UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-Q

(Mark One)

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

For the quarterly period ended March 31, 2016

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 1-13926

DIAMOND OFFSHORE DRILLING, INC.

(Exact name of registrant as specified in its charter)

Delaware	**76-0321760**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**

15415 Katy Freeway

Houston, Texas 77094

(Address of principal executive offices)

(Zip Code)

(281) 492-5300

(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 x 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 x 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 definitions of large accelerated filer, accelerated filer, and smaller reporting company in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer	x	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 x

Indicate the number of shares outstanding of each of the issuer s classes of common stock, as of the latest practicable date.

As of April 28, 2016	Common stock, $0.01 par value per share	137,169,663 shares

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DIAMOND OFFSHORE DRILLING, INC.

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QUARTER ENDED MARCH 31, 2016

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PART I. FINANCIAL INFORMATION

ITEM 1. Financial Statements.

DIAMOND OFFSHORE DRILLING, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(Unaudited)

(In thousands, except share and per share data)

	March 31, 2016	December 31, 2015
ASSETS		
Current assets:		
Cash and cash equivalents	$ 128,928	$ 119,028
Marketable securities	5,067	11,518
Accounts receivable, net of allowance for bad debts	363,597	405,370
Prepaid expenses and other current assets	110,842	119,479
Assets held for sale	6,600	14,200
Total current assets	615,034	669,595
Drilling and other property and equipment, net of accumulated depreciation	6,219,242	6,378,814
Other assets	110,323	101,485
Total assets	$ 6,944,599	$ 7,149,894
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities:		
Accounts payable	$ 51,421	$ 70,272
Accrued liabilities	289,209	253,769
Taxes payable	40,357	15,093
Short-term borrowings		286,589
Total current liabilities	380,987	625,723
Long-term debt	1,980,049	1,979,778
Deferred tax liability	230,332	276,529
Other liabilities	158,451	155,094
Total liabilities	2,749,819	3,037,124
Commitments and contingencies (Note 10)		
Stockholders equity:		

Preferred stock (par value $0.01, 25,000,000 shares authorized, none issued and outstanding)		
Common stock (par value $0.01, 500,000,000 shares authorized; 143,997,757 shares issued and 137,169,663 shares outstanding at March 31, 2016; 143,978,877 shares issued and 137,158,706 shares outstanding at December 31, 2015)	1,440	1,440
Additional paid-in capital	2,000,828	1,999,634
Retained earnings	2,406,693	2,319,136
Accumulated other comprehensive gain (loss)	(11,595)	(5,035)
Treasury stock, at cost (6,828,094 and 6,820,171 shares of common stock at March 31, 2016 and December 31, 2015, respectively)	(202,586)	(202,405)
Total stockholders equity	4,194,780	4,112,770
Total liabilities and stockholders equity	$ 6,944,599	$ 7,149,894

The accompanying notes are an integral part of the consolidated financial statements.

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DIAMOND OFFSHORE DRILLING, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

(Unaudited)

(In thousands, except per share data)

	Three Months Ended March 31, 2016	Three Months Ended March 31, 2015
Revenues:		
Contract drilling	$ 443,523	$ 599,577
Revenues related to reimbursable expenses	27,020	20,479
Total revenues	470,543	620,056
Operating expenses:		
Contract drilling, excluding depreciation	212,841	350,658
Reimbursable expenses	26,791	20,092
Depreciation	104,240	137,299
General and administrative	15,398	17,452
Impairment of assets		358,528
Restructuring and separation costs		6,168
Gain on disposition of assets	(296)	(611)
Total operating expenses	358,974	889,586
Operating income (loss)	111,569	(269,530)
Other income (expense):		
Interest income	173	583
Interest expense, net of amounts capitalized	(25,516)	(23,982)
Foreign currency transaction (loss) gain	(3,608)	5,590
Other, net	578	221
Income (loss) before income tax benefit	83,196	(287,118)
Income tax benefit	4,229	31,409
Net income (loss)	$ 87,425	$ (255,709)
Earnings (loss) per share, Basic and Diluted	$ 0.64	$ (1.86)
Weighted-average shares outstanding:		
Shares of common stock	137,162	137,151
Dilutive potential shares of common stock	44	

Total weighted-average shares outstanding	137,206	137,151
Cash dividends declared per share of common stock	$	$ 0.125

The accompanying notes are an integral part of the consolidated financial statements.

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DIAMOND OFFSHORE DRILLING, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(Unaudited)

(In thousands)

	Three Months Ended March 31,	
	2016	**2015**
Net income (loss)	$ 87,425	$ (255,709)
Other comprehensive (losses) gains, net of tax:		
Derivative financial instruments:		
Unrealized holding loss		(1,827)
Reclassification adjustment for (gain) loss included in net income	(1)	3,587
Investments in marketable securities:		
Unrealized holding loss	(6,559)	(2,123)
Reclassification adjustment for gain included in net income		
Total other comprehensive loss	(6,560)	(363)
Comprehensive income (loss)	$ 80,865	$ (256,072)

The accompanying notes are an integral part of the consolidated financial statements.

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DIAMOND OFFSHORE DRILLING, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

(In thousands)

	Three Months Ended March 31, 2016	2015
Operating activities:		
Net income (loss)	$ 87,425	$ (255,709)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation	104,240	137,299
Loss on impairment of assets		358,528
Restructuring and separation costs		6,168
Gain on disposition of assets	(296)	(611)
Loss on foreign currency forward exchange contracts		6,390
Deferred tax provision	(45,254)	(118,332)
Stock-based compensation expense	1,194	856
Deferred income, net	13,810	(3,874)
Deferred expenses, net	2,591	(46,027)
Other assets, noncurrent	92	506
Other liabilities, noncurrent	1,835	(2,262)
Payments for settlement of foreign currency forward exchange contracts designated as accounting hedges		(6,390)
Bank deposits denominated in nonconvertible currencies	293	561
Other	438	484
Changes in operating assets and liabilities:		
Accounts receivable	41,773	18,177
Prepaid expenses and other current assets	6,026	11,997
Accounts payable and accrued liabilities	(1,798)	(18,006)
Taxes payable	28,961	70,811
Net cash provided by operating activities	241,330	160,566
Investing activities:		
Capital expenditures (including rig construction)	(58,114)	(197,032)
Proceeds from disposition of assets, net of disposal costs	113,295	4,763
Proceeds from sale and maturities of marketable securities	11	11
Net cash provided by (used in) investing activities	55,192	(192,258)
Financing activities:		
Net repayment of short-term borrowings	(286,589)	

Payment of dividends		(17,144)
Other	(33)	(12)
Net cash used in financing activities	(286,622)	(17,156)
Net change in cash and cash equivalents	9,900	(48,848)
Cash and cash equivalents, beginning of period	119,028	233,623
Cash and cash equivalents, end of period	$ 128,928	$ 184,775

The accompanying notes are an integral part of the consolidated financial statements.

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DIAMOND OFFSHORE DRILLING, INC. AND SUBSIDIARIES

NOTES TO UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS

1. General Information

The unaudited consolidated financial statements of Diamond Offshore Drilling, Inc. and subsidiaries, which we refer to as Diamond Offshore, we, us or our, should be read in conjunction with our Annual Report on Form 10-K for the year ended December 31, 2015 (File No. 1-13926).

As of April 28, 2016, Loews Corporation owned approximately 53% of the outstanding shares of our common stock.

Interim Financial Information

The accompanying unaudited consolidated financial statements have been prepared in accordance with generally accepted accounting principles in the U.S., or GAAP, for interim financial information and with the instructions to Form 10-Q and Article 10 of Regulation S-X of the Securities and Exchange Commission. Accordingly, pursuant to such rules and regulations, they do not include all disclosures required by GAAP for complete financial statements. The consolidated financial information has not been audited but, in the opinion of management, includes all adjustments (consisting of normal recurring accruals) necessary for a fair presentation of the consolidated balance sheets, statements of operations, statements of comprehensive income and statements of cash flows at the dates and for the periods indicated. Results of operations for interim periods are not necessarily indicative of results of operations for the respective full years.

Use of Estimates in the Preparation of Financial Statements

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amount of revenues and expenses during the reporting period. Actual results could differ from those estimated.

Assets Held For Sale

At December 31, 2015, we reported the $14.2 million carrying value of five marketed-for-sale jack-up rigs as Assets held for sale in our Consolidated Balance Sheets. One of these rigs was sold for $8.0 million in February 2016. In March 2016, one of our previously impaired mid-water semisubmersible rigs completed its drilling contract and was sold for scrap in the second quarter of 2016. We have reported the $6.6 million aggregate carrying value of our remaining marketed-for-sale jack-up rigs and the mid-water semisubmersible rig to be sold for scrap as Assets held for sale in our Consolidated Balance Sheets at March 31, 2016.

Drilling and Other Property and Equipment

We carry our drilling and other property and equipment at cost, less accumulated depreciation. Maintenance and routine repairs are charged to income currently while replacements and betterments that upgrade or increase the functionality of our existing equipment and that significantly extend the useful life of an existing asset are capitalized. During the three months ended March 31, 2016 and the year ended December 31, 2015, we capitalized $30.7 million and $262.4 million, respectively, in replacements and betterments of our drilling fleet.

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Capitalized Interest

We capitalize interest cost for qualifying construction and upgrade projects. See Note 8. A reconciliation of our total interest cost to Interest expense, net of amounts capitalized as reported in our Consolidated Statements of Operations is as follows:

	Three Months Ended March 31, 2016	Three Months Ended March 31, 2015
	(In thousands)	
Total interest cost, including amortization of debt issuance costs	$ 28,825	$ 29,996
Capitalized interest	(3,309)	(6,014)
Total interest expense as reported	$ 25,516	$ 23,982

Debt Issuance Costs

Historically, we have presented deferred costs associated with the issuance of long-term debt as Other Assets in our unaudited consolidated balance sheets and have amortized such costs over the respective terms of the related debt. In April 2015, the Financial Accounting Standards Board, or FASB, issued Accounting Standards Update, or ASU, No. 2015-03, *Interest Imputation of Interest (Subtopic 835-30); Simplifying the Presentation of Debt Issuance Costs*, or ASU 2015-03, which requires debt issuance costs associated with our senior notes to be presented in the balance sheet as a reduction in the related long-term debt. We have adopted the provisions of ASU 2015-03 effective January 1, 2016 and have retrospectively applied its provisions to all periods presented in our Consolidated Financial Statements. The retrospective effect of our adoption of ASU 2015-03, which affected only the presentation of deferred debt issuance costs in our Consolidated Balance Sheets at December 31, 2015, is as follows:

	Other Assets	Long-term Debt
	(In thousands)	
Amount as previously presented, before adoption of ASU 2015-03	$ 116,480	$ 1,994,773
Deferred debt issuance costs	(14,995)	(14,995)
Amount as restated, after adoption of ASU 2015-03	$ 101,485	$ 1,979,778

Recent Accounting Pronouncements

In March 2016, the FASB issued ASU No. 2016-09, *Compensation Stock Compensation (Topic 718)*, or ASU 2016-09, which simplifies several aspects of the accounting for share-based payment transactions. The new guidance makes several modifications to the accounting for forfeitures, employer tax withholding on share-based compensation and the financial statement presentation of excess tax benefits or deficiencies. In addition, ASU 2016-09 clarifies the statement of cash flows presentation for certain components of share-based awards. The guidance of ASU 2016-09 is effective for interim and annual reporting periods beginning after December 15, 2017. Earlier adoption is permitted.

We are currently evaluating the provisions of ASU 2016-09 and have not yet determined the impact on our financial position, results of operations or cash flows.

In May 2014, the FASB issued ASU No. 2014-09, *Revenue from Contracts with Customers (Topic 606)*, or ASU 2014-09. The new standard supersedes the industry-specific standards that currently exist under GAAP and provides a framework to address revenue recognition issues comprehensively for all contracts with customers regardless of industry-specific or transaction-specific fact patterns. Under the new guidance, companies recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the company expects to be entitled in exchange for those goods or services. ASU 2014-09 also provides for additional disclosure requirements. In July 2015, the FASB issued ASU 2015-14, which deferred the effective date of ASU 2014-09. The guidance of ASU 2014-09 is now effective for annual reporting periods beginning after December 15, 2017, including interim periods within that reporting period, and may be adopted using a retrospective or modified retrospective approach.

In February 2016, the FASB issued ASU No. 2016-02, *Leases (Topic 842)*, or ASU 2016-02, which requires an entity to separate the lease components from the nonlease components in a contract. The lease components are to be accounted for under ASU 2016-02, which, under the guidance, may require recognition of lease assets and lease liabilities by lessees for most leases and derecognition of the leased asset and recognition of a net investment in the lease by the lessor. ASU 2016-02 also provides for additional disclosure requirements for both lessees and lessors. Nonlease components would be accounted for under ASU 2014-09. The guidance of ASU 2016-02 is effective for annual reporting periods beginning after December 15, 2018, including interim periods within that reporting period. Early adoption of ASU 2016-02 is permitted.

We are evaluating the provisions of ASU 2016-02 concurrently with the provisions of ASU 2014-09. We have not yet determined the impact of these ASUs on our financial position, results of operations or cash flows.

2. Asset Impairments

2016 During the first quarter of 2016, in response to continued deterioration of the market fundamentals in the oil and gas industry, significant cutbacks in customer capital spending plans and contract cancelations by customers, as well as recently announced regulatory requirements in the U.S. Gulf of Mexico, we evaluated ten of our drilling rigs with indications that their carrying amounts may not be recoverable Using an undiscounted, projected probability-weighted cash flow analysis,, we determined that the carrying values of these rigs were not impaired.

If market fundamentals in the oil and gas industry deteriorate or if we are unable to extend or secure new contracts for our current, actively-marketed drilling fleet or reactivate any of our cold-stacked rigs or if we experience unfavorable changes to our actual dayrates and rig utilization, we may be required to recognize additional impairment losses in future periods.

2015 Impairments During the first quarter of 2015, we evaluated 17 of our drilling rigs with indications that their carrying amounts may not be recoverable. Using an undiscounted, projected probability-weighted cash flow analysis, we determined that the carrying value of eight of these rigs, consisting of seven mid-water floaters and our older 7,875-foot water depth rated drillship, were impaired (collectively referred to as the 2015 Impaired Rigs).

We estimated the fair value of five of the 2015 Impaired Rigs that were cold stacked utilizing a market approach, which required us to estimate the value that would be received for each rig in the principal or most advantageous market for that rig in an orderly transaction between market participants. Such estimates were based on various inputs, including historical contracted sales prices for similar rigs in our fleet, nonbinding quotes from rig brokers and/or indicative bids, where applicable. We estimated the fair value of the three remaining 2015 Impaired Rig using an income approach, as they were contracted to customers at that time. The fair value of each of these rigs was estimated based on a calculation of the rig s discounted future net cash flows over its remaining economic life, which utilized significant unobservable inputs, including, but not limited to, assumptions related to estimated dayrate revenue, rig utilization, estimated equipment upgrade and regulatory survey costs, as well as estimated proceeds that may be received on ultimate disposition of the rig. Our fair value estimates were representative of Level 3 fair value measurements due to the significant level of estimation involved and the lack of transparency as to the inputs used.

During the first quarter of 2015, we recognized an impairment loss of $358.5 million to write down these rigs to their estimated recoverable amounts. Subsequent to the first quarter of 2015, we evaluated an additional eight drilling rigs, as well those rigs initially evaluated in the first quarter of 2015 that we had determined not to be impaired, for impairment. As a result of these evaluations, we determined that the carrying value of an additional nine drilling rigs, consisting of one ultra-deepwater, one deepwater and two mid-water semisubmersible rigs and five jack-up rigs, was not recoverable and recorded additional impairment losses of $2.6 million and $499.4 million in the third and fourth quarters of 2015, respectively.

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Of the 17 rigs impaired during 2015, six mid-water semisubmersible rigs, our older drillship and one marketed-for-sale jack-up rig have been sold. At March 31, 2016, five of the remaining impaired rigs were cold stacked and four jack-up rigs are marketed for sale.

3. Supplemental Financial Information

Consolidated Balance Sheets Information

Accounts receivable, net of allowance for bad debts, consist of the following:

	March 31, 2016	December 31, 2015
	(In thousands)	
Trade receivables	$ 341,440	$ 390,429
Value added tax receivables	17,221	14,475
Amounts held in escrow	9,231	4,966
Related party receivables	355	167
Other	1,074	1,057
	369,321	411,094
Allowance for bad debts	(5,724)	(5,724)
Total	$ 363,597	$ 405,370

Prepaid expenses and other current assets consist of the following:

	March 31, 2016	December 31, 2015
	(In thousands)	
Rig spare parts and supplies	$ 36,794	$ 42,804
Deferred mobilization costs	48,438	52,965
Prepaid insurance	2,964	4,483
Prepaid taxes	16,969	14,969
Other	5,677	4,258
Total	$ 110,842	$ 119,479

Accrued liabilities consist of the following:

	March 31, 2016	December 31, 2015

	(In thousands)	
Rig operating expenses	$ 55,852	$ 47,426
Payroll and benefits	45,145	59,787
Deferred revenue	50,337	31,542
Accrued capital project/upgrade costs	83,310	84,146
Interest payable	44,130	18,365
Personal injury and other claims	5,741	8,320
Other	4,694	4,183
Total	$ 289,209	$ 253,769

Consolidated Statements of Cash Flows Information

Noncash investing activities excluded from the Consolidated Statements of Cash Flows and other supplemental cash flow information is as follows:

	Three Months Ended March 31,	
	2016	2015
	(In thousands)	
Accrued but unpaid capital expenditures at period end	$ 83,310	$ 34,439
Common stock withheld for payroll tax obligations (1)	181	236
Cash interest payments (2)	908	
Cash income taxes paid, net of (refunds):		
U.S. federal		(3,344)
Foreign	16,683	21,281
State		

(1) Represents the cost of 7,923 shares and 7,810 shares of common stock withheld to satisfy payroll tax obligation incurred as a result of the vesting of restricted stock units in the three months ended March 31, 2016 and 2015, respectively. These costs are presented as a deduction from stockholders equity in Treasury stock in our Consolidated Balance Sheets at March 31, 2016 and 2015.

(2) Interest payments, net of amounts capitalized, were $0.8 million and $0 for the three-month periods ended March 31, 2016 and 2015, respectively.

4. Earnings Per Share

A reconciliation of the numerators and the denominators of our basic and diluted per-share computations follows:

	Three Months Ended March 31,	
	2016	2015
	(In thousands, except per share data)	
Net income (loss) basic and diluted numerator	$ 87,425	$ (255,709)
Weighted average shares basic (denominator):	137,162	137,151
Dilutive effect of stock-based awards	44	
Weighted average shares including conversions diluted (denominator)	137,206	137,151
Earnings (loss) per share:		
Basic	$ .64	$ (1.86)

Diluted	$	.64	$	(1.86)

The following table sets forth the share effects of stock-based awards excluded from our computations of diluted earnings per share, or EPS, as the inclusion of such potentially dilutive shares would have been antidilutive for the periods presented:

	Three Months Ended March 31,	
	2016	**2015**
	(In thousands)	
Employee and director:		
Stock options	10	35
Stock appreciation rights	1,527	1,624
Restricted stock units	169	50

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5. Marketable Securities

We report our investments as current assets in our Consolidated Balance Sheets in Marketable securities, representing the investment of cash available for current operations. See Note 7.

Our investments in marketable securities are classified as available for sale and are summarized as follows:

	March 31, 2016		
	Amortized Cost	Unrealized Gain (Loss)	Market Value
		(In thousands)	
Corporate bonds	$ 16,600	$ (11,601)	$ 4,999
Mortgage-backed securities	67	1	68
Total	$ 16,667	$ (11,600)	$ 5,067

	December 31, 2015		
	Amortized Cost	Unrealized Gain (Loss)	Market Value
		(In thousands)	
Corporate bonds	$ 16,480	$ (5,042)	$ 11,438
Mortgage-backed securities	77	3	80
Total	$ 16,557	$ (5,039)	$ 11,518

Based on current facts and circumstances, we believe that the unrealized losses on our investments in corporate bonds presented in the tables above are not indicative of the ultimate collectability of these investments, but are primarily related to the financial market s perception of the current downturn in the bond issuer s industry (oil and gas market and contract drilling industry). We have no current intent to sell these securities, nor is it more likely than not that we will be required to sell these investments prior to their maturity. Therefore, we do not consider the unrealized losses at March 31, 2016 and December 31, 2015 associated with our investments in corporate bonds to be other than temporary.

Proceeds from maturities and sales of marketable securities and the related gains and losses during each of the three-month periods ended March 31, 2016 and 2015 were not significant.

6. Derivative Financial Instruments

Foreign Currency Forward Exchange Contracts

During the three months ended March 31, 2015, we settled foreign currency forward exchange, or FOREX, contracts with aggregate notional values of approximately $57.5 million, of which the entire aggregate amounts were designated as a cash flow accounting hedge. We did not settle any FOREX contracts during the three months ended March 31, 2016, and we had no FOREX contracts outstanding at March 31, 2016 or December 31, 2015.

During the three months ended March 31, 2015, we recognized an aggregate loss of $6.4 million related to our FOREX contracts designated as accounting hedges, which we presented within Contract drilling expense, excluding depreciation in our Consolidated Statements of Operations.

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The following table presents the amounts recognized in our Consolidated Balance Sheets and Consolidated Statements of Operations related to our derivative financial instruments designated as cash flow hedges for the three-month period ended March 31, 2015.

	Three Months Ended March 31, 2015 (In thousands)
FOREX contracts:	
Amount of (loss) gain recognized in AOCGL on derivative (effective portion)	$ (2,810)
Location of (loss) gain reclassified from AOCGL into income (effective portion)	Contract drilling expense
Amount of (loss) gain reclassified from AOCGL into income (effective portion)	$ (5,520)
Location of loss recognized in income on derivative (ineffective portion and amount excluded from effectiveness testing)	Foreign currency transaction gain (loss)
Amount of loss recognized in income on derivative (ineffective portion and amount excluded from effectiveness testing)	$ (9)

During the three-month period ended March 31, 2015, we did not reclassify any amounts from AOCGL due to the probability of an underlying forecasted transaction not occurring.

7. Financial Instruments and Fair Value Disclosures

Financial instruments that potentially subject us to significant concentrations of credit or market risk consist primarily of periodic temporary investments of excess cash, trade accounts receivable and investments in debt securities, including residential mortgage-backed securities. We generally place our excess cash investments in U.S. government-backed short-term money market instruments through several financial institutions. At times, such investments may be in excess of the insurable limit. We periodically evaluate the relative credit standing of these financial institutions as part of our investment strategy.

Most of our investments in debt securities are securitized corporate bonds whereby our credit risk is mitigated by the collateral. However, we are exposed to market risk due to price volatility associated with interest rate fluctuations.

Concentrations of credit risk with respect to our trade accounts receivable are limited primarily due to the entities comprising our customer base. Since the market for our services is the offshore oil and gas industry, this customer base consists primarily of major and independent oil and gas companies and government-owned oil companies. Based on our current customer base and the geographic areas in which we operate, as well as the number of rigs currently working in a geographic area, we do not believe that we have any significant concentrations of credit risk at March 31, 2016.

In general, before working for a customer with whom we have not had a prior business relationship and/or whose financial stability may be uncertain to us, we perform a credit review on that company. Based on that analysis, we may require that the customer present a letter of credit, prepay or provide other credit enhancements. We record a provision for bad debts on a case-by-case basis when facts and circumstances indicate that a customer receivable may not be collectible and, historically, losses on our trade receivables have been infrequent occurrences.

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Fair Values

Fair value is defined as the exchange price that would be received for an asset or paid to transfer a liability (an exit price) in the principal or most advantageous market for the asset or liability in an orderly transaction between market participants on the measurement date. The fair value hierarchy prescribed by GAAP requires an entity to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. There are three levels of inputs that may be used to measure fair value:

Level 1	Quoted prices for identical instruments in active markets. Level 1 assets include short-term investments such as money market funds, U.S. Treasury Bills and Treasury notes. Our Level 1 assets at March 31, 2016 consisted of cash held in money market funds of $93.4 million and time deposits of $20.4 million. Our Level 1 assets at December 31, 2015 consisted of cash held in money market funds of $85.2 million and time deposits of $20.4 million.
Level 2	Quoted market prices for similar instruments in active markets; quoted prices for identical or similar instruments in markets that are not active; and model-derived valuations in which all significant inputs and significant value drivers are observable in active markets. Level 2 assets and liabilities include residential mortgage-backed securities, corporate bonds purchased in a private placement offering and over-the-counter FOREX contracts. Our residential mortgage-backed securities and corporate bonds were valued using a model-derived valuation technique based on the quoted closing market prices received from a financial institution. The inputs used in our valuation are obtained from a Bloomberg curve analysis which uses par coupon swap rates to calculate implied forward rates so that projected floating rate cash flows can be calculated. The valuation techniques underlying the models are widely accepted in the financial services industry and do not involve significant judgment.
Level 3	Valuations derived from valuation techniques in which one or more significant inputs or significant value drivers are unobservable. Level 3 assets and liabilities generally include financial instruments whose value is determined using pricing models, discounted cash flow methodologies, or similar techniques, as well as instruments for which the determination of fair value requires significant management judgment or estimation or for which there is a lack of transparency as to the inputs used. Our Level 3 assets at March 31, 2016 consisted of nonrecurring measurements of certain of our drilling rigs for which we recorded an impairment loss during 2015. See Note 2.

Market conditions could cause an instrument to be reclassified among Levels 1, 2 and 3. Our policy regarding fair value measurements of financial instruments transferred into and out of levels is to reflect the transfers as having occurred at the beginning of the reporting period. There were no transfers between fair value levels during the three-month periods ended March 31, 2016 and 2015.

Certain of our assets and liabilities are required to be measured at fair value on a recurring basis in accordance with GAAP. In addition, certain assets and liabilities may be recorded at fair value on a nonrecurring basis. Generally, we record assets at fair value on a nonrecurring basis as a result of impairment charges. We recorded impairment charges related to certain of our drilling rigs, which were measured at fair value on a nonrecurring basis during the three-month periods ended March 31, 2015, September 30, 2015 and December 31, 2015 of $358.5 million, $2.6 million and $499.4 million, respectively.

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Assets and liabilities measured at fair value are summarized below:

	March 31, 2016 Fair Value Measurements Using			
	Level 1	Level 2	Level 3	Assets at Fair Value
	(In thousands)			
Recurring fair value measurements:				
Assets:				
Short-term investments	$ 113,843	$	$	$ 113,843
Corporate bonds		4,999		4,999
Mortgage-backed securities		68		68
Total assets	$ 113,843	$ 5,067	$	$ 118,910
Nonrecurring fair value measurements:				
Assets:				
Impaired assets [1][2]	$	$	$ 178,415	$ 178,415

(1) Represents the book value as of March 31, 2016 of 11 drilling rigs, which were written down to their estimated recoverable amounts in 2015, of which $6.6 million and $171.8 million were reported as Assets held for sale and Drilling and other property and equipment, net of accumulated depreciation, respectively, in our Consolidated Balance Sheets at March 31, 2016. See Note 2.

(2) Excludes the fair value of one marketed-for-sale jack-up rig sold in February 2016.

	December 31, 2015 Fair Value Measurements Using				
	Level 1	Level 2	Level 3	Assets at Fair Value	Total Losses for Year Ended [1]
	(In thousands)				
Recurring fair value measurements:					
Assets:					
Short-term investments	$ 105,659	$	$	$ 105,659	
Corporate bonds		11,438		11,438	
Mortgage-backed securities		80		80	
Total assets	$ 105,659	11,518	$	$ 117,177	
Nonrecurring fair value measurements:					
Assets:					

Impaired assets [2][3]	$	$	$ 189,600	$ 189,600	$ 860,441

(1) Represents the aggregate impairment loss recognized for the year ended December 31, 2015 related to our 2015 Impaired Rigs.

(2) Represents the book value of our 2015 Impaired Rigs, which were written down to their estimated recoverable amounts during 2015, of which $14.2 million and $175.4 million were reported as Assets held for sale and Drilling and other property and equipment, net of accumulated depreciation, respectively, in our Consolidated Balance Sheets at December 31, 2015.

(3) Excludes five rigs with an aggregate fair value of $2.4 million, which were impaired in 2015, but were subsequently sold for scrap prior to December 31, 2015.

We believe that the carrying amounts of our other financial assets and liabilities (excluding long-term debt), which are not measured at fair value in our Consolidated Balance Sheets, approximate fair value based on the following assumptions:

Cash and cash equivalents The carrying amounts approximate fair value because of the short maturity of these instruments.

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Accounts receivable and accounts payable The carrying amounts approximate fair value based on the nature of the instruments.

Commercial paper The carrying amounts approximate fair value because of the short maturity of these instruments.

We consider our senior notes to be Level 2 liabilities under the GAAP fair value hierarchy and, accordingly, the fair value of our senior notes was derived using a third-party pricing service at March 31, 2016 and December 31, 2015. We perform control procedures over information we obtain from pricing services and brokers to test whether prices received represent a reasonable estimate of fair value. These procedures include the review of pricing service or broker pricing methodologies and comparing fair value estimates to actual trade activity executed in the market for these instruments occurring generally within a 10-day period of the report date. Fair values and related carrying values of our senior notes are shown below.

	March 31, 2016		December 31, 2015	
	Fair Value	Carrying Value	Fair Value	Carrying Value
	(In millions)			
5.875% Senior Notes due 2019	$ 472.1	$ 499.7	$ 506.8	$ 499.7
3.45% Senior Notes due 2023	177.9	249.2	208.0	249.2
5.70% Senior Notes due 2039	343.6	497.0	360.0	497.0
4.875% Senior Notes due 2043	493.8	748.9	455.3	748.9

We have estimated the fair value amounts by using appropriate valuation methodologies and information available to management. Considerable judgment is required in developing these estimates, and accordingly, no assurance can be given that the estimated values are indicative of the amounts that would be realized in a free market exchange.

8. Drilling and Other Property and Equipment

Cost and accumulated depreciation of drilling and other property and equipment are summarized as follows:

	March 31, 2016	December 31, 2015
	(In thousands)	
Drilling rigs and equipment	$ 9,187,672	$ 9,345,484
Construction work-in-progress	288,900	269,605
Land and buildings	64,928	64,775
Office equipment and other	71,650	71,537
Cost	9,613,150	9,751,401
Less: accumulated depreciation	(3,393,908)	(3,372,587)
Drilling and other property and equipment, net	$ 6,219,242	$ 6,378,814

Construction work-in-progress, including capitalized interest, at March 31, 2016 and December 31, 2015 was $288.9 million and $269.6 million, respectively, attributable to the *Ocean GreatWhite*, which is expected to be completed in the second half of 2016.

See Note 13 for a discussion of two sale and leaseback transactions that were executed in March 2016.

9. Credit Agreement, Commercial Paper and Credit Ratings

In February 2016, Moody s Investors Service, or Moody s, downgraded our senior unsecured credit rating to Ba2 from Baa2, with a stable outlook, and also downgraded our short-term credit rating to sub-Prime. Our current corporate credit rating for Standard & Poor s Ratings Services is BBB+ and our short-term credit rating is A2.

As a result of the Moody s downgrade, we canceled our commercial paper program due to our inability to access the commercial paper market in the foreseeable future. In addition, based on our current credit ratings, the applicable interest rate for alternate base rate loans under our revolving credit agreement is 0.25% over the greater of (i) the prime rate, (ii) the federal funds rate plus 0.50% and (iii) the daily one-month Eurodollar Rate plus 1.00%. The applicable interest rate for Eurodollar loans under our revolving credit agreement is currently 1.25% over British Bankers Association Libor. The applicable commitment fee is 0.20%, and the participation fee for performance letters of credit is 0.625%.

In January 2016, we repaid the $286.6 million in commercial paper notes outstanding at December 31, 2015 with proceeds from Eurodollar loans under our revolving credit agreement. As of March 31, 2016, there were no Eurodollar loans or other amounts outstanding under our revolving credit agreement. As of April 28, 2016, we had $1.5 billion available under our revolving credit agreement.

10. Commitments and Contingencies

Various claims have been filed against us in the ordinary course of business, including claims by offshore workers alleging personal injuries. With respect to each claim or exposure, we have made an assessment, in accordance with GAAP, of the probability that the resolution of the matter would ultimately result in a loss. When we determine that an unfavorable resolution of a matter is probable and such amount of loss can be determined, we record a liability for the amount of the estimated loss at the time that both of these criteria are met. Our management believes that we have recorded adequate accruals for any liabilities that may reasonably be expected to result from these claims.

Asbestos Litigation. We are one of several unrelated defendants in lawsuits filed in Mississippi, Louisiana and Missouri state courts alleging that defendants manufactured, distributed or utilized drilling mud containing asbestos and, in our case, allowed such drilling mud to have been utilized aboard our drilling rigs. The plaintiffs seek, among other things, an award of unspecified compensatory and punitive damages. The manufacture and use of asbestos-containing drilling mud had already ceased before we acquired any of the drilling rigs addressed in these lawsuits. We believe that we are not liable for the damages asserted and we expect to receive complete defense and indemnity from Murphy Exploration & Production Company with respect to many of the lawsuits pursuant to the terms of our 1992 asset purchase agreement with them. We also believe that we are not liable for the damages asserted in the remaining lawsuits pursuant to the terms of our 1989 asset purchase agreement with Diamond M Corporation. We are unable to estimate our potential exposure, if any, to these lawsuits at this time but do not believe that our ultimate liability, if any, resulting from this litigation will have a material effect on our consolidated financial condition, results of operations or cash flows.

Other Litigation. We have been named in various other claims, lawsuits or threatened actions that are incidental to the ordinary course of our business, including a claim by one of our customers in Brazil, Petróleo Brasileiro S.A., or Petrobras, that it will seek to recover from its contractors, including us, any taxes, penalties, interest and fees that it must pay to the Brazilian tax authorities for our applicable portion of withholding taxes related to Petrobras charter agreements with its contractors. We intend to defend these matters vigorously; however, litigation is inherently unpredictable, and the ultimate outcome or effect of these claims, lawsuits and actions cannot be predicted with certainty. As a result, there can be no assurance as to the ultimate outcome of these matters. Any claims against us, whether meritorious or not, could cause us to incur costs and expenses, require significant amounts of management time and result in the diversion of significant operational resources. In the opinion of our management, no pending or known threatened claims, actions or proceedings against us are expected to have a material adverse effect on our consolidated financial position, results of operations or cash flows.

NPI Arrangement. We received customer payments measured by a percentage net profits interest (primarily of 27%) under an overriding royalty interest in certain developmental oil-and-gas producing properties, or NPI, which we believe is a real property interest. Our drilling program related to the NPI was completed in 2011, and the balance of the amounts due to us under the NPI was received in 2013. However, in August 2012, the customer that conveyed the NPI to us filed a voluntary petition for reorganization under Chapter 11 of the Bankruptcy Code. Certain parties (including the debtor) in the bankruptcy proceedings questioned whether our NPI, and certain amounts we received under it after the filing of the bankruptcy, should be included in the debtor s estate under the bankruptcy proceeding. In 2013, we filed a declaratory judgment action in the bankruptcy court seeking a declaration that our NPI, and payments that we received from it since the filing of the bankruptcy, are not part of the bankruptcy estate. We agreed to a settlement with the company that purchased most of the debtor s assets (including the debtor s claims against our NPI) whereby the nature of our NPI will not be challenged by that party and our declaratory judgment action was dismissed. Following the settlement, the bankruptcy was converted to a Chapter 7 liquidation proceeding. Several lienholders who had previously intervened in the declaratory judgment action filed motions in the bankruptcy contending that their liens have priority and seeking disgorgement of $3.25 million of payments made to us after the bankruptcy was filed. We believe that our rights to the payments at issue are superior to these liens, and we have filed appropriate motions to dismiss these claims. In addition, the bankruptcy trustee filed counterclaims seeking disgorgement of a total of $30.0 million of pre- and post-bankruptcy payments made to us under the original NPI. The bankruptcy court has dismissed all but one of the trustee s disgorgement claims, which is limited in amount to $17.0 million. We continue to pursue all available defenses and available protections, and still expect the bankruptcy proceedings to be concluded with no further material impact to us.

Personal Injury Claims. Under our current insurance policies, which renewed effective May 1, 2016, our deductibles for marine liability insurance coverage with respect to personal injury claims not related to named windstorms in the U.S. Gulf of Mexico , which primarily result from Jones Act liability in the Gulf of Mexico, are $10.0 million for the first occurrence, with no aggregate deductible, and vary in amounts ranging between $5.0 million and, if aggregate claims exceed certain thresholds, up to $100.0 million for each subsequent occurrence, depending on the nature, severity and frequency of claims that might arise during the policy year. Our deductible for personal injury claims arising due to named windstorms in the U.S. Gulf of Mexico is $25.0 million for the first occurrence, with no aggregate deductible, and vary in amounts ranging between $25.0 million and, if aggregate claims exceed certain thresholds, up to $100.0 million for each subsequent occurrence, depending on the nature, severity and frequency of claims that might arise during the policy year.

The Jones Act is a federal law that permits seamen to seek compensation for certain injuries during the course of their employment on a vessel and governs the liability of vessel operators and marine employers for the work-related injury or death of an employee. We engage outside consultants to assist us in estimating our aggregate liability for personal injury claims based on our historical losses and utilizing various actuarial models. We allocate a portion of the aggregate liability to Accrued liabilities based on an estimate of claims expected to be paid within the next twelve months with the residual recorded as Other liabilities. At March 31, 2016 our estimated liability for personal injury claims was $38.0 million, of which $5.5 million and $32.5 million were recorded in Accrued liabilities and Other liabilities, respectively, in our Consolidated Balance Sheets. At December 31, 2015 our estimated liability for personal injury claims was $40.4 million, of which $8.2 million and $32.2 million were recorded in Accrued liabilities and Other liabilities, respectively, in our Consolidated Balance Sheets. The eventual settlement or adjudication of these claims could differ materially from our estimated amounts due to uncertainties such as:

- the severity of personal injuries claimed;
- significant changes in the volume of personal injury claims;

- the unpredictability of legal jurisdictions where the claims will ultimately be litigated;
- inconsistent court decisions; and
- the risks and lack of predictability inherent in personal injury litigation.

Purchase Obligations. The *Ocean GreatWhite*, a 10,000 foot dynamically positioned, harsh environment semisubmersible drilling rig, is under construction in South Korea at an estimated cost of $764 million, including

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shipyard costs, capital spares, commissioning, project management and shipyard supervision. The contracted price to Hyundai Heavy Industries Co., Ltd. totaling $628.5 million is payable in two installments, of which the first installment of $188.6 million has been paid. The final installment of $439.9 million is due upon delivery of the rig, which is expected to occur in the second half of 2016.

At March 31, 2016, we had no other purchase obligations for major rig upgrades or any other significant obligations, except for those related to our direct rig operations, which arise during the normal course of business. See Note 13.

Letters of Credit and Other. We were contingently liable as of March 31, 2016 in the amount of $69.0 million under certain performance, supersedeas, bid, tax and customs bonds and letters of credit. Agreements relating to approximately $63.9 million of performance, tax, supersedeas, court and customs bonds can require collateral at any time. As of March 31, 2016, we had not been required to make any collateral deposits with respect to these agreements. The remaining agreements cannot require collateral except in events of default. On our behalf, banks have issued letters of credit securing certain of these bonds.

11. Accumulated Other Comprehensive Gain (Loss)

The components of our AOCGL and related changes thereto are as follows:

	Unrealized (Loss) Gain on Derivative Financial Instruments	Unrealized (Loss) Gain on Marketable Securities	Total AOCGL
	(In thousands)		
Balance at January 1, 2016	$ 6	$ (5,041)	$ (5,035)
Change in other comprehensive loss before reclassifications, after tax of $0 and $2		(6,559)	(6,559)
Reclassification adjustments for items included in Net Income, after tax of $1 and $0	(1)		(1)
Balance at March 31, 2016	$ 5	$ (11,600)	$ (11,595)

The following table presents the line items in our Consolidated Statements of Operations affected by reclassification adjustments out of AOCGL.

Major Category of AOCGL	Three Months Ended March 31, 2016	Three Months Ended March 31, 2015	Consolidated Statements of Operations Line Items
	(In thousands)		
Derivative Financial Instruments:			
Unrealized loss on FOREX contracts	$	$ 5,520	Contract drilling, excluding

			depreciation
Unrealized gain on treasury lock agreements	(2)	(2)	Interest expense
	1	(1,931)	Income tax expense
	$ (1)	$ 3,587	Net of tax

12. Restructuring and Separation Costs

In early 2015, in response to the continuing decline in the offshore drilling market, we reviewed our cost and organization structure, and, as a result, our management approved and initiated a reduction in workforce at our onshore bases and corporate facilities, also referred to as the Corporate Reduction Plan. We recognized $6.2 million during the three-month period ended March 31, 2015 in restructuring and employee separation costs related to the Corporate Reduction Plan.

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13. Sale and Leaseback Transaction

In February 2016, we entered into a ten-year agreement with a subsidiary of GE Oil & Gas, or GE, to provide services with respect to certain blowout preventer and related well control equipment, or Well Control Equipment, on our four newly-built drillships. Such services include management of maintenance, certification and reliability with respect to such equipment. In connection with the contractual services agreement with GE, we agreed to sell the Well Control Equipment to another GE affiliate and subsequently lease back such equipment over separate ten-year operating leases.

During March 2016, we executed two sale and leaseback transactions with respect to the Well Control Equipment on the *Ocean BlackHawk* and *Ocean BlackHornet*. As a result of these transactions, we received an aggregate $105.0 million in proceeds from the sale of the Well Control Equipment on these rigs and executed two ten-year operating lease and contractual services agreements. No gain or loss was recognized on the transactions. Future commitments under the operating leases and contractual services agreements for the *Ocean BlackHawk* and *Ocean BlackHornet* are estimated to be approximately $33.0 million per annum or an aggregate $327.0 million over the term of the agreements. We expect to complete the remaining sale and leaseback transactions for the *Ocean BlackLio*n and *Ocean BlackRhino* in the second and fourth quarters of 2016, respectively.

14. Segments and Geographic Area Analysis

Although we provide contract drilling services with different types of offshore drilling rigs and also provide such services in many geographic locations, we have aggregated these operations into one reportable segment based on the similarity of economic characteristics due to the nature of the revenue earning process as it relates to the offshore drilling industry over the operating lives of our drilling rigs.

Revenues from contract drilling services by equipment type are listed below:

	Three Months Ended March 31,	
	2016	**2015**
	(In thousands)	
Floaters:		
Ultra-Deepwater	$ 325,961	$ 251,396
Deepwater	59,117	138,770
Mid-Water	47,672	176,357
Total Floaters	432,750	566,523
Jack-ups	10,773	33,054
Total contract drilling revenues	443,523	599,577
Revenues related to reimbursable expenses	27,020	20,479
Total revenues	$ 470,543	$ 620,056

Geographic Areas

Our drilling rigs are highly mobile and may be moved to other markets throughout the world in response to market conditions or customer needs. At March 31, 2016, our actively-marketed drilling rigs were en route to or located offshore five countries in addition to the United States. Revenues by geographic area are presented by attributing revenues to the individual country or areas where the services were performed.

	Three Months Ended March 31,	
	2016	2015
	(In thousands)	
United States	$ 161,582	$ 77,158
International:		
South America	121,488	193,075
Europe	102,619	151,270
Australia/Asia	64,973	137,135
Mexico	19,881	61,418
Total revenues	$ 470,543	$ 620,056

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

The following discussion should be read in conjunction with our unaudited consolidated financial statements (including the notes thereto) included elsewhere in this report and our audited consolidated financial statements and the notes thereto, Item 7, Management s Discussion and Analysis of Financial Condition and Results of Operations and Item 1A, Risk Factors included in our Annual Report on Form 10-K for the year ended December 31, 2015. References to Diamond Offshore, we, us or our mean Diamond Offshore Drilling, Inc., a Delaware corporation, and its subsidiaries.

We are a leader in offshore drilling, providing contract drilling services to the energy industry around the globe with a fleet of 30 offshore drilling rigs, which includes four jack-up rigs that we are marketing for sale. Our fleet consists of 21 semisubmersibles, including the *Ocean GreatWhite*, which is under construction, five jack-up rigs and four dynamically positioned drillships. We expect our harsh environment, ultra-deepwater semisubmersible rig, the *Ocean GreatWhite*, to be delivered in the second half of 2016.

Market Overview

Market fundamentals in the oil and gas industry have continued to deteriorate in 2016. Oil prices, which had fallen to a 12-year low below $30 per barrel in January, have rebounded slightly but continue to exhibit day-to-day volatility, due to multiple factors, including fluctuations in the current and expected level of global oil inventories and the lack of a supply response by the Organization of Petroleum Exporting Countries (OPEC). These factors, as well as other geopolitical and economic issues, combined with significant operating losses incurred by some independent and national oil companies and exploration and production companies during 2015, have resulted in significantly reduced capital spending plans for 2016 and possibly beyond, as operators struggle to stay cash neutral in the current oil price environment. There have been very few rig tenders thus far in 2016, primarily limited to short-term or well-to-well work not commencing until 2017 or later.

Since 2014, approximately 50 floater rigs have been retired and others have been cold stacked, slightly abating the current oversupply of drilling rigs. The number of available rigs continues to grow as contracted rigs come off contract and newly-built rigs are delivered. Competition for the limited number of drilling jobs continues to be intense. In some cases, dayrates have been negotiated at near break-even levels to provide for the recovery of operating costs for rigs that would otherwise be uncontracted or cold stacked. Many industry analysts have predicted that the offshore contract drilling market may remain depressed with further declines in dayrates and utilization likely in 2016 and 2017.

As a result of the depressed market conditions and continued pessimistic outlook for the near term, certain of our customers, as well as those of our competitors, have attempted to renegotiate or terminate existing drilling contracts. Such renegotiations could include requests to lower the contract dayrate, lowering of a dayrate in exchange for additional contract term, shortening the term on one contracted rig in exchange for additional term on another rig, early termination of a contract in exchange for a lump sum margin payout and many other possibilities. In addition to the potential for renegotiations, some of our drilling contracts permit the customer to terminate the contract early after specified notice periods, usually resulting in a contractually specified termination amount, which may not fully compensate us for the loss of the contract. Particularly during depressed market conditions, the early termination of a contract may result in a rig being idle for an extended period of time, which could adversely affect our financial condition, results of operations and cash flows. When a customer terminates our contract prior to the contract s scheduled expiration, our contract backlog is also adversely impacted.

Our results of operations and cash flows for the quarter ended March 31, 2016 have been negatively impacted by depressed market conditions in the offshore drilling industry. We currently expect that these adverse market conditions will continue for the foreseeable future. The continuation of these conditions for an extended period could result in more of our rigs being without contracts and/or cold stacked or scrapped and could further materially and adversely affect our financial condition, results of operations and cash flows. When we cold stack or elect to scrap a rig, we evaluate the rig for impairment. During 2015, we recognized an aggregate impairment loss of $860.4 million to write down 17 of our drilling rigs to their estimated recoverable amounts. During the first quarter of 2016, we evaluated ten of our drilling rigs with indications that their carrying amounts may not be recoverable and determined that no additional rigs were impaired at this time. See Results of Operations *Overview Three Months Ended March 31, 2016 and 2015 Impairment of Assets* and Note 2 to our unaudited consolidated financial statements included in Item 1 of Part I this report.

On April 28, 2016, our subsidiary s agent in Mexico received a letter from PEMEX Exploración y Producción, or PEMEX, purporting to exercise its contractual right to terminate its drilling contract on the *Ocean Scepter* with 30 days advance notice. We are in discussions with PEMEX regarding the matter. As of May 2, 2016, 15 rigs in our fleet were cold stacked, including four jack-up rigs that are currently being marketed for sale. See Contract Drilling Backlog for future commitments of our rigs during 2016 through 2020.

Although these general market conditions impact all segments of the offshore drilling market, the following discussion addresses market conditions within segments of the floater market.

Floater Markets

Ultra-Deepwater and Deepwater Floaters. Globally, the ultra-deepwater and deepwater floater markets continue to be depressed. Diminished or nonexistent demand, combined with an oversupply of rigs has caused floater dayrates to decline significantly. Industry analysts expect offshore drillers to continue to scrap older, lower specification rigs; however, newer and higher specification rigs have also been impacted by the recycling trend.

In an effort to manage the oversupply of rigs and potentially avoid the cost of cold stacking newly-built rigs, which, in the case of dynamically-positioned rigs, can be significant, several drilling contractors have exercised options to delay the delivery of rigs by the shipyard or have exercised their right to cancel orders due to the late delivery of rigs. As of the date of this report, industry data indicates that there are approximately 55 competitive, or non-owner-operated, newbuild floaters on order, including 16 rigs scheduled for delivery in 2016 of which 12 units are not yet contracted for future work. An additional 39 rigs are currently scheduled to be delivered between 2017 and 2021, over half of which are not yet contracted for future work. Industry analysts predict that delivery dates may shift further as newbuild owners negotiate with their respective shipyards.

Mid-Water Floaters. While conditions in the mid-water market vary slightly by region, mid-water rigs have been adversely impacted by (i) lower demand, (ii) declining dayrates, (iii) increased regulatory requirements, including more stringent design requirements for well control equipment, which could significantly increase the capital needed to comply with design requirements that would permit such rigs to work in the U.S. Gulf of Mexico, or GOM, (iv) the challenges experienced by lower specification units in this segment as a result of more complex customer specifications and (v) the intensified competition resulting from the migration of some deepwater and ultra-deepwater units to compete against mid-water units. To date, the mid-water market has seen the highest number of cold-stacked and scrapped rigs. Since 2012, we have sold 12 of our mid-water rigs for scrap. As market conditions remain challenging, we expect higher-specification rigs to take the place of lower-specification units, where possible, leading to additional lower-specification rigs being cold stacked or ultimately scrapped.

GOM Floaters. On April 14, 2016, the Bureau of Safety and Environmental Enforcement, or BSEE, issued its final well control regulations, nearly six years after the Macondo well blowout in the GOM. This final rule addresses the full range of systems and equipment associated with well control operations, focusing on requirements for blowout preventers, or BOPs, well design, well control casing, cementing, real-time monitoring and subsea containment. The regulations combine prescriptive and performance-based measures to cultivate a greater culture of safety for both oil and gas companies and offshore rig operators that minimizes risk. Key features of the well control regulations include requirements for BOPs, double shear rams, third-party reviews of equipment, real-time monitoring data, safe drilling margins, centralizers, inspections and other reforms related to well design and control, casing, cementing and subsea containment. Most of these requirements will become effective three months after publication of the final rule in the Federal Register; however, several requirements have more extended timeframes for compliance.

The issuance of these rules could result in the future retirement of older, less capable rigs, for which compliance with the new requirements is not physically or economically feasible. Additionally, some analysts predict that the new rules will drive the continued preference for modern floaters. See Important Factors That May Impact Our Operating Results, Financial Condition or Cash Flows.

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Contract Drilling Backlog

The following table reflects our contract drilling backlog as of April 1, 2016 (based on contract information known at that time), February 16, 2016 (the date reported in our Annual Report on Form 10-K for the year ended December 31, 2015), and April 20, 2015 (the date reported in our Quarterly Report on Form 10-Q for the quarter ended March 31, 2015). Contract drilling backlog as presented below includes only firm commitments (typically represented by signed contracts) and is calculated by multiplying the contracted operating dayrate by the firm contract period and adding one-half of any potential rig performance bonuses. Our calculation also assumes full utilization of our drilling equipment for the contract period (excluding scheduled shipyard and survey days); however, the amount of actual revenue earned and the actual periods during which revenues are earned will be different than the amounts and periods shown in the tables below due to various factors. Utilization rates, which generally approach 92-98% during contracted periods, can be adversely impacted by downtime due to various operating factors including, but not limited to, weather conditions and unscheduled repairs and maintenance. Contract drilling backlog excludes revenues for mobilization, demobilization, contract preparation and customer reimbursables. No revenue is generally earned during periods of downtime for regulatory surveys. Changes in our contract drilling backlog between periods are generally a function of the performance of work on term contracts, as well as the extension or modification of existing term contracts and the execution of additional contracts. In addition, under certain circumstances, our customers may seek to terminate or renegotiate our contracts.

	April 1, 2016	February 16, 2016 (In thousands)	April 20, 2015
Contract Drilling Backlog			
Floaters:			
Ultra-Deepwater [(1)]	$ 4,137,000	$ 4,415,000	$ 5,167,000
Deepwater	327,000	375,000	617,000
Mid-Water	307,000	356,000	438,000
Total Floaters	4,771,000	5,146,000	6,222,000
Jack-ups [(2)]	7,000	49,000	49,000
Total	$ 4,778,000	$ 5,195,000	$ 6,271,000

(1) Contract drilling backlog as of April 1, 2016 for our ultra-deepwater floaters includes $641.0 million for the years 2016 to 2019 attributable to future work for the semisubmersible *Ocean GreatWhite*, which is under construction.

(2) On April 28, 2016, our subsidiary s agent in Mexico received a letter from PEMEX purporting to exercise its contractual right to terminate its drilling contract on the *Ocean Scepter* with 30 days advance notice. We are in discussions with PEMEX regarding the matter.

The following table reflects the amount of our contract drilling backlog by year as of April 1, 2016.

For the Years Ending December 31,

	Total	2016 (1)	2017	2018	2019 - 2020
			(In thousands)		
Contract Drilling Backlog					
Floaters:					
Ultra-Deepwater (2)	$ 4,137,000	$ 794,000	$ 1,201,000	$ 1,142,000	$ 1,000,000
Deepwater	327,000	191,000	136,000		
Mid-Water	307,000	171,000	136,000		
Total Floaters	4,771,000	1,156,000	1,473,000	1,142,000	1,000,000
Jack-ups (3)	7,000	7,000			
Total	$ 4,778,000	$ 1,163,000	$ 1,473,000	$ 1,142,000	$ 1,000,000

(1) Represents the nine-month period beginning April 1, 2016.

(2) Contract drilling backlog as of April 1, 2016 for our ultra-deepwater floaters includes $54.0 million for the year 2016, $214.0 million for each of the years 2017 and 2018, and $159.0 million for the year 2019 attributable to future work for the *Ocean GreatWhite*, which is under construction.

(3) On April 28, 2016, our subsidiary s agent in Mexico received a letter from PEMEX purporting to exercise its contractual right to terminate its drilling contract on the *Ocean Scepter* with 30 days advance notice. We are in discussions with PEMEX regarding the matter.

The following table reflects the percentage of rig days committed by year as of April 1, 2016. The percentage of rig days committed is calculated as the ratio of total days committed under contracts, as well as scheduled shipyard, survey and mobilization days for all rigs in our fleet, to total available days (number of rigs multiplied by the number of days in a particular year). Total available days have been calculated based on the expected final commissioning date for the *Ocean GreatWhite*, which is under construction.

	For the Years Ending December 31,			
	2016 (1)	**2017**	**2018**	**2019 - 2020**
Rig Days Committed (2)				
Floaters:				
Ultra-Deepwater	47%	58%	57%	26%
Deepwater	24%	17%		
Mid-Water	19%	13%		
All Floaters	32%	34%	25%	11%
Jack-ups (3)	3%			

(1) Represents the nine-month period beginning April 1, 2016.

(2) As of April 1, 2016, includes approximately 285 currently known, scheduled shipyard days for rig commissioning, contract preparation, surveys and extended maintenance projects, as well as rig mobilization days, for the year 2016.

(3) On April 28, 2016, our subsidiary s agent in Mexico received a letter from PEMEX purporting to exercise its contractual right to terminate its drilling contract on the *Ocean Scepter* with 30 days advance notice. We are in discussions with PEMEX regarding the matter.

Important Factors That May Impact Our Operating Results, Financial Condition or Cash Flows

Regulatory Surveys, Planned Downtime and Regulatory Compliance. Our operating income is negatively impacted when we perform certain regulatory inspections, which we refer to as a 5-year survey, or special survey, that are due every five years for each of our rigs. During the remainder of 2016, we expect to spend an additional approximately 285 days for the mobilization of rigs and contract acceptance testing, including days associated with mobilization and acceptance testing for the *Ocean GreatWhite* (approximately 90 days), which is under construction and expected to be delivered in the second half of 2016 and rig modifications and acceptance testing for the *Ocean BlackRhino*, which is scheduled to begin operating under a new contract in January 2017 (approximately 105 days). We expect the *Ocean Endeavor* to be unavailable through mid-2016 (approximately 55 days) as it demobilizes out of the Black Sea. We can provide no assurance as to the exact timing and/or duration of downtime associated with regulatory inspections, planned rig mobilizations and other shipyard projects. See *Contract Drilling Backlog*.

In April 2016, BSEE issued its final well control regulations, which address the full range of systems and equipment associated with well control operations, focusing on requirements for blowout preventers, well design, well control casing, cementing, real-time monitoring and subsea containment. We are currently assessing the final rules and have not yet determined the costs to comply with the additional requirements to enable our drilling rigs to be eligible to operate in U.S. waters.

Physical Damage and Marine Liability Insurance. We are self-insured for physical damage to rigs and equipment caused by named windstorms in the GOM. If a named windstorm in the GOM causes significant damage to our rigs or equipment, it could have a material adverse effect on our financial condition, results of operations and cash flows. Under our current insurance policy, which renewed effective May 1, 2016, we carry physical damage insurance for certain losses other than those caused by named windstorms in the GOM for which our deductible for physical damage is $25.0 million per occurrence. We do not typically retain loss-of-hire insurance policies to cover our rigs.

In addition, under our current insurance policy, which renewed effective May 1, 2016, we carry marine liability insurance covering certain legal liabilities, including coverage for certain personal injury claims, and generally covering liabilities arising out of or relating to pollution and/or environmental risk. We believe that the policy limit for our marine liability insurance is within the range that is customary for companies of our size in the offshore drilling industry and is appropriate for our business. Our deductibles for marine liability coverage related to insurable events arising due to named windstorms in the U.S. Gulf of Mexico is $25.0 million for the first occurrence, with no aggregate deductible, and vary in amounts ranging between $25.0 million and, if aggregate claims exceed certain thresholds, up to $100.0 million for each subsequent occurrence, depending on the nature, severity and frequency of claims that might arise during the policy year. Our deductibles for other marine liability coverage, including personal injury claims not related to named windstorms in the U.S. Gulf of Mexico, are $10.0 million for the first occurrence and vary in amounts ranging between $5.0 million and, if aggregate claims exceed certain thresholds, up to $100.0 million for each subsequent occurrence, depending on the nature, severity and frequency of claims that might arise during the policy year.

Construction and Capital Upgrade Projects. We capitalize interest cost for the construction and upgrade of qualifying assets in accordance with accounting principles generally accepted in the U.S., or GAAP. The period of interest capitalization covers the duration of the activities required to make the asset ready for its intended use, and the capitalization period ends when the asset is substantially complete and ready for its intended use, which is expected to continue after delivery of the rigs from the shipyard and until the user acceptance phase of each project is completed. During the first quarter of 2016, we capitalized interest of $3.3 million related to the construction of the *Ocean GreatWhite* and will continue capitalizing interest on this project until its completion, which we expect to occur in the second half of 2016.

Critical Accounting Policies

Our significant accounting policies are discussed in Note 1 of our notes to audited consolidated financial statements included in our Annual Report on Form 10-K for the year ended December 31, 2015. There were no material changes to these policies during the three months ended March 31, 2016.

Results of Operations

Although we perform contract drilling services with different types of drilling rigs and in many geographic locations, there is a similarity of economic characteristics among all our divisions and locations, including the nature of services provided and the type of customers for our services. We believe that the combination of our drilling rigs into one reportable segment is the appropriate aggregation in accordance with applicable accounting standards on segment reporting. However, for purposes of this discussion and analysis of our results of operations, we provide greater detail with respect to the types of rigs in our fleet to enhance the reader s understanding of our financial condition, changes in financial condition and results of operations.

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Key performance indicators by equipment type are listed below.

	Three Months Ended March 31, 2016	2015
REVENUE EARNING DAYS (1)		
Floaters:		
Ultra-Deepwater	612	506
Deepwater	177	285
Mid-Water	181	663
Jack-ups	91	358
UTILIZATION (2)		
Floaters:		
Ultra-Deepwater	61%	51%
Deepwater	28%	45%
Mid-Water	25%	49%
Jack-ups	18%	66%
AVERAGE DAILY REVENUE (3)		
Floaters:		
Ultra-Deepwater	$ 533,000	$ 496,800
Deepwater	334,500	486,500
Mid-Water	263,100	265,900
Jack-ups	118,400	92,400

(1) A revenue earning day is defined as a 24-hour period during which a rig earns a dayrate after commencement of operations and excludes mobilization, demobilization and contract preparation days.

(2) Utilization is calculated as the ratio of total revenue-earning days divided by the total calendar days in the period for all specified rigs in our fleet (including cold-stacked rigs, but excluding rigs under construction). As of March 31, 2016, our cold-stacked rigs included three ultra-deepwater semisubmersibles, four deepwater semisubmersible, five mid-water semisubmersibles and four jack-up rigs.

(3) Average daily revenue is defined as total contract drilling revenue for all of the specified rigs in our fleet per revenue earning day.

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Comparative data relating to our revenues and operating expenses by equipment type are listed below.

	Three Months Ended March 31, 2016	2015
	(In thousands)	
CONTRACT DRILLING REVENUE		
Floaters:		
Ultra-Deepwater	$ 325,961	$ 251,396
Deepwater	59,117	138,770
Mid-Water	47,672	176,357
Total Floaters	432,750	566,523
Jack-ups	10,773	33,054
Total Contract Drilling Revenue	$ 443,523	$ 599,577
REVENUES RELATED TO REIMBURSABLE EXPENSES	$ 27,020	$ 20,479
CONTRACT DRILLING EXPENSE		
Floaters:		
Ultra-Deepwater	$ 123,736	$ 154,539
Deepwater	47,509	63,675
Mid-Water	23,884	99,320
Total Floaters	195,129	317,534
Jack-ups	6,055	21,570
Other	11,657	11,554
Total Contract Drilling Expense	$ 212,841	$ 350,658
REIMBURSABLE EXPENSES	$ 26,791	$ 20,092
OPERATING INCOME (LOSS)		
Floaters:		
Ultra-Deepwater	$ 202,225	$ 96,857
Deepwater	11,608	75,095
Mid-Water	23,788	77,037
Total Floaters	237,621	248,989
Jack-ups	4,718	11,484
Other	(11,657)	(11,554)
Reimbursable expenses, net	229	387
Depreciation	(104,240)	(137,299)
General and administrative expense	(15,398)	(17,452)
Gain on disposition of assets	296	611
Impairment of assets		(358,528)

Restructuring and separation costs		(6,168)
Total Operating Income (Loss)	$ 111,569	$ (269,530)
Other income (expense):		
Interest income	173	583
Interest expense, net of amounts capitalized	(25,516)	(23,982)
Foreign currency transaction (loss) gain	(3,608)	5,590
Other, net	578	221
Income (loss) before income tax benefit	83,196	(287,118)
Income tax benefit	4,229	31,409
NET INCOME (LOSS)	$ 87,425	$ (255,709)

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Overview

Three Months Ended March 31, 2016 and 2015

Operating Income. Operating income for the first quarter of 2016 increased $381.1 million compared to the same period of 2015, primarily due to the absence of a $358.5 million impairment loss recognized in the first quarter of 2015 combined with the favorable impact of lower depreciation expense. Depreciation expense for the first quarter of 2016 decreased $33.0 million primarily due to a lower depreciable asset base in 2016, compared to the first quarter of 2015, as a result of asset impairments taken in 2015.

Contract drilling revenue decreased $156.1 million, or 26%, during the first quarter of 2016, compared to the same quarter of 2015, primarily as a result of an aggregate of 857 fewer revenue earning days for our deepwater, mid-water and jack-up fleets, reflecting continued low demand for contract drilling services in those markets, partially offset by the favorable impact of a 106-day increase in revenue earning days for our ultra-deepwater fleet, which included the operation of three newbuild drillships that commenced drilling operations subsequent to the first quarter of 2015 and an increase in average daily revenue for our ultra-deepwater fleet, primarily due to the inclusion of $40.0 million in demobilization revenue for the *Ocean Endeavor*.

Total contract drilling expense decreased $137.8 million, or 39%, during the first quarter of 2016, compared to the same quarter of 2015, reflecting lower overall operating costs, primarily for labor and personnel ($64.6 million), repairs and maintenance ($22.8 million), freight ($6.5 million), inspections ($5.3 million) and an aggregate decrease in other rig operating and overhead costs ($38.5 million). The reduction in contract drilling expense during the first quarter of 2016 reflected reduced costs associated with rigs idled, cold stacked or retired subsequent to the first quarter of 2015, as well as cost control initiatives implemented during 2015.

Impairment of Assets. During the first quarter of 2015, we evaluated all of our mid-water semisubmersibles, as well as one drillship, for impairment. Based on this evaluation, we determined that the carrying value of our 7,875-foot water depth rated drillship, the *Ocean Clipper*, and seven of mid-water floaters, was impaired. We recorded an aggregate impairment loss of $358.5 million in the first quarter of 2015. During the first quarter of 2016, we evaluated ten of our drilling rigs with indications that their carrying amounts may not be recoverable. Based on this evaluation, we determined that the carrying values of these rigs were not impaired. See Note 2 to our unaudited consolidated financial statements included in Item 1 of Part I of this report.

Restructuring and Separation Costs. During the first quarter of 2015, in response to the continued decline in the offshore drilling market, our management approved and initiated a reduction in workforce at our onshore bases and corporate facilities, which resulted in the recognition of $6.2 million in restructuring and other employee separation related costs.

Income Tax Expense. Our effective tax rate for the three months ended March 31, 2016 was (5.1) %, compared to a 10.9% effective tax rate for the three months ended March 31, 2015. The effective tax rate in the 2016 period was lower than in the same period of 2015 primarily due to the mix of our domestic and international pre-tax earnings and losses, including asset impairments taken in various jurisdictions in 2015.

Contract Drilling Revenue and Expense by Equipment Type

Three Months Ended March 31, 2016 and 2015

Ultra-Deepwater Floaters. Revenue generated by our ultra-deepwater floaters increased $74.6 million during the first quarter of 2016, compared to the same quarter of 2015, primarily as a result of 106 incremental revenue earning days ($52.4 million) and higher average daily revenue earned ($22.2 million). Revenue earning days for the first quarter of 2016 increased, compared to the first quarter of 2015, primarily due to 204 incremental revenue earning days for our newbuild drillships and 91 incremental operating days for the *Ocean Monarch*, which was warm stacked during the first quarter of 2015. The increase in revenue earning days was partially offset by an aggregate of 99 fewer revenue earning days for the *Ocean Endeavor* and *Ocean Rover*, both of which completed contracts in the first quarter of 2016, and an aggregate 98 fewer revenue earning days for the cold-stacked *Ocean Baroness* and the *Ocean Clipper*, which was sold in November 2015. Average daily revenue increased during the first quarter of 2016, compared to the first quarter of 2015, primarily due to the inclusion of $40.0 million in demobilization revenue for the *Ocean Endeavor*, which completed its contract in the Black Sea in January 2016.

Contract drilling expense for our ultra-deepwater floaters decreased $30.8 million during the first quarter of 2016, compared to the same period of 2015. Incremental contract drilling expense for our three additional drillships operating in the GOM ($36.9 million) was more than offset by lower operating costs for our other ultra-deepwater floaters, including labor and personnel ($30.9 million), maintenance and inspections ($20.4 million), freight ($4.1 million) and other rig operating and overhead costs ($12.3 million) due to reduced costs for our cold-stacked rigs and the retired *Ocean Clipper*, as well as cost reduction initiatives implemented in 2015.

Deepwater Floaters. Revenue generated by our deepwater floaters decreased $79.7 million in the first quarter of 2016, compared to the same quarter in 2015, primarily due to 108 fewer revenue earning days. The decrease in revenue earning days for the first quarter of 2016 resulted primarily from additional downtime associated with the cold stacking and idling of rigs that had operated during the first quarter of 2015 (285 fewer days), partially offset by incremental revenue earning days for the *Ocean Victory* and *Ocean Valiant*, neither of which were under contract during the first quarter of 2015 (177 incremental days).

Contract drilling expense incurred by our deepwater floaters decreased $16.2 million during the first quarter of 2016, compared to the same period of 2015, primarily due to a net reduction in labor and personnel costs ($7.4 million), maintenance, repairs and other related costs ($3.9 million), shorebase support and overhead ($3.6 million) and other costs ($1.3 million) as a result of the cold stacking or idling of rigs.

Mid-Water Floaters. Revenue generated by our mid-water floaters during the first quarter of 2016 decreased $128.7 million compared to the same quarter in 2015, primarily due to 482 fewer revenue earning days ($128.2 million), reflecting a significant reduction in demand in the mid-water drilling market. Comparing the periods, only two of our mid-water floaters operated during both periods. Subsequent to the first quarter of 2015, we have sold nine mid-water floaters, reducing our mid-water fleet to five drilling rigs, three of which are currently cold stacked.

Contract drilling expense for our mid-water floaters decreased $75.4 million in the first quarter of 2016, compared to the prior year quarter, primarily due to reduced operating costs for our non-operating rigs.

Jack-ups. Contract drilling revenue for our jack-up fleet decreased $22.3 million during the first quarter of 2016, compared to the prior year quarter, primarily due to the cold stacking of three rigs, all of which were operating under contract in the first quarter of 2015. On April 28, 2016, our subsidiary s agent in Mexico received a letter from PEMEX purporting to exercise its contractual right to terminate its drilling contract on the *Ocean Scepter*, our sole working jack-up rig, with 30 days advance notice. We are in discussions with PEMEX regarding the matter.

Liquidity and Capital Resources

We have historically relied principally on our cash flows from operations and cash reserves to meet liquidity needs and fund our cash requirements. However, we have also utilized short-term borrowings under our $1.5 billion syndicated revolving credit agreement, or Credit Agreement, and issued commercial paper to meet our short-term liquidity needs. See Credit Agreement and Commercial Paper.

Based on our cash available for current operations and contractual backlog of $4.8 billion as of April 1, 2016, of which $1.2 billion is expected to be realized during the remainder of 2016, we believe our 2016 capital expenditures, including the final installment due on the *Ocean GreatWhite*, will be funded from our cash and cash equivalents, future operating cash flows and borrowings under our Credit Agreement, as needed. See Cash Flow, Capital Expenditures and Contractual Obligations Contractual Cash Obligations Rig Construction

Certain of our international rigs are owned and operated, directly or indirectly, by Diamond Foreign Asset Company, or DFAC, and, as a result of our intention to indefinitely reinvest the earnings of DFAC and its foreign subsidiaries to finance our foreign activities, we do not expect such earnings to be available for distribution to our stockholders or to finance our domestic activities. To the extent available, we expect to utilize the operating cash flows generated by and cash reserves of DFAC and the operating cash flows available to and cash reserves of Diamond Offshore Drilling, Inc., or DODI, to meet each entity s respective working capital requirements and capital commitments.

At March 31, 2016 and December 31, 2015, we had cash available for current operations as follows:

	March 31, 2016	December 31, 2015
	(In thousands)	
Cash and equivalents	$ 128,928	$ 119,028
Marketable securities	5,067	11,518
Total cash available for current operations	$ 133,995	$ 130,546

A substantial portion of our cash flows has been invested in the enhancement of our drilling fleet. We determine the amount of cash required to meet our capital commitments by evaluating our rig construction obligations, the need to upgrade rigs to meet specific customer requirements and our ongoing rig equipment enhancement/replacement programs. We also make periodic assessments of our capital spending programs based on current and expected industry conditions and make adjustments thereto if required. See Cash Flow, Capital Expenditures and Contractual Obligations Capital Expenditures.

We pay dividends at the discretion of our Board of Directors, or Board. Any determination to declare a dividend, as well as the amount of any dividend that may be declared, will be based on the Board s consideration of our financial position, earnings, earnings outlook, capital spending plans, outlook on current and future market conditions and business needs and other factors that our Board of Directors considers relevant at that time. On February 8, 2016, we announced that we were discontinuing our quarterly regular cash dividend. As a result, we did not pay a dividend during the three-month period ended March 31, 2016. During the three-month period ended March 31, 2015, we paid regular cash dividends totaling $17.1 million.

Depending on market and other conditions, we may, from time to time, purchase shares of our common stock in the open market or otherwise. We did not purchase any shares of our outstanding common stock during the three-month periods ended March 31, 2016 and 2015.

During the three-month period ended March 31, 2016, our primary source of cash, was an aggregate $241.3 million generated by operating activities and $113.3 million from the disposition of assets, including $105.0 million from the completion of two sale and leaseback transactions with respect to certain equipment on two of our drillships and $8.0 million in proceeds from the sale of one marketed-for-sale jack-up rig. See Cash Flow, Capital Expenditures and Contractual Obligations Contractual Cash Obligations Pressure Control by the Hour. Cash usage during the same period was primarily for capital expenditures of $58.1 million and repayment of commercial paper notes totaling

$286.6 million.

During the three-month period ended March 31, 2015, our primary source of cash, was an aggregate $160.6 million generated by operating activities and $4.8 million from the disposition of assets. Cash usage during the

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same period was primarily $197.0 million towards the construction of new rigs and our ongoing rig equipment enhancement/replacement program and $17.1 million for the payment of dividends.

We may, from time to time, issue debt or equity securities, or a combination thereof, to finance capital expenditures, the acquisition of assets and businesses or for general corporate purposes. Our ability to access the capital markets by issuing debt or equity securities will be dependent on our results of operations, our current financial condition, current credit ratings, current market conditions and other factors beyond our control.

Cash Flow, Capital Expenditures and Contractual Obligations

Our cash flow from operations and capital expenditures for the three-month periods ended March 31, 2016 and 2015 were as follows:

	Three Months Ended March 31,	
	2016	**2015**
	(In thousands)	
Cash flow from operations	$ 241,330	$ 160,566
Cash capital expenditures:		
Drillship construction	$	$ 31,796
Major upgrade of deepwater floaters		33,774
Construction of ultra-deepwater floater	19,295	7,892
Ocean Patriot enhancement project		719
Ocean Confidence service-life extension project		43,078
Rig equipment and replacement programs	38,819	79,773
Total capital expenditures	$ 58,114	$ 197,032

Cash Flow. Cash flow from operations increased approximately $80.8 million during the first three months of 2016, compared to the first three months of 2015, primarily due to a net decrease in cash payments for contract drilling and general and administrative expenses, including personnel-related, repairs and maintenance, and other rig operating costs ($188.2 million), partially offset by lower cash receipts for contract drilling services ($108.6 million). The decline in both cash receipts and cash payments related to the performance of contract drilling services reflects a reduction in contract drilling activity during the three month period ended March 31, 2016 as well as our continuing efforts to control costs.

Capital Expenditures. We currently expect total capital expenditures for the remainder of 2016 to aggregate approximately $620.0 million, of which we expect to spend approximately $510.0 million towards construction of the *Ocean GreatWhite* and the remainder on our ongoing capital maintenance and replacement programs. As of March 31, 2016, we had incurred capital expenditures of $57.3 million, including accrued expenditures. See Contractual Cash Obligations Rig Construction.

Contractual Cash Obligations Rig Construction. As of the date of this report, we have one rig, the *Ocean GreatWhite*, under construction in Ulsan, South Korea, for which we are obligated under a construction agreement with Hyundai Heavy Industries Co., Ltd, or HHI. Construction of the *Ocean GreatWhite* continues with delivery expected in the second half of 2016. The estimated total project cost, including shipyard costs, capital spares, commissioning, project management and shipyard supervision, is $764.0 million, of which $256.2 million has been incurred as of March 31, 2016. The final installment due HHI under the construction agreement of $439.9 million is due upon delivery of the rig.

Contractual Cash Obligations *Pressure Control by the Hour*. During March 2016, we executed two sale and leaseback transactions with respect to the *Ocean BlackHawk* and *Ocean BlackHornet*. Future commitments under the operating leases and contractual services agreements for the *Ocean BlackHawk* and *Ocean*

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BlackHornet are estimated to aggregate approximately $33.0 million per annum or an aggregate $327.0 million over the term of the agreements. We expect to complete the remaining sale and leaseback transactions for the *Ocean BlackLio*n and *Ocean BlackRhino* in the second and fourth quarters of 2016, respectively. See Note 10 to our unaudited consolidated financial statements included in Item 1 of Part I of this report.

We had no other purchase obligations for major rig upgrades or any other significant obligations at March 31, 2016, except for those related to our direct rig operations, which arise during the normal course of business.

Other Obligations. As of March 31, 2016, the total unrecognized tax benefits related to uncertain tax positions was $97.6 million. In addition, we have recorded a liability, as of March 31, 2016, for potential penalties and interest of $41.9 million and $3.2 million, respectively. Due to the high degree of uncertainty regarding the timing of future cash outflows associated with the liabilities recognized in these balances, we are unable to make reasonably reliable estimates of the period of cash settlement with the respective taxing authorities.

Credit Agreement and Commercial Paper

All short-term borrowings were repaid during the first quarter of 2016. In February 2016, as a result of a downgrade in our short-term credit rating, we canceled our commercial paper program due to our inability to access the commercial paper market in the foreseeable future. See Credit Ratings.

As of March 31, 2016, there were no loans or letters of credit outstanding under our Credit Agreement, and we were in compliance with all covenants thereunder. As of April 28, 2016, we had $1.5 billion available under our Credit Agreement to provide short-term liquidity for our payment obligations.

Credit Ratings

In February 2016, Moody s Investors Service downgraded our senior unsecured credit rating to Ba2 from Baa2, with a stable outlook, and also downgraded our short-term credit rating to sub-prime. Our current corporate credit rating for Standard & Poor s Ratings Services is BBB+ and our short-term credit rating is A2. Market conditions and other factors, many of which are outside of our control, could cause our credit ratings to be lowered. A downgrade in our credit ratings could adversely impact our cost of issuing additional debt and the amount of additional debt that we could issue, and could further restrict our access to capital markets and our ability to raise additional debt or rollover existing maturities. As a consequence, we may not be able to issue additional debt in amounts and/or with terms that we consider to be reasonable. One or more of these occurrences could limit our ability to pursue other business opportunities.

Other Commercial Commitments Letters of Credit

We were contingently liable as of March 31, 2016 in the amount of $69.0 million under certain performance, bid, security, tax, supersedeas and customs bonds and letters of credit. Agreements relating to approximately $63.9 million of performance, security, tax, supersedeas and customs bonds can require collateral at any time. As of March 31, 2016, we had not been required to make any collateral deposits with respect to these agreements. The remaining agreements cannot require collateral except in events of default. Banks have issued letters of credit on our behalf securing certain of these bonds. The table below provides a list of these obligations in U.S. dollar equivalents and their time to expiration.

		For the Years Ending December 31,			
	Total	2016	2017	2018	2020
		(In thousands)			
Other Commercial Commitments					
Performance bonds	$ 51,357	$ 5,122	$ 16,748	$ 10,362	$ 19,125
Supersedeas bond	9,189	9,189			
Tax bond	5,795	5,795			
Other	2,646	2,302		344	
Total obligations	$ 68,987	$ 22,408	$ 16,748	$ 10,706	$ 19,125

Off-Balance Sheet Arrangements

At March 31, 2016 and December 31, 2015, we had no off-balance sheet debt or other off-balance sheet arrangements.

New Accounting Pronouncements

See Note 1 General Information to our unaudited consolidated financial statements included in Item 1 of Part I of this report for a discussion of recently issued accounting pronouncements.

Forward-Looking Statements

We or our representatives may, from time to time, either in this report, in periodic press releases or otherwise, make or incorporate by reference certain written or oral statements that are forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, or the Securities Act, and Section 21E of the Securities Exchange Act of 1934, as amended, or the Exchange Act. All statements other than statements of historical fact are, or may be deemed to be, forward-looking statements. Forward-looking statements include, without limitation, any statement that may project, indicate or imply future results, events, performance or achievements, and may contain or be identified by the words expect, intend, plan, predict, anticipate, estimate, believe, should, could, will be, will continue, will likely result, project, forecast, budget and similar expressions. In addition, any stat concerning future financial performance (including, without limitation, future revenues, earnings or growth rates), ongoing business strategies or prospects, and possible actions taken by or against us, which may be provided by management, are also forward-looking statements. Statements made by us in this report that contain forward-looking statements may include, but are not limited to, information concerning our possible or assumed future results of operations and statements about the following subjects:

- market conditions and the effect of such conditions on our future results of operations;
- sources and uses of and requirements for financial resources and sources of liquidity;
- interest rate and foreign exchange risk;
- contractual obligations and future contract negotiations;
- business strategy;
- competitive position, including without limitation, competitive rigs entering the market;
- expected financial position;

cash flows and contract backlog;

declaration and payment of regular or special dividends;

financing plans;

market outlook;

tax planning;

debt levels and the impact of changes in the credit markets and credit ratings for our debt;

timing and duration of required regulatory inspections for our drilling rigs;

timing and cost of completion of rig upgrades, construction projects and other capital projects;

delivery dates and drilling contracts related to rig conversion or upgrade projects, construction projects, other capital projects or rig acquisitions;

idling drilling rigs or reactivating stacked rigs;

- scrapping retired rigs;
- assets held for sale;
- asset impairments and impairment evaluations;
- outcomes of legal proceedings;
- purchases of our securities;
- compliance with applicable laws; and
- availability, limits and adequacy of insurance or indemnification.

These types of statements are based on current expectations about future events and inherently are subject to a variety of assumptions, risks and uncertainties, many of which are beyond our control, that could cause actual results to differ materially from those expected, projected or expressed in forward-looking statements. These risks and uncertainties include, among others, those described or referenced under Risk Factors in Item 1A.

The risks and uncertainties referenced above are not exhaustive. Other sections of this report and our other filings with the SEC include additional factors that could adversely affect our business, results of operations and financial performance. Given these risks and uncertainties, investors should not place undue reliance on forward-looking statements. Forward-looking statements included in this report speak only as of the date of this report. We expressly disclaim any obligation or undertaking to release publicly any updates or revisions to any forward-looking statement to reflect any change in our expectations or beliefs with regard to the statement or any change in events, conditions or circumstances on which any forward-looking statement is based. In addition, in certain places in this report, we may refer to reports published by third parties that purport to describe trends or developments in energy production or drilling and exploration activity. We do so for the convenience of our investors and potential investors and in an effort to provide information available in the market intended to lead to a better understanding of the market environment in which we operate. We specifically disclaim any responsibility for the accuracy and completeness of such information and undertake no obligation to update such information.

ITEM 3. Quantitative and Qualitative Disclosures About Market Risk.

There were no material changes in our market risk components for the three months ended March 31, 2016. See Quantitative and Qualitative Disclosures About Market Risk included in Item 7A of our Annual Report on Form 10-K filed with the Securities and Exchange Commission for the year ended December 31, 2015 for further information.

ITEM 4. Controls and Procedures.

We maintain a system of disclosure controls and procedures which are designed to ensure that information required to be disclosed by us in reports that we file or submit under the federal securities laws, including this report, is recorded, processed, summarized and reported on a timely basis. These disclosure controls and procedures include controls and procedures designed to ensure that information required to be disclosed by us under the federal securities laws is accumulated and communicated to our management on a timely basis to allow decisions regarding required disclosure.

Our Chief Executive Officer, or CEO, and Chief Financial Officer, or CFO, participated in an evaluation by our management of the effectiveness of our disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) as of March 31, 2016. Based on their participation in that evaluation, our CEO and CFO concluded that our disclosure controls and procedures were effective as of March 31, 2016.

There were no changes in our internal control over financial reporting identified in connection with the foregoing evaluation that occurred during our first fiscal quarter of 2016 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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PART II. OTHER INFORMATION

ITEM 1. Legal Proceedings.

Information related to Item 1. Legal Proceedings is included in Note 10 to the condensed consolidated financial statements.

ITEM 1A. Risk Factors.

Our Annual Report on Form 10-K for the year ended December 31, 2015 includes a detailed discussion of certain material risk factors facing our company. No material changes have been made to such risk factors as of March 31, 2016.

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

Items 2(a) and 2(b) are not applicable.

(c) During the three months ended March 31, 2016, in connection with the vesting of restricted stock units held by our chief executive officer, we acquired shares of our common stock in satisfaction of tax withholding obligations that were incurred on the vesting date. The date of acquisition, number of shares and average effective acquisition price per share were as follows:

Issuer Purchases of Equity Securities

Period	Total Number of Shares Acquired	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of of Shares that May Yet Be Purchased Under the Plans or Programs
January 1, 2016 through January 31, 2016			N/A	N/A
February 1, 2016 through February 29, 2016			N/A	N/A
March 1, 2016 through March 31, 2016	7,923	$ 22.74	N/A	N/A
Total	7,923	$ 22.74	N/A	N/A

ITEM 6. Exhibits.

See the Exhibit Index for a list of those exhibits filed or furnished herewith.

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SIGNATURES

Pursuant to the requirements 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.

DIAMOND OFFSHORE DRILLING, INC.

(Registrant)

Date	May 2, 2016	By:	\s\ Gary T. Krenek Gary T. Krenek Senior Vice President and Chief Financial Officer
Date	May 2, 2016		\s\ Beth G. Gordon Beth G. Gordon Controller (Chief Accounting Officer)

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EXHIBIT INDEX

Exhibit No.	Description
3.1	Amended and Restated Certificate of Incorporation of Diamond Offshore Drilling, Inc. (incorporated by reference to Exhibit 3.1 to our Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2003) (SEC File No. 1-13926).
3.2	Amended and Restated By-laws (as amended through October 4, 2013) of Diamond Offshore Drilling, Inc. (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K filed October 8, 2013).
10.1*	Separation Agreement, dated February 22, 2016, between Diamond Offshore Management Company and Gary T. Krenek.
31.1*	Rule 13a-14(a) Certification of the Chief Executive Officer.
31.2*	Rule 13a-14(a) Certification of the Chief Financial Officer.
32.1*	Section 1350 Certification of the Chief Executive Officer and Chief Financial Officer.
101.INS*	XBRL Instance Document.
101.SCH*	XBRL Taxonomy Extension Schema Document.
101.CAL*	XBRL Taxonomy Calculation Linkbase Document.
101.LAB*	XBRL Taxonomy Label Linkbase Document.
101.PRE*	XBRL Presentation Linkbase Document.
101.DEF*	XBRL Definition Linkbase Document.

* Filed or furnished herewith.