UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

(Mark One)

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

For the quarterly period ended September 30, 2018

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 1-8590

MURPHY OIL CORPORATION

(Exact name of registrant as specified in its charter)

Delaware	71-0361522

(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification Number)
300 Peach Street, P.O. Box 7000, El Dorado, Arkansas	71731-7000
(Address of principal executive offices)	(Zip Code)

(870) 862-6411

(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.
[X] Yes [ ] No

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). [X] Yes [ ] No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, 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.

Large accelerated filer [X] Accelerated filer [ ] Non-accelerated filer [ ]
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 13(a) of the Exchange Act. [ ]

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

Number of shares of Common Stock, $1.00 par value, outstanding at October 31, 2018 was 173,056,234.

MURPHY OIL CORPORATION

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PART I – FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

Murphy Oil Corporation and Consolidated Subsidiaries

CONSOLIDATED BALANCE SHEETS (unaudited)

(Thousands of dollars)

	September 30, 2018	December 31, 2017
ASSETS		
Current assets		
Cash and cash equivalents	$ 947,732	964,988
Accounts receivable, less allowance for doubtful accounts of $1,605 in 2018 and 2017	274,193	243,472
Inventories, at lower of cost or market	94,615	105,127
Prepaid expenses	43,606	35,087
Assets held for sale	21,140	22,929
Total current assets	1,381,286	1,371,603
Property, plant and equipment, at cost less accumulated depreciation, depletion and amortization of $12,916,002 in 2018 and $12,280,741 in 2017	8,244,167	8,220,031
Deferred income taxes	346,455	211,543
Deferred charges and other assets	54,712	57,765
Total assets	$ 10,026,620	9,860,942
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities		
Current maturities of long-term debt	$ 10,454	9,902
Accounts payable	622,577	595,916
Income taxes payable	53,676	44,604
Other taxes payable	19,939	23,574
Other accrued liabilities	166,066	156,681
Liabilities associated with assets held for sale	2,802	3,530
Total current liabilities	875,514	834,207
Long-term debt, including capital lease obligation	2,903,899	2,906,520
Deferred income taxes	130,369	159,098
Asset retirement obligations	700,055	709,299
Deferred credits and other liabilities	649,855	631,627

Stockholders’ equity		
Cumulative Preferred Stock, par $100, authorized 400,000 shares, none issued	–	–
Common Stock, par $1.00, authorized 450,000,000 shares, issued 195,065,341 shares in 2018 and 195,055,724 in 2017	195,065	195,056
Capital in excess of par value	905,379	917,665
Retained earnings	5,453,414	5,245,242
Accumulated other comprehensive loss	(537,768)	(462,243)
Treasury stock	(1,249,162)	(1,275,529)
Total stockholders’ equity	4,766,928	4,620,191
Total liabilities and stockholders’ equity	$ 10,026,620	9,860,942

See Notes to Consolidated Financial Statements, page 7.

Murphy Oil Corporation and Consolidated Subsidiaries

CONSOLIDATED STATEMENTS OF OPERATIONS (unaudited)

(Thousands of dollars, except per share amounts)

	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2018	2017 1	2018	2017 1
Revenues				
Revenue from sales to customers	$ 659,806	511,192	1,921,910	1,498,093
(Loss) gain on crude contracts	(2,223)	(13,573)	(69,349)	50,365
Gain on sale of assets and other income	17,214	700	26,035	134,780
Total revenues	674,797	498,319	1,878,596	1,683,238
Costs and expenses				
Lease operating expenses	133,141	112,751	406,226	346,072
Severance and ad valorem taxes	15,067	10,816	40,100	32,771
Exploration expenses, including undeveloped lease amortization	21,838	28,492	69,911	77,356
Selling and general expenses	64,107	51,374	173,324	155,438
Depreciation, depletion and amortization	241,833	243,636	710,563	714,782
Accretion of asset retirement obligations	11,099	10,654	32,041	31,638
Redetermination expense	11,332	–	11,332	–
Other expense (benefit)	(34,387)	2,454	(44,776)	10,988
Total costs and expenses	464,030	460,177	1,398,721	1,369,045
Operating income from continuing operations	210,767	38,142	479,875	314,193
Other income (loss)				
Interest and other income (loss)	(19,478)	(53,019)	(19,445)	(106,345)
Interest expense, net	(44,492)	(48,681)	(134,264)	(138,423)
Total other loss	(63,970)	(101,700)	(153,709)	(244,768)
Income (loss) from continuing operations before income taxes	146,797	(63,558)	326,166	69,425
Income tax expense	51,038	2,760	15,801	95,602
Income (loss) from continuing operations	95,759	(66,318)	310,365	(26,177)
Income (loss) from discontinued operations, net of income taxes	(1,815)	425	(2,650)	1,177
NET INCOME (LOSS)	$ 93,944	(65,893)	307,715	(25,000)

INCOME (LOSS) PER COMMON SHARE – BASIC

Continuing operations	$ 0.55	(0.38)	1.79	(0.15)
Discontinued operations	(0.01)	-	(0.01)	0.01
Net Income (Loss)	$ 0.54	(0.38)	1.78	(0.14)
INCOME (LOSS) PER COMMON SHARE – DILUTED				
Continuing operations	$ 0.55	(0.38)	1.78	(0.15)
Discontinued operations	(0.01)	-	(0.01)	0.01
Net Income (Loss)	$ 0.54	(0.38)	1.77	(0.14)
Cash dividends per Common share	0.25	0.25	0.75	0.75
Average Common shares outstanding (thousands)				
Basic	173,047	172,573	172,949	172,509
Diluted	174,175	172,573	174,202	172,509

1 Reclassified to conform to current presentation (see Note B).

See Notes to Consolidated Financial Statements, page 7.

Murphy Oil Corporation and Consolidated Subsidiaries

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (unaudited)

(Thousands of dollars)

	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2018	2017	2018	2017
Net income (loss)	$ 93,944	(65,893)	307,715	(25,000)
Other comprehensive income (loss), net of tax				
Net (loss) gain from foreign currency translation	33,380	101,210	(53,805)	194,094
Retirement and postretirement benefit plans	3,390	2,396	10,498	7,169
Deferred loss on interest rate hedges reclassified to interest expense	585	482	1,756	1,445
Reclassification of certain tax effects to retained earnings	–	–	(30,237)	–
Other	–	–	(3,737)	–
Other comprehensive (loss) income	37,355	104,088	(75,525)	202,708
COMPREHENSIVE INCOME	$ 131,299	38,195	232,190	177,708

See Notes to Consolidated Financial Statements, page 7.

Murphy Oil Corporation and Consolidated Subsidiaries

CONSOLIDATED STATEMENTS OF CASH FLOWS (unaudited)

(Thousands of dollars)

	Nine Months Ended September 30,	
	2018	2017
Operating Activities		
Net income (loss)	$ 307,715	(25,000)
Adjustments to reconcile net income (loss) to net cash provided by continuing operations activities:		
Loss (Income) from discontinued operations	2,650	(1,177)
Depreciation, depletion and amortization	710,563	714,782
Dry hole costs (credits)	4,526	(1,139)
Amortization of undeveloped leases	31,544	40,859
Accretion of asset retirement obligations	32,041	31,638
Deferred income tax benefit	(138,755)	(3,567)
Pretax gain from sale of assets	(6)	(130,765)
Net (increase) decrease in noncash operating working capital	(2,550)	1,070
Other operating activities, net	49,217	192,097
Net cash provided by continuing operations activities	996,945	818,798
Investing Activities		
Property additions and dry hole costs	(858,356)	(706,417)
Proceeds from sales of property, plant and equipment	1,128	69,146
Purchases of investment securities 1	–	(212,661)
Proceeds from maturity of investment securities 1	–	320,828
Net cash required by investing activities	(857,228)	(529,104)
Financing Activities		
Borrowings of debt, net of issuance costs	–	541,772
Repayments of debt	–	(550,000)
Capital lease obligation payments	(7,164)	(14,687)
Withholding tax on stock-based incentive awards	(6,922)	(7,151)
Cash dividends paid	(129,780)	(129,421)
Net cash required by financing activities	(143,866)	(159,487)
Effect of exchange rate changes on cash and cash equivalents	(13,107)	(5,797)
Net increase (decrease) in cash and cash equivalents	(17,256)	124,410

Cash and cash equivalents at beginning of period	964,988	872,797
Cash and cash equivalents at end of period	$ 947,732	997,207

1 Investments are Canadian government securities with maturities greater than 90 days at the date of acquisition.

See Notes to Consolidated Financial Statements, page 7.

Murphy Oil Corporation and Consolidated Subsidiaries

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY (unaudited)

(Thousands of dollars)

	Nine Months Ended September 30,	
	2018	2017
Cumulative Preferred Stock – par $100, authorized 400,000 shares, none issued	$ –	–
Common Stock – par $1.00, authorized 450,000,000 shares, issued 195,065,341 shares at September 30, 2018 and 195,055,724 shares at September 30, 2017		
Balance at beginning of period	195,056	195,056
Exercise of stock options	9	–
Balance at end of period	195,065	195,056
Capital in Excess of Par Value		
Balance at beginning of period	917,665	916,799
Exercise of stock options, including income tax benefits	(175)	–
Restricted stock transactions and other	(32,766)	(26,553)
Stock-based compensation	20,655	20,767
Other	–	(77)
Balance at end of period	905,379	910,936
Retained Earnings		
Balance at beginning of period	5,245,242	5,729,596
Net income (loss) for the period	307,715	(25,000)
Reclassification of certain tax effects from accumulated other comprehensive loss	30,237	–
Cash dividends	(129,780)	(129,421)
Balance at end of period	5,453,414	5,575,175
Accumulated Other Comprehensive Loss		
Balance at beginning of period	(462,243)	(628,212)
Foreign currency translation (loss) gain, net of income taxes	(53,805)	194,094
Retirement and postretirement benefit plans, net of income taxes	10,498	7,169
Deferred loss on interest rate hedges reclassified to interest expense, net of income taxes	1,756	1,445
Reclassification of certain tax effects to retained earnings	(30,237)	–
Other	(3,737)	–
Balance at end of period	(537,768)	(425,504)
Treasury Stock		
Balance at beginning of period	(1,275,529)	(1,296,560)
Sale of stock under employee stock purchase plan	–	145

Awarded restricted stock, net of forfeitures	26,367	20,886
Balance at end of period – 22,018,095 shares of Common Stock in 2018 and 22,482,581 shares of Common Stock in 2017, at cost	(1,249,162)	(1,275,529)
Total Stockholders' Equity	$ 4,766,928	4,980,134

See Notes to Consolidated Financial Statements, page 7.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

These notes are an integral part of the financial statements of Murphy Oil Corporation and Consolidated Subsidiaries (Murphy/the Company) on pages 2 through 6 of this Form 10-Q report.

Note A – Nature of Business and Interim Financial Statements

NATURE OF BUSINESS – Murphy Oil Corporation is an international oil and gas company that conducts its business through various operating subsidiaries. The Company primarily produces oil and natural gas in the United States, Canada and Malaysia and undertakes oil and natural gas exploration activities in select basins around the globe.

INTERIM FINANCIAL STATEMENTS – In the opinion of Murphy's management, the unaudited financial statements presented herein include all accruals necessary to present fairly the Company's financial position at September 30, 2018 and December 31, 2017, and the results of operations, cash flows and changes in stockholders' equity for the interim periods ended September 30, 2018 and 2017, in conformity with accounting principles generally accepted in the United States of America (U.S.). In preparing the financial statements of the Company in conformity with accounting principles generally accepted in the U.S., management has made a number of estimates and assumptions related to the reporting of assets, liabilities, revenues, and expenses and the disclosure of contingent assets and liabilities. Actual results may differ from the estimates.

Financial statements and notes to consolidated financial statements included in this Form 10-Q report should be read in conjunction with the Company's 2017 Form 10-K report, as certain notes and other pertinent information have been abbreviated or omitted in this report. Financial results for the three-month and nine-month periods ended September 30, 2018 are not necessarily indicative of future results.

Note B – New Accounting Principles and Recent Accounting Pronouncements

Accounting Principles Adopted

Revenue from Contracts with Customers. In May 2014, the Financial Accounting Standards Board (FASB) issued an Accounting Standards Update (ASU), which established a comprehensive model of accounting for revenue arising from contracts with customers that superseded most revenue recognition requirements and industry-specific guidance. Under the new standard, the Company recognizes revenue when it transfers control of the commodity to customers in an amount that reflects the consideration the Company expects to be entitled to in exchange for the commodity. Additional disclosures are required to describe the nature, amount, timing and uncertainly of revenue and cash flows from contracts with customers. The Company adopted the new standard in the first quarter of 2018 using the modified retrospective method. The Company performed a review of contracts in each of its revenue streams and implemented accounting policies and internal controls to address the requirements of the ASU. Prior to January 1, 2018, the Company followed the sales method of revenue recognition under Accounting Standards Codification (ASC) Topic 605 and recorded revenue when deliveries occurred, and legal ownership of the commodity transferred to the customer.

There was no adjustment to the opening balance of stockholders' equity as at January 1, 2018, resulting from application of the new ASU promulgated in ASC Topic 606 using the modified retrospective method. The comparative information has not been adjusted and continues to be reported under ASC Topic 605 – Revenue Recognition. See also Note C for further discussion of Revenue Recognition.

Statement of Cash Flows. In August 2016, the FASB issued an ASU to reduce diversity in practice in how certain transactions are classified in the statement of cash flows. The amendment provides guidance on specific cash flow issues including debt prepayment or debt extinguishment costs, settlement of zero-coupon debt instruments or other debt instrument with coupon interest rates that are insignificant in relation to the effective interest rate of the borrowing, contingent consideration payments made after a business combination, proceeds from the settlement of insurance claims, proceeds from the settlement of corporate-owned life insurance policies, and distributions received from equity method investees. The amendments in this ASU were effective for annual and interim periods beginning after December 15, 2017. The Company adopted this guidance in the first quarter of 2018 and it did not have a material impact on its consolidated financial statements.

Compensation – Retirement Benefits. In March 2017, the FASB issued an ASU requiring that the service cost component of pension and postretirement benefit costs be presented in the same line item as other current employee compensation costs and other components of those benefit costs be presented separately from the service cost component outside a subtotal of income from operations, if presented. The update also requires that only the service cost component of pension and postretirement benefit cost is eligible for capitalization. The update is effective for annual and interim periods beginning after December 15, 2017. The Company adopted the standard in the first quarter of 2018 and it did not have a material impact on its consolidated financial statements.

Note B – New Accounting Principles and Recent Accounting Pronouncements (Contd.)

Accounting Principles Adopted (Cont.)

Compensation – Stock Compensation. In May 2017, the FASB issued an ASU which amends the scope of modification accounting for share-based payment arrangements and provides guidance on the type of changes to the terms and conditions of share-based payment awards to which an entity would be required to apply modification accounting. The update is effective for annual periods beginning after December 15, 2017 and interim periods within the annual period. The Company adopted this accounting standard in the first quarter of 2018 and it did not have a material impact on its consolidated financial statements.

Statement of Operations – Reporting Comprehensive Income. In February 2018, the FASB issued an ASU, which allows a reclassification from accumulated other comprehensive income to retained earnings for stranded tax effects resulting from the Tax Cuts and Jobs Act. The Company elected to early adopt this accounting standard during the first quarter of 2018 and recorded discrete adjustments from accumulated other comprehensive income to retained earnings of $28.4 million related to retirement and postretirement obligations and $1.8 million related to deferred loss on interest rate derivative hedges. The adoption of this ASU will have no future impact.

Recent Accounting Pronouncements

Leases. In February 2016, the FASB issued an ASU to increase transparency and comparability among companies by recognizing lease assets and lease liabilities on the balance sheet and disclosing key information about leasing arrangements. The main difference between previous Generally Accepted Accounting Principles (GAAP) and this ASU is the recognition of right-of-use assets and lease liabilities by lessees for those leases classified as operating leases under previous GAAP. The new standard is effective for financial statements issued for annual periods beginning after December 15, 2018 and interim periods within those annual periods. Early adoption is permitted for all entities. The Company anticipates adopting this guidance in the first quarter of 2019 and is currently assessing internal processes and analyzing its portfolio of contracts to assess the impact future adoption of this ASU will have on its consolidated financial statements.

Compensation – Stock Compensation. In June 2018, the FASB issued an ASU which supersedes existing guidance for equity-based payments to nonemployees and expands the scope of guidance for stock compensation to include all share-based payment arrangements related to the acquisition of goods and services from both nonemployees and employees. As a result, the same guidance that provides for employee share-based payments, including most of its requirements related to classification and measurement, applies to nonemployee share-based payment arrangements. The ASU is effective for financial statements issued for annual periods beginning after December 15, 2018 and interim periods within those annual periods. Early adoption is permitted. The Company anticipates adopting this guidance for the first quarter of 2019 and does not expect it to have a material impact on its consolidated financial statements.

Fair Value Measurement. In August 2018, the FASB issued an ASU which modifies disclosure requirements related to fair value measurement. The amendments in this ASU are effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2019. Implementation on a prospective or retrospective basis varies by specific disclosure requirement. Early adoption is permitted. The standard also allows for early adoption of any removed or modified disclosures upon issuance of this ASU while delaying adoption of the additional disclosures until their effective date. The Company is currently assessing the potential impact of this ASU to its consolidated financial statements.

Compensation-Retirement Benefits-Defined Benefit Plans-General. In August 2018, the FASB issued an ASU that modifies the disclosure requirements for employers that sponsor defined benefit pension or other postretirement plans. For public companies, the amendments in this ASU are effective for fiscal years beginning after December 15, 2020, with early adoption permitted, and is to be applied on a retrospective basis to all periods presented. The Company is currently assessing the potential impact of this ASU to its consolidated financial statements.

Note C – Revenue from Contracts with Customers

Significant Accounting Policy

Revenue is recognized when the Company satisfies a performance obligation by transferring control over a commodity to a customer; the amount of revenue recognized reflects the consideration expected in exchange for those commodities. The Company measures revenue based on consideration specified in a contract and excludes taxes and other amounts collected on behalf of third parties.

Revenue is presented as the Company's share net of certain costs associated with generation of Revenue. Examples of costs that reduce revenue include transportation, gathering, compression, and processing fees in U.S. and Canada, as well as certain required payments associated with production sharing contracts (PSCs) and export taxes in Malaysia.

Note C – Revenue from Contracts with Customers (Contd.)

Nature of Goods and Services

The Company explores for and produces crude oil, natural gas and natural gas liquids (collectively oil and gas) in select basins around the globe. The Company's revenue from sales of oil and gas production activities are primarily subdivided into three key geographic segments: the U.S., Canada, and Malaysia. Additionally, revenue from sales to customers is generated from three primary revenue streams: crude oil and condensate, natural gas liquids, and natural gas.

For operated oil and gas production where the non-operated working interest owner does not take-in-kind its proportionate interest in the produced commodity, the Company acts as an agent for the working interest owner and recognizes revenue only for its own share of the commingled production.

U.S.- In the United States, the Company primarily produces oil and gas from fields in the Eagle Ford Shale area of South Texas and in the Gulf of Mexico. Revenue is generally recognized when oil and gas are transferred to the customer at the delivery point. Revenue recognized is largely index based with price adjustments for floating market differentials.

Canada- Primarily all long-term contracts in Canada, except for certain natural gas physical forward sales fixed-price contracts, are floating commodity index priced. For the Onshore business in Canada, the recorded revenue is net of transportation and any gain or loss on spot purchases made to meet committed volumes on sales contracts for the month. For the Offshore business in Canada, contracts are based on index prices and revenue is recognized at the time of vessel load based on the volumes on the bill of lading and point of custody transfer.

Malaysia- In Malaysia, the Company has interests in nine separate PSCs. The Company serves as the operator of all these areas except for the unitized Gumusut-Kakap field. Crude oil contracts in Malaysia share similar features of largely fixed cargo quantities, variable index-based pricing, and potential discounts at the point of meeting the performance obligation when the vessel is loaded. Malaysia also has three long term Gas Sales Agreements (GSA) with terms until the end of the field life, economic life, or PSC term.

Disaggregation of Revenue

The Company reviews performance based on three key geographical segments and between onshore and offshore sources of Revenue within these geographies.

For the three months ended September 30, 2018 and 2017, the Company recognized $659.8 million and $511.2 million, respectively, from contracts with customers for the sales of oil, natural gas liquids and natural gas. For the nine months ended September 30, 2018 and 2017, the Company recognized $1,921.9 million and $1,498.1 million, respectively, from contracts with customers for the sales of oil, natural gas liquids and natural gas.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

Note C – Revenue from Contracts with Customers (Contd.)

	Three Months Ended September 30,		Nine Months Ended September 30,	
(Thousands of dollars)	2018	2017	2018	2017
Net crude oil and condensate revenue				
United States – Onshore	$ 224,714	143,527	606,186	437,504
– Offshore	93,206	43,658	259,128	145,139
Canada – Onshore	32,818	12,351	82,537	33,129
– Offshore	34,789	31,639	137,420	107,516
Malaysia – Sarawak	55,592	63,558	218,494	189,100
– Block K	102,149	122,460	298,330	287,032
Other	3,156	–	3,156	–
Total crude oil and condensate revenue	546,424	417,193	1,605,251	1,199,420
Net natural gas liquids revenue				
United States – Onshore	16,993	11,114	42,363	29,838
– Offshore	3,438	1,679	7,998	4,804
Canada – Onshore	4,137	1,323	11,053	2,636
Malaysia – Sarawak	4,960	4,985	15,153	13,526
Total natural gas liquids revenue	29,528	19,101	76,567	50,804
Net natural gas revenue				
United States – Onshore	6,872	6,031	19,934	21,072
– Offshore	3,306	2,541	9,068	7,922
Canada – Onshore	35,373	36,974	103,055	114,772
Malaysia – Sarawak	38,236	29,166	107,616	103,584
– Block K	67	186	419	519
Total natural gas revenue	83,854	74,898	240,092	247,869
Total revenue from contracts with customers	659,806	511,192	1,921,910	1,498,093
Gain (loss) on crude contracts	(2,223)	(13,573)	(69,349)	50,365
Other operating income	17,090	583	26,029	4,015
Gain on sale of assets	124	117	6	130,765
Total revenue	$ 674,797	498,319	1,878,596	1,683,238

Contract Balances and Asset Recognition

As of September 30, 2018, and December 31, 2017, receivables from contracts with customers, net of royalties and associated payables, on the balance sheet, were $187.3 million and $203.4 million, respectively. Payment terms for the Company’s sales vary across contracts and geographical regions, with the majority of the cash receipts required within 30 days of billing. Based on historical collections and ability of customers to pay, the Company did not recognize any impairment losses on receivables or contract assets arising from customer contracts during the reporting periods.

The Company has not entered into any upstream oil and gas sale contracts that have financing components as at September 30, 2018.

The Company does not employ sales incentive strategies such as commissions or bonuses for obtaining sales contracts. For the periods presented, the Company did not identify any assets to be recognized associated with the costs to obtain a contract with a customer.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

Note C – Revenue from Contracts with Customers (Contd.)

Performance Obligations

The Company recognizes oil and gas revenue when it satisfies a performance obligation by transferring control over a commodity to a customer. Judgment is required to determine whether some customers simultaneously receive and consume the benefit of commodities. As a result of this assessment for the Company, each unit of measure of the specified commodity is considered to represent a distinct performance obligation that is satisfied at a point in time upon the transfer of control of the commodity.

For contracts with market or index-based pricing, which represent the majority of sales contracts, the Company has elected the allocation exception and allocates the variable consideration to each single performance obligation in the contract. As a result, there is no price allocation to unsatisfied remaining performance obligations for delivery of commodity product in subsequent periods.

The Company has entered into several long-term, fixed-price contracts in Canada. The underlying reason for entering a fixed price contract is generally unrelated to anticipated future prices or other observable data and serves a particular purpose in the company's long-term strategy. The contractually stated price for each unit of commodity transferred under these contracts represents the stand-alone selling price of the commodity.

As at September 30, 2018, the Company had the following sales contracts in place which are expected to generate revenue from sales to customers for a period of 12 months or more starting at the inception of the contract:

Current Long-Term Contracts Outstanding at September 30, 2018

Location	Commodity	End Date	Description	Approximate Volumes
U.S. Onshore	Oil	Q2 2019	Fixed quantity delivery in Eagle Ford	4,000 BOE/Day
U.S. Onshore	Oil	Q3 2019	Fixed quantity delivery in Eagle Ford	2,000 BOE/Day
U.S. Onshore	Oil	Q4 2021	Fixed quantity delivery in Eagle Ford	2018: 19,000 BOE/Day 2019-2021: 13,000 BOE/Day
U.S. Onshore	Gas and NGL	Q2 2026	Deliveries from dedicated acreage in Eagle Ford	As produced
Canada Onshore	Gas	Q4 2020	Contracts to sell natural gas at Alberta AECO Cdn dollar 2.81/MCF	59 MMCF/Day
Canada Onshore	Gas	Q4 2020	Contracts to sell natural gas at USD Index pricing	60 MMCF/Day
Canada Onshore	Gas	Q4 2024	Contracts to sell natural gas at USD Index pricing	30 MMCF/Day
Canada Onshore	Gas	Q4 2026	Contracts to sell natural gas at USD Index	38 MMCF/Day

pricing

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

Note D – Property, Plant and Equipment

Exploratory Wells

Under FASB guidance exploratory well costs should continue to be capitalized when the well has found a sufficient quantity of reserves to justify its completion as a producing well and the Company is making sufficient progress assessing the reserves and the economic and operating viability of the project.

At September 30, 2018, the Company had total capitalized exploratory well costs pending the determination of proved reserves of $210.8 million. The following table reflects the net changes in capitalized exploratory well costs during the nine-month periods ended September 30, 2018 and 2017.

(Thousands of dollars)	2018	2017
Beginning balance at January 1	$ 175,640	148,500
Additions pending the determination of proved reserves	41,940	51,614
Reclassifications to proved properties based on the determination of proved reserves	(2,214)	(13,370)
Capitalized exploratory well costs charged to expense	(4,521)	(8,360)
Balance at September 30	$ 210,845	178,384

The capitalized well costs charged to expense during the first nine months of 2018 included the Julong East well in Block CA-1, offshore Brunei in which further development of the well has not been sanctioned by the operator and the contract term for development sanctions has now been reached. This well was originally drilled in 2012. The capitalized well costs charged to expense during the first nine months of 2017 included the Marakas-01 well in Block SK314A, offshore Malaysia, in which development of the well could not be justified due to noncommercial hydrocarbon quantities found.

The following table provides an aging of capitalized exploratory well costs based on the date the drilling was completed for each individual well and the number of projects for which exploratory well costs have been capitalized. The projects are aged based on the last well drilled in the project.

	September 30,					
	2018			2017		
(Thousands of dollars)	Amount	No. of Wells	No. of Projects	Amount	No. of Wells	No. of Projects
Aging of capitalized well costs:						
Zero to one year	$ 46,813	1	1	$ 41,609	3	2
One to two years	41,051	3	2	8,430	2	2
Two to three years	5,208	1	1	43,197	1	1
Three years or more	117,773	5	2	85,148	7	1
	$ 210,845	10	6	$ 178,384	13	6

Of the $164.0 million of exploratory well costs capitalized more than one year at September 30, 2018, $55.9 million is in Brunei, $59.8 million is in Vietnam, $27.4 million is in the U.S. and $20.9 million is in Malaysia. In all geographical areas, either further appraisal or development drilling is planned and/or development studies/plans are in various stages of completion.

Divestments

In January 2017, a Canadian subsidiary of the Company completed its disposition of the Seal field in Western Canada. Total cash consideration to Murphy upon closing of the transaction was approximately $48.8 million. Additionally, the buyer assumed the asset retirement obligation of approximately $85.9 million. A $132.4 million pretax gain was reported in the 2017 period related to the sale. Also, in 2017, a U.S. subsidiary of the Company completed its disposition of certain non-core properties in the Eagle Ford Shale area. Total cash consideration to Murphy upon closing of the transactions were approximately $19.6 million. There were no gains or losses recorded related to these non-core Eagle Ford Shale sales.

Note D – Property, Plant and Equipment (Contd.)

In 2016, a Canadian subsidiary of the Company completed a divestiture of natural gas processing and sales pipeline assets that support Murphy's Montney natural gas fields in the Tupper area of northeastern British Columbia. Total cash consideration received upon closing was $414.1 million. A gain on sale of approximately $187.0 million was deferred and is being recognized over approximately the next 18 years in the Canadian operating segment. The Company amortized approximately $5.7 million and $5.3 million of the deferred gain during the first nine months of 2018 and 2017, respectively. The remaining deferred gain of $171.3 million was included as a component of Deferred credits and other liabilities in the Company's Consolidated Balance Sheet as of September 30, 2018.

Acquisitions

In 2016, a Canadian subsidiary of Murphy Oil acquired a 70% operated working interest (WI) in Athabasca Oil Corporation's (Athabasca) production, acreage, infrastructure and facilities in the Kaybob Duvernay lands, and a 30% non-operated WI in Athabasca's production, acreage, infrastructure and facilities in the liquids rich Placid Montney lands in Alberta, the majority of which was unproved. Under the terms of the joint venture, the total consideration amounts to approximately $375.0 million of which Murphy paid $206.7 million in cash at closing, subject to normal closing adjustments, and an additional $168.0 million in the form of a carried interest on the Kaybob Duvernay property. As of September 30, 2018, $93.1 million of the carried interest had been paid. The carry is to be paid over a period through 2019.

Other

In 2006, the Kakap field in Block K was unitized with the Gumusut field in an adjacent block under a Unitization and Unit Operating Agreement (UUOA) between the operators. The Gumusut-Kakap Unit is operated by another company. In the fourth quarter 2016, the operators completed the first redetermination process for a revision to the blocks' tract participation interest, and the operator of the unitized field sought the approval of Petronas to effect the change in 2017. In 2016, the Company recorded an estimated redetermination expense of $39.1 million ($24.1 million after tax) related to an expected revision in the Company's working interest covering the period from inception through year-end 2016 at Kakap. In February 2017, the Company received Petronas' official approval to the redetermination change that reduced the Company's working interest in oil operations to 6.67% effective at April 1, 2017. Working interest redeterminations are required at different points within the life of the unitized field. Following a partial payment, the remaining redetermination liability of $17.3 million was included as a component of Other current liabilities in the Company's Consolidated Balance Sheet as of September 30, 2018.

Following a further Unitization Framework Agreement (UFA) between the governments of Brunei and Malaysia, the Company now has a 6.37% interest in the Kakap field in Block K Malaysia. The UFA unitized the Gumusut-Kakap (GK) and Geronggong/Jagus East fields effective November 23, 2017. In the fourth quarter 2017, the Company recorded an estimated redetermination liability of $15.0 million related to Company's revised working interest, which was included as a component of Other current liabilities in the Company's Consolidated Balance Sheet as of September 30, 2018.

Note E – Discontinued Operations and Assets Held for Sale

The Company has accounted for its former U.K. and U.S. refining and marketing operations as discontinued operations for all periods presented. The results of operations associated with discontinued operations for the three-month and nine-month periods ended September 30, 2018 and 2017 were as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(Thousands of dollars)	2018	2017	2018	2017
Revenues	$ –	598	6	853
Income (loss) before income taxes	(1,815)	425	(2,650)	1,177
Income tax benefit	–	–	–	–
Income (loss) from discontinued operations	$ (1,815)	425	(2,650)	1,177

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

Note E – Discontinued Operations and Assets Held for Sale (Contd.)

The following table presents the carrying value of the major categories of assets and liabilities of U.K. refining and marketing operations reflected as held for sale on the Company's Consolidated Balance Sheets at September 30, 2018 and December 31, 2017.

(Thousands of dollars)		September 30, 2018	December 31, 2017
Current assets			
Cash	$	17,409	16,631
Accounts receivable		3,731	6,298
Total current assets held for sale	$	21,140	22,929
Current liabilities			
Accounts payable	$	143	837
Refinery decommissioning cost		2,659	2,693
Total current liabilities associated with assets held for sale	$	2,802	3,530

Note F – Financing Arrangements and Debt

At September 30, 2018, the Company had a $1.1 billion senior unsecured guaranteed credit facility (2016 facility) with a major banking consortium, which expires in August 2021. At September 30, 2018, the Company had no outstanding borrowings under the 2016 facility, however, there were $28.0 million of outstanding letters of credit, which reduce the borrowing capacity of the 2016 facility. Advances under the 2016 facility will accrue interest based, at the Company's option, on either the London Interbank Offered rate plus an applicable margin (Eurodollar rate) or the alternate base rate (as defined in the 2016 facility agreement) plus an applicable margin. Had there been any amounts borrowed under the 2016 facility at September 30, 2018, the applicable base interest rate would have been 5.0625%. At September 30, 2018, the Company was in compliance with all covenants related to the 2016 facility.

The Company and its partners are parties to a 25-year lease of production equipment at the Kakap field offshore Malaysia. The lease has been accounted for as a capital lease, and payments under the agreement are to be made over a 15-year period through March 2029. Current maturities of long-term debt and long-term debt on the Consolidated Balance Sheet included $10.5 million and $128.5 million, respectively, associated with this lease at September 30, 2018.

Note G – Other Financial Information

Additional disclosures regarding cash flow activities are provided below.

(Thousands of dollars)	Nine Months Ended September 30, 2018	2017
Net (increase) decrease in operating working capital other than cash and cash equivalents:		
(Increase) decrease in accounts receivable	$ (31,178)	90,614
Decrease in inventories	16,732	5,869
(Increase) decrease in prepaid expenses	(8,695)	25,285
Increase (decrease) in accounts payable and accrued liabilities	17,946	(115,977)
Increase(decrease) in income taxes payable	2,645	(4,721)
Net (increase) decrease in noncash operating working capital	$ (2,550)	1,070
Supplementary disclosures:		
Cash income taxes paid, net of refunds	$ 77,508	25,118
Interest paid, net of amounts capitalized of $3,719 in 2018 and $3,338 in 2017	115,009	95,899
Non-cash investing activities:		
Asset retirement costs capitalized	$ 2,907	38,992
(Increase) decrease in capital expenditure accrual	(751)	42,403

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

Note H – Employee and Retiree Benefit Plans

The Company has defined benefit pension plans that are principally noncontributory and cover most North American full-time employees. All pension plans are funded except for the U.S. nonqualified supplemental plan. All U.S. tax qualified plans meet the funding requirements of federal laws and regulations. Contributions to foreign plans are based on local laws and tax regulations. The Company also sponsors health care and life insurance benefit plans, which are not funded, that cover most active and retired U.S. employees. The health care benefits are contributory; the life insurance benefits are noncontributory.

The table that follows provides the components of net periodic benefit expense for the three-month and nine-month periods ended September 30, 2018 and 2017.

	Three Months Ended September 30,			
	Pension Benefits		Other Postretirement Benefits	
(Thousands of dollars)	2018	2017	2018	2017
Service cost	$ 2,252	2,037	492	427
Interest cost	6,716	7,261	874	966
Expected return on plan assets	(7,476)	(8,070)	–	–
Amortization of prior service cost (credit)	254	259	(10)	(18)
Recognized actuarial loss	5,197	3,610	–	–
Net periodic benefit expense	$ 6,943	5,097	1,356	1,375

	Nine Months Ended September 30,			
	Pension Benefits		Other Postretirement Benefits	
(Thousands of dollars)	2018	2017	2018	2017
Service cost	$ 6,761	6,099	1,479	1,276
Interest cost	20,160	20,267	2,622	2,899
Expected return on plan assets	(22,435)	(21,730)	–	–
Amortization of prior service cost (credit)	767	767	(29)	(55)
Recognized actuarial loss	15,593	10,673	–	–
Net periodic benefit expense	$ 20,846	16,076	4,072	4,120

The components of net periodic benefit expense other than the service cost component are included in the line item "Interest and other income (loss)" in Consolidated Statements of Operations.

During the nine-month period ended September 30, 2018, the Company made contributions of $22.2 million to its defined benefit pension and postretirement benefit plans. Remaining funding in 2018 for the Company's defined benefit pension and postretirement plans is anticipated to be $7.6 million.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

Note I – Incentive Plans

The costs resulting from all share-based and cash-based incentive plans payment transactions are recognized as an expense in the Consolidated Statements of Operations using a fair value-based measurement method over the periods that the awards vest.

The 2017 Annual Incentive Plan (2017 Annual Plan) authorizes the Executive Compensation Committee (the Committee) to establish specific performance goals associated with annual cash awards that may be earned by officers, executives and certain other employees. Cash awards under the 2017 Annual Plan are determined based on the Company's actual financial and operating results as measured against the performance goals established by the Committee.

The 2012 Long-Term Incentive Plan (2012 Long-Term Plan) authorizes the Committee to make grants of the Company's Common Stock to employees. These grants may be in the form of stock options (nonqualified or incentive), stock appreciation rights (SAR), restricted stock, restricted stock units (RSU), performance units, performance shares, dividend equivalents and other stock-based incentives. The 2012 Long-Term Plan expires in 2022. A total of 8,700,000 shares are issuable during the life of the 2012 Long-Term Plan, with annual grants limited to 1% of Common shares outstanding; allowed shares not granted in an earlier year may be granted in future years.

The Company also had a 2013 Stock Plan for Non-Employee Directors (Director Plan) that permitted the issuance of restricted stock, restricted stock units and stock options or a combination thereof to the Company's Non-Employee Directors. This plan expired in May 2018.

At the Annual Shareholder Meeting held in May 2018, shareholders approved the 2018 Stock Plan for Non-Employee Directors and the 2018 Long-Term Incentive Plan. Following this approval, no further awards will be granted under the 2012 Long-Term Plan.

In the first quarter of 2018, the Committee granted 905,500 performance-based RSUs and 736,000 time-based RSUs to certain employees. The fair value of the performance-based RSUs, using a Monte Carlo valuation model, ranged from $28.27 to $30.56 per unit. The fair value of the time-based RSUs was estimated based on the fair market value of the Company's stock on the date of grant. The fair value of the time-based RSUs granted February 6, 2018 was $28.42 per unit, the fair value of the time-based RSUs granted February 20, 2018 was $26.56 per unit, and the fair value of the time-based RSUs granted March 1, 2018 was $25.69 per unit. Additionally, on February 6, 2018 the Committee granted 715,100 cash-settled RSUs (RSUC) to certain employees, and on March 9, 2018 granted 29,000 RSUCs to certain employees. The RSUC are to be settled in cash, net of applicable income taxes, and are accounted for as liability-type awards. The initial fair value of the RSUCs was equivalent to the equity-settled restricted stock units granted. Also in February, the Committee granted 77,803 shares of time-based RSUs to the Company's Directors under the Non-Employee Director Plan. These units are scheduled to vest on the third anniversary of the date of grant. The estimated fair value of these awards was $28.28 per unit on date of grant.

All stock option exercises are non-cash transactions for the Company. The employee receives net shares, after applicable withholding taxes, upon each stock option exercise. The actual income tax benefit realized from the tax deductions related to stock option exercises of the share-based payment arrangements were immaterial for the nine-month period ended September 30, 2018.

Amounts recognized in the financial statements with respect to share-based plans are shown in the following table:

	Nine Months Ended September 30,	
(Thousands of dollars)	2018	2017
Compensation charged against income before tax benefit	$ 36,348	28,264
Related income tax benefit recognized in income	5,532	8,695

Certain incentive compensation granted to the Company’s named executive officers, to the extent their total compensation exceeds $1.0 million per executive per year, is not eligible for a U.S. income tax deduction under the Tax Cuts and Jobs Act (2017 Tax Act).

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

Note J – Earnings per Share

Net income was used as the numerator in computing both basic and diluted income per Common share for the three-month and nine-month periods ended September 30, 2018 and 2017. The following table reconciles the weighted-average shares outstanding used for these computations.

	Three Months Ended September 30,		Nine Months Ended September 30,	
(Weighted-average shares)	2018	2017	2018	2017
Basic method	173,047,246	172,572,873	172,949,450	172,509,418
Dilutive stock options and restricted stock units	1,128,021	– [1]	1,252,310	– [1]
Diluted method	174,175,267	172,572,873	174,201,760	172,509,418

1Due to a net loss in the three-month and nine-month periods ended September 30, 2017, no unvested stock awards were included in the computation of diluted earnings per shares because the effect would have been anti-dilutive.

The following table reflects certain options to purchase shares of common stock that were outstanding during the periods presented but were not included in the computation of diluted shares above because the incremental shares from assumed conversion were antidilutive.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
Antidilutive stock options excluded from diluted shares	2,870,549	5,257,718	3,544,087	5,578,495
Weighted average price of these options	$ 54.06	$ 46.46	$ 50.49	$ 46.86

Note K – Income Taxes

The Company’s effective income tax rate is calculated as the amount of income tax expense (benefit) divided by income from continuing operations before income taxes. For the three-month and nine-month periods ended September 30, 2018 and 2017, the Company’s effective income tax rates were as follows:

	2018	2017
Three months ended September 30	34.8%	(4.3%)

Nine months ended September 30	4.8%	137.7%

The effective tax rates for most periods where earnings are generated, generally exceed the U.S. statutory tax rate (21% in 2018, 35% in 2017) due to several factors, including: the effects of income generated in foreign tax jurisdictions, certain of which have income tax rates that are higher than the U.S. Federal rate; U.S. state tax expense; and certain expenses, including exploration expenses, in certain foreign jurisdictions, for which no income tax benefits are available or are not presently being recorded due to a lack of reasonable certainty of adequate future revenue against which to utilize these expenses as deductions. Conversely, the effective tax rates for most periods where losses are incurred generally are lower than U.S. statutory tax rate of 21% due to similar reasons.

Due to uncertainty related to language in Section 965(n) of the 2017 Tax Act, and specifically whether current operating losses from 2017 were required to be applied to offset a company's deemed taxable repatriation of foreign earnings under the 2017 Tax Act, the Company's provisional tax expense recorded in the Company's December 31, 2017 financial statements reflected use of all the estimated 2017 tax operating loss against the deemed repatriation. This resulted in no loss carryover of 2017 tax operating losses from 2017 into 2018, and foreign tax credits of $228.2 million were fully provided for in the Company's December 31, 2017 financial statements. On April 2, 2018, the Internal Revenue Service issued new guidance related to Section 965(n). This guidance resolved an ambiguity related to an election which allowed the Company to preserve the 2017 tax net operating loss as a carryforward which resulted in utilizing the previously unused foreign tax credits against all but $36 million of current income tax on the deemed repatriation of foreign earnings. The preservation of the tax loss carryforward reduced the deferred tax expense for the first quarter of 2018 and year to date by $156 million and resulted in a $36 million charge to taxes payable relating to the deemed inclusion. The Company anticipates paying this $36 million tax payable over eight years as permitted by the 2017 Tax Act.

Note K – Income Taxes (Contd.)

The effective tax rate for the three-month period ended September 30, 2018 was above the U.S. statutory tax rate of 21% primarily due to higher tax rates in certain foreign tax jurisdictions combined with expenses in foreign jurisdictions not fully deductible from income at the U.S. statutory rate. The effective tax rate for the three-month period ended September 30, 2017 was below the U.S. statutory tax rate primarily due to the tax effect of expenses in foreign jurisdictions not being fully deductible from losses at the U.S. statutory tax rate, an estimated U.S tax charge for undistributed foreign earnings and Canadian foreign exchange losses not fully deductible at 35%. The 2017 period income before tax was a loss.

The effective tax rate for the nine-month period ended September 30, 2018 was below the U.S. statutory tax rate of 21% primarily due to the discrete tax effect of the new guidance relating to Section 965(n), offset by higher tax rates in certain foreign tax jurisdictions and expenses in foreign jurisdictions not fully deductible from income at the U.S. statutory tax rate. The effective tax rate for the nine-month period ended September 30, 2017 was above the U.S. statutory tax rate primarily due to an estimated U.S. tax charge recognized for undistributed foreign earnings and Canadian foreign exchange losses not fully deductible at the statutory rate. During the first nine-months of 2017, the Company determined that prospective earnings from its Malaysian and Canadian subsidiaries will not be considered reinvested into local operations and recorded a deferred tax charge of $65.2 million associated with the estimated tax consequence of future repatriation of Malaysian and Canadian earnings that were deemed no longer indefinitely invested.

The Company’s tax returns in multiple jurisdictions are subject to audit by taxing authorities. These audits often take multiple years to complete and settle. Although the Company believes that recorded liabilities for unsettled issues are adequate, additional gains or losses could occur in future years from resolution of outstanding unsettled matters. As of September 30, 2018, the earliest years remaining open for audit and/or settlement in our major taxing jurisdictions are as follows: United States – 2015; Canada – 2012; Malaysia – 2011; and United Kingdom – 2016.

Note L – Financial Instruments and Risk Management

Murphy often uses derivative instruments to manage certain risks related to commodity prices, foreign currency exchange rates and interest rates. The use of derivative instruments for risk management is covered by operating policies and is closely monitored by the Company’s senior management. The Company reports gains and losses on derivative instruments in the Corporate segment. The Company does not hold any derivatives for speculative purposes and it does not use derivatives with leveraged or complex features. Derivative instruments are traded primarily with creditworthy major financial institutions or over national exchanges, such as the New York Mercantile Exchange (NYMEX). The Company has a risk management control system to monitor commodity price risks and any derivatives obtained to manage a portion of such risks. For accounting purposes, the Company has not designated commodity and foreign currency derivative contracts as hedges, and therefore, it recognizes all gains and losses on these derivative contracts in its Consolidated Statements of Operations. Certain interest rate derivative contracts were accounted for as hedges and the gain or loss associated with recording the fair value of these contracts was deferred in Accumulated other comprehensive loss until the anticipated transactions occur. This deferred cost is being reclassified to Interest expense, net in the Consolidated Statements of Operations over the period until the associated notes mature in 2022.

Commodity Price Risks

The Company is subject to commodity price risk related to crude oil it produces and sells. During the first nine months of 2018 and 2017, the Company had West Texas Intermediate (WTI) crude oil swap financial contracts to economically hedge a portion of its United States production. Under these contracts, which matured monthly, the Company paid the average monthly price in effect and received the fixed contract prices. At September 30, 2018, the Company had 21,000 barrels per day in WTI crude oil swap financial contracts maturing ratably during the remainder of 2018 at an average price of $54.88.

At September 30, 2017, the Company had 22,000 barrels per day in WTI crude oil swap financial contracts maturing ratably during 2017 and 6,000 barrels per days in WTI crude oil swap financial contracts maturing ratably during 2018.

Foreign Currency Exchange Risks

The Company is subject to foreign currency exchange risk associated with operations in countries outside the U.S. The Company had no foreign currency exchange short-term derivatives outstanding at September 30, 2018 and 2017.

At September 30, 2018 and December 31, 2017, the fair value of derivative instruments not designated as hedging instruments are presented in the following table.

	September 30, 2018		December 31, 2017	
(Thousands of dollars)	Asset (Liability) Derivatives		Asset (Liability) Derivatives	
Type of Derivative Contract	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Commodity	Accounts payable	$ (44,601)	Accounts payable	$ (39,093)

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

Note L – Financial Instruments and Risk Management (Contd.)

For the three-month and nine-month periods ended September 30, 2018 and 2017, the gains and losses recognized in the Consolidated Statements of Operations for derivative instruments not designated as hedging instruments are presented in the following table.

		Gain (Loss)				
		Three Months Ended			Nine Months Ended	
(Thousands of dollars)		September 30,			September 30,	
Type of Derivative Contract	Statement of Operations Location		2018	2017	2018	2017
Commodity	Gain (loss) on crude contracts	$	(2,223)	(13,573)	(69,349)	50,365
Foreign exchange	Interest and other income (loss)		–	–	–	73
		$	(2,223)	(13,573)	(69,349)	50,438

Interest Rate Risks

Under hedge accounting rules, the Company deferred the net cost associated with derivative contracts purchased to manage interest rate risk associated with 10-year notes sold in May 2012 to match the payment of interest on these notes through 2022. During each of the nine-month periods ended September 30, 2018 and 2017, $2.2 million of the deferred loss on the interest rate swaps was charged to Interest expense in the Consolidated Statement of Operations. The remaining loss (net of tax) deferred on these matured contracts at September 30, 2018 was $8.5 million, which is recorded, net of income taxes of $2.3 million, in Accumulated other comprehensive loss in the Consolidated Balance Sheet. The Company expects to charge approximately $0.7 million of this deferred loss to Interest expense, net in the Consolidated Statement of Operations during the remaining three months of 2018.

Fair Values – Recurring

The Company carries certain assets and liabilities at fair value in its Consolidated Balance Sheets. The fair value hierarchy is based on the quality of inputs used to measure fair value, with Level 1 being the highest quality and Level 3 being the lowest quality. Level 1 inputs are quoted prices in active markets for identical assets or liabilities. Level 2 inputs are observable inputs other than quoted prices included within Level 1. Level 3 inputs are unobservable inputs which reflect assumptions about pricing by market participants.

The carrying value of assets and liabilities recorded at fair value on a recurring basis at September 30, 2018 and December 31, 2017 are presented in the following table.

September 30, 2018	December 31, 2017

(Thousands of dollars)	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Liabilities:								
Nonqualified employee savings plans	$ 15,957	–	–	15,957	16,158	–	–	16,158
Commodity derivative contracts	–	44,601	–	44,601	–	39,093	–	39,093
	$ 15,957	44,601	–	60,558	16,158	39,093	–	55,251

The fair value of WTI crude oil derivative contracts in 2018 and 2017 was based on active market quotes for WTI crude oil. The fair value of foreign exchange derivative contracts in each year was based on market quotes for similar contracts at the balance sheet dates. The income effect of changes in the fair value of crude oil derivative contracts is recorded in Gain (loss) on crude contracts in the Consolidated Statements of Operations, while the effects of changes in fair value of foreign exchange derivative contracts is recorded in Interest and other income. The nonqualified employee savings plan is an unfunded savings plan through which participants seek a return via phantom investments in equity securities and/or mutual funds. The fair value of this liability was based on quoted prices for these equity securities and mutual funds. The income effect of changes in the fair value of the nonqualified employee savings plan is recorded in Selling and general expenses in the Consolidated Statements of Operations.

The Company offsets certain assets and liabilities related to derivative contracts when the legal right of offset exists. There were no offsetting positions recorded at September 30, 2018 and December 31, 2017.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

Note M – Accumulated Other Comprehensive Loss

The components of Accumulated other comprehensive loss on the Consolidated Balance Sheets at December 31, 2017 and September 30, 2018 and the changes during the nine-month period ended September 30, 2018 are presented net of taxes in the following table.

(Thousands of dollars)		Foreign Currency Translation Gains (Losses)	Retirement and Postretirement Benefit Plan Adjustments	Deferred Loss on Interest Rate Derivative Hedges	Total
Balance at December 31, 2017	$	(274,830)	(178,987)	(8,426)	(462,243)
2018 components of other comprehensive income (loss):					
Before reclassifications to income and retained earnings		(53,805)	(32,159)	(1,815)	(87,779)
Reclassifications to income		–	10,498[1]	1,756[2]	12,254
Net other comprehensive loss		(53,805)	(21,661)	(59)	(75,525)
Balance at September 30, 2018	$	(328,635)	(200,648)	(8,485)	(537,768)

[1]Reclassifications before taxes of $13,111 are included in the computation of net periodic benefit expense for the nine-month period ended September 30, 2018. See Note H for additional information. Related income taxes of $2,613 are included in Income tax expense (benefit) for the nine-month period ended September 30, 2018.

[2]Reclassifications before taxes of $2,222 are included in Interest expense, net, for the nine-month period ended September 30, 2018. Related income taxes of $466 are included in Income tax expense (benefit) for the nine-month period ended September 30, 2018. See Note L for additional information.

Note N – Environmental and Other Contingencies

The Company's operations and earnings have been and may be affected by various forms of governmental action both in the United States and throughout the world. Examples of such governmental action include, but are by no means limited to: tax legislation changes, including tax rate changes and retroactive tax claims; royalty and revenue sharing changes; import and export controls; price controls; currency controls; allocation of supplies of crude oil and petroleum products and other goods; expropriation of property; restrictions and preferences affecting the issuance of oil and gas or mineral leases; restrictions on drilling and/or production; laws and regulations intended for the promotion of safety and the protection and/or remediation of the environment; governmental support for other forms of energy; and laws and regulations affecting the Company's relationships with employees, suppliers, customers, stockholders and others. Governmental actions are often motivated by political considerations and may be taken without full consideration of their consequences or may be taken in response to actions of other governments. It is not practical to attempt to predict the likelihood of such actions, the form the actions may take or the effect such actions may have on the Company.

Murphy and other companies in the oil and gas industry are subject to numerous federal, state, local and foreign laws and regulations dealing with the environment. Violation of federal or state environmental laws, regulations and permits can result in the imposition of significant civil and criminal penalties, injunctions and construction bans or delays. A discharge of hazardous substances into the environment could, to the extent such event is not insured, subject the Company to substantial expense, including both the cost to comply with applicable regulations and claims by neighboring landowners and other third parties for any personal injury and property damage that might result.

Note N – Environmental and Other Contingencies (Contd.)

The Company currently owns or leases, and has in the past owned or leased, properties at which hazardous substances have been or are being handled. Although the Company has used operating and disposal practices that were standard in the industry at the time, hazardous substances may have been disposed of or released on or under the properties owned or leased by the Company or on or under other locations where these wastes have been taken for disposal. In addition, many of these properties have been operated by third parties whose treatment and disposal or release of hydrocarbons or other wastes were not under Murphy's control. Under existing laws the Company could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators), to clean up contaminated property (including contaminated groundwater) or to perform remedial plugging operations to prevent future contamination. Certain of these historical properties are in various stages of negotiation, investigation, and/or cleanup and the Company is investigating the extent of any such liability and the availability of applicable defenses. The Company has retained certain liabilities related to environmental matters at formerly owned U.S. refineries that were sold in 2011. The Company also obtained insurance covering certain levels of environmental exposures related to past operations of these refineries. The Company has not retained any environmental exposure associated with Murphy's former U.S. marketing operations. The Company believes costs related to these sites will not have a material adverse effect on Murphy's net income, financial condition or liquidity in a future period.

In early 2015, the Company's subsidiary in Canada identified a leak or leaks at an infield condensate transfer pipeline at the Seal field in a remote area of Alberta. The pipeline was immediately shut down and the Company's emergency response plan was activated. In cooperation with local governmental regulators, and with the assistance of qualified consultants, an investigation and remediation plan is progressing as planned and the Company's insurers were notified. Based on the assessments done, the Company recorded $43.9 million in Other expense during 2015 and a further $3.8 million in the first quarter of 2018 associated with the estimated costs of remediating the site. The Company has spent $43.1 million from inception to September 30, 2018. Further refinements in the estimated total cost to remediate the site are anticipated in future periods. It is possible that the ultimate net remediation costs to the Company associated with the condensate leak or leaks will exceed the amount of liability recorded. The Company retained the responsibility for this remediation upon sale of the Seal field in the first quarter of 2017. As of September 30, 2018, the Company has a remaining accrued liability of $4.7 million associated with this event. In the first nine months of 2018, the Company received $25.0 million in respect to an insurance claim regarding this matter and the outcome of further insurance claims by the Company is pending.

There is the possibility that environmental expenditures could be required at currently unidentified sites, and new or revised regulations could require additional expenditures at known sites. However, based on information currently available to the Company, the amount of future remediation costs incurred at known or currently unidentified sites is not expected to have a material adverse effect on the Company's future net income, cash flows or liquidity.

Murphy and its subsidiaries are engaged in a number of other legal proceedings, all of which Murphy considers routine and incidental to its business. Based on information currently available to the Company, the ultimate resolution of environmental and legal matters referred to in this note is not expected to have a material adverse effect on the Company's net income, financial condition or liquidity in a future period.

Note O – Commitments

The Company has entered into forward sales contracts to mitigate the price risk for a portion of its 2018 to 2020 natural gas sales volumes in Western Canada. During the period from October 2018 through December 2020 the natural gas sales contracts call for deliveries of 59 million cubic feet per day at Cdn $2.81 per MCF. These natural gas contracts have been accounted for as normal sales for accounting purposes.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

Note P – Business Segments

Information about business segments and geographic operations is reported in the following tables. For geographic purposes, revenues are attributed to the country in which the sale occurs. Corporate, including interest income, other gains and losses (including foreign exchange gains/losses and realized/unrealized gains/losses on crude oil contracts), interest expense and unallocated overhead, is shown in the tables to reconcile the business segments to consolidated totals. Certain reclassifications have been made to 2017 Exploration and production and Corporate External Revenues and Income (Loss) to align with current period presentation.

		Three Months Ended September 30, 2018		Three Months Ended September 30, 2017	
(Millions of dollars)	Total Assets at September 30, 2018	External Revenues	Income (Loss)	External Revenues	Income (Loss)
Exploration and production 1					
United States	$ 4,772.2	348.7	91.6	209.4	(11.2)
Canada	1,790.3	107.1	12.5	81.9	(3.2)
Malaysia	1,604.7	201.2	54.1	220.5	67.7
Other	183.4	19.9	1.3	–	(11.0)
Total exploration and production	8,350.6	676.9	159.5	511.8	42.3
Corporate 3	1,654.9	(2.1)	(63.8)	(13.5)	(108.6)
Assets/revenue/income from continuing operations	10,005.5	674.8	95.7	498.3	(66.3)
Discontinued operations, net of tax	21.1	–	(1.8)	–	0.4
Total	$ 10,026.6	674.8	93.9	498.3	(65.9)

	Nine Months Ended September 30, 2018		Nine Months Ended September 30, 2017	
(Millions of dollars)	External Revenues	Income (Loss)	External Revenues	Income (Loss)
Exploration and production 1				
United States	$ 945.6	200.3	646.3	(21.8)
Canada 2	333.8	46.7	388.1	102.6
Malaysia	640.7	208.4	594.4	173.9
Other	19.9	(28.8)	–	(10.9)
Total exploration and production	1,940.0	426.6	1,628.8	243.8
Corporate 3	(61.4)	(116.2)	54.4	(270.0)
Revenue/loss from continuing operations	1,878.6	310.4	1,683.2	(26.2)
Discontinued operations, net of tax	–	(2.7)	–	1.2
Total	$ 1,878.6	307.7	1,683.2	(25.0)

1 Additional details about results of oil and gas operations are presented in the tables on pages 30 and 31.

2 Revenue for the nine months ended September 30, 2017 includes a pretax gain of $132.4 million related to the sale of Seal heavy oil assets in Canada.

3 In 2018, the Company reported realized and unrealized gains and losses on crude oil contracts in the Corporate segment (previously reported in the Exploration and production business) to reflect how segments are currently evaluated, how resources are allocated and how risk is managed by the Company. The 2017 amounts have been reclassified to reflect comparable disclosure.

Note Q – Subsequent Event

On October 10, 2018, the Company announced that its wholly owned subsidiary, Murphy Exploration & Production Company – USA, had entered into a definitive agreement to form a new joint venture company with Petrobras America Inc. (PAI), a subsidiary of Petrobras. The joint venture company will be comprised of Gulf of Mexico producing assets from Murphy and PAI with Murphy overseeing the operations. The transaction will have an effective date of October 1, 2018 and is expected to close by year-end 2018.

Both companies will contribute all their current producing Gulf of Mexico assets to the joint venture, which will be owned 80 percent by Murphy and 20 percent by PAI. The transaction excludes exploration blocks from both companies, with the exception of PAI's blocks that hold deep exploration rights. Murphy will pay cash consideration of $900 million to PAI, subject to normal closing adjustments. Additionally, PAI will earn an additional contingent consideration up to $150 million if certain price and production thresholds are exceeded beginning in 2019 through 2025. Also, Murphy will carry $50 million of PAI costs in the St. Malo Field if certain enhanced oil recovery projects are undertaken. Upon closing, Murphy expects to fund the transaction through a combination of cash-on-hand and the Company's 2016 facility (See Note F).

In conjunction with the joint venture, on October 10, 2018, the company entered into an amendment of its existing Credit Agreement. The amendment, once effective will provide selected covenant relief and add financial flexibility. The amended credit facility will be effective upon the closing of the joint venture transaction. The key terms of the amendment include eliminating the "collateral trigger event" clause (springing collateral, and "minimum domestic liquidity requirements" as defined in the Credit Agreement) and allows Company to execute the transaction, including contributing assets to the joint venture company.

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS

Overall Review

For the three months ended September 30, 2018, the Company produced 169 thousand barrels of oil equivalent per day. The Company invested $292 million in capital expenditures, on a value of work done basis, in the third quarter of 2018 primarily in the United States and Canada. The Company reported net income of $93.9 million for the three months ended September 30, 2018.

In the first nine months of 2018, the Company produced 169 thousand barrels of oil equivalent per day. The Company invested $893 million in capital expenditures, on a value of work done basis, in 2018 primarily in the United States and Canada. The Company reported net income of $307.7 million for the nine months ended September 30, 2018, which included an income tax gain of $120.0 million as a result of a 2018 Internal Revenue Service (IRS) interpretation of the 2017 Tax Act enacted in the fourth quarter of 2017.

During the three-month and nine-month periods ended September 30, 2018, worldwide benchmark oil prices were above average comparable benchmark prices during 2017. U.S. natural gas prices remained stable in the 2018 periods versus 2017 while Canadian prices were lower in 2018 than 2017. For the year to date, Crude oil and condensate volumes were relatively unchanged and natural gas sales volumes were higher principally as a result of growth in Canada. For the quarter, both crude oil and condensate and gas volumes were higher. In the year-to-date period, the gains from price and volume were partially offset by higher lease operating expense in the Gulf of Mexico and Canada Onshore businesses.

During the third quarter of 2018, the Company recorded Ecuador arbitration settlement income ($26.0 million), Seal insurance income ($10 million), Brunei working interest income ($16.0 million), and recorded an additional provision related to the Gumusut-Kakap field redetermination/unitization ($11.3 million).

The results are explained in more detail below.

Results of Operations

Murphy’s income (loss) by type of business is presented below.

	Income (Loss) Three Months Ended September 30,		Nine Months Ended September 30,	
(Millions of dollars)	2018	2017	2018	2017
Exploration and production	$ 159.5	42.3	426.6	243.8
Corporate and other	(63.8)	(108.6)	(116.2)	(270.0)
Income (loss) from continuing operations	95.7	(66.3)	310.4	(26.2)
Discontinued operations	(1.8)	0.4	(2.7)	1.2
Net income (loss)	$ 93.9	(65.9)	307.7	(25.0)

Exploration and Production

Results of E&P continuing operations are presented by geographic segment below.

	Income (Loss)				
	Three Months Ended		Nine Months Ended		
	September 30,		September 30,		
(Millions of dollars)	2018		2017	2018	2017
Exploration and production					
United States	$	91.6	(11.2)	200.3	(21.8)
Canada		12.5	(3.2)	46.7	102.6
Malaysia		54.1	67.7	208.4	173.9
Other International		1.3	(11.0)	(28.8)	(10.9)
Total	$	159.5	42.3	426.6	243.8

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ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS (Contd.)

Results of Operations (Contd.)

Third quarter 2018 vs. 2017

United States E&P operations reported earnings of $91.6 million in the third quarter of 2018 compared to a loss of $11.2 million in the third quarter of 2017. Results were $102.8 million favorable in the 2018 quarter compared to the 2017 period due to higher revenues ($139.3 million), lower exploration charges ($11.6 million), and lower G&A ($0.8 million), partially offset by higher lease operating expenses, depreciation, depletion and amortization, severance and income taxes ($46.8 million). Higher revenues were primarily due to higher realized prices and higher volumes at Kodiak in the U.S. Gulf of Mexico and at Eagle Ford Shale. Lower exploration charges were due to lower lease amortization. Higher lease operating expenses and depreciation expense was due primarily to higher volumes.

Canadian E&P operations reported earnings of $12.5 million in the third quarter 2018 compared to a loss of $3.2 million in the 2017 quarter. Results were favorable $15.7 million compared to the 2017 period due to higher revenue ($25.2 million) and Seal insurance proceeds ($9.6 million), partially offset by higher lease operating expense ($2.8 million), higher depreciation ($12.7 million) and higher income taxes. Higher revenues were a result of both higher volumes at the Tupper, Kaybob and Placid assets and higher realized crude prices. The Seal insurance proceeds related to cash received in relation to the spill at the now divested Seal asset. Higher lease operating expenses and depreciation are a result of higher volumes sold at Tupper, Kaybob and Placid.

Malaysia E&P operations reported earnings of $54.1 million in the third quarter of 2018 and compared to earnings of $67.7 million in the comparable 2017 period. Results were unfavorable by $13.6 million due to lower revenues ($19.3 million), higher lease operating expenses ($8.8 million) and redetermination/unitization expense ($11.3 million), partially off-set by lower depreciation ($19.4 million) and lower taxes ($7.3 million). Lower revenues are principally due to timing of volumes sold. Higher lease operating expenses are due to additional platform, onshore facilities and sub-sea maintenance at the Sarawak Asset. The redetermination/unitization cost relates to the executed unitization agreement for the Gumusut-Kakap (GK) and Geronggong/Jagus East fields originally signed in Q4 2017. Also, in the third quarter, the Brunei working interest was recorded (see below). The lower depreciation is due to lower volumes sold. Lower taxes are due to the lower pre-tax profits.

Other international E&P operations reported a profit from continuing operations of $1.3 million in the third quarter of 2018 compared to a net loss of $11.0 million in the prior year quarter. The result was $12.3 million favorable in the 2018 period versus 2017 due to the recording of net revenue and costs ($16.0 million) relating to the working interest in Block CA1 in Brunei. This follows the signing of the Brunei participation agreement on July 4, 2018, which enables the Company the right to claim its proportional share of revenues since inception as well as the obligation to settle the related past operating and capital expenditure costs since inception. In addition, ongoing current revenue of $3.2 million has been recorded. These items are partially off-set by higher exploration charges ($2.3 million) from the write-off of the Julong East well (originally drilled in 2012) in Brunei and a lower tax credit in the quarter ($3.4 million).

Nine Months 2018 vs. 2017

United States E&P operations reported earnings of $200.3 million in the first nine months of 2018 compared to a net loss of $21.8 million in the first nine months of 2017. Results were $222.1 million favorable in the 2018 period compared to the 2017 period due to higher revenues ($299.3 million) and lower depreciation ($19.9 million), partially offset by higher lease operating expenses ($26.9 million), higher exploration expenses ($7.0 million) and higher income taxes ($64.0 million). Higher revenues were primarily due to higher realized prices, while lower depreciation expense was due primarily to lower rates and lower volumes sold at Eagle Ford Shale. Higher lease operating expenses were principally a result of higher costs at Front Runner (due to 2017 Clipper well acquisition) and Kodiak work-over costs in the U.S. Gulf of Mexico business. Higher exploration expenditures are principally a result of data acquisition costs in the U.S Gulf of Mexico business.

Canadian E&P operations reported earnings of $46.7 million in the first nine months 2018 compared to earnings of $102.6 million in the 2017 period. Results were unfavorable $55.9 million due to 2017 including a pretax gain of $132.4 million (after tax: $96.0 million) related to the sale of Seal heavy oil assets in Canada in January 2017. Adjusting for the impact of gain on sale of assets, Canadian results of operations improved $40.1 million in the 2018 period compared to the 2017 period due to higher revenue ($78.1 million), insurance proceeds ($21.3 million), partially offset by higher lease operating expense ($14.2 million), higher depreciation ($34.5 million) and higher taxes ($12.4 million). Higher revenues were a result of both higher volumes at the Tupper, Kaybob and Placid assets and higher realized crude prices. Insurance proceeds related to cash received in relation to the spill at the now divested Seal asset. Higher taxes (excluding the Seal gain in 2017) are the result of higher net earnings. Higher lease operating expenses and depreciation are a result of higher volumes sold.

Malaysia E&P operations reported earnings of $208.4 million in the first nine months of 2018, compared to earnings of $173.9 million in the comparable 2017 period. Results were favorable by $34.5 million due to higher revenues ($46.3 million), lower depreciation ($18.1 million), lower other operating expenses ($10.2 million) and lower G&A ($1.9 million), partially offset by higher lease operating expenses ($18.8 million), and higher taxes ($12.2 million) and higher redetermination/unitization expense ($11.3 million). Higher revenues are principally due to higher realized prices, partially

Results of Operations (Contd.)

Nine Months 2018 vs. 2017 (Contd.)

off-set by lower volumes sold. Lower depreciation is due to lower volumes sold. Lower other expenses are due to the cost of a rig exit recorded in 2017. Higher lease operating expenses are due to higher platform, onshore facility and sub-sea maintenance costs. The higher taxes are due to higher pre-tax profits. The redetermination/unitization cost relates to the executed unitization agreement for the Gumusut-Kakap (GK) and Geronggong/Jagus East fields originally signed in Q4 2017. Also, in the third quarter, the Brunei working interest was recorded (see below).

Other international E&P operations reported a loss from continuing operations of $28.8 million in the first nine months of 2018 compared to a loss of $10.9 million in the 2017 period. The loss was $17.9 million higher in the 2018 period versus 2017 primarily due to 2017 tax benefits on investments in foreign areas ($32.9 million), lower other tax credits ($4.1 million), partially off-set by the recording of net revenue and costs ($16.0 million) relating to the working interest in Block CA1 in Brunei. This follows the signing of the Brunei participation agreement on July 4, 2018, which enables the Company the right to claim its proportional share of revenue since inception as well as the obligation to settle the related past operating and capital expenditure costs since inception. In addition, ongoing current Brunei revenue of $3.2 million has been recorded.

Exploration and Production

Third quarter 2018 vs. 2017 (Contd.)

Total hydrocarbon production averaged 168,776 barrels of oil equivalent per day in the third quarter of 2018, which represented a 10% increase from the 153,842 barrels per day produced in the 2017 quarter.

Average crude oil and condensate production was 87,755 barrels per day in the third quarter of 2018 compared to 84,230 barrels per day in the third quarter of 2017. The increase of 3,525 barrels per day was principally due to higher volumes in the Gulf of Mexico due to the shut-in of Kodiak in the 2017 quarter (3,746 barrels per day), higher volumes in Canada Onshore (2,856 barrels per day), partially off-set by lower volumes in Malaysia (4,186 barrels per day) due to field decline. On a worldwide basis, the Company's crude oil and condensate prices averaged $69.39 per barrel in the third quarter 2018 compared to $49.31 per barrel in the 2017 period, an increase of 41% quarter to quarter.

Total production of natural gas liquids (NGL) was 9,556 barrels per day in the 2018 third quarter compared to 9,128 barrels per day in the same 2017 period. The average sales price for U.S. NGL was $28.58 per barrel in the 2018 quarter compared to $18.35 per barrel in 2017. The average sales price for NGL in Canada was $41.06 per barrel in the 2018 quarter compared to $28.15 per barrel in 2017 due in part to the higher value of product produced at the Kaybob and Placid assets.

Natural gas sales volumes averaged 429 million cubic feet per day (MMCFD) in the third quarter 2018 compared to 363 MMCFD in 2017. The increase of 66 MMCFD was a result of increased volumes in Canada (49 MMCFD), Malaysia (10 MMCFD) and US (7 MMCFD). Higher volumes in Canada are a result of more wells online at the Tupper, Kaybob and Placid Onshore businesses. Higher volumes in Malaysia were due to a 2017 field shut-in. Natural gas prices for the total Company averaged $2.13 per thousand cubic feet (MCF) in the 2018 quarter, versus $2.24 per MCF average in the same quarter of 2017. Natural gas sales prices in the U.S. averaged $2.33 per MCF in the 2018 quarter versus $2.29 per MCF average in the same quarter of 2017. In Canada, natural gas sales prices averaged $1.41 per MCF in the 2018 quarter, versus $1.80 per MCF in the same quarter of 2017. The average realized price for natural gas produced in the 2018 quarter at fields offshore Sarawak was $3.91 per MCF, compared to a price of $3.52 per MCF in the 2017 quarter.

Nine Months 2018 vs. 2017

Total hydrocarbon production averaged 169,095 barrels of oil equivalent per day in the first nine months of 2018, which represented a 4% increase from the 161,917 barrels per day produced in the 2017 period.

Average crude oil and condensate production was 88,781 barrels per day in the first nine months of 2018 compared to 89,580 barrels per day in the first nine months of 2017. The decrease of 799 barrels per day was principally due to lower volumes in Malaysia (4,824 barrels per day) due to field decline, and lower volumes at Eagle Ford Shale (934 barrels per day) due to less new wells brought online, off-set by higher volumes in the Gulf of Mexico (2,872 barrels per day) and Canada (1,451 barrels per day). On a worldwide basis, the Company's crude oil and condensate prices averaged $67.01 per barrel in the first nine months 2018 compared to $49.04 per barrel in the 2017 period, an increase of 37% period to period.

Results of Operations (Contd.)

Exploration and Production (Contd.)

Nine Months 2018 vs. 2017 (Contd.)

Total production of natural gas liquids (NGL) was 9,525 barrels per day in the 2018 first nine months compared to 9,140 barrels per day in the same 2017 period. The average sales price for U.S. NGL was $23.51 per barrel in the 2018 period compared to $16.31 per barrel in 2017. The average sales price for NGL in Canada was $40.28 per barrel in the 2018 period compared to $23.52 per barrel in 2017. Average NGL prices in Malaysia in the first nine months 2018 and 2017 were $70.26 per barrel and $50.76 per barrel, respectively.

Natural gas sales volumes averaged 425 million cubic feet per day (MMCFD) in the first nine months 2018 compared to 379 MMCFD in 2017. The increase of 46 MMCFD was a result of increased volumes in Canada (46 MMCFD), partially offset by lower volumes in Malaysia (2 MMCFD) and higher volumes in U.S. (2 MMCFD). Higher volumes in Canada are a result of more wells online at the Tupper, Kaybob & Placid assets. Lower volumes in Malaysia were principally due to field decline and maintenance activities, while higher volumes in U.S are due to increased volumes at Front Runner.

Natural gas prices for the total Company averaged $2.07 per thousand cubic feet (MCF) in the 2018 period, versus $2.39 per MCF average in the same period of 2017. Natural gas sales prices in the U.S. averaged $2.30 per MCF in the 2018 period versus $2.39 per MCF average in the same period of 2017. In Canada, natural gas sales prices averaged $1.42 per MCF in the 2018 period, 26% below the $1.91 per MCF average in the same period of 2017.

Additional details about results of oil and gas operations are presented in the tables on pages 30 and 31.

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS (Contd.)

Results of Operations (Contd.)

Exploration and Production (Contd.)

Selected operating statistics for the three-month and nine-month periods ended September 30, 2018 and 2017 follow.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
Net crude oil and condensate produced – barrels per day	87,755	84,230	88,781	89,580
United States – Eagle Ford Shale	33,757	33,070	32,347	33,281
– Gulf of Mexico	14,530	10,240	14,253	11,309
Canada – Onshore	6,096	3,240	5,242	2,729
– Offshore	5,570	6,225	7,237	8,100
– Heavy1	–	–	–	201
Malaysia – Sarawak	11,608	11,508	11,936	12,727
– Block K	15,661	19,947	17,200	21,233
Brunei	533	–	566	–
Net crude oil and condensate sold – barrels per day	85,598	92,033	87,745	89,597
United States – Eagle Ford Shale	33,757	33,070	32,347	33,281
– Gulf of Mexico	14,530	10,240	14,253	11,309
Canada – Onshore	6,096	3,240	5,242	2,729
– Offshore	5,116	6,533	7,197	7,812
– Heavy 1	–	–	–	201
Malaysia – Sarawak	9,469	13,083	12,080	13,350
– Block K	16,169	25,867	16,471	20,915
Net natural gas liquids produced – barrels per day	9,556	9,128	9,525	9,140
United States – Eagle Ford Shale	6,663	6,669	6,735	6,812
– Gulf of Mexico	1,109	910	1,112	967
Canada – Onshore	1,095	510	1,005	410

Malaysia – Sarawak	689	1,039	673	951
Net natural gas liquids sold – barrels per day	9,641	9,213	9,642	–
United States – Eagle Ford Shale	6,663	6,669	6,735	9,165
– Gulf of Mexico	1,109	910	1,112	6,812
Canada – Onshore	1,095	510	1,005	–
Malaysia – Sarawak	774	1,124	790	410
Net natural gas sold – thousands of cubic feet per day	428,790	362,901	424,733	379,182
United States – Eagle Ford Shale	32,718	29,476	32,172	32,862
– Gulf of Mexico	14,798	11,232	13,968	11,654
Canada – Onshore	272,061	223,032	266,077	220,121
Malaysia – Sarawak	106,183	90,181	106,016	106,481
– Block K	3,030	8,980	6,500	8,064
Total net hydrocarbons produced – equivalent barrels per day 2	168,776	153,842	169,095	161,917
Total net hydrocarbons sold – equivalent barrels per day 2	166,704	161,730	168,176	161,959

1The Company sold the Seal area heavy oil field in January 2017.

2Natural gas converted on an energy equivalent basis of 6:1

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS (Contd.)

Results of Operations (Contd.)

Exploration and Production (Contd.)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
Weighted average Exploration and Production sales prices				
Crude oil and condensate – dollars per barrel				
United States 1 – Eagle Ford Shale	$ 72.08	48.49	68.29	48.42
– Gulf of Mexico	70.46	47.82	67.41	47.48
Canada 2 – Onshore	58.52	43.15	57.67	43.64
– Offshore	73.92	51.26	69.94	50.35
Malaysia – Sarawak 3	63.82	52.62	66.25	52.07
– Block K 3	68.67	51.36	66.35	50.95
Brunei	74.37	–	74.37	–
Natural gas liquids – dollars per barrel				
United States – Eagle Ford Shale	27.65	17.89	22.96	16.12
– Gulf of Mexico	34.49	19.00	26.85	17.84
Canada 2 – Onshore	41.06	22.77	40.28	22.48
Malaysia – Sarawak 3	69.64	49.66	70.26	49.94
Natural gas – dollars per thousand cubic feet				
United States – Eagle Ford Shale	2.27	2.44	2.26	2.53
– Gulf of Mexico	2.48	2.49	2.40	2.56
Canada 2 – Onshore	1.41	1.84	1.42	1.99
Malaysia – Sarawak 3	3.91	3.60	3.72	3.50
– Block K 3	0.24	0.25	0.24	0.24

1 In 2018, the Company reported realized and unrealized gains and losses on crude oil contracts in the Corporate segment (previously in the E&P segment) to reflect how segments are currently evaluated, how resources are allocated and how risk is managed by the Company. The 2017 amounts have been reclassified from the Exploration and Production business to reflect comparable disclosure.

2 U.S. dollar equivalent.

3 Prices are net of payments under the terms of the respective production sharing contracts.

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ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS (Contd.)

Results of Operations (Contd.)

Exploration and Production (Contd.)

OIL AND GAS OPERATING RESULTS – THREE MONTHS ENDED SEPTEMBER 30, 2018 AND 2017

(Millions of dollars)	United States 1	Canada	Malaysia	Other	Total
Three Months Ended September 30, 2018					
Oil and gas sales and other operating revenues	$ 348.7	107.1	201.2	19.9	676.9
Lease operating expenses	52.0	31.5	49.4	0.2	133.1
Severance and ad valorem taxes	14.8	0.3	–	–	15.1
Depreciation, depletion and amortization	132.6	58.6	44.3	1.0	236.5
Accretion of asset retirement obligations	4.5	1.9	4.7	–	11.1
Exploration expenses					
Dry holes	–	–	–	4.5	4.5
Geological and geophysical	0.4	–	0.1	0.7	1.2
Other Exploration	1.6	0.2	–	5.5	7.3
	2.0	0.2	0.1	10.7	13.0
Undeveloped lease amortization	7.8	0.2	–	0.8	8.8
Total exploration expenses	9.8	0.4	0.1	11.5	21.8
Selling and general expenses	14.0	6.4	3.4	6.2	30.0
Other	4.5	(9.5)	0.6	0.6	(3.8)
Results of operations before taxes	116.5	17.5	87.4	0.4	221.8
Income tax provisions	24.9	5.0	33.3	(0.9)	62.3
Results of operations (excluding corporate overhead and interest)	$ 91.6	12.5	54.1	1.3	159.5
Three Months Ended September 30, 2017					
Oil and gas sales and other operating revenues	$ 209.4	81.9	220.5	–	511.8
Lease operating expenses	43.5	28.7	40.6	–	112.8
Severance and ad valorem taxes	10.5	0.3	–	–	10.8
Depreciation, depletion and amortization	128.5	45.9	63.7	1.0	239.1
Accretion of asset retirement obligations	4.3	2.0	4.4	–	10.7
Exploration expenses					
Dry holes	(0.6)	–	(2.5)	–	(3.1)
Geological and geophysical	0.1	–	–	1.5	1.6
Other exploration	1.5	0.2	–	7.7	9.4

	1.0	0.2	(2.5)	9.2	7.9
Undeveloped lease amortization	20.4	0.2	–	–	20.6
Total exploration expenses	21.4	0.4	(2.5)	9.2	28.5
Selling and general expenses	13.2	7.3	4.6	5.1	30.2
Other	4.2	0.1	1.4	–	5.7
Results of operations before taxes	(16.2)	(2.8)	108.3	(15.3)	74.0
Income tax provisions (benefit)	(5.0)	0.4	40.6	(4.3)	31.7
Results of operations (excluding corporate overhead and interest)	$ (11.2)	(3.2)	67.7	(11.0)	42.3

1 In 2018, the Company reported realized and unrealized gains and losses on crude oil contracts in the Corporate segment (previously in the E&P segment) to reflect how segments are currently evaluated, how resources are allocated and how risk is managed by the Company. The 2017 amounts have been reclassified to reflect comparable disclosure.

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS (Contd.)

Results of Operations (Contd.)

Exploration and Production (Contd.)

OIL AND GAS OPERATING RESULTS – NINE MONTHS ENDED SEPTEMBER 30, 2018 AND 2017

(Millions of dollars)	United States 1	Canada 2	Malaysia	Other	Total
Nine Months Ended September 30, 2018					
Oil and gas sales and other operating revenues	$ 945.6	333.8	640.7	19.9	1,940.0
Lease operating expenses	162.6	91.0	152.4	0.2	406.2
Severance and ad valorem taxes	39.2	0.9	–	–	40.1
Depreciation, depletion and amortization	382.4	171.1	141.9	2.4	697.8
Accretion of asset retirement obligations	13.4	5.8	12.8	–	32.0
Redetermination expense	–	–	11.3	–	11.3
Exploration expenses					
Dry holes	–	–	–	4.5	4.5
Geological and geophysical	6.5	–	0.6	4.3	11.4
Other exploration	5.1	0.3	–	17.0	22.4
	11.6	0.3	0.6	25.8	38.3
Undeveloped lease amortization	29.2	0.6	–	1.7	31.5
Total exploration expenses	40.8	0.9	0.6	27.5	69.8
Selling and general expenses	39.0	20.7	8.3	18.1	86.1
Other	12.4	(20.9)	(0.8)	1.2	(8.1)
Results of operations before taxes	255.8	64.3	314.2	(29.5)	604.8
Income tax provisions (benefits)	55.5	17.6	105.8	(0.7)	178.2
Results of operations (excluding corporate overhead and interest)	$ 200.3	46.7	208.4	(28.8)	426.6
Nine Months Ended September 30, 2017					
Oil and gas sales and other operating revenues	$ 646.3	388.1	594.4	–	1,628.8
Lease operating expenses	135.7	76.8	133.6	–	346.1
Severance and ad valorem taxes	31.6	1.2	–	–	32.8
Depreciation, depletion and amortization	402.3	136.6	160.0	2.9	701.8

Accretion of asset retirement obligations	12.8	5.9	12.9	–	31.6
Exploration expenses					
Dry holes	(1.9)	–	0.8	–	(1.1)
Geological and geophysical	1.0	0.1	–	6.0	7.1
Other exploration	5.5	0.3	–	24.8	30.6
	4.6	0.4	0.8	30.8	36.6
Undeveloped lease amortization	39.4	1.4	–	–	40.8
Total exploration expenses	44.0	1.8	0.8	30.8	77.4
Selling and general expenses	38.7	20.9	10.2	15.0	84.8
Other	11.5	0.7	9.4	–	21.6
Results of operations before taxes	(30.3)	144.2	267.5	(48.7)	