recognition of impairment charges on certain classes of our drilling rigs or our goodwill balance if future cash flow estimates, based upon information available to management at the time, indicate that the carrying values of these rigs, goodwill or other intangible assets may not be recoverable.

A change in tax laws, treaties or regulations, or their interpretation, of any country in which we operate could result in a higher tax rate on our worldwide earnings, which could result in a significant negative impact on our earnings and cash flows from operations.

We operate worldwide through our various subsidiaries. Consequently, we are subject to changes in applicable tax laws, treaties or regulations in the jurisdictions in which we operate, which could include laws or policies directed toward companies organized in jurisdictions with low tax rates. A material change in the tax laws or policies, or their interpretation, of any country in which we have significant operations, or in which we are incorporated or resident, could result in a higher effective tax rate on our worldwide earnings and such change could be significant to our financial results.

Tax legislative proposals intending to eliminate some perceived tax advantages of companies that have legal domiciles outside the U.S. but have certain U.S. connections have repeatedly been introduced in the U.S. Congress. Recent examples include, but are not limited to, legislative proposals that would broaden the circumstances in which a non-U.S. company would be considered a U.S. resident and proposals that could override certain tax treaties and limit treaty benefits on certain payments by U.S. subsidiaries to non-U.S. affiliates.

Our company has come under investigation by two U.S. congressional committees, the Senate Finance Committee and the Senate Permanent Subcommittee on Investigations. These committees have launched separate investigations into our tax practices, specifically including but not limited to the U.S. tax implications of our change of jurisdiction of incorporation to the Cayman Islands in 1999 and to Switzerland in 2008. We are cooperating with the committees and responding to their inquiries. The outcome of the investigations is uncertain. A resulting material change in tax laws or policies, or their interpretation, could result in a higher effective tax rate on our worldwide earnings and such change could be significant to our financial results.

A loss of a major tax dispute or a successful tax challenge to our operating structure, intercompany pricing policies or the taxable presence of our key subsidiaries in certain countries could result in a higher tax rate on our worldwide earnings, which could result in a significant negative impact on our earnings and cash flows from operations.

We are a Swiss corporation that operates through our various subsidiaries in a number of countries throughout the world. Consequently, we are subject to tax laws, treaties and regulations in and between the countries in which we operate. Our income taxes are based upon the applicable tax laws and tax rates in effect in the countries in which we operate and earn income as well as upon our operating structures in these countries.

Our income tax returns are subject to review and examination. We do not recognize the benefit of income tax positions we believe are more likely than not to be disallowed upon challenge by a tax authority. If any tax authority successfully challenges our operational structure, intercompany pricing policies or the taxable presence of our key subsidiaries in certain countries; or if the terms of certain income tax treaties are interpreted in a manner that is adverse to our structure; or if we lose a material tax dispute in any country, particularly in the U.S., Norway or Brazil, our effective tax rate on our worldwide earnings could increase substantially and our earnings and cash flows from operations could be materially adversely affected. For example, there is considerable uncertainty as to the activitie s that constitute being engaged in a trade or business within the U.S. (or maintaining a permanent establishment under an applicable treaty), so we cannot be certain that the IRS will not contend successfully that we or any of our key subsidiaries were or are engaged in a trade or business in the U.S. (or, when applicable, maintained or maintains a permanent establishment in the U.S.). If we or any of our key subsidiaries were considered to have been engaged in a trade or business in the U.S. (when applicable, through a permanent establishment), we could be subject to U.S. corporate income and additional branch profits taxes on the portion of our earnings effectively connected to such U.S. business during the period in which this was considered to have occurred, in which case our effective tax rate on worldwide earnings for that period could increase substantially, and our earnings and cash flows from operations for that period could be adversely affected.

Our company has come under investigation by two U.S. congressional committees, the Senate Finance Committee and the Senate Permanent Subcommittee on Investigations. These committees have launched separate investigations into our tax practices, specifically including but not limited to the U.S. tax implications of our change of jurisdiction of incorporation to the Cayman Islands in 1999 and to Switzerland in 2008. We are cooperating with the committees and responding to their inquiries. The outcome of the investigations is uncertain. A resulting material change in tax laws or policies, or their interpretation, or a successful challenge to our operating structure, could result in a substantially higher effective tax rate on our worldwide earnings and such change could be significant to our financ ial results.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

Issuer Purchases of Equity Securities

Period	(a) Total Number of Shares Purchased (1)	(b) Average Price Paid Per Share	(c) Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs (2)	(d) Maximum Number (or Approximate Dollar Value) of Shares that May Yet Be Purchased Under the Plans or Programs (2) (in millions)
April 2010	1,369,233	$ 87.60	1,369,000	$ 3,020
May 2010	778,198	$ 77.08	777,267	$ 2,960
June 2010	173	$ 47.70	—	$ 2,960
Total	2,147,604	$ 83.78	2,146,267	$ 2,960

(1) Total number of shares purchased in the second quarter of 2010 includes 1,337 shares withheld by us in satisfaction of withholding taxes due upon the vesting of restricted shares granted to our employees under our Long-Term Incentive Plan and 2,146,267 shares repurchased under the share repurchase program described in (2) below.

(2) In May 2009, at the annual general meeting of Transocean Ltd., our shareholders approved and authorized our board of directors, at its discretion, to repurchase an amount of our shares for cancellation with an aggregate purchase price of up to CHF 3.5 billion (which is equivalent to approximately U.S. $3.2 billion at an exchange rate as of the close of trading on June 30, 2010 of USD 1.00 to CHF 1.08). On February 12, 2010, our board of directors authorized our management to implement the share repurchase program. We may decide, based upon our ongoing capital requirements, the price of our shares, matters relating to the Macondo well incident, regulatory and tax considerations, cash flow generation, the relationship between our contract backlog and our debt, general market conditions and o ther factors, that we should retain cash, reduce debt, make capital investments or otherwise use cash for general corporate purposes, and consequently, repurchase fewer or no shares under this program. Decisions regarding the amount, if any, and timing of any share repurchases would be made from time to time based upon these factors. Through June 30, 2010, we have repurchased a total of 2,863,267 of our shares under this share repurchase program at a total cost of $240 million ($83.74 per share). We have agreed not to repurchase any additional shares under our share repurchase program without 30 days notice to the DOJ. See "Part I. Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations—Sources and Uses of Liquidity—Overview."

Item 6. Exhibits

(a) Exhibits

The following exhibits are filed in connection with this Report:

Number	Description
† 3.1	Articles of Association of Transocean Ltd.
† *10.1	Drilling Contract between Vastar Resources, Inc. and R&B Falcon Drilling Co. dated December 9, 1998 with respect to the *Deepwater Horizon*, as amended
† 31.1	CEO Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
† 31.2	CFO Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
† 32.1	CEO Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
† 32.2	CFO Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
† 101.INS	XBRL Instance Document
† 101.SCH	XBRL Taxonomy Extension Schema
† 101.CAL	XBRL Taxonomy Extension Calculation Linkbase
† 101.DEF	XBRL Taxonomy Extension Definition Linkbase
† 101.LAB	XBRL Taxonomy Extension Label Linkbase
† 101.PRE	XBRL Taxonomy Extension Presentation Linkbase

† Filed herewith.

* Compensatory plan or arrangement.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on August 4, 2010.

TRANSOCEAN LTD.

By: /s/ Ricardo H. Rosa
Ricardo H. Rosa
Senior Vice President and Chief Financial Officer
(Principal Financial Officer)

By: /s/ John H. Briscoe
John H. Briscoe
Vice President and Controller
(Principal Accounting Officer)

Statuten

von Transocean Ltd.

vom 14. Mai 2010

Articles of Association of

Transocean Ltd.

as of May 14, 2010

Abschnitt 1:
Firma, Sitz, Zweck und Dauer der Gesellschaft

Artikel 1

Firma, Sitz

Unter der Firma

Transocean Ltd.
(die **Gesellschaft**)

besteht eine Aktiengesellschaft mit Sitz in Steinhausen, Kanton Zug, Schweiz.

Artikel 2

Zweck

1 Zweck der Gesellschaft ist der Erwerb, das Halten, die Verwaltung, die Verwertung und die Veräusserung von Beteiligungen an Unternehmen im In- und Ausland, ob direkt oder indirekt, insbesondere an Unternehmen, die im Bereich der Erbringung von Dienstleistungen für Offshore Öl-und Gasbohrungen, einschliesslich Management Dienstleistungen, Bohringenieurs- und Bohr-Projekt Management-Dienstleistungen für Öl-und Gasbohrungen, sowie von Öl- und Gas-Exploration und -Produktionsaktivitäten tätig sind, sowie die Finanzierung dieser Aktivitäten. Die Gesellschaft kann Grundstücke und gewerbliche Schutzrechte im In- und Ausland erwerben, halten, verwalten, belasten und verkaufen.

2 Die Gesellschaft kann alle Tätigkeiten ausüben und Massnahmen ergreifen, die geeignet erscheinen, den Zweck der Gesellschaft zu fördern, oder die mit diesem zusammenhängen.

Section 1:
Name, Place of Incorporation, Purpose and Duration of the Company

Article 1

Name, Place of Incorporation

Under the name

Transocean Ltd.
(the **Company**)

there exists a corporation with its place of incorporation in Steinhausen, Canton of Zug, Switzerland.

Article 2

Purpose

1 The purpose of the Company is to acquire, hold, manage, exploit and sell, whether directly or indirectly, participations in businesses in Switzerland and abroad, in particular in businesses that are involved in offshore contract drilling services for oil and gas wells, oil and gas drilling management services, drilling engineering services and drilling project management services and oil and gas exploration and production activities, and to provide financing for this purpose. The Company may acquire, hold, manage, mortgage and sell real estate and intellectual property rights in Switzerland and abroad.

2 The Company may engage in all types of transactions and may take all measures that appear appropriate to promote the purpose of the Company or that are related thereto.

Dauer

Artikel 3

Die Dauer der Gesellschaft ist unbeschränkt.

Abschnitt 2:

Aktienkapital

Aktienkapital

Artikel 4

Das Aktienkapital der Gesellschaft beträgt CHF 5'028'529’470, eingeteilt in 335'235’298 voll liberierte Namenaktien. Jede Namenaktie hat einen Nennwert von CHF 15 (jede Namenaktie nachfolgend bezeichnet als **Aktie** bzw. die **Aktien**).

Artikel 5

Genehmigtes Kapital

1 Der Verwaltungsrat ist ermächtigt, das Aktienkapital jederzeit bis zum 18. Dezember 2010 im Maximalbetrag von CHF 2’514’264’735 durch Ausgabe von höchstens 167’617’649 vollständig zu liberierenden Aktien mit einem Nennwert von je CHF 15 zu erhöhen. Eine Erhöhung (i) auf dem Weg einer Festübernahme durch eine Bank, ein Bankenkonsortium oder Dritte und eines anschliessenden Angebots an die bisherigen Aktionäre sowie (ii) in Teilbeträgen ist zulässig.

2 Der Verwaltungsrat legt den Zeitpunkt der Ausgabe, den Ausgabebetrag, die Art, wie die neuen Aktien zu liberieren sind, den Beginn der Dividendenberechtigung, die Bedingungen für die Ausübung der Bezugsrechte sowie die Zuteilung der Bezugsrechte, welche nicht ausgeübt wurden, fest. Nicht-ausgeübte Bezugsrechte kann der Verwaltungsrat verfallen lassen, oder er kann diese bzw. Aktien, für welche Bezugsrechte eingeräumt, aber nicht ausgeübt werden, zu Marktkonditionen platzieren oder anderweitig im Interesse der Gesellschaft verwenden.

Duration

Article 3

The duration of the Company is unlimited.

Section 2:

Share Capital

Share Capital

Article 4

The share capital of the Company is CHF 5,028,529,470 and is divided into 335,235,298 fully paid registered shares. Each registered share has a par value of CHF 15 (each such registered share hereinafter a **Share** and collectively the **Shares**).

Article 5

Authorized Share Capital

1 The Board of Directors is authorized to increase the share capital, at any time until December 18, 2010, by a maximum amount of CHF 2,514,264,735 by issuing a maximum of 167,617,649 fully paid up Shares with a par value of CHF 15 each. An increase of the share capital (i) by means of an offering underwritten by a financial institution, a syndicate of financial institutions or another third party or third parties, followed by an offer to the then-existing shareholders of the Company, and (ii) in partial amounts shall be permissible.

2 The Board of Directors shall determine the time of the issuance, the issue price, the manner in which the new Shares have to be paid up, the date from which the Shares carry the right to dividends, the conditions for the exercise of the preemptive rights and the allotment of preemptive rights that have not been exercised. The Board of Directors may allow the preemptive rights that have not been exercised to expire, or it may place such rights or Shares, the preemptive rights of which have not been exercised, at market conditions or use them otherwise in the interest of the Company.

3 Der Verwaltungsrat ist ermächtigt, die Bezugsrechte der Aktionäre zu entziehen oder zu beschränken und einzelnen Aktionären oder Dritten zuzuweisen:

(a) wenn der Ausgabebetrag der neuen Aktien unter Berücksichtigung des Marktpreises festgesetzt wird; oder

(b) für die Übernahme von Unternehmen, Unternehmensteilen oder Beteiligungen oder für die Finanzierung oder Refinanzierung solcher Transaktionen oder die Finanzierung von neuen Investitionsvorhaben der Gesellschaft; oder

(c) zum Zwecke der Erweiterung des Aktionärskreises in bestimmten Finanz- oder Investoren-Märkten, zur Beteiligung von strategischen Partnern, oder im Zusammenhang mit der Kotierung von neuen Aktien an inländischen oder ausländischen Börsen; oder

(d) für die Einräumung einer Mehrzuteilungsoption (*Greenshoe*) von bis zu 20% der zu platzierenden oder zu verkaufenden Aktien an die betreffenden Erstkäufer oder Festübernehmer im Rahmen einer Aktienplatzierung oder eines Aktienverkaufs; oder

(e) für die Beteiligung von Mitgliedern des Verwaltungsrates, Mitglieder der Geschäftsleitung, Mitarbeitern, Beauftragten, Beratern oder anderen Personen, die für die Gesellschaft oder eine ihrer Tochtergesellschaften Leistungen erbringen; oder

(f) wenn ein Aktionär oder eine Gruppe von in gemeinsamer Absprache handelnden Aktionären mehr als 15% des im Handelsregister eingetragenen Aktienkapitals der Gesellschaft auf sich vereinigt hat, ohne den übrigen Aktionären ein vom Verwaltungsrat empfohlenes Übernahmeangebot zu unterbreiten; oder zur Abwehr eines unterbreiteten, angedrohten oder potentiellen Übernahmeangebotes, welches der Verwaltungsrat, nach Konsultation mit einem von ihm beigezogenen unabhängigen Finanzberater, den Aktionären nicht zur Annahme empfohlen hat, weil der Verwaltungsrat das Übernahmeangebot in finanzieller Hinsicht gegenüber den Aktionären nicht als fair beurteilt hat.

3 The Board of Directors is authorized to withdraw or limit the preemptive rights of the shareholders and to allot them to individual shareholders or third parties:

(a) if the issue price of the new Shares is determined by reference to the market price; or

(b) for the acquisition of an enterprise, part(s) of an enterprise or participations, or for the financing or refinancing of any of such transactions, or for the financing of new investment plans of the Company; or

(c) for purposes of broadening the shareholder constituency of the Company in certain financial or investor markets, for purposes of the participation of strategic partners, or in connection with the listing of new Shares on domestic or foreign stock exchanges; or

(d) for purposes of granting an over-allotment option (*Greenshoe*) of up to 20% of the total number of Shares in a placement or sale of Shares to the respective initial purchaser(s) or underwriter(s); or

(e) for the participation of members of the Board of Directors, members of the executive management, employees, contractors, consultants or other persons performing services for the benefit of the Company or any of its subsidiaries; or

(f) following a shareholder or a group of shareholders acting in concert having accumulated shareholdings in excess of 15% of the share capital registered in the commercial register without having submitted to the other shareholders a takeover offer recommended by the Board of Directors, or for the defense of an actual, threatened or potential takeover bid, in relation to which the Board of Directors, upon consultation with an independent financial adviser retained by it, has not recommended to the shareholders acceptance on the basis that the Board of Directors has not found the takeover bid to be financially fair to the shareholders.

4 Die neuen Aktien unterliegen den Eintragungsbeschränkungen in das Aktienbuch von Artikel 7 und 9 dieser Statuten.

Artikel 6

Bedingtes Aktienkapital

1 Das Aktienkapital kann sich durch Ausgabe von höchstens 167’617’649 voll zu liberierenden Aktien im Nennwert von je CHF 15 um höchstens CHF 2’514’264’735 erhöhen durch:

(a) die Ausübung von Wandel-, Tausch-, Options-, Bezugs- oder ähnlichen Rechten auf den Bezug von Aktien (nachfolgend die **Rechte**), welche Dritten oder Aktionären in Verbindung mit auf nationalen oder internationalen Kapitalmärkten neu oder bereits begebenen Anleihensobligationen, Optionen, Warrants oder anderen Finanzmarktinstrumenten oder neuen oder bereits bestehenden vertraglichen Verpflichtungen der Gesellschaft, einer ihrer Gruppengesellschaften oder einer deren Rechtsvorgänger eingeräumt werden (nachfolgend zusammen die **mit Rechten verbundenen Obligationen**); und/oder

(b) die Ausgabe von Aktien oder mit Rechten verbundenen Obligationen an Mitglieder des Verwaltungsrates, Mitglieder der Geschäftsleitung, Arbeitnehmer, Beauftragte, Berater oder anderen Personen, welche Dienstleistungen für die Gesellschaft oder ihre Tochtergesellschaften erbringen.

4 The new Shares shall be subject to the limitations for registration in the share register pursuant to Articles 7 and 9 of these Articles of Association.

Article 6

Conditional Share Capital

1 The share capital may be increased in an amount not to exceed CHF 2,514,264,735 through the issuance of up to 167,617,649 fully paid-up Shares with a par value of CHF 15 per Share through:

(a) the exercise of conversion, exchange, option, warrant or similar rights for the subscription of Shares (hereinafter the **Rights**) granted to third parties or shareholders in connection with bonds, options, warrants or other securities newly or already issued in national or international capital markets or new or already existing contractual obligations by or of the Company, one of its group companies, or any of their respective predecessors (hereinafter collectively, the **Rights-Bearing Obligations**); and/or

(b) the issuance of Shares or Rights-Bearing Obligations granted to members of the Board of Directors, members of the executive management, employees, contractors, consultants or other persons providing services to the Company or its subsidiaries.

2 Bei der Ausgabe von mit Rechten verbundenen Obligationen durch die Gesellschaft, eine ihrer Gruppengesellschaften oder eine deren Rechtsvorgänger ist das Bezugsrecht der Aktionäre ausgeschlossen. Zum Bezug der neuen Aktien, die bei Ausübung von mit Rechten verbundenen Obligationen ausgegeben werden, sind die jeweiligen Inhaber der mit Rechten verbundenen Obligationen berechtigt. Die Bedingungen der mit Rechten verbundenen Obligationen sind durch den Verwaltungsrat festzulegen.

3 Der Verwaltungsrat ist ermächtigt, die Vorwegzeichnungsrechte der Aktionäre im Zusammenhang mit der Ausgabe von mit Rechten verbundenen Obligationen durch die Gesellschaft oder eine ihrer Gruppengesellschaften zu beschränken oder aufzuheben, falls (1) die Ausgabe zum Zwecke der Finanzierung oder Refinanzierung der Übernahme von Unternehmen, Unternehmensteilen, Beteiligungen oder Investitionen, oder (2) die Ausgabe auf nationalen oder internationalen Finanzmärkten oder im Rahmen einer Privatplatzierung erfolgt.
Wird das Vorwegzeichnungsrecht weder direkt noch indirekt durch den Verwaltungsrat gewährt, gilt Folgendes:

(a) Die mit Rechten verbundenen Obligationen sind zu den jeweils marktüblichen Bedingungen auszugeben oder einzugehen; und

(b) der Umwandlungs-, Tausch- oder sonstige Ausübungspreis der mit Rechten verbundenen Obligationen ist unter Berücksichtigung des Marktpreises im Zeitpunkt der Ausgabe der mit Rechten verbundenen Obligationen festzusetzen; und

(c) die mit Rechten verbundenen Obligationen sind höchstens während 30 Jahren ab dem jeweiligen Zeitpunkt der betreffenden Ausgabe oder des betreffenden Abschlusses wandel-, tausch- oder ausübbar.

2 The preemptive rights of the shareholders shall be excluded in connection with the issuance of any Rights-Bearing Obligations by the Company, one of its group companies, or any of their respective predecessors. The then-current owners of such Rights-Bearing Obligations shall be entitled to subscribe for the new Shares issued upon conversion, exchange or exercise of any Rights-Bearing Obligations. The conditions of the Rights-Bearing Obligations shall be determined by the Board of Directors.

3 The Board of Directors shall be authorized to withdraw or limit the advance subscription rights of the shareholders in connection with the issuance by the Company or one of its group companies of Rights-Bearing Obligations if (1) the issuance is for purposes of financing or refinancing the acquisition of an enterprise, parts of an enterprise, participations or investments or (2) the issuance occurs in national or international capital markets or through a private placement.
If the advance subscription rights are neither granted directly nor indirectly by the Board of Directors, the following shall apply:

(a) The Rights-Bearing Obligations shall be issued or entered into at market conditions; and

(b) the conversion, exchange or exercise price of the Rights-Bearing Obligations shall be set with reference to the market conditions prevailing at the date on which the Rights-Bearing Obligations are issued; and

(c) the Rights-Bearing Obligations may be converted, exchanged or exercised during a maximum period of 30 years from the date of the relevant issuance or entry.

4 Bei der Ausgabe von Aktien oder mit Rechten verbundenen Obligationen gemäss Artikel 6 Absatz 1(b) dieser Statuten sind das Bezugsrecht wie auch das Vorwegzeichnungsrecht der Aktionäre der Gesellschaft ausgeschlossen. Die Ausgabe von Aktien oder mit Rechten verbundenen Obligationen an die in Artikel 6 Absatz 1(b) dieser Statuten genannten Personen erfolgt gemäss einem oder mehreren Beteiligungsplänen der Gesellschaft. Die Ausgabe von Aktien an die Artikel 6 Absatz 1(b) dieser Statuten genannten Personen kann zu einem Preis erfolgen, der unter dem Kurs der Börse liegt, an der die Aktien gehandelt werden, muss aber mindestens zum Nennwert erfolgen.

5 Die neuen Aktien, welche über die Ausübung von mit Rechten verbundenen Obligationen erworben werden, unterliegen den Eintragungsbeschränkungen in das Aktienbuch gemäss Artikel 7 und 9 dieser Statuten.

Artikel 7

Aktienbuch, Rechtsausübung, Eintragungsbe-schränkungen, Nominees

1 Die Gesellschaft oder von ihr beauftragte Dritte führen ein Aktienbuch. Darin werden die Eigentümer und Nutzniesser der Aktien sowie Nominees mit Namen und Vornamen, Wohnort, Adresse und Staatsangehörigkeit (bei juristischen Personen mit Firma und Sitz) eingetragen. Die Gesellschaft oder der von ihr mit der Aktienbuchführung beauftragte Dritte ist berechtigt, bei Eintragung im Aktienbuch von der antragstellenden Person einen angemessenen Nachweis seiner Berechtigung an den Aktien zu verlangen. Ändert eine im Aktienbuch eingetragene Person ihre Adresse, so hat sie dies dem Aktienbuchführer mitzuteilen. Solange dies nicht geschehen ist, gelten alle brieflichen Mitteilungen der Gesellschaft an die im Aktienbuch eingetragenen Personen als rechtsgültig an die bisher im Aktienbuch eingetragene Adresse erfolgt.

4 The preemptive rights and advance subscription rights of the shareholders shall be excluded in connection with the issuance of any Shares or Rights-Bearing Obligations pursuant to Article 6 para 1(b) of these Articles of Association. Shares or Rights-Bearing Obligations shall be issued to any of the persons referred to in Article 6 para 1(b) of these Articles of Association in accordance with one or more benefit or incentive plans of the Company. Shares may be issued to any of the persons referred to in Article 6 para 1(b) of these Articles of Association at a price lower than the current market price quoted on the stock exchange on which the Shares are traded, but at least at par value.

5 The new Shares acquired through the exercise of Rights-Bearing Obligations shall be subject to the limitations for registration in the share register pursuant to Articles 7 and 9 of these Articles of Association.

Article 7

Share Register, Exercise of Rights, Restrictions on Registration, Nominees

1 The Company shall maintain, itself or through a third party, a share register that lists the surname, first name, address and citizenship (in the case of legal entities, the company name and company seat) of the holders and usufructuaries of the Shares as well as the nominees. The Company or the third party maintaining the share register on behalf of the Company shall be entitled to request at the time of the entry into the share register from the Person requesting such entry appropriate evidence of that Person's title to the Shares. A person recorded in the share register shall notify the share registrar of any change in address. Until such notification shall have occurred, all written communication from the Company to persons of record shall be deemed to have validly been made if sent to the address recorded in the share register.

2 Ein Erwerber von Aktien wird auf Gesuch als Aktionär mit Stimmrecht im Aktienbuch eingetragen, vorausgesetzt, dass ein solcher Erwerber ausdrücklich erklärt, die Aktien im eigenen Namen und auf eigene Rechnung erworben zu haben. Der Verwaltungsrat kann Nominees, welche Aktien im eigenen Namen aber auf fremde Rechnung halten, als Aktionäre mit Stimmrecht im Aktienbuch der Gesellschaft eintragen. Die an den Aktien wirtschaftlich Berechtigten, welche die Aktien über einen Nominee halten, üben Aktionärsrechte mittelbar über den Nominee aus.

3 Der Verwaltungsrat kann nach Anhörung des eingetragenen Aktionärs dessen Eintragung im Aktienbuch als Aktionär mit Stimmrecht mit Rückwirkung auf das Datum der Eintragung streichen, wenn diese durch falsche oder irreführende Angaben zustande gekommen ist. Der Betroffene muss über die Streichung sofort informiert werden.

Artikel 8

Form der Aktien

1 Die Gesellschaft gibt Aktien in Form von Einzelurkunden, Globalurkunden oder Wertrechten aus. Der Gesellschaft steht es im Rahmen der gesetzlichen Vorgaben frei, ihre in einer dieser Formen ausgegebenen Aktien jederzeit und ohne Zustimmung der Aktionäre in eine andere Form umzuwandeln. Die Gesellschaft trägt die Kosten, die bei einer solchen Umwandlung anfallen.

2 An acquirer of Shares shall be recorded upon request in the share register as a shareholder with voting rights; *provided*, *however*, that any such acquirer expressly declares to have acquired the Shares in its own name and for its own account, save that the Board of Directors may record nominees who hold Shares in their own name, but for the account of third parties, as shareholders of record with voting rights in the share register of the Company. Beneficial owners of Shares who hold Shares through a nominee exercise the shareholders' rights through the intermediation of such nominee.

3 After hearing the registered shareholder concerned, the Board of Directors may cancel the registration of such shareholder as a shareholder with voting rights in the share register with retroactive effect as of the date of registration, if such registration was made based on false or misleading information. The relevant shareholder shall be informed promptly of the cancellation.

Article 8

Form of Shares

1 The Company may issue Shares in the form of individual certificates, global certificates or uncertificated securities. Subject to applicable law, the Company may convert the Shares from one form into another form at any time and without the approval of the shareholders. The Company shall bear all cost associated with any such conversion.

2 Ein Aktionär hat keinen Anspruch auf Umwandlung von in bestimmter Form ausgegebenen Aktien in eine andere Form. Jeder Aktionär kann jedoch jederzeit die Ausstellung einer Bescheinigung über die von ihm gemäss Aktienbuch gehaltenen Namenaktien verlangen.

3 Werden Bucheffekten im Auftrag der Gesellschaft oder des Aktionärs von einer Verwahrungsstelle, einem Registrar, Transfer Agenten, einer Trust Gesellschaft, Bank oder einer ähnlichen Gesellschaft verwaltet (die **Verwahrungsstelle**), so setzt Wirksamkeit gegenüber der Gesellschaft voraus, dass diese Bucheffekten und die damit verbundenen Rechte unter Mitwirkung der Verwahrungsstelle übertragen oder daran Sicherheiten bestellt werden.

4 Für den Fall, dass die Gesellschaft beschliesst, Aktienzertifikate zu drucken und auszugeben, müssen die Aktienzertifikate die Unterschrift von zwei zeichnungsberechtigten Personen tragen. Mindestens eine dieser Personen muss ein Mitglied des Verwaltungsrates sein. Faksimile-Unterschriften sind erlaubt.

Artikel 9

Rechtsausübung

1 Die Gesellschaft anerkennt nur einen Vertreter pro Aktie.

2 Stimmrechte und die damit verbundenen Rechte können der Gesellschaft gegenüber von einem Aktionär, Nutzniesser der Aktien oder Nominee jeweils nur im Umfang ausgeübt werden, wie dieser mit Stimmrecht im Aktienbuch eingetragen ist.

Abschnitt 3:
Gesellschaftsorgane
A. Generalversammlung

2 A shareholder has no right to request a conversion of the Shares from one form into another form. Each shareholder may, however, at any time request a written attestation of the number of Shares held by it as reflected in the share register.

3 If intermediated securities are administered on behalf of the Company or a shareholder by an intermediary, registrar, transfer agent, trust company, bank or similar entity (the **Intermediary**), any transfer or grant of a security interest in such intermediated securities and the appurtenant rights associated therewith, in order for such transfer or grant of a security interest to be valid against the Company, requires the cooperation of the Intermediary.

4 If the Company decides to print and deliver share certificates, the share certificates shall bear the signatures of two duly authorized signatories of the Company, at least one of which shall be a member of the Board of Directors. These signatures may be facsimile signatures.

Article 9

Exercise of Rights

1 The Company shall only accept one representative per Share.

2 Voting rights and appurtenant rights associated therewith may be exercised in relation to the Company by a shareholder, usufructuary of Shares or nominee only to the extent that such person is recorded in the share register with the right to exercise his voting rights.

Section 3:
Corporate Bodies
A. General Meeting of Shareholders

Artikel 10

Zuständigkeit

Die Generalversammlung ist das oberste Organ der Gesellschaft.

Artikel 11

Ordentliche Generalver-sammlung

Die ordentliche Generalversammlung findet alljährlich innerhalb von sechs Monaten nach Schluss des Geschäftsjahres statt. Spätestens zwanzig Kalendertage vor der Versammlung sind der Geschäftsbericht und der Revisionsbericht den Aktionären am Gesellschaftssitz zur Einsicht aufzulegen. Jeder Aktionär kann verlangen, dass ihm unverzüglich eine Ausfertigung des Geschäftsberichts und des Revisionsberichts ohne Kostenfolge zugesandt wird. Die im Aktienbuch eingetragenen Aktionäre werden über die Verfügbarkeit des Geschäftsberichts und des Revisionsberichts durch schriftliche Mitteilung unterrichtet.

Artikel 12

Ausser-ordentliche Generalversammlung

1 Ausserordentliche Generalversammlungen finden in den vom Gesetz vorgesehenen Fällen statt, insbesondere, wenn der Verwaltungsrat es für notwendig oder angezeigt erachtet oder die Revisionsstelle dies verlangt.

2 Ausserdem muss der Verwaltungsrat eine ausserordentliche Generalversammlung einberufen, wenn es eine Generalversammlung so beschliesst oder wenn ein oder mehrere Aktionäre, welche zusammen mindestens den zehnten Teil des im Handelsregister eingetragenen Aktienkapitals vertreten, dies verlangen, unter der Voraussetzung, dass folgende Angaben gemacht werden: (a)(1) die Verhandlungsgegenstände, schriftlich unterzeichnet von dem/den antragstellenden Aktionär(en), (2) die Anträge sowie (3) der Nachweis der erforderlichen Anzahl der im Aktienbuch eingetragenen Aktien; und (b) die weiteren Informationen, die von der Gesellschaft nach den Regeln der U.S. Securities and Exchange Commission (**SEC**) in einem sog. Proxy Statement aufgenommen und veröffentlicht werden müssen.

Article 10

Authority

The General Meeting of Shareholders is the supreme corporate body of the Company.

Article 11

Annual General Meeting

The Annual General Meeting shall be held each year within six months after the close of the fiscal year of the Company. The Annual Report and the Auditor's Report shall be made available for inspection by the shareholders at the registered office of the Company no later than twenty calendar days prior to the Annual General Meeting. Each shareholder is entitled to request prompt delivery of a copy of the Annual Report and the Auditor's Report free of charge. Shareholders of record will be notified of the availability of the Annual Report and the Auditor's Report in writing.

Article 12

Extraordinary General Meetings

1 Extraordinary General Meetings shall be held in the circumstances provided by law, in particular when deemed necessary or appropriate by the Board of Directors or if so requested by the Auditor.

2 An Extraordinary General Meeting shall further be convened by the Board of Directors upon resolution of a General Meeting of Shareholders or if so requested by one or more shareholders who, in the aggregate, represent at least one-tenth of the share capital recorded in the Commercial Register and who submit (a)(1) a request signed by such shareholder(s) that specifies the item(s) to be included on the agenda, (2) the respective proposals of the shareholders and (3) evidence of the required shareholdings recorded in the share register and (b) such other information as would be required to be included in a proxy statement pursuant to the rules of the U.S. Securities and Exchange Commission (**SEC**).

Artikel 13

Einberufung

1 Die Generalversammlung wird durch den Verwaltungsrat, nötigenfalls die Revisionsstelle, spätestens 20 Kalendertage vor dem Tag der Generalversammlung einberufen. Die Einberufung erfolgt durch einmalige Bekanntmachung im Publikationsorgan der Gesellschaft gemäss Artikel 32 dieser Statuten. Für die Einhaltung der Einberufungsfrist ist der Tag der Veröffentlichung der Einberufung im Publikationsorgan massgeblich, wobei der Tag der Veröffentlichung nicht mitzuzählen ist. Die im Aktienbuch eingetragenen Aktionäre können zudem auf dem ordentlichen Postweg über die Generalversammlung informiert werden.

2 Die Einberufung muss die Verhandlungsgegenstände sowie die Anträge des Verwaltungsrates und des oder der Aktionäre, welche die Durchführung einer Generalversammlung oder die Traktandierung eines Verhandlungsgegenstandes verlangt haben, und bei Wahlgeschäften die Namen des oder der zur Wahl vorgeschlagenen Kandidaten enthalten.

Artikel 14

Traktandierung

1 Jeder Aktionär kann die Traktandierung eines Verhandlungsgegenstandes verlangen. Das Traktandierungsbegehren muss mindestens 30 Kalendertage vor dem Jahrestag des sog. Proxy Statements der Gesellschaft, das im Zusammenhang mit der Generalversammlung im jeweiligen Vorjahr veröffentlicht und gemäss den anwendbaren SEC Regeln bei der SEC eingereicht wurde, schriftlich unter Angabe des Verhandlungsgegenstandes und der Anträge sowie unter Nachweis der erforderlichen Anzahl im Aktienbuch eingetragenen Aktien eingereicht werden. Falls das Datum der anstehenden Generalversammlung mehr als 30 Kalendertage vor oder nach dem Jahrestag der vorangegangenen Generalversammlung angesetzt worden ist, ist das Traktandierungsbegehren stattdessen spätestens 10 Kalendertage nach dem Tag einzureichen, an dem die Gesellschaft das Datum der Generalversammlung öffentlich bekannt gemacht hat.

Article 13

Notice of Shareholders' Meetings

1 Notice of a General Meeting of Shareholders shall be given by the Board of Directors or, if necessary, by the Auditor, no later than twenty calendar days prior to the date of the General Meeting of Shareholders. Notice of the General Meeting of Shareholders shall be given by way of a one-time announcement in the official means of publication of the Company pursuant to Article 32 of these Articles of Association. The notice period shall be deemed to have been observed if notice of the General Meeting of Shareholders is published in such official means of publication, it being understood that the date of publication is not to be included for purposes of computing the notice period. Shareholders of record may in addition be informed of the General Meeting of Shareholders by ordinary mail.

2 The notice of a General Meeting of Shareholders shall specify the items on the agenda and the proposals of the Board of Directors and the shareholder(s) who requested that a General Meeting of Shareholders be held or an item be included on the agenda, and, in the event of elections, the name(s) of the candidate(s) that has or have been put on the ballot for election.

Article 14

Agenda

1 Any shareholder may request that an item be included on the agenda of a General Meeting of Shareholders. An inclusion of an item on the agenda must be requested in writing at least 30 calendar days prior to the anniversary date of the Company's proxy statement in connection with the previous year's General Meeting of Shareholders, as filed with the SEC pursuant to the applicable rules of the SEC, and shall specify in writing the relevant agenda items and proposals, together with evidence of the required shareholdings recorded in the share register; *provided, however,* that if the date of the General Meeting of Shareholders is more than 30 calendar days before or after such anniversary date, such request must instead be made at least by the 10th calendar day following the date on which the Company has made public disclosure of the date of the General Meeting of Shareholders.

2 Zu nicht gehörig angekündigten Verhandlungsgegenständen können keine Beschlüsse gefasst werden. Hiervon ausgenommen sind jedoch der Beschluss über den in einer Generalversammlung gestellten Antrag auf (i) Einberufung einer ausserordentlichen Generalversammlung sowie (ii) Durchführung einer Sonderprüfung gemäss Artikel 697a des Schweizerischen Obligationenrechts (**OR**).

3 Zur Stellung von Anträgen im Rahmen der Verhandlungsgegenstände und zu Verhandlungen ohne Beschlussfassung bedarf es keiner vorgängigen Ankündigung.

Artikel 15

Vorsitz der Generalversammlung, Protokoll, Stimmenzähler

1 An der Generalversammlung führt der Präsident des Verwaltungsrates oder, bei dessen Verhinderung, der Vizepräsident oder eine andere vom Verwaltungsrat bezeichnete Person den Vorsitz.

2 Der Vorsitzende der Generalversammlung bestimmt den Protokollführer und die Stimmenzähler, die alle nicht Aktionäre sein müssen. Das Protokoll ist vom Vorsitzenden und vom Protokollführer zu unterzeichnen.

2 No resolution may be passed at a General Meeting of Shareholders concerning an agenda item in relation to which due notice was not given. Proposals made during a General Meeting of Shareholders to (i) convene an Extraordinary General Meeting or (ii) initiate a special investigation in accordance with article 697a of the Swiss Code of Obligations (**CO**) are not subject to the due notice requirement set forth herein.

3 No prior notice is required to bring motions related to items already on the agenda or for the discussion of matters on which no resolution is to be taken.

Article 15

Acting Chair, Minutes, Vote Counters

1 At the General Meeting of Shareholders the Chairman of the Board of Directors or, in his absence, the Vice-Chairman or any other person designated by the Board of Directors, shall take the chair.

2 The acting chair of the General Meeting of Shareholders shall appoint the secretary and the vote counters, none of whom need be shareholders. The minutes of the General Meeting of Shareholders shall be signed by the acting chair and the secretary.

3 Der Vorsitzende der Generalversammlung hat sämtliche Leitungsbefugnisse, die für die ordnungsgemässe Durchführung der Generalversammlung nötig und angemessen sind.

Artikel 16

Recht auf Teilnahme, Vertretung der Aktionäre

Jeder im Aktienbuch eingetragene Aktionär ist berechtigt, an der Generalversammlung und deren Beschlüssen teilzunehmen. Ein Aktionär kann sich an der Generalversammlung vertreten lassen, wobei der Vertreter nicht Aktionär sein muss. Der Verwaltungsrat regelt die Einzelheiten über die Vertretung und Teilnahme an der Generalversammlung in Verfahrensvorschriften.

Artikel 17

Stimmrecht

Jede Aktie berechtigt zu einer Stimme. Das Stimmrecht untersteht den Bedingungen von Artikel 7 und 9 dieser Statuten.

Artikel 18

Beschlüsse und Wahlen

1 Die Generalversammlung fasst Beschlüsse und entscheidet Wahlen, soweit das Gesetz oder diese Statuten es nicht anders bestimmen, mit der relativen Mehrheit der abgegebenen Aktienstimmen (wobei Enthaltungen, sog. Broker Nonvotes, leere oder ungültige Stimmen für die Bestimmung des Mehrs nicht berücksichtigt werden).

3 The acting chair of the General Meeting of Shareholders shall have all powers and authority necessary and appropriate to ensure the orderly conduct of the General Meeting of Shareholders.

Article 16

Right to Participation and Representation

Each shareholder recorded in the share register is entitled to participate at the General Meeting of Shareholders and in any vote taken. The shareholders may be represented by proxies who need not be shareholders. The Board of Directors shall issue the particulars of the right to representation and participation at the General Meeting of Shareholders in procedural rules.

Article 17

Voting Rights

Each Share shall convey the right to one vote. The right to vote is subject to the conditions of Articles 7and 9 of these Articles of Association.

Article 18

Resolutions and Elections

1 Unless otherwise required by law or these Articles of Association, the General Meeting of Shareholders shall take resolutions and decide elections upon a relative majority of the votes cast at the General Meeting of Shareholders (whereby abstentions, broker nonvotes, blank or invalid ballots shall be disregarded for purposes of establishing the majority).

2 Die Generalversammlung entscheidet über die Wahl von Mitgliedern des Verwaltungsrates nach dem proportionalen Wahlverfahren, wonach diejenige Person, welche die grösste Zahl der abgegebenen Aktienstimmen für einen Verwaltungsratssitz erhält, als für den betreffenden Verwaltungsratssitz gewählt gilt. Aktienstimmen gegen einen Kandidaten, Stimmenthaltungen, sog. Broker Nonvotes, ungültige oder leere Stimmen haben für die Zwecke dieses Artikels 18 Abs. 2 keine Auswirkungen auf die Wahl von Mitgliedern des Verwaltungsrates.

3 Für die Abwahl von amtierenden Mitgliedern des Verwaltungsrates gilt das Mehrheitserfordernis gemäss Artikel 20 Abs. 2(e) sowie das Präsenzquorum von Artikel 21 Abs. 1(a).

4 Die Abstimmungen und Wahlen erfolgen offen, es sei denn, dass die Generalversammlung schriftliche Abstimmung respektive Wahl beschliesst oder der Vorsitzende dies anordnet. Der Vorsitzende kann Abstimmungen und Wahlen auch mittels elektronischem Verfahren durchführen lassen. Elektronische Abstimmungen und Wahlen sind schriftlichen Abstimmen und Wahlen gleichgestellt.

5 Der Vorsitzende kann eine offene Wahl oder Abstimmung immer durch eine schriftliche oder elektronische wiederholen lassen, sofern nach seiner Meinung Zweifel am Abstimmungsergebnis bestehen. In diesem Fall gilt die vorausgegangene offene Wahl oder Abstimmung als nicht geschehen.

2 The General Meeting of Shareholders shall decide elections of members of the Board of Directors upon a plurality of the votes cast at the General Meeting of Shareholders. A plurality means that the individual who receives the largest number of votes for a board seat is elected to that board seat. Votes against any candidate, abstentions, broker nonvotes, blank or invalid ballots shall have no impact on the election of members of the Board of Directors under this Article 18 para. 2.

3 For the removal of a serving member of the Board of Directors, the voting requirement set forth in Article 20 para. 2(e) and the presence quorum set forth in Article 21 para. 1(a) shall apply.

4 Resolutions and elections shall be decided by a show of hands, unless a written ballot is resolved by the General Meeting of Shareholders or is ordered by the acting chair of the General Meeting of Shareholders. The acting chair may also hold resolutions and elections by use of an electronic voting system. Electronic resolutions and elections shall be considered equal to resolutions and elections taken by way of a written ballot.

5 The chair of the General Meeting of Shareholders may at any time order that an election or resolution decided by a show of hands be repeated by way of a written or electronic ballot if he considers the vote to be in doubt. The resolution or election previously held by a show of hands shall then be deemed to have not taken place.

Befugnisse der Generalver-sammlung

Artikel 19

Der Generalversammlung sind folgende Geschäfte vorbehalten:

(a) Die Festsetzung und Änderung dieser Statuten;

(b) die Wahl der Mitglieder des Verwaltungsrates und der Revisionsstelle;

(c) die Genehmigung des Jahresberichtes und der Konzernrechnung;

(d) die Genehmigung der Jahresrechnung sowie die Beschlussfassung über die Verwendung des Bilanzgewinnes, insbesondere die Festsetzung der Dividende;

(e) die Entlastung der Mitglieder des Verwaltungsrates;

(f) die Genehmigung eines Zusammenschlusses mit einem Nahestehenden Aktionär (gemäss der Definition dieser Begriffe in Artikel 35 dieser Statuten); und

(g) die Beschlussfassung über die Gegenstände, die der Generalversammlung durch das Gesetz oder die Statuten vorbehalten sind oder ihr, vorbehältlich Artikel 716a OR, durch den Verwaltungsrat vorgelegt werden.

Powers of the General Meeting of Shareholders

Article 19

The following powers shall be vested exclusively in the General Meeting of Shareholders:

(a) The adoption and amendment of these Articles of Association;

(b) the election of the members of the Board of Directors and the Auditor;

(c) the approval of the Annual Report and the Consolidated Financial Statements;

(d) the approval of the Annual Statutory Financial Statements of the Company and the resolution on the allocation of profit shown on the Annual Statutory Balance Sheet, in particular the determination of any dividend;

(e) the discharge from liability of the members of the Board of Directors;

(f) the approval of a Business Combination with an Interested Shareholder (as each such term is defined in Article 35 of these Articles of Association); and

(g) the adoption of resolutions on matters that are reserved to the General Meeting of Shareholders by law, these Articles of Association or, subject to article 716a CO, that are submitted to the General Meeting of Shareholders by the Board of Directors.

Artikel 20

Besonderes Quorum 1 Ein Beschluss der Generalversammlung, der mindestens zwei Drittel der an der Generalversammlung vertretenen Stimmen und die absolute Mehrheit der an der Generalversammlung vertretenen Aktiennennwerte auf sich vereinigt, ist erforderlich für:

(a) Die Ergänzung oder Änderung des Gesellschaftszweckes gemäss Artikel 2 dieser Statuten;

(b) die Einführung und Abschaffung von Stimmrechtsaktien;

(c) die Beschränkung der Übertragbarkeit der Aktien und die Aufhebung einer solche Beschränkung;

(d) die Beschränkung der Ausübung des Stimmrechts und die Aufhebung einer solchen Beschränkung;

(e) eine genehmigte oder bedingte Kapitalerhöhung;

(f) die Kapitalerhöhung (i) aus Eigenkapital, (ii) gegen Sacheinlage oder zwecks Sachübernahme oder (iii) die Gewährung von besonderen Vorteilen;

(g) die Einschränkung oder Aufhebung des Bezugsrechts;

(h) die Verlegung des Sitzes der Gesellschaft;

(i) die Umwandlung von Namen- in Inhaberaktien und umgekehrt; und

(j) die Auflösung der Gesellschaft.

2 Ein Beschluss der Generalversammlung, der mindestens zwei Drittel aller stimmberechtigten Aktien auf sich vereinigt, ist erforderlich für:

Article 20

Special Vote 1 The approval of at least two-thirds of the votes and the absolute majority of the par value of Shares, each as represented at a General Meeting of Shareholders, shall be required for resolutions with respect to:

(a) The amendment or modification of the purpose of the Company as described in Article 2 of these Articles of Association;

(b) the creation and the cancelation of shares with privileged voting rights;

(c) the restriction on the transferability of Shares and the cancelation of such restriction;

(d) the restriction on the exercise of the right to vote and the cancelation of such restriction;

(e) an authorized or conditional increase in share capital;

(f) an increase in share capital (i) through the conversion of capital surplus, (ii) through contribution in kind or for purposes of an acquisition of assets, or (iii) the granting of special privileges;

(g) the limitation on or withdrawal of preemptive rights;

(h) the relocation of the registered office of the Company;

(i) the conversion of registered shares into bearer shares and vice versa; and

(j) the dissolution of the Company.

2 The approval of at least two-thirds of the Shares entitled to vote shall be required for:

(a) Jede Änderung von Artikel 14 Abs. 1 dieser Statuten;

(b) jede Änderung von Artikel 18 dieser Statuten;

(c) jede Änderung dieses Artikels 20 Abs. 2;

(d) jede Änderung von Artikel 21, 22, 23 oder 24 dieser Statuten; und

(e) die Abwahl eines amtierenden Mitglieds des Verwaltungsrates.

3 Zusätzlich zu etwaigen gesetzlich bestehenden Zustimmungserfordernissen ist ein Beschluss der Generalversammlung mit einer Mehrheit, die mindestens die Summe von: (i) zwei Drittel aller stimmberechtigten Aktien; zuzüglich (ii) einer Zahl von stimmberechtigten Aktien, die einem Drittel der von Nahestehenden Aktionären (wie in Artikel 35 dieser Statuten definiert) gehaltenen Aktienstimmen entspricht, auf sich vereinigt, erforderlich für (1) jeden Zusammenschluss der Gesellschaft mit einem Nahestehenden Aktionär innerhalb eines Zeitraumes von drei Jahren, seitdem diese Person zu einem Nahestehenden Aktionär wurde, (2) jede Änderung von Artikel 19(f) dieser Statuten oder (3) jede Änderung von Artikel 20 Abs. 3 dieser Statuten (einschliesslich der dazugehörigen Definitionen in Artikel 35 dieser Statuten). Das im vorangehenden Satz aufgestellte Zustimmungserfordernis ist jedoch nicht anwendbar falls:

(a) Any change to Article 14 para. 1 of these Articles of Association;

(b) any change to Article 18 of these Articles of Association;

(c) any change to this Article 20 para. 2;

(d) any change to Article 21, 22, 23 or 24 of these Articles of Association; and

(e) a resolution with respect to the removal of a serving member of the Board of Directors.

3 In addition to any approval that may be required under applicable law, the approval of a majority at least equal to the sum of: (i) two-thirds of the Shares entitled to vote; plus (ii) a number of Shares entitled to vote that is equal to one-third of the number of Shares held by Interested Shareholders (as defined in Article 35 of these Articles of Association), shall be required for the Company to (1) engage in any Business Combination with an Interested Shareholder for a period of three years following the time that such Person became an Interested Shareholder, (2) amend Article 19(f) of these Articles of Association or (3) amend this Article 20 para. 3 of these Articles of Association (including any of the definitions pertaining thereto as set forth in Article 35 of these Articles of Association); *provided*, *however*, that the approval requirement in the preceding sentence shall not apply if:

(a) der Verwaltungsrat, bevor diese Person zu einem Nahestehenden Aktionär wurde, entweder den Zusammenschluss oder eine andere Transaktion genehmigte, als Folge derer diese Person zu einem Nahestehenden Aktionär wurde;

(b) nach Vollzug der Transaktion, als Folge derer diese Person zu einem Nahestehenden Aktionär wurde, der Nahestehende Aktionär mindestens 85% der unmittelbar vor Beginn der betreffenden Transaktion allgemein stimmberechtigten Aktien hält, wobei zur Bestimmung der Anzahl der allgemein stimmberechtigten Aktien (nicht jedoch zur Bestimmung der durch den Nahestehenden Aktionär gehaltenen Aktien) folgende Aktien nicht zu berücksichtigen sind: Aktien, (x) welche von Personen gehalten werden, die sowohl Verwaltungsrats- wie Geschäftsleitungsmitglieder sind, und (y) welche für Mitarbeiteraktienpläne reserviert sind, soweit die diesen Plänen unterworfenen Mitarbeiter nicht das Recht haben, unter Wahrung der Vertraulichkeit darüber zu entscheiden, ob Aktien, die dem betreffenden Mitarbeiteraktienplan unterstehen, in einem Übernahme- oder Austauschangebot angedient werden sollen oder nicht;

(c) eine Person unbeabsichtigterweise zu einem Nahestehenden Aktionär wird und (x) das Eigentum an einer genügenden Anzahl Aktien sobald als möglich veräussert, so dass sie nicht mehr länger als Nahestehender Aktionär qualifiziert und (y) zu keinem Zeitpunkt während der drei dem Zusammenschluss zwischen der Gesellschaft und dieser Person unmittelbar vorangehenden Jahren als Nahestehender Aktionär gegolten hätte, ausgenommen aufgrund des unbeabsichtigten Erwerbs der Eigentümerschaft.

(a) Prior to such time that such Person became an Interested Shareholder, the Board of Directors approved either the Business Combination or the transaction which resulted in such Person becoming an Interested Shareholder;

(b) upon consummation of the transaction which resulted in such Person becoming an Interested Shareholder, the Interested Shareholder Owned at least 85% of the Shares generally entitled to vote at the time the transaction commenced, excluding for purposes of determining such number of Shares then in issue (but not for purposes of determining the Shares Owned by the Interested Shareholder), those Shares Owned (x) by Persons who are both members of the Board of Directors and officers of the Company and (y) by employee share plans in which employee participants do not have the right to determine confidentially whether Shares held subject to the plan will be tendered in a tender or exchange offer;

(c) a Person becomes an Interested Shareholder inadvertently and (x) as soon as practicable divests itself of Ownership of sufficient Shares so that such Person ceases to be an Interested Shareholder and (y) would not, at any time within the three-year period immediately prior to a Business Combination between the Company and such Person, have been an Interested Shareholder but for the inadvertent acquisition of Ownership;

(d) der Zusammenschluss vor Vollzug oder Verzicht auf und nach öffentlicher Bekanntgabe oder der nach diesem Abschnitt erforderlichen Mitteilung (was auch immer früher erfolgt) eine(r) beabsichtigten Transaktion vorgeschlagen wird, welche (i) eine der Transaktionen im Sinne des zweiten Satzes dieses Artikels 20 Abs. 3(d) darstellt; (ii) mit oder von einer Person abgeschlossen wird, die entweder während den letzten drei Jahren kein Nahestehender Aktionär war oder zu einem Nahestehenden Aktionär mit der Genehmigung des Verwaltungsrates wurde; und (iii) von einer Mehrheit der dannzumal amtierenden Mitglieder des Verwaltungsrates (aber mindestens einem) genehmigt oder nicht abgelehnt wird, die entweder bereits Verwaltungsratsmitglieder waren, bevor in den drei vorangehenden Jahren irgendeine Person zu einem Nahestehenden Aktionär wurde, oder die auf Empfehlung einer Mehrheit solcher Verwaltungsratsmitglieder als deren Nachfolger zur Wahl vorgeschlagen wurden. Die im vorangehenden Satz erwähnten beabsichtigten Transaktionen sind auf folgende beschränkt: (x) eine Fusion oder andere Form des Zusammenschlusses der Gesellschaft (mit Ausnahme einer Fusion, welche keine Genehmigung durch die Generalversammlung der Gesellschaft voraussetzt); (y) ein Verkauf, eine Vermietung oder Verpachtung, hypothekarische Belastung oder andere Verpfändung, Übertragung oder andere Verfügung (ob in einer oder mehreren Transaktionen), einschliesslich im Rahmen eines Tauschs, von Vermögenswerten der Gesellschaft oder einer direkten oder indirekten Tochtergesellschaft, die zur Mehrheit von der Gesellschaft gehalten wird (jedoch nicht an eine direkt oder indirekt zu 100% gehaltene Konzerngesellschaft oder an die Gesellschaft), soweit diese Vermögenswerte einen Marktwert von 50% oder mehr entweder des auf konsolidierter Basis aggregierten Marktwertes aller Vermögenswerte der Gesellschaft oder des aggregierten Marktwertes aller dann ausgegebenen Aktien haben, unabhängig davon, ob eine dieser Transaktionen Teil einer Auflösung der Gesellschaft ist oder nicht; oder (z) ein vorgeschlagenes Übernahme- oder Umtauschangebot für 50% oder mehr der ausstehenden Stimmrechte der Gesellschaft. Die Gesellschaft muss Nahestehenden Aktionären sowie den übrigen Aktionären den Vollzug einer der unter (x) oder (y) des zweiten Satzes dieses Artikels 20 Abs. 3(d) erwähnten Transaktionen mindestens 20 Kalendertage vorher mitteilen.

(d) the Business Combination is proposed prior to the consummation or abandonment of and subsequent to the earlier of the public announcement or the notice required hereunder of a proposed transaction which (i) constitutes one of the transactions described in the second sentence of this Article 20 para. 3(d); (ii) is with or by a person who either was not an Interested Shareholder during the previous three years or who became an Interested Shareholder with the approval of the Board of Directors; and (iii) is approved or not opposed by a majority of the members of the Board of Directors then in office (but not less than one) who were Directors prior to any person becoming an Interested Shareholder during the previous three years or were recommended for election to succeed such Directors by a majority of such Directors. The proposed transactions referred to in the preceding sentence are limited to (x) a merger or consolidation of the Company (except for a merger in respect of which no vote of the Company's shareholders is required); (y) a sale, lease, exchange, mortgage, pledge, transfer or other disposition (in one transaction or a series of transactions), whether as part of a dissolution or otherwise, of assets of the Company or of any direct or indirect majority-Owned subsidiary of the Company (other than to any direct or indirect wholly Owned subsidiary or to the Company) having an aggregate market value equal to 50% or more of either that aggregate market value of all of the assets of the Company determined on a consolidated basis or the aggregate market value of all the issued shares; or (z) a proposed tender or exchange offer for 50% or more of the voting shares then in issue. The Company shall give not less than 20 days' notice to all Interested Shareholders as well as to the other shareholders prior to the consummation of any of the transactions described in clause (x) or (y) of the second sentence of this Article 20 para. 3(d).

Artikel 21

Präsenzquorum

1 Die nachfolgend aufgeführten Angelegenheiten erfordern zum Zeitpunkt der Konstituierung der Generalversammlung ein Präsenzquorum von Aktionären oder deren Vertretern, welche mindestens zwei Drittel des im Handelsregister eingetragenen Aktienkapitals vertreten, damit die Generalversammlung beschlussfähig ist:

(a) Die Beschlussfassung über die Abwahl eines amtierenden Verwaltungsratsmitglieds; und

(b) die Beschlussfassung, diesen Artikel 21 oder Artikel 18, 19(f), 20, 22, 23 oder 24 dieser Statuten zu ergänzen, zu ändern, nicht anzuwenden oder ausser Kraft zu setzen.

2 Jede andere Beschlussfassung oder Wahl setzt zu ihrer Gültigkeit voraus, dass zum Zeitpunkt der Konstituierung der Generalversammlung zumindest die Mehrheit aller stimmberechtigten Aktien anwesend ist. Die Aktionäre können mit der Behandlung der Traktanden fortfahren, selbst wenn Aktionäre nach Bekanntgabe des Quorums durch den Vorsitzenden die Generalversammlung verlassen und damit weniger als das geforderte Präsenzquorum an der Generalversammlung verbleibt.

B. Verwaltungsrat

Artikel 22

Anzahl der Verwaltungs-räte

Der Verwaltungsrat besteht aus mindestens zwei und höchstens 14 Mitgliedern.

Article 21

Presence Quorum

1 The matters set forth below require that a quorum of shareholders of record holding in person or by proxy at least two-thirds of the share capital recorded in the Commercial Register are present at the time when the General Meeting of Shareholders proceeds to business:

(a) the adoption of a resolution to remove a serving Director; and

(b) the adoption of a resolution to amend, vary, suspend the operation of, disapply or cancel this Article 21 or Articles 18, 19(f), 20, 22, 23 or 24 of these Articles of Association.

2 The adoption of any other resolution or election requires that at least a majority of all the Shares entitled to vote be represented at the time when the General Meeting of Shareholders proceeds to business. The shareholders present at a General Meeting of Shareholders may continue to transact business, despite the withdrawal of shareholders from such General Meeting of Shareholders following announcement of the presence quorum at that meeting.

B. Board of Directors

Article 22

Number of Directors

The Board of Directors shall consist of no less than two and no more than 14 members.

Artikel 23

Amtsdauer

1 Die Verwaltungsräte werden vom Verwaltungsrat in drei Klassen aufgeteilt, welche als Klasse I, Klasse II und Klasse III bezeichnet werden. An jeder ordentlichen Generalversammlung soll jede Klasse Verwaltungsräte, deren Amtsdauer abläuft, für eine Amtsdauer von drei Jahren bzw. bis zur Wahl eines Nachfolgers in sein Amt gewählt werden. Der Verwaltungsrat legt die Reihenfolge der Wiederwahl fest, wobei die erste Amtszeit einer Klasse von Verwaltungsräten auch weniger als drei Jahre betragen kann. Für die Zwecke dieser Bestimmung ist unter einem Jahr der Zeitabschnitt zwischen zwei ordentlichen Generalversammlungen zu verstehen.

2 Wenn ein Verwaltungsratsmitglied vor Ablauf seiner Amtsdauer aus welchen Gründen auch immer ersetzt wird, endet die Amtsdauer des an seiner Stelle gewählten neuen Verwaltungsratsmitgliedes mit dem Ende der Amtsdauer seines Vorgängers.

Artikel 24

Organisation des Verwaltungs-rates, Entschädigung

1 Der Verwaltungsrat wählt aus seiner Mitte einen Vorsitzenden. Er kann einen oder mehrere Vizepräsidenten wählen. Er bestellt weiter einen Sekretär, welcher nicht Mitglied des Verwaltungsrates sein muss. Der Verwaltungsrat regelt unter Vorbehalt der Bestimmungen des Gesetzes und dieser Statuten die Einzelheiten seiner Organisation in einem Organisationsreglement.

2 Die Mitglieder des Verwaltungsrates haben Anspruch auf Ersatz ihrer im Interesse der Gesellschaft aufgewendeten Auslagen sowie auf eine ihrer Tätigkeit und Verantwortung entsprechende Entschädigung, die der Verwaltungsrat auf Antrag eines Ausschusses des Verwaltungsrates festlegt.

Article 23

Term of Office

1 The Board of Directors shall divide its members into three classes, designated Class I, Class II and Class III. At each Annual General Meeting, each class of the members of the Board of Directors whose term shall then expire shall be elected to hold office for a three-year term or until the election of their respective successor in office. The Board of Directors shall establish the order of rotation, whereby the first term of office of members of a particular Class may be less than three years. For purposes of this provision, one year shall mean the period between two Annual General Meetings of Shareholders.

2 If, before the expiration of his term of office, a Director should be replaced for whatever reason, the term of office of the newly elected member of the Board of Directors shall expire at the end of the term of office of his predecessor.

Article 24

Organization of the Board, Remuneration

1 The Board of Directors shall elect from among its members a Chairman. It may elect one or more Vice-Chairmen. It shall further appoint a Secretary, who need not be a member of the Board of Directors. Subject to applicable law and these Articles of Association, the Board of Directors shall establish the particulars of its organization in organizational regulations.

2 The members of the Board of Directors shall be entitled to reimbursement of all expenses incurred in the interest of the Company, as well as remuneration for their services that is appropriate in view of their functions and responsibilities. The amount of the remuneration shall be determined by the Board of Directors upon recommendation by a committee of the Board of Directors.

3 Soweit gesetzlich zulässig, hält die Gesellschaft aktuelle und ehemalige Mitglieder des Verwaltungsrates und der Geschäftsleitung sowie deren Erben, Konkurs- oder Nachlassmassen aus Gesellschaftsmitteln für Schäden, Verluste und Kosten aus drohenden, hängigen oder abgeschlossenen Klagen, Verfahren oder Untersuchungen zivil-, straf- oder verwaltungsrechtlicher oder anderer Natur schadlos, welche ihnen oder ihren Erben, Konkurs- oder Nachlassmassen entstehen aufgrund von tatsächlichen oder behaupteten Handlungen, Zustimmungen oder Unterlassungen im Zusammenhang mit der Ausübung ihrer Pflichten oder behaupteten Pflichten oder aufgrund der Tatsache, dass sie Mitglied des Verwaltungsrates oder der Geschäftsleitung der Gesellschaft sind oder waren oder auf Aufforderung der Gesellschaft als Mitglied des Verwaltungsrates, der Geschäftsleitung oder als Arbeitnehmer oder Agent eines anderen Unternehmens, einer anderen Gesellschaft, einer nicht-rechtsfähigen Personengesellschaft oder eines Trusts sind oder waren. Diese Pflicht zur Schadloshaltung besteht nicht, soweit in einem endgültigen, nicht weiterziehbaren Entscheid eines zuständigen Gerichts bzw. einer zuständigen Verwaltungsbehörde entschieden worden ist, dass eine der genannten Personen ihre Pflichten als Mitglied des Verwaltungsrates oder der Geschäftsleitung absichtlich oder grobfahrlässig verletzt hat.

3 The Company shall indemnify and hold harmless, to the fullest extent permitted by law, the existing and former members of the Board of Directors and officers, and their heirs, executors and administrators, out of the assets of the Company from and against all threatened, pending or completed actions, suits or proceedings – whether civil, criminal, administrative or investigative – and all costs, charges, losses, damages and expenses which they or any of them, their heirs, executors or administrators, shall or may incur or sustain by or by reason of any act done or alleged to be done, concurred or alleged to be concurred in or omitted or alleged to be omitted in or about the execution of their duty, or alleged duty, or by reason of the fact that he is or was a member of the Board of Director or officer of the Company, or while serving as a member of the Board of Director or officer of the Company is or was serving at the request of the Company as a director, officer, employee or agent of another corporation, partnership, joint venture, trust or other enterprise; *provided, however,* that this indemnity shall not extend to any matter in which any of said persons is found, in a final judgment or decree of a court or governmental or administrative authority of competent jurisdiction not subject to appeal, to have committed an intentional or grossly negligent breach of his statutory duties as a member of the Board of Director or officer.

4 Ohne den vorangehenden Absatz 3 dieses Artikels 24 einzuschränken, bevorschusst die Gesellschaft Mitgliedern des Verwaltungsrates und der Geschäftsleitung Gerichts- und Anwaltskosten. Die Gesellschaft kann solche Vorschüsse zurückfordern, wenn ein zuständiges Gericht oder eine zuständige Verwaltungsbehörde in einem endgültigen, nicht weiterziehbaren Urteil bzw. Entscheid zum Schluss kommt, dass eine der genannten Personen ihre Pflichten als Mitglied des Verwaltungsrates oder der Geschäftsleitung absichtlich oder grobfahrlässig verletzt hat.

4 Without limiting the foregoing paragraph 3 of this Article 24, the Company shall advance court costs and attorneys' fees to the existing and former members of the Board of Directors and officers. The Company may however recover such advanced costs if any of said persons is found, in a final judgment or decree of a court or governmental or administrative authority of competent jurisdiction not subject to appeal, to have committed an intentional or grossly negligent breach of his statutory duties as a Director of officer.

Artikel 25

Befugnisse des Verwaltungs-rates

1 Der Verwaltungsrat hat die in Artikel 716a OR statuierten unübertragbaren und unentziehbaren Aufgaben, insbesondere:

(a) die Oberleitung der Gesellschaft und die Erteilung der nötigen Weisungen;
(b) die Festlegung der Organisation; und
(c) die Oberaufsicht über die mit der Geschäftsführung betrauten Personen, namentlich im Hinblick auf die Befolgung der Gesetze, Statuten, Reglemente und Weisungen.

2 Der Verwaltungsrat kann überdies in allen Angelegenheiten Beschluss fassen, die nicht nach Gesetz oder Statuten der Generalversammlung zugeteilt sind.

3 Der Verwaltungsrat kann Beteiligungspläne der Gesellschaft der Generalversammlung zur Genehmigung vorlegen.

Artikel 26

Übertragung von Befugnissen

Der Verwaltungsrat kann unter Vorbehalt von Artikel 25 Abs. 1 dieser Statuten sowie der Vorschriften des OR die Geschäftsführung nach Massgabe eines Organisationsreglements ganz oder teilweise an eines oder mehrere seiner Mitglieder, an einen oder mehrere Ausschüsse des Verwaltungsrates oder an Dritte übertragen.

Article 25

Specific Powers of the Board

1 The Board of Directors has the non-delegable and inalienable duties as specified in Article 716a CO, in particular:

(a) the ultimate direction of the business of the Company and the issuance of the required directives;
(b) the determination of the organization of the Company; and
(c) the ultimate supervision of the persons entrusted with management duties, in particular with regard to compliance with law, these Articles of Association, regulations and directives.

2 In addition, the Board of Directors may pass resolutions with respect to all matters that are not reserved to the General Meeting of Shareholders by law or under these Articles of Association.

3 The Board of Directors may submit benefit or incentive plans of the Company to the General Meeting of Shareholders for approval.

Article 26

Delegation of Powers

Subject to Article 25 para. 1 of these Articles of Association and the applicable provisions of the CO, the Board of Directors may delegate the management of the Company in whole or in part to individual directors, one or more committees of the Board of Directors or to persons other than Directors pursuant to organizational regulations.

Artikel 27

Sitzungen des Verwaltungsrats

1 Sofern das vom Verwaltungsrat erlassene Organisationsreglement nichts anderes festlegt, ist zur gültigen Beschlussfassung über Geschäfte des Verwaltungsrates die Anwesenheit einer Mehrheit der Mitglieder des gesamten Verwaltungsrates notwendig. Kein Präsenzquorum ist erforderlich für die Statutenanpassungs- und Feststellungsbeschlüsse des Verwaltungsrates im Zusammenhang mit Kapitalerhöhungen.

2 Der Verwaltungsrat fasst seine Beschlüsse mit einer Mehrheit der von den anwesenden Verwaltungsräten abgegebenen Stimmen, vorausgesetzt, das Präsenzquorum von Absatz 1 dieses Artikels 27 ist erfüllt. Der Vorsitzende hat bei Stimmengleichheit keinen Stichentscheid.

Artikel 28

Zeichnungsberechtigung

Die rechtsverbindliche Vertretung der Gesellschaft durch Mitglieder des Verwaltungsrates und durch Dritte wird in einem Organisationsreglement festgelegt.

C. Revisionsstelle

Artikel 29

Amtsdauer, Befugnisse und Pflichten

1 Die Revisionsstelle wird von der Generalversammlung gewählt und es obliegen ihr die vom Gesetz zugewiesenen Befugnisse und Pflichten.

Article 27

Meeting of the Board of Directors

1 Except as otherwise set forth in organizational regulations of the Board of Directors, the attendance quorum necessary for the transaction of the business of the Board of Directors shall be a majority of the whole Board of Directors. No attendance quorum shall be required for resolutions of the Board of Directors providing for the confirmation of a capital increase or for the amendment of the Articles of Association in connection therewith.

2 The Board of Directors shall pass its resolutions with the majority of the votes cast by the Directors present at a meeting at which the attendance quorum of para. 1 of this Article 27 is satisfied. The Chairman shall have no casting vote.

Article 28

Signature Power

The due and valid representation of the Company by members of the Board of Directors and other persons shall be set forth in organizational regulations.

C. Auditor

Article 29

Term, Powers and Duties

1 The Auditor shall be elected by the General Meeting of Shareholders and shall have the powers and duties vested in it by law.

2 Die Amtsdauer der Revisionsstelle beträgt ein Jahr, beginnend am Tage der Wahl an einer ordentlichen Generalversammlung und endend am Tage der nächsten ordentlichen Generalversammlung.

Abschnitt 4:
Jahresrechnung, Konzernrechnung und Gewinnverteilung

Artikel 30

Geschäftsjahr

Der Verwaltungsrat legt das Geschäftsjahr fest.

Artikel 31

Verteilung des Bilanzgewinns, Reserven

1 Über den Bilanzgewinn verfügt die Generalversammlung im Rahmen der anwendbaren gesetzlichen Vorschriften. Der Verwaltungsrat unterbreitet ihr seine Vorschläge.

2 Neben der gesetzlichen Reserve können weitere Reserven geschaffen werden.

3 Dividenden, welche nicht innerhalb von fünf Jahren nach ihrem Auszahlungsdatum bezogen werden, fallen an die Gesellschaft und werden in die allgemeinen gesetzlichen Reserven verbucht.

Abschnitt 5:
Auflösung und Liquidation

Artikel 32

Auflösung und Liquidation

1 Die Generalversammlung kann jederzeit die Auflösung und Liquidation der Gesellschaft nach Massgabe der gesetzlichen und statutarischen Vorschriften beschliessen.

2 The term of office of the Auditor shall be one year, commencing on the day of election at an Annual General Meeting of Shareholders and terminating on the day of the next Annual General Meeting of Shareholders.

Section 4:
Annual Statutory Financial Statements, Consolidated Financial Statements and Profit Allocation

Article 30

Fiscal Year

The Board of Directors determines the fiscal year.

Article 31

Allocation of Profit Shown on the Annual Statutory Balance Sheet, Reserves

1 The profit shown on the Annual Statutory Balance Sheet shall be allocated by the General Meeting of Shareholders in accordance with applicable law. The Board of Directors shall submit its proposals to the General Meeting of Shareholders.

2 Further reserves may be taken in addition to the reserves required by law.

3 Dividends that have not been collected within five years after their payment date shall enure to the Company and be allocated to the general statutory reserves.

Section 5:
Winding-up and Liquidation

Article 32

Winding-up and Liquidation

1 The General Meeting of Shareholders may at any time resolve on the winding-up and liquidation of the Company pursuant to applicable law and the provisions set forth in these Articles of Association.

2 Die Liquidation wird durch den Verwaltungsrat durchgeführt, sofern sie nicht durch die Generalversammlung anderen Personen übertragen wird.

3 Die Liquidation der Gesellschaft erfolgt nach Massgabe der gesetzlichen Vorschriften.

4 Nach erfolgter Tilgung der Schulden wird das Vermögen unter die Aktionäre nach Massgabe der eingezahlten Beträge verteilt, soweit diese Statuten nichts anderes vorsehen.

Abschnitt 6:
Bekanntmachungen, Mitteilungen

Artikel 33

Bekannt-machungen, Mitteilungen

1 Publikationsorgan der Gesellschaft ist das Schweizerische Handelsamtsblatt.

2 Soweit keine individuelle Benachrichtigung durch das Gesetz, börsengesetzliche Bestimmungen oder diese Statuten verlangt wird, gelten sämtliche Mitteilungen an die Aktionäre als gültig erfolgt, wenn sie im Schweizerischen Handelsamtsblatt veröffentlicht worden sind. Schriftliche Bekanntmachungen der Gesellschaft an die Aktionäre werden auf dem ordentlichen Postweg an die letzte im Aktienbuch verzeichnete Adresse des Aktionärs oder des bevollmächtigten Empfängers geschickt. Finanzinstitute, welche Aktien für wirtschaftlich Berechtigte halten und als solches im Aktienbuch eingetragen sind, gelten als bevollmächtigte Empfänger.

Abschnitt 7:
Verbindlicher Originaltext

2 The liquidation shall be effected by the Board of Directors, unless the General Meeting of Shareholders shall appoint other persons as liquidators.

3 The liquidation of the Company shall be effectuated pursuant to the statutory provisions.

4 Upon discharge of all liabilities, the assets of the Company shall be distributed to the shareholders pursuant to the amounts paid in, unless these Articles of Association provide otherwise.

Section 6:
Announcements, Communications

Article 33

Announcements, Communications

1 The official means of publication of the Company shall be the Swiss Official Gazette of Commerce.

2 To the extent that individual notification is not required by law, stock exchange regulations or these Articles of Association, all communications to the shareholders shall be deemed valid if published in the Swiss Official Gazette of Commerce. Written communications by the Company to its shareholders shall be sent by ordinary mail to the last address of the shareholder or authorized recipient recorded in the share register. Financial institutions holding Shares for beneficial owners and recorded in such capacity in the share register shall be deemed to be authorized recipients.

Section 7:
Original Language

Verbindlicher Originaltext

Artikel 34

Falls sich zwischen der deutschen und englischen Fassung dieser Statuten Differenzen ergeben, hat die deutsche Fassung Vorrang.

Abschnitt 8:
Definitionen

Artikel 35

Aktie(n) 1 Der Begriff **Aktie(n)** hat die in Artikel 4 dieser Statuten aufgeführte Bedeutung.

Eigentümer 2 **Eigentümer(in)**, unter Einschluss der Begriffe **Eigentum**, **halten**, **gehalten**, **Eigentümerschaft** oder ähnlicher Begriffe, bedeutet, wenn verwendet mit Bezug auf Aktien, jede Person, welche allein oder zusammen mit oder über Nahestehende Gesellschaften oder Nahestehende Personen:

(a) wirtschaftliche Eigentümerin dieser Aktien ist, ob direkt oder indirekt;

(b) (1) das Recht hat, aufgrund eines Vertrags, einer Absprache oder einer anderen Vereinbarung, oder aufgrund der Ausübung eines Wandel-, Tausch-, Bezugs- oder Optionsrechts oder anderweitig Aktien zu erwerben (unabhängig davon, ob dieses Recht sofort ausübbar ist oder nur nach einer gewissen Zeit); vorausgesetzt, dass eine Person nicht als Eigentümerin derjenigen Aktien gelten soll, die im Rahmen eines Übernahme- oder Umtauschangebots, das diese Person oder eine dieser Person Nahestehende Gesellschaft oder Nahestehende Person eingeleitet hat, angedient werden, bis diese Aktien zum Kauf oder Tausch akzeptiert werden; oder (2) das Recht hat, die Stimmrechte dieser Aktien aufgrund eines Vertrags, einer Absprache oder einer anderen Vereinbarung auszuüben; vorausgesetzt, dass eine Person nicht als Eigentümerin von Aktien gilt infolge des Rechts, das Stimmrecht auszuüben, soweit der diesbezügliche Vertrag, die diesbezügliche Absprache oder die diesbezügliche andere Vereinbarung nur aufgrund einer widerruflichen Vollmacht (*proxy*) oder Zustimmung zustande gekommen ist, und diese Vollmacht (*proxy*) oder Zustimmung in Erwiderung auf eine an 10 oder mehr Personen gemachte diesbezügliche Aufforderung ergangen ist; oder

Original Language

Article 34

In the event of deviations between the German and English version of these Articles of Association, the German text shall prevail.

Section 8:
Definitions

Article 35

Share(s) 1 The term **Share(s)** has the meaning assigned to it in Article 4 of these Articles of Association.

Owner 2 **Owner**, including the terms **Own**, **Owned** and **Ownership** when used with respect to any Shares means a Person that individually or with or through any of its Affiliates or Associates:

(a) beneficially Owns such Shares, directly or indirectly;

(b) has (1) the right to acquire such Shares (whether such right is exercisable immediately or only after the passage of time) pursuant to any agreement, arrangement or understanding, or upon the exercise of conversion rights, exchange rights, warrants or options, or otherwise; *provided, however*, that a Person shall not be deemed the Owner of Shares tendered pursuant to a tender or exchange offer made by such Person or any of such Person's Affiliates or Associates until such tendered Shares are accepted for purchase or exchange; or (2) the right to vote such Shares pursuant to any agreement, arrangement or understanding; *provided, however*, that a Person shall not be deemed the Owner of any Shares because of such Person's right to vote such Shares if the agreement, arrangement or understanding to vote such Shares arises solely from a revocable proxy or consent given in response to a proxy or consent solicitation made to 10 or more Persons; or

(c) zwecks Erwerbs, Haltens, Stimmrechtsausübung (mit Ausnahme der Stimmrechtsausübung aufgrund einer widerruflichen Vollmacht (*proxy*) oder Zustimmung wie in Artikel 35 Abs. 2(b)(ii)(2) umschrieben) oder Veräusserung dieser Aktien mit einer anderen Person in einen Vertrag, eine Absprache oder eine andere Vereinbarung getreten ist, die direkt oder indirekt entweder selbst oder über ihr Nahestehende Gesellschaften oder Nahestehende Personen wirtschaftlich Eigentümerin dieser Aktien ist.

Gesellschaft 3 Der Begriff **Gesellschaft** hat die in Artikel 1 dieser Statuten aufgeführte Bedeutung.

Kontrolle 4 **Kontrolle**, einschliesslich die Begriffe **kontrollierend**, **kontrolliert von** und **unter gemeinsamer Kontrolle mit**, bedeutet die Möglichkeit, direkt oder indirekt auf die Geschäftsführung und die Geschäftspolitik einer Person Einfluss zu nehmen, sei es aufgrund des Haltens von Stimmrechten, eines Vertrags oder auf andere Weise. Eine Person, welche 20% oder mehr der ausgegebenen oder ausstehenden Stimmrechte einer Kapitalgesellschaft, rechts- oder nicht-rechtsfähigen Personengesellschaft oder eines anderen Rechtsträgers hält, hat mangels Nachweises des Gegenteils unter Anwendung des Beweismasses der überwiegenden Wahrscheinlichkeit der Beweismittel vermutungsweise Kontrolle über einen solchen Rechtsträger. Ungeachtet des Voranstehenden gilt diese Vermutung der Kontrolle nicht, wenn eine Person in Treu und Glauben und nicht zur Umgehung dieser Bestimmung Stimmrechte als Stellvertreter (*agent*), Bank, Börsenmakler (*broker*), Nominee, Depotbank (*custodian*) oder Treuhänder (*trustee*) für einen oder mehrere Eigentümer hält, die für sich allein oder zusammen als Gruppe keine Kontrolle über den betreffenden Rechtsträger haben.

(c) has any agreement, arrangement or understanding for the purpose of acquiring, holding, voting (except voting pursuant to a revocable proxy or consent as described in Article 35 para. 2(b)(ii)(2)), or disposing of such Shares with any other Person that beneficially Owns, or whose Affiliates or Associates beneficially Own, directly or indirectly, such Shares.

Company 3 The term **Company** has the meaning assigned to it in Article 1 of these Articles of Association.

Control 4 **Control**, including the terms **controlling**, **controlled by** and **under common control** with, means the possession, direct or indirect, of the power to direct or cause the direction of the management and policies of a Person, whether through the Ownership of voting shares, by contract, or otherwise. A Person who is the Owner of 20% or more of the issued or outstanding voting shares of any corporation, partnership, unincorporated association or other entity shall be presumed to have control of such entity, in the absence of proof by a preponderance of the evidence to the contrary. Notwithstanding the foregoing, a presumption of control shall not apply where such Person holds voting shares, in good faith and not for the purpose of circumventing this provision, as an agent, bank, broker, nominee, custodian or trustee for one or more Owners who do not individually or as a group have control of such entity.

Nahestehender Aktionär	5	**Nahestehender Aktionär** bedeutet jede Person (unter Ausschluss der Gesellschaft oder jeder direkten oder indirekten Tochtergesellschaft, die zur Mehrheit von der Gesellschaft gehalten wird), (i) die Eigentümerin von 15% oder mehr der ausgegebenen Aktien ist, oder (ii) die als Nahestehende Gesellschaft oder Nahestehende Person anzusehen ist und irgendwann in den drei unmittelbar vorangehenden Jahren vor dem Zeitpunkt, zu dem bestimmt werden muss, ob diese Person ein Nahestehender Aktionär ist, Eigentümerin von 15% oder mehr der ausgegebenen Stimmrechte gewesen ist, ebenso wie jede Nahestehende Gesellschaft und Nahestehende Person dieser Person; vorausgesetzt, dass eine Person nicht als **Nahestehender Aktionär** gilt, die aufgrund von Handlungen, die ausschliesslich der Gesellschaft zuzurechnen sind, Eigentümerin von Aktien in Überschreitung der 15%-Beschränkung ist; wobei jedoch jede solche Person dann als Nahestehender Aktionär gilt, falls sie später zusätzliche Aktien erwirbt, ausser dieser Erwerb erfolgt aufgrund von weiteren Gesellschaftshandlungen, die weder direkt noch indirekt von dieser Person beeinflusst werden. Zur Bestimmung, ob eine Person ein Nahestehender Aktionär ist, sind die als ausgegeben geltenden Aktien unter Einschluss der von dieser Person gehaltenen Aktien (unter Anwendung des Begriffs "gehalten" wie in Artikel 35 Abs. 2 dieser Statuten definiert) zu berechnen, jedoch unter Ausschluss von nichtausgegebenen Aktien, die aufgrund eines Vertrags, einer Absprache oder einer anderen Vereinbarung, oder aufgrund der Ausübung eines Wandel-, Bezugs- oder Optionsrechts oder anderweitig ausgegeben werden können;	Interested Shareholder	5	**Interested Shareholder** means any Person (other than the Company or any direct or indirect majority-Owned subsidiary of the Company) (i) that is the Owner of 15% or more of the issued Shares of the Company or (ii) that is an Affiliate or Associate of the Company and was the Owner of 15% or more of the issued Shares at any time within the three-year period immediately prior to the date on which it is sought to be determined whether such Person is an Interested Shareholder, and also the Affiliates and Associates of such Person; *provided*, *however*, that the term Interested Shareholder shall not include any Person whose Ownership of Shares in excess of the 15% limitation is the result of action taken solely by the Company; provided that such Person shall be an Interested Shareholder if thereafter such Person acquires additional Shares, except as a result of further corporate action not caused, directly or indirectly, by such Person. For the purpose of determining whether a Person is an Interested Shareholder, the Shares deemed to be in issue shall include Shares deemed to be Owned by the Person (through the application of the definition of Owner in Article 35 para. 2 of these Articles of Association) but shall not include any other unissued Shares which may be issuable pursuant to any agreement, arrangement or understanding, or upon exercise of conversion rights, warrants or options, or otherwise.
Nahestehende Gesellschaft	6	**Nahestehende Gesellschaft** bedeutet jede Person, die direkt oder indirekt über eine oder mehrere Mittelspersonen eine andere Person kontrolliert, von einer anderen Person kontrolliert wird, oder unter gemeineinsamer Kontrolle mit einer anderen Person steht.	Affiliate	6	**Affiliate** means a Person that directly, or indirectly through one or more intermediaries, controls, or is controlled by, or is under common control with, another Person.
Nahestehende Person	7	**Nahestehende Person** bedeutet, wenn verwendet zur Bezeichnung einer Beziehung zu einer Person, (i) jede Kapitalgesellschaft, rechts- oder nicht-rechtsfähige Personengesellschaft oder ein anderer Rechtsträger, von welcher diese Person Mitglied des Leitungs- oder Verwaltungsorgans, der Geschäftsleitung oder Gesellschafter ist oder von welcher diese Person, direkt oder indirekt, Eigentümerin von 20% oder mehr einer Kategorie von Aktien oder anderer Anteilsrechte ist, die ein Stimmrecht vermitteln, (ii) jedes Treuhandvermögen (*Trust*) oder jede andere Vermögenseinheit, an der diese Person wirtschaftlich einen Anteil von 20% oder mehr hält oder in Bezug auf welche diese Person als Verwalter (*trustee*) oder in ähnlich treuhändischer Funktion tätig ist, und (iii) jeder Verwandte, Ehe- oder Lebenspartner dieser Person, oder jede Verwandte des Ehe- oder Lebenspartners, jeweils soweit diese den gleichen Wohnsitz haben wie diese Person.	Associate	7	**Associate**, when used to indicate a relationship with any Person, means (i) any corporation, partnership, unincorporated association or other entity of which such Person is a director, officer or partner or is, directly or indirectly, the Owner of 20% or more of any class of voting shares, (ii) any trust or other estate in which such Person has at least a 20% beneficial interest or as to which such Person serves as trustee or in a similar fiduciary capacity, and (iii) any relative or spouse of such Person, or any relative of such spouse, who has the same residence as such Person.

OR	8	Der Begriff **OR** hat die in Artikel 14 Abs. 2 dieser Statuten aufgeführte Bedeutung.	CO	8	The term **CO** has the meaning assigned to it in Article 14 para. 2 of these Articles of Association.
Person	9	**Person** bedeutet jede natürliche Person, Kapitalgesellschaft, rechts- oder nicht-rechtsfähige Personengesellschaft oder jeder andere Rechtsträger;	Person	9	**Person** means any individual, corporation, partnership, unincorporated association or other entity.
Rechte	10	Der Begriff **Rechte** hat die in Artikel 6 Abs. 1 dieser Statuten aufgeführte Bedeutung.	Rights	10	The term **Rights** has the meaning assigned to it in Article 6 para. 1 of these Articles of Association.
Mit Rechten verbundenen Obligationen	11	Der Begriff **mit Rechten verbundenen Obligationen** hat die in Artikel 6 Abs. 1 dieser Statuten aufgeführte Bedeutung.	Rights-Bearing Obligations	11	The term **Rights-Bearing Obligations** has the meaning assigned to it in Article 6 para. 1 of these Articles of Association.
SEC	12	Der Begriff **SEC** hat die in Artikel 12 Abs. 2 dieser Statuten aufgeführte Bedeutung.	SEC	12	The term **SEC** has the meaning assigned to it in Article 12 para. 2 of these Articles of Association.
Transfer Agent	13	Der Begriff **Transfer Agent** hat die in Artikel 8 Abs. 3 dieser Statuten aufgeführte Bedeutung.	Transfer Agent	13	The term **Transfer Agent** has the meaning assigned to it in Article 8 para. 3 of these Articles of Association.
Zusammenschluss	14	**Zusammenschluss** bedeutet, wenn im Rahmen dieser Statuten in Bezug auf die Gesellschaft oder einen Nahestehenden Aktionär der Gesellschaft verwendet:	Business Combination	14	**Business Combination**, when used in these Articles of Association in reference to the Company and any Interested Shareholder of the Company, means:

(a) Jede Fusion oder andere Form des Zusammenschlusses der Gesellschaft oder einer direkten oder indirekten Tochtergesellschaft, die zur Mehrheit von der Gesellschaft gehalten wird, mit (1) dem Nahestehenden Aktionär oder (2) einer anderen Kapitalgesellschaft, rechts- oder nicht-rechtsfähigen Personengesellschaft oder einem anderen Rechtsträger, soweit diese Fusion oder andere Form des Zusammenschlusses durch den Nahestehenden Aktionär verursacht worden ist und als Folge dieser Fusion oder anderen Form des Zusammenschlusses Artikel 19(f) und Artikel 20 Abs. 3 dieser Statuten (sowie jede der dazu gehörigen Definition in Artikel 35 dieser Statuten) oder im Wesentlichen gleiche Bestimmungen wie Artikel 19(f), Artikel 20 Abs. 3 (und die dazugehörigen Definitionen in Artikel 35 dieser Statuten auf den überlebenden Rechtsträger) nicht anwendbar sind;

(a) Any merger or consolidation of the Company or any direct or indirect majority-Owned subsidiary of the Company with (1) the Interested Shareholder or (2) with any other corporation, partnership, unincorporated association or other entity if the merger or consolidation is caused by the Interested Shareholder and as a result of such merger or consolidation Article 19(f) and Article 20 para. 3 of these Articles of Association (including the relevant definitions in Article 35 of these Articles of Association pertaining thereto) or a provision substantially the same as such Article 19(f) and Article 20 para. 3 (including the relevant definitions in Article 35) are not applicable to the surviving entity;

(b) jeder Verkauf, Vermietung oder Verpachtung, hypothekarische Belastung oder andere Verpfändung, Übertragung oder andere Verfügung (ob in einer oder mehreren Transaktionen), einschliesslich im Rahmen eines Tauschs, von Vermögenswerten der Gesellschaft oder einer direkten oder indirekten Tochtergesellschaft, die zur Mehrheit von der Gesellschaft gehalten wird, an einen Nahestehenden Aktionär (ausser soweit der Zuerwerb unter einer der genannten Transaktionen proportional als Aktionär erfolgt), soweit diese Vermögenswerte einen Marktwert von 10% oder mehr entweder des auf konsolidierter Basis aggregierten Marktwertes aller Vermögenswerte der Gesellschaft oder des aggregierten Marktwertes aller dann ausgegebenen Aktien haben, unabhängig davon, ob eine dieser Transaktionen Teil einer Auflösung der Gesellschaft ist oder nicht;

(b) any sale, lease, exchange, mortgage, pledge, transfer or other disposition (in one transaction or a series of transactions), except proportionately as a shareholder, to or with the Interested Shareholder, whether as part of a dissolution or otherwise, of assets of the Company or of any direct or indirect majority-Owned subsidiary of the Company which assets have an aggregate market value equal to 10% or more of either the aggregate market value of all the assets of the Company determined on a consolidated basis or the aggregate market value of all the Shares then in issue;

(c) jede Transaktion, die dazu führt, dass die Gesellschaft oder eine direkte oder indirekte Tochtergesellschaft, die zur Mehrheit von der Gesellschaft gehalten wird, Aktien oder Tochtergesellschafts-Aktien an den Nahestehenden Aktionär ausgibt oder überträgt, es sei denn (1) aufgrund der Ausübung, des Tauschs oder der Wandlung von Finanzmarktinstrumenten, die in Aktien oder Aktien einer direkten oder indirekten Tochtergesellschaft, die zur Mehrheit von der Gesellschaft gehalten wird, ausgeübt, getauscht oder gewandelt werden können, vorausgesetzt, die betreffenden Finanzmarktinstrumente waren zum Zeitpunkt, in dem der Nahestehende Aktionär zu einem solchem wurde, bereits ausgegeben; (2) als Dividende oder Ausschüttung an alle Aktionäre, oder aufgrund der Ausübung, des Tauschs oder der Wandlung von Finanzmarktinstrumenten, die in Aktien oder Aktien einer direkten oder indirekten Tochtergesellschaft, die zur Mehrheit von der Gesellschaft gehalten wird, ausgeübt, getauscht oder gewandelt werden können, vorausgesetzt, diese Finanzinstrumente werden allen Aktionäre anteilsmässig ausgegeben, nachdem der Nahestehende Aktionär zu einem solchem wurde; (3) gemäss einem Umtauschangebot der Gesellschaft, Aktien von allen Aktionären zu den gleichen Bedingungen zu erwerben; oder (4) aufgrund der Ausgabe oder der Übertragung von Aktien durch die Gesellschaft; vorausgesetzt, dass in keinem der unter (2) bis (4) genannten Fällen der proportionale Anteil des Nahestehenden Aktionärs an den Aktien erhöht werden darf;

(c) any transaction which results in the issuance or transfer by the Company or by any direct or indirect majority-Owned subsidiary of the Company of any Shares or shares of such subsidiary to the Interested Shareholder, except (1) pursuant to the exercise, exchange or conversion of securities exercisable for, exchangeable for or convertible into Shares or the shares of a direct or indirect majority-Owned subsidiary of the Company which securities were in issue prior to the time that the Interested Shareholder became such; (2) pursuant to a dividend or distribution paid or made, or the exercise, exchange or conversion of securities exercisable for, exchangeable for or convertible into Shares or the shares of a direct or indirect majority-Owned subsidiary of the Company which security is distributed, pro rata, to all shareholders subsequent to the time the Interested Shareholder became such; (3) pursuant to an exchange offer by the Company to purchase Shares made on the same terms to all holders of said Shares; or (4) any issuance or transfer of Shares by the Company; *provided, however*, that in no case under (2)–(4) above shall there be an increase in the Interested Shareholder's proportionate interest in the Shares;

(d) jede Transaktion, in welche die Gesellschaft oder eine direkte oder indirekte Tochtergesellschaft, die zur Mehrheit von der Gesellschaft gehalten wird, involviert ist, und die direkt oder indirekt dazu führt, dass der proportionale Anteil der vom Nahestehenden Aktionär gehaltenen Aktien, in Aktien wandelbare Obligationen oder Tochtergesellschafts-Aktien erhöht wird, ausser eine solche Erhöhung ist nur unwesentlich und die Folge eines Spitzenausgleichs für Fraktionen oder eines Rückkaufs oder einer Rücknahme von Aktien, soweit diese(r) weder direkt noch indirekt durch den Nahestehenden Aktionär verursacht wurde; oder

(d) any transaction involving the Company or any direct or indirect majority-Owned subsidiary of the Company which has the effect, directly or indirectly, of increasing the proportionate interest in the Shares, or securities convertible into the Shares, or in the shares of any such subsidiary which is Owned by the Interested Shareholder, except as a result of immaterial changes due to fractional share adjustments or as a result of any purchase or redemption of any Shares not caused, directly or indirectly, by the Interested Shareholder; or

(e) jede direkte oder indirekte Gewährung von Darlehen, Vorschüssen, Garantien, Bürgschaften, oder garantieähnlicher Verpflichtungen, Pfändern oder anderen finanziellen Begünstigungen (mit Ausnahme einer solchen, die gemäss den Unterabschnitten (a) – (d) dieses Artikels 35 Abs. 14 ausdrücklich erlaubt ist sowie einer solchen, die proportional an alle Aktionäre erfolgt) durch die oder über die Gesellschaft oder eine direkte oder indirekte Tochtergesellschaft, die zur Mehrheit von der Gesellschaft gehalten wird, an den Nahestehenden Aktionär.

(e) any receipt by the Interested Shareholder of the benefit, directly or indirectly (except proportionately as a shareholder), of any loans, advances, guarantees, pledges or other financial benefits (other than those expressly permitted in subsections (a)–(d) of this Article 35 para. 14) provided by or through the Company or any direct or indirect majority-Owned subsidiary of the Company.

Abschnitt 9:
Übergangsbestimmungen

Artikel 36

Sacheinlage

Die Gesellschaft übernimmt bei der Kapitalerhöhung vom 19. Dezember 2008 von der Transocean Inc. in Grand Cayman, Cayman Islands (**Transocean Inc.**), gemäss Sacheinlagevertrag per 18. Dezember 2008 (**Sacheinlagevertrag**) 319’228’632 Aktien (*ordinary shares*) der Transocean Inc. Diese Aktien werden zu einem Übernahmewert von insgesamt CHF 16'476'107'961.80 übernommen. Als Gegenleistung für diese Sacheinlage gibt die Gesellschaft einem Umtauschagenten, handelnd auf Rechnung der Aktionäre der Transocean Inc. im Zeitpunkt unmittelbar vor Vollzug des Sacheinlagevertrages und im Namen und auf Rechnung der Transocean Inc., insgesamt 335'228’632 voll einbezahlte Aktien mit einem Nennwert von insgesamt CHF 5'028'429’480 aus. Die Gesellschaft weist die Differenz zwischen dem totalen Nennwert der ausgegebenen Aktien und dem Übernahmewert der Sacheinlage im Gesamtbetrag von CHF 11'447'678'481.80 den Reserven der Gesellschaft zu.

Section 9:
Transitional Provisions

Article 36

Contribution in Kind

In connection with the capital increase of December 19, 2008, and in accordance with the contribution in kind agreement as of December 18, 2008 (the **Contribution in Kind Agreement**), the Company acquires 319,228,632 ordinary shares of Transocean Inc., Grand Cayman, Cayman Islands (**Transocean Inc.**). The shares of Transocean Inc. are acquired for a total value of CHF 16,476,107,961.80. As consideration for this contribution, the Company issues to an exchange agent, acting for the account of the holders of ordinary shares of Transocean Inc. outstanding immediately prior to the completion of the Contribution in Kind Agreement and in the name and the account of Transocean Inc, a total of 335,228,632 fully paid Shares with a total par value of CHF 5,028,429,480. The difference between the aggregate par value of the issued Shares and the total value of CHF 11,447,678,481.80 is allocated to the reserves of the Company.

Zug, 14. Mai 2010

Zug, May 14, 2010

Exhibit 10.1

DRILLING CONTRACT

between

VASTAR RESOURCES, INC.

and

R&B FALCON DRILLING CO.

DATED DECEMBER 9, 1998

for

"RBS-8D"
"Deepwater Horizon"

CONTRACT NO. 980249

D-1-87.1

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Vern Buzard

DRILLING CONTRACT

RBS-8D

SEMISUBMERSIBLE DRILLING UNIT

VASTAR RESOURCES, INC.

AND

R&B FALCON DRILLNG CO.

CONTRACT NO. 980249 **DATE: DECEMBER 9, 1998**

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DRILLING CONTRACT

THIS CONTRACT ("CONTRACT") is made and entered into this 9th day of December, 1998, by and between Vastar Resources, Inc., a Delaware Corporation, hereinafter referred to as "COMPANY" and R&B Falcon Drilling Co., ("CONTRACTOR"), and shall be effective upon execution by both COMPANY and CONTRACTOR (the date when so effective, shall be referred to herein as the ("Effective Date"). COMPANY and CONTRACTOR are sometimes herein individually referred to as a "Party" and collectively referred to as the "Parties."

RECITALS

Whereas CONTRACTOR shall cause to be built, a semisubmersible drilling unit, "Drilling Unit". Whereas COMPANY desires to engage the services of CONTRACTOR, its Drilling Unit, and its equipment and all necessary crews for drilling, completing, testing, and remedial operations and support operations on a well or wells in the federal waters of the Gulf of Mexico, hereinafter referred to as "Operations" or "Work".

Whereas this CONTRACT and the attached exhibits establishes the terms and conditions contained in this document entitled "DRILLING CONTRACT" and the attached exhibits:

Exhibit A:	Dayrates
Exhibit B-1:	Drilling Unit Specifications
Exhibit B-2:	Material Equipment List
Exhibit B-3:	Consumable Material and Equipment List
Exhibit C:	Insurance Requirements
Exhibit D:	Safety, Health, and Environmental Management System
Exhibit E:	Termination Payment Schedules
Exhibit F-1:	Rig Manning
Exhibit F-2:	Cost of Additional Personnel
Exhibit G:	Vessel/Equipment Performance/Acceptance Test
Exhibit H:	Project Execution Plan

NOW, THEREFORE, COMPANY and CONTRACTOR, for and in consideration of the mutual covenants and agreements contained herein and good and valuable consideration paid by COMPANY to CONTRACTOR, the receipt and sufficiency of which are acknowledged by CONTRACTOR, the Parties hereby agree as follows:

ARTICLE 1

TERM

1.1 EFFECTIVE DATE AND DURATION

1.1.1 This CONTRACT shall remain in full force and effect for three (3) years (the "Initial Contract Term"). The Initial Contract Term shall begin on the Commencement Date. The term of this CONTRACT from its Effective Date through its Initial Contract Term and all Extension Periods shall be herein referred to as the "Contract Period."

1.1.2 With a three (3) year Initial Contract Term, COMPANY has the option (the "Extension Option") to extend this CONTRACT for five (5) consecutive one (1) year periods (each such extension period shall be herein referred to as an "Extension Period") beginning at the end of the Initial Contract Term. Each Extension Option must be exercised by COMPANY by written notice to CONTRACTOR nine (9) months before the end of the Initial Contract Term or the previous Extension Period, as the case may be. This CONTRACT, as it may have been amended as of the date on which COMPANY exercises any Extension Option, shall be extended for one (1) year with further Extension Options available to COMPANY, as provided herein and the various rates shall be mutually agreed in writing. COMPANY shall also have the option within twenty-four (24) months of the Effective Date to exercise any of the one-year options at the three (3) year rate. In addition, this CONTRACT may be extended for any additional period by any other method or manner as the Parties may mutually agree in writing.

1.1.3 COMPANY has the option from the Effective Date up to and including one (1) year after the Commencement Date, to convert this CONTRACT to a five (5) year term ("5 Year Option"). If the 5-Year Option is exercised within six (6) months from the Effective Date, then the five (5) year rate in Exhibit A shall apply. If the 5 Year Option is exercised from six (6) months of the Effective Date to one (1) year from the Effective Date, then the five (5) year rate in Exhibit A plus five thousand dollars ($5,000.00) shall apply. If the 5 Year Option is exercised from one (1) year after the Effective Date to the Commencement Date, then the five (5) year rate in Exhibit A plus seven thousand five hundred dollars ($7,500.00) s hall apply. If the option is exercised from the Commencement Date to the end of the first contract year, the five (5) year rate in Exhibit A plus ten thousand dollars ($10,000.00) shall apply from that date forward and any portion of the first contract year shall become part of the five (5) year commitment.

1.1.4 If COMPANY exercises the 5 Year Option, then COMPANY has the option, (the "Extension Option") under the five (5) year Initial Contract Term to extend this CONTRACT for three (3) consecutive one (1) year periods (each such extension period shall be herein referred to as an "Extension Period") beginning at the end of the Initial Contract Term. Each Extension Option must be exercised by COMPANY by written notice to CONTRACTOR at least nine (9) months before the end of the Initial Contract Term or the previous Extension Period, as the case may be. This CONTRACT, as it may have been amended as of the date on which CONTRACTOR exercises any Extension Option, shall be extended for one (1) year with further Extension Options available to COMPANY as provided herein and the various rates shall be mutually agreed in writing. In addition, this CONTRACT may be extended for any additional period by any other method or as the Parties may mutually agree in writing.

1.1.5 If the Initial Contract Term or any Extension Period of this CONTRACT expires while COMPANY has work in progress on any well or any other operations conducted with respect to a well with the objective of satisfying the well producibility criteria of 30 C.F.R. **§** 250.11 (1988), then COMPANY shall have the right to have the work in progress on such well or operation completed to COMPANY’S satisfaction under the terms and provisions of this CONTRACT and the term of this CONTRACT shall be deemed to be extended for the period of time required to complete such work.

1.2 COMMENCEMENT DATE

“Commencement Date” means the date and hour that the last of the following conditions has been satisfied: (i) all requirements in Exhibit G and all governmental and regulatory certifications and inspections required of the CONTRACTOR have been obtained, (ii) CONTRACTOR’S full crew is aboard, (iii) the Drilling Unit has cleared customs and other formalities, (iv) the Drilling Unit and CONTRACTOR’S full crew is in all respects ready to commence and sustain continued drilling operations during the Contract Period and (v) the Drilling Unit has arrived at the COMPANY’S first location or an alternative location, if requested by COMPANY. The Parties shall cooperate in the loading of any COMPANY’S drilling equipment and materials to minimize any delay in the Commencement Date. In the event that, despite the Partie s’ best efforts, the loading of COMPANY’S drilling equipment and materials cause a delay in the Commencement Date the CONTRACTOR shall be paid at the Standby and Moving Rate for any such delay. Notwithstanding the foregoing, however, COMPANY may require or allow the Drilling Unit to commence Work at an earlier date in which case such earlier date shall be the Commencement Date and in such event any of the above requirements for the Commencement Date which have not been satisfied shall be deemed satisfied.

The Parties agree that delivery of the Drilling Unit to the U.S. Gulf of Mexico is desired to occur twenty seven (27) months from the Effective Date, with COMPANY agreeing to take delivery as much as three (3) months sooner (“Delivery Date”).

If the Drilling Unit is not delivered to the Gulf of Mexico by thirty (30) months from the Effective Date, then COMPANY shall invoice CONTRACTOR every thirty (30) thirty days after the start of the late delivery charges a sum calculated at a rate of five thousand dollars ($5,000.00) per day during the first six (6) months of the late delivery and then at a rate of ten thousand dollars ($10,000.00) per day for each day until the Drilling Unit is delivered to the Gulf of Mexico with the total amount of such payment not to exceed one million five hundred thousand dollars ($1,500,000.00) for the late delivery of the Drilling Unit.

1.3 COMPLETION OF CONTRACT

1.3.1 Upon completion of this CONTRACT, if CONTRACTOR has no other Work for the Drilling Unit, COMPANY shall provide for tow, if required, of the Drilling Unit to, and securing in, the anchorage area at Galveston, Texas, or a mutually agreed point of no greater distance from its location of the last Work under this CONTRACT and at applicable dayrates.

1.3.2 Subject to Article 27.4, upon completion of this CONTRACT, if CONTRACTOR has other Work for the Drilling Unit, COMPANY shall have no further responsibility hereunder when all of COMPANY'S equipment has been offloaded, the well secured, and the Drilling Unit is ready to get underway.

ARTICLE 2

DAYRATES

2.1 GENERAL

COMPANY shall pay CONTRACTOR for work performed, services rendered, and materials, equipment, supplies, and personnel furnished by CONTRACTOR at the rates specified in Exhibit A. The period of time for which each rate shall be applicable shall be computed from and to the nearest half (1/2) hour. Subject to Article 2.3, the rates as specified in Exhibit A shall apply during the entire Initial Contract Term. The rates are based on CONTRACTOR'S operations being conducted on a seven (7) day week and a twenty-four (24) hour work day.

2.2 DAYRATES

Each of the dayrate classifications is as follows:

2.2.1 Moving Rate

a) From the moment operations are commenced to release the first mooring line or move the Drilling Unit off location at a drilling location and until the Drilling Unit is properly positioned at COMPANY'S next drilling location, and the Drilling Unit is ready to commence operations.

b) From the moment operations are commenced to release the first mooring line or move the Drilling Unit off location at COMPANY'S final drilling location hereunder until this Contract terminates.

2.2.2 Operating Rate commences at the time of the Commencement Date, time the Drilling Unit is, properly positioned, anchors tested, if any, at drilling draft at the location to be drilled and the Drilling Unit is ready to commence operations and continues until CONTRACTOR has completed operations at the location and the Drilling Unit has been released by COMPANY to move to the next location pursuant to Article 2.2.1(a).

2.2.3 Stand-by Rate with Crews applies while the Drilling Unit is on location with full crews waiting for COMPANY'S orders, and shall be payable during any period of time when CONTRACTOR'S crew is aboard the Drilling Unit and drilling, testing or completion operations hereunder are suspended, as a result of COMPANY'S instructions, COMPANY'S failure to issue instructions, the mechanical failure of COMPANY'S items, or the failure of COMPANY to timely provide COMPANY'S items or furnish those services set forth in Exhibit B-3.

2.2.4 Stand-by Rate without Crews applies while the Drilling Unit is on location without crews. This rate shall commence seventy-two (72) hours after notification by COMPANY to CONTRACTOR to release crews.

2.2.5(a) Mechanical Downtime applies in the event operations during the term of this CONTRACT are shut down ("Mechanical Downtime") for inspection, repair or replacement of any surface or subsurface equipment including, but not limited to CONTRACTOR'S items described in Exhibit B, including station keeping equipment, mooring equipment, anchors, chains, shackles, pendent lines, buoys, the riser, slip joint, choke and kill lines, flexible hoses, hydraulic hoses, guidelines, subsea BOP, and BOP control system. CONTRACTOR shall be allowed a maximum of twenty-four (24) hours per calendar month Mechanical Downtime with a maximum accumulation of twelve (12) days; thereafter the dayrate reduces to zero (0). Mec hanical Downtime shall commence immediately upon suspension of well operations and shall continue until completion of the inspection, repair or replacement of the equipment and operations are at the point in well operations prior to suspension. If COMPANY elects to proceed with an alternative operation, then Mechanical Downtime shall cease at the point in well operations where the alternative operation commences. Article 2.2.5(a) shall not apply to the time required to repair or replace CONTRACTOR'S choke manifolds, blowout preventors, and drill string, if the damage or destruction to the equipment is caused by exposure to unusually corrosive or otherwise destructive elements not normally encountered which are introduced into the drilling fluid from subsurface formations or the use of corrosive additives in the fluid. Article 2.2.5(a) shall not apply to normal maintenance, including, without limitation, cutting and/or slipping the drill line, which time shall be limited to 1 hour plus up to thirty (30) minutes per day (fifteen (15) hours per month maximum) for top drive maintenance. Any mobilization and/or demobilization and associated cost required to repair the Drilling Unit under Article 2.2.5(a) will be at CONTRACTOR'S expense. CONTRACTOR shall not be entitled to any compensation for Mechanical Downtime allowance not consumed during this CONTRACT.

2.2.5(b) Performance Downtime applies in the event operations during the term of this CONTRACT are shut down ("Performance Downtime") for the following reasons (i) CONTRACTOR, CONTRACTOR'S Personnel (as hereinafter defined), or the Drilling Unit should be incapable, incompetent, negligent, unreliable, or consistently poor in performance of the Work, (ii) the equipment listed in Exhibit B is incapable of being operated at the rated specifications in Exhibit B for sustained operation or (iii) CONTRACTOR fails to fulfill any of its obligations under this Contract. In the event of COMPANY'S dissatisfaction with any items identified in (i), (ii) and (iii), Performance Downtime shall commence when COMPA NY provides CONTRACTOR with written notice as to the circumstances of its dissatisfaction and work in progress is suspended and shall continue based on the following remedies. If work in progress is suspended, then Article 2.2.5(a) shall apply. CONTRACTOR shall be allowed five (5) days, from the written notice, to commence good faith efforts to remedy such circumstances. During the remedy period, the Operating Rate shall be reduced to the Standby-rate Without

Crews. In the event such circumstances are not remedied to COMPANY'S satisfaction within thirty (30) days, from the written notice, the Operating Rate shall be reduced to zero (0) dollars.

2.2.6 Hurricane Evacuation Rate applies when all of the crews have been transported to shore. This rate shall include the cost of room and board for all of CONTRACTOR'S personnel including catering personnel and any other of CONTRACTOR'S subcontractor personnel. If COMPANY elects to release CONTRACTOR'S crew, then the Standby Rate Without Crew shall be applicable from the time CONTRACTOR is notified by COMPANY until the CONTRACTOR'S crew returns to the Drilling Unit.

2.2.7 Stack Rate applies when the Drilling Unit has arrived and secured at the nearest safe harbor or stack location in the Gulf of Mexico as designated by CONTRACTOR. The Moving Rate shall apply immediately before the Stack Rate commences. The Stack Rate will continue until the unit is ready to get underway at which time the Moving Rate shall apply, or until the CONTRACT expires pursuant to Article 1.

2.3 ADJUSTMENTS IN DAYRATES

2.3.1 The dayrates set forth in Exhibit A shall remain unadjusted during the Initial Contract Term of this CONTRACT, except for rate changes as described in Article 2.3.2, Article 3, Article 4, Article 5, Article 6, and Article 30.3.

2.3.2 The dayrates set forth in Exhibit A shall be revised to reflect the change in costs from the Effective Date if the costs of any of the items hereafter listed shall vary in an amount equal to or greater than five percent (5%) from the costs thereof not earlier than the Commencement Date and not more frequent than one (1) year after the date of any revision pursuant to this Article 2.3.2.

a. Labor costs, including all benefits, of CONTRACTOR'S personnel listed in Exhibit F;

b. CONTRACTOR'S cost of catering;

c. CONTRACTOR'S cost of spare parts and supplies vary and that the parties shall use the United States Department of Labor's Producer Price Index Commodity Code No. 1191.02 - Oil Field and Gas Field Drilling Machinery - to determine what extent a price variance has occurred in said spare parts and supplies.

d. Cost of insurance not based solely on CONTRACTOR'S loss or claim record.

CONTRACTOR must show documented proof for any dayrate adjustments due to changes in CONTRACTOR'S cost of labor, insurance or catering. CONTRACTOR shall provide COMPANY with the base figures for the items specified in Article 2.3.2a.,b.,c., and d., thirty (30) days after the Effective Date. Base figures from which such revisions (either upward or downward) will be determined for the items in this Article 2.3.2 shall be provided by CONTRACTOR sixty (60) days prior to the estimated Commencement Date. These base figures shall be agreed upon by both parties and approved in writing by COMPANY prior to the Commencement Date.

2.3.3 If, at the request of COMPANY, it becomes necessary for CONTRACTOR to change the work schedule of its personnel or change the location of its Homeport or area of operations, which impacts the CONTRACTOR'S actual cost, the daily rates set out in Appendix A shall be adjusted accordingly, with appropriate back up data.

2.3.4 CONTRACTOR shall be responsible for costs and expenses incurred by CONTRACTOR in complying with any law, regulation, or ruling of a government, governmental agency, or regulatory authority having jurisdiction over the operations of the Drilling Unit to the extent that the law, regulation, or ruling has changed or been imposed subsequent to the Commencement Date. Where compliance with the changed law, regulation, or ruling results in modifications of the Drilling Unit or the purchase of equipment which change CONTRACTOR'S cost, the dayrates shall be adjusted with the additional direct cost and expenses amortized over the life of the Drilling Unit. The increased dayrates shall become effective upon completion of the modifications, and the Drilling Unit commences operations. CONTRACTOR shall be solely responsible for mobilization and demobilization and associated cost; during such time the dayrate shall be zero (0) dollars.

ARTICLE 3

PERSONNEL AND PAYMENTS

3.1 PERSONNEL CLASSIFICATIONS, NUMBERS AND REPRESENTATION

3.1.1 CONTRACTOR shall furnish, at its sole expense, personnel in the numbers and classifications as set forth in Exhibit F.

3.1.2 During any period of time that CONTRACTOR fails to provide on the Drilling Unit the numbers or classifications of personnel specified in Exhibit F, the rate being paid the CONTRACTOR shall be reduced by the overtime hourly rate for the absent crew member(s) as specified in Exhibit F. This reduced rate shall commence on the second day of the crew shortage.

3.1.3 The number of personnel to be furnished by CONTRACTOR under the terms hereof as specified in Exhibit F may be increased or decreased by mutual consent of COMPANY and CONTRACTOR, in which case the rates set forth in Article 2 shall be increased or decreased by an amount equal to the change in CONTRACTOR'S cost.

3.1.4 CONTRACTOR represents that all of CONTRACTOR'S personnel shall be fully qualified, trained, competent, able bodied and fit for their respective assignments and shall have complied with all necessary laws and regulations in connection therewith. The minimum standard for qualification and training is set forth in Exhibit F. CONTRACTOR shall be able to communicate verbally and in writing by means of a common language at all times.

3.2 OVERTIME COMPENSATION

3.2.1 COMPANY shall pay CONTRACTOR for overtime work of personnel employed by CONTRACTOR who are required to work in excess of their regularly scheduled hours, when requested by COMPANY, at the rates specified in Exhibit F.

3.2.2 In the event the departure of the crews from the drilling site is delayed more than two (2) hours after the normal scheduled departure time due to delays in the transportation schedule which are not caused by the negligence or fault of CONTRACTOR, COMPANY shall pay CONTRACTOR for time in excess of two (2) hours at the hourly overtime rate for each employee as specified in Exhibit F.

3.2.3 In the event that the time of transportation of crews between the Drilling Unit and the shorebase or between the shorebase and Drilling Unit is in excess of two (2) hours for each one-way trip, which are not the result of the negligence or other fault of CONTRACTOR, COMPANY shall pay CONTRACTOR for time in excess of two (2) hours for each trip at the hourly overtime rate for each employee as specified in Exhibit F.

ARTICLE 4

OTHER PAYMENTS

4.1 CHANGE IN HOMEPORT OF OPERATIONS

The Homeport of operations for the Drilling Unit under this CONTRACT is any Gulf of Mexico port between and inclusive of Corpus Christi, TX and Pascagoula, MS.

4.2 EXCESS MEALS AND LODGINGS

COMPANY shall pay CONTRACTOR for the cost of meals and lodging for COMPANY'S personnel and subcontractors (other than CONTRACTOR) that are in excess of ten (10) people per day calculated over a period of one (1) calendar month at CONTRACTOR'S actual cost.

4.3 ANCHOR HANDLING AND TOWING VESSEL CHARGES

COMPANY shall pay all anchor handling and towing vessel charges if required, for movement of the Drilling Unit.

4.4 OTHER CHARGES

COMPANY shall pay CONTRACTOR for other charges as per Article 6, Article 7, and Article 8.

ARTICLE 5

DRILLING UNIT MODIFICATIONS

5.1 PRE-COMMENCEMENT

Any modification to the Drilling Unit before the Commencement Date shall be pursuant to Exhibit H.

5.1.1 POST-COMMENCEMENT DATE

Any modification to the Drilling Unit after the Commencement Date shall be as agreed in a separate written agreement. In the event the Drilling Unit is taken out of service or placed into shelter or harbor for COMPANY requested modifications, the rate that shall be payable per day, or pro rata for any part of a day during which such activity occurs shall be Standby Rate, which shall be payable for the period of time beginning when the Drilling Unit ceases operations to move off the drilling or well location until it moves back to location and commences full operations; provided, however, that if the Drilling Unit has changed locations, CONTRACTOR shall be credited at the Moving Rate for the time that would otherwise have been spent moving to the new location. In such case, the related modification costs and harbor expenses including, but not limited to, customs or other duties or imposts, harbor tugs if required, demurrage, wharfage, harbor and port fees and dues, landing, pilotage, lighterage, stevedoring, customs agent fees, anchor handling, any tow in and out, fuel, and canal charges, if applicable will be paid by COMPANY in a mutually agreed adjustment to the daily rates

ARTICLE 6

OTHER REIMBURSEMENTS

6.1 LICENSES AND PERMITS

CONTRACTOR shall be responsible for all licenses, permits, or other authorization which are required to be obtained by CONTRACTOR subsequent to the Commencement Date. COMPANY agrees to reimburse CONTRACTOR for all cost associated with licenses, permits or other authorization which are required to be obtained by CONTRACTOR should COMPANY designate a location outside the federal waters of the Gulf of Mexico. COMPANY will obtain any required licenses, permits or authorizations which are required to be obtained by COMPANY.

ARTICLE 7

MATERIALS, SUPPLIES, EQUIPMENT, AND SERVICES

TO BE FURNISHED BY CONTRACTOR

7.1 MATERIALS, SUPPLIES, EQUIPMENT, & SERVICES

7.1.1 CONTRACTOR shall furnish and maintain at its sole expense all items designated in Exhibit B under the heading FURNISHED BY CONTRACTOR. Any additional items not specifically mentioned elsewhere in this CONTRACT and found necessary to perform work shall be furnished by COMPANY at its sole expense.

7.1.2 All items of equipment, materials, supplies, services, and service personnel required for operations hereunder that are to be FURNISHED BY CONTRACTOR as specified in Exhibit B may be furnished by COMPANY upon the mutual consent of COMPANY and CONTRACTOR and billed to CONTRACTOR at actual invoice cost less all cash discounts obtained by COMPANY plus a five (5) percent handling charge plus applicable taxes if taxes are applied to the cost reimbursement. A copy of invoice(s) for equipment, materials, supplies, services, and service personnel shall accompany COMPANY'S invoice to CONTRACTOR and must have the signature of CONTRACTOR'S representative for reimbursement to COMPANY.

7.1.3 All items of equipment, materials, supplies, services, and service personnel required for operations hereunder that are to be FURNISHED BY CONTRACTOR AND REIMBURSED BY COMPANY as specified in Exhibit B are to be billed to COMPANY at actual invoice cost less all cash discounts obtained by CONTRACTOR plus a five (5) percent handling charge. A copy of invoice(s) for equipment, materials, supplies, services, and service personnel shall accompany CONTRACTOR'S invoice to COMPANY and must have the signature of COMPANY'S representative's for reimbursement to CONTRACTOR.

7.1.4 Any equipment, materials, or supplies purchased by COMPANY for the account of CONTRACTOR pursuant to Articles 7.1.2 and 7.1.3. above shall thereafter become the property of COMPANY unless agreed to by the Parties.

7.1.5 CONTRACTOR shall provide at CONTRACTOR'S expense a drill pipe and drill collar inspection in accordance with API-IADC Standards prior to the Commencement Date. All of the drill pipe and drill collars shall be new. The costs of subsequent drill pipe and drill collar inspections during the term of this CONTRACT shall be borne by the COMPANY or CONTRACTOR as provided in Exhibit B.

ARTICLE 8

MATERIALS, SUPPLIES, EQUIPMENT, AND SERVICES

TO BE FURNISHED BY COMPANY

8.1 MATERIALS, SUPPLIES, EQUIPMENT, & SERVICES

8.1.1 COMPANY shall furnish and maintain at its sole expense all items designated in Exhibit B hereof under the heading "FURNISHED BY VASTAR".

8.1.2 All items of equipment, materials, supplies, services, and service personnel required for operations hereunder that are to be "FURNISHED BY VASTAR" as specified in Exhibit B may be furnished by CONTRACTOR upon the mutual consent of COMPANY and CONTRACTOR and billed to COMPANY at actual invoice cost less all cash discounts obtained by CONTRACTOR plus a five (5) percent handling charge plus applicable tax gross up if taxes are applied to the cost reimbursement. A copy of invoice(s) for equipment, materials, supplies, services, and service personnel shall accompany CONTRACTOR'S invoice to COMPANY and must have COMPANY'S representative's signature for reimbursement to CONTRACTOR.

8.1.3 Any equipment, materials, or supplies purchased by CONTRACTOR for the account of COMPANY pursuant to Article 8.1.2 above shall thereafter become the property of COMPANY.

ARTICLE 9

PAYMENTS

9.1 TIME OF PAYMENT

COMPANY shall make payments under this CONTRACT in U.S. currency in accordance with the terms of Article 2, Article 3, Article 4, Article 5, Article 6, Article 7, and Article 8 of this CONTRACT, on or before the last working day of the month following the receipt of a valid invoice form CONTRACTOR if received within five (5) calendar days after the month being invoiced If COMPANY receives an invoice after five (5) calendar days from the end of the month being invoiced then the payment will be due twenty (20) working days after receipt of the invoice. Thereafter, valid and undisputed amounts remaining due and unpaid shall earn simple interest at the rate of one and one-half percent (1 1/2%) per month. Should COMPANY question any item of an invoice, COMPANY may withhold payment of t he amount in question, without interest, until the matter is resolved between the Parties, but COMPANY shall pay promptly the amount not in question. COMPANY shall have the right to set off any undisputed and liquidated amount payable by COMPANY to CONTRACTOR under this CONTRACT or under any instrument executed in connection herewith against any amount payable by CONTRACTOR to COMPANY under this CONTRACT.

9.2 IDENTIFICATION OF CHARGES

All invoices must reference charges by block name and number and well number (e.g., Viosca Knoll Blk. 1001 No. 1). OCS numbers or state numbers are not acceptable references.

9.3 <u>PLACE OF INVOICE PRESENTATION</u>

Invoices, accompanied by copies of the original vouchers or such records, receipts, or other evidence as may be requested by COMPANY to support the invoices rendered, shall be sent to COMPANY'S office in Houston, Texas at the address below on or before the tenth (10th) of each month next succeeding the month during which the Work was performed or the expense incurred. The invoices to COMPANY should be directed as follows:

Vastar Resources, Inc.

P.O. Box 219275

Houston, TX 77218-9275

ATTN: DRILLING INVOICES

9.4 <u>PLACE OF PAYMENT</u>

All payments shall be directed to CONTRACTOR as follows:

Wells Fargo Bank

1000 Louisiana

Houston, TX 77002

Account Number

ABA Number

SWIFT Number

<u>ARTICLE 10</u>

<u>PAYMENT OF CLAIMS</u>

10.1 <u>CLAIMS</u>

CONTRACTOR shall pay all claims for equipment, labor, materials, services, and supplies to be furnished by it hereunder and shall allow no lien or charge resulting from such claims to be fixed upon any well lease or other property of COMPANY. CONTRACTOR shall protect, release, defend, indemnify, and hold harmless COMPANY from and against all such claims and liens. COMPANY may, at its option, pay and discharge any (i) amounts secured by such liens or (ii) overdue charges for CONTRACTOR'S equipment, labor, materials, services, and supplies under this CONTRACT and may thereupon deduct the amount or amounts so paid by COMPANY from any sums due, or which thereafter become due, to CONTRACTOR hereunder.

10.2 <u>NOTICE OF CLAIMS</u>

CONTRACTOR shall promptly give COMPANY notice in writing of any claim made or proceeding commenced against CONTRACTOR for which CONTRACTOR claims to be entitled to indemnification under this CONTRACT. CONTRACTOR shall confer with COMPANY concerning the defense of any such claim proceeding, shall permit COMPANY to be represented by counsel in defense thereof, and shall not effect settlement of, nor compromise, any such claim or proceeding without COMPANY'S written consent.

COMPANY shall promptly give CONTRACTOR notice in writing of any claim made or proceeding commenced against COMPANY for which COMPANY claims to be entitled to indemnification under this CONTRACT. COMPANY shall confer with CONTRACTOR concerning the defense of any such claim proceeding, shall permit COMPANY to be represented by counsel in defense thereof, and shall not effect settlement of, nor compromise, any such claim or proceeding without CONTRACTOR'S written consent.

ARTICLE 11

TAXES AND FEES

11.1 TAXES AND FEES ON DRILLING UNIT, CREW, AND OPERATIONS

CONTRACTOR shall be responsible for, pay, and protect, release, defend, indemnify and hold harmless COMPANY from all taxes, including, income taxes of whatsoever kind, and any addition, penalty, interest, or similar item imposed with respect to such taxes, levies, customs charges, duties, fees, or other charges of whatsoever kind without contribution or indemnity from COMPANY whatsoever which may be levied by any national, territorial possession, state, provincial, local, or municipal government, authority, or other agency having jurisdiction over the Operating Area on, in connection with, or related to the Drilling Unit, its crew, its equipment, and any and all materials, equipment, or operations in performance of this CONTRACT. Notwithstanding any other provision of this CONTRACT, COMPANY shall bear ultimate liability for any end user taxe s such as, but not limited to, value added taxes and sales taxes imposed on COMPANY or which CONTRACTOR is required by law to collect. COMPANY and CONTRACTOR will make payments in accordance with the laws and regulations governing these taxes.

11.2 PAYROLL TAXES

CONTRACTOR shall make all necessary reports and pay all taxes, licenses, and fees levied or assessed on CONTRACTOR in connection with or incident to the performance of this CONTRACT by any governmental agency having jurisdiction over the Operating Area for unemployment compensation insurance, old age benefits, social security, or any other taxes upon the wages or salaries paid by CONTRACTOR, its agents, employees, and representatives. CONTRACTOR shall require the same agreement of, and be liable for any breach of the agreement by, any of its subcontractors.

11.3 TAXES PAID BY COMPANY

CONTRACTOR shall reimburse COMPANY on demand for all the taxes or governmental charges, state or federal, outlined in Articles 11.1 and 11.2, which COMPANY may be required or deems necessary to pay on account of CONTRACTOR or its employees or subcontractors. At its election, COMPANY is authorized to deduct all sums so paid for the taxes and governmental charges from any money due CONTRACTOR hereunder and provide official tax receipts within sixty (60) days.

ARTICLE 12

COMPANY'S RIGHT TO QUESTION INVOICES AND AUDIT

12.1 QUESTION INVOICES

Payment of any invoice shall not prejudice the right of COMPANY to question the propriety of any charges therein, provided that COMPANY, within four (4) years after the date of the invoice in question, shall deliver to CONTRACTOR written notice of objections to any item or items, the propriety of which it questions, specifying the reasons for the objections. Should COMPANY so notify CONTRACTOR, adjustments shall be made as the propriety or impropriety of the item may be mutually determined.

12.2 AUDIT

CONTRACTOR shall maintain a complete and correct set of records pertaining to all aspects of this CONTRACT, including the performance hereof by CONTRACTOR. If any payment provided for hereunder is to be made on the basis of CONTRACTOR'S cost, COMPANY shall have the Drilling Unit to inspect and audit any and all records relating to the cost any time during the term of this CONTRACT and up to a period of four (4) years after the recorded date of the record in question, provided that CONTRACTOR shall have the right to exclude any trade secrets, formulas, or processes from the inspection and audit. Should the results of any audit so require, the Parties will make appropriate adjustments or payments.

ARTICLE 13

DEPTH

13.1 DEPTH

The depth of each well to be drilled hereunder will be specified by COMPANY, which COMPANY may amend from time to time. The depth so specified is hereinafter referred to as the "Contract Depth", subject to the right of COMPANY to direct, at any time, a stoppage of Work at a lesser depth.

ARTICLE 14

DRILLING UNIT

14.1 REPRESENTATION OF DRILLING UNIT

The Drilling Unit shall be fully equipped as specified in Exhibit B and shall meet the requirements of Exhibit G, and shall be adequate to drill and complete wells in the Operating Area to the depths as specified in Article 14.2 hereof and in water depths as specified in Article l4.3. CONTRACTOR represents that the Drilling Unit satisfies all requirements of Articles 14.1.1, 14.4 and 14.6, and is capable of operating to its full capacity as rated by the manufacturer. CONTRACTOR shall maintain the Drilling Unit at optimal operating condition, in accordance with good oilfield practices throughout the duration of the CONTRACT.

14.1.1 CONTRACTOR represents that (i) the Drilling Unit and related equipment shall be in a condition to permit its continuous and efficient operation during the Contract Period, subject to required periods of maintenance, repair, drydocking and inspection by regulatory bodies and classification societies, (ii) it will diligently perform the Work in a good workmanlike manner consistent with applicable industry standards and practices, (iii) it will use sound technical principles where applicable, (iv) it will perform the Work in compliance with this Contract, (v) it will furnish material and equipment in good condition to sufficiently meet the applicable CONTRACT requirements and good oilfield practices and (vi) where mutually agreed, it will furnish used material and equipment, fit f or the intended use. CONTRACTOR shall bear any cost incurred in placing the Drilling Unit in a condition to function continuously and efficiently during the entire Contract Period. CONTRACTOR agrees to ensure that the Drilling Unit and all equipment and materials furnished by CONTRACTOR are adequately maintained and in such condition as to permit their continuous and efficient operation. CONTRACTOR shall appropriately protect and secure all COMPANY’S equipment and materials placed in its care. CONTRACTOR also agrees to carry out visual inspection on, and make available to COMPANY to test any of CONTRACTOR’S equipment in the manner prescribed by COMPANY.

Notwithstanding the foregoing, CONTRACTOR shall carry out, at CONTRACTOR’S expense, a full and detailed inspection of its drill pipe, drill collars, bottom hole assemblies and other down-hole and surface drilling equipment in accordance with Exhibit B prior to commencing the Work. COMPANY reserves the right to ensure that such inspection is carried out satisfactorily and, accordingly, shall have access to all related inspection reports. CONTRACTOR shall give COMPANY three weeks notice of inspection in order that COMPANY may have a third person witness the inspections to ensure they are carried out in accordance with Exhibit G.

14.1.2 COMPANY shall have the right before the Commencement Date to inspect and reject for sound reasons any part of the Drilling Unit not meeting the requirements of this Contract; provided, however, such right shall not in any way relieve CONTRACTOR of its own obligations, including, without limitation, the obligation to inspect and maintain the Drilling Unit and related equipment in efficient operating condition. COMPANY shall have access and the right to review all commissioning, testing, and acceptance documents pertaining to the Drilling Unit. Unless waived by COMPANY, the Commencement Date shall not occur prior to the date on which CONTRACTOR has satisfactorily remedied any defect.

14.2 MAXIMUM DRILLING DEPTH RATING

CONTRACTOR represents that the Drilling Unit is mechanically capable of drilling wells to the depth specified in Exhibit B-1.

14.3 MAXIMUM WATER DEPTH RATING

CONTRACTOR represents that the Drilling Unit is mechanically capable of drilling wells in water depths and during environmental conditions, as specified in Exhibit B-I.

14.4 TECHNOLOGY

CONTRACTOR and COMPANY agree to explore the latest technologies, including riserless drilling, in an effort to incorporate same into the construction and operation of the Drilling Unit. CONTRACTOR shall make such technology available to COMPANY as soon as CONTRACTOR has the right to install and use such technology on its commercial drilling units, subject to any existing third party contracts as of the Commencement Date. Such installation shall be done pursuant to Article 5.

14.5 APPLICABLE LAWS

Subject to Article 2.3.4, CONTRACTOR represents that during the Contract Period, the Drilling Unit is outfitted, conformed, and equipped to meet all applicable laws, rules, requirements, and regulations promulgated by the U.S. Coast Guard, the U.S. Environmental Protection Agency, the United States of America Department of the Interior as well as any other agency, bureau, or department of the U.S. federal, territorial possession, state, municipal, or local governments, any political subdivisions thereof, having jurisdiction over the operations in U. S. federal waters.

14.6 SAFETY OF PORT

COMPANY does not and shall not be deemed to warrant the safety of any port, place, berth, dock, anchorage, location, or submarine line and shall be under no liability in respect thereof, except as specifically provided for under Article 31.

14.7 OPERATING AREA

The Drilling Unit shall be capable of operating year around in the federal waters of the U. S. Gulf of Mexico. Additionally, the Drilling Unit will be designed to allow for operations in other areas of U. S. federal waters, offshore West Africa and the United Kingdom and other areas of the world, all subject to modifications and outfitting required by the controlling jurisdictions of each different operating area and to the operating limits set forth in Exhibit “G”.

ARTICLE 15

PERFORMANCE OF DRILLING OPERATIONS

15.1 OPERATIONS OF DRILLING UNIT

CONTRACTOR shall be solely responsible for the operation of the Drilling Unit, including, without limitation, supervising moving operations, and the positioning of the Drilling Unit on drilling locations as required by COMPANY, as well as such operations on board the Drilling Unit as may be necessary or desirable for the safety of the Drilling Unit.

15.2 PREVENTION OF FIRE AND BLOWOUTS

CONTRACTOR shall maintain well control equipment in accordance with good oilfield practices at all times and shall use all reasonable means to control and prevent fire and blowouts and to protect the hole and all other property of the COMPANY. CONTRACTOR shall use the blowout prevention equipment specified in Exhibit B hereof on all strings of casing unless otherwise directed by COMPANY. CONTRACTOR shall pressure test the blowout prevention devices as often as instructed by COMPANY, usually once every seven (7) days, and shall function test the blowout prevention devices by opening and closing to assure operating condition at each trip for a bit change. CONTRACTOR shall record the results of all the tests on the Daily Drilling Report Form defined in Section 19.1 hereof. CONTRACTOR shall use kelly sub protectors and drill pipe protectors. In any event, CONTRACTOR, at a minimum, shall use, test, and maintain blowout prevention equipment in accordance with all applicable governmental rules, regulations, and orders then in effect.

15.3 DEVIATION OF THE HOLE

CONTRACTOR shall use precaution in accordance with good oilfield practices in the Area of Operations, to drill a hole which will not deviate excessively from the limits specified by COMPANY. CONTRACTOR shall run angle and directional measuring devices acceptable to, and at the intervals directed by COMPANY. CONTRACTOR shall record the results of the deviation survey on the Daily Drilling Report Form.

15.4 DRILL PIPE MEASUREMENT

CONTRACTOR shall measure the total length of drill pipe in service with a steel tape before setting casing or liner, before logging, after reaching final depth, and whenever requested by COMPANY and shall promptly enter all the measurements on the Daily Drilling Report Form.

15.5 CASING PROGRAM

The casing program shall be as specified by COMPANY.

15.6 MUD PROGRAM

CONTRACTOR shall use all reasonable care to make and maintain drilling mud having weight, viscosity, water loss, and other characteristics to satisfy the requirements as specified by COMPANY. CONTRACTOR shall exercise due diligence to prevent the well from blowing out, and to enable the efficient drilling, logging, and testing of all formations without caving or formation contamination. While drilling, CONTRACTOR shall test drilling mud for weight, viscosity, water loss, and other necessary characteristics as instructed by COMPANY and shall record the results of the tests and the material volume usage on the Daily Drilling Report Form.

15.7 COMPLETION OR ABANDONMENT OF WELLS

CONTRACTOR shall perform all work necessary to tube, equip, and complete or abandon each well in the manner specified by COMPANY.

15.8 SAMPLES

CONTRACTOR shall save and preserve for COMPANY samples of formations penetrated, and properly prepare and label COMPANY’S containers. COMPANY shall designate the sampling frequency.

15.9 CORING

CONTRACTOR shall core at the depths which COMPANY shall specify and shall deliver all cores in COMPANY’S containers, properly labeled, to COMPANY and shall not allow any third person access to the cores or to the samples referred to in Article 15.8, or to any core or sample data, without COMPANY'S consent.

15.10 FORMATION TESTS

If during the course of drilling CONTRACTOR encounters evidence of oil or gas, or other hydrocarbon substances, then CONTRACTOR shall immediately notify COMPANY, and should COMPANY desire a test to determine the productivity of any formation so encountered then, CONTRACTOR shall make such a test if it is feasible under existing conditions.

15.11 ANCHOR HANDLING AND TOWING

COMPANY shall supply any required anchor handling and towing vessels to move the Drilling Unit between locations.

ARTICLE 16

INSPECTION OF MATERIALS

16.1 INSPECTION BY CONTRACTOR

CONTRACTOR shall carefully perform a visual inspection of all materials and appliances furnished by COMPANY when delivered into CONTRACTOR'S possession and shall notify COMPANY'S representative of any apparent defects so that COMPANY may replace the defective materials or appliances. Upon the termination of this CONTRACT, CONTRACTOR shall return to COMPANY all materials and appliances received by CONTRACTOR from COMPANY or purchased by CONTRACTOR for COMPANY'S account then in CONTRACTOR'S possession.

16.2 INSPECTION BY COMPANY

Excluding the Drilling Unit and its major equipment, COMPANY shall have the right to inspect and reject, for any valid cause, any items furnished by CONTRACTOR in Exhibit B-3. CONTRACTOR at its sole cost, risk and expense shall replace and/or repair the rejected items, or replace them with items free of defects.

ARTICLE 17

SAFETY

17.1 GENERAL

CONTRACTOR shall have the primary responsibility for the safety of all its operations, shall take all measures necessary or proper to protect the personnel and facilities and, in addition, shall observe all safety rules and regulations of any governmental agency having jurisdiction over operations conducted hereunder. CONTRACTOR shall place the highest priority on safety while performing the work. CONTRACTOR shall also observe all of COMPANY'S safety rules and guidelines as set forth in "Safety and Health Manual" of Vastar Resources, Inc., and the requirements contained in Exhibit D. The CONTRACTOR may also have its own safety manual and when CONTRACTOR'S and COMPANY'S safety manuals conflict, CONTRACTOR'S safety manual shall control.

17.2 UNDER TOW

At all times during movement of the Drilling Unit between locations, CONTRACTOR shall have full responsibility for control of the Drilling Unit and shall have final authority regarding the safety and operation of the Drilling Unit, associated equipment, and personnel on board.

17.3 SAFETY EQUIPMENT

CONTRACTOR shall furnish any needed personal protection equipment that CONTRACTOR'S personnel may require in order to safely perform CONTRACTOR'S obligations under this CONTRACT.

17.4 EMERGENCY EVACUATION PLAN

The CONTRACTOR shall furnish COMPANY with information regarding the Emergency Evacuation Plan ("EEP") for the CONTRACTOR'S Drilling Unit. The information supplied shall include station bills, a list of fire fighting equipment, list of emergency crafts onboard, and all other information required to describe the EEP in order to meet federal regulations in 46 C.F.R. 109 for MODU's. The COMPANY shall submit as part of the COMPANY'S EEP, information and/or data as required by 33 C.F.R. 146.2 10.

ARTICLE 18

PERFORMANCE OF THE WORK

18.1 INDEPENDENT CONTRACTOR RELATIONSHIP

In performing the work set forth in this CONTRACT, CONTRACTOR shall act at all times as an independent contractor. Unless otherwise mutually agreed, CONTRACTOR shall not make any commitment or incur any charges or expense in the name of COMPANY. CONTRACTOR expressly agrees, acknowledges and stipulates that neither this CONTRACT nor the performance of CONTRACTOR'S obligations or duties hereunder shall ever result in CONTRACTOR, or anyone employed by CONTRACTOR, being i) an employee, agent, servant, or representative of COMPANY, or ii) entitled to any benefits from COMPANY, including without limitation, pension, profit sharing or accident, health, medical, life or disability insurance benefits or coverage, to which employees of COMPANY may be entitled. The sole and only compensation to which CONTRACTOR shall be entitled to under this CON TRACT are the payments provided for herein. COMPANY shall have no direction or control of CONTRACTOR or its employees and agents except in the results to be obtained. The actual performance and superintendence of all work hereunder shall be by CONTRACTOR, but the work shall meet the approval of COMPANY and be subject to the general right of inspection herein provided in order for COMPANY to secure the satisfactory completion of the work.

18.2 COMPANY'S REPRESENTATIVE

COMPANY shall be entitled to designate a representative(s), who shall at all times have complete access to the Drilling Unit for the purpose of observing or inspecting operations performed by CONTRACTOR in order to determine whether, in COMPANY'S sole opinion, CONTRACTOR has complied with the terms and conditions of this CONTRACT. The representative(s) shall be empowered to act for COMPANY in all matters relating to CONTRACTOR'S daily performance of the work. CONTRACTOR shall cooperate at all times with and render reasonable assistance to the representative(s) of COMPANY or representative(s) of any of COMPANY'S other contractor(s).

18.3 DISCIPLINE

CONTRACTOR shall maintain at all times strict discipline and good order among its employees. Should COMPANY determine, for just cause, that the conduct of any of CONTRACTOR'S personnel is detrimental to COMPANY'S interest, COMPANY shall notify CONTRACTOR in writing of the reasons for requesting removal of such personnel and CONTRACTOR shall replace the personnel at CONTRACTOR'S expense.

18.4 TAKEOVER BY COMPANY

In the event that CONTRACTOR shall fail to take proper steps to supply properly skilled workmen or tools, machinery or appliances for the performance of the work on any well hereunder, or shall otherwise neglect or willfully discontinue or delay commencement of the work to be performed on any such well, for a period of five (5) consecutive days after notice by COMPANY, then COMPANY shall have the right, by giving CONTRACTOR notice of its intention to do so, to take possession of the well, and the supervision and control of the drilling equipment and tools, machinery and appliances of CONTRACTOR and drill the well to completion or otherwise complete the work on said well. CONTRACTOR shall continue to have custody of and be solely responsible for its Drilling Unit and the locating and maintaining of it, and COMPANY or its representatives shall have supervision and control of such facilities only to the extent of the drilling or other operations involved. Following any such taking of possession by COMPANY, whether COMPANY is successful or unsuccessful in completing the well, or restoring same to production, the actual incremental cost directly related to the assumed operations to COMPANY (with no allowance to CONTRACTOR, other than dayrate, for the use of its drilling equipment and tools, machinery and appliances), shall be deducted from the applicable dayrate during such period and the balance, if any, paid to CONTRACTOR. COMPANY shall be liable for the return of such drilling equipment and tools, machinery and appliances to CONTRACTOR in as good condition as when received, natural wear and weathering, accidental loss or breakage excepted.

COMPANY SHALL INDEMNIFY, DEFEND AND HOLD CONTRACTOR HARMLESS FROM AND AGAINST ANY AND ALL LOSS, COST, CLAIM OR CAUSE OF ACTION ARISING DIRECTLY OR INDIRECTLY FROM COMPANY'S SUPERVISION OF CONTRACTOR'S DRILLING EQUIPMENT AND TOOLS DURING THAT PERIOD OF TIME IN WHICH COMPANY HAS TAKEN OVER SUPERVISION AND CONTROL OF CONTRACTOR'S DRILLING EQUIPMENT AND TOOLS. THE LIABILITY PROVISIONS HEREOF AND CONTRACTOR'S INDEMNITY OBLIGATIONS HEREUNDER SHALL REMAIN IN FULL FORCE AND EFFECT AS TO ANY AND ALL DAMAGE, LOSS, COST, CLAIM OR CAUSE OF ACTION

ARISING DIRECTLY OR INDIRECTLY PRIOR TO COMPANY'S TAKEOVER OF CONTRACTOR'S DRILLING EQUIPMENT AND TOOLS OR AFTER SUCH DRILLING EQUIPMENT AND TOOLS ARE RETURNED TO THE POSSESSION OF CONTRACTOR. During such a takeover, COMPANY shall obtain insurance coverage with the same coverages as the insurance required to be carried by CONTRACTOR, naming CONTRACTOR and endorsed to waive subrogation.

18.5 CHANGE OF SUPERVISORY PERSONNEL

CONTRACTOR shall notify OPERATOR of any proposed change in supervisory personnel prior to the proposed change.

ARTICLE 19

RECORDS TO BE FURNISHED BY CONTRACTOR

19.1 DAILY DRILLING REPORTS

CONTRACTOR shall keep and furnish to COMPANY one (1) copy of the Daily Drilling Report Form showing the depth of the hole, formation penetrated, and any other data required by COMPANY or governmental authority. CONTRACTOR shall supply the report on the standard API-IADC Report Form. When CONTRACTOR prepares such form, it shall be referred to as the "Daily Drilling Report Form".

19.2 ACCIDENT REPORTS

CONTRACTOR shall report to COMPANY, as soon as possible, all accidents or occurrences resulting in injuries to CONTRACTOR'S employees or to any third parties, as well as any damage to property of third persons, arising out of or during the course of operations of CONTRACTOR or its subcontractors. CONTRACTOR shall furnish COMPANY with a copy of all reports made by CONTRACTOR to its insurer or to others as requested by COMPANY of the accidents and occurrences.

19.3 DELIVERY TICKETS

CONTRACTOR shall furnish to COMPANY delivery tickets covering any materials or supplies furnished to CONTRACTOR by vendors for which COMPANY is obligated to reimburse CONTRACTOR. These shall be turned in to COMPANY'S representative as received with the Daily Drilling Report Form. The quantity, description, and condition of materials and supplies so furnished shall be verified and checked by CONTRACTOR. The delivery tickets shall be properly certified as to receipt by CONTRACTOR and must have COMPANY'S representative's signature for reimbursement to CONTRACTOR.

19.4 LOGS

CONTRACTOR shall diligently maintain navigational logs, equipment maintenance, and testing logs, and such other logs and documentation designated by COMPANY. Any maintained log or documentation shall not create any additional burden on CONTRACTOR that is not already required elsewhere in this CONTRACT. CONTRACTOR shall provide a copy of any log upon COMPANY'S request.

ARTICLE 20

INSURANCE

20.1 INSURANCE

Without limiting the indemnity obligation or liabilities of CONTRACTOR or its insurer, at all times during the term of this CONTRACT, CONTRACTOR shall maintain insurance covering the operations to be performed under this CONTRACT as set forth in Exhibit C.

ARTICLE 21

INDEMNITY FOR PERSONAL INJURY OR DEATH

21.1 CONTRACTOR'S PERSONNEL

CONTRACTOR SHALL PROTECT, RELEASE, DEFEND, INDEMNIFY AND HOLD HARMLESS COMPANY FROM AND AGAINST ALL CLAIMS, DEMANDS AND CAUSES OF ACTION ASSERTED BY CONTRACTOR, CONTRACTOR'S SUBSIDIARIES AND AFFILIATED COMPANIES, CONTRACTORS OF ANY SUCH PARTIES, AND THEIR RESPECTIVE OFFICERS, DIRECTORS, AGENTS, INVITEES, EMPLOYEES AND ANY OF THEIR RELATIVES FOR PERSONAL INJURY (INCLUDING BODILY INJURY), ILLNESS, OR DEATH, THAT ARISE OUT OF OR ARE RELATED TO WORK PERFORMED HEREUNDER.

21.2 COMPANY'S PERSONNEL

COMPANY SHALL PROTECT, RELEASE, DEFEND, INDEMNIFY AND HOLD HARMLESS CONTRACTOR FROM AND AGAINST ALL CLAIMS, DEMANDS AND CAUSES OF ACTION ASSERTED BY COMPANY, COMPANY'S SUBSIDIARIES, CO-OWNERS AND JOINT VENTURERS (IF ANY), CONTRACTORS OF ANY SUCH PARTIES (EXCEPT CONTRACTOR, AS SET FORTH IN ARTICLE 21.1 HEREOF), AND THEIR RESPECTIVE OFFICERS, DIRECTORS, AGENTS, INVITEES, EMPLOYEES AND ANY OF THEIR RELATIVES FOR PERSONAL INJURY (INCLUDING BODILY INJURY), ILLNESS, OR DEATH, THAT ARISE OUT OF OR ARE RELATED TO WORK PERFORMED HEREUNDER.

ARTICLE 22

RESPONSIBILITY FOR LOSS OF OR DAMAGE TO THE EQUIPMENT

22.1 CONTRACTOR'S DRILLING UNIT

EXCEPT AS SPECIFICALLY PROVIDED FOR IN ARTICLE 22.3, CONTRACTOR SHALL ASSUME ALL RISK OF LOSS OF OR DAMAGE TO AND SHALL PROTECT,

RELEASE, DEFEND, INDEMNIFY AND HOLD HARMLESS COMPANY FROM AND AGAINST ANY AND ALL CLAIMS FOR LOSS OF OR DAMAGE TO (INCLUDING SALVAGE OR REMOVAL COSTS) ITS DRILLING UNIT AND EQUIPMENT.

FOR PURPOSES OF THIS ARTICLE 22, ALL EQUIPMENT BELONGING TO CONTRACTOR'S PARENT, SUBSIDIARIES, AFFILIATES, SUBCONTRACTORS, PARTNERS, JOINT VENTURERS, EMPLOYEES, OR AGENTS SHALL BE CONSIDERED TO BE CONTRACTOR'S EQUIPMENT.

22.2 USE OF CONTRACTOR'S EQUIPMENT

COMPANY shall have unrestricted right to use all of CONTRACTOR'S equipment provided under this CONTRACT during such times as COMPANY or both COMPANY and CONTRACTOR are engaged in bringing a well being drilled under this CONTRACT under control, provided however, that such use, in CONTRACTOR'S sole opinion, does not endanger CONTRACTOR'S personnel or the Drilling Unit.

22.3 CONTRACTOR'S IN HOLE-EQUIPMENT

COMPANY SHALL ASSUME ALL RISK OF LOSS OF OR DAMAGE TO CONTRACTOR'S IN-HOLE, SUBSEA AND MOORING EQUIPMENT WHEN THE EQUIPMENT IS IN THE HOLE OR IN USE BELOW THE SURFACE OF THE WATER TO THE EXTENT CONTRACTOR'S INSURANCE DOES NOT COMPENSATE CONTRACTOR, REGARDLESS OF WHEN OR HOW THE DESTRUCTION OR DAMAGE OCCURS, UNLESS SAID LOSS OF OR DAMAGE IS A RESULT OF CONTRACTOR'S SOLE NEGLIGENCE, GROSS NEGLIGENCE OR WILLFUL MISCONDUCT, IN WHICH CASE CONTRACTOR IS SOLELY RESPONSIBLE FOR ALL LOSS OF OR DAMAGE. FOR PURPOSES OF THIS SECTION 22.3, ALL EQUIPMENT BELONGING TO CONTRACTOR'S SUBCONTRACTORS, PARTNERS, JOINT VENTURERS, EMPLOYEES, OR AGENTS SHALL BE CONSIDERED TO BE CONTRACTOR'S EQUIPMENT. COMPANY'S RESPONSIBILITY FOR LOSS OF CONTRACTOR'S INHOLE, SUBSEA AND MOORING EQUIPMENT IS LIMITED TO CONT RACTOR'S CIF REPLACEMENT COST LESS DEPRECIATION AT THE RATE OF THREE-FOURTHS OF ONE PERCENT (0.75%) PER MONTH OF USE UNDER THIS CONTRACT.

COMPANY SHALL ASSUME THE RISK OF LOSS FOR AND PROTECT, RELEASE, DEFEND, INDEMNIFY AND HOLD HARMLESS CONTRACTOR FOR DAMAGE TO OR DESTRUCTION OF CONTRACTOR'S CHOKE MANIFOLDS, BLOWOUT PREVENTORS, AND DRILL STRING CAUSED BY EXPOSURE TO UNUSUALLY CORROSIVE OR OTHERWISE DESTRUCTIVE ELEMENTS NOT NORMALLY ENCOUNTERED WHICH ARE INTRODUCED INTO THE DRILLING FLUID FROM SUBSURFACE FORMATIONS OR THE USE OF CORROSIVE ADDITIVES IN THE FLUID, UNLESS SAID LOSS OF OR DAMAGE IS A RESULT OF CONTRACTOR'S NEGLIGENCE, GROSS NEGLIGENCE OR WILLFUL MISCONDUCT IN WHICH CASE CONTRACTOR IS SOLELY RESPONSIBLE FOR ALL LOSS OR DAMAGE.

22.4 <u>COMPANY'S EQUIPMENT</u>

COMPANY SHALL ASSUME THE RISK OF LOSS FOR AND PROTECT, RELEASE, DEFEND, INDEMNIFY, AND HOLD HARMLESS CONTRACTOR FROM AND AGAINST ANY AND ALL CLAIMS FOR LOSS OF OR DAMAGE TO COMPANY'S EQUIPMENT AND PROPERTY. FOR THE PURPOSE OF THIS ARTICLE 22 ONLY, ALL EQUIPMENT AND PROPERTY BELONGING TO COMPANY'S PARENT, SUBSIDIARIES, AFFILIATES, CONTRACTORS (OTHER THAN CONTRACTOR) SUBCONTRACTORS, PARTNERS, JOINT VENTURERS, EMPLOYEES, OR AGENTS SHALL BE CONSIDERED TO BE COMPANY'S EQUIPMENT.

22.5 <u>RESPONSIBILITY DURING MOBILIZATION FROM KOREA</u>

CONTRACTOR SHALL ASSUME FULL RESPONSIBILITY FOR AND SHALL PROTECT, RELEASE, DEFEND, INDEMNIFY, AND HOLD HARMLESS COMPANY AND ITS' JOINT OWNERS HARMLESS FROM AND AGAINST ANY LOSS, CLAIM, DAMAGE, FINE, PENALTY, DEMAND OR LIABILITY, FOR POLLUTION OR PROPERTY DAMAGE, WITHOUT MONETARY LIMITATIONS, MADE BY ANY ENTITY OR PERSON WHILE THE DRILLING UNIT IS MOBILIZING FROM KOREA TO THE GULF OF MEXICO PRIOR TO THE COMMENCMENT DATE.

<u>ARTICLE 23</u>

<u>LOSS OF HOLE OR RESERVOIR</u>

23.1 <u>LOSS OR DAMAGE TO THE HOLE</u>

SHOULD THE HOLE BE LOST OR DAMAGED, THE LOSS OR DAMAGE WILL BE BORNE BY COMPANY AND COMPANY SHALL PROTECT, RELEASE, DEFEND, INDEMNIFY, AND HOLD HARMLESS CONTRACTOR FROM AND AGAINST ALL CLAIMS FOR LOSS OF OR DAMAGE TO THE HOLE. NOTWITHSTANDING THE PREVIOUS SENTENCE, IF THE HOLE IS LOST OR DAMAGED DUE TO CONTRACTOR'S NEGLIGENCE, GROSS NEGLIGENCE, WILLFUL MISCONDUCT OR ITS AGENTS', OR SUBCONTRACTORS OR THEIR FAILURE TO COMPLY WITH COMPANY'S INSTRUCTIONS, THEN AS CONTRACTOR'S SOLE LIABILITY, CONTRACTOR SHALL BE OBLIGATED AT COMPANY'S ELECTION TO REDRILL THE HOLE TO THE POINT AT WHICH THE HOLE WAS LOST AT EIGHTY PERCENT (80%) OF THE OPERATING RATE BUT OTHERWISE SUBJECT TO THIS DRILLING CONTRACT.

23.2 <u>COST OF CONTROL OF BLOWOUT OR CRATER</u>

IN THE EVENT ANY WELL BEING DRILLED HEREUNDER SHALL BLOWOUT, CRATER OR CONTROL BE LOST FROM ANY CAUSE, COMPANY SHALL BEAR THE ENTIRE COST AND EXPENSE OF KILLING THE WELL OR OF OTHERWISE BRINGING THE WELL UNDER CONTROL AND SHALL PROTECT, RELEASE, DEFEND, INDEMNIFY, AND HOLD HARMLESS CONTRACTOR FROM AND

AGAINST ALL CLAIMS, SUITS, DEMANDS, AND CAUSES OF ACTION FOR COSTS ACTUALLY INCURRED IN CONTROLLING THE WELL.

23.3 UNDERGROUND DAMAGE

COMPANY SHALL PROTECT, RELEASE, DEFEND, INDEMNIFY, AND HOLD HARMLESS CONTRACTOR FOR ANY AND ALL CLAIMS ON ACCOUNT OF (I) INJURY TO, DESTRUCTION OF, LOSS, OR IMPAIRMENT OF ANY PROPERTY RIGHT IN OR TO OIL, GAS, OR OTHER MINERAL SUBSTANCES OR WATER, IF AT THE TIME OF THE ACT OR OMISSION CAUSING THE INJURY, DESTRUCTION, LOSS, OR IMPAIRMENT, THE SUBSTANCE HAD NOT BEEN REDUCED TO PHYSICAL POSSESSION ABOVE THE SURFACE OF THE EARTH, OR (II) ANY LOSS OR DAMAGE TO ANY FORMATION, STRATA, OR RESERVOIR BENEATH THE SURFACE OF THE EARTH.

ARTICLE 24

POLLUTION

24.1 CONTRACTOR RESPONSIBILITY

CONTRACTOR SHALL ASSUME FULL RESPONSIBILITY FOR AND SHALL PROTECT, RELEASE, DEFEND, INDEMNIFY, AND HOLD COMPANY AND ITS JOINT OWNERS HARMLESS FROM AND AGAINST ANY LOSS, DAMAGE, EXPENSE, CLAIM, FINE, PENALTY, DEMAND, OR LIABILITY FOR POLLUTION OR CONTAMINATION, INCLUDING CONTROL AND REMOVAL THEREOF, ORIGINATING ON OR ABOVE THE SURFACE OF THE LAND OR WATER, FROM SPILLS, LEAKS, OR DISCHARGES OF FUELS, LUBRICANTS, MOTOR OILS, PIPE DOPE, PAINTS, SOLVENTS, BALLAST, AIR EMISSIONS, BILGE SLUDGE, GARBAGE, OR ANY OTHER LIQUID OR SOLID WHATSOEVER IN POSSESSION AND CONTROL OF CONTRACTOR AND WITHOUT REGARD TO NEGLIGENCE OF ANY PARTY OR PARTIES AND SPECIFICALLY WITHOUT REGARD TO WHETHER THE SPILL, LEAK, OR DISCHARGE IS CAUSED IN WHOLE OR IN PART BY THE NEGLIGENCE OR OTHER FAULT OF COMPANY, ITS CONTRACTORS, (OTHER THAN CONTRACTOR) PARTNE RS, JOINT VENTURERS, EMPLOYEES, OR AGENTS. IN ADDITION TO THE ABOVE, CONTRACTOR TO A LIMIT OF FIFTEEN MILLION DOLLARES (US$ 15,000,000.00) PER OCCURANCE, SHALL RELEASE INDEMNIFY AND DEFEND COMPANY FOR CLAIMS FOR LOSS OR DAMAGE TO THIRD PARTIES ARISING FROM POLLUTION IN ANY WAY CAUSED BY THE DRILLING UNIT WHILE IT IS OFF THE DRILLING LOCATION, WHILE UNDERWAY OR DURING DRIVE OFF OR DRIFT OFF FROM THE DRILLING LOCATION.

24.2 COMPANY RESPONSIBILITY

COMPANY SHALL ASSUME FULL RESPONSIBILITY FOR AND SHALL PROTECT, RELEASE, DEFEND, INDEMNIFY, AND HOLD CONTRACTOR HARMLESS FROM AND AGAINST ANY LOSS, DAMAGE, EXPENSE, CLAIM, FINE, PENALTY,

DEMAND, OR LIABILITY FOR POLLUTION OR CONTAMINATION, INCLUDING CONTROL AND REMOVAL THEREOF, ARISING OUT OF OR CONNECTED WITH OPERATIONS UNDER THIS CONTRACT HEREUNDER AND NOT ASSUMED BY CONTRACTOR IN ARTICLE 24.1 ABOVE, WITHOUT REGARD FOR NEGLIGENCE OF ANY PARTY OR PARTIES AND SPECIFICALLY WITHOUT REGARD FOR WHETHER THE POLLUTION OR CONTAMINATION IS CAUSED IN WHOLE OR IN PART BY THE NEGLIGENCE OR FAULT OF CONTRACTOR.

24.3 CLEAN UP OPERATIONS

Initiation of clean up operations by either Party shall not be an admission or assumption of liability by such initiating Party or Parties.

ARTICLE 25

INDEMNITY OBLIGATION

25.1 INDEMNITY OBLIGATION

EXCEPT TO THE EXTENT ANY SUCH OBLIGATION IS SPECIFICALLY LIMITED TO CERTAIN CAUSES ELSEWHERE IN THIS CONTRACT, THE PARTIES INTEND AND AGREE THAT THE PHRASE "SHALL PROTECT, RELEASE, DEFEND, INDEMNIFY AND HOLD HARMLESS" MEANS THAT THE INDEMNIFYING PARTY SHALL PROTECT, RELEASE, DEFEND, INDEMNIFY, AND HOLD HARMLESS THE INDEMNIFIED PARTY OR PARTIES FROM AND AGAINST ANY AND ALL CLAIMS, DEMANDS, CAUSES OF ACTION, DAMAGES, COSTS, EXPENSES (INCLUDING REASONABLE ATTORNEYS FEES), JUDGMENTS AND AWARDS OF ANY KIND OR CHARACTER, WITHOUT LIMIT AND WITHOUT REGARD TO THE CAUSE OR CAUSES THEREOF, INCLUDING PREEXISTING CONDITIONS, WHETHER SUCH CONDITIONS BE PATENT OR LATENT, THE UNSEAWORTHINESS OF ANY VESSEL OR VESSELS (INCLUDING THE DRILLING UNIT), BREACH OF REPRESENTATION OR WARRANTY, EXPRESSED OR IMPLIED, BREACH OF CONTRACT, S TRICT LIABILITY, TORT, OR THE NEGLIGENCE OF ANY PERSON OR PERSONS, INCLUDING THAT OF THE INDEMNIFIED PARTY, WHETHER SUCH NEGLIGENCE BE SOLE, JOINT OR CONCURRENT, ACTIVE, PASSIVE OR GROSS OR ANY OTHER THEORY OF LEGAL LIABILITY AND WITHOUT REGARD TO WHETHER THE CLAIM AGAINST THE INDEMNITEE IS THE RESULT OF AN INDEMNIFICATION AGREEMENT WITH A THIRD PARTY.

25.2 BENEFIT OF INDEMNITIES

TO THE EXTENT A PARTY IS ENTITLED TO INDEMNIFICATION IN ARTICLES 21, 22, 23, AND 24, SUCH PARTY'S PARENT, SUBSIDIARIES, AFFILIATES, CO-OWNERS AND JOINT VENTURERS (IF ANY), AND THEIR RESPECTIVE OFFICERS, DIRECTORS, AGENTS AND EMPLOYEES, THE DRILLING UNIT AND ITS LEGAL AND BENEFICAL OWNERS, IN REM OR IN PERSONAM SHALL ALSO BE ENTITLED TO SUCH INDEMNIFICATION AND DEFENSE THEREUNDER. ANY

SUCH PERSON SO ENTITLED TO INDEMNIFICATION AND DEFENSE UNDER THIS ARTICLE 25.2 ARE HEREINAFTER REFERRED TO AS AN “EXTENDED BENEFICIARY OF INDEMNIFICATIONS.

25.3 Third Party Beneficiaries

Except as otherwise specifically agreed nothing in this Contract shall be construed or applied so as to permit any person or entity not a direct signatory party hereto (except for a successor or permitted assignee of such direct signatory party) to enforce or seek damages against either signatory party hereto for any breach of this Contract. The definition of CONTRACTOR and COMPANY herein shall not be construed to enable or entitle any person or entity other than the signatory parties hereto or a successor or permitted assignee of such a signatory party to directly sue or seek relief against the other signatory party hereto except to the extent that any Extended Beneficiary of Indemnification (as defined in Article 25.2) shall be expressly permitted to enforce such rights of indemnification against the indemnitor. Except for any EXTENDED BEN EFICIARY OF INDEMNIFICATION, no persons or entities are intended to be or become third party beneficiaries of this contract.

ARTICLE 26

LAWS, RULES, AND REGULATIONS

26.1 LAWS, RULES AND REGULATIONS

CONTRACTOR and COMPANY shall comply with all governmental laws, rules, and regulations or orders which are now or hereafter shall become applicable to its operations covered by this CONTRACT or arising out of the performance of such operations.

26.2 EQUAL OPPORTUNITY CLAUSE

To the extent applicable and in connection with the performance of work under this CONTRACT, CONTRACTOR agrees to comply with the following Equal Employment Opportunity and/or Affirmative Action requirements and all other similar requirements as the same are enacted or become applicable to the CONTRACT: Section 202 of Executive Order 11246, as amended by Executive Order 11375, relating to equal employment opportunities, the implementing rules and regulations of the Secretary of Labor and all contract clauses and requirements which are applicable and set forth therein are incorporated herein by specific reference. In particular, CONTRACTOR hereby certifies that it does not maintain segregated facilities. In making this certification, CONTRACTOR incorporates each and all of the provisions of the approved form of certification contained in 41 C .F.R. Section 60-1.8(b) the same as if such provisions were fully set forth herein and signed by CONTRACTOR. Sections 503 and 504 of the Rehabilitation Act of 1973 and Title IV of the Vietnam Era Veterans Readjustment Assistance Act of 1974 relating to employment and advancement of employment of qualified handicapped individuals, disabled veterans and veterans of the Vietnam Era, the implementing rules and regulations of the Secretary of Labor and all contract clauses and requirements which are applicable and set forth therein are incorporated herein by specific reference pursuant to 41 C.F.R. Section 60-741.22 and 41 C.F.R. Section 60-250.22.

26.3 CERTIFICATE OF FINANCIAL RESPONSIBILITY

COMPANY, in cooperation with the CONTRACTOR, shall obtain, at COMPANY'S expense, and maintain evidence of a Certificate of Financial Responsibility from the U.S. Coast Guard covering the Drilling Unit as required by 33 C.F.R. Part 135 and the Outer Continental Shelf Lands Act of 1978. COMPANY will file for the certificate before the well is spud and will coordinate the filing with COMPANY. A copy of filed certificate shall be furnished to CONTRACTOR prior to spud and CONTRACTOR must maintain a copy on the Drilling Unit.

ARTICLE 27

TERMINATION

27.1 TERMINATION BY COMPANY

27.1.1 COMPANY shall have the option to terminate this CONTRACT subject only to (i) payment of amounts earned by CONTRACTOR before termination, and demobilization of the Drilling Unit pursuant to Article 1.3 and (ii) payment of the Lump Sum set forth in Exhibit E. Terminating pursuant to Article 27.1.1 does not limit any other right of termination which COMPANY may have. The termination shall not affect any right or obligation which accrued prior to the termination.

27.1.2 In the event the shipyard where the Drilling Unit is being constructed fails or is unable to deliver the Drilling Unit within the time limits and operational specifications of its contract with CONTRACTOR such that CONTRACTOR has the ability to terminate the construction contract, CONTRACTOR shall so advise COMPANY in writing.

If COMPANY desires to accept the Drilling Unit with later delivery or reduced operational specifications, then COMPANY shall so notify CONTRACTOR within a reasonable time following COMPANY'S receipt of notice under this Article, and upon timely receipt of notice by CONTRACTOR, CONTRACTOR shall not terminate the construction contract and this CONTRACT shall be suitably amended to reflect the later delivery and the reduced operational specifications in Exhibit G, with all other terms and conditions remaining in full force and effect. If such later delivery or reduced operational specifications result in a claim by CONTRACTOR against the Drilling Unit constructor, any net savings to CONTRACTOR as a result of such claim shall be credited to COMPANY against CONTRACTOR'S invoices or remitted to COMPANY as COMPANY shall direct.

If COMPANY does not desire to accept the Drilling Unit with such later delivery or reduced operational specifications, then COMPANY shall so notify CONTRACTOR within a reasonable time following COMPANY'S receipt of notice under this Article, and upon timely receipt of such notice by CONTRACTOR, this CONTRACT shall terminate and COMPANY shall have no obligations under Exhibit E.

27.2 TERMINATION BY CONTRACTOR

CONTRACTOR may cancel this CONTRACT for non-payment of its invoices for services under this CONTRACT, except for portions of the invoices which COMPANY may dispute in good faith. However, CONTRACTOR may cancel under this Article no sooner than one hundred and twenty (120) days after payment was due and only after giving ninety (90) days notice thereof, during which period COMPANY shall have the opportunity to correct the breach.

27.3 LOSS OF DRILLING UNIT

In the event of actual or constructive total loss of the Drilling Unit (as determined by CONTRACTOR'S underwriters), termination shall be immediate with neither CONTRACTOR nor CONTRACTOR'S underwriters having any recourse against COMPANY, or obligations pursuant to Exhibit E, except for CONTRACTOR'S claim to amounts CONTRACTOR earned up to the date of such loss. Contractor shall be responsible for any removal or salvage costs.

27.4 PROVISION AFTER EXPIRATION OF CONTRACT

Notwithstanding the termination of this CONTRACT, COMPANY and CONTRACTOR shall continue to be bound by the provisions of this CONTRACT that reasonably require some action or forbearance after the expiration of the term of this CONTRACT.

ARTICLE 28

FORCE MAJEURE

28.1 FORCE MAJEURE

The term Force Majeure as used in this Article 28 shall mean acts of God, adverse sea or weather conditions beyond the design operating perimeters of the Drilling Unit including wind, sea and current, earthquakes, flood, war, civil disturbances, strikes, lockouts or other industrial disturbances by persons other than employees of CONTRACTOR, governmentally imposed rules, regulations or moratoriums or any other cause whatsoever, whether similar or dissimilar to the causes herein enumerated, not within the reasonable control of either Party which, through the exercise of due diligence said party is unable to foresee or overcome. In no event shall the term Force Majeure include normal, reasonably foreseeable, or reasonably avoidable operational delays or strikes, lockouts or other industrial disturbances by employees of CONTRACTOR. In the event that either Party hereto is rendered unable, wholly or in part, by Force Majeure to carry out its obligations under this CONTRACT, it is agreed that such Party shall give notice and details of the Force Majeure in writing to the other Party as promptly as possible after its occurrence. In such cases, the obligations of the Party giving the notice shall be suspended during the continuance of any inability so caused, except that COMPANY shall be obligated to pay to CONTRACTOR the applicable Dayrates. Should a condition of Force Majeure continue for more than thirty (30) consecutive days, this CONTRACT may be immediately terminated at the option of COMPANY by delivering written notice thereof to CONTRACTOR.

Except for its obligation to make payments of monies hereunder, neither Party to this CONTRACT shall be considered in default in performance of such obligations hereunder to the extent that the performance of such obligations, or any of them is delayed or prevented by Force Majeure.

ARTICLE 29

CONFIDENTIAL INFORMATION, LICENSE AND PATENT INDEMNITY

29.1 CONFIDENTIAL INFORMATION

29.1.1 CONTRACTOR agrees to hold in confidence, and not disclose to any third party or use for any purpose other than performance of the work, all or any part of the well information (including the location and type of operations performed), logs, cores, core data, cuttings, maps, data, plans, reports, manuscripts, procedures, schedules, drawings, specifications, results, models, computer programs, or any product which is: a) received or ascertained by CONTRACTOR directly or indirectly from COMPANY, its licensors or other contractors; or b) otherwise acquired by CONTRACTOR, its employees, representatives, or subcontractors in connection with, as a result of, or incident to performance of the work ("INFORMATION"). CONTRACTOR shall secure prior written agreements from its subcontractors, and suppliers who will be engaged in the per formance of the Work, or may be exposed to INFORMATION ensuring their compliance with the provisions of Article 29. Nothing herein contained should preclude CONTRACTOR from providing INFORMATION required by any governmental authority.

29.1.2 CONTRACTOR shall not use COMPANY'S name or COMPANY'S affiliate's name in any promotional materials, or make any publicity release regarding the Work or INFORMATION hereunder except as may be required by law, regulation or rule of any governmental entity or stock exchange without first obtaining the written approval of COMPANY.

29.1.3 CONTRACTOR agrees to comply with all the laws and regulations governing the export of INFORMATION from the United States.

29.1.4 Any other warranty, representation, limitation, or indemnification provision of this CONTRACT shall not affect the obligations of Article 29.

29.1.5 All INFORMATION, whether completed or not, shall be the property of COMPANY for its copying, use, modification, distribution, or disclosure without accounting, in whatever way COMPANY may determine, notwithstanding copyright or other restrictive legends placed thereon by CONTRACTOR, its employees, its subcontractors, or its suppliers. All INFORMATION shall be turned over to COMPANY promptly at COMPANY'S request or at the termination of operations.

29.2.2 CONTRACTOR agrees to grant, and hereby grants to COMPANY an irrevocable, paid up, nonexclusive worldwide license to make, use, sell, copy, modify, disclose, distribute, and license under any and all patent, copyright, trade secret and other proprietary rights owned or controlled by CONTRACTOR, its parent or subsidiaries, to the extent needed for making, using, selling, or licensing equipment, materials, or other goods according to INFORMATION supplied by CONTRACTOR or to produce, copy, distribute, and use copyrighted materials based on using such INFORMATION.

29.3 PATENT INDEMNITIES

29.3.1 CONTRACTOR SHALL PROTECT, DEFEND, INDEMNIFY AND HOLD HARMLESS COMPANY AGAINST LOSS OR DAMAGE ARISING OUT OF ANY CLAIM OR SUIT FOR MISAPPROPRIATION OF TRADE SECRET OR FOR PATENT, COPYRIGHT OR OTHER PROPRIETARY RIGHT INFRINGEMENT ARISING OUT OF INCIDENT TO OR IN CONNECTION WITH (A) PERFORMANCE OF THE WORK BY CONTRACTOR, OR (B) COMPANY'S POSSESSION, USE OR SALE OF GOODS, EQUIPMENT OR MATERIALS FURNISHED BY CONTRACTOR, OR (C) COMPANY'S PRODUCTION OF COPYRIGHTED WORKS INCORPORATING OR PREPARED ACCORDING TO DOCUMENTS OR OTHER TANGIBLE MATERIALS FURNISHED BY CONTRACTOR, AND COMPANY'S POSSESSION, MODIFICATION, USE, SALE, DISTRIBUTION, COPYING OR LICENSING OF SUCH DOCUMENTS, MATERIALS OR WORKS. COMPANY shall promptly notify CONTRACTOR of any such claim or suit and afford CONTRACTOR an opportunity at CONTRACTOR'S expense to undertake the defense of any such suit, provided that COMPANY, at its election, may join in such defense at its expense. If CONTRACTOR refuses or fails to defend such suit, CONTRACTOR shall reimburse COMPANY in full for COMPANY'S costs and expenses in the defense of such suit including attorneys' fees. CONTRACTOR shall pay promptly any judgments or decrees which may be entered against COMPANY in such suit, and in the event of the grant of injunctive relief, CONTRACTOR shall provide non-violating INFORMATION, equipment, and/or material equal in value and efficiency and failing so to do, shall pay COMPANY all damages suffered by reason of such failure.

29.3.2 COMPANY SHALL PROTECT, DEFEND, INDEMNIFY AND HOLD HARMLESS CONTRACTOR AGAINST LOSS OR DAMAGE ARISING OUT OF ANY CLAIM OR SUIT FOR MISAPPROPRIATION OF TRADE SECRET OR FOR PATENT, COPYRIGHT OR OTHER PROPRIETARY RIGHT INFRINGEMENT ARISING OUT OF INCIDENT TO OR IN CONNECTION WITH (A) CONTRACTOR"S POSSESSION, USE OF EQUIPMENT OR MATERIALS FURNISHED BY COMPANY IN ACCORDANCE WITH EXHIBIT B-3, OR (B) CONTRACTOR'S PRODUCTION OF COPYRIGHTED WORKS INCORPORATING OR PREPARED ACCORDING TO DOCUMENTS OR OTHER TANGIBLE MATERIALS FURNISHED BY COMPANY, AND CONTRACTOR'S POSSESSION, MODIFICATION, USE, SALE, DISTRIBUTION, COPYING OR LICENSING OF SUCH DOCUMENTS, MATERIALS OR WORKS. CONTRACTOR shall promptly notify COMPANY of any such claim or suit and afford COMPANY an opportunity at COMPANY'S expense to undertake the defense of any such suit, provided that CONTRACTOR, at its election, may join in such defense at its expense. If COMPANY refuses or fails to defend such suit, COMPANY shall reimburse CONTRACTOR in full for CONTRACTOR"S costs and expenses in the defense of such suit including attorneys' fees. COMPANY shall pay promptly any judgments or decrees entered against CONTRACTOR in such suit.

ARTICLE 30

ASSIGNMENT OF CONTRACT

30.1 ASSIGNMENT BY CONTRACTOR

CONTRACTOR shall not sublease or assign this CONTRACT, other than to its parent company or an affiliate or subsidiary thereof, without first obtaining the written consent of COMPANY. Such consent shall not be unreasonably withheld. COMPANY may require CONTRACTOR or its parent, subsidiaries or affiliates to issue a performance guarantee in a mutually agreeable form.

30.2 ASSIGNMENT BY COMPANY

30.2.1 COMPANY shall have the right to assign this CONTRACT to Atlantic Richfield Company, its divisions, subsidiaries (whether wholly or partially owned by Atlantic Richfield Company) and affiliates. CONTRACTOR shall look exclusively to the assignee of COMPANY for any matter during the period of assignment in the event of any such assignment by COMPANY. The time the Drilling Unit is operating for the assignee shall count towards the Contract Period.

30.2.2 Subject to Article 30.2.1, COMPANY shall have the right to assign its rights and obligations hereunder, in whole or in part, to third persons for wells within the Gulf of Mexico, with written consent of CONTRACTOR, and such consent shall not be unreasonably withheld. In the event of any such assignment under this Article 30.2.2 to a third party with CONTRACTOR'S written consent, COMPANY shall thereafter have no liability for any matter or operations hereunder and shall have no further responsibility to CONTRACTOR or other person hereunder during the time the right is assigned. CONTRACTOR shall look exclusively to the assignee of COMPANY for any matter during the period of assignment in the event of any such assignment by COMPANY. The time the Drilling Unit is operating for the assignee shall count toward the Contract Period.

30.2.3 COMPANY shall have the right to assign its rights and obligations hereunder, in whole or in part, to third parties for wells within the Gulf of Mexico, without the consent of CONTRACTOR. In the event of any such assignment under this Article 30.2.3, COMPANY shall provide written notice to CONTRACTOR prior to the use of the Drilling Unit on behalf of the assignee. In the event of such an assignment, COMPANY shall remain fully liable and responsible to CONTRACTOR for complete performance of all terms, conditions, and obligations imposed by this CONTRACT. The time the Drilling Unit is operating for the assignee shall count toward the Contract Period.

30.3 ASSIGNMENT OUTSIDE OF OPERATING AREA

In the event any assignment being contemplated under the provisions of this Article 30 is to involve operations outside of the Operating Area (as defined in Article 14.6), the dayrates provided for herein shall be adjusted to reflect any documented increases or decreases in CONTRACTOR'S cost of operations, including but not limited to taxes and fees in Article 11.

ARTICLE 31

INGRESS AND EGRESS OF LOCATION

31.1 INGRESS AND EGRESS OF LOCATION

31.1.1 COMPANY shall provide CONTRACTOR with rights of ingress and egress to the well location and provide any related drilling permits or licenses for the performance by CONTRACTOR of all Work.

31.1.2 COMPANY makes no warranty or representation, express or implied, and hereby disclaims all such warranties or representations as to any conditions with respect to any port, place, dock, anchorage, access route, location, or submarine line relating to the Work, except at the well location.

ARTICLE 32

COMPANY'S POLICIES

32.1 UNAUTHORIZED PERSONS ON JOB SITES

Only (i) CONTRACTOR'S authorized employees or subcontractors, (ii) other authorized employees and persons, including invitees, authorized by COMPANY, or (iii) representatives of governmental agencies will be permitted to enter any job site where Work is to be performed under this CONTRACT. CONTRACTOR is obligated to take such steps as are reasonably necessary to prevent unauthorized persons from entering a job site.

32.2 DRUGS, FIREARMS, AND SEARCHES

CONTRACTOR shall abide by and help enforce COMPANY'S policy regarding drugs, firearms, and alcohol. The policy is as follows: The use, possession, or transportation of firearms, alcoholic beverages, illegal drugs, narcotics, or other controlled or dangerous substances, and unauthorized drugs for which a person does not have a current prescription, while on COMPANY'S Premises is prohibited. The term "COMPANY'S Premises" is used in its broadest sense to include all work locations, buildings, structures, installations, Drilling Unit, and all other facilities, both onshore and offshore, including the point of embarkation and debarkation for all boats, planes, and helicopters owned or controlled by COMPANY or one of its affiliated companies or otherwise being utilized for COMPANY'S business for transportation o f persons to and from these facilities.

To ensure compliance with this policy, COMPANY may require CONTRACTOR, upon written request, to conduct unannounced periodic inspections of all individuals and their personal effects while on COMPANY'S Premises. Violation of this policy or refusal to submit to an inspection by COMPANY'S or CONTRACTOR'S personnel could result in disciplinary action up to and including discharge will be cause for immediate removal of the individual from COMPANY'S Premises.

ARTICLE 33

NOTICES

33.1 NOTICES

Any notice provided or permitted to be given under this CONTRACT shall be in writing, and may be served by personal delivery or by depositing same in the mail, addressed to the Party to be notified, postage prepaid, and registered or certified with a return receipt requested. Notice deposited in the mail in the manner described above shall be deemed to have been given and received on the date of the delivery as shown on the return receipt. Notice served in any other manner shall be deemed to have been given and received only if and when actually received by the addressee (except that notice given by telecopier shall be deemed given and received upon receipt only if received during normal business hours and if received other than during normal business hours shall be deemed received as of the opening of business on the next Business Day (for purposes of this CONTRACT, the term "Business Day") shall mean any day except a Saturday, Sunday or other day on which commercial banks in Houston, Texas are required or authorized by law to be closed). For purposes of notice, the addresses of the Parties shall be as follows:

33.2 FOR COMPANY

Vastar Resources, Inc.

15375 Memorial Drive

Houston, TX 77079

ATTN: Don Weisinger

FAX: (281) 584-6810 or 6670

TELEPHONE: (281) 584-6021

33.3 FOR CONTRACTOR

R&B Falcon Drilling Co.

901 Threadneedle

Houston, TX 77079-2911

ATTN: President

FAX: (281)496-4363

TELPHONE: (281)496-5000

33.4 ORAL NOTICES

Notices may be given orally only with respect to minor questions involved in the immediate drilling of any well concerned.

ARTICLE 34

CONSEQUENTIAL DAMAGES

34.1 CONSEQUENTIAL DAMAGES

Neither Party shall be liable to the other for incidental special, indirect, statutory, exemplary, punitive, or consequential damages suffered by such party resulting from or arising out of this CONTRACT, including, without limitation, loss of profits, or business interruptions however they may be caused.

ARTICLE 35

WAIVERS AND ENTIRE CONTRACT

35.1 WAIVERS

None of the terms and conditions of this CONTRACT shall be deemed waived by either Party unless the waiver is executed in writing and then only by the duly authorized agents or representative of that Party. The failure of either Party to execute any right of termination shall not act as a waiver of any right of that Party provided hereunder. No waiver of the provisions of this CONTRACT shall be deemed or shall constitute a waiver of any other provisions hereof (whether or not similar), nor shall such waiver constitute a continuing waiver unless otherwise expressly provided.

35.2 ENTIRE CONTRACT

This CONTRACT, including all exhibits attached hereto and made a part hereof by this reference, constitute the entire agreement between the Parties with respect to the subject matter hereof and thereof and supersede all prior agreements, understandings, negotiations, discussions and commitments, whether oral or written with respect to same. The right of either Party to require strict adherence to the terms hereof and performance hereunder will not be affected by any previous waiver of course of dealing. Neither this CONTRACT nor any supplement, amendment, alteration, modification, or waiver will be binding on a Party unless signed by duly authorized agents or representatives of CONTRACTOR and COMPANY, or in the case of termination, by the duly authorized agents or representatives of the Party seeking termination. In the event of conflict bet ween the terms and conditions of the text of this CONTRACT and those in any of the Exhibits, the terms and conditions of the text of this CONTRACT shall prevail.

35.3 GOVERNING LAW

This CONTRACT shall be construed and the relations between the parties determined in accordance with the General Maritime Law of the United States of America, not including, however, any of its conflicts of law rules which would direct or refer to the laws of another jurisdiction.

35.4 ARBITRATION

Any controversy or claim arising out of or relating to this CONTRACT, or the breach thereof, which cannot be resolved satisfactorily between the parties, shall be settled by arbitration in Houston, Texas, in accordance with the rules of the American Arbitration Association Commercial Disputes. If no agreement can be reached by the Parties on discovery disputes, then the Federal Rules of Civil Procedure shall govern and judgement upon the award rendered by the arbitrator(s) may be entered in any court of competent jurisdiction.

IN WITNESS WHEREOF, the parties hereto have executed this CONTRACT on the 9th day of December, 1998.

R&B Falcon Drilling Co.		**Vastar Resources, Inc.**	
BY:	/s/ Paul B. Loyd, Jr. Paul B. Loyd, Jr.	By	/s/ Charles D. Davidson Charles D. Davidson
TITLE:	Attorney-in-Fact (Chairman R&B Falcon Corporation)	TITLE:	President and CEO

EXHIBIT A

DAYRATES

	RATES PER 24 HOUR DAY	
	Three (3) Year Option	Five (5) Year Option
Operating Rate	$199,950.00 per day	$189,200.00 per day
Moving Rate	$199,950.00 per day	$189,200.00 per day
Standby Rate With Crews	$199,950.00 per day	$189,200.00 per day
Standby Rate Without Crews	$199,950.00 per day less documented cost savings	$189,200.00 per day less documented cost savings
Stack Rate With Crews	$199,950.00 per day less documented cost savings	$189,200.00 per day less documented cost savings
Stack Rate Without Crews	$199,950.00 per day less documented cost savings	$189,200.00 per day less documented cost savings
Equipment Repair Rate	$ -0- per day	$ -0- per day
Hurricane Evacuation Rate	Standby Rates without crews plus documented expenses of evacuated crew	Standby Rates without crews plus documented expenses of evacuated crew

EXHIBIT B-1

Drilling Unit Specifications

GENERAL DESCRIPTION, DIMENSIONS & CRITERIA

General Description

The RBS8D is a 5th generation, harsh environment, dynamically positioned semi-submersible, suitable for worldwide operations in up to 10,000' water depth.

The vessel has twin "dog-bone"-shaped lower hulls, four (4) columns, canted in the transverse plane, each with a Column Outer Belt (COB) at the drilling draft, two (2) transverse horizontal, four (4) diagonal horizontal braces, and a watertight rectangular box-type upper hull.

Designed for harsh environments, the vessel features variable deck & column loads (per 1.2.4 of this document), very low motions, and high specification drilling systems, with machinery spaces and two-level quarters for 130 personnel.

Eight 5.5 MW azimuth thrusters plus six 7 MW engines provide reliable and redundant DPS-3 station keeping ability.

Principal Dimensions

	Metric Units	U.S. Units
Overall Structure		
Length (overall)	120.7 m	396.00 ft.
Breadth (overall)	78.0 m	255.91 ft.
Upper Hull		
Length	81.5 m	267.40 ft.
Breadth	61.0 m	200.13 ft.
Depth	8.5 m	27.89 ft.
Main Deck		
Length	84.1 m	275.93 ft.
Breadth	61.0 m	200.13 ft.
Pontoons (two each)		
Length	114.0 m	373.96 ft.
Breadth (amidship)	13.4 m	43.96 ft.
Breadth (ends)	16.5 m	54.13 ft.
Depth	9.10 m	29.86 ft.
Corner Radius	3.00 m	9.84 ft.
Transverse Distance (c. to c.)	61.5 m	201.77 ft.

Columns (four each)		
Horizontal Section (Lx B)		
	17.0 m x l6.5 m (@ WL)	55.8 ft. x 54.l ft.
	14.0 m x 16.5 m (bottom)	45.93 ft. x 54.13 ft.
Corner Radius	3.00 m	9.84 ft.
Vertical Height	23.9 m	78.41 ft.
Longitudinal Distance (c. to c.)	60.0 m	196.85 ft.
Transverse Distance (c. to c.) at Top	46.00 m	150.92 ft.
at Bottom	61.5 m	201.77 ft.
Transverse Braces (two each)		
Length	45.0 m	147.64 ft.
Breadth	6.0 m	19.68 ft.
Depth	3.00 m	9.84 ft.
Corner Radius	0.60 m	1.97 ft.
Longitudinal Distance (c. to c.)	68.0 m	223.10 ft.
Centerline Elevation	1.5 m	4.92 ft.
Diagonal Braces (four each)		
Diameter	3.0 m	9.84 ft.
Centerline Elevation	1.5 m	4.92 ft.
Elevations		
Drill Floor	46.0 m	150.92 ft.
Main Deck (at sides)	41.5 m	136.15 ft.
Second Deck	38.0 m	124.67 ft.
Third Deck (Inner bottom Top)	34.5 m	113.19 ft.
Upper Hull Bottom	33.0 m	108.27 ft.
Lower Hull Top	9.1 m	29.86 ft.
Draft		
Operating Condition (G.O.M.)	23.00 m	75.46 ft.
Severe Storm Condition (G.O.M.)	16.50 m	54.13 ft.
Transit Condition	8.80 m	28.87 ft.

Storage Capacities
(subject to adjustments)

	Metric Units	U.S. Units
Pipe Racks	871 m^2	9,376 ft^2
Riser (90' joints)	3,048.5 m	10,000 ft
Total Open Deck	2,005 m^2	21,578 ft^2
Bulk Cement	232 m^3	8,205 ft^3
Bulk Barite	387 m^3	13,675 ft^3
Cement Day Tank	62 m^3	2,200 ft^3
Barite Day Tank	68 m^3	2,400 ft^3
Total Bulk Storage	750 m^3	26,480 ft^3
Sack Storage	10,000 Sx	10,000 Sx
Drilling Mud Deck	750 m^3	4,434 bbl.
Drilling Mud (Column)	908 m^3	5,710 bbl.
Base Oil	480 m^3	3,019 bbl
Column Brine Storage	480 m^3	3,019 bbl.
Pontoon Brine Storage *)	3,975 m^3	25,000 bbl.
DW-Col.	1,736 m^3	10,918 bbl.
DW-pontoons	1424 m^3	8,956 bbl.
Fuel Oil	3,468 m^3	21,811 bbl
Potable Water	644 m^3	4,050 bbl
Helicopter Fuel	TBD	TBD
Refrigeration Storage	45 m^2	484 $ft.^2$
Dry Storage	60 m^2	646 $ft.^2$
SWB — pontoons *)	16,308 m^3	102,565 bbl
Quarters	130 Persons	130 Persons
Heliport	S-61, Super Puma	S-61, Super Puma

(*) Note: Pontoon Brine Storage and SWB are interchangeable

GULF OF MEXICO

METOCEAN DESIGN CRITERIA *)

Condition	OPERATION (DP Mode)	SURVIVAL (transit / future moored)	
	Drilling	Moored	Vessel
Item	10 Year Eddy + 10 year Tropical Storm	20Year Tropical + 10 Year Eddy (API Criteria)	100 Year Tropical Storm (ABS/API)
Wind (1 hour)	26.1 m/s (50.8 kn)	30.5 m/s (59.2 kn)	44.9 m/s (87.2 kn)
Wind (1 min.)	30.9 m/s (60 kn)	36.0 m/s (70 kn)	53.1 m/s (103 kn)
Wind (3 sec.)	35.8 m/s (69.5 kn)	41.7 m/s (81.0 kn)	61.7 m/s (120 kn)
Wave Hgt. Significant	7.9 m (26.0 ft)	9.4 m (31.0 ft)	12.5 m (41.0 ft)
Peak Period	(PMS)	12.0 sec.	15.0 sec.
Wave Height Maximum	14.7 m (48.2 ft)	17.5 m (57.3 ft)	22.0 m (72.2 ft)
Current:			
Surface	1.8 m/s, (3.5 kn)	1.8 m/s, (3.5 kn)	1.0 m/s (1.9 kn)
100 ft.	1.7 m/s, (3.4 kn)	1.7 m/s, (3.4 kn)	
200 ft.	1.2 m/s (2.4 kn)	1.2 m/s (2.4 kn)	
400 ft.	1.0 M/s (2.0 kn)	1.0 m/s (2.0 kn)	
1000 ft.	0.5 m/s (1.0 kn)	0.5 m/s (1.0 kn)	
2000 ft.	0.3 m/s (0.5 kn)	0.3 m/s (0.5 kn)	
Seafloor	0.1 m/s, (0.1 kn)	0.1 m/s, (0.1 kn)	

***) Metocean Design Criteria in the DP mode relate to drilling conditions with all engines (6 x 7.0 MW power) on line and any one thruster down.**

1.2.4 Variable Drilling Loads (VDL)

DP Mode — No Mooring

Item	Division	Operation Condition MT	KG (m) (Operating) (m)	Survival Condition MT	Transit Condition MT	Remark
Light Ship		**22,325**	**26.15**	**22,325**	**22,325**	
VDL (Variable Dlg. Loads)	**Upper Hull & Abv.**	**5,596**	**37.40**	**5,596**		**(note 1)**
	Columns	**2,057**	**22.85**	**2,057**		
VDL Total	**(Dk. + Col.)**	**7,653**	**33.49**	**7,653**	**7,450**	
Pontoon Loads: Drill Water, Potable Water, Water, Fuel Oil, Lube Oil, and Ballast Water		**17,530**	**5.57**	**10,722**	**2,984**	
Displacement (MT)		**47,509**	**19.68**	**40,700**	**32,759**	

Future Mooring + Thruster Assist

Item	Division	Operation Condition MT	KG (m) (Operating) (m)	Survival Condition MT	Transit Condition MT	Remark
Light Ship		**22,325**	**26.15**	**22,325**	**22,325**	
Mooring Load		**2,135**	**22.00**	**2,135**	**1,784**	
VDL (Variable Dlg. Loads)	**Upper Hull & Abv.**	**5,596**	**37.40**	**5,596**		**(note 1)**
	Columns	**2,057**	**22.85**	**2,057**		
VDL Total	**(Dk. + Col.)**	**7,653**	**33.49**	**7,653**	**5,696**	**(note 2)**
Pontoon Loads: Drill Water, Potable Water, Water, Fuel Oil, Lube Oil, and Ballast Water		**15,395**	**5.55**	**8,587**	**2,984**	
Displacement (MT)		**47,509**	**20.49**	**40,700**	**32,759**	

Notes:

1) Variable Drilling Load computation is based on a derrick height of 170 ft. Derrick extension beyond 170 ft will impact max. VDL.

2) Mooring equipment weight of 1,784 MT is included in transit VDL + pontoon load; alternatively, field transit may be conducted at column draft.

Classification Society

American Bureau of Shipping

XA1 “Column Stabilized Drilling Unit”, XCDS, (P), DPS-3

Rules and Regulations

· SOLAS, 74 Convention, 78 Protocol with Amendments through 1997

1988 Amendments to the 1974 SOLAS Convention concerning Radio Communications for the Global Maritime Distress and Safety System (GMDSS)

· API /AISC

· OCIMF

· US Coast Guard Requirements

· MARPOL 73 COW, Regulation 13F, etc., (Annexes I, IV, & V) (Oil) IOPP, with the Protocol 1978, and amendments to Annex I and Annex V of 1992.

(refer to section 053 Damage stability)

· IMO Resolutions A.468(XII), “Code on Noise Levels Onboard Ships”, 1981, and USCG NVIC 12-82 as well

· IMO Resolution A.574(XIV), “Recommendations on General Requirements for Electric Navigational Aids”

· IMO MSC/circ. 403, “Draft Guidelines on Navigation Bridge Visibility except field of vision (blind sector).

· IMO MODU Code, 1989 with amendments of 1991 (ABS Statement-of-Fact).

· 1966 Loadline Conference and all amendments and IMO Resolutions A.513 (XIII) and A.514 (XIII)

· International Convention on Tonnage Measurement of Ships, 1969, as amended by IMO Resolution A.493 (XII) and Resolution A.494 (XII).

· 1972 International Prevention of Collision at sea Convention, including amendments of 1981, 1987, and 1989

· 1988 Amendments to the 1974 SOLAS Convention concerning Radio Communications for the Global Maritime Distress and Safety System (GMDSS)

· International Electro Technical Commission (IEC) Publication No. 60092 for electrical installation of ships.

· International Electro Technical Commission (IEC) Publication No. 61892 for Mobile and Fixed Offshore Units - electrical installations,

· U.S.C.G. Regulations for Marine Sanitation Devices (CFR title 33-Part 159)

Registration

The Vessel shall be registered under USA Flag.

The estimated Light Ship weight is 22,325 metric tons, the estimated Light Ship VCG is 26.15m above baseline. The approximate breakdown is as follows:

Item	M. Tonnes	L. Tons
HSW	13,603	13,390
BFE	3,433	3,379
OFE	4,619	4,547
<SUBTOTAL>	<21,655>	<21,316>
OTHERS	220	218
MARGIN	450	443
TOTAL	**22,325**	**21,977**

EXHIBIT B-2

MATERIAL EQUIPMENT LIST

TABLE OF CONTENTS

E14	Choke Manifold
E15	Hydraulic BOP Test Pump
E16	Wellhead Running/Retrieving/Testing Tools

SECTION F - MUD SYSTEM/BULK SYSTEM

Fl	High Pressure Mud System
F2	Low Pressure Mud System
F3	Bulk System

SECTION G - CASING/CEMENTING EQUIPMENT

G1	Casing Equipment
G2	Cement Equipment

SECTION H - INSTRUMENTATION/COMMUNICATION

H1	Drilling Instrumentation at Driller's Position
H2	Drilling Parameter Recorder
H3	Instrumentation at Choke Manifold
H4	Standpipe Pressure Gauge
H5	Deviation Equipment
H6	Calibrated Pressure Gauges
H7	Rig Communication System
H8	Environmental Instrumentation
H9	Additional MODU Specific Instrumentation
H10	Radio Equipment

SECTION I - PRODUCTION TEST EQUIPMENT

11	Burners
12	Burner Booms
13	Lines Required on Burner Booms
14	Sprinkler System
15	Fixed Lines for Well Tesing
16	Power Requirement

SECTION J - WORKOVER TOOLS

SECTION K - ACCOMMODATION

K1	Offices
K2	Living Quarters

SECTION L - SAFETY EQUIPMENT

L1	General Safety Equipment
L2	Gas Detection
L3	Fire Fighting Equipment
L4	Breathing Apparatus
L5	Emergency First Aid Equipment
L6	Helideck Rescue Equipment
L7	Rig Safety Store
L8	Emergency Warning Alarms
L9	Survival Equipment

SECTION M - POLLUTION PREVENTION EQUIPMENT

Ml	Sewage Treatment
M2	Garbage Compaction
M3	Garbage Disposal/Grinder

SECTION N - THIRD PARTY EQUIPMENT (SPACE PROVIDED)

SECTIONS

A. UNIT SPECIFICATIONS

GENERAL

Unit Name	:	RBS8-D
Rig Type	:	SEMISUBMERSIBLE
Unit/design/shape		IHI - RBF Exploration
Unit flag	:	UNITED STATES
Unit classification	:	ABS
IMO Certification (yes/no)	:	YES
Which code version	:	1989 as ammended 1991
Year of construction	:	2,000
Construction yard	:	HYUNDAI
Type of Positioning system (anchor/dp/c	:	DPS-3

A.1 MAIN DIMENSIONS/TECHNICAL

DESCRIPTION

Weight (light ship)	lt:	21,977
Overall width	ft:	255.9
Overall length	ft:	396
Main deck width	ft:	200.1
Main deck length	ft:	275.9
Main deck depth	ft:	27.9
Number of main columns/diameter	No x ft:	4 x 55.8 x 54.1 (WL) 45.9 x 54.1 (Bottom)
Number of small columns/diameter	No x ft	0
Drilling draft/related displacement	ft - lt:	75.5 / 46,767
Transit draft/related displacement	ft - lt:	28.9 / 32,247
Survival draft/related displacement	ft - lt:	54 / 40,064
Moon pool dimensions	ft x ft:	21 X 93
Maximum opening through spider deck	ft - lt:	N/A
Pontoon length	ft - lt:	374
Pontoon breadth (ends / middle)		54.1 / 44.0
Pontoon height	ft - lt:	29.9
Accommodation for maximum no. of persons	:	130

A.2 STORAGE CAPACITIES

Fuel	bbls:	21,811
Drilling water	bbls:	19,874
Potable water	bbl:	4050
Active liquid mud (see F.2)	bbl:	4434 (100%)
Mud processing tank (see F.2)	bbl:	450 (100%)
Reserve liquid mud (see F.2)	bbl:	5710 (100%)
Bulk bentonite/barite (see F.3)	cu ft:	13,675 (100%)
Bulk cement (see F.3)	cu ft:	11000 (100%)
Sack storage	No. or ft2:	10000 sxs
Pipe racks area	ft2:	9,376
Load bearing capacity	lb/ft2:	500
Riser racks area	ft:	10,000
Load bearing capacity	lb/ft2:	300
Miscellaneous storage area	ft2:	See Drawing
Brine storage (Column)	bbls:	3019 (100%)

Brine storage (Pontoon)	bbls:	25,000 (100%)
Base oil mud storage	bbls:	3019 (100%)
Ballast system	bbls:	102,565

A.3 PROPULSION/THRUSTERS

Thrusters\Type (azimuth/in line)	:	AZIMUTH - FULL 360
Quantity	:	8
Location (aft, opposite corners, 4 corners	:	FOUR CORNERS
Driven by electric motor (yes/no)	:	YES - VARIABLE SPEED DRIVE
Make/type	:	Kamewa
Power output (HP ea)	:	6633
Propeller type (fixed/variable pitch)	:	FIXED
Nozzled (yes/no)	:	YES
Thruster power (HP total)	:	53064

DP SYSTEM :

Class III Dynamic Positioning System in accordance with ABS DPS-3 requirements and recommendations. System to consist of a main triple redundant dynamic positioning system and shall accept inputs from the team selected and proven state of the art Acoustic Positioning System, two differential GPS (DGPS) based on correction signal inputs from different sources, (3) three gyrocompass, (3) three vertical reference units with redundant feeds to the DP system, and three wind sensors, as well as operator input and input from the ERA (Electrical Riser Angle) system. The system shall be powered from a redundant UPS. A single dynamic positioning system of similar design as the main DP system, will accept inputs from the APS, the two DGPS's, the ERA system, one gyrocompass, one vertical reference unit, and one wind sensor. The system contains the Power Management System and is interfaced with the Integrated Alarm and Control System. The system shall be powered from a dedicated UPS.

Position reference : HYDRO ACOUSTIC & GLOBAL POSITIONING

Integrated Alarm And Control System:

The IACS will operate as the Sys.Control and Data acquisition sys. for the MODU. The IACS will perform several different functions including: Power Management Sys., Machinery Monitoring and Control, Manual Thruster Control and Autopilot, Dynamic Positioning Control, Ballast / Bunker Monitoring and Control, Bulk Storage Sys. Monitoring and Control.

A.4 OPERATIONAL CAPABILITIES

Maximum designed water depth capability	ft:	10000
Outfitted max. water depth capability	ft:	8000
Normal min. water depth cpability	ft:	250
Drilling depth capability (rated)	ft:	30000
Transit speed towed (historical avg)	knots:	4.5

Transit speed self propelled (historical avg)	knots:	7.5

A.5 VARIABLE LOADING (VL)

Transit VL	mt	See B-1
Drilling VL	mt	See B-1
Survival VL	mt	See B-1

A.6 ENVIRONMENTAL LIMITS

Drilling (including station keeping)		See Exhibit B-1
Air gap	ft:	32.8
Sign. Wave Height	ft:	26
Max. wave height	ft:	48.2
Spec. peak period	sec:	PMS
Max. wind velocity	knots:	60 (1 min.)
Max. current velocity	knots:	See B-1
Max. heave	ft:	N/A
Max. pitch	degrees:	N/A
Max. roll	degrees:	N/A
Survival (excluding station keeping)		
Air gap	ft:	54.2
Sig. Wave height	ft:	41
Max. wave height	ft:	72.2
Spec. peak period	sec:	15
Max. wind velocity	knots:	103 (1 min.)
Max. current velocity	knots:	1.9
Max. heave	ft:	N/A
Max. pitch	degrees:	N/A
Max. roll	degrees:	N/A
Transit (field move)		
Air gap	ft:	79.4
Max. wave height	ft:	30-40
Max. wave period	sec:	8-12
Max. wind velocity	knots:	60-70
Max. current velocity	knots:	2-3
Max. heave	ft:	N/A
Max. pitch	degrees:	N/A
Max. roll	degrees:	N/A

A.7 MOORING SYSTEM		**MOD'S REQ'D FOR THE FUTURE INSTALLATION OF OPERATOR FURNISHED CHAIN WINDLASSES WILL BE PERFORMED DURING THE CONSTRUCTION PHASE AT THE SHIPYARD INCLUDING FOUNDATIONS / PRIMARY PIPING & WIRING.**

A.7.1 ANCHOR WINCHES

Quantity	no.:	N/A
Make		
Type (electric/hydraulic/diesel)	:	
Rated pull	mt	
Speed low gear	ft/m:	

Test load	:	
Control locations (local/remote/both)	:	
Emergency release (type/location)	:	
A.7.2 FAIRLEADS		Foundations to be installed in shipyard
Quantity	no:	
Make	:	
Free rotating range	degrees:	
A.7.3 ANCHORS		Company Supplied
A.7.3.1 ANCHORS - Primary		Company Supplied
A.7.3.2 ANCHORS - Spare		Company Supplied
A.7.4 ANCHOR LINES		Company Supplied to be installed at later date
A.7.5 ANCHOR LINE RUNNING / RETRIE'		N/A
A.7.5.1 PENNANT LINES		N/A
A.7.5.2 ANCHOR BUOYS		N/A
A.7.5.3 CHASER		N/A
A.7.6 TOWING GEAR		
Towing bridle size	inches:	Installation of a tow bridle will be evaluated by the team.
Hook-up system	:	
Rating	lt:	
Power required for infield tow	bollard pull lt:	N/A
Power required for ocean tow	bollard pull lt:	N/A
Spare bridle	yes/no:	yes
A.7.7 SUPPLY VESSEL MOORING LINES	:	
Quantity	no.:	4
System	mt:	TO BE EVALUATED BY TEAM
Rating	lt:	TBA
A.8 MARINE LOADING HOSES		
Location of loading manifolds (port/stbd	:	BOTH
A.8.1 POTABLE WATER HOSE		
Quantity	no.:	2 x 150'
Size	inch:	3
Make/Type	:	TBA
Color coding	yes/no:	YES
Make/Type/Connection		TBA
A.8.2 DRILLING WATER HOSE		
Quantity	no.:	2 x 150'
Size	inch:	4
Make/Type	:	TBA
Color coding	yes/no:	YES
Make/Type connection	:	TBA
A.8.3 GAS OIL HOSE		
Quantity	no.:	2 x 150'
Size	inch:	4

Make/Type	:	TBA
Color coding	yes/no:	yes
Make/Type connection	:	TBA
PRESSURE RATING	p.s.i	150 wp

A.8.4 MUD CHEMICAL HOSE

Quantity	no.:	2 x 150’
Size	inch:	5
Make/Type	:	TBA
Color coding	yes/no:	YES
Make/Type connection	:	TBA

A.8.5 CEMENT HOSE

Quantity	no.:	2 x 150’
Size	inch:	5
Make/ Type	:	TBA
Color coding	yes/no:	YES
Make/Type connection	:	TBA

A.8.6 BASE OIL HOSE

Quantity	no.:	2 x 150’
Size	inch:	4
Make/Type	:	TBA
Color coding	yes/no:	YES
Make/Type connection	:	TBA
Pressure Rating		150 psi wp

A.8.7 BRINE HOSE

Quantity	no.:	2 x 150’
Size	inch:	4
Make/Type	:	TBA
Color coding	yes/no:	YES
Make/Type connection	:	TBA

A. 9 CRANES, HOISTS, AND MATERIALS HANDLING

A. 9.1 CRANES, REVOLVING, MAIN

Quantity	no.:	2
Specification (API, etc.)		ABS /US-DEN
Make	:	LIEBHERR
Type	:	PEDESTAL
Location (stbd, port, aft, frwd)	:	PORT & STBD
Maximum rated capacity (main hook)	mt	100
Maximum rated capacity (whip hook)	mt	15
Boom length	ft:	150
Line length (no Boom	ft:	1893
Main Hoist	ft:	1920
Whip line	ft:	475

Maximum capacity and hoisting speeds

			Radius	Metric
Main Hoist	Platform Lift	4 lines	Meters	Tons
			6.6	92

	10	92		
			11	92
			15	84.7
			20	71.8
			25	62.8
			30	55.6
			35	47.2
			40	39.7
			45	33.8
			48	31.1
				No Load
			Radius Meters	Metric Tons
Main Hoist	Seastate Lift	4 lines	6.6	51.5
			10	46
			11	44.8
			15	40.7
			20	36.8
			25	33.5
			30	30.6
			35	26.4
			40	22.4
			45	19.4
			48	18
				No load
			Radius Meters	Metric Tons
Main Hoist	Platform Lift	2 lines	6.6	50
			10	50
			11	50
			15	50
			20	50
			25	50
			30	50
			35	47.2
			40	39.7
			45	33.8
			48	31.1
				No load
			Radius Meters	Metric Tons
Main Hoist	Seastate Lift	2 lines	6.6	31.9
			10	31.9
			11	31.9
			15	31.9
			20	31.9
			25	31.9
			30	30.6

35	26.4		
		40	22.4
		45	19.4
		48	18
			No Load
		Radius Meters	Metric Tons
Whip Line	Platform Lift	51	15
	Seastate lift	51	10
			No Load

Hook load indicator automatically corrected for boom angle	yes/no:	YES
Alarm (audible, visual, both)	:	BOTH
Automatic brake	yes/no:	YES
Safety latch on hooks	yes/no:	YES
Crown saver (limit switch)	yes/no:	YES
Boom illumination	yes/no:	YES
Baskets for personnel transfer	no.:	2

A. 9.2 CRANES, REVOLVING, SECONDARY

Quantity	no.:	1
Specification (API, etc.)	:	API
Make	:	OUT REACH
Type	:	KNUCKLEBOOM
Location (stbd, port, aft, frwd)	:	FORWARD
Maximum rated capacity (main hook)	lt:	3.57
Maximum rated capacity (whip hook)	lt:	N/A
Boom length	ft:	68
Line length (nominal)	ft:	N/A

A. 9.3 FORKLIFTS

Quantity	no.:	1
Make/Type	:	TBA
Rated capacity	lt:	TBA
Explosion proof	yes/no:	YES

A. 9.4 MONORAIL OVERHEAD CRANES

Quantity	no.:	1
Make	:	MARITIME HYDRAULICS
Type	:	GANTRY TYPE
Rated capacity	mt	36
Location	:	AFT RISER DECK

A. 9.5 BOP HANDLING SYSTEM

Make/Type	HYDRALIFT BRIDGE CRANE
Rated capacity (5 Ram Stack =551,300 lbs (250mt)) 310 T	

BOP CARRIER

Make/Type	Hydralift “C” Cart complete with false rotary deck.
Rated Capacity	310 Tons

A. 9.6 AIR HOISTS/DERRICK WINCHES

A. 9.6.1 RIG FLOOR WINCHES (Non man-riding)

Quantity	no.:	4
Make	:	INGERSAL RAND
Type	:	HYDRAULIC
Rated capacity	st:	5.5
Wire diameter	inch:	0.75
Automatic brakes	yes/no:	YES
Overload protection	yes/no:	NO
Automatic spooling	yes/no:	YES

A. 9.6.2 MONKEY BOARD WORK WINCH

Quantity	no.:	1
Make	:	IR
Type	:	
Rated capacity	st:	0.25
Wire diameter	yes/no:	3/8”
Automatic brakes	yes/no:	YES
Overload protection	yes/no:	NO

A. 9.6.3 RIG FLOOR “MAN-RIDING” WINCH

Quantity	no.:	2
Make	:	Ingersoll Rand
Type	:	Hydraulic
Rated capacity	st:	0.25
Wire diameter/non-twist wire	inch:	3/8”
Automatic brakes	yes/no:	Yes
Overload protection	yes/no:	No
Automatic spooling	yes/no:	Yes
Certified for man-riding	yes/no:	Yes

A. 9.6.4 UTILITY WINCH (i.e. Deck Winch) **N/A**

A. 9.6.5 CELLAR DECK WINCH

Quantity	no.:	4
Make	:	Ingersoll Rand
Type	:	Air
Rated capacity	st:	5.5
Wire diameter	inch:	.75
Automatic brakes	yes/no:	No
Overload protection	yes/no:	No
Automatic spooling	yes/no:	Yes
Man -riding	:	2

A.10 HELICOPTER LANDING DECK

Location		PORT/FWD. MAIN DECK
Dimensions	ft. x ft.:	72.8 X 72.8
Perimeter safety net	yes/no:	YES
Load capacity	lt:	9.15

Designed for helicopter type	:	SIKORSKY S-61
Tie down points	yes/no:	YES
Covered by foam fire system (See L.36)	yes/no:	YES

A.10.1 HELICOPTER REFUELING SYSTEM

Fuel storage capacity	U.S. gals:	1440
Jettisonable	yes/no:	NO
Fuel transport containers	qty:	2
Volume (ea)	:	720
Covered by foam fire system (See L.3.5)	yes/no:	YES

A.11 AUXILIARY EQUIPMENT

A.11.1 WATER DISTILLATION

Quantity	no.:	4
Make/Type		Alfa Laval or equivalent
Capacity (each/total)	cu. ft./day:	26 Metric Ton each (Depending on engine utilization)

A.11.2 BROILERS **N/A**

A.11.3 AIR CONDITIONING

Quantity	no.:	5
Make/Type	:	
Capacity (total system)	tons:	

A.11.4 ELECTRIC WELDING SETS

Quantity	no.:	3
Current capacity	amp:	400
Make/Type	:	Lincoln S-7046 SAE 400

A.11.5 HIGH PRESSURE CLEANER

Quantity	no.:	1
Make/Type	:	Weatherford
Electric/pneumatic	:	Electric
Max delivered pressure	psi:	2700
Ring Main	yes/no	Yes
Outlets	Number	6

B. GENERAL RIG SPECIFICATIONS

B.1 DERRICK AND SUBSTRUCTURE

B.1.1. DERRICK/MAST

Make/Type	:	DRECO
Rated for wind speed:		
With full set back	knots:	100
With no set back	knots:	100
Height	ft:	210 estimated. Final height to be evaluated by Dreco.
Dimensions of base	ft x ft:	48X48
Dimensions of crown	ft x ft:	18x18
Gross nominal capacity	st.:	1250
Maximum Number of lines	no.:	14

Ladders with safety cages and rests	yes/no:	yes
Platform for crown sheave access	yes/no:	yes
Counter balance, system for rig tongs and pipe spinning tong	yes/no:	yes
Lighting system explosion proof	yes/no:	yes

(adjustable fingers on the right hand side can have any one of the casing below racked back at any one time, but not all)		**Unit is capable of field transiting with 238 stands of drillpipe without exceeding rated design loads of derrick.**
Make/Type	:	Varco
Racking platform total capacity with 5-1	ft:	31,000 (nominal)
Fixed Fingers (on left side of derrick) - u	ft:	20000 (nominal)
Adjustable fingers (on right side) - 7" Ca	ft:	11000 (nominal)
or		
Adjustable fingers (on right side) - 9-5/8	ft:	11000 (nominal)
or		
Adjustable fingers (on right side) - 13-3/	ft:	9500 (nominal)
Racking platform capacity of 8" - 9" DC	no.:	8

Auxiliary Derrick (Moonpool)

Make / Type		Dreco
Capacity		300 Tons

B.1.3 AUTOMATIC PIPE RACKER

Make/Type	:	2 - Varco PRS-6 Pipe Rackers Pipe racker on forward side to be capable of handling 20", 16", 13-3/8", 11-3/4", 9-7/8", 7-5/8", and 7" casing

B.1.4 CASING STABBING BOARD

Make/Type	:	Dreco / Hyd.
Adjustable from/to height above R/table	ft/ft:	Adjustable Casing Stabbing Basket - 45' reach

Auxiliary Pipe Handler (Moonpool)

Make / Type		National

B.1.5 SUBSTRUCTURE

Make/Type	:	H.H.I
Height	ft :	14.75'
Width	ft:	80
Length	ft:	71
Setback capacity	st:	1000
Hookload	st	1000
Simultaneous setback-hookload capacity	st:	2000
Tensioner capacity	st	1750
Clear height below R/table beams (from	ft:	29.5

B.1.6 WEATHER PROOFING

Rig floor windbreaks height	ft:	10
Derrickman windbreaks height	ft:	15

B.1.7 DERRICK TV CAMERA SYSTEM

Camera located at	:	Monkey Board/ Crown
Make/Type	:	Color
Zoom/Pan/Tilt-function	yes/no:	yes
Monitor located at	:	Driller’s House

B.2 DRAWWORKS AND ASSOCIATED EQUIPMENT

B.2.1 DRAWWORKS

Make/Type	:	Dreco/Hitec
Drum type	:	Lebus Grooving, 2” drill line
Spinning cathead type	:	Refer D 2.1.7
Breakout cathead type	:	N/A
Crown block safety device	:	YES
Make	:	
Model	:	
Rated input power continuous	hp:	6900
Rated input power maximum	hp:	8400
Drum Diameter	inches:	73.5
Maximum line pull 14 lines	st:	1000
Maximum line pull 12 Lines		
Maximum line pull 10 lines	st:	600
Maximum line pull 8 lines	st:	
Independent fresh water cooling system for drawworks	yes/no:	yes

B.2.2 DRAWWORKS POWER

Number of electric motors	no.:	8
Make	:	General Electric
Model	:	GEB 22A1
Output power continuous	hp:	1150
Output power intermittent (max.)	hp:	1400

B.2.3 AUXILIARY BRAKE

Make	:	Hitec
Model	:	Regenerative AC braking,
Independent back-up system type	:	Failsafe disc brakes

B.2.4 SANDLINE **NA**

B.2.5 AUTOMATIC DRILLER

Make/Type	:	Hitec

AUXILIARY DRAWWORKS (Moonpool)

Make / Type	National / AC
Lift Capacity	300 Tons
Input HP	1,000

B.3 DERRICK HOISTING EQUIPMENT

B.3.1 CROWN BLOCK

Make/Type	:	Dreco
Rated capacity	st:	1000
No. of sheaves	no.:	7
Sheave diameter	inches:	72
Sheave grooved for line size	inches:	2

AUXILIARY CROWN BLOCK (Moonpool)

Make / Type		Dreco
Rated Capacity		300 Tons

B.3.2 TRAVELING BLOCK

Make/Type	:	Dreco
Rated capacity	st:	1000
No. of sheaves	no.:	7
Sheave diameter	inches:	72
Sheave grooved for line size	inch:	2

AUXILIARY TRAVELING BLOCK

Make / Type		Dreco
Rated Capacity		300 Tons

B.3.3 HOOK N/A

Make/Type	:	
Rated capacity	st:	
Complete with spring assembly/hook loc	yes/no:	

B.3.4 SWIVEL

Make/Type	:	None
Rated capacity	st:	
Test/working pressure	psi/psi:	
Gooseneck and washpipe minimum ID >	yes/no:	
Left hand pin connection size	inches:	
Access fitting for wireline entry on top o	yes/no:	

B.3.5 DRILLING LINE

Diameter	inch:	2”
Type	:	6 x 26 EIPS, IWRC
Length (original)	ft:	12500
Support frame for drum/cover	yes/no:	yes
Drilling line drum power driven	yes/no:	yes
Spare reel drilling line	yes/no:	no
Location (rig, shore, etc.)	:	

B.3.6 ANCHOR DEAD LINE

Make/Type	:	Dreco
Weight sensor	yes/no:	yes

B.3.7 DRILL STRING MOTION COMPENSATOR

Make/Type	:	Hitec ASA Active Heave Comp.
Stroke	ft:	14.5

Capacity - compensated	st:	500
Capacity - locked	st:	1000

B.3.8 BLOCK GUIDANCE SYSTEM

Make/Type	:	DRECO

B.3.9 RETRACTION SYSTEM FOR TRAVELING BLOCK

Make/Type	:	Varco/Retrac. Dolly

B.4 ROTATING SYSTEM

B.4.1 ROTARY TABLE

Make/Type	:	Varco
Maximum opening	inches:	60
Rated capacity	st:	1000
Static load capacity	st:	1000
Rotating load capacity	st @ rpm:	TBA
Two speed gearbox	yes/no:	No
Max RPM @t Max Torque	RPM/ Ft lbs	17/48000
Emergency chain drive	yes/no:	no
Driven by an independent electric motor	yes/no:	No
Electric motor type/make	:	Hydraulic x 4
Maximum continuous torque	ft/lbs:	48000
Drip pan/mud collection system	yes/no:	yes

B 4.2 ROTARY TABLE ADAPTER BUSHING

Size	“	60 1/2 x 49 1/2
Quanity	:	1
Size	“	49 1/2 x 37 1/2
Quanty	:	

B.4.3 MASTER BUSHING

Make/Type	:	Varco MPCH
Size	inch:	37-1/2
Inset Bushings	#’s	3,2,1

B.4.4 KELLY BUSHING

B.4.5 TOP DRIVE

Make	:	National or Varco
Type (electric/hydraulic)	:	Electric
Rated capacity	st:	1000 or 750 (if 750 parking system to be supplied)
Test/working pressure	psi/psi:	11250 / 7500
Remote operated kelly cock	yes/no:	YES
If driven by electric motor		
Make/Type	:	GE GEB-20AC
Output power	hp:	1150
Output torque	ft lbs:	Per Manufacturers rating
Max Torque @ Max RPM	Ft lb/s RPM	Per Manufacturers rating
Two speed gearbox	yes/no:	No
Maximum rotary speed	rpm:	270
Cooling system type	:	AIR

B.4.6 TOP DRIVE MAKEOUT/BREAKOUT SYSTEM

Make	:	National or Varco
Model	:	
Type	:	HYDRAULIC
Max. breakout torque that can be applied	ft/lbs:	100000

B.4.7 RAISED BACKUP SYSTEM

Make	:	Varco
Model	:	RBS 4
Torque rating	:	100,000 Ft Lb
Vertical Travel	:	10 Ft
Pipe range	:	4 3/4” to 8 1/4”

C. POWER SUPPLY SYSTEMS

C.1 RIG POWER PLANT

C.1.1 DIESEL ENGINES

Quantity	no.:	6
Make/Type	:	18V32
Maximum continuous power	hp:	7290
At rotation speed of	rpm:	720
Equipped with spark arrestors	yes/no:	YES
Mufflers installed	yes/no:	YES
Total fuel consumption, drilling (average	bbl/day:	Av 375. Estimate only, based on GOM weather and will vary depending on operations

C.1.2 DC - GENERATOR	Type:	N/A

C.1.3 AC-GENERATOR

Quantity	no.:	6
Make/Type	:	TBA
Continuous power	kw:	7000
At rotation speed of	rpm:	720
Output volts	volts:	42,000 kw
Quantity	no.:	
Make/Type	:	
Continuous power	kw:	
At rotation speed of	rpm:	
Output volts	volts:	

C.1.4 VARIABLE FREQUENCY DRIVES

Number of Inverters	no.:	19 INVERTERS
Make/Type	:	TBA
Maximum continuous power (total)	kw:	15130 KW
Output volts	volts:	0-600AC

C.1.5 TRANSFORMER SYSTEM

Quantity	no.:	8 THRUSTER TRANSFORMERS
Make/Type	:	TBA
Continuous power (each)	KVA:	5000 KVA

Output volts	volts:	2300
Frequency	Hz:	60
Quantity	no.:	6 DRILLING TRANSFORMERS
Make/Type	:	TBA
Continuous power (each)	KVA:	2500
Output volts	volts:	600
Frequency	Hz:	60

C.1.6 EMERGENCY SHUTDOWN

Emer. shutdown switches for complete power sys.		CENTRAL CONTROL ROOM
(AC and DC), located at the following points	:	RIG FLOOR
		ENGINE CONTROL ROOM

C.1.7 AUXILIARY POWER SUPPLY

Power supply for a mud logging unit	yes/no:	YES
Power supply available:		
Output volts	volts:	480
Frequency	Hz:	60
Current	amps:	100
Phase	single/three	THREE

C.1.8 COMPRESSED AIR SYSTEMS

Air Compressors - High Pressure:		
Quantity	no:	2
Make	:	Hamworthy
Model	:	w1234
Rated capacity	cu ft/hr:	65 cfm
Working press	psi:	5000
Prime mover (electric/diesel)	hp:	Electrical
Continuous power	hp:	60
Air dryers		
Quantity	no.:	2
Make/Type	:	Hamworthy Regenerative Tower (Dual)
Rated Capacity	cu ft/min:	
Air Compressors - Medium Pressure (rig air):		
Quantity	no:	3
Make	:	Gardner Denver
Model	:	EGQSP Rotary Screw
Rated capacity	cu ft/hr:	750 SCFM
Working press	psi:	125 psi
Prime mover (electric/diesel)	hp:	Electric
Continuous power	hp:	200
Air dryers		
Quantity	no.:	3
Make/Type	:	Dessicant Domnick Hunter / DX110 Heatless
Rated Capacity	cu ft/min:	1080 scfm
Air Compressors - Low Pressure (bulk air):		None - Reducing Stations
Quantity	no:	2
Make	:	Kimray
Model	:	Reducing Valve / Back Pressure Valve ABY / AAU 3”
Rated capacity	cu ft/hr:	10,600 Each
Working press	psi:	60

C.2 EMERGENCY GENERATOR - Emergency Generator not required due to power system design

C.2.1 ENGINE

AUXILIARY POWER PLANT

C.2.1 ENGINE		Data, for Anchored ver.may change for RBS8-D
Quantity	no.:	1
Make/Type	:	CATERPILLAR 3508B
Maximum output	kw:	500
At rotation speed	rpm:	1200
Starting methods (automatic, manual, air	:	AUTOMATIC
Max. angle of operation	degrees:	22.5 PER ABS

C.2.2 AC-GENERATOR

Quantity	no.:	1
Make/Type	:	CATERPILLAR SR4
Maximum output	kw:	500
At rotation speed	rpm:	1200
Output volts	volts:	480
Capable of back-feeding to main bus	yes/no:	YES - TO 480V BUS

C.3 PRIMARY ELECTRIC MOTORS

C.3.1 PROPULSION MOTORS	Type:	See Thruster Motors

C.3.2 THRUSTER MOTORS

Quantity	no.:	8
Type (AC/DC)	:	TBA
Power of each	MW	5.5
Total power	MW	

D. DRILLSTRING EQUIPMENT

D.1 TUBULARS

D.1.1 KELLIES

D.1.2 TOP DRIVE SAVER SUBS

Quantity	no.:	2
Connection type	:	HT 55
API classification	:	8 C
Protector	yes/no:	No
Quantity	no.:	2
Connection type	:	4 1/2 IF
API classification	:	8 C
Protector	yes/no:	No

D.1.3 DRILL PIPE

Drill pipe OD	inch:	5.5
Grade	:	S135
Total length	ft:	22000
Range	:	3
Weight	lbs/ft:	21.9 Nonimal
Tensile yield strength Premium	lbs:	621000
Internally plastic coated	yes/no:	Yes,TK-34
Tool joint OD/ID	inch/inch:	71 /4” x 4” provisional
Make up torque	Ftt/lbs	46300
Tool joint pin length	inch:	10
Tapered shoulder tool joints	degree:	18
Connection type	:	HT 55
Type of hardfacing	:	Armacor M
API classification	:	PREMIUM
Thread protectors	yes/no:	Yes
Drill pipe OD	inch:	5
Grade	:	S-135
Total length	ft:	8000
Range	:	3
Weight	lbs/ft:	19.5 Nominal
Tensile yield strength Premium	lbs	560000
Internally plastic coated	yes/no:	Yes TK-34
Tool joint OD/ID	inch/inch:	6 5/8” x 3 1 1/6”
make up Torque	Ft/lbs	32900
Tool joint pin length	inch:	9”
Tapered shoulder tool joints	degree:	18
Connection type	:	4 1/2 “IF
Type of hardfacing	:	Armacor M
API classification	:	PREMIUM
Thread protectors	yes/no:	Yes
Drill pipe OD	inch:	5.5
Grade	:	S-135
Total length	ft:	8000
Range	:	3
Weight	lbs/ft:	38
Tensile yield s Premium	lbs	1170600
Internally plastic coated	yes/no:	Yes
Tool Joint OD/ID	inch/inch:	7 1/8 x 3 3/4 Provisional
Tool joint pin length	inch:	10
Tapered shoulder tool joints	degree:	18
Connection type	:	HT 55
Type of hardfacing	:	Armacor M
API classification	:	Premium
Thread protectors	yes/no:	Yes

D.1.4 DRILL PIPE PUP JOINTS (Integral)

O.D		5.5”
Grade/Yield	:	4145 H Equiv. To 120K

Tool joint OD/ID	inch/inch:	7 1/4 x 3 3/4 ”
Weight	LB/FT	40
Connection type		HT-55
Stress relief pin groove	:	No
Boreback on box	:	No
Internally plastic coated	yes/no:	No
Thread protectors	yes/no:	Yes,
Length	ft:	10
Quantity	no:	1
Length	ft:	15
Quantity	no:	2
Length	ft:	20
Quantity		1
O.D	:	5”
Grade/ Yield	:	4145 H equiv to 120 K
Tool joint OD/ID	inch/inch:	6 5/8” x 2 3/4 ”
Grade	:	4145 H Equiv. To 120K
Weight	LB/FT	TBA
Connection type		4 1/2” IF
Stress relief pin groove	:	Yes
Boreback on box	:	Yes
Internally plastic coated	yes/no:	No
Thread protectors	yes/no:	Yes
Length	ft:	10
Quantity	no:	1
Length	ft:	15
Quantity	no:	2
Length	ft:	20
Quantity		1
Thread protectors	yes/no:	yes

D.1.5 DRILL PIPE PUP JOINT:	Size:	N/A

D 1.6 HEAVY WEIGHT DRILL PIPE (Integral)

Quantity	no.:	30
Nominal size OD	inch:	5”
Weight	lbs/ft:	49.1 Nonimal
Range	:	2
Tool joint OD	inch:	6 5/8”
Tool joint ID	inch:	3 1/16”
Pin Stress relief groove	yes/no	yes
Box , Bore back	yes/no	yes
Type of hardfacing	:	Pinnchrome (team to review)
Internally plastic coated	yes/no:	No
Connection type	:	4 1/2 IF
Thread protectors	yes/no:	Yes, Bale type
Quantity	no.:	30
Nominal size OD	inch:	5 1/2”
Weight	lbs/ft:	58” Nonimal
Range	:	2

Tool joint OD	inch:	7 1/4”
Tool joint ID	inch:	3 3/4”
Pin Stress relief groove	yes/no	No
Box , Bore back	yes/no	No
Type of hardfacing	:	Pinnchrome (Team to review)
Internally plastic coated	yes/no:	No
Connection type	:	HT 55
Thread protectors	yes/no:	yes, Bale type

D.1.7 DRILL COLLARS

Quantity	no.:	15
OD body	inches:	9.5
ID body	inches:	3”
Nominal Length of each joint	ft:	31.5 Nominal
Drill collar body (slick/spiral)	:	SPIRAL
Recess for “zip” elevator	yes/no:	yes
Recess for slips	yes/no:	yes
Stress relief pin groove	yes/no:	YES
Boreback on box	yes/no:	YES
B.S.R		2.72
Connection type	:	7 5/8”reg
Thread protectors	yes/no:	yes, Bale type
Quantity	no.:	15
OD body	inches:	8 1/4”
ID body	inches:	2 13/16”
Nominal Length of each joint	ft:	31.5 Ft Nomimal
Drill collar body (slick/spiral)	:	SPIRAL
Recess for “zip” elevator	yes/no:	yes
Recess for slips	yes/no:	yes
Stress relief pin groove	yes/no:	YES
Boreback on box	yes/no:	YES
B.S.R.		2.93
Connection type	yes/no:	6 5/8” reg
Thread protectors	yes/no:	yes, Bale type
Quantity	no.:	30
OD body	inches:	6 1/2
ID body	inches:	2 1/2”
Nominal Length of each joint	ft:	31.5 Ft Nominal
Drill collar body (slick/spiral)	:	SPIRAL
Recess for “zip” elevator	yes/no:	YES
Recess for slips	yes/no:	YES
Stress relief pin groove	yes/no:	YES
Boreback on box	yes/no:	YES
B.S.R		2.73
Connection type	yes/no:	4 ” IF
Thread protectors	yes/no:	yes, Bale type

D.1.8 SHORT DRILL COLLARS	Company Supplied
D.1.9 NON-MAGNETIC DRILL COLLARS	Company Supplied
D.1.10 CORE BARRELS	Company Supplied

D.1.11 STABILIZERS		Company Supplied
D.1.12 ROLLER REAMERS		Company Supplied
D.1.13 SHOCK ABSORBERS (Damping Sub)		Company Supplied
D.1.14 DRILLING JARS		Company Supplied

D.1.15 INSIDE BOP VALVE

Quantity	no.:	2
Make	:	SMF (provisional)
OD	inch:	TBA
Connection type	:	HT 55
Working pressure rating	psi:	15000
Quantity	no.:	2
Make	:	SMF (provisional)
OD	inch:	6 5/8”
Connection Type		4 1/2 IF
Working Pressure	psi	15000

D.1.16 FULL OPENING SAFETY VALVE

Quanty		2
Make	:	SMF (provisional)
O.D/ I.D	no.:	TBA (Team to review & advise)
Connection type	:	HT 55
Working Pressure		15000
Quanty		2
Make	:	SMF (provisional)
O.D/ I.D	no.:	6 5/8” / 2 13/16”
Connection type	:	4 1/2 IF
Working Pressure		15000

D.1.17 CIRCULATION HEAD		N/A

D.1.18 TOP DRIVE VALVES

Upper		
Quantity	no.:	2
Make/Type	:	Varco
Working pressure	psi:	15000
Max. OD body	inch:	TBA
Min. ID body	inch:	TBA
Connection type	:	7 5/8 Reg
Lower		
Quantity	no.:	2
Make/Type	:	Varco
Working pressure	psi:	15000
Max. OD body	inch:	TBA
Min. ID body	inch:	TBA
Connection type	:	7 5/8 Reg

D.1.19 CIRCULATION SUBS		Company Supplied
D.1.20 CUP TYPE TESTERS		Company Supplied
D.1.21 PLUG TYPE TESTERS		Company Supplied
D.1.22 DROP-IN VALVES		Company Supplied

D.1.23 NEAR-BIT SUBS (Box-Box)

Quantity	no.:	2
OD size	inch:	9 1/2”
ID size	inch:	3”
Top connection	inch:	7 5/8 Reg
Boreback	Yes/No	Yes
BSR	:	2.25. - 3
Bottom connection	inch:	7 5/8 REG
Boreback	Yes/No	No
Bored for float valve	yes/no:	yes
Float size	inch:	5F-6R
Quantity	no.:	2
OD size	inch:	9 1/2”
ID size	inch:	2 13/16”
Top connection	inch:	7 5/8 REG
Boreback	Yes/No	Yes
BSR	:	2.25 - 3
Bottom connection	inch:	6 5/8 REG
Boreback	Yes/No	No
Bored for float valve	yes/no:	YES
Float size	inch:	5F-6R
Quantity	no.:	2
OD size	inch:	8 1/4”
ID size	inch:	2 13/16”
Top connection	inch:	6 5/8 Reg
Boreback	Yes/No	Yes
BSR	:	2.25 - 3
Bottom connection	inch:	6 5/8 Reg
Boreback	Yes/No	No
Bored for float valve	yes/no:	YES
Float size	inch:	5F-6R
Quantity	no.:	2
OD	inch:	6 1 /2
ID	inch:	2 1/2”
Top connection	inch:	4 1/2 XH
Boreback	Yes/No	Yes
BSR	:	2.25 - 3
Bottom connection	inch:	4 1/2 Reg
Boreback	Yes/No	No
Bored for float valve	yes/no:	YES
Float size	inch:	4 R

D.1.24 CROSSOVER SUBS

Quantity	no.:	2
OD size	inch:	8 1/4” x 9 1/2”
Top connection size	inch:	6 5/8 REG
Type (pin/box)	:	BOX
I.D	:	2 13/16”
B.S.R	:	2.25 - 3
Boreback	Yes/No	Yes
Bottom connection size	inch:	7 5/8 REG
Type (pin/box)	:	PIN

I.D	:	3”
B.S.R	:	2.25 - 3
Relief Groove	Yes/No	Yes
Quantity	no.:	2
OD size	inch:	7 1/4” x 8 1/4”
Top connection size	inch:	HT 55
Type (pin/box)	:	BOX
ID	inch:	3”
B.S.R	:	2.25 - 3
Boreback	Yes/No	No
Bottom connection size	inch:	6 5/8 Reg
Type (pin/box)	:	PIN
I.D	:	3”
B.S.R	:	2.25 - 3
Relief Groove	Yes/No	Yes
Quantity	no.:	2
OD	inch:	7 1/4” x 6 1/2”
Top connection size	inch:	HT 55
Type (pin/box)	:	BOX
ID	inch:	2 1/2”
B.S.R	:	2.25 - 3
Boreback	Yes/No	No
Bottom connection size	inch:	4 1/2 XH (NC 46)
Type (pin/box)	:	PIN
I.D	:	2 1/2”
B.S.R	:	2.25 - 3
Relief Groove	Yes/No	Yes
Quantity	no.:	2
OD size	inch:	6 1/2” x 8 1/2”
Top connection size	inch:	4 IF (NC 46)
Type (pin/box)	:	BOX
ID	inch:	2 1/2”
B.S.R	:	2.25 - 3
Boreback	Yes/No	Yes
Bottom connection	inch:	6 5/8 Reg
Type (pin/box)	:	PIN
ID	inch:	2 1/2”
B.S.R	:	2.25 - 3
Relief Groove	Yes/No	Yes
Quantity	no.:	2
OD size	inch:	7 1/4 x 6 5/8
Top connection size	inch:	HT55
Type (pin/box)	:	Box
ID size	inch:	2 13/16”
B.S.R	:	2.25 - 3
Boreback	Yes/No	No
Bottom connection size	inch:	4 1/2 IF (NC 50)
Type (pin/box)	:	Pin
ID size	inch:	2 13/16”
B.S.R	:	2.25 - 3
Relief Groove:	Yes/No	Yes
Quantity	no.:	2

OD size	inch:	6 5/8 x 6 5/8
Top connection size	inch:	4 1/2 IF (NC 50)
Type (pin/box)	:	Box
ID size	inch:	2 1/2”
B.S.R	:	2.25 - 3
Boreback	Yes/No	Yes
Bottom connection size	inch:	4 IF (NC 46)
Type (pin/box)	:	Pin
ID size	inch:	2 1/2”
B.S.R	:	2.25 - 3
Relief Groove	Yes/No	Yes
Quantity	no.:	2
OD size	inch:	6 5/8 x 8 1/4
Top connection size	inch:	4 1/2 IF
Type (pin/box)	:	Box
ID size	inch:	2 13/16”
B.S.R	:	2.25 - 3
Boreback	Yes/No	YES
Bottom connection size	inch:	6 5/8 Reg
Type (pin/box)	:	Pin
ID size	inch:	2 13/16”
B.S.R	:	2.25 - 3
Relief Groove	Yes/No	Yes

D 1.25 STABBING SUBS - Approximately 9” long

Quantity	no.:	1
OD size	inch:	9.5
ID size	inch:	3
Top connection size	inch:	HT 55
Type (pin/box)	:	Box
Bottom connection size	inch:	7 5/8 Reg
Type (pin/box)	:	PIN
Quantity	no.:	1
OD size	inch:	9.5
Top connection size	inch:	4 1/2 IF
Type (pin/box)	:	Box
ID size	inch:	3
Bottom connection size	inch:	7 5/8 Reg
Type (pin/box)	:	PIN
Quantity	no.:	1
OD size	inch:	8.25
ID size	inch:	2 13 /16
Top connection size	inch:	HT 55
Type (pin/box)	:	BOX
Bottom connection size	inch:	6 5/8 REG
Type (pin/box)	:	PIN
Quantity	no.:	1
OD size	inch:	6.5
ID size	inch:	2.8125
Top connection size	inch:	HT 55
Type (pin/box)	:	BOX
Bottom connection size	inch:	4 IF

Type (pin/box)	:	PIN

D.1.26 PUMP IN / TESTING SUBS

Quantity	Pin/Box	1
Connection		HT 55 Box
Union type		2” 1502 Female
Quantity		1
Connection	Pin/Box	HT 55 Pin
Union Type		2” 1502 Female
Quantity		1
Connection	Pin/Box	4 1/2 IF Box
Union type		2” 1502 Female
Quantity		1
Connection	Pin/Box	4 1/2 IF Pin
Union type		2” 1502 Female
Quantity		1
Connection	Pin/Box	7 5/8 Reg Pin
Union Type		2” 1502 Female

D 1.27. SIDE ENTRY SUBS

Quantity		1
Top Connection	Box/Pin	HT 55 Box
Lower connection		HT 55 Pin
Outlet size and type		2” 1502 Female
Quantity		1
Top Connection	Box/Pin	4 1/2 IF Box
Lower connection		4 1/2 IF Pin
Outlet size and type		2” 1502 Female

D.1.28 DRILLING BUMPER SUBS	Company Supplied
D.1.29 HOLE OPENERS	Company Supplied
D.1.30 UNDERREAMERS	Company Supplied

D.2 HANDLING TOOLS

D.2.1 DRILL PIPE ELEVATORS

Quantity	:	2
Make	:	Varco
Model	st:	BX 475
Drill Collars inserts 150 Ton		6 1/2” , 8 1/4” , 9 1/2”
Casing inserts 350 Ton	“	Company Supplied
Drill pipe Inserts 500 Ton		5 , 5 1/2”
Elevators 750 Ton		5”, 5-1/2”
BOP handling elevators	st:	1000 Refer E 6.10

D.2.2 DRILL COLLAR ELEVATORS

Size	inch:	N/A
Quantity	no.:	
Make	:	
Model	:	
Rated capacity	st:	

Size	inch:	N/A
Quantity	no.:	
Make	:	
Model	:	
Rated capacity	st:	
Size	inch:	N/A
Quantity	no.:	
Make	:	
Model	:	
Rated capacity	st:	
Size	inch:	N/A
Quantity	no.:	
Make	:	
Model	:	
Rated capacity	st:	

D.2.3 TUBING ELEVATORS	Type:	Company Supplied

D.2.4 DRILL PIPE HAND SLIPS

Size	inch	5 1/2 ”
Quantity	no.:	1
Make/Type	:	VARCO / SDXL
Size	inch	5
Quantity	no.:	1
Make/Type	:	VARCO / SDXL

D.2.5 POWER SLIPS

Make/Type			Varco PS 30
Quantity			1
Slip assembly	20” to 18 5/8”		1
Slip Assmebly	16 ” to 6 5/8		1
Slip Assembly	2 3/8 to 10 3/4”		1
Insert carriers Drillpipe		:	5 ”, 5 1/2” ,
Insert Carriers Drill collars			6 1/2, 8 1/4,9 1/2
Insert carriers Casing			Company supplied
Die sets for 13 3/8” 9 5/8 & 7” carriers			Company supplied
	MOUSEHOLE SLIPS		Varco 18” Power Slips.

D.2.6 DRILL COLLAR SLIPS

Size	inch:	9.5
Quantity	no.:	1
Make/Type	:	VARCO / DCS-L
Size	inch:	8.25
Quantity	no.:	1
Make/Type	:	VARCO / DCS-L
Size	inch:	6.1/2
Quantity	no.:	1
Make/Type	:	VARCO / DCS-R

D.2.7 DRILL COLLAR SAFETY CLAMPS

Quantity	no.:	1

Model		MP-L
Range	:	19 3/8” to 4 1/2 “

D.2.8 TUBING SLIPS	:	Company Supplied
D.2.9 TUBING SPIDER	:	Company Supplied
D.2.10 DRILL COLLAR LIFTSUBS	:	As needed
D.2.11 DC LIFTING PLUGS	:	n/a

D.2.12 BIT BREAKER

Quantity	no.:	1
For bit size	inch:	26
Quantity	no.:	1
For bit size	inch:	17.1/2”
Quantity	no.:	1
For bit size	inch:	14 3/4”
Quantity	no.:	1
For bit size	inch:	12. 1/4
Quantity	no.:	1
For bit size	inch:	8.1/2

D.2.13. GAUGE RINGS

Sizes		26, 17 1/2, 14 3/4, 12 1/4, 8 1/2

D.2.14 ELEVATOR LINKS

Quantity of sets	no.:	1
Make/Type	:	VARCO
Size	inch:	3.5
Length	ft:	11
Rated capacity	st:	500
Quantity of sets	no.:	1
Make/Type	:	VARCO
Size	inch:	4 3/4”
Length	ft:	22
Rated capacity	st:	750
Quantity of sets	no.:	1
Make/Type	:	VARCO
Size	inch:	4 3/4”
Length	ft:	22
Rated capacity	st:	1000

D.2.15 DRILL PIPE SPINNER	Type:	Varco SSW-40

D.2.16 MUD SAVER BUCKET

Make	:	Dreco
Size	inch:	9 3/4 to 3 1/2”
Operation	:	Remote from DWS

D.2.17 EZY TORGUE

Make/Type	:	Varco
Maximum linepull	lb:	31000
Quantity		2

D.2.18 ROTARY RIG TONGS

Quantity	no.:	2
Make/Type	:	Varco HT 100
Size range (max OD/min OD)	inch/inch:	17 to 4
Torque rating	ft lbs:	Max 100,000, reduces depending on size
Quantity	no.:	2
Make/Type	:	Varco HT 50
Size range (max OD/min OD)	:	17 1/4 to 20”
Torque rating	Ft/lb:	50000

D.2.19 TUBING TONGS (MANUAL)
D.2.20 TUBING TONGS (POWER)

D.2.21 IRON ROUGHNECK

Make/Type	:	VARCO / AR3200
Size range (max OD/min OD) Drill Coll inch/inch:		4 “ to - 9 1/2”
Size range (max OD/min OD) Drillpipe		3 1/2” to 6 5/8

D.3 FISHING EQUIPMENT

D.3.1 OVERSHOTS

Quantity	no.:	1
Make/Type	:	F.S
Top sub connection type	:	6 5/8 Reg
Overshot OD	inch:	11 3/4”
Max catch size	inch:	9 1/2”
To catch size Spiral grapple	inch:	9.1/2
		9 3/8,8 1/2,8 3/8,8 1/4,8 1/8,7 1/4,7 1/8,7, 6 7/8, 6 5/8,6
To catch size Basket grapple	inch:	1/2, 6 3/8, 5 1/2, 5
Control rings		For above grapples
Extension sub length	ft:	2.5
Lipped guide (oversize, regular)	“:	113/4,15, 21
Quantity	no.:	1
Make/Type	:	TBA S.H Series 150
Top sub connection type	:	4 IF
Overshot OD	inch:	8.3/8
Max catch size	inch:	7 1/4”
To catch size Spiral grapple	inch:	7 1/4, 7 1/8, 7, 6 7/8,
To catch size Basket grapple	inch:	6 5/8, 6 1/2, 6 3/8, 5 1/2, 5
Control rings		For above grapples
Extension sub length	ft:	2.5
Lipped guide (oversize, regular)	:	8 3/8, 11,

D.3.2 HYDRAULIC FISHING JAR	Company Supplied
D.3.3 JAR INTENSIFIER	Company Supplied
D.3.4 SURFACE JAR	Company Supplied

D.3.5 FISHING BUMPERSUBS

Quantity	no.:	1
Make/Type	:	TBA
OD body	inch:	8
Min.ID	inch:	3.5

Stroke	inch:	20
Connection type	:	6 5/8 Reg
Quantity	no.:	1
Make/Type	:	TBA
OD body	inch:	6.25
Min. ID	inch:	2.25
Stroke	inch:	20
Connection type	:	4 IF

D.3.6 SAFETY JOINTS		Company Supplied
D.3.7 JUNK BASKETS (REVERSE CIRC.)		Company Supplied
D.3.8 JUNK SUBS		Company Supplied
Quantity	no.:	1
Make/Type	:	TBA
For hole size	inch:	17.5
Boot OD	inch:	12.875
Connection type	:	7 5/8 Reg
Quantity	no.:	1
Make/Type	:	TBA
For hole size	inch:	12.25
Boot OD	inch:	9.625
Connection type	:	6 5/8 Reg
Quantity	no.:	1
Make/Type	:	TBA
For hole size	inch:	8.5
Boot OD	inch:	6.625
Connection type	:	4 1/2 Reg

D.3.9 FLAT BOTTOM JUNK MILL		Company Supplied

D.3.10 MAGNET FISHING TOOL

Quantity	no.:	1
Make/Type	:	TBA/ Flush guide
OD body	inch:	16
Hole size	inch:	17.5
Connection type	:	6 5/8 reg

D.3.11 TAPER TAPS		Company Supplied
D.3.12 DIE COLLARS		Company Supplied

E. WELL CONTROL/SUBSEA EQUIPMENT

E.1 LOWER RISER DIVERTER ASSY		**N/A**

E.2 PRIMARY BOP STACK (from bottom to top)

Stack complete with:		
· guide frame	yes/no:	YES
· pick up attachment	yes/no:	YES
· transport base	yes/no:	YES
Size (bore)	inch:	18.75
Working pressure	psi:	15000
H2S service	yes/no:	YES

E.2.1 ALTERNATE HYDRAULIC CONNECT N/A

E.2.2 HYDRAULIC WELLHEAD CONNECTOR

Size	inch:	18-3/4”
Make/Type	:	Vetco SD H-4
Working pressure	psi:	15000
Hot tap for underwater intervention ROV	yes/no:	YES
Spare connector same type	yes/no:	NO
Hydrate seal	yes/no:	Yes (1 oring & 1 Lip seal Option as STD.)
Glycol Injection (ROV)	yes/no:	yes (4 x 1” Npt @ 90 deg increments
Pilot Operated check Valve, close function	Yes/No:	Yes

E.2.3 RAM TYPE PREVENTERS

Preventers:		
Quantity	no.:	5
Bore size	inch:	18.3/4”
Working Pressure	psi:	15000
Make	:	CAMERON or equivalent
Model	:	TYPE T1
Type (single/double)	:	Double x2 , Single x 1
Stack Configuration	:	Al, A2, CL, SSCSR BSR,VBR,VBR,LFPR,CH
Ram locks	yes/no:	YES
Preventer connection type - top	:	CX18 (BX-164 Option Available)
Preventer connection type - bottom	:	CX18 (BX-164 Option Available)
Side oultlets	yes/no:	YES
Size	inch:	3.1/16
Connection type	:	No. 6 CAMERON CLAMP AX GROOVE
Super/Shear rams:		Less than or equal to 13-5/8”
Quantity	no.:	1 set
Blind/Shear rams:		
Quantity	no.:	1 set
Variable rams:		
Quantity	no.:	1 set
Size range (max/min)	inch/inch:	Customer to advise
Quantity	no.:	1 set
Size range (max/min)	inch-inch:	Customer to advise
Pipe rams:		
Quantity	no.:	1 set
Size	inch:	Customer to advse

E.2.4 STACK CONFIGURATION
(Blind/Shear/Pipe/Variable)

Upper Shear ra Cavity 5		SSCSR (Less than or equal to 13-5/8”)
Lower shear ra Cavity 4	:	BSR
Middle Upper Cavity 3	:	VBR
Middle Lower Cavity 2	:	VBR
Lower rams Cavity 1	:	LFPR
Position of side outlets - kill		
Upper	:	Below BSR (Cavity #4)
Lower	:	Below LFPR (Cavity #1)

Position of side outlets - choke		
LMRP		Below upper Annular (Al)
Stack		Below Top VBR (Cavity #3)
Stack	:	Below Bottom VBR (Cavity #2)

E.2.5 ANNULAR TYPE PREVENTER ON STACK

Size	inch:	n/a
Working pressure	psi:	n/a
Make/Type	:	n/a

E.2.6 MANDREL

Make/Type	:	Cameron 18-3/4 10 HC
Size	inch:	18.75

E.2.7 FAIL-SAFE HYDRAULIC VALVES
(Kill and Choke)

Quantity on each side outlet	no.:	2
Size (ID)	inch:	42430
Make/Type	:	Cameron MCS
Working pressure	psi:	15000
Solid block	yes/no:	YES

E.2.8 SUBSEA ACCUMULATORS

(See also E.7.1 - Surface Accummulator Unit)

Quantity	no.:	17 (team to evaluate)
Useful capacity per accumulator (w/o prUS gallons	:	13.1
Bottle working pressure	psi:	5000 (team to evaluate)

E.2.9 HYDRAULIC CONTROL POD/RECEPTACLES

Quantity	no.:	2
Redundancy	%:	100
Color Coded	yes/no:	YES
Remote regulation of operating pressure for functions requiring lower operating press	yes/no:	YES
Spare control pod	yes/no:	NO
Deadman system	yes/no:	YES
Pressure & tempreture Sensor’s LMRP	yes/no:	YES

E.3 PRIMARY LOWER MARINE RISER PACKAGE
(From Bottom To Top)
E.3.1 HYDRAULIC CONNECTOR

Make/Type	:	Cameron 18-3/4-10 HC or equivalent
Size	inch:	18.75
Working pressure	psi:	10000
Hot tap for underwater intervention	yes/no:	YES
Spare connector same type	yes/no:	NO

E.3.2 ANNULAR TYPE PREVENTER (LMRP)

Size	inch:	18-3/4”
Qty.	no:	2
Working pressure	psi:	10000
Make/Type (2*70.5=141” Total Heigl	:	CAMERON TYPE DL

E.3.3 FLEX JOINT

Make/Type	:	Oil States 18-3/4”
Size	inch:	21
Max deflection	degrees:	20 (10 from vertical)

E.3.4 RISER ADAPTER

Make/Type	:	Vetco HMF-class H
Size	inch:	21

E.3.5 CONNECTION LINES TO RISER

Type (rigid loops, coflexip, etc.)	Make:	COFLEXIP
	Size:	3-1/16
	WP:	15,000 psi
	Collapse Psi	12,7l0psi

E.3.6 RISER CENTRALIZER Hydralift

E.4 ANNULAR GAS HANDLER

Make / Type		Supplied by Company at later date. Hard piping and control functions to be supplied by Contractor
Rating		1,500 psi
Number Outlets		2
Number Valves		4

E.5 SECONDARY LOWER MARINE RISER P N/A

E.6 PRIMARY MARINE RISER SYSTEM

E.6.1 MARINE RISER JOINTS To be designed for 10,000’ wd

Make/Model	:	Vetco or equivalent (HMF-class H)
OD	inch	To be determined by final riser analysis
ID	inch	To be determined by final riser analysis
Wall thickness	inch:	To be determined by final riser analysis
Average length of each joint	ft:	90
Weight of one complete joint (in air)	Ibs:	62,311 for 5k buoancy, 54,424 for 3k buoancy, 31,620 for 3/4” Slick, 36,900 1” slick
Quantity	no.:	Sufficient for 8,000 ft. water depth
Pipe material	grade:	API 5L Grade X80 Mod.
Minimum yield strength	psi:	80KSI
Type riser connectors	:	HMF- class H
Dogs	no.:	To be determined by final riser analysis

Pup joints:

Quantity	no.:	1
Length	ft:	45.0’
Quantity	no.:	1
Length	ft:	37.5’
Quantity	no.:	1
Length	ft:	30.0’
Quantity	no.:	1
Length	ft:	22.5’

Quantity	no.:	1
Length	ft:	15’

E.6.2 TELESCOPIC JOINT

Make/Type	:	Vetco
Size (ID)	inch:	19.25
Stroke	ft:	65
Double Seals	yes/no:	YES
Working pressure	psi	500
Spare telescoping joint	yes/no:	no
Location	:	N/A
Rotating support ring for riser tensioners	type:	Vetco SDC
Connection points	no.:	6

E.6.3 KILL/CHOKE LINES

Quantity	no.:	2
Outside diameter	inch:	6.5
Inside diameter	inch:	4.5
Working pressure	psi:	15000
LMRP Isolation valves	YES/NO	YES. Fail Close

E.6.4 BOOSTER LINES (If Fitted)

Quantity	no.:	1
Outside diameter	inch:	4.5
Inside diameter	inch:	3.83
Working pressure	psi:	6000
LMRP Isolation valve	YES/NO	YES

E.6.5 HYDRAULIC SUPPLY LINES

Quantity	no.:	1
Outside Diameter	inch:	3.5
Inside Diameter	inch:	2.62
Working pressure	psi:	5000

E.6.6 UPPER BALL (FLEX) JOINT

Make/Type	:	Oilstates Diverter 3
Size	inch:	21-1/4
Maximum deflection	deg.:	30 (15 from vertical)
Spare upper ball (flex) joint	yes/no.:	NO

E.6.7 BUOYANCY MODULES (If Fitted)

Make	:	To be determined by riser analysis
Quantity of buoyed riser joints	no.:	To be determined by riser analysis
OD of buoyed riser joints	inch:	To be determined by riser analysis
Length of each module	ft:	To be determined by riser analysis
Volume of each module	ft3:	To be determined by riser analysis
Buoyancy in seawater	st/ft3:	To be determined by riser analysis
Rated water depth	ft:	To be determined by riser analysis
Make	:	To be determined by riser analysis
Quantity of buoyed riser joints	no.:	To be determined by riser analysis
OD of buoyed riser joints	inch:	To be determined by riser analysis

Length of each module	ft:	To be determined by riser analysis
Volume of each module	ft3:	To be determined by riser analysis
Buoyancy in seawater	st/ft3:	To be determined by riser analysis
Rated water depth	ft:	To be determined by riser analysis

E.6.8 MARINE RISER SPIDER

Make/Type	:	VETCO / HYDRAULIC

E.6.9 Marine Riser Gimbal

Make/Type	:	VETCO

E.6.10 RISER HANDLING TOOLS

Tool, riser lifting	no.:	3
1000 ton Solid Body Elevators	no :	1 set (team to evaluate)
Type	:	HMF- Class h
Torque Wrenches	:	2 - dual speed

E.6.11 RISER TEST TOOLS

Quantity	no.:	2
Type	:	HMF- Class H Hydraulic Test Tool

E.6.12 INSTRUMENTED RISER JT	:	N/A

E.7 SECONDARY MARINE RISER	:	N/A

E.8 DIVERTER BOP
(For installation in fixed bell nipple)

Make/Type	:	Hydril 60
Max Bore Size	inch:	21-1/4
Working pressure	psi:	500
Number of diverter outlets	no.:	2
Outlet OD	inch:	14
Insert packer size ID	inch:	N/A CSO
Element type.	:	Nitrile rubber
Running from diverter to	:	Overboard , port/ starb./ Poorboy MGS

E.8.1 DIVERTER FLOWLINE

Quantity	no.:	1
I.D of flowline	inch:	16” Nominal
Valve types	:	Diverter Sleeve
Size	inch:	16
Working pressure	psi:	500
Control valve type (air/hydraulic/etc.)	:	HYDRAULIC
Remote controlled from	location:	DRILLERS WORKSTATION

E.8.2 DIVERTER CONTROL PANELS

Driller’s panel

Make	:	CAMERON OR EQUIVALENT
Model	:	MULTIPLEX
Location	:	DRILLERS WORKSTATION
Locking/unclocking control	yes/no:	YES

Remote panel		
Make		: CAMERON
Model		: MULTIPLEX
Location		: CONTROL ROOM
Locking/unclocking control	yes/no	: YES

E.9 SUBSEA SUPPORT SYSTEM

E.9.1 RISER TENSIONERS		Ability To Skid Tensioners From Well Centerline
Quantity	no.:	6
Make/Type	:	HYDRALIFT - INLINE
Capacity each tensioner	st:	800 kips
Maximum stroke	ft:	50
Wireline size	inch:	N/A (9" ROD)
Line travel	ft:	N/A (9" ROD)
Independent air compressors	yes/no:	YES
Independent air drying unit	yes/no:	YES
Riser Recoil System	yes/no:	yes

E.9.2 GUIDELINE SYSTEM	N/A
E.9.3 REMOTE GUIDELINE REPL. TOOL	N/A
E.9.4 REMOTE GUIDELINE CUTTING TOOL	N/A
E.9.5 POD LINE TENSIONERS	TURN DOWN SHEAVE'S COMPLETE WITH STORM LOOP WITHIN MOONPOOL INCLUDED WITHIN DESIGN LAYOUT

E.9.6 TENSIONER/COMPENSATOR AIR PRESSURE VESSELS

Quantity	no.:	30
Total capacity	ft3:	2747
Rated working pressure	psi:	3000
Pressure relief valve installed	yes/no:	YES

E.10 BOP CONTROL SYSTEM

Cameron or equivalent Mux system including: 2 each remote control panels, one located in driller's house and one in the control room, both panels incorporate full function and monitoring system for BOP's and diverter system. 1 each pod test stand and Mux system analyzer consisting of test stand and portable computer test set. 2 each Mux cable reels complete with 11,000' of Multiplex cable, one reel blue and one reel yellow for functioning yellow and blue pods plus one spare. 2 each stack mounted pods, complete with subsea electronics

E.10.1 SURFACE ACCUMULATOR UNIT

(See also E.2.8 & E.4.8 - Subsea Accumulators)

Make	:	CAMERON or equivalent
Model/Type	:	MUX
Location	:	ACCUMULATOR ROOM
Soluble oil reservoir capacity	US gallons:	300
Oil/water mix.capacity	US gals/min:	838
Glycol reservoir capacity	US gallons:	1000

No. of bottles installed	no.:	38 team to evaluate bottles required for 10,000’
Useful cap. per accum. (w/o pre-charge)US gallons	:	40
Bottle working pressure	psi:	5000
Control manifold model	:	MULTIPLEX
Regulator type	:	PRESSURE SWITCH / RELIEF VALVES
Total useful accumulator volume (surface and stack)		
Equals all preventer opening and closing	yes/no:	YES
Plus percent additional volume	%:	50

E.10.2 ACCUMULATOR HYDRAULIC PUMPS

Electric Driven		
Quantity	no.:	2
Power source	:	From BUS A
Make	:	US Motors
Model	:	
Each driven by motor of power	hp:	100
Flow rate of each pump	US gals/min:	26
At minimum operating pressure	psi:	5000
Secondary		
Quantity	no.:	1
Power source	:	From BUS B
Make	:	US Motors
Model	:	
Each driven by motor of power	hp:	100
Flow rate of each pump	US gals/min:	26
At minimum operating pressure	psi:	5000

E.10.3 DRILLER’S CONTROL PANEL

Graphic control panel at driller’s position showing subsea functions with controls for the following functions of the BOP stack Location.		Driller Work Station.
Boost Line Control Valve	yes/no:	YES
Marine riser connector	yes/no:	YES
All annular type BOP’s	yes/no:	YES
All ram type BOP’s	yes/no:	YES
Lock for ram type BOPs	yes/no:	YES
Wellhead and LMRP connector	yes/no:	YES
Inner and outer kill and choke line valve:	yes/no:	YES
Low acc. pressure warning	yes/no:	YES
Low reservoir level warning	yes/no:	YES
Low rig air pressure warning	yes/no:	YES
Pressure regulator for annular	yes/no:	YES
Flowmeter	yes/no:	YES
Quantity of pressure gauges	no.:	7+
Emergency push button for automatic riser disconnection	:	YES
Other control functions	yes/no:	YES
Control panel make	:	CAMERON
Control panel model	:	MULTIPLEX

E.10.4 REMOTE CONTROL PANELS

Ability to operate main closing unit valv	yes/no:	NO
Quantity	no.:	2
Make/Model	:	CAMERON / MULTIPLEX
Locations	:	DRILLERS WORK STATION & CONTROL ROOM
Operating System Routing (Direct/via Primary Control Panel)	:	DIRECT DUAL BUS

E.11 SUBSEA CONTROL SYSTEM

E.11.1 HOSE REELS

Quantity	no.:	2 Bop Control (MUX)
Location	:	MOONPOOL
Make/Type	:	CAMERON
Maximum storage length each	ft:	11000
Drive motor type	:	AIR
Quantity	no.:	1 HOTLINE
Location	:	MOONPOOL
Make/Type	:	SYNFLEX (KEVLAR)
Maximum storage length each	ft:	11,000
Drive motor type	:	AIR

E.11.2 POD HOSE

E.11.3 POD HOSE MANIFOLD

Make/Model	:	NONE
Surface test stump	yes/no:	YES

E.11.4 SURFACE TEST POD	yes/no:	N/A
E.12 ACOUSTIC EMER. BOP CONTROL SYS	:	N/A

E.13 SUBSEA AUXILARY EQUIPMENT

E.13.1 HOLE POSITION INDICATOR

Make/Type	:	Simrad
Quantity of monitors	no.:	2 (Blue pod / Yellow pod)
Monitor location	:	Drillers Work station
Monitor location	:	Control Room
Recorder	yes/no:	no

E.13.2 RISER ANGLE INDICATOR

Make/Type	:	To be incorporated into Mux system
Quantity of monitors	no.:	2 (Blue pod / Yellow pod)
Monitor location	:	Drillers Work station
Monitor location	:	Control Room
Recorder	yes/no:	no
Location		Flex joint neck

E.13.3 SLOPE INDICATORS

Make	:	RECAN

Quantity	no.:	3
Provision for installation on		
BOP	yes/no:	YES
Pin Connector	yes/no:	NO
Other	:	LOWER STACK, LMRP & RISER

E.13.5 ROV System — Power and foundations supplied

E.14 CHOKE MANIFOLD — Per Drawing # D-233669

E.14.1 CHOKE MANIFOLD (For Instrumentation, see H.3)

Make	:	CONTROL FLOW
Minimum ID	inch:	3-1/16
Maximum WP	psi:	15000
H2S service	yes/no:	YES
Quantity of fixed chokes	no.:	n/a
Make	:	n/a
Model	:	n/a
Size (ID)	inch:	n/a
Quantity of adjustable chokes	no.:	n/a
Make	:	n/a
Model	:	n/a
Size (ID)	inch:	n/a
Quantity of power chokes	no.:	3 (team to evaluate)
Make	:	CONTROL FLOW
Model	:	15000
Size (ID)	inch:	2 Team to evaluate
Power choke remote control panel	yes/no:	YES
Make	:	Houston Digital
Model	:	CPU 27" MONITOR AND MANUAL HYD. BACK-UP.
Location	:	DRILLERS WORKSTATION / CHOKE MANIFOLD
Glycol injection	yes/no:	NO

E.14.2 FLEXIBLE CHOKE AND KILL LINES (Connecting Riser to Drilling Unit)

Quantity	no.:	2
Make/Type	:	Coflexip
ID	inch:	3 (team to review)
Working pressure/test pressure	psi/psi:	15000 / 22500
Quantity	no.:	n/a
Make/Type	:	n/a
ID	inch:	n/a
Working pressure/test pressure	psi/psi:	n/a

E.15 BOP TESTING EQUIPMENT

E.15.1 HYDRAULIC BOP TEST PUMP

Make	:	SHAFFER
Model/Type	:	ELECTRO HYDRAULIC VARIABLE SPEED 5 GPM
Pressure rating	psi:	22500

Chart recorder	yes/no:	0-5000 0-30000

E.15.2 BOP TEST STUMP

Quantity	no.:	1
Test pressure	psi:	15000
Type	:	VETCO / CAMERON
Size	:	18.75
Connected to deck (welded/bolted)	:	BOLTED

E.16 WELLHEAD RUNNING/RETRIEVING/TESTING TOOLS (RT/RRT/TT)

E.16.1 RT's FOR CASING INSTALLATION	Company Supplied
E.16.2 RRT's FOR CASING INSTALLATION	Company Supplied
E.16.3 MISCELLANEOUS TOOLS	Company Supplied
E.16.4 DP HANG-OFF SUBS	Company Supplied
E.16.5 MINI HOSE BUNDLE FOR HYD. R. TOOLS	Company Supplied

E.16.6 EMERGENCY BOP RECOVER	yes/no:	yes
Make/type	:	CAMERON

F.1 HIGH PRESSURE MUD SYSTEM

System working pressure	psi:	7500
System test pressure	psi:	11250
Built to which design standard	:	ANSI, API

F.1.1 MUD PUMPS

Quantity	no.:	4
Make	:	National
Model	:	14P-220
Type (Triplex/Duplex)	:	Triplex
Liner sizes available	inch:	5" - 9"
Mud pump drive motors	no.:	2
Motor type	:	AC
Continuous power rating per motor	hp:	1150
Fluid end	type:	Two piece
Maximum working pressure	psi:	7500
Test pressure	psi:	11250
Pump stroke counter	type:	Hitec
Supercharging pump	type:	Halco
Driven by motor of power	bp:	100
Discharge/Suction line ID	inch/inch	5" / 10"
M.P. Pulsation Dampener	type:	White Rock
Soft Pump	:	I system
Reset Relief Valve	type:	TBA
Working flowrate per pump at 90% of max spm		
Maximum SPM	:	105 SPM @ 100%

F.1.2 TRANSFER PUMPS/MIXING PUMPS (centrifugal)

Treatment pumps (Desilter/Desander)

Quantity		4
Make		Halco
Model		2500
Drive motor type		Electric
Power output		100 hp
Impeller		14”
Impeller speed		1200 rpm
Packing type		Mechanical seal

Mixing Pumps

Quantity	no.:	2
Make	:	Halco
Model	:	2500
Drive motor type	:	Electric /Belt
Power output	hp:	100
Impeller	:	14”
Impeller speed	RPM:	1200
Packing type	;	Mechanical seal

Shearing Pumps

Quantity	no.:	2
Make	:	Halco
Model	:	T 6550
Drive motor type	:	Electric /Belt
Power output	hp:	100
Impeller	:	Shearing type
Impeller speed	RPM:	1800
Packing type	;	Mechanical seal

Charging Pumps

Quantity	no.:	4
Make	:	Halco
Model	:	2500
Drive motor type	:	Electric /Belt
Power output	hp:	100
Impeller	:	14”
Impeller speed	RPM:	1200
Packing type	;	Mechanical seal

Column Transfer

Quantity	no.:	4
Make	:	Halco
Model	:	2500
Drive motor type	:	Electric /Belt
Power output	hp:	125
Impeller	:	12
Impeller speed	RPM:	1800
Packing type	;	Mechanical seal

F.1.3 BOOSTER PUMP

Quantity	no.:	Rig Mud pump
Make/Type	:	
Pumping capacity (each)	US gals/min:	

Drive motor type	:	
Power output	hp:	

F.1.4 STANDPIPE MANIFOLD

Quantity of standpipes	no.:	2 @ 7500 psi wp
Standpipes ID	inch:	5
H-Type standpipe manifold	yes/no:	yes
Kill line outlet	yes/no:	yes
Fill-up/bleed-off line outlet	yes/no:	yes
Outlets (total)	no.:	4
ID	inch:	5 & 3
Type connections	:	Weco
Dimensions OD x ID	inch x inch:	6 x 5
Design standard	:	ANSI, API

F.1.5 ROTARY HOSES

Quantity	no.:	2 @ 7500 psi wp
Make/Type	:	Beattie
ID x length	inch x ft:	4 x 88
Snubbing lines	yes/no:	yes

F.1.6 CEMENTING HOSE

Type (i.e. Coflexip)	:	Beattie
Length	ft:	85
ID	inch:	3
Working pressure	psi:	15000

F.1.7 CHIKSAN STEEL HOSES

Integral non-screwed	yes/no:	yes
Make/type	:	TBA / 1502
ID Nonimal	inch:	2”
Section length	ft:	
Quantity	no.:	
Section length	ft:	
Quantity	no.:	
Sweep swivels, make/type	:	
Nom. size ID	inch:	
Fittings, non-screwed type	yes/no:	Yes
Suitable for H2S service	yes/no:	

F.2 LOW PRESSURE MID SYSTEM

F.2.1 MUD TANKS

Quantity	no.:	15
Column Tanks		
Quanity	:	4
Capacity 85%		4600
Surface Tanks		

Quanity		10
Capacity 85%		4000
Capacity, tank No. 1	bbls:	460
Type (active/reserve)	:	Active
Capacity, tank No. 2	bbls:	460
Type (active/reserve)	:	Active
Capacity, tank No. 3	bbls:	460
Type (active/reserve)	:	Active
Capacity, tank No. 4	bbls:	650
Type (active/reserve)	:	Active
Capacity, tank No. 5	bbls:	650
Type (active/reserve)	:	Active
Capacity, tank No. 6	bbls:	680
Type (active/reserve)	:	Active
Capacity, tank No. 7	bbls:	160
Type (active/reserve)	:	Chemical
Capacity, tank No. 8	bbls:	160
Type (active/reserve)	:	Chemical
Capacity, tank No. 9	bbls:	160
Type (active/reserve)	:	Chemical
Capacity, tank No. 10	bbls:	160
Type (active/reserve)	:	Chemical
Mixer in each tank	yes/no:	Yes
Mud guns in each tank	yes/no:	Yes

F.2.2 PROCESSING TANKS

Quantity	no.:	6
Total capacity (@ 100%)	bbls:	450
Capacity Sand Trap tank	bbls:	75
Capacity degasser tank	bbls:	75
Capacity desander tank	bbls:	75
Capacity desilter tank	bbls:	75
Capacity desilter tank	bbls:	75
Capacity treated mud tank	bbls:	75

F.2.3 PILL/SLUG TANK

Capacity (@ 100%)	bbls:	150
Mud agitator	yes/no:	yes
Mud guns	yes/no:	yes

F.2.4 TRIP TANK

Capacity (@ 100%)	bbls:	100 2 x 50
Capacity/foot	bbls/ft:	TBA
Level indicator	yes/no:	yes
Electric pump make		Halco x 2
Model/type	:	Cent.
Motor output	hp:	30
Facility for casing fill-up	yes/no:	no
Alarm and strip chart recorder (See H.1.;11)	yes/no:	Yes

F.2.5 STRIPPING TANK

Capacity (@100%)	bbls:	10 Approx
Capacity/foot	bbls/ft:	TBA
Equalizing facility with triptank	yes/no:	Yes
Transfer pump	yes/no:	No
Alarm and strip chart recorder (See H.1.	yes/no:	Yes

F.2.6 CHEMICAL MIXING TANK

		Separate mixing tank above for mixing caustic
Capacity	bbls:	See F.2.1 Tks. 7- 10
Chemical mixer type	:	

F.2.7 SHALE SHAKERS

Primary:		
Quantity	no.:	7
Make/Model	:	Brandt/LCM-2D CS
Type	:	Linear Motion/ Cascading
Driven by no. of electric motors	no.:	3
Design flowrate	bbl/min:	Depending on Mud Characteristics
Cascading:		
Quantity	no.:	See Above
Make/Model	:	
Type	:	
Driven by no. of electric motors	no.:	
Design flowrate	bbl/min:	

F.2.8 DESANDER

Quantity	no.:	Desander cones over one cascading shale shaker
Make/Model	:	Brandt
Type	:	
Number of cones x sizes	no. x inch:	6 X 12” w/ discharge overboard
Type/size centrifugal pump	:	
Driven by electric motor of	hp:	
Is pump dedicated to desander	yes/no:	
Max. flowrate	bbl/min:	

F.2.9 DESILTER

Quantity	no.:	Desilter cones over one cascading shale shaker
Make/Model	:	Brandt
Type	:	
Number of cones x sizes	no. x inch:	40 X 4” W/ discharge over shaker or overboard
Type/size centrifugal pump	:	
Driven by electric motor of	hp:	
Is pump dedicated to desilter	yes/no:	
Max. flowrate	bbl/min:	

F.2.10 MUD CLEANER

Quantity	no.:	N/A
Make/Model	:	
Type	:	
Number of cones x sizes	no. x inch:	

Type/size centrifugal pump	:	
Driven by electric motor of	hp:	
Is pump dedicated to mud cleaner	yes/no:	
Max. flowrate	bbl/min:	

Inlet and outlet for centrifuge to be provided

F.2.11 MUD/GAS SEPARATOR (Poor Boy)		Shall be capable to direct flow from flowline to MGS
Make/Type	:	Swaco
Gas discharge line ID	inch:	12” nominal
Gas discharge location, primary		Top
Can discharge be tied into burner system	yes/no:	no
Mud seal height	:	20
Calculated gas throughput	mmscf:	20
Dimensions		OAL 41.5 ft. X 6 ft.

F.2.12 DEGASSER

Quanty		2
Make/Type	:	Burgess/1500
Capacity	:	1000 GPM x 2
Type/size centrifugal pump	:	N/A
Driven by electric motor of power	hp:	N/A
Discharge line running to	:	6”
Vacuum pump make	:	Internal
Type	:	

F.2.13 MUD AGITATORS

Quantity	no.:	6
Make/Model	:	Philadelphia
Driven by motor of power	hp	15
Located in tanks (See F.2.1 for tank numbers)		8, 9, & 10
Quantity	no.:	3
Make/Model	:	Philadelphia
Driven by motor of power	hp	5
Located in tanks (See F.2.1 for tank numbers)		Shaker Tanks
Quantity	no.:	4
Make/Model	:	Philadelphia
Driven by motor of power	hp	10
Located in tanks (See F.2.1 for tank numbers)		1, 2, 3, & 4
Quantity	no.:	3
Make/Model	:	Philadelphia
Driven by motor of power	hp	40
Located in tanks (See F.2.1 for tank numbers)		5, 6, & 7

F.2.14 MUD CENTRIFUGE

Quantity	no.:	Power and space for 2

F.2.15 MUD HOPPER

Quantity	no.:	2
Make/Model	:	Halco

Feed pump make/model	:	Mixing pumps

F.2.16 SHEARING HOPPERS

Quantity	no.:	2
Make/Model	:	Halco/105-15
Feed pump make/model	:	Mixing pumps

F.2.17 DECK HOPPER

Quantity	no.:	1
Make/Model	:	Halco
Feed pump make/model	:	Mixing pumps

F.3 BULK SYSTEM
F.3.1 BARITE/BENTONITE SILOS

Quantity	no.:	5
Capacity of each silo	C.F.:	2500
Locations	:	Columns
Type weight loadcell	:	Hydraulic
Manufacturer	:	Martin Decker
Pressure rating		65
Relief valve(s) installed	yes/no:	yes

F.3.2 BARITE DAY TANKS

Quantity		2
Capacity of each silo	C.F:	1200
Locations	:	Moonpool
Type weight loadcell	:	Hydraulic
Manufacturer	:	Martin Decker
Pressure rating	psi:	65
Relief valve(s) installed	yes/no:	yes

F.3.3 SURGE TANK FOR BARITE

Quantity	no.:	2
Capacity of each tank	It:	70
Type weight loadcell	:	Hydraulic
Manufacturer	:	Martin Decker
Pressure rating	psi:	65
Relief valve(s) installed	yes/no:	yes

F.3.4 CEMENT SILOS

Quantity		3
Capacity of each silo	C.F:	2800
Locations	:	Columns
Type weight loadcell	:	Hydraulic
Manufacturer	:	Martin Decker
Pressure rating	psi:	65
Relief valve(s) installed	yes/no:	yes
Separate mud/cement loading facilities	yes/no:	yes
Discharge line for cement independent from		

barite/bentonite discharge line	yes/no:	Yes

F.3.5 CEMENT DAY TANKS

Quantity		2
Capacity of each silo	C.F:	1100
Locations	:	Cement Room
Type weight loadcell	:	Hydraulic
Manufacturer	:	Martin Decker
Pressure rating	psi:	65
Relief valve(s) installed	yes/no:	yes

F.3.6 SURGE TANK FOR CEMENT		Third party

F.3.7 BULK TRANSFER SYSTEM (See also C.1.8 - Compressed Air Systems)

Independent air system for the silos and surge tanks consisting of a high-volume low-pressure compressor and air drier	yes/no:	no
Air reduced from main air supply through pressure regulators	yes/no:	yes
Separate volume tank and drier	yes/no:	no

G. CASING/CEMENTING EQUIPMENT		Company Supplied
G.1 CASING EQUIPMENT		Company Supplied
G.1.1 API CASING DRIFT		Company Supplied
G.1.2 CLAMP-ON CSG THREAD PROT'S		Company Supplied

G.1.3 CASING ELEVATOR

Manufacturer		Company Supplied
Type		
Capacity	st:	
Inserts for	inch:	

G.1.3 SIDE DOOR CASING ELEVATOR		Company Supplied
G.1.4 SINGLE JOINT CASING ELEVATOR		Company Supplied
G.1.5 SLIP TYPE ELEVATOR/SPIDERS		
Quantity	no.:	Company Supplied

G.1.6 CASING SLIPS (Hand)

Quantity	no.:	Company Supplied
Make/Type	:	
For OD casing	inch:	
Quantity	no.:	
Make/Type	:	
For OD casing	inch:	
Quantity	no.:	
Make/Type	:	
For OD casing	inch:	

G.1.7 CASING BOWLS

Quantity	no.:	Company Supplied

Make/Type	:	
For OD casing (max/min)	inch/inch:	
Quantity	no.:	
Make/Type	:	
For OD casing (max/min)	inch/inch:	
Quantity	no.:	
Make/Type	:	
For OD casing (max/min)	inch/inch:	

G.1.8 CASING TONGS Company Supplied
G.1.9 POWER CASING TONGS Company Supplied
G.1.10 POWER UNIT FOR CASING AND TUBING TONGS

Quantity	no.:	1 Central Hydraulic unit
Driven by electric motor	yes/no:	YES

G.1.11 CASING CIRCULATING HEAD (Swedge) Company Supplied
G.1.12 CASING SPEARS (Internal) Company Supplied
G.1.13 CASING CUTTERS (Internal) Company Supplied
G.1.14 CROSSOVER CASING TO DRILL PIPE Company Supplied
G.1.15 CASING SCRAPERS Company Supplied

G.2 CEMENTING EQUIPMENT
G.2.1 CEMENT UNIT Company Supplied

G.2.2 CEMENTING MANIFOLD

Discharge manifold working pressure	psi:	15000
Cement pump discharge lines min. ID	inch:	3 Nonimal
Cement pump discharge lines working p	psi:	15000

G.2.3 CEMENT KELLY N/A
G.2.4 CEMENTING TUBING N/A

H. INSTRUMENTATION/COMMUNICATION
H.1 DRILLING INSTRUMENTATION AT DRILLER'S POSITION

H.1.1 WEIGHT INDICATOR

Make/Type	:	HITEC SMART DRILLING INSTRUMENTATION
Sensor type	:	ELECTRONIC DEADEND
Calibrated for number of lines strung (6, 8, 10, 12, etc.)	no.:	USER SELECTABLE

H.1.2 STANDPIPE PRESSURE GAUGES

Quantity	no.:	TBA
Make/Type	:	HITEC SMART DRILLING INSTRUMENTATION
Pressure range (maximum)	psi:	TBA

H.1.3 CHOKE MANIFOLD PRESSURE GAUGE

Quantity	no.:	2
Make/Type		HITEC SMART DRILLING INSTRUMENTATION
Pressure range (maximum)	psi:	0 - 15,000

H.1.4 ROTARY SPEED TACHOMETER

Make/Type	:	HITEC SMART DRILLING INSTRUMENTATION
Capacity range (maximum)	rpm:	0 - 200

H.1.5 ROTARY TORQUE INDICATOR	:	HITEC SMART DRILLING INSTRUMENTATION

H.1.6 MOTION COMPENSATOR INSTRUMENTS

Make/Type	:	HITEC SMART DRILLING INSTRUMENTATION
Hook position indicator	yes/no:	YES
Lock/unlock indicator	yes/no:	YES

H.1.7 PUMP STROKE COUNTERS

Make/Type	:	HITEC SMART DRILLING INSTRUMENTATION
One pump stroke indicator and one cumulative pump stroke counter for each pump.	yes/no:	YES

H.1.8 TONG TORQUE INDICATOR

Make/Type	:	
Capacity range (maximum)	ft lbs:	

H.1.9 PIT VOLUME TOTALIZER

Make/Model	:	HITEC SMART DRILLING INSTRUMENTATION
Floats in active mud tanks	yes/no:	YES
Floats in reserve mud tanks	yes/no:	YES
Loss/Gain indicator	yes/no:	YES
Alarm (audio and visual)	yes/no:	YES

H.1.10 MUD FLOW INDICATOR

Make/Model	:	HITEC SMART DRILLING INSTRUMENTATION
High/low alarm (audio and visual)	yes/no:	YES

H.1.11 TRIP TANK INDICATOR

Make/Model	:	HITEC SMART DRILLING INSTRUMENTATION
Chart recorder	yes/no:	DATA LOGGING
Alarm	yes/no:	YES

H.1.12 GENERAL ALARM SYS.	yes/no:	YES

H.1.13 AUTOMATIC DRILLER

Make/Type	:	HITEC SMART DRILLING INSTRUMENTATION

H.1.14 REMOTE CHOKE CONTROL UNIT (See E.14.1)

Make/Model	:	Houston Digital

H.2 DRILLING PARAMETER RECORDER

Quantity	no.:	USER DEFINED ELECT. DATA ACQUISITION
Location - 1	:	DRILLERS HOUSE
Location - 2	:	
Make/Type	:	HITEC SMART DRILLING INSTRUMENTATION
Quantity of pens	no.:	USER DEFINED ELECT. DATA ACQUISITION
Parameter recorded	:	”
Parameter recorded	:	”
Parameter recorded	:	”

Parameter recorded	:	”
Parameter recorded	:	”
Parameter recorded	:	”
Parameter recorded	:	”
Parameter recorded	:	”

H.3 INSTRUMENTATION AT CHOKE MANIFOLD

H.3.1 STANDPIPE PRESSURE GAUGE

Make/Type	:	Strain gauge
Pressure range (maximum)	psi:	0-10,000

H.3.2 CHOKE MANIFOLD PRESSURE GAUGE

Make/Type	:	Strain gauge
Pressure range	psi:	0-15,000
H.3.1 and H.3.2 combined on one panel	yes/no:	yes
Visible from choke operating position	yes/no:	yes

H.4 STANDPIPE PRESSURE GAUGE		Strain Gauges
Make/Type	:	OTECO
Pressure range	psi:	0-10,000
Visible from driller’s position	yes/no:	No

H.5 DEVIATION EQUIPMENT

H.5.1 MEASURING DEVICE

Quantity	no.:	1
Make/Type	:	Totco
Deviation range	degree:	0 - 8 / 0-12

H.5.2 WIRELINE WINCH

Make/Model	:	Mathey
Wire length (nominal)	ft:	25000
Depth counter	yes/no:	yes
Wire size	inch:	3/16
Pull indicator	Ibs:	yes

H.6 CALIBRATED PRESS. GAUGES	:	Strain Gauges

H.7 RIG COMMUNICATION SYSTEM

H.7.1 TELEPHONE SYSTEM

No. of stations	no.:	120
Make/Type	:	Mitel Exchange
Explosion proof	yes/no:	AS REQ’D.
No. of stations	no.:	
Make/Type	:	
Explosion proof	yes/no:	

H.7.2 PUBLIC ADDRESS SYSTEM

Can be combined with above	yes/no:	YES

Make/Type	:	Akusta
Explosion proof	yes/no:	AS REQ'D.

H.7.3 DRILL FLOOR - DERRICKMAN'S TALKBACK (For Intercom System)

No. of stations	no.:	14
Location	:	DWS - 2 / PHS
Location	:	CCR / ECR
Location	:	FLOOR, ROV, CP AREA, MONKEY BD., MP ROOM, MOONPOOL, SHAKERS, CROWN
Make/Type	:	AKUSTA
Explosion proof	yes/no:	AS REQ'D.

H.7.4 HAND-HELD VHF RADIOS

Quantity		12 MIN.
Make/Type		Earmark VOX 130

H.8 ENVIRONMENTAL INSTRUMENTATION

H.8.1 TEMPERATURE INDICATORS

Air temperature		Yes
Make/Model		Kongsberg
Sea water temperature		TBA
Make/Model	:	TBA
Recorder	yes/no:	Yes

H.8.2 BAROMETRIC PRESSURE	yes/no:	Yes
Make/Model		Kongsberg
Recorder		Yes

H.8.3 HUMIDITY SENSING INDICATOR		Yes
Make/Model		Kongsberg
Recorder		No

H.8.4 WIND SPEED/DIRECTION		Yes - QTY. 2
Make/Model		Kongsberg
Recorder		Yes

H.8.5 WAVE PROFILE RECORDER		No

H.9 ADDITIONAL MODULE SPECIFIC INSTRUMENTATION

H.9.1 ROLL, PITCH AND HEAVE INDICATOR

Make/Type		Kongsberg
Recorder		

H.9.2 GYRO COMPASS

Make/Model		C. Plath / Navagat X
Located at		CCR ELECT. SPACE

H.9.3 ECHO SOUNDER		Yes
Make/Model		Skipper
Located at		Bridge

Recorder		No
H.9.4 CURRENT INDICATOR		Doppler Current Profiler
Make/Model		TBA
Located at		Lower Hull Penetration
Recorder		TBA
H.9.5 WEATHER FACSIMILE RECOI		Yes
Make/Model	:	JRC / JAX - 9A
Located at	:	Radio Room
Recorder	yes/no:	Yes
H.9.6 RADAR	YES	Yes
Quantity	1	1
Make/Model		Norcontrol / Databridge 2000 BL
Located at		Bridge
Bandwidth	cm:	X-Band
Quantity	no.:	1
Make/Model	:	Norcontrol / Databridge 2000 BL
Located at	:	Bridge
Bandwidth	cm:	S-Band
H.10 RADIO EQUIPMENT		
H.10.1 SSB TRANSCEIVER		
Quantity		1
Make/Model		Sailor / RE2100
Power	watts:	600
Frequency ranges	hz:	100 khz - 30 MHz
(Synthesized/crystal)	:	Synthesized
Facsimile capable		No
Telex capable		N/A
H.10.2 E.P.I.R.B's		
Quantity		2
Make/Model	:	COSPAS / SARSAT / TRON 30S MK II
H.10.3 VHF RADIO TELEPHONE		
Quantity		5
Make/Model		Norcontrol - Sailor / RT 2048 W/ DSC
Power	watts:	25 W
Channels		
H.10.4 VHF RADIO TRANSCEIVER		
Quantity	no.:	3
Make/Model	:	Norcontrol - Sailor / RT 2048
Power	watts:	25 W
H.10.5 RADIO BEACON TRANSM		
Quantity		1
Make/Model	:	Southern Avionics / SA 100
Power	watts:	100 W

H.10.6 AEORNAUTICAL VHF TRANS

Quantity		1
Make/Model	:	Jotron
Power	watts:	40 W PEP
Frequency range	hz:	118 - 137
(Synthesized/crystal)	:	

H.10.7 WATCH RECEIVER

Quantity		1
Make/Model	:	Sailor / R501
Frequency	khz:	2182

H.10.8 SCRAMBLER

Quantity	no.:	No
Make/Model	:	

H.10.9 TELEX

Quantity	no.:	N/A
Make/Model	:	

H.10.10 SATELLITE COMM. SYS

Make/Model	:	NERA / C-10-0	/ NERA / H2095 B
Type	:	Type B	/ Type C
Facsimile link		Yes	
Telex link		Yes	
Telephone link		Data Link (9.6 K bits / Message Terminal	
Other capabilities	:		

1. PRODUCTION TEST EQUIPMENT

1.1 BURNERS	N/A
1.2 BURNER BOOMS	Foundations Only
1.3 LINES ON BURNER BOOMS	N/A

1.3.1 OIL LINE

OD	inch:	4”
Working pressure	psi:	1480 psi
Connection type at burner end	:	Suitable to connect to well test equipment
H2S	yes/no:	Yes
Pressure gauge connection at barge end	inch:	Provided by well test company

1.3.2 GAS LINE

OD	inch:	3”
Working pressure	psi:	1480 psi
Extended beyond burner by	ft:	Provided by well test company
Connection type at burner end	type:	Suitable to connect to well test equipment
H2S	yes/no:	Yes
Pressure gauge connection at barge end	inch:	Provided by well test company

1.3.3 WATER LINE

OD	inch:	Seawater - 1-1/2”
Working pressure	psi:	285 psi

Connection type at burner end	type:	Suitable to connect to well test equipment
Pressure gauge connection at barge end	inch:	Provided by well test company

I.3.4 AIR LINE

OD	inch:	4”
Working pressure	psi:	285 psi
Connection type at burner end	type:	Suitable to connect to well test equipment
Pressure gauge connection at barge end	inch:	Provided by well test company

I.3.5 PILOT GASLINE

ID	inch:	Provided by well test company
Working pressure	psi:	
Connection type at burner end	type:	
Pressure gauge connection at rig end	inch:	

I.4 SPRINKLER SYSTEM

Sufficient to give protection to rig and personnel against heat radiation damage from the b	yes/no:	Provided by well test company

1.5 FIXED LINES FOR WELL TESTING

1.5.1 DRILL FLOOR TO SEPARATOR AREA

Type (Screwed/welded, both)	:	Tested and certified flexible flowlines provided by well test co. for connecting from rig floor to well test equip.

1.5.2 SEPARATOR AREA TO BOTH BURNER BOOMS

Type (screwed/welded, both.)	:	Welded
Quantity	no.:	2 ea. / one oil / one gas
Size OD	inch:	3” Gas / 4” Oil
Working pressure	psi:	1480 psi
Connection type at separator	type:	Suitable for connecting to well test company
Connection type at boom	type:	As above
Number of valves/lines	no.:	Provided by well test company
Size of valves	inch:	Provided by well test company
H2S	yes/no:	Yes
Valves installed near separator area for switching gas to either burner.	yes/no:	Yes

I.53 MUD PUMPS TO 2-BURNER **: N/A**

I.5.4 RIG AIR SYSTEM TO BOTH BURNER BOOMS

Type (screwed/welded, both)	:	Welded
Quantity	no.:	1 ea. Port and Starboard
Size OD	inch:	4”
Working pressure	psi:	
Non-return valves fitted	yes/no:	Yes

I.5.5 OIL STORAGE TANK TO OVERBOARD

Type (screwed/welded, both)	:	Provided by well test company
Quantity	no.:	
Size ID	inch:	

Working pressure psi:
Height above water level ft:
Connection type at separator area type:

I.5.6 SEPARATOR TO VENTSTACK OF RIG
Type (screwed/welded, both) : No vent from separator. Relief to flair
Quantity no.:
Size ID inch:
Working pressure psi:
Connection type at separator area type:

I.6 AUXILIARY POWER AVAILABILITY

I.6.1 FOR FIELD LABORATORY
Quantity kw 2 - 480 volt boxes
Volts v:
Frequency hz:

I.6.2 FOR CRUDE TRANSFER PUMP
Quantity kw: Yes, as above
volts v:
Frequency hz:

I.6.3 FOR ELECTRIC HEATERS
Quantity kw: Yes, as above
Volts v:
Frequency hz:

J. WORKOVER TOOLS Company Supplied
K. ACCOMMODATION
K.1 OFFICES

K.1.1 CO. REP.'S OFFICE
Quantity 3
Complete with desk, filing cabinet(s) and other necessary furniture YES
Unrestricted view to drill floor NO(CCTV MONITOR)

K.1.2 CONT. REP.'S OFFICE
Quantity 3
Unrestricted view to drill floor NO(CCTV MONITOR)

K.1.3 RADIO ROOM YES
Quantity 1

K.1.4 HOSPITAL ROOM
Number of beds/bunks 2 Beds
Wash basin YES
Medical cabinet YES
Dangerous drugs locker YES

K.1.5 MUD LABORATORY AND FACILITIES

Separate room	yes/no:	YES
Equippped with:		
Mud balance	yes/no:	YES
Marsh funnel	yes/no:	YES
Filtration kit	yes/no:	YES
Sand content kit	yes/no:	YES
Stopwatch	yes/no:	YES

K.2 LIVING QUARTERS

K.2.1 TOTAL PERSONS ACCOMODATED

Quantity		130

K.2.2 ACCOMODATION FOR COMPANY'S PERSONNEL

Total quantity		60
Quantity of single bed rooms		2
C/W attached toilet		YES
Quantity of two bed rooms		30
C/W attached toilet		YES
Quantity of four bed rooms		0
C/W attached toilet	N/A	

K.2.3 ACCOMODATION FOR CONTRACTOR'S PERSONNEL

Total quantity		70
Quantity of single bed rooms		7
C/W attached toilet		YES
Quantity of two bed rooms		30
C/W attached toilet		YES
Quantity of four bed rooms		O
C/W attached toilet	N/A	

K.2.4 GALLEY

Quantity		1

K.2.5 MESS SEATING CAPACITY

Main mess		60
Aux. mess		N/A

K.2.6 MEETING ROOMS

Quantity		1

K.2.7 RECREATION ROOMS

Quantity		2
Recreation facilities:		YES
TV		YES
VCR		YES
Pool Table		NO
Ping Pong Table		YES
Computer		NO
Other		DARTS/CARDS/READING

.2.8 OTHER ROOMS

Laundry		1 + 2 In change room for dirty clothes
Dry food store		1
Refrigerator		3
Change Rooms		4
Prayer Room		NO
Cinema		NO
Workout/Weight Room		YES

L. SAFETY EQUIPMENT

L.1 GENERAL SAFETY EQUIPMENT

L.1.1 GENERAL PERSONNEL PROTECTIVE GEAR

Safety bats (contractor only/everyone/not supplied	:	CONTACTOR ONLY
Safety boots (contractor only/everyone/not supplied	:	CONTACTOR ONLY
Safety clothing (contractor only/everyone/not supplied	:	CONTACTOR ONLY
Ear protection (contractor only/everyone/not supplied	:	EVERYONE
Rubber gloves (contractor only/everyone/not supplied	:	CONTACTOR ONLY
Rubber aprons (contractor only/everyone/not supplied	:	CONTACTOR ONLY
Fullface visors (contractor only/everyone/not supplied	:	CONTACTOR ONLY
Eye shields (for grinding machines, etc.)		
(Contractor only/everyone/not supplied	:	CONTRACTOR ONLY
Dust masks (contractor only/everyone/not supplied	:	CONTACTOR ONLY
Rubber gloves - elbow length for chemical handling		
(Contractor only/everyone/not supplied	:	CONTACTOR ONLY
Explosion proof handtorches c/w batteries		
(Contractor only/everyone/not supplied	:	CONTACTOR ONLY
Safety belts c/w lines (contractor only/everyone/not supplied	:	CONTRACTOR ONLY

L.1.2 EYE WASH STATIONS

Quantity		no.:	3
Make/model		:	TBA
Located at		pot water	MUD PROCESS ROOM
Located at	piping		DRILL FLOOR
Located at		:	MUD MIXING ROOM

L.1.3 DERRICK SAFETY EQUIPMENT

Derrick escape chute (rem chute)	no.:	N/A
Make/Type	:	
Derrick safety belts	no.:	2 W/ INERTIA REEL
Make/Type	:	TBA

L.1.4 DERRICK CLIMBING ASSISTANT

Make/Type

L.1.5 FRESH AIR BLOWERS (Bug Blowers)

Quantity	:	3
Make/Type	:	
Located at	:	Rig Floor
Located at	:	

L.2 GAS/FIRE/SMOKE DETECTION

L.2.1 H2S MONITORING SYSTEM

Make/Type	:	TBA
Sampling points at:		
Bellnipple	yes/no:	YES
Drillfloor	yes/no:	YES
Shale shaker	yes/no:	YES
Mud tanks	yes/no:	YES
Ventilation system into living quarters	yes/no:	YES
Other	:	YES
General alarm	yes/no:	
Alarm types (audible, visual, both) at:		
Driller's console	:	BOTH
Engine room	:	BOTH
Mud room	:	BOTH
Living quarters each level	:	AUDIBLE
Central area each structural level	:	BOTH
Other	:	BOTH
Central alarm panel	yes/no:	YES
Located at	:	CCR

L.2.2 COMBUSTIBLE GAS MONITORING SYSTEM

Make/Type	:	Simrad Integrated Alarm and Control System
Sampling points at:	yes/no:	
Bellnipple	yes/no:	YES
Drill floor	yes/no:	YES
Shale Shaker	yes/no:	YES
Mud tanks	yes/no:	YES
Ventilation system into living quarters	yes/no:	YES
Other	:	YES
General alarm	yes/no:	
Alarm types (audible, visual, both) at:		
Driller's console	:	BOTH
Other	:	BOTH
		YES

L.2.3 H2S DETECTORS (Portable)

Quantity	no.:	TBA
Make/Type	:	
Phials for H2S: measuring range		
from 1 to 20 ppm	no.:	
from 100 to 600 ppm	no.:	

L.2.4 CO2 GAS DETECTORS (Portable)

Quantity	no.:	TBA
Make/Type	:	
Phials for CO2: measuring range		
from 1 to 20 ppm	no.:	
from 20 to 200 ppm	no.:	
om 250-3000 ppm	no:	

L.2.5 EXPLOSIMETERS

Quantity	no.:	TBA
Make/Type	:	

L.2.6 FIRE/SMOKE DETECTORS IN ACCOMODATION

Make/type	:	THERMAL
Fire detection	yes/no:	YES
Smoke detection	yes/no:	YES
Central alarm panel	yes/no:	YES
Location	:	CCR

L.3 FIRE FIGHTING EQUIPMENT

L.3.1 FIRE PUMPS

Quantity	no.:	2
Make/Model	:	Patterson
Type	:	CENTRIFUGAL
Output	US gals/min:	550
All offtake points supplied by each pump	yes/no:	YES
Location of pumps	:	AUX. MACHINE ROOM PORT
Location of pumps	:	AUX. MACHINE ROOM FWD.
Fire fighting water delivery conforms to	yes/no:	YES
MODU spec version	:	

L 3.2 HYDRANTS AND HOSES

Hydrants positioned such that any point may be reached by a single hose length from two separate hydrants	yes/no:	YES
Quantity of hydrants	no.:	48
Hose connections/hydrant	no.:	46 X 1
Hose max. diam.	inch:	2.5” OD
Length	ft:	50’

L.3.3 PORTABLE FIRE EXTINGUISHERS

Quantity (total)	no.:	70
Type 1- CO2	no./lbs:	2 @ 4
	no./lbs:	37 @ 15
	no./lbs:	2 @ 150
Type 2 - Dry chemical	no./lbs:	17 @ 5
	no./lbs:	9 @ 10
	no./lbs:	3 @ 50
Type 3 - Foam	no./lbs:	0
	no./lbs:	0
	no./lbs:	0
Mounted adjacent to access ways and escape routes	yes/no:	yes

L.3.4 FIRE BLANKETS

Location	:	RIG FLOOR, GALLEY, HELICOPTER BOX
Quantity	no.:	3

L.3.5 FIXED FOAM SYSTEM

Automatically injected into fixed fire water system at central point with remote manual control	yes/no:	YES
Make/Type	:	Patterson
Quantity foam stored on site	GALLONS	700 GPM

Inductor tube	yes/no:	YES
Foam nozzles	no.:	4
Located at	:	HELIPORT -3 TURRET MOUNTED
Located at	:	HELIPORT -1 HOSE REELS
Located at	:	

L.3.6 HELIDECK FOAM SYSTEM

Dedicated system adequate for at least 10 minutes fire fighting at the rate quoted in the IMO MODU code	yes/no:	YES
IMO MODU code version	:	TBA
Make/Type	:	DOOLY
Quantity of monitors	no.:	3
Foam type	:	TBA
Rate	US gals/min:	350 gal. min. each

L.3.7 FIXED FIRE EXTINGUISHING SYSTEM

Protected spaces		
Engine room, type (Halon/CO2)		CO2
Paint locker, type (Halon/CO2)		CO2
Emergency generator, type (Halon/CO2)		CO2
SCR room, type (Halon/CO2)		CO2
Other (specify location & type)		CO2 IN MUD PUMP ROOM
Alarms (audible, visual or both)	:	
Automatic shutting of mechanical ventilation in protected spaces	yes/no:	YES
Remote manual release located at	:	
Remote manual release located at	:	
Remote manual release located at	:	

L.3.8 MANUAL WATER DELUGE SYSTEM	yes/no:	YES
Protected spaces	:	DRILL FLOOR, LIFEBOATS
Protected spaces	:	LIFERAFTS, MOONPOOL
Water supplied from fire main line	yes/no:	YES MAIN SALT WATER RING

L.3.9 WATER SPRINKLER SYSTEM IN ACCOMODATION

Automatic	yes/no:	YES
Working pressure	psi:	130
Pressurized tank capacity	ft3:	53.47

L.4 BREATHING APPARATUS : TBA

L.5 EMERGENCY FIRST AID EQUIPMENT

L.5.1 FIRST AID KITS

Quantity no.: TBA

L.5.2 BURN KITS

Quantity no.: TBA

L.5.3 RESUSCITATORS

Quantity no.: TBA

Charged (spare) oxygen cylinders	no.:	

L.5.4 STRETCHERS

Quantity	no.:	TBA
Type	:	
Located at	:	

L.6 HELIDECK RESCUE EQUIPMENT

L.6.1 STORAGE BOXES

Quantity	no.:	TBA
Construction material	:	FIBERGLASS
Max height open	inch:	TBA

L.6.2 EQUIPMENT

Aircraft axe	yes/no:	YES
Large firemans rescue axe	yes/no:	YES
Crowbar	yes/no:	YES
Heavy duty hacksaw	yes/no:	YES
Spare blades	yes/no:	YES
Grapnel hook	yes/no:	NO
Length of wire rope attached	ft:	
Quick release knife	yes/no:	YES
Bolt croppers	yes/no:	YES

L.7 RIG SAFETY STORE

Equipment to repair, recharge and restock		R&BF will carry all spares necessary to ensure an efficient and safe operation.

L.8 EMERGENCY WARNING ALARMS

Approved system to give warning of different emergencies	yes/no:	YES

L.9 SURVIVAL EQUIPMENT

L.9.1 LIFEBOATS

Make/Type	:	TBA
Quantity	no.:	2
Capacity	person/craft:	65
Locations (fore, apt, port, stbd)	:	2 FORE
Fire protection	yes/no:	YES
Radios	yes/no:	YES
Flares	yes/no:	YES
Food	yes/no:	YES
First aid kits	yes/no:	YES
Maker/Type	:	TBA
Quantity	no.:	2
Capacity	person/craft:	65
Locations (fore, apt, port, stbd)	:	AFT
Fire protection	yes/no:	YES
Radios	yes/no:	YES
Flares	yes/no:	YES

Food	yes/no:	YES
First aid kits	yes/no:	YES

L.9.2 LIFERAFTS

Make/Type	:	TBA
Quantity	no.:	3
Capacity	person/craft:	30
Davit launched	yes/no:	YES & FLOAT FREE
Locations (fore, apt, port, stbd)	:	FORE
Fire protection	yes/no:	
Radios	yes/no:	TBA
Flares	yes/no:	YES
Food	yes/no:	YES
First aid kits	yes/no:	YES
Make/Type	:	TBA
Quantity	no.:	2
Capacity	person/craft:	30
Davit launched	yes/no:	YES
Locations (fore, apt, port, stbd)	:	AFT
Fire protection	yes/no:	
Radios	yes/no:	TBA
Flares	yes/no:	YES
Food	yes/no:	YES
First aid kits	yes/no:	YES

L.9.3 RESCUE BOAT

Make/Type	:	Port Fwd lifeboat is designated as a rescue boat
Engine power	hp:	

L.9.4 LIFE JACKETS

Make/Type		**TBA**
Quantity	no.:	163

L.9.5 LIFE BUOYS

Make/Type	:	TBA
Quantity	no.:	10

L.9.6 WORK VESTS

Make/Type	:	TBA
Quantity	no:	25

L.9.7 ESCAPE LADDERS/NETS

Make/Type	:	PERMANENT LADDERS
Quantity	no.:	4, 1 PER CORNER COL.

L.9.8 DISTRESS SIGNALS

Type	:	TBA
Quantity	no.:	1 SET

M. POLLUTION PREVENTION EQUIPMENT

M.1 SEWAGE TREATMENT

Make/Model	:	HAMMWORTHY (USCG APPROVED)
System type	:	BIOLOGICAL
Conforms to (Marpol annex IV, etc.)	:	YES

M.2 GARBAGE COMPACTION

Make/Model	:	To be provided
System type	:	
Conforms to (Marpol annex IV, etc.)	:	
Make/Model	:	
System type	:	
Conforms to (Marpol annex IV, etc.)	:	

M.3 GARBAGE DISPOSAL/GRINDER

Make/Model	:	To be provided
System type	:	
Conforms to (Marpol annex IV, etc.)	:	

N.1 THIRD PARTY EQUIPMENT

Mud Loggers (available sq feet)	555 sq. ft.
MWD / LWD (available sq feet)	555 sq. ft.
Cement Unit (available sq. feet)	1,087 sq. ft.
ROV (available sq. feet)	1184 sq. ft.
Electric Log (available sq. feet)	895 sq. ft.

EXHIBIT B-3

MATERIAL, SUPPLIES AND SERVICES

Categories: I. Furnished by CONTRACTOR, paid by CONTRACTOR.
II. Furnished by COMPANY, paid by COMPANY.
III. Furnished by CONTRACTOR, paid by COMPANY.

Category I

Furnished by CONTRACTOR, paid by CONTRACTOR

1.1 Fuel storage.
1.2 Lube oils and greases.
1.3 Tool joint lubricant for CONTRACTOR’S drill string.
1.4 Replacement screens on shale shaker for screen sizes 84 mesh and coarser.
1.5 Replacement screens for mud cleaner(s) for screen sizes 150 mesh and coarser.
1.6 Initial set of rig hoses for receiving or discharge of liquid and bulk consumables from workboats.
1.7 Initial installation and utility provision for AC drive cementing unit and cement mixing pumps in shipyard. (rental only - as provided in Rental Agreement).
1.8 Initial installation for ROV unit and installation of ROV cursor system. Provision of utilities for electric motor generator for ROV main power.
1.9 Welding services with welder in CONTRACTOR’S crew (overtime not included).
1.10 Except as otherwise provided in Exhibit “B-2” herein rig and equipment maintenance, running supplies, spares and replacement parts, and services for continuous operation of CONTRACTOR’S equipment.
1.11 Towing bridle and replacement of same from Drilling Unit to towing vessel(s) during all rig moves.
1.12 Supply vessel mooring system at Drilling Unit.
1.13 Labor on the Drilling Unit to load and unload all CONTRACTOR’S and COMPANY’S equipment, materials and supplies between supply vessels and Drilling Unit.
1.14 CONTRACTOR’S Shore Base.
1.15 Medical doctor on notice in the Operating Area for emergency treatment of CONTRACTOR’S personnel injured aboard the Drilling Unit.
1.16 Meals, bunk and accommodations, including medical services, on board Drilling Unit for all CONTRACTOR’S personnel and an average of ten (10) COMPANY and COMPANY third party personnel per day.
1.17 Personnel for Drilling Unit and shore base as set out in Exhibit “F”.
1.18 Disposal of all liquids and other waste generated by CONTRACTOR including drum disposal.

1.19 Complement of personal protective equipment required to handle completion brines and synthetic base mud for those crew members with potential exposure.
1.20 Blowout preventers, choke and kill lines, ring gaskets, controls, handling, testing tools and spare parts as required set out in Exhibit "B-2".
1.21 Wellhead connector and spare parts as required in Exhibit "B-2" to adapt CONTRACTOR'S BOP stack to COMPANY'S wellhead.
1.22 All other well control equipment components and replacement parts, including failsafe valves, riser, choke and kill lines and choke manifold. All replacement parts shall be Original Manufacturer's Equipment.
1.23 Initial set of ram packer elements, annular elements, top seals, related equipment as required in Exhibit "B-2" CONTRACTOR'S BOP EQUIPMENT. All elements, packers, seals and related rubber goods shall be Original Manufacturer's Equipment and oil mud compatible.
1.24 Manifolding and piping as required to flare burners for oil, gas, water and air.
1.25 CONTRACTOR shall conduct a drillpipe inspection on all drillpipe, drill collars, subs, rotary and handling tools prior to spudding the first well under this CONTRACT. A specified inspection including all optional inspections as specified by API-RP7G, such as; Transverse Defect inspection using induction coils and a magnetic particle inspection of tube ends, couplings, and verification of defects found by gamma ray wall thickness inspection. Drillpipe must satisfy criteria as new or premium drillpipe to be used on COMPANY'S wells.
1.26 CONTRACTOR shall conduct an inspection on all drillpipe after every 100,000' drilled or 1500 rotating hours (whichever is less). Inspection type will satisfy criteria spelled out in API-IADC specified inspection for used drillpipe. Inspection will include all operational inspections in same API criteria along with magnetic particle for tube ends and couplings. Drillpipe must satisfy criteria as new or premium drillpipe to be used on COMPANY'S wells.
1.27 CONTRACTOR shall conduct an inspection on topdrive valves and subs, all drill collars, subs and related bottom hole assembly components every 250 rotating hours. All bottom hole assembly components shall meet a bending strength ratio of 2.25 to 3.00.
1.28 Living Quarters to accommodate 130 personnel minimum. Must have separate facilities for up to 10 women.
1.29 Three COMPANY designated offices. One for COMPANY'S drilling supervisors, one for COMPANY'S third partys and one for COMPANY'S geologists. All offices complete with intercom system, television, VCR's, surge suppression for up to 4 computers, 2 desks and file cabinets.
1.30 All equipment shall comply with MMS regulations.
1.31 Spare parts inventory for surface and subsurface BOP equipment as per CONTRACTOR BOP EQUIPMENT LIST, Exhibit B-2. Spare parts inventory list to be provided to and agreed by COMPANY.
1.32 Supply labor required to test, service, and maintain, all surface, and subsurface BOP and well control equipment and tools including COMPANY'S wellhead running tools.
1.33 Mud pump liners and pistons for two (2) sizes as specified by COMPANY.
1.34 Fishing tools to include overshots, grapples, and crossover subs required to catch all contractor supplied drill string and bottom hole assembly components

listed in Exhibit “B-2”.

1.35 Diver services and equipment as required by CONTRACTOR.
1.36 Mud bucket for each size of CONTRACTOR supplied drill pipe.
1.37 Outside pipe wipers for each size of CONTRACTOR supplied drill pipe.
1.38 Pressure washer for rig floor and maintaining same.
1.39 Mud vacuum system for rig floor clean up and maintenance.
1.40 Space and utilities for the following COMPANY’S third party equipment: electric wireline logging unit, MWD/LWD logging unit, mud logging unit and two (2) centrifuges.
1.41 Space or accommodation for COMPANY’S warehouse.

Category II
Furnished by COMPANY, paid by COMPANY

2.1 Thread compound for COMPANY’S connectors and casing.
2.2 Potable and fresh water for drilling, cementing and wash down of CONTRACTOR’S equipment and for personnel use but with respect to the latter only in excess of the capacity of the distillation unit.
2.3 Diesel fuel.
2.4 Drill sites, location surveys, marker buoys.
2.5 All permits and licenses required for the drilling site and to permit access thereto and egress therefrom.
2.6 Weather forecast service.
2.7 Stabilizers, including sleeves and spare parts and maintenance.
2.8 Core heads, core catchers and coring service charges.
2.9 Drilling bits, bit breakers (not supplied per Exhibit B-2), underreamers, hole openers, shock subs, wall scrapers, and other down hole tools, plus maintenance and repairs.
2.10 Water based mud, chemicals and additives.
2.11 Synthetic oil base mud, oil emulsion and other special drilling and completion fluids for completing wells.
2.12 Mud engineering services, and other mud supervision.
2.13 Mud centrifuge.
2.14 Pumping and blowing of bulk materials from work boats to Drilling Unit and between workboats and dock storage facilities.
2.15 All completion and production equipment, including hangers, packers, liners, floats, centralizers, scratchers, casing shoes, float collars, wellheads, spacer spools, Christmas trees including ring gaskets, valves, well connections and all necessary tools and equipment for installation.
2.16 Wellhead running retrieving, handling and testing tools.
2.17 Cementing unit and cement mixing pumps.
2.18 Cement and cement services, including special rental charge.
2.19 Electric logging unit, services and related tools.
2.20 Gun perforating and related services.
2.21 Mud logging unit and related services.

2.22 Whipstocks, directional drilling tools and services.
2.23 All surface and down hole survey equipment and services, except for drift indicators and slick line unit as described in Exhibit "B-2".
2.24 Drill stem, formation testing tools and services.
2.25 Test tanks and accessories for production testing.
2.26 Well test burner equipment, burners, separators, flow meters, any other well testing equipment, including installation costs and well testing services.
2.27 All permanent or special installations and services, including services for controlling blowouts and fires.
2.28 Diver, ROV services and equipment as required by COMPANY.
2.29 Additional welding services required by COMPANY.
2.30 Spare parts and operating supplies for COMPANY'S tools and equipment.
2.31 All transportation required for CONTRACTOR'S and COMPANY'S equipment, supplies, drilling and potable water and personnel between shore and Drilling Unit.
2.32 Transportation from base of operations to Drilling Unit by sea, air and/or helicopter.
2.33 Anchor handling vessels and crews to deploy and recover mooring system at COMPANY'S drilling location.
2.34 Dock and dockside facilities, including cranes and trucks, labor equipment for loading and unloading CONTRACTOR'S and COMPANY'S equipment, materials and supplies at COMPANY'S shore base, port charges, pilot fees, canal fees, wharfage, agent fees and related costs for movement of equipment and material at COMPANY'S shore base and dock facilities.
2.35 Any radio equipment required by COMPANY in excess of those described in Exhibit "B-2", and maintenance of such radio equipment.
2.36 All radio permits and licenses for COMPANY'S radios.
2.37 Disposal of all liquid and other waste generated by COMPANY including drum disposal.
2.38 Disposal of cuttings, mud materials from the well, if required.
2.39 Wellhead, wellhead gasket, wear bushing and bore protectors. All other gaskets and bore protectors for CONTRACTOR'S account.
2.40 Casing and or tubing tools and crews not listed in Exhibit "B-2".
2.41 All casing, tubing and accessories.
2.42 Casing cutting tools.
2.43 Drill pipe, drill collars and accessories other than that furnished by CONTRACTOR listed in Exhibit "B-2".

Category III

Furnished by CONTRACTOR, paid by COMPANY

3.1	Special safety equipment required other than as described in Exhibit “D”.
3.2	Replacement screens on shale shakers for screen sizes finer than 84 mesh.
3.3	Replacement screens on mud cleaners for screen sizes finer than 150 mesh.
3.4	Welding consumables for welding COMPANY furnished equipment.
3.5	Additional off tour labor authorized by COMPANY for mixing cement, moving mud materials, COMPANY’S tubulars, etc.
3.6	Overtime beyond normal work schedule and extra CONTRACTOR personnel requested by COMPANY.
3.7	Replacement of CONTRACTOR supplied supply vessel mooring system ropes.
3.8	Replacement set of ram packer elements, top seals and annular elements. All elements, packers, seals and related rubber goods shall be Original Equipment Manufacturer equipment and oil mud compatible.
3.9	Replacement of CONTRACTOR supplied hoses for receiving and discharge of liquid and bulk consumables from workboats.
3.10	Meals and accommodations on board the Drilling Unit for COMPANY and COMPANY’S third party personnel in excess of an average of ten (10) per day calculated over a period of one (1) calendar month will be billed at CONTRACTOR’S actual cost.

EXHIBIT C

INSURANCE REQUIREMENTS

1. The insurance required to be carried by CONTRACTOR under this Contract is as follows:

a. Workers' Compensation as may be required by the laws of the jurisdictions which the work is performed, including occupational disease. If the performance of the CONTRACT requires the use of watercraft or is performed over water, CONTRACTOR shall provide coverage for liability under the U.S. Longshoreman's and Harbor Workers Compensation Act, the Outer Continental Shelf Lands Act, and liability for admiralty benefits and damages under the Jones Act, Death on the High Seas Act, and general maritime laws on all employees except members of crews of vessels if crew liabilities are covered under Protection and Indemnity Insurance, and shall further provide that a claim "in rem", or against the Drilling Unit, shall be treated as a claim against the employer.

b. Employer's Liability Insurance with limits not less than $10,000,000 per occurrence covering injury or death to any employee.

c. Comprehensive General Liability Insurance, including contractual liability insuring the indemnity agreement as set forth in the Contract and products-completed operations coverage with a combined single limit of not less than $10,000,000 covering bodily injury, sickness, death and property damage. This insurance shall provide that a claim "in rem" or against the Drilling Unit be treated as a claim against the insured.

d. Comprehensive Automobile Liability Insurance including contractual liability, insuring owned, non-owned, hired, and all vehicles used by CONTRACTOR with a combined single limit of not less than $10,000,000 applicable to bodily injury, sickness, or death and loss of or damage to property in any one occurrence.

e. Watercraft Insurance: If the performance of this CONTRACT requires the use of watercraft to be provided by CONTRACTOR, CONTRACTOR shall carry or require the owners of the watercraft to carry: (1) Hull and Machinery (including Collision Liability) insurance, subject to the American Institute Hull Clauses or equivalent, in an amount not less than the stated value of the watercraft (any language in this policy which limits the coverage of an insured who is not an owner or who is not entitled to limitation of liability shall not apply to the extent the owner has assumed liability for the loss); (2) Protection and Indemnity Insurance, in an amount not less than the stated value of the watercraft or $5,000,000, whichever is greater (any language in this policy which limits the coverage o f an insured who is not an owner or who is not entitled to limitation of liability shall not apply to the extent the owner has assumed liability for the loss); and (3) in respect to all chartered vessels, Marine Operator's Charterer's Legal Liability insurance with limits of not less that $5,000,000.

f. Aircraft Insurance: If the performance of this Contract requires the use of aircraft provided by CONTRACTOR, CONTRACTOR shall carry, or require the owners of the aircraft to carry: (1) All Risks Hull insurance in an amount equal to the replacement value of the aircraft, and (2) Bodily Injury Liability, including Passenger Liability of not less than $2,000,000 per passenger seat in any one occurrence and $25,000,000 property damage in any one occurrence.

g. All Risks Hull and Machinery/Physical Damage Insurance, includingCollision Liability, blowout and cratering coverage, in an amount equal to full value of the CONTRACTOR’S Drilling Unit and other equipment employed, including CONTRACTOR’S associated equipment and non-floating items normally situated in the ocean, such as blowout preventers, riser systems, anchors, anchor chains, and/or cable, pendant wires and pendant buoys. This coverage shall include at least $5,000,000 for costs or expenses of the removal of the wreck or debris of the Drilling Unit.

h. Protection and Indemnity Insurance on the Drilling Unit owned and/or operated by the CONTRACTOR in an amount of not less than the full value of the Drilling Unit or Five Million Dollars ($5,000,000), whichever is greater. This coverage may exclude liability to CONTRACTOR’S employees and members of the crew of the insured drilling unit provided the insurance set forth in Sections “a and b” hereof is warranted to remain in full force and effect during the term of this Contract. (Any language in this policy which limits the coverage of an insured who is not an owner or who is not entitled to limitations of liability shall not apply to the extent the owner has assumed liability for the loss.)

i. Pollution Liability Insurance on the vessel, in accordance with the terms of entry provided by the CONTRACTOR’S P&I Club (as required by the Oil Pollution Act of 1990 OPA 90).

2. All the insurance shall be carried by CONTRACTOR at CONTRACTOR’S expense with an insurance company or companies authorized to do business in the jurisdictions where the work is to be performed and satisfactory to Vastar. CONTRACTOR shall furnish certificates of insurance to Vastar evidencing the insurance required hereunder and, upon request, Vastar may examine true copies of the actual policies. Each certificate shall provide that the insurance is in full force and effect and that it shall not be canceled or materially changed without thirty (30) days (seven (7) days with respect to war risks, prior written notice to Vastar. All certificates must contain reference to endorsements (i.e., Additional Insured, Waiver of Subrogation, etc.) as required herein.

3. Vastar, its subsidiaries and affiliated companies, co-owners, and joint venturers, if any, and their employees, officers, and agents shall be named as additional insureds in each of CONTRACTOR’S policies, except Workers’ Compensation for liabilities assumed by CONTRACTOR under the terms of this Contract.

4. All CONTRACTOR'S insurance policies shall be endorsed to provide that underwriters and insurance companies of CONTRACTOR shall not have any right of subrogation against Vastar, its subsidiaries, co-owners and joint venturers, if any, and their agents, employees, officers, invitees, servants, contractors, subcontractors, insurers, and underwriters.

5. Any coverage provided to Vastar by the CONTRACTOR'S insurance under this CONTRACT is primary insurance and shall not be considered contributory insurance with any insurance policies of Vastar, its subsidiaries, co-owners and joint venturers, if any..

6. All policies shall be endorsed to provide that there will be no recourse against Vastar for payment of premium.

7. CONTRACTOR shall require all its subcontractors to carry adequate insurance coverage during the term they are engaged in performing any work hereunder. Subcontractors shall furnish Vastar acceptable evidence of insurance upon its request.

8. Except where specifically provided for in this Contract any and all deductibles in the required insurance policies shall be assumed by, for the account of, and at CONTRACTOR'S sole risk.

9. In the event the premium for war, expropriation, nationalization and non re-exportation risks insurance for the CONTRACTOR'S Drilling Unit increases as a result of the importation of the Drilling Unit into a specific Area of Operations, CONTRACTOR shall notify Vastar of the increase in premium prior to payment by CONTRACTOR, and Vastar, at its sole option shall, within 48 hours of being given such notice either agree to reimburse CONTRACTOR for the documented increase in premium or allow the Drilling Unit to depart the Area of Operations for safe harbor once the well in progress is made safe.

EXHIBIT D

SAFETY, HEALTH, AND ENVIRONMENT MANAGEMENT SYSTEM

CONTRACTOR agrees in addition to CONTRACTOR'S Safety, Health and Environment program and COMPANY'S Safety, Health and Environment Manual ("SHE Manual"). to develop a **"RIG SITE SAFETY MANAGEMENT SYSTEM"**. The system shall contain provisions for self-monitoring and accountability.

The Rig Site Safety Management System shall, at a minimum, address the following items:

1. Safety and job planning meetings.

2. Training drills to verify viability of all response plans and to develop personnel.

3. A "Work Permit System" to include the following:

a. Hotwork outside safe welding areas,

b. Confined Space Entry,

c. Working on High Pressure Lines,

d. Pumping of Hazardous Materials,

e. Maintenance of Life Boats,

f. Bypassing or repairs to "Critical Safety Systems,"

g. Handling of radioactive sources and explosives,

h. Any work involving Dynamic Positioning system equipment,

i. Work on or near remote start equipment, and

j. Crane offload or backload lifts from workboat greater than 15 tons.

CONTRACTOR shall ensure that:

1. All chemicals received and shipped from the Drilling Unit are properly labeled, container undamaged, and a MSDS sheet accompanies product shipment. CONTRACTOR shall be responsible for the proper disposition of CONTRACTOR'S generated waste such as, but not limited to; lube oils, motor oils, antifreeze, batteries, tires, rubber products, junk iron, drill line, etc.

2. An inventory of all hazardous materials and chemicals is maintained on the Drilling Unit.

3. All radioactive sources and explosives shall be stored in appropriate and approved magazines.

4. All source containers are to be locked and stored in a safe area away from normal operations, living quarters and passage ways.

5. All personal protective equipment is identified and required to be used with each work activity.

6. CONTRACTOR will provide a Readiness Checklist for the following critical operations including, but not limited to, such as; Drill floor pre-tour, DP pre-tour, hydrocarbon transfer, lifesaving equipment, monthly Drilling Unit inspection, radioactive and explosives usage.

7. CONTRACTOR shall have in place a Safety Observation Program.

8. CONTRACTOR shall perform; pre-tour safety and weekly safety meetings, fire, abandon, man overboard and helicopter crash drills. Scenario drill records are to filed on location and be available for review by COMPANY’S personnel and regulatory bodies.

9. CONTRACTOR shall provide a designated firefighting team and equipment complete with back-up firefighting team.

10. CONTRACTOR and COMPANY will work together to incorporate an individual safety incentive program to be combined with safety and rig personnel performance and mutually agreed upon at a later date.

11. CONTRACTOR shall have an active Alcohol and Drug Screening Program. CONTRACTOR agrees to conduct periodic searches and testing for such substances. CONTRACTOR’S personnel who are considered to be safety sensitive personnel under the Department of Transportation regulations shall be subject to and in compliance with the U.S. Coast Guard regulations with respect to drug and alcohol testing as set forth in 46 CFR Parts 4 and 16, and 49 CFR Part 40.

12. CONTRACTOR shall ensure that all its employees receive Hazardous Materials training and how to use OSHA Form 20, known as Materials Safety Data Sheets, which permits employee reporting on toxic substances.

13. CONTRACTOR shall maintain current records of training and certification of personnel for the following: Hazcom, Well Control, Ballast Control, Crane Operations, Hotwork Firewatch Training, Welding, and Electrical. CONTRACTOR is required to maintain a Training Matrix Schedule for each position.

14. CONTRACTOR shall insure that Drilling Unit housekeeping, cleanliness and personal hygiene meets requirements of COMPANY’S SHE manual.

15. CONTRACTOR shall have on location at all times at least two (2) personnel trained in oil spill containment and hazardous materials handling and clean up.

16. CONTRACTOR shall immediately report to COMPANY’S representative, regardless of quantity, all environmentally sensitive spills such as, but not limited to, hydrocarbons or toxic materials.

17. CONTRACTOR to have an updated Spill Contingency Plan on site at all times.

18. CONTRACTOR shall immediately report to COMPANY'S representative and maintain records of the following: all incidents including but not limited to near misses, first aids, recordable accidents, lost time injuries, illnesses, spills, pollution, incidents involving hazardous and explosive materials, property and equipment damage.

19. CONTRACTOR shall maintain a daily Personnel on Board list to include personnel name, company and position.

20. During hurricane season, CONTRACTOR shall keep an updated Hurricane Evacuation Procedure complete with operational times to: secure the well, recover the riser/BOP's, secure the rig and offload all non essential or all personnel if required.

CONTRACTOR SAFETY REPORTING:

CONTRACTOR shall provide to the COMPANY'S Safety, Health and Environmental Representative a completed accident investigation report within twenty-four hours of each occurrence designated in Exhibit D-18 above. CONTRACTOR shall submit additional information each month concerning safety performance of CONTRACTOR'S employees in connection with the work performed hereunder. The following is a breakdown of the information that shall be submitted on or before the tenth day of each month for the previous month's safety performance.

1. Total man hours worked (month / YTD)

2. Total lost time accidents (month / YTD)

3. Total lost time days (month / YTD)

4. Total recordable accidents (month / YTD)

5. Total first aid cases (month / YTD)

6. Total cost equipment / property damage (month / YTD)

7. Any safety or health inspections, warnings, notices or asserted violations issued by any governmental agencies

This information should be mailed or telecopied to:

SHE Representative

Vastar Resources, Inc.

15375 Memorial Drive

Houston, Texas 77079

Telephone: 281/584-6100

FAX: 281/584-6810

SAFETY MANUAL RECEIPT ACKNOWLEDGMENT

Attached to the Drilling Contract between Vastar Resources, Inc.. and R&B Falcon Drilling Co. dated as of December 9, 1998.

Ron Tafery a duly authorized representative of Contractor and on behalf of Contractor hereby acknowledges receipt of the “Safety and Health Manual” of Vastar Resources, Inc. Contractor agrees that they have or agree to become familiar with said Safety and Health Manual and shall, to the extent not inconsistent with Contractor’s manual, policy and procedures, comply and cause Contractor’s employees, agents and others under Contractor’s control entering upon Vastar Resources’ premises in the performance of work or services or in connection therewith to comply with the applicable standards contained in the Safety and Health Manual of Vastar Resources, Inc. Vastar is not required by Contractor to police Contractor’s compliance with any safety, health, and environmental rules, laws, regulations or orders and Contractor’s agreement to comply therewith shall not impose any obligation on the part of Vastar under such rules, laws regulations or orders.

Contractor: R&B Falcon Drilling Co.

Name:	Ron Tafery
Title:	Vice President
Signature:	/s/ Ron Tafery
Date:	December 9, 1998

EXHIBIT E

TERMINATION PAYMENT SCHEDULE

Termination Pursuant to Article 27

Should COMPANY terminate the CONTRACT pursuant to Article 27.1, COMPANY shall pay CONTRACTOR a Lump Sum Payment as liquidated damages and not as a penalty, within ninety (90) days of termination calculated as follows:

Lump Sum equals Operating Rate less eighty (80)% of the documented operating costs times the number of days remaining under the Contract Term discounted to present value using the annual prime rate of interest as posted by CitiBank N.A. on the first day of the month in which Company terminates the Contract.

During the remaining Contract Period, CONTRACTOR shall make a good faith effort to market the Drilling Unit. Should CONTRACTOR be successful, CONTRACTOR shall refund to COMPANY any funds actually received or accrued from any other entity for the use of the Drilling Unit as follows:

(1) The repayment will be reduced by the eighty percent (80%) of the fixed cost not already paid by COMPANY.

(2) The repayment will be reduced by an amount equal to five percent (5%) as an incentive for CONTRATOR to actively market the Drilling Unit.

(3) Repayments by CONTRACTOR to COMPANY shall never exceed Contract Rate.

EXHIBIT F-1

CREW COMPLEMENT

Drill Crew	Total	On Board	Remarks
Drilling Rig Supt	2	1	
Toolpusher	4	2	
Driller	4	2	
Asst. Driller	8	4	
Pumpman	4	2	
Floorman	12	6	
Maintenance Supervisor (Electrical)	2	1	
Electrician	4	2	
Assistant Electrician	2	1	
Electronic Technician	4	2	
Mechanic	4	2	
Assistant Mechanic	2	1	
Welder	2	1	
Sub Sea Engineer	2	1	
Assistant Sub Sea	2	1	
Crane Operator	4	2	
Roustabout	16	8	
RTSC	2	1	
Medic	2	1	
Materialsman	4	2	
Captain/OIM	2	1	
Chief Officer	2	1	
D.P. Operator	4	2	
Assist. D.P. Operator	4	2	
A.B. Seaman/Painters	6	3	
Chief Engineer	2	1	
First Engineer	2	1	
2nd Engineer	4	2	
Oiler/Motorman	4	2	
Boatswain	2	1	
Galley	As Needed		
Total:	118	59	

a) Galley crew ratio of one to every 10 persons on board.
b) A mutually agreed pre-commencement manning schedule shall be attached.
c) Contractor may, with Company approval, reduce the marine crew manning based upon Coast Guard requirements, when available.

EXHIBIT F-2

COST OF ADDITIONAL PERSONNEL

Title	Total	On Drilling Rig	Regular Hourly Rate ($)	Overtime Rate with Burden	Daily Rate Per Man (w/ Burden)
Drilling Rig Supt	2	1	34.83	75.76	831.81
Toolpusher	4	2	30.48	66.29	736.47
Driller	4	2	25.69	55.88	637.43
Asst. Driller	8	4	17.85	38.83	465.29
Pumpman	4	2	13.50	29.36	369.78
Floorman	12	6	13.00	28.28	358.80
Maintenance Supervisor (Electrical)	2	1	26.12	56.81	641.12
Electrician	4	2	21.77	47.36	551.36
Assistant Electrician	2	1	16.50	35.89	435.65
Electronic Technician	4	2	22.86	49.72	575.30
Mechanic	4	2	21.77	47.36	551.36
Assistant Mechanic	2	1	16.50	35.89	435.65
Welder	2	1	15.75	34.26	419.18
Sub Sea Engineer	2	1	25.44	55.33	631.95
Assistant Sub Sea	2	1	21.77	47.36	551.36
Crane Operator	4	2	16.55	36.00	436.75
Roustabout	16	8	11.00	23.93	314.88
RTSC	2	1	17.85	38.83	465.29
Medic	2	1	15.67	34.09	417.42
Materialsman	4	2	15.02	32.67	398.00
Captain/OIM	2	1	35.70	77.65	850.88
Chief Officer	2	1	26.12	56.81	641.12
D.P. Operator	4	2	29.17	63.45	707.86
Assist. D.P. Operator	4	2	22.64	49.24	570.47
A.B. Seaman/Painters	6	3	11.00	23.93	314.88
Chief Engineer	2	1	28.30	61.55	688.79
First Engineer	2	1	22.64	49.24	570.47
2nd Engineer	4	2	19.59	42.62	503.50
Oiler/Motorman	4	2	14.00	30.45	380.76
Boatswain	2	1	17.42	37.89	455.85
Galley	As Needed				
Total:	118	59			

RBS8-D REPORTING ORGANIZATION CHART

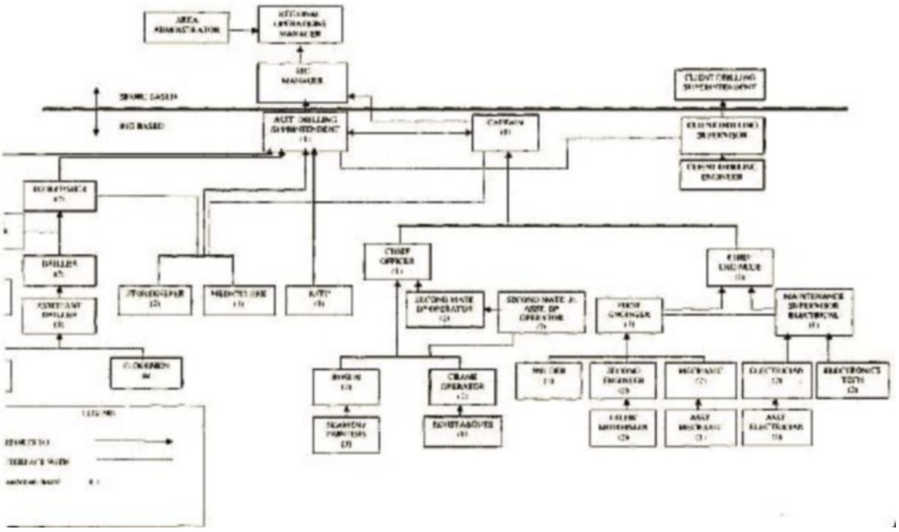

EXHIBIT G

VESSEL / EQUIPMENT PERFORMANCE / ACCEPTANCE

VESSEL TESTS / ACCEPTANCE

CONTRACTOR and COMPANY agree that the Drilling Unit must satisfy various sea worthy type certifications, including but not limited to, U.S. Coast Guard, ABS, and certifications pertinent to the flag the vessel will be registered under. CONTRACTOR shall supply COMPANY with a copy of these certificates witnessed or approved by any regulatory body.

CONTRACTOR shall provide OPERATOR with a preliminary copy of the Drilling Unit’s Operations Manual as soon as it is available, prior to the Commencement Date and a final signed, dated and approved by ABS, as soon as received.

Additional vessel and equipment function/acceptance test criteria shall be developed and mutually agreed by CONTRACTOR and COMPANY and provided by the CONTRACTOR as a condition of delivery of the vessel. These shall include, but not be limited to: vessel, equipment acceptance, seatrials, full scale recoil test, dynamic position system (DP) / power systems failure mode effect analysis (FMEA) and fault tree analysis and a blowout preventer (BOP) multiplex control system (Mux) System FMEA and fault tree analysis. In principle, Shipyard Sea Trials shall be conducted as specified in the Shipyard Specifications, Chapter 18, Test and Trials. Additional test may be required upon arrival in the Gulf of Mexico, as mutually agreed. The project managers of the Parties agree to provide the following:

·	Vessel / equipment acceptance / seatrials procedures:	one (1) month prior to delivery
·	DP/power systems FMEA and fault tree analysis:	two (2) month after final design
·	BOP mux control system FMEA and fault tree analysis:	two (2) month after final design

EXHIBIT H

PROJECT EXECUTION PLAN

Construction and operation of the Drilling Unit (RBS8D) represents a major financial commitment to the Parties. Additionally, the Drilling Unit will be an integral part of COMPANY’S long range business plan for oil and gas exploration in the deepwater’s of the Gulf of Mexico. Any change in cost, delivery or operability relating to the Drilling Unit could have a substantial impact on COMPANY’S plan, therefore, COMPANY must be notified immediately of any changes that would effect these items.

To help mitigate the risk, a mutually agreed Project Execution Plan will be developed to insure the Drilling Unit is delivered on time, within budget, is outfitted and will operate in accordance with this CONTRACT. To ensure that the latest technology is incorporated and maximum performance achieved, representatives from third party suppliers shall also be included. As a minimum, The Project Execution Plan will address the following items in appropriate detail:

- Project Goals/Operating Principles
- Project Organization
- Roles/Responsibilities/Accountabilities
- Project Description/Schedule/Milestones
- Overall Assurance Plan
- Safety
- Interface Coordination Plan (Communication)
- Quality Plan
- Document Control
- Approval Process
- Change Control Procedures
- Management of Change
- Meeting/Presentation Schedule
- Risk Management Register
- Cost Control

Without limiting CONTRACTOR’S obligations under this CONTRACT, COMPANY will provide representatives to monitor the design and construction of the Drilling Unit. Any changes to the Drilling Unit that would effect the Dayrate, delivery or operability will require an amendment to the CONTRACT as set forth in Article 35.2. All changes to the design or specifications set forth in this CONTRACT require the Company Project Manager approval.

The project manager of the Parties agree to have a mutually agreed Project Execution Plan finalized by February 1, 1999.

April 13, 1999

Vastar Resources, Inc.

15375 Memorial Drive

Houston, TX 77079

Attention: Mr. Don Weisinger

Re: Drilling Contract dated December 08, 1998 between Vastar Resources, Inc. and R&B Falcon Drilling Co. for the Drilling Unit "RBS-8D" - Effective Date Establishment of Base Figures in accordance with Article 2.3.2 of the Contract

Gentlemen:

Pursuant to Article 2.3.2, we wish to advise that our base figures for the 4 items are as follows:

a. Labor (all inclusive)	U.S.$21,420 \ Day
b. Catering	U.S.$2,364 \ Day
c. Spare Parts & Supplies	PPI Code No. 1191.02 Base = 133.8 (Preliminary - December, 1998) -
d. Insurance	U.S.$2,660 \ Day

As the United States Department of Labor has not yet published the final December, 1998 index for Code No. 1191.02 "Oil Field and Gas Field Drilling Machinery", the above base index of 133.8 is still officially classified as preliminary and may be subject to change. The final index will be published in early May 1999. We shall write to you again at this time either to confirm 133.8 as the final figure or to advise the new figure. In any event, we felt it best not to further delay the submission to you of the other base figures due to the 4 month time lag in the publication of Government economic statistics.

Whilst writing, we wish to bring to your attention the following errors in Exhibit F-2 "Cost of Additional Personnel":

Title	Hrly Rate Shown		Correct Hrly Rate
Drilling Rig Supt	$ 34.83	Should be	$ 35.70
Captain/OIM	$ 35.70	Should be	$ 34.83
Chief Officer	$ 26.12	Should be	$ 27.43
D. P. Operator	$ 29.17	Should be	$ 23.08
Assist D. P. Operator	$ 22.64	Should be	$ 20.90

We shall go ahead and formally change Exhibit F-2 to show the correct rates and revised corresponding extension figures upon receipt of your agreement to the above.

Sincerely yours,
R&B Falcon Drilling Co.

/s/ W.L. Ellis
W.L. Ellis
Regional Operations Manager

Contract Budget Request
RBS8-D Vastar Resources, Inc. / Gull of Mexico
Expatriate Rig Payroll

Exchange Rate: US $1.00 =1 U.S. $ [03PAY]

Rig-based	Budgeted On Board Expats	Budgeted Total Expats	Annual Work Days	Regular Monthly Base	Regular Monthly Travel Pay	Total Per Employee Regular Monthly Total	Regular Annual Total	Payroll/ Calendar Day	Payroll Per Work Day
Asst. Superintendent*	1.00	2.00	182.50	8,000		8,000	96,000	263	526
Toolpusher	2.00	4.00	182.50	7,000		7,000	84,000	230	460
Tourpusher						0	0		
Barge Engineer*				6,000		6,000	72,000		
Asst. Barge Engineer*				4,800		4,800	57,600		
Maintenance Supervisor*	1.00	2.00	182.50	6,000		6,000	72,000	197	395
Driller	2.00	4.00	182.50	5,900		5,900	70,800	194	388
Alternate Driller	4.00	8.00	182.50	5,000		5,000	60,000	164	329
Alternate Driller Trainee						0	0		
Derrickman				3,330		3,330	39,960		
Pumpman	2.00	4.00	182.50	3,101	250	3,351	40,212	110	220
Motorman				3,215		3,215	38,580		
Welder	1.00	2.00	182.50	3,617		3,617	43,404	119	238
Crane Operator	2.00	4.00	182.50	3,800		3,800	45,600	125	250
Heavy Lift Crane Operator**						0	0		
Barge Captain						0	0		
Asst. Barge Captain						0	0		
Control Room Operator*				4,500		4,500	54,000		
Asst. Control Room Operator*				3,600		3,600	43,200		
Mechanic	2.00	4.00	182.50	5,000		5,000	60,000	164	329
Asst. Mechanic	1.00	2.00	182.50	3,790		3,790	45,480	125	249
Mechanic Helper						0	0		
Electronic Technician*	2.00	4.00	182.50	5,250		5,250	63,000	173	345
Electrician	2.00	4.00	182.50	5,000		5,000	60,000	164	329
Asst. Electrician	1.00	2.00	182.50	3,790		3,790	45,480	125	249
Electrician Helper						0	0		
Subsea Engineer*	1.00	2.00	182.50	7,000		7,000	84,000	230	460
Asst. Subsea Engineer*	1.00	2.00	182.50	5,000		5,000	60,000	164	329
Materialsman						0	0		
Storekeeper	2.00	4.00	182.50	3,450		3,450	41,400	113	227
Medic	1.00	2.00	182.50	3,450		3,450	41,400	113	227
Radio Operator				3,101		3,101	37,212		
Floorman	6.00	12.00	182.50	2,986	250	3,236	38,832	106	213
Lead Roustabout						0	0		
Roustabout	8.00	16.00	182.50	2,526	250	2,776	33,312	91	183
Paint Foreman						0	0		
Painter				2,124		2,124	25,488		
Captain/Master***	1.00	2.00	182.50	8,000		8,000	96,000	263	526
Chief Officer***	1.00	2.00	182.50	6,300		6,300	75,600	207	414
First Officer***				5,300		5,300	63,600		
Second Officer***				4,800		4,800	57,600		
Third Officer***				4,200		4,200	50,400		
Chief Engineer***	1.00	2.00	182.50	6,500		6,500	78,000	214	427
First Engineer***	1.00	2.00	182.50	6,000		6,000	72,000	197	395
Second Engineer***	2.00	4.00	182.50	5,200		5,200	62,400	171	342
Bosun***	1.00	2.00	182.50	4,000		4,000	48,000	132	263
Deck Supervisor***				4,000		4,000	48,000		
D.P. Operator***	2.00	4.00	182.50	5,300		5,300	63,000	174	348
Asst. D.P. Operator***	2.00	4.00	182.50	4,800		4,800	57,600	158	316
Oiler***	2.00	4.00	182.50	3,215	250	3,465	41,580	114	228
Able Seaman***	3.00	6.00	182.50	2,526	250	2,776	33,312	91	183
Rig Safety & Training Coordinator	1.00	2.00	182.50	4,100		4,100	49,200	135	270
Other						0	0		
Total	59.00	118.00	Overtime Wages Total				0		
			OIM Premium ($4,800 if applicable)				4,800		
			Total Annual Expatriate Payroll				6,257,544		
			Total Per Day Expatriate Payroll				17,144	(Posts to Rig Payroll)	
			Total Payroll Burden Per Day			20%	3,429	(Posts to Payroll Burden)	

* Semisubmersibles Only
** Super Tenders Only

Contract Budget Request
RBS8-D / Vastar Resources, Inc. / Gulf of Mexico
Expatriate Training Costs

Exchange Rate: US $1.00 =1 U.S. $ [09XPTTRN]

Employee Name	Employee Position	Name of School	School Location	# of Days	Training Wages Per Day	Outside Tuition	International Airfare	Domestic/ Charter	Hotel Per Day	Meals Per Day	Other
T.B.A.	Various	Well Control		10	75	2,500	300		100	35	20
T.B.A.	Various	Cyberchair		10	75	2,500	300		100	35	20
T.B.A.	Various	Varco		10	75	2,500	300		100	35	20
T.B.A.	Various	PM		10	75	2,500	300		100	35	20
T.B.A.	Various	GE		10	75	2,500	300		100	35	20
T.B.A.	Various	Burgess		10	75	2,500	300		100	35	20
T.B.A.	Various	Brandt		10	75	2,500	300		100	35	20
T.B.A.	Various	Fire Fighting		10	75	2,500	300		100	35	20
T.B.A.	Various	Sea Survival		10	75	2,500	300		100	35	20
T.B.A.	Various	Wartslia		10	75	2,500	300		100	35	20
T.B.A.	Various	Kamewa		10	75	2,500	300		100	35	20
T.B.A.	Various	Simrad		10	75	2,500	300		100	35	20
T.B.A.	Various	High Voltage		10	75	2,500	300		100	35	20
T.B.A.	Various	Alborg		10	75	2,500	300		100	35	20
T.B.A.	Various	Bridge Mgn		10	75	2,500	300		100	35	20
T.B.A.	Various	Radar		10	75	2,500	300		100	35	20
T.B.A.	Various	GMDSS		10	75	2,500	300		100	35	20
T.B.A.	Various	HLO		10	75	2,500	300		100	35	20
T.B.A.	Various	Crane Ops		10	75	2,500	300		100	35	20
T.B.A.	Various	AWC		10	75	2,500	300		100	35	20
T.B.A.	Various	STOP / H2S		10	75	2,500	300		100	35	20
T.B.A.	Various	EPT		10	75	2,500	300		100	35	20
T.B.A.	Various	DGPS		10	75	2,500	300		100	35	20
				230	1,725	57,500	6,900	0	2,300	805	460

Total Training Wages	17,250	
Total Outside Tuition	57,500	
Total Training Travel	38,410	
Total Training Costs	113,160	
Per Day Training Costs	310	(Posts to Training Costs)

Contract Budget Request
RBS8-D / Vastar Resources, Inc. / Gulf of Mexico
Expatriate Operational Travel

Exchange Rate: US $1.00 =1 U.S. $ [15EXTRAV]

Crew Change Commuter Travel

Airport of Origin	Total Personnel	Annual Roundtrips Per Emp.	Cost Per Trip: International Airfare	Cost Per Trip: Domestic/ Charter	Cost Per Trip: Hotel	Cost Per Trip: Meals	Cost Per Trip: Other	Total Annual costs	Commuter Schedule	Round Trips Per Year
East Coast	12	8.69		300	75	35	20	44,840	7x7	26.07
West Coast	12	8.69		300	75	35	20	44,840	14x14	13.04
North Central	12	8.69		200	75	35	20	34,412	21x21	8.69
Texas	12	8.69		100	75	35	20	23,984	28x28	6.52
Louisana	12	8.69		100	75	35	20	23,984	35x35	5.21
Mississippi	12	8.69		100	75	35	20	23,984	42x42	4.35
Other	4							0	56x56	3.26
								0	14x7	17.38
								0	21x14	10.43
								0	28x14	8.69
								0	56x28	4.35
								0	112x56	2.17
								0		
								0		
								0		
								0		
								0		
								0		
								0		
								0		
								0		
								0		
								0		
								0		
								0		
								0		
								0		
								0		
								0		
								0		
Expatriate Commuters	76		Total Annual Expatriate Commuter Travel					196.046		
			Expat Cost / Man / Calendar Day				7.07			
			Total Annual Expatriate Operationl Travel					196,046		
			Total Per Day Expatriate Operational Travel					537	(Posts to Operational Travel)	

Contract Budget Request
RBS8-D / Vastar Resources, Inc. / Gulf of Mexico
Catering

Exchange Rate: US $1.00 =1 U.S. $ [12CAT]

Category	Personnel On Board	Manday Rate	Total/Day Per Category	Annual Catering Costs
Expatriate	59.00	34.26	2,021	737,789
TCN	0.00	34.26	0	0
National	0.00	34.26	0	0
Total Regular Crews	59.00		2,021	737,789
AVG OPERATOR ON BOARD	30.00	34.26	1,028	375,147
OPERATOR RECHARGE	(20.00)	(34.26)	(685)	(250,098)
NET OPERATOR CATERING	10.00			

NOTE:

AVG OPERATOR ON BOARD = ACTUAL AVERAGE OPERATOR/THIRD PARTY PERSONNEL ON BOARD. MANUAL INPUT REQUIRED.
OPERATOR RECHARGE = AUTOMATIC CALCULATION.
NET OPERATOR CATERING = CONTRACT SPECIFIED NUMBER OF OPERATOR/THIRD PARTY PERSONNEL TO PROVIDE CATERING.
MANUAL INPUT REQUIRED.

Office Staff	0.00	34.26	0	0	
Crew Change	0.00	34.26	0	0	
Other Mandays	0.00	34.26	0	0	
Total Other Mandays	0.00		0	0	
			Other Annual Amounts	0	
			Other Annual Amounts	0	
			Total Annual Catering Cost	862,838	
Daily Personnel On Board	89.00		Total Per Day Catering Cost	2,364	(Posts to Catering)

Bureau of Labor Statistics Data

Data extracted on: April 12, 1999 (10:20 AM)

Producer Price Index-Commodities

Series Catalog:

Series ID : wpu119102

Not Seasonally Adjusted
Group : Machinery and equipment
Item : Oil field and gas field drilling machinery
Base Date : 8200

Data:

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Ann
1989	96.9	97.1	97.2	97.1	97.6	97.6	97.6	98.4	98.6	99.3	99.5	99.5	98.0
1990	99.6	99.6	99.2	99.2	99.3	99.9	100.2	101.5	105.8	106.2	106.6	106.6	102.0
1991	106.7	107.7	108.7	108.8	110.0	110.0	110.0	110.0	110.0	110.0	110.1	110.1	109.3
1992	110.1	110.1	110.1	110.1	110.2	110.4	110.6	110.6	110.6	110.8	112.4	112.5	110.7
1993	112.8	112.9	113.3	112.1	112.0	112.2	112.3	112.3	113.4	113.4	113.4	114.6	112.9
1994	114.6	114.6	114.6	114.6	114.7	114.9	115.4	115.4	115.9	117.8	117.8	117.8	115.7
1995	118.3	118.6	119.2	119.2	119.3	119.6	120.4	120.4	120.4	122.0	122.2	122.2	120.1
1996	124.0	124.0	124.0	124.3	124.2	124.8	125.3	125.3	125.3	126.2	126.6	127.1	125.1
1997	127.7	127.9	128.6	129.1	129.2	129.3	129.3	129.5	129.7	130.3	131.4	132.0	129.5
1998	133.1	132.9	133.1	133.0	133.0	133.0	132.9	132.9	132.9	133.6	133.6	133.8(P)	133.2(P)
1999	134.0(P)	133.9(P)	133.9(P)										

P: Preliminary. All indexes are subject to revision four months after original publication.

Data Home Page

BLS Home Page

http://146.142.4.24/cgi-bin/srgatc

Memo

To:	**John Luedtke**	**Date:**	**August 3, 1998**
From:	**Robert B. Carvell**		
Subject:	**Estimated Annual Premium**		
	RBS-8 M		
	Effective 15 March 1998		

CONFIDENTIAL

I.	Coverage:	All Risk Hull & Machinery
	Insured Value:	$325,000,000
	Deductible:	$250,000 Per Occurrence
	NET ANNUAL PREMIUM:	$528,996.80
II.	Coverage:	Loss of Hire
	Daily Indemnity:	$189,000
	Policy Limits:	180 Days
	Deductible Period	21 Days
	NET ANNUAL PREMIUM	$232,867
III.	Coverage:	Primary Marine Protection & Indemnity
	Policy Limits:	$1,000,000 Per Occurrence
	Deductible:	$100,000 Per Occurrence
	NET ANNUAL PREMIUM (U.S. WATERS)	$182,000.00
	NET ANNUAL PREMIUM (FOREIGN WATERS)	$ 78,000.00
IV.	Coverage:	Excess Liability
	Policy Limits:	$400,000,000
	Deductible:	XS of Primary Marine P&I
	NET ANNUAL PREMIUM	$6,795.00

Continued/......

V.	Coverage: Policy Limits: Deductible NET ANNUAL PREMIUM		Contingent Energy Exploration & Development $100,000,000 $250,000 Per Occurrence $704.76
VI.	U.S. Brokers: ANNUAL FEE		Aon Risk Services, Inc. $19,379.85
TOTAL ANNUAL PREMIUM:		(U.S. Waters) (Foreign Waters)	$970,743.41 $866,743.41

Mike Roth
MARKETING MANAGER NAR

R & B FALCON DRILLNG CO.
311 BROADFIELD BLVD., SUITE 400
HOUSTON, TEXAS 77084

July 24, 2001

Vastar Resources, Inc
15375 Memorial Drive
Houston, TX 77079

Attn: Mr. Don Weisinger

Re: Vastar Resources Inc. ("Vastar") & R & B Falcon Drilling Company ("R &B")
Drilling Contract — RBS-8D — Deepwater Horizon ("Rig") (hereinafter referred to as the "Contract")

Deepwater Horizon Contract Amendment — Additional Personnel

Dear Mr. Weisinger,

Reference is made for all purposes to that certain *Offshore Drilling/Workover/Completion Contract* dated December 9, 1998 ("Contract"), by and between **R&B Falcon Drilling Co.** ("R&B") and **Vastar Resources, Inc.** ("Vastar").

Upon Commencement Date of the Contract, Vastar has requested and R&B agrees to provide two additional (2) Deck Foremen, four (4) Assistant Pumphands, four (4) Solid Control Technicians and four (4) Roustabouts in addition to those specified to be provided in Exhibit F-2 of the Contract, for operations on the semi-submersible Deepwater Horizon. Exhibit F-2 shall be amended, effective as of June 26, 2001 to provide for these additional personnel, at cost to be paid by Vastar based upon the following rates, subject to the labor cost escalations set forth therein:

Title	Total	On Rig	Overtime Rate (per person per hour) with Burden	Daily Rate (per person) with Burden	Total Day Rate with Burden
Asst. Pumpman	4	2	$ 27.18	$ 368.30	$ 736.60
Solid Control Tech	4	2	$ 27.18	$ 368.30	$ 736.60
Deck Foreman	2	1	$ 38.14	$ 478.93	$ 478.93
Roustabout	4	2	$ 23.08	$ 332.89	$ 665.78
TOTAL ADDITIONAL PERSONNEL	14	7			$ 2,617.91

Above rates are exclusive of a $65.00 per manday cost of training and transportation.

Vastar reserves the right to elect to release one or all of the above additional personnel upon thirty (30) days written notice to R&B. R&B may, if at that time R&B deems such personnel necessary for its operations, elect to retain such personnel at its own cost.

PHONE: 281-647-8518 FAX: 281-647-8754 EMAIL:mroth@deepwater.com

Except as expressly amended herein, the terms and conditions of the Contract shall remain in full force and effect as originally executed.

If the above and foregoing sets forth your understanding of the agreement between R&B and Vastar, please sign both originals in the space provided below and return one fully executed original agreement to the undersigned.

Sincerely,
R & B Falcon Drilling Co.

/s/ Mike Roth
Mike Roth

AGREED AND ACCEPTED
THIS 26 DAY OF JULY, 2001

VASTAR RESOURCES INC.

SIGNED	***/s/ Don Weisinger***
PRINTED	***Don Weisinger***
TITLE	***Drilling Team Leader***

TERRY BONNO
SR. MARKETING REPRESENTATIVE

R & B FALCON DRILLING COMPANY
311 BROADFIELD BLVD., SUITE 400
HOUSTON, TEXAS 77084

December 12, 2001

BP America Production Company
Attn: Don Weisinger
501 WestLake Park Blvd.
Houston, TX 77079

Reference: **Drilling Contract No. 980249** between **Vastar Resources Inc.** , predecessor in interest to BP America Production Company ("BP") and **R&B Falcon Drilling Company** ("R&B") dated December 9, 1998 for RBS-8D (now known as the **Deepwater Horizon),** as amended (the "Contract")

Subject: **Letter of Agreement for Cost Escalation and Naming Convention Adjustments**

Dear Mr. Weisinger,

In accordance with Article 2 – Dayrates, Section 2.3 – Adjustment in Dayrates, we have recently completed an analysis of the costs of the Deepwater Horizon. To assist in clarification of position titles as related to the merger between R&B Falcon and Transocean, we have amended Exhibit F-1 – Crew Compliment and Exhibit F-2 – Cost of Additional Personnel. Both amended exhibits are attached and titled, ***Exhibit F-1a*** and ***Exhibit F-2a,*** which are the original Exhibit F-1 and F-2 with the only revisions made are position title changes as per the Naming Conventions of the merged com pany and will supercede the originals.

Cost analysis for the ***Deepwater Horizon*** has been calculated based on the contract and the Establishment of Base Figures letter dated April 13, 1999. All costs have been reviewed and adjusted relative to the Contract Section 2.3.2 a) Labour Costs, b) Catering Costs, c) Spare Parts/Supplies Element, and d) Insurance Element. Please find the attached documents to substantiate our escalations including the Basis for Cost Escalations spreadsheet, Personnel List with rates, and the Bureau of Labor Statistics Data printout. The attached Basis for Cost Escalation Spreadsheet specifies the base rates, the new totals after this escalation and the variance column indicates the increase or decrease as appropriate per section. Payments of such adjustments shall be deeme d to be effective beginning on the date the rig commenced operations, September 18, 2001. R&B shall issue an invoice for this retroactive adjustment and BP shall pay this invoice in accordance with the billing and payment procedures in the Contract.

In accordance with the terms of the referenced contract, the parties agree to the following new dayrate changes under this letter of agreement:

2.3.2a The Base Labor cost adjustment will be an increase of $6,876 from the baseline of $21,420 with a new total of $28,296. Labor will also increase by $239 on the additional personnel to a new total of $2,613.

2.3.2b Contractor's cost of catering has decreased by ($541) to a new total of $2,067 under the baseline of $2,608.

PHONE: 281-675-8848 FAX: 281-647-8754 EMAIL:tbonno@deepwater.com

2.3.2c Based on the initial base Spare Parts/Supplies Element of $12,692, there will be an increase of $1,159 to a new baseline of $13,851.

2.3.2d The insurance element has decreased by $861 over the baseline figure of $2,660 and the new Total Base Insurance Cost will be $1,799.

Except as expressly provided herein, the terms and conditions of the Contract shall remain in full force and effect. Each party represents that this letter agreement has been validly executed and delivered, and has been duly authorized by all action necessary for the authorization therefore.

In summary, the following changes are effective as follows:

Paragraph	2.3.2a	$	6,876	
Paragraph	2.3.2a		239	(additional personnel)
Paragraph	2.3.2b		(541)	
Paragraph	2.3.2c		1,159	
Paragraph	2.3.2d		(861)	
Total		$	6,872	

If the above and foregoing sets forth your understanding of the agreement between R&B and BP, please sign both originals in the space provided below and return one fully executed original agreement to the undersigned.

If you have any questions, please contact the undersigned or John Keeton at Transocean's Park Ten Office 281-647-8500.

Sincerely,

/s/ Terry Bonno
Terry Bonno
Sr. Marketing Representative
On Behalf of R & B Falcon Drilling Co.

AGREED AND ACCEPTED
THIS 13th DAY OF JUNE, 2002

BP AMERICA PRODUCTION COMPANY

SIGNED	***/s/ R. Kevin Guerre***
PRINTED	***R. Kevin Guerre***
TITLE	***TL - SCM***

EXHIBIT F-1a

CREW COMPLEMENT

Drill Crew	Total	On Board
~~Drilling Rig Supt~~/OIM	2	1
Toolpusher	4	2
Driller	4	2
Asst. Driller	8	4
Pump**hand**	4	2
Floorhand ~~Roughneck~~	12	6
~~Maintenance~~ **Electrical Supervisor** ~~(Electrical)~~	2	1
Chief Electrician	4	2
~~Assistant~~ Electrician	2	1
Chief Electronic Technician	4	2
Chief Mechanic	4	2
~~Assistant~~ Mechanic	2	1
Welder	2	1
Sub Sea **Supervisor** ~~Engineer~~	2	1
Assistant Sub Sea	2	1
Crane Operator	4	2
Roustabout	16	8
Rig Safety & Training **Coordinator** ~~Officer~~	2	1
Medic	2	1
~~Materialsman~~ **Materials Coordinator**	4	2
~~Captain~~ **Master**/~~OIM~~	2	1
Chief **Mate** ~~Officer~~	2	1
D. P. Operator	4	2
Assist. D.P. Operator	4	2
A.B. Seaman/Painters	6	3
Chief Engineer	2	1
First **Asst.** Engineer	2	1
2nd**Asst.** Engineer	4	2
Motor**hand**	4	2
~~Boatswain~~ **Bosun**	2	1
Galley	As Needed	
Tota1:	118	59

a) Galley crew ratio of one to every 10 persons on board.

b) A mutually agreed pre-commencement manning schedule shall be attached.

c) Contractor may, with Company approval, reduce the marine crew manning based upon Coast Guard requirements, when available.

Contract No. 980249

BASIS FOR COST ESCALATIONS
DEEPWATER HORIZON
As of September 1, 2001

	Per Baseline Costs Plus July 24, 2001 Letter	Sept. 2001	2001 Variance
Base Labor Cost:			
Labor & Burden (per schedule)	$ 20,573	25,476	4,903
Training & Transportation Costs	847	2,820	1,973
Total Base Labor Cost	**$ 21,420**	**$ 28,296**	**$ 6,876**
Percentage Increase			**32%**
Additional Crew Increase per agreement dated July 24, 2001			
Labor & Burden (per schedule)	2,163	2,278	115
Training & Transportation Costs	$ 211	335	**124**
Total Additional Personnel Cost	**$ 2,374**	**$ 2,613**	**$ 239**
Percentage Increase			**10%**
Base Catering Cost:			
59 Combined Personnel @ $ 27.20	$ 2,021	$ 1,605	(417)
7 Additional Personnel @ $ 27.20	$ 244	$ 190	(53)
10 Company Personnel @ $ 27.20	$ 343	$ 272	(71)
Total Base Catering Costs	**$ 2,608**	**$ 2,067**	**$ (541)**
Percentage Increase			**-21%**
Base Insurance Cost	**$ 2,660**	**$ 1,799**	**$ (861)**
Percentage Increase			**-32%**
Base Repair and Maintenance Cost	**$ 12,692**	**$ 13,851**	**$ 1,159**
Percentage Increase			**9%**
Total Baseline Operating Costs	**$ 41,754**	**$ 48,626**	**$ 6,872**

Horizon Cost Escalations

DEEPWATER HORIZON

Adjusted Base Labor as of September 1, 2001

Gulf of Mexico Crew Complement				A	B	C	D
	No. of Personnel			GOM Base Labor w/Burden		GOM Overtime Rates	
JOB CODE	On Board	Assigned To Rig	JOB CLASSIFICATION	Daily Rate (per person) w/ Burden*	Total Daily On Board Cost**	Daily Rate w/ Burden**	Hourly Rate w/ Burden**
	1	2	Offshore Installation Manager	930.23	855.23	Salaried	
	2	4	Toolpusher	761.90	1,373.80	Salaried	
	2	4	Driller	650.87	1,151.74	650.12	54.18
	4	8	Assistant Driller	493.35	1,673.41	462.88	38.57
	2	4	Pumphand	408.82	667.65	362.40	30.20
	10	20	Floorhand	395.57	3,205.71	346.65	28.89
	10	20	Roustabout	353.97	2,789.67	297.20	24.77
	1	2	Welder	475.62	400.62	441.80	36.82
	2	4	Crane Operator	493.35	836.70	462.88	38.57
	2	4	Chief Mechanic	581.84	1,013.67	568.06	47.34
	1	2	Mechanic	471.20	396.20	436.55	36.38
	2	4	Motor Operator	395.97	641.93	347.12	28.93
	1	2	Electrical Supervisor	663.46	588.46	Salaried	
	2	4	Chief Electrician	581.84	1,013.67	568.06	47.34
	1	2	Electrician	471.20	396.20	436.55	36.38
	2	4	Chief Electronic Technician	590.67	1,031.34	578.56	48.21
	1	2	Senior Sub Sea Supervisor	768.23	693.23	Salaried	
	1	2	Assistant Sub Sea Supervisor	546.43	471.43	525.97	43.83
	2	4	Materials Coordinator	435.79	721.58	394.46	32.87
	1	2	Master	810.10	735.10	Salaried	
	1	2	Chief Mate	675.99	600.99	679.98	56.66
	1	2	Chief Engineer	751.42	676.42	Salaried	
	1	2	1st Assist. Engineer	634.12	559.12	630.21	52.52
	2	4	2nd Assist. Engineer	599.57	1,049.14	589.14	49.10
	2	4	Dynamic Position Operator	546.43	942.86	525.97	43.83
	2	4	Assistant Dynamic Position Operator	457.95	765.89	420.79	35.07
	1	2	Deck Pusher	512.80	437.80	486.00	40.50
	1	2	Bosun	457.95	382.95	420.79	35.07
	3	6	Able Bodied Seaman	413.70	1,016.11	368.20	30.68
	1	2	Rig & Safety Training Technician*	466.78	391.78	431.29	35.94
	1	2	Rig Medic/Clerk	348.23	273.23	290.38	24.20
	66	**132**		**Total Base Labor Costs =**	**$ 27,753.63**		

*** Does include catering, transportation, or training expense.**

**** Does NOT include catering transportation, or training expense.**

Notes:

1) **The figures in column "A" are to be used as the basis for adding personnel to the permanent crew and for determining the credit for crew members short.**
2) **The figures in column "B" are the product of multiplying the number of "on board" personnel by the "Daily Rate w/ Burden" in column "A". The Sum of column "B" is the "Total Base Labor Cost" per day.**
3) **The figures in columns "C" and "D" are the basis for charging the Operator for overtime hours worked at the request of the Operator.**

Data extracted on: June 13, 2002 (10:18 AM)

Producer Price Index-Commodities

Series Catalog:

Series ID : wpu119102

Not Seasonally Adjusted
Group : Machinery and equipment
Item : Oil field and gas field drilling machinery
Base Date : 8200

Data :

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Ann
1992	110.1	110.1	110.1	110.1	110.2	110.4	110.6	110.6	110.6	110.8	112.4	112.5	110.7
1993	112.8	112.9	113.3	112.1	112.0	112.2	112.3	112.3	113.4	113.4	113.4	114.6	112.9
1994	114.6	114.6	114.6	114.6	114.7	114.9	115.4	115.4	115.9	117.8	117.8	117.8	115.7
1995	118.3	118.6	119.2	119.2	119.3	119.6	120.4	120.4	120.4	122.0	122.2	122.2	120.1
1996	124.0	124.0	124.0	124.3	124.2	124.8	125.3	125.3	125.3	126.2	126.6	127.1	125.1
1997	127.7	127.9	128.6	129.1	129.2	129.3	129.3	129.5	129.7	130.3	131.4	132.0	129.5
1998	133.1	132.9	133.1	133.0	133.0	133.0	132.9	132.9	132.9	133.6	133.6	133.6	133.1
1999	133.8	133.7	133.7	133.9	133.9	134.0	134.0	133.7	133.7	133.7	134.4	134.6	133.9
2000	134.9	136.3	136.3	136.3	136.5	136.5	136.5	136.6	136.7	138.7	138.7	138.7	136.9
2001	143.5	143.9	144.0	144.0	144.0	145.5	145.6	145.8	145.7	146.1	146.1	146.1	145.0
2002	146.2	146.0(P)	146.7(P)	146.7(P)	146.5(P)								

Preliminary. All indexes are subject to revision four months after original publication.

Bureau of Labor Statistics
Square Building
2 Massachusetts Ave., NE
Washington, DC 20212-0001

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Data questions: **blsdata_staff@bls.gov**
Technical (web) questions: **webmaster@bls.gov**
Other comments: **feedback@bls.gov**

Memo

To:	Terry Bonno	**Date:**	December 6, 2001
From:	James Mitchell, Director of Risk Management		
Subject:	Estimated Annual Premium – Deepwater Horizon		

CONFIDENTIAL

The following annual premiums have been established for the Deepwater Horizon and are effective September 1, 2001:

Coverage:	All Risk Hull & Machinery
Insured Value:	$350,000,000
Deductible:	($5MM/$7.5MM/$7.5MM/$10MM aggregate layers)
NET ANNUAL PREMIUM:	$470,329
Coverage:	Primary Marine Protection & Indemnity
Policy Limits:	$1,000,000 per occurrence
Deductible:	$250,000 Per Occurrence
NET ANNUAL PREMIUM (US WATERS):	$125,352
NET ANNUAL PREMIUM (FOREIGN WATERS):	$53,796
Coverage:	Excess Liability
Insured Value:	$452,000,000
Deductible:	XS of Primary Marine P&I
NET ANNUAL PREMIUM:	$26,334
U.S. BROKERS:	McGriff Seibels & Williams, Inc.
ANNUAL FEE	$34,454
TOTAL ANNUAL PREMIUM: (U.S. WATERS)	$656,469
TOTAL ANNUAL PREMIUM: (FOREIGN WATERS)	$584,913

Rig Name Contractor & No.	Effective Date	Commence Date	Duration Mos. &	Last Update/	Reoccurrence Timing	Reoccurrence Condition
Horizon(2)						
Vastar (BP)						
01-063	Dec. 8, 1998	Sept. 1, 2001			Annually	=> 5%

	12/8/98 Baselines	9/1/01 Costs		
A. Baseline Labor	$ 21,420	$ 28,296	32.10%	$ 6,876
Addtl Personnel	$ 2,374	$ 2,613		$ 239
Total Labor	**$ 23,794**	**$ 30,909**		**$ 7,115**
B. Catering	$ 2,608	$ 2,067		$ -541
C. Cost of R&M	***$ 12,692***	$ 13,851		$ 1,159
BLS Indices	133.6	145.8	9.13%	
D. Insurance Premiums	$ 2,660	1,799.00		$ -861
	$ 41,754	$ 48,626		$ 6,872
				16%

Summary

Escalations and baselines provide for increases in labor costs, catering costs, increases in the cost of repairs and maintenance and insurance premiums. All increases must exceed 5% and can be addressed as early as the Commencement Date and then only annually there after.

R & B FALCON DRILLNG CO.
1311 BROADFIELD BLVD., SUITE 400
HOUSTON, TEXAS 77084

JOHN KEETON
RIG MANAGER

April 23, 2002

Vastar Resources, Inc.
C/O BP America Inc.
15375 Memorial Drive
Houston, TX 77079

Attn: Mr. Mike Stefanov

Reference: **Deepwater Horizon Letter Agreement — Additional Personnel for Mad Dog Project CONTRACTOR-5121-2002-005**

Dear Mr. Stefanov,

Reference is made for all purposes to that certain *Offshore Drilling/Workover/Completion Contract* dated December 9, 1998 (“Contract”), by and between **R&B Falcon Drilling Co.** (“Contractor”) and **Vastar Resources, Inc.** (“Company”), as amended.

Company has requested and Company and Contractor agree that CONTRACTOR will provide one (1) additional OIM and one (1) additional Sr. Toolpusher to work on the Mad Dog Project. The OIM and the Sr. Toolpusher will be shorebased and work at CONTRACTOR’s Park 10 office and at COMPANY’s offices as required to support the Mad Dog Project on an even rotating schedule. Work will commence on or about May 15, 2002 with an expected duration of approximately three (3) months.

CONTRACTOR shall invoice COMPANY at the rate of US$1,200 (one thousand two hundred) per day with CONTRACTOR being responsible for all costs for lodging, food, transportation and CONTRACTOR required training. The OIM and Sr. Toolpusher will be available for work seven days a week on an even rotating schedule and COMPANY shall be billed for the full seven days each week. CONTRACTOR will supply supporting documentation with each monthly invoice as evidence of days available for work.

COMPANY reserves the right to release the services of the OIM and Sr. Toolpusher at anytime upon thirty (30) days prior written notice to CONTRACTOR. COMPANY and CONTRACTOR will document when the OIM and Sr. Toolpusher are released from duty for services on this special Mad Dog Project assignment, thus ending the applicability of this contract amendment.

All other terms and conditions of the referenced Contract, as amended, shall remain in full force and effect.

If the above sets forth your understanding of the agreement, please sign both originals in the space provided below and return one (1) fully signed original to us for our file.

PHONE: 832-587-8533 FAX: 832-587-8754 EMAIL:JKeeton@houston.deepwater.com

We appreciate this opportunity to be of service to BP. If you have questions, please contact Terry Bonno for commercial concerns at 832-587-8848 or myself for technical concerns at 832-587-8533.

Sincerely,

/s/ John Keeton
John Keeton
R & B Falcon Drilling Co.

/ks

AGREED AND ACCEPTED THIS 24 DAY OF APRIL, 2002

VASTAR RESOURCES INC.

SIGNED	***/s/ Allen Cook***
PRINTED	***Allen Cook***
TITLE	***MD Well Delivery TL***

R & B FALCON DRILLNG CO.
1311 BROADFIELD BLVD., SUITE 400
HOUSTON, TEXAS 77084

TERRY BONNO
SR. MARKETING REPRESENTATIVE

June 3, 2002

BP America Production Company
501 WestLake Park Blvd.
Houston, TX 77079

Attn: Mr. Jon Sprague
Mr. Charles Taylor

Reference: **Deepwater Horizon Letter Agreement — Additional Personnel for Deepwater Horizon CONTRACTOR-5121-2002-006**

Gentlemen:

Reference is made for all purposes to that certain *Offshore Drilling/Workover/Completion Contract* dated December 9, 1998 ("Contract"), by and between **R&B Falcon Drilling Co.** ("Contractor") and **Vastar Resources, Inc. predecessor in interest to BP America Production Company** ("Company"), as amended.

Company and CONTRACTOR have recently discussed and agreed that the current manning level on the Deepwater Horizon is not sufficient to produce the potential operating efficiency levels for this type of Drilling Unit. In addition, recent feedback from the crew provided clear evidence that the crews feel that there are insufficient personnel to conduct simultaneous operations.

In a recent survey of crewing levels on similar Drilling Units in our fleet the following results were obtained:

	Horizon	Nautilus	Marianas
Crew Total	72	88	96

Based on these findings and our experience on these Drilling Units, CONTRACTOR suggests the following additional personnel to be added to the Deepwater Horizon on a semi-permanent basis to afford both companies the opportunity to conduct simultaneous operations.

Upon execution of this Letter Agreement by COMPANY and CONTRACTOR, CONTRACTOR agrees to provide two (2) additional Toolpushers, four (4) Floorhands, four (4) Crane Operators and eight (8) Roustabouts in addition to those specified to be provided in Exhibit F-2 of the Contract as amended, for operation on the semi-submersible Deepwater Horizon. Exhibit F-2 shall be amended to provide for these additional personnel, at cost to be paid by COMPANY based upon the following rates (as per the Escalation Letter Agreement dated December 12, 2001), subject to the cost escalations set forth therein:

Title	Total	On Rig	Overtime Rate (per person per hour) with Burden	Daily Rate (per person) with Burden	Total Day Rate with Burden
Toolpusher	2	1	N/A	$ 761.90	$ 761.90
Floorhand	4	2	$ 28.89	$ 395.57	$ 791.14
Crane Operator	4	2	$ 38.57	$ 493.35	$ 986.70
Roustabout	8	4	$ 24.77	$ 353.97	$ 1,415.88
TOTAL ADDITIONAL PERSONNEL	18	9			$ 3,955.62

In addition, COMPANY requests that one (1) additional Driller and welder per crew be added during the upcoming

PHONE: 832-587-8848 FAX: 832-587-8754 EMAIL:tbonno@houston.deepwater.com

twenty-one day batch setting exercise on Atlantis as follows:

Title	Total	On Rig	Overtime Rate (per person per hour) with Burden	Daily Rate (per person) with Burden	Total Day Rate with Burden
Driller	2	1	$ 54.18	$ 650.87	$ 650.87
Welder	2	1	$ 36.82	$ 475.62	$ 475.62
TOTAL ADDITIONAL PERSONNEL	4	2			$ 1,126.49

COMPANY reserves the right to release the services of the additional personnel at anytime upon thirty (30) days prior written notice to CONTRACTOR.

All other terms and conditions of the referenced Contract, as amended, shall remain in full force and effect.

If the above sets forth your understanding of the agreement, please sign both originals in the space provided below and return one (1) fully signed original to us for our file.

We appreciate this opportunity to be of service to BP. If you have questions, please contact me for commercial concerns at 832-587-8848 or John Keeton for technical concerns at 832-587-8533.

Sincerely,

/s/ Terry Bonno
Terry Bonno
R & B Falcon Drilling Co.

/ks

AGREED AND ACCEFTED THIS 10th DAY OF JUNE, 2002

BP AMERICA PRODUCTION COMPANY

SIGNED	***/s/ R Kevin Guerre***
PRINTED	***R Kevin Guerre***
TITLE	***TL-SCM***

R & B FALCON DRILLNG CO.
1311 BROADFIELD BLVD., SUITE 400
HOUSTON, TEXAS 77084

TERRY BONNO
SR MARKETING REPRESENTATIVE

June 12, 2002

BP America Production Company
501 WestLake Park Blvd.
Houston, TX 77079

Attn: Mr. Don Weisinger

Reference: **Deepwater Horizon Letter Agreement** – **Cameron Variable Bore Rams Deepwater Horizon**
CONTRACTOR-5121-2002-007

Gentlemen:

Reference is made for all purposes to that certain *Offshore Drilling/Workover/Completion Contract* dated December 9, 1998 (“Contract”), by and between **R&B Falcon Drilling Co.** (“Contractor”) and **Vastar Resources, Inc.** (“Vastar”), predecessor in interest to **BP America Production Company** (“Company”), as amended.

Company and Contractor have recently discussed and agreed to provide a Cameron 3-1/2” X 6-5/8” Variable Bore Rams (“Equipment”) for use on the Deepwater Horizon. This Letter Agreement outlines the terms and conditions to provide the Equipment as follows:

1. The Equipment is limited to the following components

Description	Quantity
Variable Bore Ram 18-3/4” 15M BOP, 3-1/2” X 6-5/8” OD Pipe, API 16A, ABS and DNV Certification	2
Ram Wear Pad, Right Side 18-3/4” BOP	2
Ram Wear Pad, Left Side 18-3/4” BOP	2
Screw, Ram Wear Pads	8

2. Company has authorized Contractor to purchase Equipment and has agreed to a dayrate reimbursement fee of $125.00 per day to be paid over the remainder of the Contract on the Deepwater Horizon. Dayrate reimbursement fee shall commence on June 13, 2002.

3. If the Contract is terminated prior to September 18, 2004, Company shall reimburse Contractor via a lump sum payment of $125.00 per day times the days remaining in contract after termination date. Such payment shall be due within thirty days after presentation of an invoice to Company.

4. The Equipment provided under this agreement shall become part of Contractor’s equipment and incorporated into Exhibit B-2 of the Contract.

All other terms and conditions of the referenced Contract, as amended, shall remain in full force and effect.

PHONE: 832-587-8848 FAX: 832-587-8754 EMAIL:tbonno@houston.deepwater.com

If the above sets forth your understanding of the agreement, please sign both originals in the space provided below and return one (1) fully signed original to us for our file.

We appreciate this opportunity to be of service to BP. If you have questions, please contact me for commercial concerns at 832-587-8848 or John Keeton for technical concerns at 832-587-8533.

Sincerely,

/s/ Terry Bonno
Terry Bonno
R & B Falcon Drilling Co.

/ks

AGREED AND ACCEPTED THIS 20th DAY OF JUNE, 2002

BP AMERICA PRODUCTION COMPANY

SIGNED	***/s/ Jerry R Rhoads***
PRINTED	***Jerry R Rhoads***
TITLE	***Contracts Specialist***

R & B FALCON DRILLNG CO.
1311 BROADFIELD BLVD., SUITE 400
HOUSTON, TEXAS 77084

CHRISTOPHER S. YOUNG
SR. MARKETING REPRESENTATIVE

August 26, 2002

BP America Production Company
501 WestLake Park Blvd.
Houston, TX 77079

Attn: Mr. Randy Rhoads

Reference: **Deepwater Horizon Letter Agreement -**
CONTRACTOR-5121-2002-010

Gentlemen:

Reference is made for all purposes to that certain *Offshore Drilling/Workover/Completion Contract* dated December 9, 1998 ("Contract"), by and between **R&B Falcon Drilling Co.** ("Contractor") and **Vastar Resources,Inc. predecessor in interest to BP America Production Company** ("Company"), as amended.

This is to document the recent agreement between our Mr. Doug Halkett and your Mr. Jon Sprague with respect to the cost of re-drilling the GC74344 well as a result of the recent "lost hole" incident.

Due to the special circumstances involved in the recent event in which the hole was lost while running 20" casing, the parties agree that, by way of compromise and in order to avoid further disputes with respect to the obligations under the Contract with respect to such event, commencing as of 13:00 August 15, 2002, Contractor shall be obligated at Company's election to re-drill the hole, and Company shall pay ninety percent (90%) of the applicable Operating Rate, until such time as the depth at which the hole was lost is reached, but otherwise all subject to the terms and conditions of the Contract. Once we reach the depth at which the hole was lost, the parties agree that the applicable Operating Rate shall control per the Contract.

All other terms and conditions of the referenced Contract, as amended, shall remain in full force and effect.

If the above sets forth your understanding of the agreement, please sign both originals in the space provided below and return one (1) fully signed original to us for our files. We appreciate this opportunity to be of service to BP. If you have questions, please contact me at 832-587-8506 or John Keeton at 832-587-8533.

Yours very truly,

/s/ Christopher S. Young
Christopher S. Young
R & B Falcon Drilling Co.

PHONE: 832-587-8506 FAX: 832-587-8754 EMAIL:cyoung@houston.deepwater.com

/ks

AGREED AND ACCEPTED THIS 16th DAY OF SEPTEMBER, 2002

BP AMERICA PRODUCTION COMPANY

SIGNED	***/s/ Jerry R Rhoads***
PRINTED	***Jerry R Rhoads***
TITLE	***Contracts Specialist***

R&B FALCON DRILLING COMPANY
1311 BROADFIELD, SUITE 400
HOUSTON, TX 77084

CHRISTOPHER S. YOUNG
SR. MARKETING REPRESENTATIVE

September 18, 2002

BP America Production Company
501 WestLake Park Blvd.
Houston, TX 77079

Attn: Mr. Randy Rhoads

Re: **Drilling Contract No. 980249** dated December 9, 1998 by and between **R&B Falcon Drilling Company** ("Contractor") and **Vastar Resources, Inc. predecessor in interest to BP America Production Company** ("Company"), as amended for RBS-8D (now known as the **Deepwater Horizon)**

Subject: **Letter of Agreement for adding Deck Pusher**
CONTRACTOR-5121-2002-011

Dear Mr. Rhoads,

This letter will serve as our agreement to add another Deck Pusher to the crew complement of the Deepwater Horizon. Upon execution of this Letter Agreement by Company, Contractor agrees to provide one (1) Deck Pusher onboard the **Deepwater Horizon** in addition to those specified to be specified to be provided in Exhibit F-2 of the Contract as amended. Since we added the Deck Pusher in August, Exhibit F-l of the Contract shall be amended, as of August 1, 2002 to provide for the following additional personnel:

Title	On Board	Assigned to Rig	Daily Rate per Person w/ Burden	Hourly Overtime Rate w/Burden
Deck Pusher	1	2	$ 512.80	$ 40.50

Therefore, the amended crew complement shall show two (2) Deck Pushers "On Board" and four (4) "Assigned to Rig". The amended crew complement is attached. In summary, all rates in the Contract shall increase by **$512.80** per day effective August 1, 2002. Except as specifically provided herein, all other terms and conditions of the Contract shall remain in full force and effect. Please indicate your agreement in the space provided below and return one fully executed copy of this letter to me for our files.

If you have any questions, please contact John Keeton at (832) 587-8533 or me at (832) 587-8506. Thank you for the opportunity to be of service.

Sincerely,

/s/ Christopher S. Young
Christopher S. Young
Sr. Marketing Representative
On Behalf of R & B Falcon Drilling Co.

PHONE: (832) 587 8506 FAX: (832) 587 8754 EMAIL:cyoung@houston.deepwater.com

AGREED AND ACCEPTED THIS 2ND DAY OF DECEMBER, 2002

BP AMERICA PRODUCTION COMPANY

SIGNED	***/s/ Jerry R Rhoads***
PRINTED	***Jerry R Rhoads***
TITLE	***Contracts Specialist***

DEEPWATER HORIZON

Adjusted Base Labor as of September 18, 2002

	Gulf of Mexico Crew Complement			A	B	C	D
	No. of Personnel			GOM Base Labor w/Burden		GOM Overtime Rates	
JOB CODE	On Board	Assigned To Rig	JOB CLASSIFICATION	Daily Rate (per person) w/ Burden*	Total Daily On Board Cost* *	Daily Rate w/ Burden* *	Hourly Rate w/ Burden* *
1883	1	2	Offshore Installation Manager	930.23	855.23	Salaried	
1276	3	6	Toolpusher	761.90	2,060.70	Salaried	
1295	2	4	Driller	650.87	1,151.74	650.12	54.18
1302	4	8	Assistant Driller	493.35	1,673.41	462.88	38.57
1845	2	4	Pumphand	408.82	667.65	362.40	30.20
1296	12	24	Floorhand	395.57	3,846.86	346.65	28.89
1297	14	28	Roustabout	353.97	3,905.54	297.20	24.77
799	1	2	Welder	475.02	400.02	441.00	36.82
1289	4	8	Crane Operator	493.35	1,673.41	462.88	38.57
1381	2	4	Chief Mechanic	581.84	1,013.67	568.06	47.34
1286	1	2	Mechanic	471.20	396.20	436.55	36.38
1305	2	4	Motor Operator	395.97	641.93	347.12	28.93
1355	1	2	Electrical Supervisor	663.46	588.46	Salaried	
1345	2	4	Chief Electrician	581.84	1,013.67	568.06	47.34
1280	1	2	Electrician	471.20	396.20	436.55	36.38
1387	2	4	Chief Electronic Technician	590.67	1,031.34	578.56	48.21
1388	1	2	Senior Sub Sea Supervisor	768.23	693.23	Salaried	
1372	1	2	Assistant Sub Sea Supervisor	546.43	471.43	525.97	43.83
394	2	4	Materials Coordinator	435.79	721.58	394.46	32.87
1668	1	2	Master	810.10	735.10	Salaried	
1299	1	2	Chief Mate	675.99	600.99	679.98	56.66
1539	1	2	Chief Engineer	751.42	676.42	Salaried	
0	1	2	1st Assist. Engineer	634.12	559.12	630.21	52.52
0	2	4	2nd Assist. Engineer	599.57	1,049.14	589.14	49.10
1688	2	4	Dynamic Position Operator	546.43	942.86	525.97	43.83
1323	2	4	Assistant Dynamic Position Operator	457.95	765.89	420.79	35.07
1238	2	4	Deck Pusher	512.80	875.60	486.00	40.50
1298	1	2	Bosun	457.95	382.95	420.79	35.07
1300	3	6	Able Bodied Seaman	413.70	1,016.11	368.20	30.68
1608	1	2	Rig & Safety Training Technician*	466.78	391.78	431.29	35.94
1677	1	2	Rig Medic/Clerk	351.73	276.73	294.53	24.54
	76	**152**		**Total Base Labor Costs =**	**$ 31,475.54**		

* **Does include catering, transportation, or training expense.**

* * **Does NOT include catering transportation, or training expense.**

Notes:

1) **The figures in column "A" are to be used as the basis for adding personnel to the permanent crew and for determining the credit for crew members short.**

2) **The figures in column "B" are the product of multiplying the number of "on board" personnel by the "Daily Rate w/ Burden" in column "A". The Sum of column "B" is the "Total Base Labor Cost" per day.**

3) **The figures in columns "C" and "D" are the basis for charging the Operator for overtime hours worked at the request of the Operator.**

AGREEMENT FOR ASSIGNMENT OF DRILLING CONTRACT

This Agreement ("Agreement") is entered into this 14 day of October, 2002 between R&B FALCON DRILLING CO. (hereinafter "RBFDC"), an Oklahoma corporation having an office at Park Ten Centre, 1311 Broadfield Boulevard, Suite 400, Houston, Texas 77084 and TRANSOCEAN HOLDINGS INC. (hereinafter "THI"), a Delaware corporation, having an office at 4 Greenway Plaza, Houston, Texas 77046. RBFDC and THI may hereinafter sometimes be referred to individually as "Party" and collectively as "Parties".

WHEREAS, RBFDC is a party to that drilling contract No. 980249 of December 9, 1998 with VASTAR RESOURCES, INC. (hereinafter "VASTAR"), now succeeded in interest by BP AMERICA PRODUCTION COMPANY (hereinafter "BP"), pertaining to the mobile offshore drilling unit "DEEPWATER HORIZON" (hereinafter "RIG"), as amended to date (hereinafter "Drilling Contract"); and,

WHEREAS, RBFDC wishes to assign the Drilling Contract to THI and THI is willing to accept said assignment.

NOW THEREFORE, for Ten Dollars (US$10.00) and other good and valuable consideration including the mutual covenants and agreements contained in this Agreement, the Parties agree as follows:

1.0 Effective at midnight October 31, 2002, RBFDC assigns to THI all of RBFDC's rights and obligations under the Drilling Contract, and THI accepts the assignment and agrees to assume and perform all the said obligations under the Drilling Contract.

2.0 RBFDC agrees to notify and provide reasonably requested documentation to the other party to the Drilling Contract to effect the assignment.

3.0 Written notice to a Party under this Agreement will be considered to be properly served if received at the Party's address appearing above by personal delivery or registered mail.

4.0 Any failure by a Party to enforce the terms of this Agreement or to exercise any rights will not constitute a waiver of those terms or rights, nor will it constitute any precedence.

5.0 This Agreement is to be governed by and construed in accordance with the governing law provisions of the Drilling Contract.

IN WITNESS WHEREOF, the Parties execute this Agreement as of the date first above written.

R&B FALCON DRILLING CO.

By: /s/ Jean P. Cahuzac
Name: Jean P. Cahuzac
Title: Vice President

TRANSOCEAN HOLDINGS INC.

By: /s/ Eric B. Brown
Name: Eric B. Brown
Title: Vice President

TRANSOCEAN OFFSHORE DEEPWATER DRILLING INC.
1311 BROADFIELD, SUITE 400
HOUSTON, TX 77084

CHRISTOPHER S. YOUNG
SR. MARKETING REPRESENTATIVE

November 1, 2002

BP America Production Company
501 WestLake Park Blvd.
Houston, TX 77079

Attn: Mr. Randy Rhoads

Re: **Drilling Contract No. 980249** dated December 9, 1998 (“Contract”) by and between **R&B Falcon Drilling Company predecessor in interest to Transocean Holdings, Inc,**(“Contractor or TODDI”) and **Vastar Resources, Inc. predecessor in interest to BP America Production Company** (“Company”), as amended for RBS-8D (now known as the **Deepwater Horizon)**< /div>

Subject: **Letter of Agreement for 6 5/8” Drill Pipe Rental**
CONTRACTOR-5121-2002-011

Dear Randy,

This letter is to document the agreement between Transocean Offshore Deepwater Drilling Inc. (TODDI) and Company for the rental of 18,000 feet of 6 5/8” R-3 drill pipe for use on the Deepwater Horizon.

Company and TODDI hereby agree to the following terms and conditions:

1. TODDI shall purchase the following pipe and rent it to Company over the remaining term of the Contract referenced above. Specifications of the pipe are as follows:

Footage	18,000	Joints	439
Pipe OD	6 5/8”	Connection	6 5/8 FH
Weight	34.01	OD	8 1/4”
Grade	S-135	ID	4 1/4”
Upset	IEU	Pin Tong	10”
Range	3	Box Tong	13”
Internal Coating	TK 34 XT*	Hardfacing Pin	None
Inspection	Truscope AS	Hardfacing Box	Armacor M
Delivery	16 weeks*		
Make & Break & 95% wall included			

* Changes from Grant Prideco quote 30726

2. Tooljoints (Pin & Box) shall be manufactured long enough to provide for a minimum of two full recuts and still have sufficient tong space excluding proud hardbanded area. Company’s coating, hardbanding and make & break specifications are attached and made a part of this Agreement.

PHONE: (832) 587-8506 FAX: (832) 587-8754 EMAIL:cyoung@houston.deepwater.com

3. The rental rate will be approximately $3,000/day assuming that 18 months will be remaining on the contract at time of pipe delivery and that the total cost of the pipe is approximately $1.29 million. The exact calculation will be made when the pipe is delivered and the total cost (based on good footage) and the remaining number of days in the term are known. The total rental amount to be recovered will be calculated at 1.27418155 times the total cost of the pipe. The total cost of the pipe will include inspection and transportation.

4. The rental rate shall begin upon delivery of the pipe to TODDI following acceptance in accordance with Company's QA/QC specifications and inspection criteria. These specifications and criteria are made a part of this Agreement. The rental rate shall cease when the total rental paid equals 1.27418155 times the final cost of the pipe. The rental agreement will continue as long the Contract is in force however the rental rate will be zero after the total rental paid equals 1.27418155 times the final cost of the pipe.

5. Contractor shall furnish all handling equipment required for this pipe during the term of the rental at no cost to Company.

6. Initial inspection is included in the cost of the pipe. Company reserves the right to re-inspect the pipe at Company's cost. Company will be responsible for all inspections during the term of the rental.

7. The pipe shall be treated as Contractor's in-hole equipment per Article 22.3 of the Contract except for the cost of inspections.

8. During the term of the rental, Company will have the option of moving the pipe to another Transocean Rig at Company's option and expense.

If you are in agreement with the above, please sign in the space provided below and return one fully executed copy of this letter to me for our files.

If you have any questions, please contact John Keeton at (832) 587-8533 or me at (832) 587-8506. Thank you for the opportunity to be of service.

Sincerely,

/s/ Christopher S. Young
Christopher S. Young
Sr. Marketing Representative

AGREED AND ACCEPTED THIS 3RD DAY OF FEBRUARY, 2003
BP AMERICA PRODUCTION COMPANY

SIGNED	***/s/ Jerry R Rhoads***
PRINTED	***Jerry R Rhoads***
TITLE	***Contracts Specialist***

B P DEIP

INTERNAL PLASTIC COATING OF DRILL PIPE AND WORKSTRINGS

Approved By: ______________________ Date: ______________________

1.0 **<u>Scope</u>.**

1.1 This procedure details the BP GoM requirements for internal plastic coating of both new and used drill pipe, workstrings and pup joints. Additionally, this procedure details the BP GoM minimum requirements for used internal plastic coatings.

1.2 This procedure includes a visual examination of all threaded connections after internal blasting at final inspection. All workstring tubing, and workstring tubing pup joints will be full length drifted at final inspection.

2.0 **<u>Referenced Documents</u>.**

2.1 The following documents are used as references for establishing this procedure.

2.1.1 NACE TM-01-70

2.1.2 NACE TM-03-89

2.1.3 BP GoM OCTG Inspection Procedures and Requirements.

2.1.4 The Coating Contractor's Standard Operating Procedures manual for the application and inspection of internal coatings.

3.0 **<u>Contractors Internal Coating Operating Procedures And Equipment Capabilities</u>.**

3.1 The coating Contractor shall provide to BP for approval, complete standard operating procedures and equipment capabilities applicable to the individual pieces of equipment utilized for this process. The procedures will be of sufficient detail to enable the operator to perform required setup, calibration and adjustments to the equipment for preparation, application and inspection of the coatings.

4.0 **<u>Requirements For Material And Equipment</u>.**

4.1 All material, equipment, tools and supplies furnished by the Contractor shall be of good quality and adequate design, shall be maintained in good condition during use, shall conform to the requirements described in the Contractor's Specifications and Standard Operating Procedures and shall be subject to BP's approval.

5.0 **<u>Preparation</u>.**

5.1 Thread protectors shall be removed cleaned and stored until they are re-applied after final inspection.

5.2 All threaded connections shall be cleaned with steam cleaners, soapy water, varsol or other mineral spirits.

5.3 The material will then be visually examined internally for obvious defects, such as ridges or rough surfaces that would limit the coat-ability of the material. Rejected lengths will be identified, marked, segregated from the prime material and BP will be notified. No attempt will be made to coat these lengths until corrections have been made. Material with uncorrectable damage will be classified as "not suitable for coating" (NSC).

5.4 The material will undergo a thermal cleaning by prebaking the material at 600° – 800° F (pipe temperature) for a minimum period of 2 hours or as agreed to by BP. Longer prebake periods may be required depending upon the characteristics of the material being processed.

5.5 In order to insure that the proper oven temperatures are maintained, the BP QA/QC Inspector will be given a copy of the heat charts. These heat charts will be included with the BP QA/QC Inspector's final job report. Additionally, at BP's request the contractor will satisfactorily demonstrate to the BP QA/QC Inspector that the surface temperature of the pipe meets but does not exceed the established temperature limitations during the thermal cleaning, regardless of the method by which the material is heated (i.e., conveyor system or batch ovens).

5.6 After thermal cleaning is completed, the material will be internally blasted "to white metal" with an abrasive material to thoroughly clean and roughen the metal surface in order to form a suitable anchor pattern for coating.

Note: "White metal" blast cleaning is defined by NACE as follows: "White metal blasting cleaning is a method of preparing steel surfaces which, when viewed without magnification, shall be free of all visible oil, grease, dirt, drilling mud, cement, mill scale, rust, paint and coatings." All surfaces blasted to "white metal" will be inspected visually from both ends, without magnification, using visual comparators to insure proper surface preparation to NACE TM-01-70.

5.7 The abrasive blasting operation will be repeated until the proper "white metal" surface condition is achieved.

5.8 The Material must be dry before abrasive blasting begins.

5.9 The compressed air used for abrasive blasting shall be free of water and oil. At the beginning of each shift the operator will verify this. The operator will partially open the air supply at the blast station and hold a clean cloth or blotter against the airflow. If any oil or water is found, the system must be cleaned or dried prior to abrasive cleaning. Air pressure will be provided at 85 to 110 P.S.I. as measured at the blast plot.

5.10 The abrasive materials used for cleaning will be coarse Flintabrasive, Garnet, or other abrasive material meeting the Contractor's specifications. Prior to the start of the job, the Contractor shall present, blast material specifications and quality control procedures for abrasive materials, to BP for acceptance.

5.11 Prior to abrasive blasting, the material shall have protector masks installed to protect threads, seal areas and shoulders from damage.

5.12 After abrasive blasting, the material shall be thoroughly cleaned with dry, oil free compressed air to remove abrasive blasting material and other foreign material from the surface area.

5.13 The Contractor will conduct tests on both ends of the first 10 blasted pieces to establish that the anchor profile depth and appearance are satisfactory. Thereafter, tests will be conducted on both ends of every twenty-fifth piece. The test must be conducted with Testex Coarse Press-O-Film or equivalent and measured with the appropriate gauge. These tests will be conducted after full length blasting but before end blasting. Acceptable anchor profile depth will be verified to the Contractor's Specifications. At BP's request the BP QA/QC Inspector shall witness these tests, maintain the test results and include them with the final job report.

5.14 After the material is blasted and the anchor profile depth and appearance tests are completed, the material will be visually inspected to determine coat-ability. The material will be classified "not suitable for coating" (NSC), if, in the opinion of the Contractors representative or the BP QA/QC Inspector, the surface condition of the material would preclude application of coatings to the material in accordance with the Contractors Specifications. The Contractor must, however, make every reasonable effort to blast the surface of the material to a coat-able condition. The NSC material will be identified, marked and segregated from the coat-a ble material and BP shall be notified. If it is determined by the Contractor or the BP QA/QC Inspector that a second blast attempt on the NSC joint would possibly result in a coat-able piece, a second blast attempt, of at least two (2) passes, will be made.

6.0 **Internal Plastic Coating Application.**

6.1 Application of the coating material, as designated by BP, will be performed so that the required film thickness and coating properties are attained.

6.2 Coating, mixing, and thinning will be controlled in accordance with the Contractor's Standard Operating Procedures. These procedures will specify the coating material handling requirements, mixing methods, and general equipment settings necessary for a quality application.

6.3 Individual coats should produce a uniform continuous coverage of the internal surface. When additional coats are required to meet specifications, those additional processes will be the decision and responsibility of the Contractor.

6.4 Prior to coating, the material shall be properly masked to protect the threads, seal areas and shoulders from coating overspray or damage.

6.5 When required, a sample from each batch of liquid coating will be taken. This sample will be sealed with tape, properly labeled with the batch number, job number and well charges. At BP's request the BP QA/QC Inspector shall witness this process and initial each sample. The sample will be retained by the Contractor for subsequent evaluation, as directed, by BP.

6.6 Different coating batches will not be mixed on individual lengths of material.

6.7 The coating batch number(s) applicable to each BP order must be documented by the Contractor and retained in a permanent job file. At BP's request the BP QA/QC Inspector will verify the coating batch(s) utilized and include them in the final job report.

6.8 The shelf life of the batch(s) utilized on the BP material will be verified and documented by the Contractor. If the age of the coating exceeds the manufacturer's suggested shelf life, it will not be applied to the BP material. At BP's request the BP QA/QC inspector will verify the shelf life of the batch(s) utilized and include them in the final job report.

6.9 The first coat of coating shall be applied as soon as possible after blasting. In no case shall coating be delayed more than one (1) hour without reblasting. If the event a rust bloom or visual oxidation occurs before the application of the first coat, the material must be re-blasted.

6.10 Coating thickness and number of coats shall be in accordance with the Contractor's coating specifications and provide a dry film thickness (DFT) as specified by the Contractor.

6.11 Coating intermediate and final bake temperatures and times shall be in accordance with the Contractor's coating specifications. Intermediate baking will be performed at 250° – 350° F for periods of 45 minutes to 1-1/2 hours depending on coating, material size and weight. Final baking will be done at temperatures of 400° – 500° F for periods of 1-4 hours depending on coating, material size and weight. The staging of temperatures during final bake is permitted. In order to insure that proper oven temperatures are maintained the BP QA/QC Inspector will be given a copy of the heat charts. These heat charts will be incl uded with the BP QA/QC Inspector's final job report. Additionally, at BP's request the Contractor shall satisfactorily demonstrate to the BP QA/QC Inspector that the surface temperature of the material meets but does not exceed the established temperature limitations for both the intermediate and final bakes regardless of the method by which the material is heated (i.e., conveyor system or batch ovens).

6.12 Minor irregularities in individual coats may be repaired to meet specifications anytime prior to final bake at the option of the Contractor. Repairs of this nature are limited to the end area of material where thickness of repairs can be measured. Minor surface irregularities that are within the coating thickness specifications will be considered acceptable. Runs, sags, blobs, filled threads and/or blisters will be rejected.

6.13 The Contractor will conduct a sufficient number of visual and film thickness checks on the material in order to assure conformity to final product specifications.

7.0 **Final Inspection.**

7.1 After the final bake, the BP QA/QC Inspector shall conduct, at random, a dry film thickness test and visual inspection of the coated material. In addition to obvious defects such as blobs, blisters, etc., the visual inspection will verify that the final coating color is within the Contractors specifications. The color of the coating should be uniform throughout the entire length of the material.

7.2 The color of finished baked coatings is variable. The Contractor will maintain coating color standards at the coating facility. The coating color standards will be used to determine the acceptable finished color of all thermoset coatings. Lengths that contain coating color within the standard range of the coating color standards will be considered acceptable. After each final bake, the color will be verified with the proper comparator. The BP QA/QC Inspector shall witness the coating color inspection process.

7.3 The material shall be visually inspected from each end with sufficient light to detect any coating anomalies. The material will be sufficiently rotated during the visual inspection to inspect the entire inside area of the material. The material must be in a single layer for the inspection. Material will not be stacked during the final inspection. The final product should be free of runs, sags, and blisters. Surface roughness or surface irregularities will not be considered cause for rejection provided that the coating thickness is within specification.

7.4 The dry film thickness of the material will be measured on both ends of the material with a MIKROTEST DFG magnetic thickness gauge. The calibration of the thickness gauge will be conducted at the beginning of each shift or every eight hours, whichever comes first, and must be witnessed by the BP QA/QC Inspector. Material with coating thickness outside of the specified ranges (specified by the Contractor) will be rejected and reprocessed.

BP requires the average Dry Film Thickness to be .5 mils greater than the Contractor's specified minimum Dry Film Thickness and .5 mils less than the Contractor's specified maximum Dry Film Thickness. However, if any Dry Film Thickness measurement of the coating is not within this range, three additional Dry Film Thickness measurements must be taken. These measurements will be taken at 90°, 180°, and 270° and an average of the four readings will then be computed. If this average falls in the Contractor's specified Dry Film Thickness range that end of the piece is acceptable and if this average falls out of the Contractor's specified Dry Film Thickness range the whole piece is rejected.

7.5 Coatings on the face of the pipe ends are exempted from the standard minimum coating thickness requirements.

8.0 **Holiday Testing.**

8.1 Holiday testing will be performed per NACE Standard TM-03-84 on each length of pipe coated with thin film holiday free internal coating. The testing will be performed utilizing a "Tinker-Rasor" type M-1 holiday tester or equivalent, which is calibrated at the beginning of each shift or when requested by the BP QA/QC Inspector. All calibrations and testing must be witnessed by the BP QA/QC Inspector. The procedure for holiday testing of the material is as follows:

- A 2" thick cellulose sponge probe head saturated with selected electrolyte and detergent will be employed.

- The sponge will be large enough to insure a 360° contact throughout the length of the pipe. The sponge will be replaced when worn.

- A constant potential of 67.5 volts DC will be maintained between the sponge probe and the body of the tube during testing. The negative lead shall be connected to the pipe and the positive lead shall have continuity to the sponge. The tester alarm shall be activated before the testing of each joint to insure that continuity exists between the tube body and the holiday tester.

- The sponge probe will be moved through the pipe at a rate of 60 fpm ±5%.

- Each length of pipe will be holiday tested once at the Contractor's facility. Thin film coatings will be defined as holiday free when the electrical resistance between the wet sponge and the tube body is at no point less than 80,000 ohms.

- The holiday test will be performed in both directions while running the wet sponge in and out of the tube.

- All thin film corrosion coatings for both new and used pipe will be holiday free and will be applied and tested in accordance with the methods outlined above.

- The holiday free specifications will apply only while the material is at the Contractor's coating facility.

- All coated pipe that is rejected shall be reprocessed according to surface preparation, application, and inspection procedures as outlined in this specification. Those coated lengths not meeting holiday specifications after being coated a second time are to be classified as NSC. Any length that Contractor or BP determines to be unsuitable for coating (NSC) due to internal surface defects (e.g., slivers, pitting, etc.) will be set aside. This pipe will be reprocessed only upon instructions from BP.

9.0 Full Length Drifting.

9.1 After final inspection, each length will be full length drifted with a plastic or wooden drift mandrel meeting the applicable API specifications for coated material with the exception of drill pipe products, which do not require full length drifting.

10.0 Visual Thread Inspection.

10.1 After final inspection and full length drifting, is completed, the threads and sealing surfaces shall be visually inspected in accordance with the procedure BP-DEIP-P004. Thread compound, as specified by BP, will be applied to all threaded surfaces and the proper clean dry thread protectors installed.

11.1 Marking and Stenciling.

11.1 The Contractor will re-apply inspection bands and stencils as instructed by BP. Further, a clear mill varnish, acceptable to BP, will be applied to the outer surface of the material to prevent corrosion.

12.1 Documentation, Records And Reporting.

12.1 At the end of the job, the Contractor will provide BP the following documents:

- Prebake Heat Charts.
- Testex Coarse Press-O-Film test strips.
- Coating Batch number(s).
- Intermediate Bake Heat Charts.
- Final Bake Heat Charts.
- Final report, stating the piece quantity, Prime and rejects (including NSC), along with the footage’s. The reason for rejection must be reported.
- Individual pipe tally sheets indicating “threads off’ footage.

12.2 Documentation, records and reporting requirements as listed in BP-DEIP-P005 shall apply.

13.0 Health, Safety And Environmental.

13.1 Health, safety and environmental requirements as listed in BP-DEIP-P001 shall apply.

14.0 Visual Inspection Of Used Internal Plastic Coatings.

15.1

BP DEIP

HARDBANDING OF

DRILL PIPE TOOLJOINTS

HEAVY WEIGHT DRILL PIPE

AND DRILL COLLARS

Approved By: ______________________________ Date: ______________________________

1.0 **Scope**.

1.1 This procedure details the BP GoM requirements for the hardbanding of drill pipe tooljoints (loose or attached), heavyweight drill pipe and drill collars. It is applicable to new or used non-hardbanded material and material which requires re-hardbanding.

1.2 The application of proud wear resistant alloy hardfacing bands onto tooljoints, heavyweight drill pipe and drill collars significantly reduces external wear and casing wear.

2.0 **Referenced Documents**.

2.1 The following documents were used as reference for establishing this procedure.

2.1.1 Part 1 BP Drill-string Hardbanding Specification for General Release (4/6/2000).

2.1.2 ISO 9002 Quality Systems – Model for quality assurance in production and installation.

2.1.3 ISO 9003 Quality Systems – Model for quality assurance in final inspection and test.

2.1.4 API Q1 – Specification for Quality Programs.

2.1.5 ASME IX – ASME Boiler and Pressure Vessel Code. Welding and Brazing Qualifications.

2.1.6 ASTM E 709 – Standard Guide for Magnetic Particle Examination.

2.1.7 ASTM E 165 – Standard Test Method for Liquid Penetrant Examination.

2.1.8 API Specification 7 - Rotary Drill Stem Elements.

2.1.9 API Recommended Practice 7G - Drill Stem Design and Operating Limits.

3.0 **Quality Assurance**.

3.1 The Applicator shall operate a Quality Assurance organization responsible for formulating and implementing a Quality System, which insures that the requirements of this procedure are met.

3.2 The Applicator's Ouality System shall be based on ISO 9002 and ISO 9003 or API Q1. Particular attention is drawn to Section 4.8.2 in ISO 9002 and Section 3.12 in API Q1 concerning Special Processes. Hardbanding and the associated practices are considered to be Special Processes and shall be qualified strictly in accordance with the requirements of this procedure.

3.3 The effectiveness of the Applicator's Quality System will be subject to monitoring by BP and may be audited following and agreed period of notice.

4.0 **Hardbandinq Types**.

4.1 There are two basic types or categories of hardbanding for drill pipe tooljoints, heavyweight drill pipe and drill collars utilized in the Oil Industry today. These comprise weld overlays that consist of wear resistant alloys that do not contain tungsten carbide granules and weld overlays consisting of tungsten carbide granules within a metallic substrate (normally a low carbon steel). In this procedure these types will be referred to as "Wear Resistant Alloy Overlays" and "Tungsten Carbide Overlays".

4.2 **Wear Resistant Alloy Overlays.** These materials are hard alloys containing no solid particles. Therefore, unlike tungsten carbide overlays, there is no possibility of hard particles standing proud or becoming exposed from a softer matrix and producing severe abrasive wear of the casing. Wear resistant alloy overlays are required when applying hardfacing for BP GoM and are strongly recommended verses tungsten carbide overlays in all cases.

4.3 **Tungsten Carbide Overlays.** These consist of granules of tungsten carbide in a steel matrix. The use of tungsten carbide overlays is not permitted when applying hardfacing for BP GoM on drill pipe tooljoints, heavyweight drill pipe or drill collars. The use of drill pipe with tungsten carbide overlays is not permitted without the express consent of the responsible BP Engineer. Since heavyweight drill pipe and drill collars are used in open-hole sections the majority of time while drilling, BP GoM may accept tungsten carbide overlays on these items. However, if tungsten carbide overlays are used on heavyweight drill pipe or drill collars BP GoM reserves the right to examine the hardfacing for acceptance on a case, by case basis.

5.0 <u>Welding Issues</u>.

5.1 **Welding Processes.** Hardbanding shall be deposited by the use of a mechanized GMAW welding technique using a solid wire or cored wire consumable. Self shielded or open arc welding techniques may also be used. Other techniques for the deposition of hardbanding may be proposed for consideration by BP.

The hardbanding shall be applied as individual circumferential weld beads laid side by side to achieve the specified width of hardbanding. The as welded surface shall be smooth and the adjacent beads shall be deposited with sufficient overlap to avoid the formation of inter-bead troughs or valleys. High crowns or severe ridges must also be avoided.

5.2 **Preheat And Interpass Temperature.** A minimum preheat temperature of 400°F shall be achieved through the full thickness of the component prior to the start of hardbanding or application of mild steel (butter-pass) and this temperature shall be maintained as the minimum interpass temperature throughout the welding process. The maximum interpass temperature for the application of hardbanding or mild steel shall be 650°F.

5.3 **Post Weld Thermal Regime.** Immediately on completion of welding, the component shall be subjected to one of the following alternative thermal regimes:

5.3.1 The temperature of the internal and external surface of the component shall be measured and if necessary the component shall be heated such that a temperature of 650°F is attained through the full thickness. The component shall then be allowed to slow cool to ambient temperature while fully wrapped in an insulating blanket or specially constructed insulating can. The components shall be kept under cover and shall not be exposed to any wind, drafts or rain during the cooling period.

5.3.2 The component shall be placed in an oven and maintained at a temperature of 400°F for a minimum period of two (2) hours prior to slow cooling under insulation, as detailed in section 5.3.1 above.

5.4 **Welding Parameters.** The welding parameters employed for hardbanding should be based on those recommended by the consumable manufacturer. However, it should be noted that these parameter values are often provided for guidance only and Applicators should undertake sufficient welding procedure development work to insure that they have established a stable welding condition prior to welding procedure qualification.

5.5 Welding Procedures (WPS). All welding procedures associated with the application of hardbanding or mild steel shall be qualified in accordance with ASME IX, QW 216, QW 453 and the requirements of this procedure. Production welding equipment shall be employed for the welding procedure qualification.

Individual welding procedures shall be qualified by the Applicator for:

- The application of flush and proud hardbanding. A separate WPS is required for each type of hard metal consumable.
- The application of mild steel.
- The application of mild steel (butter-pass), flush and proud hardbanding on re-hardbanded components. A separate WPS is required for each type of hard metal consumable.

The application of mild steel and hardbanding on re-hardbanded components may be qualified in a single procedure.

The welding procedure specification (WPS) and procedure qualification record (PQR) shall be submitted to BP GoM for approval prior to the commencement of any production welding. These documents shall be prepared in the ASME format with supplementary pages as necessary to provide a full and detailed description of the hardbanding procedure.

5.6 Welding Procedure Qualification (PQR). All welding procedure qualifications shall be performed on a 4145H tubular material, preferred size of 6 5/8" OD and 2 3/4" ID, representing a typical drill collar. The manufacturer's certificate, including full details of heat treatment, mechanical testing results and chemical analysis, for this material and the welding consumable shall be included in the PQR documentation. All relevant welding p arameters shall be monitored and recorded during the production of the test weld and reported in the PQR.

The hardbanding shall be allowed to stand at ambient temperature for a minimum of forty-eight (48) hours prior to the examination detailed in Note 3, QW 453. The acceptance criteria for this examination shall be as detailed in section 10.0 of this procedure.

Subsequent to the above an ultrasonic examination of the hardbanding and parent metal interface shall be performed to demonstrate freedom from lack of fusion or any under bead cracking. The surface of the hardbanding shall be prepared for this examination by machining or grinding. Testing shall examine the full width of the hardbanding at five equally spaced locations around the circumference.

Following the above ultrasonic examination the Rockwell hardness of each band of hardfacing shall be measured at each of the five locations and each hardness reading shall meet the published recommendations of the consumable supplier.

Two coupons shall be cut and prepared for examination as detailed in Note 8, QW 453 except that only one surface on each need be polished and etched. These coupons shall be taken at least 90° apart. A macrograph shall be taken of each prepared surface and included in the PQR.

Additionally, three (3) vertical hardness traverses shall be made across the fusion boundary from the weld deposit into the heat-affected zone of the 4145H material. These measurements shall be made using a Vickers indenter with either a 5kg or 10kg load.

A full chemical analysis shall be performed in accordance with Note 9, QW 453.

5.7 Manufacturing Reference Standards. Subsequent to the testing detailed in Section 5.6 above the remainder of the welding procedure qualification test piece shall be retained by the Applicator to act as a reference standard during production.

5.8 Welder/Machine Operators Performance Qualification. Working in accordance with a qualified WPS each hardbanding welder/machine operator shall manufacture a test piece as detailed in section 5.6 in order to demonstrate his ability. The test piece shall be subjected to the examination detailed in Note 3, QW 453 and meet the criteria outlined in section 10.0 of this procedure. Each welder/machine operator performing a successful welding procedure qualification test shall be deemed to have completed a satisfactory performance test.

The Applicator's Quality Assurance department shall maintain a record of each welder/machine operator's qualification and working experience. A welder/machine operators qualification shall lapse and re-qualification will be required if he/she does not perform hardbanding for a period exceeding three months.

5.9 Production Welding. Production welding shall be undertaken strictly in accordance with the qualified welding procedures. All welder/machine operators shall be qualified in accordance with section 5.8. A copy of the basic elements of the WPS shall be available for reference at each hardbanding station.

Appropriate shop floor supervision and detailed working procedures shall be available to ensure hardbanding is deposited to this Specification at all times. Regular monitoring and recording of preheat temperatures, welding set up, welding parameters and the post weld thermal regime shall form an integral part of these procedures. All production records shall be retained within the Applicator's Quality System archives.

6.0 Hardbandinq Configurations.

6.1 Definitions. When applying new hardbanding and for the purposes of this procedure the following definitions shall apply.

- "Proud" hardbanding is an overlay that stands proud from the base material. Tolerances for proud hardbanding are + 3/32" to + 1/8" as measured from the base material surface.

- "Flush" hardbanding is an overlay that is flush with the base material surface. Tolerances for flush hardbanding are + 1/64" and — 0 as measured from the base material surface.

6.2 Drill Pipe Tooljoints. Hardbanding (Wear Resistant Alloy Overlay) shall be applied in the following locations:

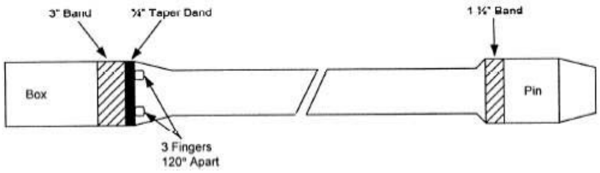
- A three (3") inch wide band on the box tooljoint OD next to the taper. These bands shall be applied proud.

- One 3/4" wide band on the box tooljoint 18° taper. This band shall be applied flush.

- Three 3/4" long fingers 120° apart projecting from the base of the hardbanding on the box tooljoint taper onto the box upset. Fingers shall be applied flush.

- A one and one half (1 1/2") inch wide band on the pin tooljoint OD next to the taper. These bands shall be applied proud.

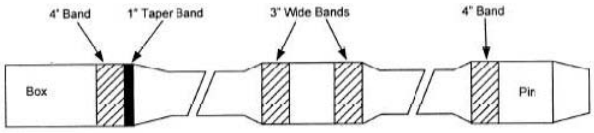
Figure 1.1 (Drill Pipe)



6.3 **Heavy Weight Drill Pipe.** Hardbanding (Wear Resistant Alloy Overlay) shall be applied in the following locations:

- One 4” inch wide band on the box and pin tooljoint OD next to the taper. These bands shall be applied proud.
- One 1” wide band on the tapered section of the box tooljoint. This band shall be applied flush.
- Two 3” wide bands on each end of the center wear pad. These bands shall be applied proud.

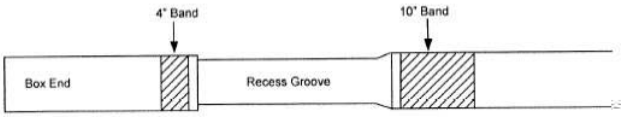
Figure 1.2 (Heavy Weight Drill Pipe)



6.4 **Drill Collars With Slip Recess Groove.** Hardbanding (Wear Resistant Alloy Overlay) shall be applied in the following locations:

- One, 4” wide band on the box end OD located 1” away from the beginning of the slip recess groove. This band shall be applied proud.
- One, 10” wide band on the drill collar OD located 1” away from the end of the slip recess groove. This band shall be applied proud.

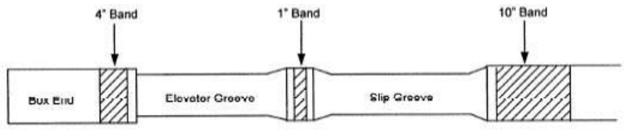
Figure 1.3 (Drill Collar with Slip Recess Groove)



6.5 Drill Collars With Slip And Elevator Recess Grooves. Hardbanding (Wear Resistant Alloy Overlay) shall be applied in the following locations:

- One, 4” wide band on the box end OD located 1” away from the beginning of the slip recess groove. This band shall be applied proud.
- One, 1” wide band on the wear pad OD between the two recess grooves. This band shall be applied proud.
- One, 10” wide band on the drill collar OD located 1” away from the end of the slip recess groove. This band shall be applied proud.

Figure 1.4 (Drill Collar with Slip And Elevator Recess Grooves)



7.0 Pre-Hardbandinq Considerations.

7.1 Mill Slots, Chip Slots and Identification Grooves. Inspect the tooljoints to determine if there are mill slots, chip slots, identification grooves or other machined areas on the tooljoints that will interfere with the application of hardbanding per section 6.2. If machined areas exist and will interfere with the hardbanding application process notify the Material Supplier prior to hardbanding the material and obtain permission to fill the machined areas in with mild steel. The application of mild steel shall meet the requirements outlined in section 5.0 and 9.0.

7.2 Internal Plastic Coating. Inspect the material to determine if it is internally plastic coated. If the material is internally plastic coated notify the Material Supplier prior to hardbanding the material and inform the Material Supplier that the material will require re-coating after the hardbanding process.

Note: Under no circumstances shall material be filled with water during the hardbanding process to preserve the internal plastic coating.

7.3 Pre-Existing Hardband. Inspect the material to determine it the material has been previously hardbanded. If the material has been previously hardbanded notify the Material Supplier prior to the hardbanding the material and inform the Material Supplier that the existing hardbanding will have to be removed in accordance with section 9.0 prior to applying the new hardbanding.

Note: Under no circumstances shall new hardband be applied over pre-existing hardband of any type without prior approval by the BP QA/QC Manager.

8.0 <u>Hardbanding Procedure</u>.

8.1 Machining. When applying proud hardbanding, a groove shall be machined into the surface of the material prior to the application of hardbanding. The groove depth shall be 1/32" (+/-.010") as measured from the surface of the material. When applying flush hardbanding, a groove shall be machined into the surface of the material prior to the application of hardbanding. The groove depth shall be 3/32" (- 0 + 1/32") as measured from the surface of the material. When applying flush hardbanded fingers, three, 3/4" long, 1/2" wide and 3/32" deep slots shall be ground into the drill pipe box end upset. All groove and slot widths shall equal the intended width of the hardbanding to be applied as defined in section 6.0.

Note: It may be necessary to modify the groove depth on the box taper to achieve a smooth tie in to the three (3) inch band located on the box OD.

8.2 Surface Preparation. Hardbanding shall be deposited onto a machined or ground white metal surface. This surface shall be free from dirt, drilling mud, cement, paint, rust, cutting fluid, grease etc. Additionally, a two (2) inch band on either side of the machined area shall be thoroughly cleaned and degreased.

8.3 Preheat. Preheat the area requiring hardbanding in accordance with the BP approved WPS (See section 5.0 for more details). The preheat temperature shall be verified on each area requiring hardbanding on each piece with a calibrated pyrometer or the properly rated temperature sticks. When temperature sticks are used the Applicator shall have at a minimum, temperature sticks rated to the preheat temperature and maximum interpass temperature.

8.4 Hardbanding Application. Apply hardbanding to the material in accordance with the BP approved WPS (See section 5.0 for more details).

8.5 Interpass Temperature. Monitor the interpass temperature throughout the hardband application process to insure the minimum and maximum interpass temperatures are maintained in accordance with the BP approved WPS (See section 5.0 for more details). The interpass temperature shall be measured with a calibrated pyrometer or the properly temperature sticks. When temperature sticks are used the Applicator shall have at a minimum, temperature sticks rated to the minimum interpass temperature and maximum interpass temperature.

8.6 Post Weld Thermal Regime / Slow Cooling. Immediately on completion of the hardband application, the material shall be subjected to a post weld thermal regime in accordance with the BP approved WPS (See section 5.0 for more details).

8.7 Surface Finish. After the material has slow cooled to ambient temperature, remove all weld spatter or protrusions by grinding, sanding or machining methods. Close control of the hardband welding parameters should result in a good surface finish, such that it is not usually necessary to grind, sand or machine the entire hardbanded surface.

Note: Unless specified by BP, Amorphous type hardfacings do not require post application grinding or sanding to increase the surface hardness of the material.

8.8 Inspection. Perform a dimensional inspection on each hardbanded area to insure the requirements outlined in section 6.0 have been met.

8.8.1 Perform a visual inspection on each hardbanded area. Acceptance and rejection criteria shall be per section 10.0.

Note: When required by BP, contrast paint shall be applied to the hardbanding in order to assist the visual examination.

8.8.2 Clean all connections and perform a visual inspection on the threaded and sealing surfaces in accordance with procedure BP-DEIP-P004.

8.8.3 Perform a bi-directional wet magnetic particle inspection on the HAZ and at least two (2) inches of the surrounding parent metal around all hardbanded areas. The bi-directional WMPI shall be performed in accordance with procedure BP-DEIP-P002 (the transverse MPI method shall be per section 7.0 and the longitudinal MPI method shall be per section 8.0). Acceptance and rejection criteria shall be per section 10.0.

8.9 **Finishing.** Blow the material ID out with compressed air to remove any debris. Apply the appropriate thread compound to all connections as specified by the Material Supplier and install clean dry thread protectors wrench tight. Apply a thin coat of rust inhibitor to the freshly hardbanded, ground, sanded or machined areas.

9.0 **Removal of Existing Hardbanding and Application of Mild Steel.**

9.1 **Removal of Existing Hardbanding.** The removal of existing hardbanding shall be performed with pre-approved methods or techniques such as, plasma arc gouging, grinding or machining. When plasma arc gouging techniques are used care shall be taken to minimize the heat input.

9.1.1 After removal of the existing hardbanding with plasma arc gouging techniques, the excavated area shall be machined smooth to provide a suitable surface for WMPI.

9.2 **Inspection.** All areas where previous hardbanding has been removed shall be etched with a 5% Nital solution to verify that all of the hardband material has been removed. This process shall be repeated as many times as necessary to insure all previous hardband material has been completely removed.

9.2.1 Perform a bi-directional wet magnetic particle inspection on all areas where hardbanding has been removed and all areas that have been affected during the removal process. The bi-directional WMPI shall be performed in accordance with procedure BP-DEIP-P002 (the transverse MPI method shall be per section 7.0 and the longitudinal MPI method shall be per section 8.0). Acceptance and rejection criteria shall be per section 10.0.

9.3 **Application of Mild Steel.** Apply mild steel to the previously excavated areas and/or mill slots, chip slots or identification grooves if necessary in accordance with the BP approved WPS (See section 5.0 for more details).

9.4 **Machining.** Machine the areas where mild steel has been applied back to the original OD or taper of the area.

Note: Grooves for new hardbanding as outlined in section 8.1 can be machined in conjunction with the above machining process prior to performing the WMPI detailed in section 9.5.

9.5 **Inspection.** Perform a bi-directional wet magnetic particle inspection on all areas where mild steel has been applied. The bi-directional WMPI shall be performed in accordance with procedure BP-DEIP-P002 (the transverse MPI method shall be per section 7.0 and the longitudinal MPI method shall be per section 8.0). Acceptance and rejection criteria shall be per section 10.0.

10.0 Acceptance Criteria.

10.1 Mild Steel And Parent Material. Relevant indications on the external or internal surface (including HAZ) of parts shall be removed by grinding or machining, provided that the part still conforms to BP's, the Manufacturer's or API acceptance criteria after the removal process.

Note: All areas that have had indications removed shall be re-inspected in accordance with the appropriate MPI method in accordance with procedure BP-DEIP-P002 section 7.0, 8.0 or 9.0 after the removal process to insure complete imperfection removal.

10.2 Wear Resistant Alloy Overlays. These hard wear resistant deposits possess relatively low ductility. Therefore, weld metal cracking often occurs transverse to the weld bead under the influence of residual stresses. Typically, these cracks may run straight across the weld bead or at an angle between 30° and 45°. Occasionally the cracks will interconnect. This is acceptable as long as the cracks are less than 1/16" wide or have a minimum spacing of 1/2" apart when the cracks run across the full width of the hardbanded region. If cracks fail to meet this criteria remove the deposit and re-hardband the material in accordance with sections 8.0 and 9.0.

Figure 1.5 (Transverse Cracks)

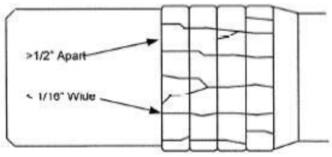


Figure 1.5 illustrates an acceptable configuration of transverse cracks. Crack widths are less than 1/16" and cracks extending the full width of the hardband deposit are greater than 1/2" apart.

If there are circumferentially running cracks, these are unacceptable where a single continuous crack is greater than 3" long, as they can result in a premature fatigue failure of the material. Additionally, flaking or spalling of the hardband deposit is unacceptable. In such circumstances remove the deposit and re-hardband the material in accordance with sections 8.0 and 9.0.

Figure 1.6 (Circumferential Cracks and Flaking)

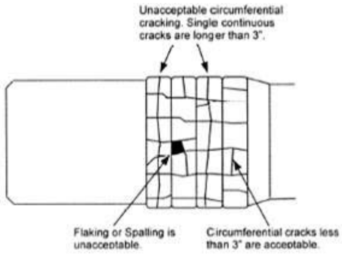


Figure 1.5 illustrates unacceptable circumferential cracking and flaking and acceptable circumferential cracking.

Small troughs between individual weld beads are acceptable as long as they are no more than 1/8” wide or 1/16” deep.

Figure 1.7 (Inter-Bead Troughs)

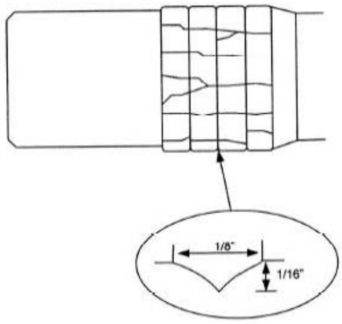


Figure 1.7 illustrates Inter-Bead Troughs. “Troughs” are acceptable if less than 1/8” wide and 1/16” deep.

If any cracking is detected in the HAZ, mild steel or parent material, the hardbanding and cracked areas must be completely removed in accordance with section 9.0, provided that the material still conforms to BP’s, the Manufacturer’s or API acceptance criteria after the removal process. The area shall be re-hardbanded in accordance with section 8.0.

If there are surface breaking non-linear defects, such as porosity on the hardband weld beads greater than 1/8” diameter or 1/16” deep, these may be filled using semi-automatic GMAW or SMAW. This type of repair must be performed with a consumable matching the composition of the hardband material and will require a BP approved WPS (See section 5.0 for more details).

Note: The acceptance criteria outlined in this section are the minimum requirements BP will accept, regardless of the Hardband Manufacturer’s, Material Supplier or Applicator’s acceptance criteria. However, it is necessary to obtain and review the Hardband Manufacturer’s, Material Supplier and Applicator’s acceptance criteria to insure the material is inspected correctly.

11.0 <u>Documentation, Records and Reporting</u>.

11.1 The Applicator shall submit to BP an inspection record, which will clearly state that the hardbanding has been applied and inspected in accordance with this procedure. The scope and content of this record shall include:

- A reference list of the Applicator’s procedures used in the production of the hardbanding and a copy of the WPS(s) and PQR(s).
- A copy of all NDE reports.

11.2 Documentation, records and reporting requirements as listed in procedure BP-DEIP-P005 shall apply.

12.0 **General Requirements.**

12.1 General requirements as listed in procedure BP-DEIP-P001 shall apply.

13.0 **Marking And Stenciling.**

13.1 Marking and stenciling requirements as listed in procedure BP-DEIP-P001 shall apply.

14.0 **Documentation, Records and Reporting.**

14.1 Documentation, records and reporting requirements as listed in procedure BP-DEIP-P005 shall apply.

15.0 **Health, Safety And Environmental.**

15.1 Health, safety and environmental requirements as listed in BP-DEIP-P001 shall apply.

BP DEIP

MAKE AND BREAK OF

DRILL PIPE AND WORKSTRING

TOOLJOINTS

Approved By: ____________________ Date: ____________________

1.0 Scope.

1.1 This procedure describes the processes established to make and break new drill pipe and workstring tooljoints, both, affixed or loose.

1.2 Since newly machined connections are susceptible to galling the make and break process is utilized to break in new connections (tooljoints) by work hardening the connection surface.

2.0 Personnel Qualifications.

2.1 Personnel performing make and break operations must be trained and experienced in the operation of the make and break unit.

3.0 Required Materials & Equipment.

3.1 **Hydraulic Make And Break Unit.** The make and break unit shall be capable of making up and breaking out two joints of range III drill pipe together to the manufacturers recommended torque value.

3.1.1 The unit shall be equipped with load cells and gauges capable of indicating the torque values obtained in Ft./Lbs.

3.1.2 Calibration of the load cells and gauges on the make and break unit shall be performed a minimum of once every six (6) months. The calibration documentation shall be available for review at the job site.

3.1.3 The make and break unit shall be equipped with the properly sized power and backup tongs.

3.1.4 Power and backup tongs will utilize low stress, large contact surface area dies to reduce grip marks.

3.2 **Additional Required Equipment.** The following equipment shall be available on the job sight and in good working order: Depth (pit) gauge, files, 50' metal tally tape, absorbent pad, catch pans, cleaning solvent, cleaning brushes, thread compound, dope brushes, assorted paints and metal markers.

4.0 Make And Break Procedures.

4.1 Remove the thread protectors and stack them off the ground to prevent contamination with dirt, grit, grass etc.

4.2 Visually inspect the condition of the thread compound to insure a thin uniform coat of make-up thread compound has been applied and is not contaminated with dirt, grit, rust, scale etc.

Note: The thread compound must be an approved make-up compound such as ZN-50 or Jet Lube Kopr-Kote. If the thread compound on the connections is not an approved make-up compound (i.e., kendex) it must removed by cleaning the connections with solvent, varsol etc. and drying the connections prior to applying the proper make-up thread compound.

4.3 Verify the make and break unit has been set up properly prior to commencing the make and break operation. The unit must be level and both tongs must be perpendicular to the tooljoints. In addition, the tooljoints shall be centered in the tongs and tong dies shall contact the tooljoints in a uniform fashion to prevent excessive grip marks and slippage.

4.4 Recommended torque values shall be obtained from the drill pipe manufacturer or their published documents prior to the start up of the make and break operation.

4.5 The make and break process shall consist of and be performed in the order listed below.

1. Make up a box and pin connection to 100% of the specified optimum torque value. Break out the box and pin connections.

2. Clean both connections and perform visual inspection for damages or excessive grip marks. Repair any minor damages with a file or emery cloth and apply a thin coating of dry moly lubricant over the repaired connection.

Note: If the connections are damaged beyond minor field repair shut the make and break operation down and contact the responsible BP Inspection Coordinator for further instructions.

3. Provided that the damages are minor or non-existent repeat the operations outlined in step one (1) above two (2) more times without cleaning the connections.

4. After the third make and break cycle clean both connections and perform visual inspection for damages. Repair any minor damages with a file or emery cloth and apply a thin coating of dry moly lubricant over the repaired connection.

5. Repeat the operations outlined in steps one (1), two (2), three (3) and four (4) on the next four (4) sets of boxes and pins.

6. Provided that the damages are minor or non-existent on the first five (5) sets connections the remaining connections in the order shall be made up to 100% of the specified optimum torque value and broken out three (3) consecutive times without cleaning the connections between make and break cycles.

7. Clean all connections after the final make and break cycle and perform a visual inspection for damages or excessive grip marks. Repair any minor damages with a file or emery cloth and apply a thin coating of dry moly lubricant over the repaired connection.

8. Allow the connections to dry or dry the connections with compressed air. Apply a thin, uniform film of the specified thread compound to all connections and install thread protectors wrench tight.

5.0 **Visual And Dimensional Inspection.**

5.1 Visual and dimensional requirements as listed in procedure BP-DEIP-P004 shall apply.

6.0 **General Requirements.**

6.1 General requirements as listed in procedure BP-DEIP-P001 shall apply.

7.0 **Marking And Stenciling.**

7.1 Marking and stenciling requirements as listed in procedure BP-DEIP-P001 shall apply.

8.0 Documentation, Records and Reporting.

8.1 Documentation, records and reporting requirements as listed in procedure BP-DEIP-P005 shall apply.

9.0 Health, Safety And Environmental.

9.1 Health, safety and environmental requirements as listed in BP-DEIP-P001 shall apply.

TRANSOCEAN HOLDINGS INC.
1311 BROADFIELD, SUITE 400
HOUSTON, TX 77084

CHRISTOPHER S. YOUNG
SR. MARKETING REPRESENTATIVE

January 6, 2003

BP America Production Company
501 WestLake Park Blvd.
Houston, TX 77079

Attn: Mr. Jon Sprague — Atlantis Wells Delivery Leader

Re: **Drilling Contract No. 980249** dated December 9, 1998 by and between **R&B Falcon Drilling Company predecessor in interest to Transocean Holdings Inc.** ("Contractor") and **Vastar Resources, Inc. predecessor in interest to BP America Production Company** ("Company"), as amended for RBS-8D (now known as the **Deepwater Horizon**)

Subject: Letter of Agreement for adding Offshore Safety Assistant
CONTRACTOR-5121-2002-011

Dear Mr. Sprague:

This letter will confirm our agreement to add additional Transocean personnel to the crew complement of the **Deepwater Horizon**. Upon execution of this Letter Agreement by Company, Contractor agrees to provide two (2) Offshore Safety Advisors (OSA) on the **Deepwater Horizon** in addition to those specified to be specified to be provided in Exhibit F-1 of the Contract as amended. Exhibits F-1 and F-2 of the Contract shall be amended, as of January 1, 2003 to provide for the following additional personnel:

Title	On Board	Assigned to Rig	Daily Rate per Person w/ Burden	Hourly Overtime Rate w/Burden
Offshore Safety Advisor	1	2	$ 930.23	NA

Therefore, the amended crew complement shall show one (1) OSA "On Board" and two (2) "Assigned to Rig". The amended crew complement is attached. In summary, all rates in the Contract shall increase by **$930.23** per day effective January 1, 2003. Except as specifically provided herein, all other terms and conditions of the Contract shall remain in full force and effect. Please indicate your agreement in the space provided below and return one fully executed copy of this letter to me for our files.

If you have any questions, please contact John Keeton at (832) 587-8533 or me at (832) 587-8506. Thank you for the opportunity to be of service.

Sincerely,

/s/ Christopher S. Young
Christopher S. Young
Sr. Marketing Representative
On Behalf of Transocean Holdings Inc..

PHONE: (832) 587-8506 FAX: (832) 587-8754 EMAIL: cyoung@houston.deepwater.com

AGREED AND ACCEPTED THIS 27th DAY OF JANUARY, 2003

BP AMERICA PRODUCTION COMPANY

SIGNED	***/s/ Jerry R Rhoads***
PRINTED	***Jerry R Rhoads***
TITLE	***Contracts Specialist***

TRANSOCEAN HOLDINGS INC.
1311 BROADFIELD, SUITE 400
HOUSTON, TX 77084

CHRISTOPHER S. YOUNG
SR. MARKETING REPRESENTATIVE

January 7, 2003

BP America Production Company
501 WestLake Park Blvd.
Houston, TX 77079

Attn: Mr. Jon Sprague — Atlantis Wells Delivery Leader

Re: **Drilling Contract No. 980249** dated December 9, 1998 (“Contract”) by and between **R&B Falcon Drilling Company predecessor in interest to Transocean Holdings Inc.** (“Contractor”) and **Vastar Resources, Inc. predecessor in interest to BP America Production Company** (“Company”), as amended for RBS-8D (now known as the **Deepwater Horizon**)

Subject: Letter of Agreement for Recycling program — Deepwater Horizon
CONTRACTOR-5121-2002-011

Dear Mr. Sprague:

This letter will confirm our agreement that effective, January 1, 2003, the parties desire to amend the Contract in order for Contractor to implement a recycling program on the Deepwater Horizon and that Company shall reimburse Contractor for the costs and charges associated with this Service as detailed in Attachment 1, which is attached hereto and made a part of this Letter Agreement.

Except as expressly amended herein, the terms and conditions of the Contract, as previously amended, will remain in effect. Please indicate your agreement in the space provided below and return one fully executed copy of this letter to me for our files. If you have any questions, please contact John Keeton at (832) 587-8533 or me at (832) 587-8506. Thank you for the opportunity to be of service.

Sincerely,

/s/ Christopher S. Young
Christopher S. Young
Sr. Marketing Representative
On Behalf of Transocean Holdings Inc..

AGREED AND ACCEPTED THIS 7th DAY OF FEBRUARY, 2003

BP AMERICA PRODUCTION COMPANY

SIGNED	***/s/ Jerry R Rhoads***
PRINTED	***Jerry R Rhoads***
TITLE	***Contracts Specialist***

PHONE: (832) 587-8506 FAX: (832) 587-8754 EMAIL: cyoung@houston.deepwater.com

ATTACHMENT 1
SCOPE OF WORK AND COMPENSATION
RECYCLING PROGRAM — DEEPWATER HORIZON

1. Scope of Work

Company has requested and Contractor has agreed to provide a recycling program covering recyclable waste materials from Contractor's Deepwater Horizon Drilling Unit ("Rig"). This program will commence on 1/1, 2003 and shall continue for the remaining primary term of the Contract unless terminated by Company by providing written notice thirty (30) days in advance of the termination date.

Contractor (or its subcontractor) will provide the following services:

1. Provide a recycling service to reduce and separate the waste on the Rig.
2. Furnish recycling and general waste compactor units to the Rig.
3. Supply storage bins at dock locations for collection of recycled materials.
4. Collect and transport compacted bags of recycled materials from the storage bins.
5. Track and provide totals of the volume of recycled material collected
6. Maintain and repair compactor units as needed.
7. Training of Rig personnel in operating, tagging and delivery of the recycled materials to the storage bins

At the Fourchon dock location, Company shall be responsible for ensuring that properly marked recyclable material received at the dock is placed into the appropriate "Recycle the Gulf" storage bin(s) for collection.

2. Rates

Company shall reimburse Contractor the following fees and costs during the term of this recycling service:

Service Fee $75.00/day

This Service Fee includes:
1. Equipment on the Rig to separate and compact recyclables
2. Storage Bin located at dock location (Fourchon)
3. Pick up and transportation (from Fourchon dock)
4. Employee Training packet
5. Processing service

Recycle the Gulf Bags — New	5.5 cuft Tri-2 Bags	$ 10.35/each
	14 cuft 6 x 2 bags	$ 10.15/each

Model 4000 Trash Compactor Bags	$ 10.20/each
Processing Fee (per bag of recycled material)	$ 1.85/bag

TRANSOCEAN OFFSHORE DEEPWATER DRILLING, INC.
4 GREENWAY PLAZA (77046)
POST OFFICE BOX 2765
HOUSTON, TEXAS 77252-2765

Gregory L. Cauthen
Senior Vice President, Chief Financial Officer and Treasurer

February 18, 2003

BP America Production Company
501 WestLake Park Blvd.
Houston, TX 77079

Attn: Mr. Randy Rhoads

Re: **Drilling Contract No. 980249** dated December 9, 1998 by and between **R&B Falcon Drilling Company predecessor in interest to Transocean Holdings Inc.** ("Contractor") and **Vastar Resources, Inc. predecessor in interest to BP America Production Company** ("Company"), as amended for RBS-8D (now known as the **Deepwater Horizo n**)

Subject: **Direct Payment of Invoices**
CONTRACTOR-5121-2002-011

Dear Randy,

This letter is a formal request for BP to pay invoices related to the Contract referenced above by wire transfer to the following account:

Transocean Holdings Inc
Wells Fargo Bank
Houston, Texas
Beneficiary: Transocean Holdings Inc
Account number:
ABA Number:
SWIFT Number:

Thank you for your cooperation. If you have any questions, please contact John Keeton at (832) 587-8533 or Chris Young at (832) 587-8506. Thank you for the opportunity to be of service.

Sincerely,

/s/ Gregory L. Cauthen
Gregory L. Cauthen
Senior Vice President, Chief
Financial Officer & Treasurer

cc: Craig Duncan
Chris Young

TRANSOCEAN HOLDINGS INC.
4 GREENWAY PLAZA
HOUSTON, TX 77046

CHRISTOPHER S. YOUNG
SR. MARKETING REPRESENTATIVE

February 28, 2003

BP America Production Company
501 WestLake Park Blvd.
Houston, TX 77079

Attn: Mr. Randy Rhoads

Re: **Drilling Contract No. 980249** dated December 9, 1998 by and between **R&B Falcon Drilling Company predecessor in interest to Transocean Holdings Inc.** ("Contractor") and **Vastar Resources, Inc. predecessor in interest to BP America Production Company** ("Company"), as amended for RBS-8D (now known as the **Deepwater Horizon**)

Subject: **Letter of Agreement for Cost Escalation 2003**
CONTRACTOR-5121-2002-011

Dear Randy,

We performed the "annual" cost analysis for the ***Deepwater Horizon*** as of January 1, 2003 in accordance with Article 2.3 "Adjustment in Dayrates" of the Contract referenced above. The following table summarizes the Baseline Cost changes detailed on the attached schedule "Basis for Cost Escalation":

Reference	2001 Baseline Costs plus Previous Agreements	Actual Baseline Costs @ Jan. 1, 2003	Increase/ (Decrease)	Dayrate Increase/ (Decrease)
2.3.2a Base Labor Costs	**$ 36,008**	**$ 36,139**	**$ 131**	*****
2.3.2b Catering Costs	**$ 2,366**	**$ 2,780**	**$ 414**	**$ 414**
2.3.2c Maintenance Element	**13,851**	**13,946**	**$ 95**	*****
2.3.2d Insurance	**$ 1,799**	**$ 5,137**	**$ 3,338**	**$ 3,338**
Total	**$ 54,024/day**	**$ 58,002/day**		**$ 3,752/day**

* According to Article 2.3.2, rates for each item must vary by => 5% before they can be adjusted.

Notes:

2.3.2a Base Labor rates did not change but several of our "burdens" did change on January 1. FICA limits increased as well as pension accruals and some insurance related items. We reduced the utilization bonus. The net result was a slight increase but not the 5% required to trigger an increase. Please note that the total includes all personnel added by letter agreement.

2.3.2b Contractor's cost of catering has increased from $27.20 per man per day to $31.95, an increase of 17.5%. Please note the catering cost shown on the accompanying schedule only reflects the crew complement in the contract (77 on board the rig) while we actually have 83.

PHONE: (832) 587-8506 FAX: (832) 587-8754 EMAIL:cyoung@houston.deepwater.com

2.3.2c The Maintenance Element of the Baseline Cost increased $95 per day based on the change on the relevant Producer Price Index. The Index number for December 2002 increased to 146.8 from 145.8 in August of 2001, an increase of .69 %. The Bureau of Labor Statistics Data for the Producer Price Index series ID: WPU119102 is attached. Since the change was less than 5% we did not include it in the rate adjustment.

2.3.2d The insurance element increased $3,338 per day for a 186% increase and accounts for the majority of the overall cost increase. The cost of the various coverages is broken out on the accompanying schedule. Insurance costs increased dramatically throughout the industry for reasons already discussed. Please note that we lowered the insured value of the rig from $350 million to $320 million and increased the deductible from $500,000 to $10 million to reduce the H&M premium. Without the increased deductible, the premiums would have been significantly higher. Basically, we are self-insured for the first $10 million of coverage. The Marine P&I insurance cost shown on the accompanying schedule reflects a $4,832 per assigned person per year accrual determined by our insurance c ompany for the self-insured $10 million.

The following documents are attached for reference: 1) “Basis for Cost Escalations” schedule; 2) “Adjusted Base Labor as of January 1, 2003”; 3) the Bureau of Labor Statistics Data for the relevant Producer Price Index, and 4) a statement of our annual insurance premiums.

In summary, all rates in the Contract shall increase by **$3,752 per day effective January 1, 2003**. Except as specifically provided herein, all other terms and conditions of the Contract shall remain in full force and effect.

Please indicate your agreement in the space provided below and return one fully executed copy of this letter to me for our files. If you have any questions, please contact John Keeton at (832) 587-8533 or me at (832) 587-8506. Thank you for the opportunity to be of service.

Sincerely,

/s/ Christopher S. Young
Christopher S. Young
Sr. Marketing Representative
On Behalf of R & B Falcon Drilling Co.

AGREED AND ACCEPTED THIS 17 DAY OF APRIL, 2003

BP AMERICA PRODUCTION COMPANY

SIGNED	***/s/ J. W. Farnsworth***
PRINTED	***J. W. Farnsworth***
TITLE	***VP Exploration***

BASIS FOR COST ESCALATIONS
DEEPWATER HORIZON
January 1, 2003
$ Per Day

	2001 Baseline Costs Plus Agreements	2001 Baseline Costs Plus Subsequent Agreements	January 2003 Actual Baseline Costs	Actual Variance	Dayrate Increase	Adjusted 2003 Baseline Costs
2.3.2a) Base Labor Cost:						
Labor & Burden (for original Contract Crew Complement)	$ 25,476	$ 25,476	$ 25,598	$ 122		$ 25,476
Training & Transportation Costs (for original Contract Crew Complement)	$ 2,820	$ 2,820	$ 2,820	$ 0		$ 2,820
** Labor & Burden for 7 Addl Personnel included in 2001 Baseline Calc.	$ 2,278	NA	NA	NA		NA
** Training & Transportation Costs (7 Addl Personnel incl. In 2001)	$ 335	NA	NA	NA		NA
*** Labor & Burden (18 Addl Pers. (incl. 7 added above) @ Jan 2003)	$ 0	$ 6,852	$ 6,860	$ 9		$ 6,852
*** Training & Transportation Costs (18 Addl Personnel - Onboard)	$ 0	$ 860	$ 860	$ 0		$ 860
Total Base Labor Cost	**$ 30,909**	**$ 36,008**	**$ 36,139**	**$ 131**	**$ 0**	**$ 36,008**
Percentage Increase				**036%***		
2.3.2b) Base Catering Cost:						
59 Contractor Personnel in Original Contract	$ 1,605	$ 1,605	$ 1,885	$ 280		$ 1,885
** 7 Additional Personnel included in 2001 Baseline Cost Calculation	$ 190	NA	NA	NA		NA
*** 18 Additional Personnel (including the 7 Addtl. Included in 2001)	$ 0	$ 490	$ 576	$ 86		$ 576
10 Company Personnel	$ 272	$ 272	$ 320	$ 48		$ 320
Total Base Catering Costs	**$ 2,067**	**$ 2,366**	**$ 2,780**	**$ 414**	**$ 414**	**$ 2,780**
Percentage Increase				**17.5%**		
2.3.2c) Base Maintenance Element:	**$ 13,851**	**$ 13,851**	**$ 13,946**	**$ 95**	**$ 0**	**$ 13,851**
Percentage Increase				**0.69%***		
2.3.2d) Base Insurance Cost:						
Hull & Machinery	$ 1,289	$ 1,289	$ 2,422	$ 1,133		$ 2,422
Marine P&I	$ 343	$ 343	$ 2,039	$ 1,695		$ 2,039
Excess Liability	$ 72	$ 72	$ 520	$ 448		$ 520
Brokers Fee	$ 94	$ 94	$ 110	$ 15		$ 110
Oil Pollution	$ 0	$ 0	$ 46	$ 46		$ 46
Total Base Insurance Cost:	**$ 1,799**	**$ 1,799**	**$ 5,137**	**$ 3,338**	**$ 3,338**	**$ 5,137**
Percentage Increase				**185.6%**		
Total	**$ 48,626**	**$ 54,024**	**$ 58,002**	**$ 3,977**	**$ 3,752**	**$ 57,776**
				Total Dayrate Increase =	**$ 3,752/day**	

* Note: The Index did not vary by 5% so the baseline cost and index stays the same as in 2001

** Note: The 7 Addl Personnel are shown as line items to identify that they were included in the previous (2001) escalation.

*** 18 Addtl. Personnel represent all addtl. Personnel added to the crew complement since the original contract.

DEEPWATER HORIZON
Adjusted Labor as of
January 1, 2003

No. Of Personnel			A	B	C	D
			GOM Base Labor		GOM Overtime Rates	
On Board	Assigned To Rig	JOB CLASSIFICATION	Daily Rate per person (inc. TT&C)	Total Daily on Board Cost	Daily Overtime Rates	Hourly Overtime Rates
1	2	OIM	965.59	871.93	824.67	68.72
1	2	OSA - Horizon	889.04	795.38	748.12	62.34
3	6	Toolpusher	786.15	2,077.48	645.23	53.77
2	4	Driller	662.47	1,137.62	621.66	51.81
4	8	Assistant Driller	511.05	1,669.57	441.18	36.76
2	4	Pumpman	430.72	674.11	345.42	28.79
12	24	Floorman	386.35	3,901.75	342.26	28.52
14	28	Roustabouts	346.81	3,998.53	295.13	24.59
1	2	Welder	494.23	400.57	421.13	35.09
4	8	Crane Operator	511.05	1,009.57	441.10	36.76
2	4	Chief Mechanic	595.17	1,003.03	541.45	45.12
1	2	Mechanic	490.02	396.36	416.11	34.68
2	4	Motor Operator	386.77	651.13	342.76	28.56
1	2	Electrical Supervisor	675.09	581.43	534.17	44.51
2	4	Chief Electrician	595.17	1,003.03	541.45	45.12
1	2	Electrician	490.02	396.36	416.11	34.68
2	4	Chief Electronic Technician	603.59	1,019.85	551.47	45.96
1	2	Senior Sub Sea Sup	777.26	683.60	636.35	53.03
1	2	Assistant Subsea	561.53	467.87	501.34	41.78
2	4	Material Co-Ordinator	456.37	725.43	376.00	31.33
1	2	Master	863.11	769.45	722.19	60.18
1	2	Chief Mate	687.71	594.05	651.74	54.31
1	2	Chief Engineer	803.26	709.59	662.34	55.19
1	2	1st Assistant Engineer	645.65	551.99	601.61	50.13
2	4	2nd Assistant Engineer	612.00	1,036.68	561.50	46.79
2	4	DP Operator	561.53	935.73	501.34	41.78
2	4	Assistant Dp Operator	477.40	767.49	401.07	33.42
2	4	Deck Pusher	497.81	873.21	475.11	39.59
1	2	Bosun	477.40	383.74	401.07	33.42
3	6	AB Seaman	403.59	1,027.17	362.81	30.23
1	2	RSTT	485.82	392.16	411.10	34.26
1	2	Medic	385.88	292.22	291.98	24.33
0	0	-	—	—	—	—
0	0	-	—	—	—	—
0	0	-	—	—	—	—
0	0	-	—	—	—	—
0	0	-	—	—	—	—
0	0	-	—	—	—	—
0	0	-	—	—	—	—
0	0	-	—	—	—	—
77	**154**		**Total Labor Costs =**	**$ 32,458.08**		

The figures in column "A" are to be used as the basis for adding personnel to the permanent crew and for determining the credit for crew members short. This includes all Training, Transportation and Catering costs.

The figures in column "B" are the daily cost of all crew members excluding Training, Transportation and Catering costs.

The figures in column "C" are the daily cost of overtime excluding Training, Transportation and Catering costs (assuming a daily schedule of 12 hours)

The figures in column "D" are the hourly cost of overtime excluding Training, Transportation and Catering costs.

BETSY KELLY
MANAGER-INSURANCE

TRANSOCEAN OFFSHORE DEEPWATER DRILLING INC.
4 GREENWAY PLAZA
HOUSTON, TX 77046

Chris Young
Transocean Holdings, Inc.
1311 Broadfield
Houston, TX 77083

Re: Annual Premiums for Deepwater Horizon 2003

Chris,

Current Insurance as of January 1, 2003:

Coverage:	All Risk Hull & Machinery
Insured Value:	$ 320,000,000
Deductible:	$10,000,000
NET ANNUAL PREMIUM:	$ 883,943
Coverage:	Primary Marine Protection & Indemnity
Deductible:	$10,000,000 per occurrence
NET ANNUAL COST:	$ 744,235*
Coverage:	Excess Liability
Insured Value:	$452,000,000
Deductible:	XS of Primary Marine P & I
NET ANNUAL PREMIUM:	$ 189,799
Coverage:	Oil Pollution
NET ANNUAL PREMIUM:	$ 16,820
U.S. Broker:	McGriff, Seibels & Williams, Inc
Annual Fee:	$ 40,024

* Based on Self Insured Accrual of $4,832 per person x 154 people assigned

(713) 232-7766 FAX (713) 232-7630 TEL BKELLY@HOUSTON.DEEPWATER.COM

U. S. Department of Labor
Bureau of Labor Statistics
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Data extracted on: January 31, 2003 (12:09:59 PM)

Producer Price Index-Commodities

Series Id: WPU119102
Not Seasonally Adjusted
Group: Machinery and equipment
Item: Oil field and gas field drilling machinery
Base Date: 8200

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
1992	110.1	110.1	110.1	110.1	110.2	110.4	110.6	110.6	110.6	110.8	112.4	112.5	110.7
1993	112.8	112.9	113.3	112.1	112.0	112.2	112.3	112.3	113.4	113.4	113.4	114.6	112.9
1994	114.6	114.6	114.6	114.6	114.7	114.9	115.4	115.4	115.9	117.8	117.8	117.8	115.7
1995	118.3	118.6	119.2	119.2	119.3	119.6	120.4	120.4	120.4	122.0	122.2	122.2	120.1
1996	124.0	124.0	124.0	124.3	124.2	124.8	125.3	125.3	125.3	126.2	126.6	127.1	125.1
1997	127.7	127.9	128.6	129.1	129.2	129.3	129.3	129.5	129.7	130.3	131.4	132.0	129.5
1998	133.1	132.9	133.1	133.0	133.0	133.0	132.9	132.9	132.9	133.6	133.6	133.6	133.1
1999	133.8	133.7	133.7	133.9	133.9	134.0	134.0	133.7	133.7	133.7	134.4	134.6	133.9
2000	134.9	136.3	136.3	136.3	136.5	136.5	136.5	136.6	136.7	138.7	138.7	138.7	136.9
2001	143.5	143.9	144.0	144.0	144.0	145.5	145.6	145.8	145.7	146.1	146.1	146.1	145.0
2002	146.2	146.2	146.6	146.6	146.4	146.4	146.4	146.4	146.8(P)	146.8(P)	146.8(P)	146.8(P)	146.5(P)

(P): Preliminary. All indexes are subject to revision four months after original publication.

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TRANSOCEAN OFFSHORE DEEPWATER DRILLING INC.
1311 BROADFIELD, SUITE 400
HOUSTON, TX 77084

CHRISTOPHER S. YOUNG
SR. MARKETING REPRESENTATIVE

March 3, 2003

BP America Production Company
501 WestLake Park Blvd.
Houston, TX 77079

Attn: Mr. Randy Rhoads

Re: **Drilling Contract No. 980249** dated December 9, 1998 by and between **R&B Falcon Drilling Company predecessor in interest to Transocean Holdings Inc.** ("Contractor") and **Vastar Resources, Inc. predecessor in interest to BP America Production Company** ("Company"), as amended for RBS-8D (now known as the **Deepwater Horizon**)

Subject: **Letter of Agreement for Rental of 6 5/8" HWDP**
CONTRACTOR-5121-2002-011

Dear Randy,

This letter is to reflect our agreement to purchase 23 joints of 6 5/8" drill pipe (per Smith's Quote No. D03-0557) and rent it to BP over the remaining term of the Contract referenced above. The total rental amount will be 1.27418155 times the cost of the pipe. The pipe cost $107,311.56 including inspection. Therefore, the total rental payment will be $136,734.40 over the remaining term of the contract. We received the pipe on March 3, 2003. Therefore, the rental rate will be **$242.01** per day starting March 4, 2003 and ending September 18, 2004. If the Contract should be terminated for any reason, BP agrees to pay the difference between $136,734.40 and the total rental paid up to that time. BP will be responsible for all inspections during the term of the rental. The pipe shall be treated as Contractor's in-hole equipment per Article 22 of the Contract.

Please indicate your agreement in the space provided below and return one fully executed copy of this letter to me for our files. If you have any questions, please contact John Keeton at (832) 587-8533 or me at (832) 587-8506. Thank you for the opportunity to be of service.

Sincerely,

/s/ Christopher S. Young
Christopher S. Young
Sr. Marketing Representative

AGREED AND ACCEPTED THIS 14th DAY OF APRIL, 2003
BP AMERICA PRODUCTION COMPANY

SIGNED	*/s/ Jerry R Rhoads*
PRINTED	*Jerry R Rhoads*
TITLE	*Contracts Specialist*

PHONE: (832) 587-8506 FAX: (832) 587-8754 EMAIL:cyoung@houston.deepwater.com

TRANSOCEAN OFFSHORE DEEPWATER DRILLING INC.
1311 BROADFIELD, SUITE 400
HOUSTON, TX 77084

CHRISTOPHER S. YOUNG
SR. MARKETING REPRESENTATIVE

March 20, 2003

BP America Production Company
501 WestLake Park Blvd.
Houston, TX 77079

Attn: Mr. Randy Rhoads

Re: **Drilling Contract No. 980249** dated December 9, 1998 by and between **R&B Falcon Drilling Company** (“Contractor”) and **Vastar Resources, Inc. predecessor in interest to BP America Production Company** (“Company”), as amended for RBS-8D (now known as the **Deepwater Horizon**)

Subject: **Letter of Agreement for 6 5/8” Drill Pipe Rental dated November 1, 2002**
CONTRACTOR-5121-2002-011

Dear Randy,

This letter is to document the actual cost and daily rental rate for the 6 5/8” drill pipe referenced in our November 1, 2002 letter agreement.

According to the November 1, 2002 Agreement, the total rental amount will be 1.27418155 times the actual cost of the pipe. The pipe cost **$1,352,110.27** including trucking and inspection so the total rental payment will be **$1,722,833.96** over the remaining term of the contract. Therefore, the daily rental rate will be **$3,208.26** per day starting on April 1, 2003 and continuing through September 18, 2004 (537 days). If the contract is terminated for any reason prior to September 18, 2004, BP agrees to pay the difference between $1,722,833.96 and the total rental paid up to the time of termination.

BP will be responsible for all inspections during the term of the rental. The pipe shall be treated as Contractor’s in-hole equipment per Article 22 of the Contract.

If you have any questions, please contact John Keeton at (832) 587-8533 or me at (832) 587-8506. Thank you for the opportunity to be of service.

Sincerely,

/s/ Christopher S. Young
Christopher S. Young
Sr. Marketing Representative
AGREED AND ACCEPTED THIS 14th DAY OF APRIL, 2003
BP AMERICA PRODUCTION COMPANY

SIGNED	***/s/ Jerry R Rhoads***
PRINTED	***Jerry R Rhoads***
TITLE	***Contracts Specialist***

PHONE: (832) 587-8506 FAX: (832) 587-8754 EMAIL:cyoung@houston.deepwater.com

TRANSOCEAN OFFSHORE DEEPWATER DRILLING INC.
1311 BROADFIELD, SUITE 400
HOUSTON, TX 77084

CHRISTOPHER S. YOUNG
SR. MARKETING REPRESENTATIVE

November 1, 2002

BP America Production Company
501 WestLake Park Blvd.
Houston, TX 77079

Attn: Mr. Randy Rhoads

Re: **Drilling Contract No. 980249** dated December 9, 1998 ("Contract") by and between **R&B Falcon Drilling Company predecessor in interest to Transocean Holdings, Inc,**("Contractor or TODDI") and **Vastar Resources, Inc. predecessor in interest to BP America Production Company** ("Company"), as amended for RBS-8D (now known as the **Deepwater Horizon**)

Subject: **Letter of Agreement for 6 5/8" Drill Pipe Rental**
CONTRACTOR-5121-2002-011

Dear Randy,

This letter is to document the agreement between Transocean Offshore Deepwater Drilling Inc. (TODDI) and Company for the rental of 18,000 feet of 6 5/8" R-3 drill pipe for use on the Deepwater Horizon.

Company and TODDI hereby agree to the following terms and conditions:

1. TODDI shall purchase the following pipe and rent it to Company over the remaining term of the Contract referenced above. Specifications of the pipe are as follows:

Footage	18,000	Joints	439
Pipe OD	6 5/8"	Connection	6 5/8 FH
Weight	34.01	OD	8 1/4"
Grade	S-135	ID	4 1/4"
Upset	IEU	Pin Tong	10"
Range	3	Box Tong	13"
Internal Coating	TK34 XT*	Hardfacing Pin	None
Inspection	Truscope AS	Hardfacing Box	Armacor M
Delivery	16 weeks*		
Make & Break & 95% wall included			

* Changes from Grant Prideco quote 30726

2. Tooljoints (Pin & Box) shall be manufactured long enough to provide for a minimum of two full recuts and still have sufficient tong space excluding proud hardbanded area. Company's coating, hardbanding and make & break specifications are attached and made a part of this Agreement.

PHONE: (832) 587-8506 FAX: (832) 587-8754 EMAIL:cyoung@houston.deepwater.com

3. The rental rate will be approximately $3,000/day assuming that 18 months will be remaining on the contract at time of pipe delivery and that the total cost of the pipe is approximately $1.29 million. The exact calculation will be made when the pipe is delivered and the total cost (based on good footage) and the remaining number of days in the term are known. The total rental amount to be recovered will be calculated at 1.27418155 times the total cost of the pipe. The total cost of the pipe will include inspection and transportation.

4. The rental rate shall begin upon delivery of the pipe to TODDI following acceptance in accordance with Company's QA/QC specifications and inspection criteria. These specifications and criteria are made a part of this Agreement. The rental rate shall cease when the total rental paid equals 1.27418155 times the final cost of the pipe. The rental agreement will continue as long the Contract is in force however the rental rate will be zero after the total rental paid equals 1.27418155 times the final cost of the pipe.

5. Contractor shall furnish all handling equipment required for this pipe during the term of the rental at no cost to Company.

6. Initial inspection is included in the cost of the pipe. Company reserves the right to re-inspect the pipe at Company's cost. Company will be responsible for all inspections during the term of the rental.

7. The pipe shall be treated as Contractor's in-hole equipment per Article 22.3 of the Contract except for the cost of inspections.

8. During the term of the rental, Company will have the option of moving the pipe to another Transocean Rig at Company's option and expense.

If you are in agreement with the above, please sign in the space provided below and return one fully executed copy of this letter to me for our files.

If you have any questions, please contact John Keeton at (832) 587-8533 or me at (832) 587-8506. Thank you for the opportunity to be of service.

Sincerely,

/s/ Christopher S. Young
Christopher S. Young
Sr. Marketing Representative

AGREED AND ACCEPTED THIS 3RD DAY OF FEBRUARY, 2003
BP AMERICA PRODUCTION COMPANY

SIGNED	***/s/ Jerry R Rhoads***
PRINTED	***Jerry R Rhoads***
TITLE	***Contracts Specialist***

TRANSOCEAN HOLDINGS INC.
1311 BROADFIELD, SUITE 400
HOUSTON, TX 77084

CHRISTOPHER S. YOUNG
SR. MARKETING REPRESENTATIVE

November 12, 2003

BP Deepwater Development Company
501 WestLake Park Blvd.
Houston, TX 77079

Attn: Mr. Jon Sprague – Atlantis Wells Delivery Leader

Re: **Drilling Contract No. 980249** dated December 9, 1998 by and between **R&B Falcon Drilling Company predecessor in interest to Transocean Holdings Inc.** ("Contractor") and **Vastar Resources, Inc. predecessor in interest to BP America Production Company** ("Company"), as amended for RBS-8D (now known as the **Deepwater Horizon)**

Subject: **Letter of Agreement for adding Tool Pusher in BP's Office**
CONTRACTOR-5121-2002-011

Dear Mr. Sprague:

Upon execution of this Letter Agreement by COMPANY, CONTRACTOR agrees to provide one (1) Tool Pusher to work in BP's offices in addition to those specified in Exhibit F-1 of the Contract as amended.

COMPANY has requested and CONTRACTOR agrees that CONTRACTOR will provide one (1) additional Sr. Toolpusher to work in COMPANY's offices during the Atlantis Project. The Sr. Toolpusher will be shore based and work at COMPANY's offices as required to support the Atlantis Project on an even rotating schedule. Work will commence on or about December 1, 2003.

CONTRACTOR shall invoice COMPANY at the rate of US$786 (Seven Hundred Eighty Six) per day worked and for all documented reasonable and necessary travel costs and living (room and board) expenses (at no mark-up to actual costs). The Sr. Toolpusher will be available for work seven days a week on 14 day on and 14 day off schedule and COMPANY shall be billed monthly for every day available for work during the month. CONTRACTOR will supply supporting documentation with each monthly invoice as evidence of days available for work.

COMPANY reserves the right to release the services of the Sr. Toolpusher at anytime upon thirty (30) days prior written notice to CONTRACTOR. COMPANY and CONTRACTOR will document when the Sr. Toolpusher is released from duty for services on this special Atlantis Project assignment, thus ending the applicability of this contract amendment.

Except as specifically provided herein, all other terms and conditions of the Contract shall remain in full force and effect. Please indicate your agreement in the space provided below and return one fully executed copy of this letter to me for our files.

If you have any questions, please contact John Keeton at (832) 587-8533 or me at (832) 587-8506. Thank you for the opportunity to be of service.

PHONE: (832) 587-8506 FAX: (832) 587-8754 EMAIL:cyoung@houston.deepwater.com

BP
Horizon – TP in BP's office
TSF File #01-063

Sincerely,

/s/ Christopher S. Young
Christopher S. Young
Sr. Marketing Representative
On Behalf of Transocean Holdings Inc.,

AGREED AND ACCEPTED THIS 1st DAY OF DECEMBER, 2003

BP DEEPWATER DEVELOPMENT COMPANY

SIGNED	***/s/ Jerry R Rhoads***
PRINTED	***Jerry R Rhoads***
TITLE	***Contracts Specialist***

TRANSOCEAN HOLDINGS INC.
4 GREENWAY PLAZA
HOUSTON, TX 77046

CHRISTOPHER S. YOUNG
SR. MARKETING REPRESENTATIVE

February 28, 2004

BP America Production Company
501 WestLake Park Blvd.
Houston, TX 77079

Attn: Mr. Randy Rhoads

Re: **Drilling Contract No. 980249** dated December 9, 1998 by and between **R&B Falcon Drilling Company predecessor in interest to Transocean Holdings Inc.** (“Contractor”) and **Vastar Resources, Inc. predecessor in interest to BP America Production Company** (“Company”), as amended for RBS-8D (now known as the **Deepwater Horizon)**

Subject: **Letter of Agreement for Cost Escalation 2003**
Transocean Ref: 5121-2001063-027

Dear Randy,

We performed the “annual” cost analysis for the ***Deepwater Horizon*** as of January 1, 2004 in accordance with Article 2.3 “Adjustment in Dayrates” of the Contract referenced above. The following table summarizes the Baseline Cost changes detailed on the attached schedule “Basis for Cost Escalation”:

Reference	2003 Baseline Costs plus Previous Agreements	Actual Baseline Costs @ Jan. 1, 2003	Increase/ (Decrease)	Dayrate Increase/ (Decrease)
2.3.2a Base Labor Costs	$ 36,008	$ 36,099	$ 91	*
2.3.2b Catering Costs	$ 2,780	$ 2,650	$ (130)	$ (130)
2.3.2c Maintenance Element	$ 13,851	$ 14,589	$ 738	$ 738
2.3.2d Insurance	$ 5,137	$ 5,137	0	
Total	$ 57,776/day	$ 58,475/day		$ 608day

* According to Article 2.3.2, rates for each item must vary by => 5% before they can be adjusted.

Notes:

2.3.2a Base Labor rates changed by the adjustment of the utilization bonus and pension accruals. The net result was a slight increase but not the 5% required to trigger an increase.

2.3.2b We have changed catering companies on the ***Horizon*** which has provided a decrease from $31.95 per man per day to $30.45, a decrease of 6.3%. Please note the catering cost shown on the accompanying schedule only reflects the crew complement in the contract (77 on board the rig) while we actually have 83.

PHONE: (832) 587-8506 FAX: (832) 587-8754 EMAIL:cyoung@houston.deepwater.com

2.3.2c The Maintenance Element of the Baseline Cost increased $738 per day based on the change on the relevant Producer Price Index. The Index number for December 2003 increased to 153.8 from 145.8 in August of 2001, an increase of 5.33%. The Bureau of Labor Statistics Data for the Producer Price Index series ID: WPU119102 is attached.

2.3.2d Costs of insurance premiums have not changed due to the fact that our Risk Department negotiated a 14 month agreement for the previous increases. We will keep you advised of any increases regarding insurance.

The following documents are attached for reference: 1) “Basis for Cost Escalations” schedule; 2) “Adjusted Base Labor as of January 1, 2004”; and 3) the Bureau of Labor Statistics Data for the relevant Producer Price Index.

In summary, the following adjustments will be made:

Paragraph 2.3.2b		(130)
Paragraph 2.3.2c		738
Total Increase	$	608 net increase effective January 1, 2004

Except as specifically provided herein, all other terms and conditions of the Contract shall remain in full force and effect.

Please indicate your agreement in the space provided below and return one fully executed copy of this letter to me for our files. If you have any questions, please contact John Keeton at (832) 587-8533 or me at (832) 587-8506. Thank you for the opportunity to be of service.

Sincerely,

/s/ Christopher S. Young
Christopher S. Young
Sr. Marketing Representative
On Behalf of R & B Falcon Drilling Co.

AGREED AND ACCEPTED THIS 31 DAY OF MARCH, 2004

BP AMERICA PRODUCTION COMPANY

SIGNED	***/s/ Scott Sigurdson***
PRINTED	***Scott Sigurdson***
TITLE	***Wells Manager***

BASIS FOR COST ESCALATIONS
DEEPWATER HORIZON
January 1, 2004
$ Per Day

Clause No.:		January 2003 Actual Baseline Costs	January 2004 Actual Baseline Costs	Variance	Adjusted 2004 Baseline Costs
2.3.2a)	**Base Labor Cost:**				
	Labor & Burden (per schedule)	$ 25,476	$ 25,626	$ 150	$ 25,476
	Training & Transportation Costs	$ 2,820	$ 3,024	$ 204	$ 2,820
**	Labor & Burden (18 Addl Personnel - Onboard)	$ 6,852	$ 6,792	$ -59	$ 6,852
**	(Training & Transportation Costs (18 Addl Personnel - Onboard)	$ 860	$ 656	$ -204	$ 860
	Total Base Labor Cost	**$ 36,008**	**$ 36,099**	**$ 91**	**$ 36,008**
	Percentage Increase			**0.25%***	
2.3.2b)	**Base Catering Cost:**				
	59 Contractor Personnel	$ 1,885	$ 1,797	$ -88	$ 1,797
**	18 Additional Personnel	$ 576	$ 549	$ -27	$ 549
	10 Company Personnel	$ 320	$ 305	$ -15	$ 305
	Total Base Catering Costs	**$ 2,780**	**$ 2,650**	**$ -130**	**$ 2,650**
	Percentage Increase			**-6.3%**	
2.3.2c)	**Base Maintenance Element:**	**$ 13,851**	**$ 14,589**	**$ 738**	**$ 14,589**
	Percentage Increase			**5.33%**	
2.3.2d)	**Base Insurance Cost:**				
	Hull & Machinery	$ 2,422	$ 2,422	$ 0	$ 2,422
	Marine P&I	$ 2,039	$ 2,039	$ 0	$ 2,039
	Excess Liability	$ 520	$ 520	$ 0	$ 521
	Brokers Fee	$ 110	$ 110	$ 0	$ 110
	Oil Pollution	$ 46	$ 46	$ 0	$ 46
	Total Base Insurance Cost:	**$ 5,137**	**$ 5,137**	**$ 0**	**$ 5,137**
	Percentage Increase			**0.0%**	
Total Baseline Operating Costs		**$ 57,776**	**$ 58,475**	**$ 608**	**$ 58,384**
			Total Dayrate Increase =		**$ 608/day**

* Note: The Index did not vary by 5% so the baseline cost and index stays the same as in 2003
**Note: The 7 Addl Personnel are included as line items to identify that they were included in the previous escalation.
The 18 Addl Personnel includes all personnel added to the contract and these lines indicate the increases on all Addl Personnel.

DEEPWATER HORIZON
Adjusted Labor as of
January 1, 2004

No. of Personnel On Board	Assigned To Rig	JOB CLASSIFICATION	A GOM Base Labor Daily Rate per person (inc. TT&C)	B GOM Base Labor Total Daily on Board Cost	C GOM Overtime Rates Daily Overtime Rates	D GOM Overtime Rates Hourly Overtime Rates
1	2	OIM	958.32	866.16	818.90	68.24
1	2	OSA - Horizon	868.26	776.10	728.84	60.74
3	6	Toolpusher	793.31	2,103.44	653.89	54.49
2	4	Driller	659.31	1,134.31	619.69	51.64
4	8	Assistant Driller	508.91	1,667.01	440.42	36.70
2	4	Pumpman	427.86	671.40	343.80	28.65
12	24	Floorman	383.58	3,886.55	340.75	28.40
14	28	Roustabouts	342.07	3,953.17	291.27	24.27
1	2	Welder	483.29	391.13	409.87	34.16
4	8	Crane Operator	499.66	1,630.00	429.39	35.78
2	4	Chief Mechanic	591.28	998.23	538.59	44.88
1	2	Mechanic	493.19	401.03	421.68	35.14
2	4	Motor Operator	397.26	675.10	357.04	29.75
1	2	Electrical Supervisor	659.31	567.15	519.90	43.32
2	4	Chief Electrician	589.72	995.12	536.74	44.73
1	2	Electrician	488.44	396.28	416.02	34.67
2	4	Chief Electronic Technician	597.91	1,011.50	546.50	45.54
1	2	Senior Sub Sea Sup	759.49	667.32	620.07	51.67
1	2	Assistant Subsea	559.02	466.86	500.14	41.68
2	4	Material Co-Ordinator	451.60	718.88	372.10	31.01
1	2	Master	852.37	760.21	712.95	59.41
1	2	Chief Mate	671.59	579.43	634.32	52.86
1	2	Chief Engineer	759.56	667.40	620.14	51.68
1	2	1st Assistant Engineer	658.33	566.17	618.52	51.54
2	4	2nd Assistant Engineer	653.50	1,122.68	612.76	51.06
2	4	DP Operator	561.07	937.81	502.58	41.88
2	4	Assistant Dp Operator	475.10	765.88	400.11	33.34

Exhibit 31.1

CEO CERTIFICATION PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Steven L. Newman, certify that:

1. I have reviewed this report on Form 10-Q of Transocean Ltd.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:

   a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared; and

   b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles; and

   c) evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting.

5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of registrant’s board of directors (or persons performing the equivalent function):

   a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Dated: 2010	August 4,	/s/ Steven L. Newman
		Name: Steven L. Newman
		President and Chief Executive Officer

Exhibit 31.2

CFO CERTIFICATION PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Ricardo H. Rosa, certify that:

1. I have reviewed this report on Form 10-Q of Transocean Ltd.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:

   a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared; and

   b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles; and

   c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting.

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

   a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Dated:	August 4, 2010	/s/ Ricardo H. Rosa Name: Ricardo H. Rosa Senior Vice President and Chief Financial Officer

Exhibit 32.1

CERTIFICATION PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002 (SUBSECTIONS (a) AND (b) OF SECTION 1350, CHAPTER 63 OF TITLE 18, UNITED STATES CODE)

Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (Subsections (a) and (b) of Section 1350, Chapter 63 of Title 18, United States Code), I, Steven L. Newman, Chief Executive Officer of Transocean Ltd., a Swiss corporation (the "Company"), hereby certify, to my knowledge, that:

(1) the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2010 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Dated: August 4, 2010

/s/ Steven L. Newman
Name: Steven L. Newman
President and Chief Executive Officer

The foregoing certification is being furnished solely pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (Subsections (a) and (b) of Section 1350, Chapter 63 of Title 18, United States Code) and is not being filed as part of the Report or as a separate disclosure document.

A signed original of this written statement required by Section 906 has been provided to Transocean Ltd. and will be retained by Transocean Ltd. and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32.2

CERTIFICATION PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002 (SUBSECTIONS (a) AND (b) OF SECTION 1350, CHAPTER 63 OF TITLE 18, UNITED STATES CODE)

Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (Subsections (a) and (b) of Section 1350, Chapter 63 of Title 18, United States Code), I, Ricardo H. Rosa, Senior Vice President and Chief Financial Officer of Transocean Ltd., a Swiss corporation (the “Company”), hereby certify, to my knowledge, that:

(1) the Company’s Quarterly Report on Form 10-Q for the quarter ended June 30, 2010 (the “Report”) fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Dated: August 4, 2010

/s/ Ricardo H. Rosa
Name: Ricardo H. Rosa
Senior Vice President and Chief Financial Officer

The foregoing certification is being furnished solely pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (Subsections (a) and (b) of Section 1350, Chapter 63 of Title 18, United States Code) and is not being filed as part of the Report or as a separate disclosure document.

A signed original of this written statement required by Section 906 has been provided to Transocean Ltd. and will be retained by Transocean Ltd. and furnished to the Securities and Exchange Commission or its staff upon request.