DIAMOND OFFSHORE DRILLING, INC.
Form 10-Q
July 31, 2017

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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-Q

(Mark One)

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

For the quarterly period ended June 30, 2017

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 No

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of large accelerated filer, accelerated filer, smaller reporting company, and emerging growth company in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer	Accelerated filer
Non-accelerated filer (Do not check if a smaller reporting company)	Smaller reporting company
Emerging growth company	

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 7(a)(2)(B) of the Securities Act.

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

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

As of July 27, 2017 Common stock, $0.01 par value per share 137,226,991 shares

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DIAMOND OFFSHORE DRILLING, INC.

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QUARTER ENDED JUNE 30, 2017

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PART I. FINANCIAL INFORMATION

ITEM 1. Financial Statements.

DIAMOND OFFSHORE DRILLING, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS

(Unaudited)

(In thousands, except share and per share data)

	June 30, 2017	December 31, 2016
ASSETS		
Current assets:		
Cash and cash equivalents	$ 160,969	$ 156,233
Accounts receivable, net of allowance for bad debts	311,517	247,028
Prepaid expenses and other current assets	107,690	102,146
Asset held for sale		400
Total current assets	580,176	505,807
Drilling and other property and equipment, net of accumulated depreciation	5,490,158	5,726,935
Other assets	122,929	139,135
Total assets	$ 6,193,263	$ 6,371,877
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities:		
Accounts payable	$ 32,717	$ 30,242
Accrued liabilities	110,702	182,159
Taxes payable	13,672	23,898
Short-term borrowings		104,200
Total current liabilities	157,091	340,499
Long-term debt	1,981,458	1,980,884
Deferred tax liability	143,619	197,011
Other liabilities	119,277	103,349
Total liabilities	2,401,445	2,621,743
Commitments and contingencies (Note 7)		
Stockholders equity:		
Preferred stock (par value $0.01, 25,000,000 shares authorized, none issued and outstanding)		
	1,441	1,440

Common stock (par value $0.01, 500,000,000 shares authorized; 144,080,636 shares issued and 137,224,156 shares outstanding at June 30, 2017; 143,997,757 shares issued and 137,169,663 shares outstanding at December 31, 2016)		
Additional paid-in capital	2,007,798	2,004,514
Retained earnings	1,985,640	1,946,765
Accumulated other comprehensive (loss) gain	(2)	1
Treasury stock, at cost (6,856,480 and 6,828,094 shares of common stock at June 30, 2017 and December 31, 2016, respectively)	(203,059)	(202,586)
Total stockholders equity	3,791,818	3,750,134
Total liabilities and stockholders equity	$ 6,193,263	$ 6,371,877

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

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DIAMOND OFFSHORE DRILLING, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(Unaudited)

(In thousands, except per share data)

	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016
Revenues:				
Contract drilling	$ 392,170	$ 357,409	$ 755,727	$ 800,932
Revenues related to reimbursable expenses	7,119	31,338	17,788	58,358
Total revenues	399,289	388,747	773,515	859,290
Operating expenses:				
Contract drilling, excluding depreciation	196,217	198,336	399,740	411,177
Reimbursable expenses	6,790	16,527	17,268	43,318
Depreciation	85,982	105,016	179,211	209,256
General and administrative	19,010	18,139	36,493	33,537
Impairment of assets	71,268	678,145	71,268	678,145
Gain on disposition of assets	(802)	(747)	(2,148)	(1,043)
Total operating expenses	378,465	1,015,416	701,832	1,374,390
Operating income (loss)	20,824	(626,669)	71,683	(515,100)
Other income (expense):				
Interest income	396	269	571	442
Interest expense, net of amounts capitalized	(27,251)	(24,156)	(54,847)	(49,672)
Foreign currency transaction (loss) gain	(927)	(3,513)	160	(7,121)
Other, net	(62)	(12,046)	(125)	(11,468)
(Loss) income before income tax benefit	(7,020)	(666,115)	17,442	(582,919)
Income tax benefit	22,969	76,178	22,046	80,407
Net income (loss)	$ 15,949	$ (589,937)	$ 39,488	$ (502,512)
Earnings (loss) per share, Basic and Diluted	$ 0.12	$ (4.30)	$ 0.29	$ (3.66)
Weighted-average shares outstanding:				
Shares of common stock	137,224	137,170	137,199	137,166
Dilutive potential shares of common stock	3		36	
Total weighted-average shares outstanding	137,227	137,170	137,235	137,166

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

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DIAMOND OFFSHORE DRILLING, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(Unaudited)

(In thousands)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	**2016**	**2017**	**2016**
Net income (loss)	$ 15,949	$ (589,937)	$ 39,488	$ (502,512)
Other comprehensive (losses) gains, net of tax:				
Derivative financial instruments:				
Reclassification adjustment for gain included in net income (loss)	(1)	(2)	(3)	(3)
Investments in marketable securities:				
Unrealized holding gain (loss)		1		(6,558)
Reclassification adjustment for loss included in net income (loss)		11,600		11,600
Total other comprehensive (loss) gain	(1)	11,599	(3)	5,039
Comprehensive income (loss)	$ 15,948	$ (578,338)	$ 39,485	$ (497,473)

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

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DIAMOND OFFSHORE DRILLING, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

(In thousands)

	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016
Operating activities:		
Net income (loss)	$ 39,488	$ (502,512)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation	179,211	209,256
Loss on impairment of assets	71,268	678,145
Gain on disposition of assets	(2,148)	(1,043)
Loss on sale of marketable securities		12,146
Deferred tax provision	(54,425)	(162,531)
Stock-based compensation expense	2,651	2,829
Deferred income, net	11,524	(16,363)
Deferred expenses, net	16,866	4,751
Other assets, noncurrent	(1,619)	(900)
Other liabilities, noncurrent	407	4,189
Other	1,202	1,484
Changes in operating assets and liabilities:		
Accounts receivable	(64,489)	80,782
Prepaid expenses and other current assets	(6,154)	2,281
Accounts payable and accrued liabilities	(12,291)	(59,788)
Taxes payable	(4,610)	52,744
Net cash provided by operating activities	176,881	305,470
Investing activities:		
Capital expenditures (including rig construction)	(71,889)	(533,412)
Proceeds from disposition of assets, net of disposal costs	4,077	167,298
Proceeds from sale and maturities of marketable securities	23	4,592
Net cash used in investing activities	(67,789)	(361,522)
Financing activities:		
Net (repayment of) proceeds from short-term borrowings	(104,200)	40,711
Other	(156)	(408)
Net cash (used in) provided by financing activities	(104,356)	40,303

Net change in cash and cash equivalents	4,736	(15,749)
Cash and cash equivalents, beginning of period	156,233	119,028
Cash and cash equivalents, end of period	$ 160,969	$ 103,279

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

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DIAMOND OFFSHORE DRILLING, INC. AND SUBSIDIARIES

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

1. General Information

The unaudited condensed 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 Fo 10-K for the year ended December 31, 2016 (File No. 1-13926).

As of July 27, 2017, Loews Corporation owned approximately 53% of the outstanding shares of our common stock.

Interim Financial Information

The accompanying unaudited condensed 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 condensed consolidated financial information has not been audited but, in the opinion of management, includes all adjustments (consisting of normal recurring adjustments) necessary for a fair presentation of Diamond Offshore s condensed 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.

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 six-month period ended June 30, 2017 and the year ended December 31, 2016, we capitalized $9.3 million and $177.6 million, respectively, in replacements and betterments of our drilling fleet. See Note 6.

Impairment of Long-Lived Assets

We evaluate our property and equipment for impairment whenever changes in circumstances indicate that the carrying amount of an asset may not be recoverable (such as, but not limited to, a decision to retire, scrap or cold stack a rig, contracted backlog of less than one year for a rig, or excess spending over budget on a newbuild construction project or major rig upgrade). We utilize an undiscounted probability-weighted cash flow analysis in testing an asset for potential impairment. Our assumptions and estimates underlying this analysis include the following:

dayrate by rig;

utilization rate by rig if active, warm stacked or cold stacked (expressed as the actual percentage of time per year that the rig would be used at certain dayrates);

the per day operating cost for each rig if active, warm stacked or cold stacked;

the estimated annual cost for rig replacements and/or enhancement programs;

the estimated maintenance, inspection or other reactivation costs associated with a rig returning to work;

salvage value for each rig; and

estimated proceeds that may be received on disposition of each rig.

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Based on these assumptions, we develop a matrix for each rig under evaluation using multiple utilization/dayrate scenarios, to each of which we assign a probability of occurrence. We arrive at a projected probability-weighted cash flow for each rig based on the respective matrix and compare such amount to the carrying value of the asset to assess recoverability.

The underlying assumptions and assigned probabilities of occurrence for utilization and dayrate scenarios are developed using a methodology that examines historical data for each rig, which considers the rig s age, rated water depth and other attributes, and then assesses the rig s future marketability in light of the current and projected market environment at the time of assessment. Other assumptions, such as operating, maintenance, inspection and reactivation costs, are estimated using historical data adjusted for known developments, cost projections for re-entry of rigs into the market and future events that are anticipated by management at the time of the assessment.

Management s assumptions are necessarily subjective and are an inherent part of our asset impairment evaluation, and the use of different assumptions could produce results that differ from those reported. Our methodology generally involves the use of significant unobservable inputs, representative of a Level 3 fair value measurement, which may include assumptions related to future dayrate revenue, costs and rig utilization, quotes from rig brokers, the long-term future performance of our rigs and future market conditions. Management s assumptions involve uncertainties about future demand for our services, dayrates, expenses and other future events, and management s expectations may not be indicative of future outcomes. Significant unanticipated changes to these assumptions could materially alter our analysis in testing an asset for potential impairment. For example, changes in market conditions that exist at the measurement date or that are projected by management could affect our key assumptions. Other events or circumstances that could affect our assumptions may include, but are not limited to, a further sustained decline in oil and gas prices, cancelations of our drilling contracts or contracts of our competitors, contract modifications, costs to comply with new governmental regulations, growth in the global oversupply of oil and geopolitical events, such as lifting sanctions on oil-producing nations. Should actual market conditions in the future vary significantly from market conditions used in our projections, our assessment of impairment would likely be different. See Note 2.

Capitalized Interest

We capitalize interest cost for rig construction or upgrades, as well as other qualifying projects. A reconciliation of our total interest cost to Interest expense, net of amounts capitalized as reported in our Condensed Consolidated Statements of Operations is as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
	(In thousands)			
Total interest cost, including amortization of debt issuance costs	$ 27,254	$ 28,046	$ 54,850	$ 56,871
Capitalized interest	(3)	(3,890)	(3)	(7,199)
Total interest expense as reported	$ 27,251	$ 24,156	$ 54,847	$ 49,672

Stock-Based Compensation

In March 2016, the Financial Accounting Standards Board, or FASB, issued Accounting Standards Update, or ASU, No. 2016-09, *Compensation - Stock Compensation (Topic 718)*, or ASU 2016-09. ASU 2016-09 requires that all excess tax benefits and tax deficiencies be recognized in the income statement as discrete tax items when share-based awards vest or are settled. The update also clarifies the statement of cash flows presentation for certain components of share-based awards and provides for a policy election to either estimate the number of awards expected to vest or account for forfeitures when they occur. ASU 2016-09 is effective for fiscal years beginning after December 15, 2016 and was adopted by us on January 1, 2017.

The guidance requiring (i) excess tax benefits to be recorded in the condensed consolidated statement of operations, (ii) exclusion of excess tax benefits from the computation of assumed proceeds under the treasury stock method when calculating earnings per share, and (iii) presentation of excess tax benefits as an operating activity on the statement of cash flows, rather than as a financing activity, has been applied prospectively effective January 1, 2017. We have elected to account for forfeitures of share-based awards in the period in which such forfeitures occur rather than using an estimated forfeiture rate and have adopted this change using a modified retrospective approach, which resulted in a $0.6 million reduction in opening retained earnings. The impact to our Condensed Consolidated Balance Sheets is as follows:

	Retained Earnings	Additional Paid-in Capital
	(In thousands)	
Balance as of January 1, 2017 before adoption	$ 1,946,765	$ 2,004,514
Adjustment for making election to account for forfeitures as they occur	(634)	634
Balance as of January 1, 2017 after adoption	$ 1,946,131	$ 2,005,148

Recent Accounting Pronouncements

In August 2016, the FASB issued ASU No. 2016-15, *Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments*, or ASU 2016-15. ASU 2016-15 provides specific guidance on eight cash flow classification issues not specifically addressed by GAAP: debt prepayment or debt extinguishment costs; settlement of zero-coupon debt instruments; contingent consideration payments; proceeds from the settlement of insurance claims; proceeds from the settlement of corporate-owned life insurance policies; distributions from equity method investees; beneficial interests in securitization transactions; and separately identifiable cash flows and application of the predominance principle. The amendments in ASU 2016-15 are effective for interim and annual periods beginning after December 15, 2017. ASU 2016-15 should be applied using a retrospective transition method, unless it is impracticable to do so for some of the issues. In such case, the amendments for those issues would be applied prospectively as of the earliest date practicable. Early adoption is permitted. We are currently evaluating the provisions of ASU 2016-15 but do not expect ASU 2016-15 to have a significant impact on the presentation of cash receipts and cash payments within our condensed consolidated statements of cash flows.

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 non-lease 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. Non-lease 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 expect to adopt ASU 2016-02 on January 1, 2019. We are currently reviewing the provisions of the accounting standard, but have not yet determined the impact of ASU 2016-02 on our financial position, results of operations or cash flows or our expected transition method.

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 provides a five-step analysis of transactions to determine when and how revenue is recognized and requires enhanced disclosures about revenue. In July 2015, the FASB issued ASU 2015-14, which deferred the effective date of ASU 2014-09. ASU 2014-09 is now effective for annual reporting periods beginning after December 15, 2017. We plan to adopt ASU 2014-09 effective January 1, 2018 using the modified retrospective approach whereby we will record the cumulative effect of applying the new standard to all outstanding contracts as of January 1, 2018 as an adjustment to opening retained earnings.

When applying the new standard, we plan to account for the integrated services provided within our drilling contracts as a single performance obligation composed of a series of distinct time increments, which will be satisfied over time. We will determine the total transaction price for each individual contract by estimating both fixed and variable consideration expected to be earned over the term of the contract. Consideration that does not relate to a distinct good or service, such as mobilization, demobilization, and contract preparation revenue, will be allocated across the single performance obligation and recognized ratably over the term of the contract. All other components of consideration within a contract, including the dayrate revenue, will continue to be recognized in the period when the services are performed. We expect our revenue recognition under ASU 2014-09 to differ from our current revenue recognition pattern only as it relates to demobilization revenue. Such revenue, which is recognized upon completion of a contract under current GAAP, will be estimated at contract inception and recognized over the term of the contract under the new guidance. Additionally, we expect that the cumulative effect adjustment to opening retained earnings required by the modified retrospective adoption approach will not be significant as it will primarily consist of the impact of the timing difference related to recognition of demobilization revenue for affected contracts. Not all contracts include a demobilization provision.

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2. Impairment of Assets

During the second quarter of 2017, we evaluated seven of our drilling rigs with indicators of impairment. Due to the continued deterioration of market fundamentals in the contract drilling industry, as well as newly-available market projections, which indicated that a full market recovery is likely to occur further in the future than had previously been estimated, we determined that the carrying values of one ultra-deepwater and one deepwater semisubmersible rig were impaired (we collectively refer to these two rigs as the 2017 Impaired Rigs).

We estimated the fair value of the 2017 Impaired Rigs using an income approach, whereby the fair value of each rig was estimated based on a calculation of the rig s future net cash flows. As described in Note 1, these calculations utilized significant unobservable inputs, including estimated proceeds that may be received on ultimate disposition of the rig, and are representative of Level 3 fair value measurements due to the significant level of estimation involved and lack of transparency as to the inputs used. During the second quarter of 2017, we recorded an impairment loss of $71.3 million related to our 2017 Impaired Rigs.

In the second quarter of 2016, we evaluated 15 of our drilling rigs with indicators of impairment. Based on our assumptions and analyses at that time, we determined that the carrying values of eight of these rigs, consisting of three ultra-deepwater, three deepwater and two mid-water semisubmersible rigs, were impaired (we collectively refer to these eight rigs as the 2016 Impaired Rigs). During the second quarter of 2016, we recorded impairment losses of $670.0 million and $8.1 million related to our 2016 Impaired Rigs and related rig spare parts and supplies, respectively.

As of June 30, 2017, there were nine rigs in our drilling fleet for which there were no current indicators that their carrying amounts may not be recoverable and, thus, were not evaluated for impairment at that time. If market fundamentals in the offshore oil and gas industry deteriorate further or a projected market recovery is further delayed, we may be required to recognize additional impairment losses in future periods.

3. Supplemental Financial Information

Condensed Consolidated Balance Sheets Information

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

	June 30, 2017	December 31, 2016
	(In thousands)	
Trade receivables	$ 299,180	$ 236,040
Value added tax receivables	16,509	14,639
Related party receivables	194	149
Other	1,093	1,659
	316,976	252,487
Allowance for bad debts	(5,459)	(5,459)
Total	$ 311,517	$ 247,028

Prepaid expenses and other current assets consist of the following:

	June 30, 2017	December 31, 2016
	(In thousands)	
Rig spare parts and supplies	$ 30,099	$ 25,343
Deferred rig start-up costs	59,985	61,488
Prepaid BOP lease	3,873	3,873
Prepaid insurance	4,758	3,771
Prepaid taxes	3,613	2,894
Other	5,362	4,777
Total	$ 107,690	$ 102,146

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Accrued liabilities consist of the following:

	June 30, 2017	December 31, 2016
	(In thousands)	
Rig operating expenses	$ 28,524	$ 33,732
Payroll and benefits	36,686	45,619
Deferred revenue	9,871	9,522
Accrued capital project/upgrade costs	3,649	60,308
Interest payable	18,365	18,365
Personal injury and other claims	5,037	6,424
Other	8,570	8,189
Total	$ 110,702	$ 182,159

Condensed Consolidated Statements of Cash Flows Information

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

	Six Months Ended June 30,	
	2017	2016
	(In thousands)	
Accrued but unpaid capital expenditures at period end	$ 3,649	$ 70,800
Common stock withheld for payroll tax obligations [1]	473	181
Cash interest payments[2]	51,603	52,491
Cash income taxes paid, net of (refunds):		
Foreign	33,319	33,485
State	94	1

[1] Represents the cost of 28,386 shares and 7,923 shares of common stock withheld to satisfy payroll tax obligations incurred as a result of the vesting of restricted stock units in the six months ended June 30, 2017 and 2016, respectively. These costs are presented as a deduction from stockholders equity in Treasury stock in our Condensed Consolidated Balance Sheets at June 30, 2017 and 2016.

[2] Interest payments, net of amounts capitalized, were $51.6 million and $45.6 million for the six-month periods ended June 30, 2017 and 2016, respectively.

4. Earnings Per Share

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	**2016**	**2017**	**2016**
	(In thousands, except per share data)			
Net income (loss) basic and diluted numerator	$ 15,949	$ (589,937)	$ 39,488	$ (502,512)
Weighted average shares basic (denominator):	137,224	137,170	137,199	137,166
Dilutive effect of stock-based awards	3		36	
Weighted average shares including conversions diluted (denominator)	137,227	137,170	137,235	137,166
Earnings (loss) per share:				
Basic	$ 0.12	$ (4.30)	$ 0.29	$ (3.66)
Diluted	$ 0.12	$ (4.30)	$ 0.29	$ (3.66)

The following table sets forth the share effects of stock-based awards excluded from our computations of diluted earnings per share, or EPS, for the periods presented:

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	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
	(In thousands)			
Employee and director:				
Stock options		8	1	8
Stock appreciation rights	1,301	1,536	1,355	1,536
Restricted stock units	1,274	739	933	658

5. 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.

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 has consisted 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, we do not believe that we have any significant concentrations of credit risk at June 30, 2017.

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.

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 and U.S. Treasury bills and notes. Our Level 1 assets at June 30, 2017 consisted of cash held in money market funds of $124.3 million and time deposits of $20.6 million. Our Level 1 assets at December 31, 2016 consisted of cash held in money market funds of $125.7 million and time deposits of $20.6 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 may include residential mortgage-backed securities, corporate bonds purchased in a private placement offering and over-the-counter foreign currency forward exchange contracts. Our Level 2 assets at June 30, 2017 and December 31, 2016 consisted solely of residential mortgage-backed securities, which 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 June 30, 2017 and December 31, 2016 consisted of nonrecurring measurements of certain of our drilling rigs and associated spare parts and supplies for which we recorded impairment losses in the second quarter of 2017 and during 2016.

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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 six-month period ended June 30, 2017 or the year ended December 31, 2016.

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 and related rig spare parts and supplies, which were measured at fair value on a nonrecurring basis, during each of the three-month periods ended June 30, 2017 and 2016, of $71.3 million and $678.1 million, respectively.

Assets and liabilities measured at fair value are summarized below.

	June 30, 2017 Fair Value Measurements Using				
	Level 1	Level 2	Level 3	Assets at Fair Value	Total Losses for Six Months Ended
			(In thousands)		
Recurring fair value measurements:					
Assets:					
Short-term investments	$ 144,907	$	$	$ 144,907	
Mortgage-backed securities		12		12	
Total assets	$ 144,907	$ 12	$	$ 144,919	
Nonrecurring fair value measurements:					
Assets:					
Impaired assets [(1)]	$	$	$ 2,000	$ 2,000	$ 71,268

(1) Represents the total book value as of June 30, 2017 of one ultra-deepwater semisubmersible rig and one deepwater semisubmersible rig, which were written down to their estimated recoverable amounts during the second quarter of 2017.

	December 31, 2016 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	$ 146,360	$	$	$ 146,360	
Mortgage-backed securities		35		35	
Total assets	$ 146,360	$ 35	$	$ 146,395	
Nonrecurring fair value measurements:					
Assets:					
Impaired assets (2)	$	$	$ 69,153	$ 69,153	$ 678,145

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(1) Represents impairment losses of $8.1 million and $670.0 million recognized during the year ended December 31, 2016 related to our rig spare parts and supplies and certain impaired rigs, respectively.

(2) Represents the total book value as of December 31, 2016 for 11 drilling rigs ($45.5 million) and for rig spare parts and supplies ($23.6 million), which were previously written down to their estimated recoverable amounts. Of the total fair value, $23.6 million, $0.4 million and $45.1 million were reported as Prepaid expenses and other current assets, Asset held for sale and Drilling and other property and equipment, net of accumulated depreciation, respectively, in our Condensed Consolidated Balance Sheets at December 31, 2016.

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 Condensed 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.

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

Short-term borrowings The carrying amounts approximate fair value because of the short term 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 June 30, 2017 and December 31, 2016. 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.

	June 30, 2017		December 31, 2016	
	Fair Value	Carrying Value	Fair Value	Carrying Value
	(In millions)			
5.875% Senior Notes due 2019	$ 513.8	$ 499.8	$ 518.6	$ 499.8
3.45% Senior Notes due 2023	217.5	249.3	215.0	249.3
5.70% Senior Notes due 2039	377.5	497.1	392.5	497.1
4.875% Senior Notes due 2043	487.5	748.9	532.7	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.

6. Drilling and Other Property and Equipment

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

	June 30, 2017	December 31, 2016
	(In thousands)	
Drilling rigs and equipment	$ 8,887,448	$ 8,950,385
Land and buildings	63,279	64,449
Office equipment and other	75,754	73,108
Cost	9,026,481	9,087,942
Less: accumulated depreciation	(3,536,323)	(3,361,007)
Drilling and other property and equipment, net	$ 5,490,158	$ 5,726,935

During the three-month and six-month periods ended June 30, 2017, we recognized an aggregate impairment loss of $71.3 million related to the 2017 Impaired Rigs. See Notes 1 and 2.

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7. 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 Louisiana 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 in the 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, all litigation is inherently unpredictable, and the ultimate outcome or effect of any claim, lawsuit or action cannot be predicted with certainty. As a result, there can be no assurance as to the ultimate outcome of any litigation matter. Any claims against us, whether meritorious or not, could cause us to incur significant costs and expenses and require significant amounts of management and operational time and 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 after 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 filed motions to dismiss the claims. In November 2016, the court dismissed the lienholders claims, and the lienholders are appealing the ruling. 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. In December 2016, the company that purchased most of the debtor s assets from bankruptcy also filed for bankruptcy. We continue to pursue 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, 2017, 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 U.S. 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 June 30, 2017 our estimated liability for personal injury claims was $32.3 million, of which $4.6 million and $27.7 million were recorded in Accrued liabilities and Other liabilities, respectively, in our Condensed Consolidated Balance Sheets. At December 31, 2016 our estimated liability for personal injury claims was $32.9 million, of which $6.1 million and $26.8 million were recorded in Accrued liabilities and Other liabilities, respectively, in our Condensed 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.

Letters of Credit and Other. We were contingently liable as of June 30, 2017 in the amount of $18.3 million under certain performance, tax, supersedeas, court and customs bonds and letters of credit. Agreements relating to approximately $15.4 million of tax, supersedeas, court and customs bonds can require collateral at any time. As of June 30, 2017, 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.

8. 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 June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
	(In thousands)			
Floaters:				
Ultra-Deepwater	$ 282,535	$ 214,102	$ 526,000	$ 540,063
Deepwater	66,905	67,191	134,848	126,308
Mid-Water	36,543	56,694	84,828	104,366
Total Floaters	385,983	337,987	745,676	770,737
Jack-ups	6,187	19,422	10,051	30,195
Total contract drilling revenues	392,170	357,409	755,727	800,932
Revenues related to reimbursable expenses	7,119	31,338	17,788	58,358
Total revenues	$ 399,289	$ 388,747	$ 773,515	$ 859,290

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 June 30, 2017, our active drilling rigs were located offshore in 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.

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	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
	(In thousands)			
United States	$ 164,188	$ 130,609	$ 310,456	$ 292,191
International:				
South America	111,498	106,702	214,179	228,189
Australia/Asia	72,883	47,662	138,561	112,636
Europe	44,533	87,551	100,268	190,170
Mexico	6,187	16,223	10,051	36,104
Total revenues	$ 399,289	$ 388,747	$ 773,515	$ 859,290

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 condensed consolidated financial statements (including the notes thereto) included in Item 1 of Part I of this report and our audited consolidated financial statements (including 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, 2016. References to Diamond Offshore, we, us or our mean Diamond Offshore Drilling, Inc., a Delaware corporation, and its subsidiaries.

We provide contract drilling services to the energy industry around the globe with a fleet of 19 offshore drilling rigs, excluding five semisubmersibles rigs that we plan to retire and scrap in the near future. These retired units, which are currently cold stacked, include the *Ocean Baroness*, *Ocean Alliance*, *Ocean Vanguard*, *Ocean Nomad* and *Ocean Princess*. As of the date of this report, our current fleet consists of four drillships, 14 semisubmersibles and one jack-up rig. The *Ocean Monarch*, which had been in a shipyard for a survey and contract modifications since the first quarter of 2017, began operating under the first of three contracts in Australia late in the second quarter of 2017. Six of our rigs are currently cold-stacked, in addition to the five rigs to be scrapped, consisting of three ultra-deepwater and three deepwater semisubmersible rigs. See Contract Drilling Backlog.

Market Overview

At the end of the second quarter of 2017, the spot price for Brent crude oil was $47.08 per barrel, having fluctuated within a general range of $45-$55 per barrel throughout the first half of 2017. This day-to-day volatility in oil price is attributable to multiple factors, including fluctuations in the current and expected level of global oil inventories and estimates of global oil demand. Production cuts by the Organization of the Petroleum Exporting Countries, or OPEC, which have now been extended until the end of the first quarter of 2018, initially buoyed oil prices from previous lows in 2016; however, the favorable price impact of the OPEC cuts is currently being negated by increased production by U.S. shale producers and other non-OPEC producing countries, resulting in volatile commodity prices. Capital spending for offshore exploration and development has continued to decline, with 2017 capital spending estimated by some industry analysts to decrease up to 20% from 2016 levels. If these market estimates are realized, it would represent three consecutive years of decline in offshore spending. Some industry analysts have also reported that there has been and may continue to be a shift in capital spending towards land-based activity. However, customer inquiries and new tenders have increased in 2017, compared to 2016, for offshore rig availability in 2018 and beyond.

Competition among offshore drillers remains intense as rig supply exceeds demand, despite the cold stacking and retirement of numerous rigs during 2016. Additionally, based on industry data as of the date of this report, there are in excess of 30 floater rigs currently on order, with scheduled deliveries from 2017 through 2021. The majority of these rigs are not currently contracted for future work, which further increases competition.

Dayrates continue to be depressed and, in some cases, have been negotiated at break-even or below cost levels in order to enable drilling contractors to recover a portion of operating costs for rigs that would otherwise be uncontracted or cold stacked. Discussions with our customers indicate a preference for hot rigs rather than the reactivation of cold-stacked rigs. This preference incentivizes drilling contractors to accept lower rates for the sole purpose of maintaining their rigs in an active state and allowing for at least partial cost recovery. Some industry analysts have predicted that demand for drilling rigs in the offshore market will slowly improve, but utilization growth will not be significant enough to impact dayrates for some time.

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As a result of the current depressed market conditions in the offshore drilling industry 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 have included requests to lower the contract dayrate, in some cases in exchange for additional contract term, shorten the term on one contracted rig in exchange for additional term on another rig, terminate a contract in exchange for a lump sum 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 requirement for the customer to pay a contractually specified termination amount, which may not fully compensate us for the loss of the contract. Some of our customers have also utilized such contract clauses to seek to renegotiate or terminate a drilling contract or claim that we have breached provisions of our drilling contracts in order to avoid their obligations to us under circumstances where we believe we are in compliance with the contracts.

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. When we cold stack or expect to scrap a rig, we evaluate the rig for impairment. See Contract Drilling Backlog for future commitments of our rigs during 2017 through 2020.

Contract Drilling Backlog

The following table reflects our contract drilling backlog as of July 1, 2017 (based on information available at that time), January 1, 2017 (the date reported in our Annual Report on Form 10-K for the year ended December 31, 2016), and August 1, 2016 (the date reported in our Quarterly Report on Form 10-Q for the quarter ended June 30, 2016). 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. 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, which could adversely affect our reported backlog.

In August 2016, our subsidiary received notice of termination of its drilling contract from Petróleo Brasileiro S.A., or Petrobras, the customer for the *Ocean Valor*. We do not believe that Petrobras had a valid or lawful basis for terminating the contract and in August 2016, we filed a lawsuit in Brazil, claiming that Petrobras purported termination of the contract was unlawful and requested an injunction to prohibit the contract termination. In September 2016, a Brazilian court issued a preliminary injunction, suspending Petrobras purported termination of the contract and ordering that the contract remain in effect until the end of the term or further court order. Petrobras appealed the granting of the injunction, but in March 2017, the court ruled against Petrobras appeal and upheld the injunction. As a result of the favorable ruling, both the injunction and the *Ocean Valor* contract remain in effect. Petrobras has the right to seek to appeal the ruling to the Superior Court of Justice. We intend to continue to defend our rights under the contract, which is estimated to conclude in accordance with its terms in October 2018. However, litigation is inherently unpredictable, and there can be no assurance as to the ultimate outcome of this matter. The rig is currently on standby earning a reduced dayrate.

	July 1, 2017	January 1, 2017	August 1, 2016
		(In thousands)	
Contract Drilling Backlog			
Ultra-Deepwater Floaters [1]	$ 2,705,000	$ 3,215,000	$ 3,875,000
Deepwater Floaters	82,000	197,000	291,000
Other Rigs [2]	156,000	152,000	250,000
Total	$ 2,943,000	$ 3,564,000	$ 4,416,000

(1) Contract drilling backlog as of July 1, 2017 for our ultra-deepwater floaters includes $194.5 million for 2017 and 2018 attributable to contracted work for the *Ocean Valor* under the contract that Petrobras has attempted to terminate, which is currently in effect pursuant to an injunction granted by a Brazilian court.

(2) Includes contract drilling backlog for our mid-water floaters and jack-up rig.

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The following table reflects the amount of our contract drilling backlog by year as of July 1, 2017.

	Total	For the Years Ending December 31, 2017 (1)	2018	2019	2020
		(In thousands)			
Contract Drilling Backlog					
Ultra-Deepwater Floaters (2)	$ 2,705,000	$ 582,000	$ 1,112,000	$ 842,000	$ 169,000
Deepwater Floaters	82,000	68,000	14,000		
Other Rigs (3)	156,000	57,000	34,000	45,000	20,000
Total	$ 2,943,000	$ 707,000	$ 1,160,000	$ 887,000	$ 189,000

(1) Represents the six-month period beginning July 1, 2017.

(2) Contract drilling backlog as of July 1, 2017 for our ultra-deepwater floaters includes $75.3 million and $119.2 million for the years 2017 and 2018, respectively, attributable to contracted work for the *Ocean Valor* under the contract that Petrobras has attempted to terminate, which is currently in effect pursuant to an injunction granted by a Brazilian court.

(3) Includes contract drilling backlog for our mid-water floaters and jack-up rig.

The following table reflects the percentage of rig days committed by year as of July 1, 2017. 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, including cold-stacked rigs, multiplied by the number of days in a particular year).

	For the Years Ending December 31, 2017 (1)	2018	2019	2020
Rig Days Committed (2)				
Ultra-Deepwater Floaters	62%	64%	45%	9%
Deepwater Floaters	33%	4%		
Other Rigs (3)	21%	14%	17%	7%

(1) Represents the six-month period beginning July 1, 2017.

(2) As of July 1, 2017, includes approximately 60 and 65 currently known, scheduled shipyard days for contract preparation, mobilization of rigs, surveys and extended maintenance projects for the remainder of 2017 and for the year 2018, respectively.

(3) Includes committed days for our mid-water floaters and jack-up rig.

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

Regulatory Surveys and Planned Downtime. Our operating income is negatively impacted when we perform certain regulatory inspections, which we refer to as a special survey, that are due every five years for most of our rigs. The inspection interval for our North Sea rigs is two-and-one-half years. During the remainder of 2017, we expect to spend approximately 60 days for a special survey for the *Ocean Patriot* after completion of its current contract. In addition, we expect to spend approximately 65 days in 2018 for contract preparation and the mobilization of the *Ocean Monarch* in connection with a future contract offshore Victoria, Australia. 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.

Physical Damage and Marine Liability Insurance. We are self-insured for physical damage to rigs and equipment caused by named windstorms in the U.S. Gulf of Mexico, as defined by the relevant insurance policy. If a named windstorm in the U.S. Gulf of Mexico 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, 2017, we carry physical damage insurance for certain losses other than those caused by named windstorms in the U.S. Gulf of Mexico 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, 2017, 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.

Patent Discussions. From time to time, third parties contact us to inquire as to whether our services have infringed upon their intellectual property rights. We were recently contacted by a representative of another offshore drilling contractor, Transocean Ltd., or Transocean, with inquiries about our drillships (*Ocean BlackHawk Ocean BlackHornet*, *Ocean BlackRhino* and *Ocean BlackLion*) with regard to three United States patents previously owned by Transocean pertaining to certain dual-activity drilling operations. We have cooperated with Transocean to provide the requested information. The Transocean patents, which expired in May 2016, do not apply to drilling activities outside the United States or to activities that occurred after the expiration of the patents. In the past, Transocean has used the patents as a basis to file patent infringement lawsuits against a number of oil and gas drilling companies, including most recently against Seadrill Americas, Inc., Noble Corporation plc and Pacific Drilling, Inc. Foreign counterparts of the Transocean patents have been invalidated in various countries around the world, including Norway and South Korea.

Capitalization of Interest. We capitalize interest cost for rig construction or upgrades, as well as other qualifying projects, in accordance with accounting principles generally accepted in the U.S. The period of interest capitalization covers the duration of the activities required to make the asset ready for its intended use. The capitalization period ends when the asset is substantially complete and ready for its intended use. During 2016, we ceased capitalizing interest related to the construction of the *Ocean GreatWhite* and do not currently have any ongoing rig construction projects for which we capitalized interest costs during the first half of 2017. At this time, we expect the capitalization of interest costs to be minimal in 2017, relating primarily to qualifying software development projects.

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, 2016. There were no material changes to these policies during the six months ended June 30, 2017.

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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 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. 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.

Key performance indicators by equipment type are listed below.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
REVENUE-EARNING DAYS (1)				
Floaters:				
Ultra-Deepwater	648	473	1,189	1,085
Deepwater	247	223	508	400
Mid-Water	92	181	272	362
Jack-ups	82	58	134	149
UTILIZATION (2)				
Floaters:				
Ultra-Deepwater	59%	47%	55%	54%
Deepwater	45%	35%	47%	31%
Mid-Water	20%	30%	30%	27%
Jack-ups	86%	13%	49%	16%
AVERAGE DAILY REVENUE (3)				
Floaters:				
Ultra-Deepwater	$ 436,000	$ 452,400	$ 442,200	$ 497,800
Deepwater	270,400	300,700	265,300	315,600
Mid-Water	396,900	313,300	311,800	288,200
Jack-ups	74,900	334,900	74,900	202,700

(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 June 30, 2017, our cold-stacked rigs included four ultra-deepwater, three deepwater and three mid-water semisubmersible rigs. In addition, one previously cold stacked jack-up rig was sold in April 2017.

(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 June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
CONTRACT DRILLING REVENUE				
Floaters:				
Ultra-Deepwater	$ 282,535	$ 214,102	$ 526,000	$ 540,063
Deepwater	66,905	67,191	134,848	126,308
Mid-Water	36,543	56,694	84,828	104,366
Total Floaters	385,983	337,987	745,676	770,737
Jack-ups	6,187	19,422	10,051	30,195
Total Contract Drilling Revenue	$ 392,170	$ 357,409	$ 755,727	$ 800,932
REVENUE RELATED TO REIMBURSABLE EXPENSES	$ 7,119	$ 31,338	$ 17,788	$ 58,358
CONTRACT DRILLING EXPENSE				
Floaters:				
Ultra-Deepwater	$ 136,661	$ 127,185	$ 278,534	$ 250,921
Deepwater	31,340	34,776	64,420	82,285
Mid-Water	15,771	25,862	35,038	49,746
Total Floaters	183,772	187,823	377,992	382,952
Jack-ups	6,978	6,876	12,301	12,931
Other	5,467	3,637	9,447	15,294
Total Contract Drilling Expense	$ 196,217	$ 198,336	$ 399,740	$ 411,177
REIMBURSABLE EXPENSES	$ 6,790	$ 16,527	$ 17,268	$ 43,318
OPERATING INCOME (LOSS)				
Floaters:				
Ultra-Deepwater	$ 145,874	$ 86,917	$ 247,466	$ 289,142
Deepwater	35,565	32,415	70,428	44,023
Mid-Water	20,772	30,832	49,790	54,620
Total Floaters	202,211	150,164	367,684	387,785
Jack-ups	(791)	12,546	(2,250)	17,264
Other	(5,467)	(3,637)	(9,447)	(15,294)
Reimbursable expenses, net	329	14,811	520	15,040
Depreciation	(85,982)	(105,016)	(179,211)	(209,256)
General and administrative expense	(19,010)	(18,139)	(36,493)	(33,537)
Impairment of assets	(71,268)	(678,145)	(71,268)	(678,145)
Gain on disposition of assets	802	747	2,148	1,043

Total Operating Income (Loss)	$ 20,824	$ (626,669)	$ 71,683	$ (515,100)
Other income (expense):				
Interest income	396	269	571	442
Interest expense, net of amounts capitalized	(27,251)	(24,156)	(54,847)	(49,672)
Foreign currency transaction (loss) gain	(927)	(3,513)	160	(7,121)
Other, net	(62)	(12,046)	(125)	(11,468)
(Loss) income before income tax benefit	(7,020)	(666,115)	17,442	(582,919)
Income tax benefit	22,969	76,178	22,046	80,407
NET INCOME (LOSS)	$ 15,949	$ (589,937)	$ 39,488	$ (502,512)

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Overview

Three Months Ended June 30, 2017 and 2016

Operating Income (Loss). Operating results for the second quarter of 2017 increased $647.5 million compared to the same period of 2016, primarily due to a lower impairment loss recognized in the 2017 period ($606.9 million), higher utilization of our fleet and a $19.0 million decrease in depreciation expense. The decrease in depreciation expense was primarily due to a lower depreciable asset base in the second quarter of 2017, compared to the second quarter of 2016, as a result of asset impairments taken in 2016. During the second quarter of 2016, we recognized $14.6 million in net reimbursable revenue associated with the completion of the *Ocean Endeavor* s demobilization from the Black Sea.

Contract drilling revenue increased $34.8 million, or 10%, during the second quarter of 2017, compared to the second quarter of 2016, primarily as a result of an aggregate of 134 incremental revenue-earning days for our fleet, of which 91 additional days were attributable to the recently completed *Ocean GreatWhite*, which commenced its first contract in the first quarter of 2017. Comparing the two quarters, contract drilling expense remained relatively flat across our fleet, decreasing an aggregate of $2.1 million during the second quarter of 2017. Incremental contract drilling expense for the *Ocean GreatWhite* ($10.5 million) was more than offset by lower overall operating costs for the fleet, primarily for labor and personnel ($8.6 million) and an aggregate net decrease in other rig operating and overhead costs ($4.0 million), as we continue to see results from our cost control measures initiated in prior periods.

Impairment of Assets. During the second quarter of 2017, we evaluated seven of our drilling rigs with indicators of impairment and determined that the carrying values of two rigs (one ultra-deepwater and one deepwater semisubmersible rig) were impaired. As a result, we recorded an aggregate impairment loss of $71.3 million to write down these rigs to their estimated scrap values in the second quarter of 2017. During the second quarter of 2016, we recognized an aggregate impairment charge of $678.1 million with respect to the carrying values of two mid-water, three deepwater, and three ultra-deepwater semisubmersible rigs, including related rig spares and supplies. See Notes 1 and 2 to our unaudited condensed consolidated financial statements included in Item 1 of Part I of this report.

Other, net. During the second quarter of 2016, we sold our investment in privately-held corporate bonds for a total realized loss of $12.1 million.

Income Tax Benefit. We recorded net income tax benefits of $23.0 million and $76.2 million for the three months ended June 30, 2017 and 2016, respectively. The difference in the amount of income tax benefit recognized in the 2017 period, compared to the prior year period, was in large part due to the mix of our domestic and international pre-tax earnings and losses, inclusive of the impairment losses recognized in the second quarters of 2017 and 2016. The income tax benefit for the second quarter of 2017 included a $24.9 million tax benefit related to asset impairments in the U.S. tax jurisdiction. The income tax benefit for the second quarter of 2016 included a tax benefit of $143.1 million related to asset impairments during the quarter in the U.S. tax jurisdiction, partially offset by a valuation allowance of $77.3 million for current and prior year tax assets associated with foreign tax credits.

Six Months Ended June 30, 2017 and 2016

Operating Income (Loss). Operating results for the first six months of 2017 increased $586.8 million compared to the same period of 2016, primarily due to a lower impairment loss recognized in the 2017 period ($606.9 million), lower contract drilling expense ($11.4 million) and reduced depreciation expense ($30.0 million). These favorable variances were partially offset by the unfavorable effect of a $45.2 million decrease in contract drilling revenue during the first half of 2017, compared to the same period of 2016, and the recognition of $14.6 million in net reimbursable income for the *Ocean Endeavor* during the 2016 period. Depreciation expense decreased primarily due to a lower depreciable asset base in 2017, compared to the first half of 2016, as a result of asset impairments taken in 2016.

Contract drilling revenue decreased $45.2 million, or 6%, during the first half of 2017, compared to the first half of 2016, primarily as a result of lower average daily revenue earned by most of the rigs in our fleet, partially offset by the favorable impact of an aggregate of 107 incremental revenue-earning days.

Total contract drilling expense decreased $11.4 million during the first six months of 2017 compared to the same period of 2016. Excluding incremental contract drilling expense for the *Ocean GreatWhite* ($22.1 million), aggregate contract drilling expense decreased $33.5 million, reflecting lower costs for labor and personnel ($18.2 million), repairs and maintenance ($14.5 million) and a net decrease in other rig operating and overhead costs ($0.8 million).

Other, net. During the second quarter of 2016, we sold our investment in privately-held corporate bonds for a total recognized loss of $12.1 million.

Income Tax Benefit. We recorded net income tax benefits of $22.0 million and $80.4 million for the six months ended June 30, 2017 and 2016, respectively. The difference in the amount of income tax benefit recognized in the first half of 2017, compared to the prior year period, was primarily due to the mix of our domestic and international pre-tax earnings and losses, inclusive of the impairment losses recognized in the second quarters of 2017 and 2016. The net tax benefit for the first six months of 2017 and 2016 included U.S. tax benefits of $24.9 million and $143.1 million, respectively, related to the impairment of assets in the U.S. tax jurisdiction. The income tax benefit for the six months ended June 30, 2016 was net of additional tax expense associated with a valuation allowance of $77.3 million recognized during the period for current and prior year tax assets associated with foreign tax credits.

Contract Drilling Revenue and Expense by Equipment Type

Three Months Ended June 30, 2017 and 2016

Ultra-Deepwater Floaters. Revenue generated by our ultra-deepwater floaters increased $68.4 million during the second quarter of 2017, compared to the same quarter of 2016, primarily as a result of 175 incremental revenue-earning days ($79.0 million), partially offset by lower average daily revenue earned ($10.6 million). Revenue-earning days increased in the second quarter of 2017, primarily due to incremental revenue-earning days for the *Ocean GreatWhite* (91 days), the *Ocean BlackRhino*, which was between contracts during the prior year quarter (84 days), and less unplanned downtime for repairs (61 days) to our other ultra-deepwater rigs. The increase in revenue-earning days was partially offset by fewer revenue-earning days for the *Ocean Monarch*, which was in the shipyard for a survey and contract modifications during the second quarter of 2017 prior to beginning a new contract in June (61 days). Average daily revenue decreased during the second quarter of 2017, compared to the second quarter of 2016, primarily due to the *Ocean Valor* earning a reduced, standby dayrate during 2017 and a lower dayrate earned by the *Ocean Monarch* under its new contract.

Contract drilling expense for our ultra-deepwater floaters increased $9.5 million during the second quarter of 2017, compared to the second quarter of 2016, primarily due to incremental costs associated with our Pressure Control by the Hour® program, or PCbtH program, that has now been implemented on all of our drillships ($8.0 million), incremental contract drilling expense for the *Ocean GreatWhite* ($10.5 million) and higher costs associated with the mobilization of rigs ($4.3 million). These incremental costs were partially offset by lower costs for labor and personnel ($2.9 million), repairs and maintenance ($2.7 million), shorebase support and overhead ($6.2 million) and other costs ($1.5 million).

Deepwater Floaters. Revenue and contract drilling expense for our deepwater floaters decreased $0.3 million and $3.4 million, respectively, in the second quarter of 2017 compared to the same period in 2016. The reduction in revenue during the second quarter of 2017 resulted from lower average daily revenue earned ($7.5 million), offset by the effect of 24 incremental revenue-earning days ($7.2 million). Contract drilling expense for the second quarter of 2017 also declined, reflecting lower costs for labor and personnel ($0.7 million), maintenance and repairs ($2.2 million), equipment rentals ($1.0 million) and other rig operating and overhead costs ($1.4 million), partially offset by an increase in costs related to the mobilization of rigs ($1.9 million).

Mid-Water Floaters. Revenue generated by our mid-water floaters during the second quarter of 2017 decreased $20.2 million compared to the same quarter of 2016, primarily due to the warm-stacking of the *Ocean Guardian* after completion of its contract in early April 2017 ($18.5 million). Contract drilling expense for our mid-water floaters decreased $10.1 million during the second quarter of 2017, compared to the prior year quarter, due to reduced costs incurred by the *Ocean Guardian* ($4.4 million) combined with lower contract drilling expense ($5.7 million) for our other mid-water rigs, including rigs that were sold after the first half of 2016.

Jack-ups. Subsequent to the second quarter of 2016, we sold four cold-stacked jack-up rigs and currently own one jack-up rig, the *Ocean Scepter*. Contract drilling revenue attributable to our current and previously-owned jack-up rigs decreased $13.2 million during the second quarter of 2017, compared to the prior year quarter, while contract drilling expense remained flat. Contract drilling revenue decreased primarily due to a reduced dayrate earned by the *Ocean Scepter* ($14.4 million), which began operating under a new contract offshore Mexico in 2017, and the absence of loss of hire insurance proceeds recognized in the second quarter of 2016 ($4.9 million). These reductions in revenue were partially offset by the favorable impact of 24 incremental revenue-earning days for the *Ocean Scepter* ($6.1 million) in the second quarter of 2017.

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Six Months Ended June 30, 2017 and 2016

Ultra-Deepwater Floaters. Revenue generated by our ultra-deepwater floaters decreased $14.1 million during the first half of 2017, compared to the same period of 2016, primarily as a result of lower average daily revenue earned ($66.1 million), partially offset by 104 incremental revenue-earning days for our ultra-deepwater fleet ($52.0 million). Average daily revenue decreased during the first half of 2017, primarily due to the absence of $40.0 million in demobilization revenue recognized in the first quarter of 2016 for the *Ocean Endeavor*, combined with the effect of lower dayrates earned under new contracts for both the *Ocean Monarch* (June 2017) and *Ocean BlackRhino* (February 2017). The increase in revenue-earning days was primarily due to incremental revenue-earning days for the *Ocean GreatWhite* (168 days), the *Ocean BlackRhino,* which was warm stacked for much of the prior year period (93 days), and reduced downtime for repairs (58 days). The increase in revenue-earning days was partially offset by incremental downtime for the *Ocean Monarch*, which was in the shipyard for a survey and contract modifications during much of the first half of 2017 (136 days) and the cold stacking of other rigs (79 days).

Contract drilling expense for our ultra-deepwater floaters increased $27.6 million during the first six months of 2017, compared to the first half of 2016, primarily due to incremental costs associated with the PCbtH program on our drillships ($20.3 million) and incremental contract drilling expense for the *Ocean GreatWhite* ($22.1 million). Excluding these incremental costs, contract drilling expense for our ultra-deepwater floaters decreased $14.8 million in the first half of 2017, compared to the prior year period, primarily due to lower contract drilling expense attributable to cold-stacked rigs ($13.2 million).

Deepwater Floaters. Revenue generated by our deepwater floaters increased $8.5 million in the first half of 2017, compared to the same period in 2016, primarily due to 108 incremental revenue-earning days ($34.1 million), partially offset by a reduction in average daily revenue earned ($25.6 million). The increase in revenue-earning days resulted primarily from 140 incremental days for the *Ocean Apex*, which operated through the first six months of 2017 under a contract that commenced in the second quarter of 2016. Average daily revenue decreased during the first half of 2017, primarily as a result of a lower dayrate being earned by the *Ocean Valiant* under its current contract in the North Sea, which commenced in the fourth quarter of 2016.

Contract drilling expense for our deepwater floaters decreased $17.9 million during the first half 2017, compared to the first half of 2016, primarily due to a net reduction in costs associated with labor and personnel ($3.5 million), maintenance and repairs ($8.4 million), equipment rental ($2.0 million) and other rig operating and overhead costs ($4.0 million) attributable to various factors, including the cold stacking of rigs and implementation of cost control measures for our working rigs and shorebase operations in 2016.

Mid-Water Floaters. Revenue and contract drilling expense for our mid-water floaters decreased $19.5 million and $14.7 million, respectively, during the first half 2017 compared to the same period of 2016. The decrease in revenue reflects 90 fewer revenue-earning days ($25.9 million), partially offset by an increase in average daily revenue earned ($6.4 million). The decrease in revenue-earning days primarily relates to the completion of the final contract for the *Ocean Ambassador* in March 2016 prior to the rig being sold. Only two of our mid-water floaters operated during both periods, while the remainder of our mid-water fleet remained cold stacked or was sold during 2016. The decrease in contract drilling expense was primarily due to reduced costs related to the *Ocean Ambassador* ($8.3 million) and a reduction in labor and personnel costs for the remainder of the fleet ($4.2 million).

Jack-ups. Contract drilling revenue attributable to our current and previously-owned jack-up rigs decreased $20.1 million during the first half of 2017, compared to the first half of 2016, while contract drilling expense remained stable, decreasing $0.6 million. As of the beginning of the second quarter of 2017, we had sold all but one jack-up rig. The *Ocean Scepter*, which had been idle since completion of its contract in Mexico during May 2016, commenced operations offshore Mexico in February 2017 under a new contract. The decrease in contract drilling revenue was primarily due to 15 fewer revenue-earning days and lower average daily revenue earned by the rig during the first half of 2017, compared to the prior year period ($15.2 million), as well as the absence of $4.9 million in loss of hire insurance proceeds recognized in the second half of 2016.

Liquidity and Capital Resources

We principally rely on our cash flows from operations and cash reserves to meet our liquidity needs. We may also utilize borrowings under our $1.5 billion syndicated revolving credit agreement, or Credit Agreement. See Credit Agreement.

Based on our cash available for current operations and contractual backlog of $2.9 billion as of July 1, 2017, of which $0.7 billion is expected to be realized during the remainder of 2017, we believe future capital spending and debt service requirements will be funded from our cash and cash equivalents, future operating cash flows and borrowings under our Credit Agreement, as needed. See Sources and Uses of Cash Capital Expenditures.

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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. Although we do not intend to repatriate the earnings of DFAC, and have not provided U.S. income taxes for such earnings, except to the extent that such earnings were immediately subject to U.S. income taxes, these earnings could become subject to U.S. income tax if remitted, or if deemed remitted as a dividend; however, it is not practical to estimate this potential liability.

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. to meet each entity s respective working capital requirements and capital commitments. At June 30, 2017 and December 31, 2016, we had cash available for current operations, including cash reserves of DFAC, as follows:

	June 30, 2017	December 31, 2016
	(In thousands)	
Cash and cash equivalents	$ 160,969	$ 156,233
Marketable securities	12	35
Total cash available for current operations	$ 160,981	$ 156,268

A substantial portion of our cash flows has historically 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 Sources and Uses of Cash Capital Expenditures.

We pay dividends at the discretion of our Board of Directors, or Board, and 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 considers relevant at that time. We did not pay any dividends in 2016 or in the first half of 2017.

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 six-month periods ended June 30, 2017 and 2016.

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.

Sources and Uses of Cash

During the six-month period ended June 30, 2017, our primary sources of cash were an aggregate $176.9 million generated by operating activities and $4.1 million from the disposition of assets. Cash usage during the same period was primarily $104.2 million for the net repayment of borrowings under our Credit Agreement and capital expenditures aggregating $71.9 million.

Our cash flow from operations and capital expenditures for the six-month periods ended June 30, 2017 and 2016 were as follows:

	Six Months Ended June 30,	
	2017	2016
	(In thousands)	
Cash flow from operations	$ 176,881	$ 305,470
Cash capital expenditures:		
Construction of ultra-deepwater floater	$	$ 446,737
Rig equipment and replacement programs	71,889	86,675
Total capital expenditures	$ 71,889	$ 533,412

Cash Flow from Operations. Cash flow from operations decreased $128.6 million during the first six months of 2017, compared to the first six months of 2016, primarily due to lower cash receipts for contract drilling services ($202.8 million), partially offset by a net decrease in cash payments for contract drilling expenses, including personnel-related, repairs and maintenance, overheads and other rig operating costs ($74.2 million). The decline in both cash receipts and cash payments related to the performance of contract drilling services reflects continuing depressed market conditions in the offshore drilling industry, as well as positive results of our continuing focus on controlling costs.

Capital Expenditures. As of the date of this report, we expect total capital expenditures for 2017 to aggregate approximately $145.0 million for our ongoing capital maintenance and replacement programs.

We had no other purchase obligations for major rig upgrades at June 30, 2017.

Other Obligations. As of June 30, 2017, the total net unrecognized tax benefits related to uncertain tax positions was $63.2 million. 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

At June 30, 2017, we had no borrowings outstanding under our Credit Agreement, and were in compliance with all covenants thereunder. As of July 27, 2017, we had $1.5 billion available under our Credit Agreement to provide liquidity for our payment obligations.

Credit Ratings

On July 28, 2017, Moody s Investor Services downgraded our corporate credit rating to Ba3 with a negative outlook from Ba2 with a stable outlook. Our current corporate credit rating by S&P Global Ratings remains BB- with a negative outlook. 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 funds by issuing additional debt. 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.

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Other Commercial Commitments - Letters of Credit

We were contingently liable as of June 30, 2017 in the amount of $18.3 million under certain performance, tax, supersedeas, customs bonds and letters of credit. Agreements relating to approximately $15.4 million of tax, supersedeas, court and customs bonds can require collateral at any time. As of June 30, 2017, 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	2017	2018
	(In thousands)		
Other Commercial Commitments			
Performance bonds	$ 1,000	$	$ 1,000
Supersedeas bond	9,189	9,189	
Tax bond	5,639	5,639	
Other	2,518	1,310	1,208
Total obligations	$ 18,346	$ 16,138	$ 2,208

Off-Balance Sheet Arrangements

At June 30, 2017 and December 31, 2016, we had no off-balance sheet debt or other off-balance sheet arrangements.

New Accounting Pronouncements

See Note 1 General Information to our unaudited condensed 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, 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, may, might, will, likely result, project, forecast, budget and similar expressions. In addition, any statement 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, as so defined. 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;

contractual obligations and future contract negotiations;

interest rate and foreign exchange risk;

operations outside the United States;

business strategy;

growth opportunities;

competitive position, including without limitation, competitive rigs entering the market;

expected financial position;

cash flows and contract backlog;

future term of the Petrobras drilling contract for the *Ocean Valor* and the enforcement of our rights under the contract;

idling drilling rigs or reactivating stacked rigs;

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;

budgets for capital and other expenditures;

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

timing and cost of completion of capital projects;

delivery dates and drilling contracts related to capital projects or rig acquisitions;

plans and objectives of management;

idling drilling rigs or reactivating stacked rigs;

scrapping retired rigs;

assets held for sale;

asset impairments and impairment evaluations;

our internal controls and remediation of our material weakness in internal control over financial reporting;

outcomes of disputes and 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 in our Annual Report on Form 10-K for the year ended December 31, 2016.

The risks and uncertainties referenced above are not exhaustive. Other sections of this report and our other filings with the Securities and Exchange Commission 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 six months ended June 30, 2017. See Quantitative and Qualitative Disclosures About Market Risk included in Item 7A of our Annual Report on Form 10-K for the year ended December 31, 2016 for further information.

ITEM 4. Controls and Procedures.

Evaluation of Disclosure Controls and Procedures

We maintain a system of disclosure controls and procedures that 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.

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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 June 30, 2017. Based on their participation in that evaluation, our CEO and CFO concluded that our disclosure controls and procedures were effective as of June 30, 2017.

Changes in Internal Control over Financial Reporting

Other than with respect to the remediation procedures detailed below for the previously identified material weakness, there were no changes in our internal control over financial reporting identified in connection with the foregoing evaluation that occurred during our second fiscal quarter of 2017 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

As previously discussed in our 2016 Annual Report on Form 10-K, as of December 31, 2016, we identified a material weakness in the design of our controls over the application of changes in foreign exchange rates when measuring our liability for uncertain tax positions denominated in foreign currencies. These liabilities for uncertain tax positions are considered monetary liabilities and are required to be revalued in accordance with Accounting Standards Codification 830 *Foreign Currency Matters*. We had historically utilized a manual (non-system) calculation to revalue our foreign liability for uncertain tax positions, as appropriate. Prior to the completion of our year-end financial reporting process for fiscal year 2016, it was discovered that our revaluation of our liability for uncertain tax positions did not properly reflect appropriate changes for current foreign exchange rates. This omission resulted in an improper measurement of certain of our liabilities for uncertain tax positions. As a result, we concluded that we failed to adequately design and operate our internal controls over the application of changes in foreign exchange rates in revaluation of liabilities for foreign uncertain tax positions to mitigate the risk of a material error.

We have designed and implemented new controls and processes to remediate the underlying cause of the material weakness discussed above. Specifically, during the first fiscal quarter of 2017, we implemented the following actions:

- we enhanced our control process related to the creation of new accounts to ensure all foreign-denominated accounts are appropriately established in our accounting system for re-measurement, when required;

- we redesigned processes to require foreign-denominated accounts to be re-measured by our accounting system, thereby eliminating off-line manual calculations; and

- we enhanced our reconciliation procedures with respect to monetary assets and liabilities, including liabilities for uncertain tax positions, to require a comparison of the local currency balance to the U.S. dollar equivalent for reasonableness.

During the second fiscal quarter of 2017, we completed our testing of the operational effectiveness of the actions discussed above. We have concluded that the enhanced control processes have now been operating for a sufficient period of time so as to provide reasonable assurance as to their effectiveness, and, as a result, that the material weakness described above was remediated as of June 30, 2017.

PART II. OTHER INFORMATION

ITEM 1. Legal Proceedings.

Information related to certain legal proceedings is included in Note 7 to our unaudited condensed consolidated financial statements included in Item 1 of Part I of this report.

ITEM 1A. Risk Factors.

Our Annual Report on Form 10-K for the year ended December 31, 2016 includes a detailed discussion of certain material risk factors facing our company. No material changes have been made to such risk factors as of June 30, 2017.

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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 June 30, 2017, in connection with the vesting of restricted stock units held by our officers and certain of our employees, which were awarded under an equity incentive compensation plan, 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 Shares that May Yet Be Purchased Under the Plans or Programs
April 1, 2017 through April 30, 2017	20,464	$ 16.71	N/A	N/A
May 1, 2017 through May 31, 2017			N/A	N/A
June 1, 2017 through June 30, 2017			N/A	N/A
Total	20,464	$ 16.71	N/A	N/A

ITEM 6. Exhibits.

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

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 July 31, 2017

By: /s/ Kelly Youngblood
Kelly Youngblood
Senior Vice President and Chief Financial Officer

Date July 31, 2017

/s/ Beth G. Gordon
Beth G. Gordon

Vice President and 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).
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.