UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2017

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES**

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)**

Registrant's telephone number, including area code: **(870) 862-6411**

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock, $1.00 Par Value	**New York Stock Exchange**
Series A Participating Cumulative Preferred Stock Purchase Rights	**New York Stock Exchange**

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☒ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Website, if any, every Interactive Data File required to be submitted and posted 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 and post such files). Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

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

Large accelerated filer	☒	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 ☐ No ☒

Aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of the last business day of the registrant's most recently completed second fiscal quarter (as of June 30, 2017) – $4,189,400,296.

Number of shares of Common Stock, $1.00 Par Value, outstanding at January 31, 2018 was 172,572,873.

Documents incorporated by reference:

Portions of the Registrant's definitive Proxy Statement relating to the Annual Meeting of Stockholders on May 9, 2018 have been incorporated by reference in Part III herein.

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2017 FORM 10-K
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PART I

Item 1. BUSINESS

Summary

Murphy Oil Corporation is a worldwide oil and gas exploration and production company. As used in this report, the terms Murphy, Murphy Oil, we, our, its and Company may refer to Murphy Oil Corporation or any one or more of its consolidated subsidiaries.

The Company was originally incorporated in Louisiana in 1950 as Murphy Corporation. It was reincorporated in Delaware in 1964, at which time it adopted the name Murphy Oil Corporation, and was reorganized in 1983 to operate primarily as a holding company of its various businesses. For reporting purposes, Murphy's exploration and production activities are subdivided into four geographic segments, including the United States, Canada, Malaysia and all other countries. Additionally, Corporate activities include interest income, interest expense, foreign exchange effects, the impact of the Tax Cuts and Jobs Act (2017 Tax Act) and administrative costs not allocated to the segments. The Company's corporate headquarters are located in El Dorado, Arkansas.

The Company has transitioned from an integrated oil company to an enterprise entirely focused on oil and gas exploration and production activities. The Company completed the sale of the remaining downstream assets in the United Kingdom (U.K.) during 2015 after selling its U.K. retail marketing assets during 2014.

At December 31, 2017, Murphy had 1,128 employees.

In addition to the following information about each business activity, data about Murphy's operations, properties and business segments, including revenues by class of products and financial information by geographic area, are provided on pages 24 through 41, 71 through 73, 104 through 115 and 117 of this Form 10-K report.

Interested parties may obtain the Company's public disclosures filed with the Securities and Exchange Commission (SEC), including Form 10-K, Form 10-Q, Form 8-K and other documents, by accessing the Investor Relations section of Murphy Oil Corporation's Website at www.murphyoilcorp.com.

Exploration and Production

The Company explores for and produces crude oil, natural gas and natural gas liquids worldwide. The Company's exploration and production management team directs the Company's worldwide exploration and production activities. This business maintains upstream operating offices in several locations around the world, with the most significant of these including Houston in Texas, Calgary in Alberta, and Kuala Lumpur in Malaysia.

During 2017, Murphy's principal exploration and production activities were conducted in the United States by wholly owned Murphy Exploration & Production Company – USA (Murphy Expro USA), in Malaysia, Australia, Brunei, Mexico and Vietnam by wholly owned Murphy Exploration & Production Company – International (Murphy Expro International) and its subsidiaries, and in Western Canada and offshore Eastern Canada by wholly-owned Murphy Oil Company Ltd. (MOCL) and its subsidiaries. Murphy's hydrocarbon production in 2017 was in the United States, Canada and Malaysia.

Unless otherwise indicated, all references to the Company's oil, natural gas liquids and natural gas production volumes and proved crude oil, natural gas liquids and natural gas reserves are net to the Company's working interest excluding applicable royalties. Also, unless otherwise indicated, references to oil throughout this document could include crude oil, condensate and natural gas liquids where applicable volumes include a combination of these products.

Total worldwide crude oil and condensate production in 2017 averaged 90,431 barrels per day, a decrease of 13% compared to 2016. The decrease in 2017 was primarily due to the Syncrude divestiture in mid-2016, lower production from Seal as a result of the divesture in January 2017 and lower production in Malaysia resulting from normal decline. Excluding Syncrude and Seal, crude oil and condensate production averaged 90,281 barrels per day in 2017 and 95,998 barrels per day in 2016. Natural gas liquids produced in 2017 averaged 9,151 barrels per day, in line with 2016. The Company's worldwide sales volume of natural gas averaged 384 million cubic feet (MMCF) per day in 2017, an increase of 1% from 2016 levels. The increase in natural gas sales volume in 2017 was primarily attributable to higher volumes at Canada from development of the Tupper, Kaybob & Placid assets, partially offset by lower gas volumes in the United States and Malaysia. Murphy's worldwide 2017 production on a barrel of oil equivalent basis (six thousand cubic feet of natural gas equals one barrel of oil) was 163,536 barrels per day, a decrease of 7% compared to 2016.

Total production in 2018 is currently expected to average between 166,000 and 170,000 barrels of oil equivalent per day (BOED).

United States

In the United States, Murphy primarily has production of crude oil, natural gas liquids and natural gas from fields in the Eagle Ford Shale area of South Texas and in the deepwater Gulf of Mexico. The Company produced approximately 54,000 barrels of crude oil and gas liquids per day and approximately 45 MMCF of natural gas per day in the U.S. in 2017. These amounts represented 54% of the Company's total worldwide oil and gas liquids and 12% of worldwide natural gas production volumes.

The Company holds rights to approximately 135 thousand gross acres in South Texas in the Eagle Ford Shale unconventional oil and gas play. Total 2017 production in the Eagle Ford area was 41,500 barrels of oil and liquids per day and approximately 33 MMCF per day of natural gas. On a barrel of oil equivalent basis, Eagle Ford production accounted for 76% of total U.S. production volumes in 2017. In 2018, production for the U.S. Onshore business is forecast to be lower and average approximately 40,000 barrels of oil and gas liquids per day and 29 MMCF of natural gas per day. At December 31, 2017, the Company's proved reserves for the U.S. Onshore business totaled 185.3 million barrels of crude oil, 40.2 million barrels of natural gas liquids, and 189.2 billion cubic feet of natural gas.

During 2017, approximately 24% of total U.S. hydrocarbon production was produced at fields in the Gulf of Mexico. Approximately 87% of Gulf of Mexico production in 2017 was derived from five fields, including Dalmatian, Medusa, Kodiak, Front Runner and Thunder Hawk. The Company holds a 70% operated working interest in Dalmatian in DeSoto Canyon Blocks 4 and 134, a 60% operated interest in Medusa in Mississippi Canyon Blocks 538/582, a 29.1% non-operated interest in Kodiak in Mississippi Canyon Blocks 727/771, and 62.5% operated working interests in the Front Runner field in Green Canyon Blocks 338/339 and the Thunder Hawk field in Mississippi Canyon Block 734. Total daily production in the Gulf of Mexico in 2017 was 12,400 barrels of liquids and approximately 12 MMCF of natural gas. Production in the Gulf of Mexico in 2018 is expected to total approximately 13,500 barrels of oil and gas liquids per day and 12 MMCF of natural gas per day. At December 31, 2017, Murphy had total proved reserves for Gulf of Mexico fields of 42.2 million barrels of oil and gas liquids and 34.1 billion cubic feet of natural gas. Total U.S. proved reserves at December 31, 2017 were 224.7 million barrels of crude oil, 43.0 million barrels of natural gas liquids, and 223.3 billion cubic feet of natural gas.

Canada

In Canada, the Company holds one wholly-owned natural gas area (Tupper) in the Western Canadian Sedimentary Basin (WCSB), working interests in the Kaybob Duvernay and liquids rich Placid Montney lands and two non-operated assets – the Hibernia and Terra Nova fields offshore Newfoundland in the Jeanne d'Arc Basin.

The Company has 110 thousand gross acres of Tupper Montney mineral rights located in northeast British Columbia. In 2016, the Company completed its transaction to divest natural gas processing and sales pipeline assets that support Murphy's Montney natural gas fields in the Tupper area. Total cash consideration received by Murphy upon closing of the transaction was $414.1 million. Connected with this sale, the Company entered into a commitment for natural gas processing capacity for minimum monthly payments through 2035.

In 2016, the Company acquired a 70% operated working interest in Kaybob Duvernay lands and a 30% non-operated working interest in liquids rich Placid Montney lands in Alberta.

In the fourth quarter 2016, the Company entered into an agreement to sell its wholly-owned Seal field located in the Peace River oil sands area of northwest Alberta. This sale was completed in January 2017 and the Company received net proceeds of $48.8 million.

Daily production in 2017 in the WCSB averaged 3,700 barrels of oil and gas liquids and approximately 226 MMCF of natural gas, and increase of 195% (excluding Seal and Syncrude divestitures) and 8% versus 2016, respectively. Oil and natural gas daily production for 2018 in Western Canada, is expected to average 6,500 barrels and approximately 262 MMCF, respectively. The expected increase in oil production in 2018 arises from continued drilling and development in the Kaybob Duvernay and Placid Montney areas acquired in mid-2016. The expected increase in natural gas volumes in 2018 is primarily the result of new wells brought on line in the Tupper area and additional capacity at the Tupper West processing facility of 17 MMCFD commencing in late 2017. Total WCSB proved liquids and natural gas reserves at December 31, 2017, were approximately 36.3 million barrels and 1.2 trillion cubic feet, respectively.

Murphy has a 6.5% working interest in Hibernia, while at Terra Nova the Company's working interest is 10.475%. Oil production in 2017 was about 8,100 barrels of oil per day for the two offshore Canada fields. Oil production for 2018 for offshore Canada is anticipated to be approximately 7,400 barrels per day.

The decrease in anticipated 2018 oil production is primarily the result of a planned turnaround at Hibernia. Total proved oil reserves at December 31, 2017 for the two fields were approximately 20.9 million barrels.

In June 2016, MOCL completed the sale of its 5% undivided interest in Syncrude Canada Ltd. (Syncrude) for net proceeds of $739.1 million.

Malaysia

In Malaysia, the Company has majority interests in nine separate production sharing contracts (PSCs). The Company serves as the operator of all these areas other than the unitized Kakap-Gumusut field. The PSCs cover approximately 2.67 million gross acres. In December 2014 and January 2015, the Company sold 30% of its interest in substantially all of its Malaysian oil and gas assets for net proceeds of approximately $1.88 billion.

Murphy has a 59.5% interest in oil and natural gas discoveries in two shallow-water blocks, SK 309 and SK 311, offshore Sarawak. Approximately 13,500 barrels of oil and gas liquids per day were produced in 2017 at Blocks SK 309/311. Oil and gas liquids production in 2018 at fields in Blocks SK 309/311 (Sarawak) is anticipated to total about 12,500 barrels per day.

The Company has a gas sales contract for the Sarawak area with Petronas, the Malaysian state-owned oil company, and has an ongoing multi-phase development plan for several natural gas discoveries on these blocks. The gas sales contract allows for gross sales volumes of 250 MMCF per day through September 2021, but allows the Company to deliver higher sales volumes as requested. Total net natural gas sales volume offshore Sarawak was about 105 MMCF per day during 2017. Sarawak net natural gas sales volumes are anticipated to be approximately 102-103 MMCF per day in 2018.

Total proved reserves of liquids and natural gas at December 31, 2017 for Blocks SK 309/311 were 9.8 million barrels and approximately 129 billion cubic feet (BCF), respectively.

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 owners. The Gumusut-Kakap Unit is operated by another company. In the fourth quarter 2016, the owners 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 taxes) 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 further Unitization Framework Agreement (UFA) between the governments of Brunei and Malaysia the Company now has a 6.35% interest in the Kakap field in Block K Malaysia as of December 31, 2017. 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 expense of $15 million ($9.3 million after taxes) related to the Company's revised working interest.

The Siakap oil field was developed as a unitized area with the Petai field owned by others, and the combined development is operated by Murphy, with a tie-back to the Kikeh field with production beginning in 2014. Oil production at Block K averaged approximately 20,300 barrels per day during 2017. Oil production at Block K is anticipated to average approximately 17,700 barrels per day in 2018. The reduction in Block K Kikeh oil production in 2018 is primarily attributable to overall field decline and reduction in working interest at Kakap as described above.

The Company has a Block K natural gas sales contract with Petronas that calls for gross sales volumes of up to 120 MMCF per day. Gas production in Block K will continue until the earlier of lack of available commercial quantities of associated gas reserves or expiry of the Block K production sharing contract. Natural gas production in Block K in 2017 totaled 8 MMCF per day. Daily gas production in 2018 in Block K is expected to average about 5-6 MMCF per day. Total proved reserves booked in Block K at the end of 2017 were 42.4 million barrels of crude oil and about 24.3 billion cubic feet of natural gas.

The Company also has an interest in deepwater Block H offshore Sabah. In early 2007, the Company announced a significant natural gas discovery at the Rotan well in Block H. The Company followed up Rotan with several other nearby discoveries. Murphy's interests in Block H range between 42% and 56%. Total gross acreage held by the Company at the end of 2017 in Block H was 679 thousand gross acres. In early 2014, Petronas and the Company sanctioned a Floating Liquefied Natural Gas (FLNG) project for Block H, and agreed terms for sales of natural gas to be produced with prices tied to an oil index. First production is currently expected at Block H in mid-2020. At December 31, 2017, total natural gas proved reserves for Block H were approximately 335.2 billion cubic feet.

The Company had a 42% interest in a gas holding area covering approximately 1,854 gross acres in Block P. This interest expired in January 2018.

In November 2017, the Company acquired a 59.5% working interest in Sarawak SK405B PSC. The block SK405B is approximately 2,305 square kilometers (890 square miles) and has water depths in the range from 10 to 50 meters (33 to 164 feet). Under the terms of the PSC, the Company will operate the block with a participating interest of 59.5%.

In February 2016, the Company acquired a 40% working interest in Block Deepwater SK2A PSC, offshore Sarawak. The Company operates the block with a commitment to acquire and process new 3D seismic. The commitment was fulfilled during 2016. A decision to enter the next phase of the PSC, involving a one-well commitment, will be made in the future. This block includes 609 thousand gross acres.

In February 2015, the Company acquired a 50% interest in Block SK 2C, offshore Sarawak. The Company operates the block that carried one well commitment during the one year initial exploration period. The exploration well was drilled in 2015, and the first exploration period was extended for a further eighteen months. In 2016, the Company elected not to enter the next exploration period. The block was relinquished with the exception of an application made for a gas holding area comprising the Paus gas and oil discovery. The Company holds an 80% working interest in the gas holding area application, which is under consideration by government authorities.

In May 2013, the Company acquired an interest in shallow-water Malaysia Block SK 314A. The PSC covered a three-year exploration period. The Company's working interest in Block SK 314A is 59.5%. This block includes 488 thousand gross acres. The Company has a 70% carry of a 15% partner in this concession through the minimum work program. The first two exploration wells were drilled in 2015 and the third well in 2016. The Company has successfully secured an annexation of an open area in Sarawak to SK314A to complete the remaining fourth and fifth exploration commitment wells.

Australia

In Australia, the Company holds six offshore exploration permits and serves as operator of four of them.

In December 2017, Murphy signed a farm-in agreement to acquire a 40% non-operated interest in AC/P21 in the Vulcan Basin, offshore Western Australia. Acquisition of multiclient 3D seismic commenced over the permitted area in December 2017. The permit comprises approximately 165 thousand acres and expires in June 2019.

In March 2015, Murphy was awarded the AC/P59 license, another acreage position in the Vulcan Basin. The block covers approximately 288 thousand gross acres. The exploration requires 3D seismic reprocessing, which was completed in 2016. The permit expires in 2021.

In April 2014 and June 2014, Murphy was awarded licenses AC/P57 and AC/P58 in the Vulcan Basin. The blocks cover approximately 82 thousand and 692 thousand gross acres, respectively. These exploration permits require 3D seismic reprocessing and a gravity survey that were completed in 2017. The permits expire in 2020.

The Company was awarded permit EPP43 in the Ceduna Basin, offshore South Australia, in October 2013. The Company operates and holds a 50% working interest in the concession covering approximately 4.08 million gross acres. The exploration permit has commitments for 2D and 3D seismic, which was completed in the first half of 2015 and processed in 2016. This permit expires in 2020.

In November 2012, Murphy acquired a 20% non-operated working interest in permit WA-408-P in the Browse Basin. The permit comprised approximately 417 thousand gross acres. Murphy drilled two wells in

2013. The first well found hydrocarbon but was deemed commercially unsuccessful and was written off to expense. The second well was also unsuccessful, and costs were expensed in 2013. Although extended in 2016, the permit was released in 2017.

The Company also acquired permit WA-481-P in the Perth Basin, offshore Western Australia, in August 2012. All commitments were fulfilled in 2015. In 2016, the Company's working interest was sold to another company.

In May 2012, Murphy was awarded permit WA-476-P in the Carnarvon Basin, offshore Western Australia. The Company formerly held 100% working interest in the permit which covers 177 thousand gross acres. The permit had a primary term work commitment consisting of seismic data purchase and geophysical studies. All primary term commitments were completed. This permit was released in 2017.

The Company's first permit in Australia was acquired in 2007. It consisted of a 40% interest in Block AC/P36 in the Browse Basin. Murphy renewed the exploration permit for an additional five years, and in that process relinquished 50% of the gross acreage. In 2012, Murphy increased its working interest in the remaining acreage to 100% and subsequently farmed out a 50% working interest and operatorship. The license now covers 482 thousand gross acres and expires in 2019. The existing work commitment includes further geophysical work.

Brunei

In late 2010, the Company entered into two production sharing agreements for properties offshore Brunei. The Company had a 5% working interest in Block CA-1 and a 30% working interest in Block CA-2. In 2015, the Company exercised a preemptive right that increased its working interest in Block CA-1 to 8.051%. The CA-1 and CA-2 blocks cover 1.44 million and 1.49 million gross acres, respectively. Four exploration wells were drilled in Block CA-1 and six exploration wells were drilled in Block CA-2 by the end of 2017.

The Jagus East discovery in Block CA-1 now forms part of a unitized field with the GK Unit in Malaysia. On November 23, 2017, both the governments of Brunei and Malaysia signed a UFA (see Malaysia section above). Following this unitization the Company's working interest in the Brunei section of the Kakap field will be adjusted.

The Company has a 30% non-operating working interest in Block CA-2. In December 2014, the authority PetroleumBrunei approved a gas marketing plan which sets an eight-year gas holding period until December 2022. The consortium is presently carrying out a concept select study to assist in commercial discussions.

Vietnam

In November 2012, the Company signed a PSC with Vietnam National Oil and Gas Group and PetroVietnam Exploration Production Company (PVEP), where it acquired a 65% interest and operatorship of Blocks 144 and 145. The blocks cover approximately 6.56 million gross acres and are located in the outer Phu Khanh Basin. The Company acquired 2D seismic for these blocks in 2013 and undertook seabed surveys in 2015 and 2016. The commitment of acquiring, processing and interpreting six hundred square kilometers (600 km^2) of 3D seismic has been extended to 2019.

In June 2013, the Company acquired a 60% working interest and operatorship of Block 11-2/11 under another PSC. The block covers 677 thousand gross acres. The Company acquired 3D seismic and performed other geological and geophysical studies in this block in 2013. This concession carries a three-well commitment. The first exploration well was drilled in 2016 and the second and third wells were drilled in 2017. These wells discovered hydrocarbons, and a commercial assessment is ongoing.

In August 2015, the Company signed a farm-in agreement to acquire 35% of Block 15-1/05. PVEP is currently the operator of the block and the exploration phase expires December 2018. The exploration license calls for one exploration well commitment, which is planned to be drilled in 2018. Murphy is working with its partners on the Block 15-1/05 LDV discovery for a Declaration of Commerciality in 2018.

Mexico

In December 2016, Murphy and joint venture partners were the high bidder on Block 5, which was offered as part of Mexico's fourth phase, Round one deepwater auction (Round 1.4). Murphy was formally awarded the block in March 2017. Murphy is the operator of the Block with a 30% working interest. Block 5 is located in the deepwater Salinas basin covering approximately 640,000 gross acres (2,600 square kilometers) and water depths in this block range from 2,300 to 3,500 feet (700 to 1,100 meters). The initial exploration period for the license is four years and includes a work program commitment of one well. Murphy currently plans to drill an exploration well on this block in late 2018.

Brazil

In September 2017, the Company entered into a farm-in agreement with Queiroz Galvão Exploração e Produção S.A. (QGEP) to acquire a 20% working interest in Blocks SEAL-M-351 and SEAL-M-428, located in the deepwater Sergipe-Alagoas Basin, offshore Brazil. QGEP retained a 30% working interest in the blocks and, in a separate but related transaction, ExxonMobil Exploração Brasil Ltda. (an affiliate of ExxonMobil Corporation) farmed into the remaining 50% working interest as the operator.

In addition, Murphy and its co-venturers were the high bidder in Brazil's Round 14 lease sale for Blocks SEAL-M-501 and SEAL-M-503, which are adjacent to SEAL-M-351 and SEAL-M-428. ExxonMobil will operate the block and Murphy has a 20% working interest. ExxonMobil Exploração Brasil Ltda has a 50% working interest and QGEP will retain a 30% working interest in the blocks.

Murphy's total acreage position in Brazil is 746,000 gross acres over the four highly prospective blocks, offsetting several major Petrobras discoveries, with no well commitments. The Company's total commitment is approximately $18 million, which includes signature bonuses and seismic costs, $6.4 million of which was paid in 2017, with the remainder to be paid in 2018.

Ecuador

Murphy sold its 20% working interest in Block 16, Ecuador in March 2009. In October 2007, the government of Ecuador passed a law that increased its share of revenue for sales prices that exceed a base price (about $23.36 per barrel at December 31, 2008) from 50% to 99%. The government had previously enacted a 50% revenue sharing rate in April 2006. The Company initiated arbitration proceedings against the government in one arbitral body claiming that the government did not have the right under the contract to enact the revenue sharing provision. In 2010, the arbitration panel determined that it lacked jurisdiction over the claim due to technicalities. The arbitration was refiled in 2011 before a different arbitral body and the arbitration hearing was held in late 2014. On February 10, 2017, the arbitration panel issued its final decision and awarded Murphy the sum of $31.3 million. Under the rules of the arbitral tribunal, there are very limited procedural or jurisdictional grounds under which a final award can be set aside. However, a party may seek to set aside a final award via a proceeding in Netherlands district court located in The Hague. In May 2017, Ecuador instituted such a proceeding. Murphy has filed its opposition and the matter is pending.

Proved Reserves

Total proved reserves for crude oil, natural gas liquids and natural gas as of December 31, 2017 are presented in the following table.

	Proved Reserves		
	Crude Oil	Natural Gas Liquids	Natural Gas
Proved Developed Reserves:	(MMBOE)		(BCF)
United States	126.3	23.3	127.7
Canada	21.9	1.0	547.0
Malaysia	37.3	0.3	144.6
Total proved developed reserves	185.5	24.6	819.3
Proved Undeveloped Reserves:			
United States	98.4	19.7	95.6
Canada	29.6	4.6	665.5
Malaysia	14.6	–	346.7
Total proved undeveloped reserves	142.6	24.3	1,107.8
Total proved reserves	328.1	48.9	1,927.1

Murphy Oil's total proved reserves and proved undeveloped reserves increased during 2017 as presented in the table below:

(Millions of oil equivalent barrels)	Total Proved Reserves	Total Proved Undeveloped Reserves
Beginning of year	684.5	341.1
Revisions of previous estimates	(5.6)	2.0
Extensions and discoveries	71.3	61.1
Improved recovery	2.0	–
Conversions to proved developed reserves	–	(52.9)
Purchases of properties	5.8	0.4
Production	(59.7)	–
End of year	698.3	351.7

During 2017, Murphy's proved reserves increased by 13.8 million barrels of oil equivalent (MMBOE). The most significant additions to total proved reserves related to drilling, well performance, and re-allocation of capital to higher performing drilling areas in the Eagle Ford Shale area of South Texas that added 30.7 MMBOE, Montney gas area of Western Canada that added 25.8 MMBOE, and in the Kaybob Duvernay and Placid Montney areas in Canada that added 7.7 MMBOE. Drilling and well performance in the Gulf of Mexico added 3.4 MMBOE. At December 31, 2017, Murphy acquired increased working interests in two fields located in the Gulf of Mexico, adding 4.8 MMBOE. In 2017, Murphy's proved reserves in Malaysia were reduced by 3.5 MMBOE following the results of a non-operated field equity redetermination.

Murphy's total proved undeveloped reserves at December 31, 2017 increased 10.6 MMBOE from a year earlier. The proved undeveloped reserves reported in the table as extensions and discoveries during 2017 were predominantly attributable to two areas – drilling and re-allocation of capital to higher performing drilling areas in the Eagle Ford Shale area of South Texas and the Tupper area in Western Canada. Both of these areas had active development work ongoing during the year. The majority of proved undeveloped reserves associated with revisions of previous estimates was the result of higher oil and gas prices extending the economic life of well locations planned for development within the next five years. The majority of the proved undeveloped reserves migration to the proved developed category are attributable to drilling in Eagle Ford Shale, Malaysia and Tupper. The Company spent approximately $453 million in 2017 to convert proved undeveloped reserves to proved developed reserves. The Company expects to spend about $648 million in 2018, $720 million in 2019 and $716 million in 2020 to move currently undeveloped proved reserves to the developed category. The anticipated level of spending in 2018 primarily includes drilling in the Eagle Ford Shale, Kaybob, Placid and Tupper areas. In computing MMBOE, natural gas is converted to equivalent barrels of oil using a ratio of six thousand cubic feet (MCF) to one barrel of oil.

At December 31, 2017, proved reserves are included for several development projects, including oil developments at the Eagle Ford Shale in South Texas, Montney shale at Tupper, the Kakap, Kikeh, Siakap fields, offshore Sabah, in Malaysia and natural gas developments offshore Sarawak and offshore Block H in Malaysia. Total proved undeveloped reserves associated with various development projects at December 31, 2017 were approximately 351.7 MMBOE, which represent 50% of the Company's total proved reserves.

Certain development projects have proved undeveloped reserves that will take more than five years to bring to production.

The Company operates deepwater fields in the Gulf of Mexico that have three undeveloped locations that exceed this five-year window. Total reserves associated with the three locations amount to less than 1% of the Company's total proved reserves at year-end 2017. The development of certain of these reserves stretches beyond five years due to limited well slots available, thus making it necessary to wait for depletion of other wells prior to initiating further development of these locations.

The second project that will take more than five years to develop is offshore Malaysia. The Block H development project has undeveloped proved reserves that make up 8% of the Company's total proved reserves at year-end 2017. This operated project will take longer than five years from discovery to be completely developed due to a deferral of development and construction of FLNG facilities operated by another company. Field start up is expected to occur in 2020.

Murphy Oil's Reserves Processes and Policies

The Company employs a Manager of Corporate Reserves (Manager) who is independent of the Company's oil and gas operational management. The Manager reports to the Senior Vice President, Planning & Performance, of Murphy Oil Corporation, who in turn reports to the Chief Financial Officer of Murphy Oil. The Manager makes annual presentations to the Board of Directors about the Company's reserves. The Manager reviews and discusses reserves estimates directly with the Company's reservoir engineering staff in order to make every effort to ensure compliance with the rules and regulations of the SEC and industry. The Manager utilizes independent, well known and respected third-party firms to audit reserves. The Manager coordinates and oversees these third-party audits. The third-party audits are performed annually and under Company policy generally target coverage of at least one-third of the barrel oil-equivalent volume of the Company's proved reserves. The Company reports its internal assessments of proved reserves and only uses the third-party audit results as an independent assessment of its internal computations. Internal audits may also be performed by the Manager and qualified engineering staff from areas of the Company other than the area being audited by third parties.

Each significant exploration and production office maintains one or more Qualified Reserve Estimators (QRE) on staff. The QRE is responsible for estimating and evaluating reserves and other reserves information for his or her assigned area. The QRE may personally make the estimates and evaluations of reserves or may supervise and approve the estimation and evaluation thereof by others. A QRE is professionally qualified to perform these reserves estimates due to having sufficient educational background, professional training and professional experience to enable him or her to exercise prudent professional judgment.

This requires a minimum of three years practical experience in petroleum engineering or petroleum production geology, with at least one year of such experience being in the estimation and evaluation of reserves, and either a bachelors or advanced degree in petroleum engineering, geology or other discipline of engineering or physical science from a college or university of recognized stature, or the equivalent thereof from an appropriate government authority or professional organization.

Larger offices of the Company also employ a Regional Reserves Coordinator (RRC) who supervises the local QREs. The RRC is usually a senior QRE that has the primary responsibility for coordinating and submitting reserves information to senior management.

The Company's QREs maintain files containing pertinent data regarding each significant reservoir. Each file includes sufficient data to support the calculations or analogies used to develop the values. Examples of data included in the file, as appropriate, include: production histories; pertinent drilling and workover histories; bottom hole pressure data; volumetric, material balance, analogy or other pertinent reserve estimation data; production performance curves; narrative descriptions of the methods and logic used to determine reserves values; maps and logs; and a signed copy of the conclusion of the QRE stating, that in their opinion, the reserves have been calculated, reviewed, documented and reported in compliance with the regulations and guidelines contained in the reserves training manual. The Company's reserves are maintained in an industry-recognized reservoir engineering software system, which has adequate access controls to avoid the possibility of improper manipulation of data. When reserves calculations are completed by QREs and appropriately reviewed by RRCs and the Manager, the conclusions are reviewed and discussed with the heads of the Company's exploration and production business and other senior management as appropriate. The Company's Controller's department is responsible for preparing and filing reserves schedules within the Form 10-K report.

Murphy provides annual training to all company reserves estimators to ensure SEC requirements associated with reserves estimation and Form 10-K reporting are fulfilled. The training includes materials provided to each participant that outlines the latest guidance from the SEC as well as best practices for many engineering and geologic matters related to reserves estimation.

Qualifications of Manager of Corporate Reserves

The Company believes that it has qualified employees preparing oil and gas reserves estimates. Mr. F. Michael Lasswell serves as Corporate Reserves Manager having joined the Company in 2012. Prior to joining Murphy, Mr. Lasswell was employed as a Regional Coordinator of reserves at a major integrated oil company. He worked in several capacities in the reservoir engineering department with the oil company from 2002 to 2012. Mr. Lasswell earned a Bachelor's of Science degree in Civil Engineering and a Master's of Science degree in Geotechnical Engineering from Brigham Young University. Mr. Lasswell has experience working in the reservoir engineering field in numerous areas of the world, including the North Sea, the U.S. Arctic, the Middle East and Asia Pacific. He is a member of the Society of Petroleum Engineers (SPE), is a past member of its Oil and Gas Reserves Committee (OGRC) and is also co-author of a paper on the Recognition of Reserves which was published by the SPE. Mr. Lasswell has also attended numerous industry training courses.

More information regarding Murphy's estimated quantities of proved reserves of crude oil, natural gas liquids and natural gas for the last three years are presented by geographic area on pages 106 through 112 of this Form 10-K report. Murphy has not filed and is not required to file any estimates of its total proved oil or gas reserves on a recurring basis with any federal or foreign governmental regulatory authority or agency other than the U.S. Securities and Exchange Commission. Annually, Murphy reports gross reserves of properties operated in the United States to the U.S. Department of Energy; such reserves are derived from the same data from which estimated proved reserves of such properties are determined.

Crude oil, condensate and natural gas liquids production and sales, and natural gas sales by geographic area with weighted average sales prices for each of the three years ended December 31, 2017 are shown on pages 30 and 32 of this Form 10-K Report. In 2017, the Company's production of oil and natural gas represented approximately 0.1% of worldwide totals.

Production expenses for the last three years in U.S. dollars per equivalent barrel are discussed beginning on page 34 of this Form 10-K report. For purposes of these computations, natural gas sales volumes are converted to equivalent barrels of oil using a ratio of six MCF of natural gas to one barrel of oil.

Supplemental disclosures relating to oil and gas producing activities are reported on pages 104 through 117 of this Form 10-K report.

At December 31, 2017, Murphy held leases, concessions, contracts or permits on developed and undeveloped acreage as shown by geographic area in the following table. Gross acres are those in which all or part of the working interest is owned by Murphy. Net acres are the portions of the gross acres attributable to Murphy's interest.

	Developed		Undeveloped		Total	
Area (Thousands of acres)	Gross	Net	Gross	Net	Gross	Net
United States – Onshore	104	91	63	59	167	150
– Gulf of Mexico	14	6	565	303	579	309
Total United States	118	97	628	362	746	459
Canada – Onshore	86	71	486	345	572	416
– Offshore	101	8	43	2	144	10
Total Canada	187	79	529	347	716	426
Malaysia	257	149	2,417	1,210	2,674	1,359
Mexico	–	–	636	191	636	191
Brazil	–	–	746	148	746	148
Australia	–	–	5,792	2,986	5,792	2,986
Brunei	–	–	2,935	562	2,935	562
Vietnam	–	–	7,998	4,937	7,998	4,937
Spain	–	–	8	1	8	1
Totals	562	325	21,689	10,744	22,251	11,069

Certain acreage held by the Company will expire in the next three years.

Scheduled acreage expirations in 2018 include 427 thousand net acres in Block 144 in Vietnam; 427 thousand net acres in Block 145 in Vietnam; 266 thousand net acres in Block 15-1/05 in Vietnam; 81 thousand net acres in Block 11-2/11 in Vietnam; 116 thousand net acres in Block CA-1 in Brunei; 15 thousand net acres in Western Canada and 87 thousand net acres in the United States.

Acreage currently scheduled to expire in 2019 include 447 thousand net acres in Block CA-2 in Brunei; 140 thousand net acres in Western Canada; 120 thousand net acres in Block AC/P36 in Australia; and 24 thousand net acres in the United States.

Scheduled expirations in 2020 include 415 thousand net acres in Block AC/P58 in Australia; 101 thousand net acres in Western Canada; 37 thousand net acres in Block 351 in Brazil; 37 thousand net acres in Block 428 in Brazil; and 11 thousand net acres in the United States.

As used in the three tables that follow, “gross” wells are the total wells in which all or part of the working interest is owned by Murphy, and “net” wells are the total of the Company’s fractional working interests in gross wells expressed as the equivalent number of wholly-owned wells. An “exploratory” well is drilled to find and produce crude oil or natural gas in an unproved area and includes delineation wells which target a new reservoir in a field known to be productive or to extend a known reservoir beyond the proved area. A “development” well is drilled within the proved area of an oil or natural gas reservoir that is known to be productive.

The following table shows the number of oil and gas wells producing or capable of producing at December 31, 2017.

	Oil Wells		Gas Wells	
	Gross	Net	Gross	Net
Country				
United States	908	757	6	4
Canada	34	24	380	315
Malaysia	93	48	55	33
Totals	1,035	829	441	352

Murphy’s net wells drilled in the last three years are shown in the following table.

	United States		Canada		Malaysia		Other		Totals	
	Pro-ductive	Dry	Pro-ductive	Dry	Pro-ductive	Dry	Pro-ductive	Dry	Pro-ductive	Dry
2017										
Exploratory	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Development	**68.7**	**-**	**27.2**	**-**	**-**	**-**	**-**	**-**	**95.9**	**-**
2016										
Exploratory	-	-	-	-	-	0.7	-	-	-	0.7
Development	51.5	-	7.0	-	3.0	-	-	-	61.5	-
2015										
Exploratory	-	2.2	-	-	2.0	1.2	-	1.2	2.0	4.6
Development	109.6	-	7.0	-	15.9	-	-	-	132.5	-

Murphy’s drilling wells in progress at December 31, 2017 are shown in the following table. The year-end well count includes wells awaiting various completion operations. The U.S. net wells included below are essentially all located in the Eagle Ford Shale area of South Texas.

	Exploratory		Development		Total	
Country	Gross	Net	Gross	Net	Gross	Net
United States	-	-	18.0	16.8	18.0	16.8
Canada	-	-	17.0	12.3	17.0	12.3
Totals	-	-	35.0	29.1	35.0	29.1

Refining and Marketing – Discontinued Operations

The Company decommissioned the Milford Haven refinery units and completed the sale of its remaining downstream assets in the U.K. in 2015 for cash proceeds of $5.5 million. The Company has accounted for and reported this U.K. downstream business as discontinued operations for all periods presented.

Environmental

Murphy's businesses are subject to various international, national, state, provincial and local environmental laws and regulations that govern the manner in which the Company conducts its operations. The Company anticipates that these requirements will continue to become more complex and stringent in the future.

Further information on environmental matters and their impact on Murphy are contained in Management's Discussion and Analysis of Financial Condition and Results of Operations on pages 25 and 49.

Website Access to SEC Reports

Murphy Oil's internet Website address is http://www.murphyoilcorp.com. Information contained on the Company's Website is not part of this report on Form 10-K.

The Company's Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and any amendments to these reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 are available on Murphy's Website, free of charge, as soon as reasonably practicable after such reports are filed with, or furnished to, the SEC. You may also access these reports at the SEC's Website at http://www.sec.gov.

Item 1A. RISK FACTORS

Volatility in the global prices of crude oil, natural gas liquids and natural gas can significantly affect the Company's operating results.

Among the most significant variables affecting the Company's results of operations are the sales prices for crude oil and natural gas that it produces. The indices against which much of the Company's production is priced have been significantly lower in the years 2015-2017 (vs. pre-2015 years), and sales prices for crude oil and natural gas can be significantly different in U.S. markets compared to other international markets.

West Texas Intermediate (WTI) crude oil prices averaged approximately $51 in 2017, compared to $43 per barrel in 2016 and $49 per barrel in 2015 (2014 prices averaged $93 per barrel). The closing price for WTI at the end of 2017 was approximately $60 per barrel. As demonstrated by the significant decline in WTI prices in late 2014 and further declines over 2015 and early 2016, prices can be volatile. In addition, the sales prices for sour crude oils do not always move in relation to price changes for WTI and lighter/sweeter crude oils. Certain U.S. and Canadian crude oils and all crude oil produced in Malaysia, generally price off oil indices other than WTI, and these indices are influenced by different supply and demand forces than those that affect the U.S. WTI prices. The most common crude oil indices used to price the Company's crude include Louisiana Light Sweet (LLS), Brent and Malaysian crude oil indices.

The average New York Mercantile Exchange (NYMEX) natural gas sales price was $2.96 per thousand cubic feet (MCF) in 2017, up from $2.48 per MCF in 2016 and $2.61 per MCF in 2015 (2014 prices averaged $4.34 per MCF). The closing price for NYMEX natural gas as of December 31, 2017, was $3.30 per MCF. Certain natural gas production offshore Sarawak have been sold in recent years at a premium to average NYMEX natural gas prices due to pricing structures built into the sales contracts. Associated natural gas produced at fields in Block K offshore Sabah, representing approximately 6% of the Company's 2017 natural gas sales volumes, is sold at heavily discounted prices compared to NYMEX gas prices as stipulated in the sales contract.

The Company cannot predict how changes in the sales prices of oil and natural gas will affect its results of operations in future periods. The Company seeks to hedge a portion of its exposure to the effects of changing prices of crude oil and natural gas by selling forwards, swaps and other forms of derivative contracts. In addition, the Company seeks to maximize realized prices for Canadian gas through a combination of physical forward sales and marketing to a variety of locations.

Low oil and natural gas prices may adversely affect the Company's operations in several ways in the future.

As noted elsewhere in this report, crude oil prices were lower in the 2015-2017 period versus pre-2015 years. WTI oil prices averaged approximately $51 per barrel in 2017, but have improved to above $60 per barrel by the end of 2017 and early 2018. Lower oil and natural gas prices adversely affect the Company in several ways:

- Lower sales value for the Company's oil and natural gas production reduces cash flows and net income.
- Lower cash flows may cause the Company to reduce its capital expenditure program, thereby potentially restricting its ability to grow production and add proved reserves. The Company may restrict its capital expenditures to balance its cash positions going forward.
- Lower oil and natural gas prices could lead to impairment charges in future periods.
- Reductions in oil and natural gas prices could lead to reductions in the Company's proved reserves in future years. Low prices could make certain of the Company's proved reserves uneconomic, which in turn could lead to removal of certain of the Company's 2017 year-end reported proved oil reserves in future periods. These reserve reductions could be significant.

- Lower oil prices can impact the Company's financial metrics, and the credit rating agencies tend to lower credit ratings during periods of low commodity prices. In addition, banks and other suppliers of financing capital generally reduce their lending limits in response to lower oil price environments. In February 2016, Moody's Investor Services downgraded the Company's unsecured notes to a "B1" rating, and in August 2017 subsequently upgraded the Company's unsecured notes rating to "Ba3" (stable). In February 2016, Fitch Rating downgraded the Company's notes to below investment grade, and further downgraded them in August 2017 to "BB" (stable). Both current ratings by Moody's Investor Services and Fitch Ratings are below investment grade. Standard & Poor's rates the Company's debt as investment grade at "BBB-". The Company's ability to obtain financing is affected by the Company's debt credit ratings and competition for available debt financing. Any further lowering of the Company's debt credit ratings could increase the Company's cost of capital and make it more difficult for the Company to borrow.
- Lower prices for oil and natural gas could lead to weaker market prices for the Company's common stock and could cause the Company to lower its dividend.

Certain of these effects are further discussed in risk factors that follow.

Murphy's commodity price risk management may limit the Company's ability to fully benefit from potential future price increases for oil and natural gas.

The Company routinely enters into various contracts to protect its cash flows against lower oil and natural gas prices. Because of these contracts, if the prices for oil and natural gas increase in future periods, the Company will not fully benefit from the price improvement on all of its production.

Murphy Oil's businesses operate in highly competitive environments, which could adversely affect it in many ways, including its profitability, its ability to grow, and its ability to manage its businesses.

Murphy operates in the oil and gas industry and experiences competition from other oil and gas companies, which include state-owned foreign oil companies, major integrated oil companies, private equity investors and independent producers of oil and natural gas. Many of the state-owned and major integrated oil companies and some of the independent producers that compete with the Company have substantially greater resources than Murphy. In addition, the oil industry as a whole competes with other industries in supplying energy requirements around the world. Murphy competes, among other things, for valuable acreage positions, exploration licenses, drilling equipment and human resources.

If Murphy cannot replace its oil and natural gas reserves, it may not be able to sustain or grow its business.

Murphy continually depletes its oil and natural gas reserves as production occurs. In order to sustain and grow its business, the Company must successfully replace the oil and natural gas it produces with additional reserves. Therefore, it must create and maintain a portfolio of good prospects for future reserves additions and production by obtaining rights to explore for, develop and produce hydrocarbons in prospective areas. In addition, it must find, develop and produce and/or purchase reserves at a competitive cost to be successful in the long-term. Murphy's ability to operate profitably in the exploration and production business, therefore, is dependent on its ability to find, develop and produce and/or purchase oil and natural gas reserves at costs that are less than the realized sales price for these products. In response to lower oil prices in recent years, the Company reduced its exploration program in 2016 and 2017 compared to previous years' levels, this may reduce the rate at which it is able to replace reserves. The Company continually reviews opportunities to acquire additional reserves at low cost and in 2016 acquired a 70% operated working interest (WI) of Athabasca Oil Corporation's (Athabasca) production, acreage, infrastructure and facilities in the Kaybob Duvernay lands, and a 30% non-operated WI of Athabasca's production, acreage, infrastructure and facilities in the liquids rich Placid Montney lands in Alberta.

Murphy's proved reserves are based on the professional judgment of its engineers and may be subject to revision.

Proved reserves of crude oil, natural gas liquids (NGL) and natural gas included in this report on pages 106 through 112 have been prepared by qualified Company personnel or qualified independent engineers based on an unweighted average of crude oil, NGL and natural gas prices in effect at the beginning of each month of the respective year as well as other conditions and information available at the time the estimates were prepared. Estimation of reserves is a subjective process that involves professional judgment by engineers about volumes to be recovered in future periods from underground oil and natural gas reservoirs. Estimates of economically recoverable crude oil, NGL and natural gas reserves and future net cash flows depend upon a number of variable factors and assumptions, and consequently, different engineers could arrive at different estimates of reserves and future net cash flows based on the same available data and using industry accepted engineering practices and scientific methods. Under existing SEC rules, reported proved reserves must be reasonably certain of recovery in future periods.

Murphy's actual future oil and natural gas production may vary substantially from its reported quantity of proved reserves due to a number of factors, including:

- Oil and natural gas prices which are materially different from prices used to compute proved reserves
- Operating and/or capital costs which are materially different from those assumed to compute proved reserves
- Future reservoir performance which is materially different from models used to compute proved reserves, and
- Governmental regulations or actions which materially impact operations of a field.

The Company's proved undeveloped reserves represent significant portions of total proved reserves. As of December 31, 2017, approximately 43% of the Company's crude oil and condensate proved reserves, 50% of natural gas liquids proved reserves and 57% of natural gas proved reserves are undeveloped. The ability of the Company to reclassify these undeveloped proved reserves to the proved developed classification is generally dependent on the successful completion of one or more operations, which might include further development drilling, construction of facilities or pipelines, and well workovers.

The discounted future net revenues from our proved reserves as reported on pages 116 and 117 should not be considered as the market value of the reserves attributable to our properties. As required by generally accepted accounting principles (GAAP), the estimated discounted future net revenues from our proved reserves are based on an unweighted average of the oil and natural gas prices in effect at the beginning of each month during the year. Actual future prices and costs may be materially higher or lower than those used in the reserves computations.

In addition, the 10% discount factor that is required to be used to calculate discounted future net revenues for reporting purposes under GAAP is not necessarily the most appropriate discount factor based on our cost of capital and the risks associated with our business and the crude oil and natural gas business in general.

Exploration drilling results can significantly affect the Company's operating results.

The Company drills exploratory wells which subjects its exploration and production operating results to exposure to dry holes expense, which may have adverse effects on, and create volatility for, the Company's results of operations. In response to lower oil prices, the Company has reduced its exploration program from pre-2015 levels. In 2017 exploration wells were drilled offshore Vietnam and in the Gulf of Mexico. The Company's 2018 planned exploratory drilling program includes three wells in the Gulf of Mexico, one well in Vietnam and one well in Block 5, Mexico.

Potential federal or state regulations could increase the Company's costs and/or restrict operating methods, which could adversely affect its production levels.

The Company's onshore North America oil and gas production is dependent on a technique known as hydraulic fracturing whereby water, sand and certain chemicals are injected into deep oil and gas bearing reservoirs in North America. This process creates fractures in the rock formation within the reservoir which enables oil and natural gas to migrate to the wellbore. The Company primarily uses this technique in the Eagle Ford Shale in South Texas and in Western Canada. This practice is generally regulated by the states, but at times the U.S. has proposed additional regulations under the Safe Drinking Water Act. In June 2011, the State of Texas adopted a law requiring public disclosure of certain information regarding the components used in the hydraulic fracturing process. The Provinces of British Columbia and Alberta have also issued regulations related to hydraulic fracturing activities under their jurisdictions. It is possible that the states, the U.S., Canadian provinces and certain municipalities adopt further laws or regulations which could render the process unlawful, less effective or drive up its costs. If any such action is taken in the future, the Company's production levels could be adversely affected or its costs of drilling and completion could be increased.

In April 2016, the U.S. Department of the Interior's (DOI) Bureau of Safety and Environmental Enforcement (BSEE) enacted broad regulatory changes related to Gulf of Mexico well design, well control, casing, cementing, real-time monitoring, and subsea containment, among other items. These changes are known broadly as the Well Control Rule, and compliance is required over the next several years. However, some provisions remain for which BSEE future enforcement action and intent are unclear, so risk of impact leading to increased future cost on the Company's Gulf of Mexico operations remains.

In July 2016, the DOI's Bureau of Ocean Energy Management (BOEM) issued an updated Notice to Lessees and Operators (NTL) providing details on revised procedures BOEM will be using to determine a lessee's ability to carry out decommissioning obligations for activities on the Outer Continental Shelf (OCS), including the Gulf of Mexico. This revised policy became effective in September 2016 and institutes new criteria by which the BOEM will evaluate the financial strength and reliability of lessees and operators active on the OCS. If the BOEM determines under the revised policy that a company does not have the financial ability to meet its decommissioning and other obligations, that company will be required to post additional financial security as assurance. In January 2017 BOEM extended the implementation timeline for the NTL by six months for properties which have co-lessees, and in February 2017 BOEM withdrew sole liability orders issued in December 2016 to allow time for the new administration to review the financial assurance program for decommissioning. Although the Company believes the new BOEM policy will likely lead to increased costs for its Gulf of Mexico operations, it does not currently believe that the impact will be material to its operations in the Gulf of Mexico.

In the future, BOEM and/or BSEE may impose new and more stringent offshore operating regulations which may adversely affect the Company's operations.

Hydraulic fracturing exposes the Company to operational and regulatory risks and third-party claims.

Hydraulic fracturing operations subject the Company to operational risks inherent in the drilling and production of oil and natural gas. These risks include underground migration or surface spillage due to releases of oil, natural gas, formation water or well fluids, as well as any related surface or ground water contamination, including from petroleum constituents or hydraulic fracturing chemical additives. Ineffective containment of surface spillage and surface or ground water contamination resulting from hydraulic fracturing operations, including from petroleum constituents or hydraulic fracturing chemical additives, could result in environmental pollution, remediation expenses and third-party claims alleging damages, which could adversely affect the Company's financial condition and results of operations. In addition, hydraulic fracturing requires significant quantities of water; the waste water from oil and gas operations is often disposed of through underground injection. Certain increased seismic activities have been linked to underground water injection. Any diminished access to water for use in the hydraulic fracturing process, any inability to properly dispose of waste water, or any further restrictions placed on waste water, could curtail the Company's operations or otherwise result in operational delays or increased costs.

Climate change initiatives and other environmental rules or regulations could reduce demand for crude oil and natural gas, which may adversely impact the Company's business.

The issue of climate change has caused considerable attention to be directed towards initiatives to reduce global greenhouse gas emissions. An international climate agreement (the "Paris Agreement") was agreed to at the 2015 United Nations Framework Convention on Climate Change in Paris, France. The Paris Agreement entered into force in November 2016, however, after originally entering the agreement the U.S. administration has subsequently withdrawn from this agreement. The U.S. remains the only country not part of the Paris Agreement. It is possible that the Paris Agreement, if fully implemented, and other such initiatives, including environmental rules or regulations related to greenhouse gas emissions and climate change, may reduce the demand for crude oil and natural gas globally. While the magnitude of any reduction in hydrocarbon demand is difficult to predict, such a development could adversely impact the Company and other companies engaged in the exploration and production business. The Company continually monitors the global climate change agenda initiatives and plans accordingly based on its assessment of such initiatives on its business.

Capital financing may not always be available to fund Murphy's activities.

Murphy usually must spend and risk a significant amount of capital to find and develop reserves before revenue is generated from production. Although most capital needs are funded from operating cash flow, the timing of cash flows from operations and capital funding needs may not always coincide, and the levels of cash flow generated by operations may not fully cover capital funding requirements, especially in periods of low commodity prices such as those experienced in recent years. Therefore, the Company maintains financing arrangements with lending institutions to meet certain funding needs. The Company periodically renews these financing arrangements based on foreseeable financing needs or as they expire. The Company has a primary bank financing facility with capacity of $1.1 billion that now matures in August 2021. There is the possibility that financing arrangements may not always be available at sufficient levels required to fund the Company's activities in future periods. As of December 31, 2017, the Company's long-term debt was rated "Ba3" (stable) by Moody's Investor Services and "BB" (stable) by Fitch Ratings. These credit ratings are below investment grade and could adversely affect our cost of capital and our ability to raise debt as needed in public markets in future periods. Additionally, in order to obtain debt financing in future years, the Company may have to provide more security to its lenders. Below investment grade credit ratings by certain agencies have led to increased debt service costs for certain outstanding notes, and also made it more likely that the Company would have to post collateral such as letters of credit or cash as financial assurance of its performance under certain contractual arrangements. The Company's primary revolving credit facility requires granting of security by the Company in certain circumstances, which have not occurred at this time. See further explanation in Note F of the Consolidated Financial Statements. The Company has a shelf registration statement on file with the U.S. Securities and Exchange Commission that permits the offer and sale of debt and/or equity securities through October 2018.

Murphy has limited or virtually no control over several factors that could adversely affect the Company.

The ability of the Company to successfully manage development and operating costs is important because virtually all of the products it sells are energy commodities such as crude oil, NGL and natural gas, for which the Company has little or no influence on the sales prices or regional and worldwide consumer demand for these products. Changes in commodity prices also impact the volume of production attributed to the Company under production sharing contracts in Malaysia. Economic slowdowns, such as those experienced in 2008 and 2009, had a detrimental effect on the worldwide demand for these energy commodities, which effectively led to reduced prices for oil and natural gas for a period of time. An abundant supply of crude oil in recent years also led to a severe decline in worldwide oil prices. Lower prices for crude oil, NGL and natural gas inevitably lead to lower earnings for the Company. The low crude oil price environment in the 2015-2017 period has caused the Company to reduce spending on certain discretionary drilling programs, which in turn hurts the Company's future production levels and future cash flow generated from operations. The Company often experiences pressure on its operating and capital expenditures in periods of strong crude oil and natural gas prices because an increase in exploration and production activities due to high oil and gas sales prices generally leads to higher demand for, and consequently higher costs for, goods and services in the oil and gas industry. The increase in oil prices in 2017 has led to some upward inflation pressure in oil field goods and service costs during the year.

Certain of the Company's major oil and natural gas producing properties are operated by others. Therefore, Murphy does not fully control all activities at certain of its revenue generating properties. During 2017, approximately 14% of the Company's total production was at fields operated by others, while at December 31, 2017, approximately 9% of the Company's total proved reserves were at fields operated by others.

Additionally, the Company relies on the availability of transportation and processing facilities that are often owned by others. These third-party systems and facilities may not always be available to the Company, and if available, may not be available at a price that is acceptable to the Company.

Failure of our partners to fund their share of development costs or obtain financing could result in delay or cancellation of future projects, thus limiting our growth and future cash flows.

Some of Murphy's development projects entail significant capital expenditures and have long development cycle times. As a result, the Company's partners must be able to fund their share of investment costs through the development cycle, through cash flow from operations, external credit facilities, or other sources, including financing arrangements. Murphy's partners are also susceptible to certain of the risk factors noted herein, including, but not limited to, commodity price declines, fiscal regime changes, government project approval delays, regulatory changes, credit downgrades and regional conflict. If one or more of these factors negatively impacts a project partners' cash flows or ability to obtain adequate financing, it could result in a delay or cancellation of a project, resulting in a reduction of the Company's reserves and production, which negatively impacts the timing and receipt of planned cash flows and expected profitability.

Murphy's operations and earnings have been and will continue to be affected by worldwide political developments.

Many governments, including those that are members of the Organization of Petroleum Exporting Countries (OPEC), unilaterally intervene at times in the orderly market of crude oil and natural gas produced in their countries through such actions as changing fiscal regimes (including corporate tax rates), setting prices, determining rates of production, and controlling who may buy and sell the production.

On December 22, 2017, the U.S. enacted into legislation the Tax Cuts and Jobs Act (2017 Tax Act). For the year ended December 31, 2017, Murphy recorded a tax expense of $274.0 million associated with the 2017 Tax Act. The charge includes the impact of a deemed repatriation of foreign income and the re-measurement of the future value of deferred tax assets and liabilities. Separately, Murphy expects to receive cash refunds or credits of $29.7 million over the next four years relating to Alternative Minimum Tax (AMT) credits generated in earlier years. Murphy continues to assess the impact of this legislation including, among other things, the carry-forward of 2017 net operating losses, the change to U.S. federal tax rates, the possible limitations on the deductibility of interest paid, the option for expensing of capital expenditures, the migration from a worldwide system of taxation to a territorial system, and the use of new anti-base erosion provisions. The tax expense recorded in 2017 is a reasonable estimate based on published guidance available at this time and is considered provisional. The ultimate impact of the 2017 Tax Act may differ from these estimates due to changes in interpretations and assumptions made by the company, as well as additional regulatory guidance that may be issued. There is substantial uncertainty regarding interpretations and details of certain aspects of the 2017 Tax Act. The impact of the legislation on our business and on holders of our common shares is uncertain and could be adverse, as well as favorable. The SEC has permitted U.S. registrants one year to complete and recognize the effects of the 2017 Tax Act.

As of December 31, 2017, approximately 19% of the Company's proved reserves, as defined by the SEC, were located in countries other than the U.S. and Canada. In addition, prices and availability of crude oil, natural gas and refined products could be influenced by political unrest and by various governmental policies to restrict or increase petroleum usage and supply. Other governmental actions that could affect Murphy's operations and earnings include expropriation, tax changes, royalty increases, redefinition of international boundaries, preferential and discriminatory awarding of oil and gas leases, restrictions on drilling and/or production, restraints and controls on imports and exports, safety, and relationships between employers and employees. Governments could also initiate regulations concerning matters such as currency fluctuations, currency conversion, protection and remediation of the environment, and concerns over the possibility of global warming caused by the production and use of hydrocarbon energy.

A number of non-governmental entities routinely attempt to influence industry members and government energy policy in an effort to limit industry activities, such as hydrocarbon production, drilling and hydraulic fracturing with the desire to minimize the emission of greenhouse gases such as carbon dioxide, which may harm air quality, and to restrict hydrocarbon spills, which may harm land and/or groundwater.

Additionally, because of the numerous countries in which the Company operates, certain other risks exist, including the application of the U.S. Foreign Corrupt Practices Act, the Canada Corruption of Foreign Officials Act, the Malaysia Anti-Corruption Commission Act, the U.K. Bribery Act, the Brazil Clean Companies Act, the Mexico General Law of the National Anti-Corruption System, and other similar anti-corruption compliance statutes.

It is not possible to predict the actions of governments and hence the impact on Murphy's future operations and earnings.

Murphy's business is subject to operational hazards, security risks and risks normally associated with the exploration for and production of oil and natural gas.

The Company operates in urban and remote, and sometimes inhospitable, areas around the world. The occurrence of an event, including but not limited to acts of nature such as hurricanes, floods, earthquakes (and other forms of severe weather), mechanical equipment failures, industrial accidents, fires, explosions, acts of war, civil unrest, piracy and acts of terrorism could result in the loss of hydrocarbons and associated revenues, environmental pollution or contamination, personal injury, (including death), and property damages for which the Company could be deemed to be liable and which could subject the Company to substantial fines and/or claims for punitive damages.

The location of many of Murphy's key assets causes the Company to be vulnerable to severe weather, including hurricanes and tropical storms. A number of significant oil and natural gas fields lie in offshore waters around the world. Probably the most vulnerable of the Company's offshore fields are in the U.S. Gulf of Mexico, where severe hurricanes and tropical storms have often led to shutdowns and damages. The U.S. hurricane season runs from June through November. Although the Company maintains insurance for such risks as described elsewhere in this Form 10-K report, due to policy deductibles and possible coverage limits, weather-related risks are not fully insured. The Company has in the past experienced operational delays in Malaysia due to tropical storms in the South China Sea.

In addition, the Company has risks associated with cybersecurity attacks. Although the Company maintains processes and systems to monitor and avoid damages from security threats, there can be no assurance that such processes and systems will successfully avert such security breaches. A successful breach could lead to system disruptions, loss of data or unauthorized release of highly sensitive data. This could lead to property or environmental damages and could have an adverse effect on the Company's revenues and costs.

Murphy's insurance may not be adequate to offset costs associated with certain events and there can be no assurance that insurance coverage will continue to be available in the future on terms that justify its purchase.

Murphy maintains insurance against certain, but not all, hazards that could arise from its operations. The Company maintains liability insurance sufficient to cover its share of gross insured claim costs up to approximately $500 million per occurrence and in the annual aggregate. Generally, this insurance covers various types of third-party claims related to personal injury, death and property damage, including claims arising from "sudden and accidental" pollution events. The Company also maintains insurance coverage with an additional limit of $400 million per occurrence ($850 million for Gulf of Mexico claims not related to a named windstorm), all or part of which could be applicable to certain sudden and accidental pollution events. These policies have deductibles ranging from $10 million to $25 million. The occurrence of an event that is not insured or not fully insured could have a material adverse effect on the Company's financial condition and results of operations in the future.

Lawsuits against Murphy and its subsidiaries could adversely affect its operating results.

The Company is involved in numerous lawsuits seeking cash settlements for alleged personal injuries, property damages and other business-related matters. Certain of these lawsuits will take many years to resolve through court proceedings or negotiated settlements. None of the currently pending lawsuits are considered individually material or aggregate to a material amount in the opinion of management.

The Company is exposed to credit risks associated with sales of certain of its products to third parties and associated with its operating partners.

Although Murphy limits its credit risk by selling its products to numerous entities worldwide, it still, at times, carries substantial credit risk from its customers. For certain oil and gas properties operated by the Company, other companies which own partial interests may not be able to meet their financial obligation to pay for their share of capital and operating costs as they come due. The inability of a purchaser of the Company's oil or natural gas or a partner of the Company to meet their respective payment obligations to the Company could have an adverse effect on Murphy's future earnings and cash flows.

Murphy's operations could be adversely affected by changes in foreign currency conversion rates.

The Company's worldwide operational scope exposes it to risks associated with foreign currencies. Most of the Company's business is transacted in U.S. dollars, and therefore the Company and most of its subsidiaries are U.S. dollar functional entities for accounting purposes. However, the Canadian dollar is the functional currency for all Canadian operations.

In certain countries, such as Canada and Malaysia significant levels of transactions occur in currencies other than the functional currency. In Malaysia, such transactions include tax and other supplier payments, while in Canada, certain crude oil sales are priced in U.S. dollars. In late 2016, Malaysian authorities altered the local currency rules such that 75% of the proceeds of export oil and gas sales must be converted to local currency when received; plus, beginning in 2017, resident suppliers of goods and services to the Company must be paid in local currency.

This exposure to currencies other than the functional currency can lead to impacts on consolidated financial results from foreign currency translation. Exposures associated with current and deferred income tax liability and asset balances in Malaysia are generally not hedged. A strengthening of the Malaysian ringgit against the U.S. dollar would be expected to lead to currency gains in consolidated operations; losses would be expected if the ringgit weakens versus the dollar. In Canada, currency risk is often managed by selling forward U.S. dollars to match the collection dates for crude oil sold in that currency. On occasions the Canadian business may hold assets or incur liabilities denominated in a currency which is not Canadian dollars which could lead to exposure to foreign exchange rate fluctuations. See also Note L in the Notes to Consolidated Financial Statements for additional information on derivative contracts.

The costs and funding requirements related to the Company's retirement plans are affected by several factors.

A number of actuarial assumptions impact funding requirements for the Company's retirement plans. The most significant of these assumptions include return on assets, long-term interest rates and mortality. If the actual results for the plans vary significantly from the actuarial assumptions used, or if laws regulating such retirement plans are changed, Murphy could be required to make more significant funding payments to one or more of its retirement plans in the future and/or it could be required to record a larger liability for future obligations in its Consolidated Balance Sheet.

Item 1B. UNRESOLVED STAFF COMMENTS

The Company had no unresolved comments from the staff of the U.S. Securities and Exchange Commission as of December 31, 2017.

Item 2. PROPERTIES

Descriptions of the Company's oil and natural gas properties are included in Item 1 of this Form 10-K report beginning on page 1. Information required by the Securities Exchange Act Industry Guide No. 2 can be found in the Supplemental Oil and Gas Information section of this Annual Report on Form 10-K on pages 104 to 117 and in Note E – Property, Plant and Equipment beginning on page 71.

Executive Officers of the Registrant

Present corporate office, length of service in office and age at February 1, 2018 of each of the Company's executive officers are reported in the following listing. Executive officers are elected annually, but may be removed from office at any time by the Board of Directors.

Roger W. Jenkins – Age 56; Chief Executive Officer since August 2013. Mr. Jenkins served as Chief Operating Officer from June 2012 to August 2013. Mr. Jenkins was Executive Vice President Exploration and Production from August 2009 through August 2013 and has served as President of the Company's exploration and production subsidiary since January 2009.

Eugene T. Coleman – Age 59; Executive Vice President since December 2016. Mr. Coleman has also served as Executive Vice President, Offshore of the Company's exploration and production subsidiary from 2011 to 2017.

Walter K. Compton – Age 55; Executive Vice President and General Counsel since February 2014. Mr. Compton was Senior Vice President and General Counsel from March 2011 to February 2014.

John W. Eckart – Age 59; Executive Vice President and Chief Financial Officer since March 2015. Mr. Eckart was Senior Vice President and Controller from December 2011 to March 2015.

Michael K. McFadyen – Age 50; Executive Vice President since December 2016. Mr. McFadyen has also served as Executive Vice President, Onshore of the Company's exploration and production subsidiary from 2011 to 2017.

Christopher D. Hulse – Age 39, Vice President and Controller since June 2017. Mr. Hulse was Vice President, Finance, Onshore from September 2015 to June 2017.

Kelli M. Hammock – Age 46; Senior Vice President, Administration since February 2014. Ms. Hammock was Vice President, Administration from December 2009 to February 2014.

K. Todd Montgomery – Age 53; Senior Vice President, Planning and Performance since January 2017. Mr. Montgomery served as Senior Vice President, Corporate Planning & Services from March 2015 to January 2017.

E. Ted Botner – Age 53; Vice President, Law and Secretary since March 2015. Mr. Botner was Secretary and Manager, Law from August 2013 to March 2015.

Tim F. Butler – Age 55; Vice President, Tax since August 2013. Mr. Butler was General Manager, Worldwide Taxation from August 2007 to August 2013.

John B. Gardner – Age 49; Vice President and Treasurer since March 2015. Mr. Gardner served as Treasurer from August 2013 to March 2015.

Barry F.R. Jeffery – Age 59; Vice President, Health, Safety, Environment and Risk Management since June 2017. Mr. Jeffery was Vice President, Insurance, Security and Risk from July 2015 to June 2017.

Kelly L. Whitley – Age 52; Vice President, Investor Relations and Communications since July 2015. Ms. Whitley joined the Company in 2015 following 20 years of investor relations experience with exploration and production as well as oil field services companies in the U.S. and Canada.

Item 3. LEGAL PROCEEDINGS

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 matters referred to in this item is not expected to have a material adverse effect on the Company's net income or loss, financial condition or liquidity in a future period.

Item 4. MINE SAFETY DISCLOSURES

Not applicable.

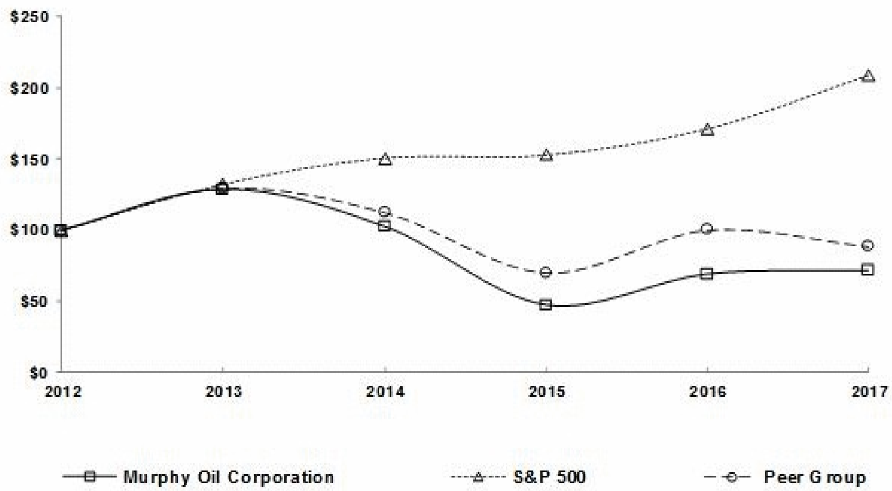
PART II

Item 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

The Company's Common Stock is traded on the New York Stock Exchange using "MUR" as the trading symbol. There were 2,506 stockholders of record as of December 31, 2017. Information as to high and low market prices per share and dividends per share by quarter for 2017 and 2016 are reported on page 118 of this Form 10-K report.

SHAREHOLDER RETURN PERFORMANCE PRESENTATION

The following graph presents a comparison of cumulative five-year shareholder returns (including the reinvestment of dividends) as if a $100 investment was made on December 31, 2012 in the Company, the Standard & Poor's 500 Stock Index (S&P 500 Index) and, the Company's peer group. The companies in the peer group include Anadarko Petroleum Corporation, Apache Corporation, Cabot Oil & Gas Corporation, Chesapeake Energy Corporation, Cimarex Energy Co., Devon Energy Corporation, Encana Corporation, EOG Resources, Inc., Hess Corporation, Marathon Oil Corporation, Newfield Exploration Company, Noble Energy, Inc., Pioneer Natural Resources Corporation, Range Resources Corporation, Southwestern Energy Company and Whiting Petroleum Corporation. This performance information is "furnished" by the Company and is not considered as "filed" with this Form 10-K report and it is not incorporated into any document that incorporates this Form 10-K report by reference.



		2012	2013	2014	2015	2016	2017
Murphy Oil Corporation	$	100	129	103	47	69	71
S&P 500 Index		100	132	151	153	170	208
Peer Group		100	129	113	70	100	89

Item 6. SELECTED FINANCIAL DATA

(Thousands of dollars except per share data)						
Results of Operations for the Year		**2017**	2016	2015	2014	2013
Sales and other operating revenues	$	**2,097,695**	1,809,575	2,787,116	5,288,933	5,312,686
Net cash provided by continuing operations		**1,129,675**	600,795	1,183,369	3,048,639	3,210,695
Income (loss) from continuing operations		**(310,936)**	(273,943)	(2,255,772)	1,024,973	888,137
Net income (loss)		**(311,789)**	(275,970)	(2,270,833)	905,611	1,123,473
Cash dividends – diluted		**172,565**	206,635	244,998	236,371	235,108
Per Common share – diluted						
Income (loss) from continuing operations	$	**(1.81)**	(1.59)	(12.94)	5.69	4.69
Net income (loss)		**(1.81)**	(1.60)	(13.03)	5.03	5.94
Average common shares outstanding (thousands) – diluted		**172,524**	172,173	174,351	180,071	189,271
Cash dividends per Common share		**1.00**	1.20	1.40	1.325	1.25
Capital Expenditures for the Year [1]						
Continuing operations						
Exploration and production	$	**960,870**	789,721	2,127,197	3,742,541	3,943,956 [2]
Corporate and other		**14,821**	21,740	59,886	14,453	22,014
		975,691	811,461	2,187,083	3,756,994	3,965,970
Discontinued operations		**–**	–	159	12,349	154,622
	$	**975,691**	811,461	2,187,242	3,769,343	4,120,592
Financial Condition at December 31						
Current ratio		**1.64**	1.04	0.83	1.02	1.06
Working capital (deficit)	$	**537,396**	56,751	(277,396)	76,155	222,621
Net property, plant and equipment		**8,220,031**	8,316,188	9,818,365	13,331,047	13,481,055
Total assets		**9,860,942**	10,295,860	11,493,812	16,742,307	17,509,484
Long-term debt		**2,906,520**	2,422,750	3,040,594	2,536,238	2,936,563
Stockholders' equity		**4,620,191**	4,916,679	5,306,728	8,573,434	8,595,730
Per share		**26.77**	28.55	30.85	48.30	46.87
Long-term debt – percent of capital employed [3]		**38.6**	33.0	36.4	22.8	25.5
Stockholder and Employee Data at December 31						
Common shares outstanding (thousands)		**172,573**	172,202	172,035	177,500	183,407
Number of stockholders of record		**2,506**	2,588	2,713	2,556	2,598

[1] Capital expenditures include accruals for incurred but unpaid capital activities, while property additions and dry holes in the Statements of Cash Flows are cash-based capital expenditures and do not include capital accruals and geological, geophysical and certain other exploration expenses that are not eligible for capitalization under oil and gas accounting rules.

[2] Excludes property addition of $358.0 million associated with noncash capital lease at the Kakap field.

[3] Long-term debt – percent of capital employed – total long-term debt at the balance sheet date divided by the sum of total long-term debt plus total stockholders' equity at that date.

Item 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Murphy Oil Corporation is a worldwide oil and gas exploration and production company. A more detailed description of the Company's significant assets can be found in Item 1 of this Form 10-K report.

Significant Company operating and financial highlights during 2017 were as follows:

- Income from continuing operations before income taxes of $71.8 million (2016 loss: $493.1 million)
- Issued $550 million of 5.75% senior notes due 2025 and repaid $550 million of notes that were to mature in December 2017
- Produced 163,536 barrels of oil equivalent (BOE) per day
- Achieved an overall lease operating expense per BOE of $7.89
- Reduced selling and general expenses by 16% year over year
- Replaced 123% of total proved reserves
- Maintained approximately $1.0 billion of cash and short-term securities throughout 2017

Murphy's continuing operations generate revenue by producing crude oil, natural gas liquids (NGL) and natural gas in the United States, Canada and Malaysia and then selling these products to customers. The Company's revenue is highly affected by the prices of crude oil, natural gas and NGL. In order to make a profit and generate cash in its exploration and production business, revenue generated from the sales of oil and natural gas produced must exceed the combined costs of producing these products, depreciation of capital expenditures, and expenses related to exploration, administration, and for capital borrowed from lending institutions and note holders.

Changes in the price of crude oil and natural gas have a significant impact on the profitability of the Company. In 2017 liquids represented 61% of total hydrocarbons produced on an energy equivalent basis. In 2018, the Company's ratio of hydrocarbon production represented by liquids is expected to be 59%. When oil-price linked natural gas in Malaysia is combined with oil production, the Company's 2018 total expected production is approximately 70% linked to the price of oil. If the prices for crude oil and natural gas are lower in 2018 or beyond, this will have an unfavorable impact on the Company's operating profits. As described on page 49, the Company has entered into fixed price derivative swap contracts in the United States that will reduce its exposure to changes in crude oil prices for approximately 44% of its expected 2018 U.S. oil production and holds fixed price forward delivery contracts that will reduce its exposure to changes in natural gas prices for approximately 30% of the natural gas it expects to produce in Western Canada in 2018. In addition, a further portion of Western Canada gas production is marketed to a variety of locations, diversifying risk further.

Oil prices and North American natural gas prices strengthened in 2017 compared to the 2016 period. The sales price of a barrel of West Texas Intermediate (WTI) crude oil averaged $50.95 in 2017, $43.32 in 2016 and $48.80 in 2015. The sales price of a barrel of Platts Dated Brent crude oil increased to $54.28 per barrel in 2017, following averages of $43.69 per barrel and $52.46 per barrel in 2016 and 2015, respectively. The WTI index increased approximately 18% over the prior year while Dated Brent experienced a 24% increase in 2017. During 2017 the discount for WTI crude compared to Dated Brent increased compared to the prior year. The average WTI to Dated Brent discount was $3.33 per barrel during 2017, compared to $0.37 per barrel in 2016 and $3.66 per barrel in 2015. In early 2018, Dated Brent has been trading at a similar premium to WTI as 2017 average levels. Worldwide oil prices began to weaken in the fall of 2014 and continued to soften throughout 2015 and into 2016. The softening of prices beginning in late 2014 and continuing into 2016 caused average oil prices for both 2015 and 2016 periods to be below the average levels achieved in 2017. Crude oil prices in early 2018 were above the 2017 average prices.

The NYMEX natural gas price per million British Thermal Units (MMBTU) averaged $2.96 in 2017, $2.48 in 2016 and $2.61 in 2015. NYMEX natural gas prices in 2017 were 19% above the average price in 2016, with the increase largely due to demand generated by LNG export growth and overland deliveries to Mexico. NYMEX natural gas prices in 2016 were 5% below the average price experienced in 2015, with the price decrease generally caused by domestic production elevating inventories to record levels and much warmer than normal winter season temperatures reducing residential demand. On an energy equivalent basis, the market continued to discount North American natural gas and NGL compared to crude oil in 2017. Natural gas prices in North America in 2018 have thus far been above the average 2017 levels due to higher demand and lower inventory levels in both cases.

Results of Operations

Murphy Oil's results of operations, with associated diluted earnings per share (EPS), for the last three years are presented in the following table.

(Millions of dollars, except EPS)		Years Ended December 31, 2017	2016	2015
Income (loss) from continuing operations before income taxes	$	**71.8**	(493.1)	(3,282.3)
Net loss	$	**(311.8)**	(276.0)	(2,270.8)
Diluted EPS		**(1.81)**	(1.60)	(13.03)
Loss from continuing operations	$	**(310.9)**	(274.0)	(2,255.8)
Diluted EPS		**(1.81)**	(1.59)	(12.94)
Loss from discontinued operations	$	**(0.9)**	(2.0)	(15.0)
Diluted EPS		**0.00**	(0.01)	(0.09)

On December 22, 2017, the U.S. enacted into legislation the Tax Cuts and Jobs Act (2017 Tax Act). For the year ended December 31, 2017, Murphy recorded a tax expense of $274.0 million directly related to the impact of the 2017 Tax Act. The charge includes the impact of a deemed repatriation of accumulated foreign earnings and the re-measurement of deferred tax assets and liabilities. Separately, Murphy expects to receive cash refunds or credits of $29.7 million over the next four years relating to Alternative Minimum Tax (AMT) credits generated in earlier years. Murphy continues to assess the impact of this legislation including, among other things, the carryforward of 2017 net operating losses, refinement of post-1986 accumulated foreign earnings and profits computations, the change to U.S. federal tax rates, the possible limitations on the deductibility of interest expense, the option for expensing of capital expenditures, the migration from a worldwide system of taxation to a territorial system, and the use of new anti-base erosion provisions. The tax expense recorded in 2017 is a reasonable estimate based on published guidance available at this time and is considered provisional. The ultimate impact of the 2017 Tax Act may differ from these estimates due to changes in interpretations and assumptions made by the company, as well as additional regulatory guidance.

Murphy Oil's net loss in 2017 included a tax charge of $274.0 million related to the 2017 Tax Act enacted on December 22, 2017. Results of continuing operations before taxes in 2017 were improved versus 2016. In 2017, loss from continuing operations of $310.9 million ($1.81 per dilute share) worsened from a loss of $274.0 million ($1.59 per diluted share) in 2016. The results for 2017 were favorably impacted by higher revenues due to higher realized oil and natural gas sales prices, lower unrealized losses on forward sales commodity contracts, gain on sale of the Seal property in Western Canada, lower lease operating expenses, lower depreciation expense, non-recurring impairment expense in 2016, and lower selling and general expenses, but these were more than offset by higher tax charges (caused by higher pre-tax income and the impact of the 2017 Tax Act), higher exploration expenses, higher other expenses, higher foreign exchange charges, and higher interest expenses.

In 2017 the Company's discontinued operations was a loss of $0.9 million.

Murphy Oil's net loss in 2016 was primarily caused by low realized oil and gas prices that did not fully cover all expenses, which included extraction costs, selling and general expense, net interest expense, impairments and redetermination expense. Results of continuing operations in 2016 were $1,981.8 million improved over 2015 due to lower impairment expense in 2016, plus lower expenses in 2016 for lease operations, depreciation, exploration, deepwater rig contract exit costs, and administration and no reoccurrence of a deferred tax charge in 2015 associated with a distribution from a foreign subsidiary. Results in 2016 included a $71.7 million after-tax gain on sale of the Company's five percent interest in Syncrude, while 2015 results included a $218.8 million after-tax gain on sale of 10% of the Company's oil and gas assets in Malaysia. In 2016 and 2015, the Company's refining and marketing operations generated losses of $2.5 million and $14.8 million, respectively, which led to overall losses from discontinued operations in each year.

Further explanations of each of these variances are found in more detail in the following.

Segment Results – In the following table, the Company's results of operations for the three years ended December 31, 2017, are presented by segment. More detailed reviews of operating results for the Company's exploration and production and other activities follow the table.

(Millions of dollars)		**2017**	2016	2015
Exploration and production – continuing operations				
United States	$	**(2.6)**	(205.4)	(615.7)
Canada		**112.5**	(35.9)	(583.4)
Malaysia		**224.2**	171.1	(653.2)
Other		**(37.5)**	(54.7)	(158.6)
Total exploration and production – continuing operations		**296.6**	(124.9)	(2,010.9)
Corporate and other		**(607.5)**	(149.1)	(244.9)
Loss from continuing operations		**(310.9)**	(274.0)	(2,255.8)
Loss from discontinued operations		**(0.9)**	(2.0)	(15.0)
Net loss	$	**(311.8)**	(276.0)	(2,270.8)

Exploration and Production – Exploration and production (E&P) continuing operations recorded a profit of $296.6 million in 2017 compared to a loss of $124.9 million in 2016 and a loss of $2,010.9 million in 2015. Crude oil price realizations averaged $51.21 per barrel in the current year compared to $42.32 per barrel in 2016, a price increase of 21% year over year. U.S. natural gas realized price per thousand cubic feet (MCF) averaged $2.49 in the current year compared to $1.89 per MCF in 2016, a price increase of 32% year over year. Canada natural gas realized price per MCF averaged US$1.97 in the current year compared to US$1.72 per MCF in 2016, a price increase of 15% year over year. Oil and gas production costs, including associated production taxes, on a per-unit basis, were $8.63 in 2017 (2016: $9.44), which together with lower oil and natural gas volumes sold, resulted in $91.3 million lower costs in 2017.

2017 vs 2016 – In 2017 profit from E&P operations of $296.6 million (2016: loss of $124.9 million) improved by $421.5 million. The results for 2017 were favorably impacted by higher revenues due to higher realized oil and natural gas sales prices, gain on sale of the Seal property in Western Canada, lower lease operating expenses, lower depreciation expense, non-recurring impairment expense in 2016, lower selling and general expenses, lower redetermination expense, partially offset by higher exploration expenses and higher other expenses.

Revenues of $2,220.5 million were $415.9 million higher than 2016 as a result of higher realized oil prices and natural gas liquid prices in all operating locations and an unrealized gain of $13.7 million (2016: loss of $125.0 million) on forward commodity price contracts, gain on the sale of Seal property of $129.0 million, offset by lower sales volumes, principally in Malaysia (as a result of natural field decline) and as a result of the sale of the Syncrude asset in Western Canada. The gain on the sale of Seal property of $129.0 million was a result of the sale of this property in January 2017, with the gain based on cash proceeds of $48.8 million and a benefit from the acquirer's acceptance of abandonment obligations.

Lease operating expenses of $468.4 million were $91.0 million lower in 2017 principally as a result of the disposal of the Syncrude asset in mid-2016, the disposal of Seal property in January 2017 and also lower operating expenses in the Company's U.S. Onshore business as a result of continued management effort to reduce costs.

Depreciation, depletion and amortization expenses of $939.9 million were $97.4 million lower in 2017 due to the disposal of the Syncrude asset in mid-2016 and lower volumes produced at Block K in Malaysia.

There was no impairment recorded in 2017. In 2016, impairments expenses were $95.1 million as a result of 2016 impairments on the Company's Terra Nova field and Seal heavy oil field in Western Canada (now divested) all of which were incurred in the first quarter of 2016 following further price declines from year-end 2015 levels.

Selling and general expenses of $123.7 million were $23.7 million lower in 2017 as a result of cost saving activities in the Company throughout 2017.

Redetermination expense of $15.0 million in 2017 (relating to the unitization of Gumusut/Kakap (GK) and Geronggong/Jagus East fields) was $24.1 million lower than 2016 (see below). The unitization results in a revised interest in the Kakap field in Block K Malaysia of 6.35%. Following this unitization the Company's working interest in the Brunei section of the Kakap field will be adjusted.

Exploration costs of $122.8 million were $20.9 million higher in 2017 due to higher amortization of U.S. leases and higher geological and geophysical expenses in Mexico.

Other expenses of $30.7 million were higher in 2017 by $16.8 million, principally as a result of U.S. drilling inventory write downs to net realizable value. Income tax charges of $137.1 million were $292.2 million higher than 2016 due to higher profits. The effective income tax rate of 31.6% for the E&P business was 23.8% different to 2016 on absolute basis as a result of deferred tax benefits related to Canadian dispositions in the earlier year (which increased the 2016 tax credit against a 2016 pretax loss).

2016 vs. 2015 – Compared to 2015, total sales volumes in 2016 for crude oil, natural gas and natural gas liquids fell 17%. Oil sale volumes were lower in 2016 primarily due to lower production from the Company's Eagle Ford Shale field and Syncrude and heavy oil fields in Canada due to well decline and significantly less drilling beginning in the last half of 2015 and continuing into 2016. Synthetic oil production in Canada decreased due to impacts from the sale of the Company's interests in Syncrude at the end of the second quarter of 2016 and maintenance work and downtime associated with forest fires in the surrounding area leading up to the disposition. Heavy oil sales volumes in Canada were lower in 2016 due to well decline and uneconomic wells being shut-in. Lower oil production and sales in Malaysia in 2016 were primarily attributable to natural well decline in most fields, partially offset by higher production at Kakap. Natural gas liquid sales volumes decreased primarily due to lower natural gas production in the Eagle Ford Shale. Natural gas sales volumes decreased in North America due to lower gas volumes in the Gulf of Mexico primarily in the Dalmatian field and lower volumes from the Eagle Ford Shale area in south Texas, offset in part by higher gas production volumes in the Tupper area in Western Canada. Lower natural gas production in Malaysia was primarily due to higher unplanned downtime, lower net entitlement at Sarawak and more gas injection at Kikeh.

Lease operating expenses of $559.4 million declined $272.9 million in 2016 compared to 2015 essentially due to sale of interest in Syncrude, lower service costs, cost saving initiatives and a lower average foreign exchange rate in Canada.

Severance and ad valorem taxes of $43.8 million decreased by $22.0 million in 2016 primarily due to lower average realized sales prices for oil and natural gas volumes in the U.S. and lower well valuations due to significantly lower commodity prices.

Exploration expenses of $101.9 million were $369.1 million less in 2016 than the prior year primarily due to lower dry hole costs, lower geological and geophysical costs, lower exploration costs in other foreign areas and lower undeveloped lease amortization.

Selling and general expenses of $147.4 million in 2016 decreased by 17% versus 2015, as the Company implemented further key organizational changes including lowering staffing levels from the end of the prior year.

Depreciation, depletion and amortization expense of $1,037.3 million fell by $570.6 million due to both lower volumes sold and lower per-unit capital amortization rates. The lower capital amortization rates were primarily the result of impairment charges in the last half of 2015 and first quarter of 2016.

Impairment expense associated with asset writedowns was approximately $95.1 million in 2016 compared to $2.5 billion in 2015. The decrease was primarily due to the significant 2015 writedowns of assets in oil and natural gas fields offshore Malaysia, the Seal heavy oil field in Western Canada and fields in deepwater Gulf of Mexico due to decline in oil prices. Impairments in 2016 were at the Company's Terra Nova field and Seal heavy oil field in Western Canada all of which were incurred in the first quarter of 2016 following further price declines from year-end 2015 levels.

Redetermination expense of $39.1 million ($24.1 million after taxes) in 2016 related to an expected reduction in the Company's working interest covering the period from inception through year-end 2016 at its non-operated Kakap-Gumusut field in Block K Malaysia. The final redetermination adjustment will be settled in cash.

Deepwater rig contract exit costs was a benefit of $4.3 million in 2016 due to lower final costs incurred and paid compared to estimated costs of $282.0 million recorded in 2015 for two deepwater rigs that were under contract in the Gulf of Mexico. Due to capital constraints, these rigs were released before their contract expiration dates and the remaining obligations owed in 2016 under the contracts were expensed in 2015.

Other operating expense was $60.4 million lower in the current year primarily due to recording estimated costs of remediating a site at the Seal field in a remote area of Alberta in 2015 and an adjustment of previously recorded exit costs in 2016 associated with ceasing production operations in the Republic of Congo versus a charge in 2015 for uncollectible accounts receivables from partners in the Republic of Congo.

Income tax benefits in 2016 were $155.1 million compared to benefits of $1.1 billion in the prior year. The benefits reported in 2015 were the result of large pretax losses, a significant portion of which was related to impairments, plus no local income taxes owed on the Malaysia sale and a deferred tax benefit due to the purchaser assuming certain future tax payment obligations upon the Malaysia sale. The effective tax rate in 2016 was 55.4% up from 35.6% in 2015. The 2016 period was favorably affected by deferred tax benefits recognized related to the Canadian asset dispositions and income tax benefits on investments in foreign exploration areas.

A summary of oil and gas revenues is presented in the following table.

(Millions of dollars)		**2017**	2016	2015
United States – Oil and gas liquids	**$**	**913.3**	650.7	1,176.9
– Natural gas		**37.9**	35.1	70.4
Canada – Conventional oil and gas liquids		**203.7**	171.7	181.0
– Synthetic oil		**–**	60.7	203.0
– Natural gas		**155.1**	130.0	167.7
Malaysia – Oil and gas liquids		**639.9**	623.7	790.6
– Natural gas		**138.2**	127.6	185.4
Total oil and gas revenues	**$**	**2,088.1**	1,799.5	2,775.0

The following table contains selected operating statistics for the three years ended December 31, 2017.

	2017	2016	2015
Net crude oil and condensate produced – barrels per day			
United States – Eagle Ford Shale	**34,649**	35,858	47,325
Gulf of Mexico	**11,551**	12,372	13,794
Canada – onshore	**3,004**	1,046	115
offshore	**8,091**	8,737	7,421
heavy[1]	**150**	2,766	5,341
synthetic[1]	–	4,637	11,699
Malaysia[1] – Sarawak	**12,674**	13,365	15,249
Block K	**20,312**	24,619	25,456
Total crude oil and condensate produced	**90,431**	103,400	126,400
Net crude oil and condensate sold – barrels per day			
United States – Eagle Ford Shale	**34,649**	35,858	47,326
Gulf of Mexico	**11,551**	12,372	13,794
Canada – onshore	**3,004**	1,046	115
offshore	**7,525**	8,886	7,151
heavy[1]	**150**	2,766	5,341
synthetic[1]	–	4,637	11,699
Malaysia[1] – Sarawak	**12,454**	12,464	16,360
Block K	**19,867**	24,376	26,583
Total crude oil and condensate sold	**89,200**	102,405	128,369
Net natural gas liquids produced – barrels per day			
United States – Eagle Ford Shale	**6,867**	6,929	7,558
Gulf of Mexico	**947**	1,302	1,998
Canada	**508**	210	10
Malaysia[1] – Sarawak	**829**	786	668
Total net gas liquids produced	**9,151**	9,227	10,234
Net natural gas liquids sold – barrels per day			
United States – Eagle Ford Shale	**6,867**	6,929	7,558
Gulf of Mexico	**947**	1,302	1,998
Canada	**508**	210	10
Malaysia[1] – Sarawak	**1,048**	720	606
Total net natural gas liquids sold	**9,370**	9,161	10,172
Net natural gas sold – thousands of cubic feet per day			
United States – Eagle Ford Shale	**32,629**	35,789	38,304
Gulf of Mexico	**11,901**	17,242	49,068
Canada	**226,218**	208,682	196,774
Malaysia[1] – Sarawak	**104,616**	106,380	121,650
Block K	**8,358**	10,070	21,818
Total natural gas sold	**383,722**	378,163	427,614
Total net hydrocarbons produced – equivalent barrels per day[2]	**163,536**	175,654	207,903
Total net hydrocarbons sold – equivalent barrels per day[2]	**162,524**	174,593	209,809
Estimated net hydrocarbon reserves – million equivalent barrels[2,3]	**698.3**	684.5	774.0

[1] The Company sold the Seal area heavy oil property in January 2017 and its 5% non-operated interest in Syncrude Canada Ltd. in June 2016. The Company sold a 10% interest in Malaysia properties in January 2015. Production in this table includes production for these sold interests through the date of disposition.
[2] Natural gas converted on an energy equivalent basis of 6:1.
[3] At December 31.

The Company's total crude oil and condensate production averaged 90,431 barrels per day in 2017, compared to 103,400 barrels per day in 2016 and 126,400 barrels per day in 2015. The 2017 crude oil production level was 13% below 2016. Crude oil production in the United States totaled 46,200 barrels per day in 2017, down from 48,230 barrels per day in 2016. The decrease in U.S. crude oil production year over year was primarily due to well decline and shut-ins due to weather events which was only partially offset by new drilling. Heavy crude oil production in Western Canada fell from 2,766 barrels per day in 2016 to 150 barrels per day in 2017, with the reduction attributable to the sale of Seal asset in January 2017. Crude oil volumes produced offshore Eastern Canada totaled 8,091 barrels per day in 2017, down from 8,737 barrels per day in the previous year. There was no synthetic crude oil production in Canada in 2017 compared to 4,637 barrels per day in 2016 due to the Company selling its 5% interest in Syncrude in June 2016. Crude oil production offshore Sarawak decreased from 13,365 barrels per day in 2016 to 12,674 barrels per day in 2017. Block K in Malaysia had crude oil production of 20,312 barrels per day in 2017, down from 24,619 barrels per day in 2016. Lower oil production in 2017 in Malaysia was primarily attributable to natural well decline at most fields.

The Company's total crude oil and condensate production averaged 103,400 barrels per day in 2016, compared to 126,400 barrels per day in 2015. Crude oil production in the United States totaled 48,230 barrels per day in 2016, down from 61,119 barrels per day in 2015. The 21% decrease in U.S. crude oil production year over year was primarily due to well decline and lower drilling. Heavy crude oil production in Western Canada fell from 5,341 barrels per day in 2015 to 2,766 barrels per day in 2016 due to wells shut-in and natural well performance decline in the Seal area. Crude oil volumes produced offshore Eastern Canada totaled 8,737 barrels per day in 2016, up from 7,421 barrels per day in the previous year due to less unplanned maintenance. Crude oil production offshore Sarawak decreased from 15,249 barrels per day in 2015 to 13,365 barrels per day in 2016. Block K in Malaysia had crude oil production of 24,619 barrels per day in 2016, down from 25,456 barrels per day in 2015. Lower oil production in 2016 in Malaysia was primarily attributable to natural well decline at most fields, partially offset by higher production at Kakap.

The Company produced natural gas liquids (NGL) of 9,151 barrels per day in 2017, largely in line with 9,227 barrels per day produced in 2016. Eighty-five percent of the Company's NGL production in 2017 was derived from Gulf of Mexico and Eagle Ford Shale areas in the United States.

The Company's NGL production of 9,227 barrels per day in 2016 was down from 10,234 barrels per day in 2015. The lower NGL volumes of 1,007 barrels per day in 2016 were mostly attributable to decreased natural gas produced from the Eagle Ford Shale and in the Gulf of Mexico.

Worldwide sales of natural gas averaged 383.7 million cubic feet (MMCF) per day in 2017 compared to 378.2 MMCF per day in 2016. The 2017 increase in natural gas sales volumes is attributable to 8% increase in natural gas production in Canada, primarily in Tupper and Placid areas, offset in part by lower gas production in the Gulf of Mexico and in the Eagle Ford Shale area in United States.

Worldwide sales of natural gas were 378.2 MMCF per day in 2016, compared to 427.6 MMCF per day in 2015. Natural gas sales volumes decreased in North America in 2016 compared to 2015 due to lower gas volume in the Gulf of Mexico primarily in the Dalmatian field and lower volume from the Eagle Ford Shale area in south Texas, offset in part by higher gas production volumes in the Tupper area in Western Canada.

The following table contains the weighted average sales prices for the three years ended December 31, 2017.

		2017	2016	2015
Weighted average sales prices				
Crude oil and condensate – dollars per barrel				
United States – Eagle Ford Shale	$	**50.49**	42.11	48.14
Gulf of Mexico		**49.24**	41.63	46.80
Canada [1] – onshore		**46.68**	42.01	41.06
offshore		**53.39**	43.12	50.54
heavy [2]		**25.12**	16.40	23.28
synthetic [2]		–	35.59	47.56
Malaysia – Sarawak [3]		**53.26**	46.02	50.13
Block K [3]		**52.72**	45.27	51.50
Natural gas liquids – dollars per barrel				
United States – Eagle Ford Shale		**17.70**	11.51	11.18
Gulf of Mexico		**19.57**	12.84	12.82
Canada [1]		**25.00**	20.63	22.31
Malaysia – Sarawak [3]		**51.00**	38.30	50.55
Natural gas – dollars per thousand cubic feet				
United States – Eagle Ford Shale		**2.49**	1.88	2.24
Gulf of Mexico		**2.49**	1.92	2.36
Canada [1]		**1.97**	1.72	2.35
Malaysia – Sarawak [3]		**3.55**	3.21	4.23
Block K		**0.24**	0.25	0.24

[1] U.S. dollar equivalent.
[2] The Company sold the Seal area heavy oil property in January 2017 and its 5% non-operated interest in Syncrude Canada Ltd. in June 2016.
[3] Prices are net of payments under the terms of the respective production sharing contracts.

The Company's average worldwide realized sales price for crude oil and condensate was $51.21 per barrel in 2017 compared to $42.38 per barrel in 2016 and $47.99 per barrel in 2015. The average realized crude oil sales price was approximately 21% higher in 2017 compared to the prior year. West Texas Intermediate (WTI) crude oil averaged 18% more in 2017 compared to 2016. Dated Brent and Kikeh oil sold for approximately 24% and 22% higher in 2017, respectively, while Light Louisiana Sweet crude oil sold at 20% above 2016 levels. The average realized sales prices for U.S. crude oil and condensate amounted to $50.19 per barrel in 2017, 20% higher than 2016. Heavy oil produced in Canada averaged a sales price of $25.12 per barrel in 2017, a 53% increase from 2016. The average sales price for crude oil produced offshore Eastern Canada increased 24% to $53.39 per barrel in 2017. Crude oil sold in Malaysia averaged $52.93 per barrel in 2017, 16% higher than $45.52 in 2016.

The Company's average worldwide realized sales price for crude oil and condensate was $42.38 per barrel in 2016 compared to $47.99 per barrel in 2015. The average realized crude oil sales price was 12% lower in 2016 compared to 2015. WTI crude oil averaged 11% less in 2016 compared to 2015. Dated Brent and Kikeh oil each sold for approximately 16% less in 2016, while Light Louisiana Sweet crude oil sold at 14% below 2015 levels. The average realized sales prices for U.S. crude oil and condensate amounted to $41.99 per barrel in 2016, 12% lower than 2015. Heavy oil produced in Canada averaged $16.40 per barrel in 2016, a 30% decrease from 2015. The average sales price for crude oil produced offshore Eastern Canada declined 15% to $43.12 per barrel in 2016. The average realized sales price for the Company's synthetic crude oil was $35.59 per barrel in 2016, down 25% from the prior year. Crude oil sold in Malaysia averaged $45.52 per barrel in 2016, 11% lower than in 2015.

The average sales price for NGL in 2017 was higher than prices realized during 2016, with a significant increase in prices in the United States. NGL was sold in the U.S. for an average of $17.93 per barrel in 2017, up 53% from 2016. NGL produced in Malaysia in 2017 was sold for an average of $50.99 per barrel, 33% above the 2016 average of $38.30 per barrel.

The average sales price for NGL in 2016 was on par with prices realized during 2015. NGL was sold in the U.S. for an average of $11.72 per barrel in 2016, up 1% from the average price of $11.55 per barrel in 2015. NGL produced in Malaysia in 2016 was sold for an average of $38.30 per barrel, 24% below the 2015 average of $50.55 per barrel.

North American natural gas prices were also higher in 2017 than during 2016, essentially driven by an overall increase in commodity prices and a colder winter. The average posted price at Henry Hub in Louisiana was $2.96 per MMBTU in 2017 compared to $2.48 per MMBTU in 2016 and $2.61 per MMBTU in 2015. In 2017, U.S. natural gas was sold at an average of $2.49 per thousand cubic feet (MCF), a 32% increase compared to 2016. Natural gas sold in Canada averaged $1.97 per MCF in 2017, up 15% from 2016. Natural gas sold in 2017 from Sarawak, Malaysia averaged $3.55 per MCF, up 11% from the prior year.

North American natural gas prices were weaker in 2016 than 2015, essentially driven by an unseasonably warm winter demand season. The average posted price at Henry Hub in Louisiana was $2.48 per MMBTU in 2016 compared to $2.61 per MMBTU in 2015 and $4.33 per MMBTU in 2014. In 2016, U.S. natural gas was sold at an average of $1.89 per MCF, an 18% decrease compared to 2015. Natural gas sold in Canada averaged $1.72 per MCF in 2016, down 27% from 2015. Natural gas sold in 2016 from Sarawak, Malaysia averaged $3.21 per MCF, down 24% from the prior year.

Based on 2017 sales volumes and deducting taxes at 35%, each $1.00 per barrel oil sales price fluctuation and $0.10 per MCF gas sales price fluctuation would have affected 2017 revenue from exploration and production operations by $15.9 million and $6.2 million, respectively

Production-related expenses for continuing exploration and production operations during the last three years are shown in the following table.

(Millions of dollars)		**2017**	2016	2015
Lease operating expense	**$**	**468.4**	559.4	832.3
Severance and ad valorem taxes		**43.7**	43.8	65.8
Depreciation, depletion and amortization		**939.9**	1,037.3	1,607.9
Total	**$**	**1,452.0**	1,640.5	2,506.0

Cost per equivalent barrel sold for these production-related expenses are shown by geographical area in the following table.

(Dollars per equivalent barrel)		**2017**	2016	2015
United States – Eagle Ford Shale				
Lease operating expense	$	**7.35**	9.10	10.27
Severance and ad valorem taxes		**2.46**	2.07	2.50
Depreciation, depletion and amortization (DD&A) expense		**25.64**	25.83	26.71
United States – Gulf of Mexico				
Lease operating expense		**13.71**	9.28	9.42
Severance and ad valorem taxes		**–**	0.02	0.01
DD&A expense		**20.20**	23.06	22.60
Canada – Onshore				
Lease operating expense		**4.95**	5.26	4.65
Severance and ad valorem taxes		**0.10**	0.30	0.34
DD&A expense		**9.92**	10.61	12.78
Canada – Offshore				
Lease operating expense		**9.61**	8.58	14.34
DD&A expense		**12.95**	11.08	12.51
Malaysia – Sarawak				
Lease operating expense		**5.24**	5.41	7.82
DD&A expense		**8.09**	8.68	18.78
Malaysia – Block K				
Lease operating expense		**14.13**	11.23	13.20
DD&A expense		**14.60**	13.60	26.25
Total oil and gas operations				
Lease operating expense		**7.89**	8.75	10.87
Severance and ad valorem taxes		**0.74**	0.69	0.86
DD&A expense		**15.85**	16.24	21.00
Total oil and gas operations – excluding synthetic oil operations				
Lease operating expense		**7.89**	7.87	9.21
Severance and ad valorem taxes		**0.74**	0.66	0.84
DD&A expense		**15.85**	16.41	21.53

Lease operating expenses totaled $468.4 million in 2017, compared to $559.4 million in 2016 and $832.3 million in 2015. Lease operating expense per BOE for the overall Company was $7.89 per BOE, $0.86 per BOE lower than 2016. Lease operating expense per BOE in the Eagle Ford Shale was $7.35 which was $1.75 per BOE lower than 2016 due to cost saving initiatives, partly offset by increases in service costs. No lease operating expense was incurred for Syncrude operations (2016: $41.15 per BOE) as a result of the disposal of this business in mid-2016. Lease operating expense per BOE in Canada (excluding Syncrude) was $5.67 per BOE which was $0.21 per BOE lower due to lower costs at the Seal operations and higher volumes at Kaybob and Placid. Lease operating expense per BOE in Gulf of Mexico was $13.71 per BOE which was $4.43 higher than 2016 as a result of workover expenses on the Kodiak well. Lease operating expense per BOE at Sarawak was $5.24 which was $0.17 per BOE lower. Lease operating expense per BOE at Block K was $14.13, which was $2.90 higher than 2016 due to a 2016 credit for costs from a non-operating partner.

Lease operating expenses totaled $559.4 million in 2016, compared to $832.3 million in 2015 and $1,089.9 million in 2014. Lease operating expense per BOE in the Eagle Ford Shale decreased $1.17 on a per BOE due to lower service costs and cost-saving initiatives offset in part by lower volumes produced. Lease operating expense for conventional operations in Canada improved in 2016 by $0.30 per BOE due to lower costs in the Seal heavy oil area and a lower Canadian dollar exchange rate, offset in part by increased cost sharing for third-party processing in the Tupper area. Synthetic oil operations costs per barrel increased by $2.27 per BOE primarily due to lower volumes produced prior to the disposition and higher maintenance cost resulting from unplanned downtime, offset in part by a lower Canadian dollar exchange rate. Lease operating expense at Sarawak decreased by $2.41 per BOE and benefited from lower logistics and maintenance cost in the 2016 period. Operating expense in Block K decreased by $1.97 per BOE and benefited from higher volumes produced at the main Kakap field.

Severance and ad valorem taxes totaled $43.7 million in 2017, $43.8 million in 2016 and $65.8 million in 2015. Severance and ad valorem taxes in the U.S. in 2017 compared to 2016 were in line on an absolute basis. Severance and ad valorem taxes in the U.S. in 2016 compared to 2015 were lower primarily due to weaker average commodity prices in the Eagle Ford Shale and lower well valuations.

Depreciation, depletion and amortization expense for exploration and production operations totaled $939.9 million in 2017 and $1,037.3 million in 2016 and $1,607.9 million in 2015. The $97.4 million decrease in 2017 compared to 2016 was primarily due to lower per-unit capital amortization rates and lower oil volumes sold. Gulf of Mexico depreciation rate per BOE decreased in 2017 due to lower cost production mix. Depreciation per BOE in other countries were in line with 2016.

Depreciation, depletion and amortization expense for exploration and production operations totaled $1,037.3 million in 2016 and $1,607.9 million in 2015. The $570.6 million decrease in 2016 compared to 2015 was primarily due to lower per-unit capital amortization rates and lower oil and natural gas volume sold. Eagle Ford Shale rate per equivalent barrel decreased due to reserve additions and cost improvements on 2016 drilling activities. The unit cost in the Gulf of Mexico decreased in 2016 due to reserve additions, mix of production and lower unit rates due to impairment of assets. Canada conventional operations rate per barrel of oil equivalent decreased in 2016 due to a lower Canadian dollar exchange rate, higher mix of production from the Tupper area and property impairments. Depreciation per barrel in both Sarawak and Block K improved in 2016 due primarily to the impairment of these assets in the prior year.

Exploration expenses for each of the last three years are shown in total in the following table, and amounts are reported by major operating area on pages 114 and 115 on this Form 10-K report. Expenses other than undeveloped lease amortization are included in the capital expenditures total for exploration and production activities.

(Millions of dollars)		**2017**	2016	2015
Dry holes	$	**(4.2)**	15.1	296.8
Geological and geophysical		**22.5**	13.5	49.9
Other		**42.7**	29.9	48.8
		61.0	58.5	395.5
Undeveloped lease amortization		**61.8**	43.4	75.4
Total exploration expenses	$	**122.8**	101.9	470.9

Dry hole expense in 2017 was a credit of $4.2 million, which was $19.3 million lower than 2016 primarily due to credits relating to wells drilled in prior years. Dry hole cost in other foreign areas of $3.0 million credit in 2017 was primarily attributable to credits on two 2011 wells in Brunei Block CA-2.

Geological and geophysical (G&G) expense in 2017 of $22.5 million was $9.0 million higher than 2016 primarily driven by $5.8 million of charges for Block CA-2 in Brunei, $3.3 million for higher spending in Vietnam, $2.5 million in the U.S., $1.1 million in Malaysia, and $1.1 million in Brazil, offset primarily by lower spending of $2.9 million in Canada offshore and $1.2 million in Mexico.

Other exploratory costs in 2017 of $42.7 million was $12.8 million higher compared to 2016 primarily due to higher spending of $4.2 million in Mexico, $2.6 million in Australia, $2.5 million in Brazil, and $1.9 million in Brunei.

Undeveloped lease amortization costs in 2017 of $61.8 million was $18.4 million higher in 2017 primarily due to $23.5 million of higher lease amortization in the Gulf of Mexico, $7.9 million of lease amortization in Midland Basin, offset by lower lease amortization of $9.5 million at Eagle Ford Shale and $2.6 million at Tupper West.

Dry hole expense in 2016 of $15.1 million was $281.7 million lower than 2015 primarily due to lower overall exploration drilling. Dry hole cost in 2016 in Malaysia of $4.5 million is primarily attributable to one unsuccessful well in Block SK 314A. Dry hole cost in other foreign areas of $10.2 million in 2016 is primarily attributable to one unsuccessful well in Block 11-2/11 in Vietnam.

G&G expense in 2016 of $13.5 million was $36.4 million lower than 2015 primarily due to reduced spending in Australia, Vietnam and Gulf of Mexico.

Other exploratory costs in 2016 of $29.9 million was $18.9 million lower compared to 2015 due to reduced spending in Australia, Equatorial Guinea, Namibia, and Gulf of Mexico.

Undeveloped lease amortization costs in 2016 of $43.4 million was $32.0 million lower than 2015 primarily due to lower lease relinquishments in the Eagle Ford Shale area during 2016.

The exploration and production business recorded expenses of $42.6 million in 2017, $46.7 million in 2016 and $48.7 million in 2015 for accretion on discounted abandonment liabilities. Because the liability for future abandonment of wells and other facilities is carried on the balance sheet at a discounted fair value, accretion must be recorded annually so that the liability will be recorded at full value at the projected time of abandonment. The $4.1 million decrease in 2017 compared to 2016 primarily related to lower abandonment liabilities resulting from the Canadian Seal asset disposition, changes in estimates and a lower Canadian dollar exchange rate. The $2.0 million decrease in 2016 compared to 2015 related primarily to lower abandonment liabilities resulting from the Canadian Syncrude asset disposition, changes in estimates and a lower Canadian dollar exchange rate.

The effective income tax rate for exploration and production continuing operations was 31.6% in 2017, 55.4% in 2016 and 35.6% in 2015.

The effective rate in 2017 was lower than 2016 as a result of 2016 deferred tax benefits recognized related to the Canadian Syncrude asset disposition and income tax benefits on investments in foreign exploration areas; in 2016 these items increased the tax credit reported on a pre-tax loss and hence increased the effective tax rate.

The effective tax rate in 2016 was greater than the 2015 effective tax rate as well as the statutory U.S. tax rate of 35.0%. The 2016 period benefited from deferred tax benefits recognized related to the Canadian asset dispositions and income tax benefits on investments in foreign exploration areas; these items increased the tax credit reported on the 2016 pre-tax loss and hence increased the effective tax rate.

At December 31, 2017, 142.7 million barrels of the Company's crude oil and condensate proved reserves, 24.4 million barrels of NGL proved reserves and 167.0 billion cubic feet of natural gas proved reserves were undeveloped. On a worldwide basis, the Company spent approximately $452.9 million in 2017, $494.3 million in 2016, and $1.74 billion in 2015 to develop proved reserves.

At December 31, 2017, 98.3 million barrels of the Company's U.S. crude oil proved reserves, 19.7 million barrels of U.S. NGL proved reserves and 95.6 billion cubic feet of U.S. natural gas proved reserves were undeveloped. In the U.S., total proved undeveloped reserves represent 44% of total proved reserves on a barrel of oil equivalent basis as of December 31, 2017. Approximately 91% of the total U.S. undeveloped reserves (on a barrel of oil equivalent basis) are associated with the Company's Eagle Ford Shale operations in South Texas. Further drilling and facility construction are generally required to reclassify the undeveloped reserves in the Eagle Ford Shale area to developed reserves. The deepwaters of the Gulf of Mexico accounted for the remaining 9% of proved undeveloped reserves at December 31, 2017.

In the Western Canadian Sedimentary Basin, undeveloped natural gas proved reserves totaled 665.5 billion cubic feet, with the migration of these reserves, dependent on both development drilling and completion of processing and transportation facilities.

In Block K Malaysia, oil proved undeveloped reserves of 12.8 million barrels are primarily at the Kikeh field, where undeveloped proved oil reserves are subject to further drilling before being reclassified to developed. Also in Malaysia, there were 346.7 billion cubic feet of undeveloped natural gas proved reserves at various offshore fields at year-end 2017. These undeveloped natural gas reserves in Malaysia are mainly associated with Block H, where a development project commenced following sanction in 2014. First production at Block H is currently expected in 2020.

Corporate – The after-tax costs of corporate activities, which include interest income and expense, foreign exchange effects, corporate overhead not allocated to operating functions, and the impact of the 2017 Tax Act were $607.5 million in 2017, $149.1 million in 2016 and $244.9 million in 2015.

2017 vs 2016 – The net costs of Corporate activities in 2017 were unfavorable to 2016 by $458.4 million primarily due to the impact of the 2017 Tax Act, foreign exchange losses and higher interest expense, partially offset by lower administrative expenses.

The impact of the 2017 Tax Act resulted in a charge of $274.0 million principally as a result of a deemed repatriation of foreign earnings and the revaluation of deferred tax assets and liabilities.

The after-tax effects of foreign currency exchange losses were $65.3 million in 2017, $117.6 million unfavorable to 2016. These effects arose due to transactions denominated in currencies other than the respective operations' predominant functional currency. The foreign currency loss recognized in 2017 was mostly realized in Canada relating to an inter-company loan between foreign subsidiaries denominated in U.S. dollars. The Canadian operation's functional currency is the Canadian dollar. In Malaysia, net deferred tax assets and prepaid current income tax amounts reported in its balance sheet were revalued to the Malaysian operation's functional currency of U.S. dollars.

Interest expense of $181.8 million was $33.6 million higher in 2017 as a result of bonds issued in the third quarter 2017 for net proceeds of $541.0 million. Administrative expenses associated with corporate activities were lower in 2017 by $18.9 million, primarily due to a higher allocation of costs to the exploration and production businesses.

2016 vs 2015 – The net costs of Corporate activities in 2016 were favorable to 2015 by $95.8 million mostly due to higher tax benefits and lower administrative cost, partially offset by lower 2016 benefits from foreign currency exchange and higher net interest costs.

Interest income was $1.1 million unfavorable in 2016 compared to 2015 due to lower average invested cash balances in Canada.

The after-tax effects of foreign currency exchange were a gain of $52.3 million in 2016, $34.4 million lower than in 2015. These effects arose due to transactions denominated in currencies other than the respective operations' predominant functional currency. The foreign currency gain recognized in 2016 was mostly realized in Canada relating to an inter-company loan between foreign subsidiaries denominated in U.S. dollars. The Canadian operation's functional currency is the Canadian dollar. Following impairments in the prior period and lower taxable earnings, Malaysia has net deferred tax assets and prepaid current income tax amounts reported in its balance sheet. The change in income tax position in 2016 was less dramatic than 2015 and led to a lower benefit relating to income taxes in local currency. The Malaysian operation's functional currency is the U.S. dollar.

Administrative expenses associated with corporate activities were lower in 2016 by $11.7 million, primarily due to lower employee compensation expense.

Depreciation expense was $4.9 million higher in 2016 compared to 2015 due to depreciation of both the new corporate building and from installation of newly acquired software.

Interest expense in 2016 was $27.8 million higher than 2015 due principally to higher average interest rates in the 2016 period due to an increase of 1% on the coupon rates on $1.5 billion of the Company's outstanding notes effective June 1, 2016 following a credit downgrade of the Company by Moody's Investor Services in February 2016. Additionally, interest expense increased in 2016 due to issuance of $550 million of 8-year, 6.875% notes in August 2016.

Total benefit for income taxes was higher in 2016 compared to 2015 by $148.6 million. The improvement in 2016 is due primarily to a U.S deferred tax charge of $188.5 million associated with a $2.0 billion distribution from a foreign subsidiary in the 2015 period.

Discontinued Operations – The Company has presented a number of businesses as discontinued operations in its consolidated financial statements. These are principally the refining and marketing operations (R&M) and the U.K. exploration and production business. The Company has accounted for these businesses as discontinued operations for all periods presented.

Refining and Marketing – The Company has now transitioned to a fully independent oil and gas exploration and production company. Murphy formerly had a significant U.K. refining and marketing business. In 2014, Murphy Oil sold its U.K. retail marketing business. In 2014, the Company decided to decommission and abandon the Milford Haven, Wales refinery. The Company sold the remainder of its U.K. downstream assets in 2015. The U.K. downstream business is reported as discontinued operations for all periods presented.

Loss of $0.9 million in 2017 was principally related to administrative expenses related to the legacy R&M business.

The loss from R&M operations of $2.5 million in 2016 was primarily related to foreign exchange losses and administrative expenses from the legacy U.K. business.

The loss in 2015 from U.K. R&M operations of $14.8 million was primarily related to loss on sale of assets, employee severance costs, legal fees and other abandonment costs related to asset closures. The Company sold the U.K. finished product terminal operations during 2015 for cash proceeds of $5.5 million.

Capital Expenditures

As shown in the selected financial data on page 24 of this Form 10-K report, capital expenditures from continuing operations, including exploration expenditures, were $975.7 million in 2017, $811.5 million in 2016 and $2.19 billion in 2015. The 2015 amount excluded capital expenditures of $0.2 million related to discontinued operations. Capital expenditures included $61.0 million, $58.5 million and $395.5 million, respectively, in 2017, 2016 and 2015 for exploration costs that were expensed.

Capital expenditures for exploration and production continuing operations totaled $960.9 million in 2017, $789.7 million in 2016 and $2.13 billion in 2015.

2017 – E&P capital expenditures in 2017 included $63.4 million for leases acquisition ($50.4 million for U.S. Onshore Midland basin acquisitions and $13.0 million for licenses in Brazil), $807.2 million for development drilling activities, $79.1 million for exploration activities and $11.2 million other expenditures (principally administrative and a proved property acquisition in the Gulf of Mexico). The development drilling activities were principally in the Company's U.S. Eagle Ford Shale and Canadian Onshore (Tupper, Kaybob and Placid) businesses. Exploration activities principally included geological and geophysical (G&G) studies in Mexico, exploration drilling in Vietnam and supporting administrative costs.

2016 – E&P capital expenditures in 2016 included $18.6 million for lease acquisitions principally in the U.S., $206.7 million for a property acquisition in Kaybob Duvernay and Placid Montney in Alberta, Canada, $70.1 million for exploration activities, and $494.3 million for oil and gas project developments. U.S. lease acquisitions included new leases acquired onshore and in the Gulf of Mexico. Exploration activities included drilling wells in the Gulf of Mexico, Malaysia, Australia and Vietnam. Additionally, exploration activities included seismic acquisitions in the Gulf of Mexico and other areas, primarily related to prospects in Australia and Southeast Asia. Development capital expenditures in 2016 included $226.9 million for the drilling and completion program in the Eagle Ford Shale; $10.3 million for Gulf of Mexico development activities including Kodiak and Dalmatian South; $118.6 million for development work in the Western Canadian Sedimentary Basin; $3.4 million for the Syncrude project; $32.3 million combined for Hibernia and Terra Nova; $3.4 million for development projects in deepwater Malaysia, including Kikeh, Kakap and Siakap; $72.4 million for oil and natural gas projects offshore Sarawak Malaysia; and $16.7 million for development of a Floating Liquified Natural Gas (FLNG) project for Block H Malaysia.

2015 – E&P capital expenditures in 2015 included $12.6 million for lease acquisitions principally in the U.S., $371.9 million for exploration activities, and $1.74 billion for oil and gas project developments. U.S. lease acquisitions included acreage extensions in the Eagle Ford Shale as well as new leases acquired in the Gulf of Mexico. Exploration activities included drilling wells in the Gulf of Mexico, Malaysia, Australia and Vietnam. Additionally, exploration activities included seismic acquisitions in the Gulf of Mexico and other areas, primarily related to prospects in Australia and Southeast Asia. Development capital expenditures in 2015 included $830.2 million for the drilling and completion program in the Eagle Ford Shale; $508.6 million for Gulf of Mexico development activities including Kodiak and Dalmatian South; $116.5 million for development work in the Western Canadian Sedimentary Basin; $23.6 million for the Syncrude project; $41.7 million combined for Hibernia and Terra Nova; $67.8 million for development projects in deepwater Malaysia, including Kikeh, Kakap and Siakap; $144.3 million for oil and natural gas projects offshore Sarawak Malaysia; and $23.8 million for development of a FLNG project for Block H Malaysia.

Exploration and production capital expenditures are shown by major operating area on page 113 of this Form 10-K report.

Cash Flows

Operating activities – Cash provided by operating activities of continuing operations was $1.13 billion in 2017, $600.8 million in 2016 and $1.18 billion in 2015. Cash flows associated with formerly owned U.K. businesses have been classified as discontinued operations in the Company's consolidated financial statements.

Cash flow provided by continuing operations was $528.9 million higher in 2017 than in 2016 due to higher realized oil and natural gas sales prices, lower lease operating expenses and lower selling and general expenses. Also, 2016 included $266.6 million relating to payments for a deepwater rig contract exit.

Cash flow provided by continuing operations was $582.6 million lower in 2016 than in 2015 due to generally weaker crude oil and natural gas sales prices in 2016 together with lower volume sold, partially offset by lower lease operating expenses and lower severance and ad valorem taxes.

The total reductions of operating cash flows for interest paid during the three years ended December 31, 2017, 2016 and 2015 were $152.5 million, $132.1 million and $117.7 million, respectively.

Investing activities – Capital expenditures of the exploration and production business represent the most significant spend component of investing activities. Property additions and dry hole costs for continuing operations used cash of $1.01 billion in 2017, $926.9 million in 2016 and $2.55 billion in 2015.

Cash of $212.7 million, $695.9 million and $911.8 million was spent in 2017, 2016 and 2015, respectively, to acquire Canadian government securities with terms greater than 90 days at the time of purchase. Proceeds from maturities of Canadian government securities with maturities greater than 90 days at date of acquisition were $320.8 million in 2017, $761.0 million in 2016 and $1,129.1 million in 2015.

Proceeds from sales of assets generated cash of $69.5 million in 2017, $1.16 billion in 2016 and $423.9 million in 2015. The 2017 proceeds primarily relate to sale of the Seal business in Canada for $48.8 million and non-core U.S. onshore property divestments. The 2016 proceeds primarily arose due to sale of Syncrude and natural gas processing and sales pipeline assets that support natural gas fields in the Tupper area in Canada, and 2015 proceeds primarily related to sale of 10% of the Company's oil and gas assets in Malaysia.

Financing activities – During 2017 the Company issued $550 million notes in August 2017 that bear a rate of 5.75% and mature on August 15, 2025 for net proceeds of $541.6 million; these proceeds were used to redeem the Company's $550 million 3.50% notes in September 2017. The 3.50% notes had a maturity date of December 2017 and were retired early.

During 2016, the Company borrowed $541.4 million by issuing 6.875% notes maturing in 2024. The Company used $600.0 million cash during 2016 to repay long-term debt under its revolving credit facility.

In 2015, the Company paid $250.0 million to repurchase 5.97 million shares, of its Common stock.

Cash used for dividends to stockholders was $172.6 million in 2017, $206.6 million in 2016 and $245.0 million in 2015. The Company decreased its dividend rate by 29% in 2016 as the annualized dividend was lowered from $1.40 per share to $1.00 per share effective in the third quarter 2016. In 2017, 2016 and 2015, cash of $7.1 million, $1.1 million and $9.0 million, respectively, was used to pay statutory withholding taxes on stock-based incentive awards that vested with a net-of-tax payout.

Discontinued operations – At end of 2017, the Company's U.K. discontinued operations had cash of $16.6 million (2016: $4.1 million; 2015: $7.9 million). This cash is classified within Current assets held for sale on the Consolidated Balance Sheet. At the end of 2017 the cash balance was $12.5 million higher than the cash balance at the end of 2016, primarily due to the collections of a previously outstanding tax receivable. At the end of 2016 the cash balance was $3.8 million lower than the cash balance at the end of 2015, primarily due to expenses related to shutdown operations. In 2015, the Company's discontinued operations in the U.K. required $15.0 million of operating cash. The 2015 activities primarily related to the U.K. refinery and terminal operations which were sold in June 2015. In 2015, the sale of U.K. terminal assets generated cash of $5.0 million. In connection with the sales of the various U.K. assets, the Company repatriated cash from the U.K. of $184 million in 2015.

Financial Condition

At the end of 2017 working capital (total current assets less total current liabilities) amounted to $537.4 million (2016: $56.7 million; 2015: $277.4 million). Total working capital increased in 2017 primarily due to long-term debt that was classified as a current liability at the end of 2016. This 2017 maturing debt was replaced with a similar amount of long-term debt due in 2025 during 2017.

Cash and cash equivalents at the end of 2017 totaled $965.0 million (2016: 872.8 million). The increase in 2017 primarily related to the conversion of Canadian government securities with maturities greater than 90 days to cash. Canadian government securities held at the end of 2016 totaled $111.5 million. These slightly longer-term Canadian investments were purchased in 2016 because of a tight supply of shorter-term securities available for purchase in Canada.

Long-term debt at year-end 2017 was $483.8 million higher than year-end 2016, principally as a result of be issuance of $550 million notes in August 2017 that bear a rate of 5.75% and mature in August 2025. At the end of 2017, long-term debt represented 38.6% (2016: 33.0%) of total capital employed; the increase is principally due to the 2017 notes refinancing.

Long-term debt at year-end 2016 was $617.8 million lower than year-end 2015. The decrease in debt in 2016 was primarily due to repayment of $600.0 million in debt drawn at year-end 2015 under its 2011 revolving credit facility.

Stockholders' equity was $4.62 billion at the end of 2017 (2016: $4.92 billion; 2015: $5.31 billion). Stockholders' equity declined in 2017 primarily due to net loss incurred and cash dividends paid on its common stock. Stockholders' equity declined in 2016 primarily due to net loss incurred and cash dividends on its common stock, partially offset by an improvement in the foreign currency translation balance due to a stronger Canadian dollar against the U.S. dollar during the year. A summary of transactions in stockholders' equity accounts is presented in the Consolidated Statements of Stockholders' Equity on page 64 of this Form 10-K report.

Other significant changes in Murphy's balance sheet at the end 2017, compared to 2016 are discussed below.

Deferred income tax assets decreased $154.4 million to $211.5 million (2016: $365.9 million) principally as a result of the impact of the 2017 Tax Act which resulted in the revaluation of deferred tax assets to the newly enacted U.S. federal tax rate of 21% (prior to the 2017 Tax Act: 35%).

Deferred income tax liabilities increased $90.0 million to $159.1 million (2016: $69.1 million) principally as a result of current year Canadian taxable profits utilizing prior taxable losses and the change from a U.S. net deferred tax asset position to a net deferred tax liability position, due in part, to withholding tax liability recorded on $1.3 billion of foreign earnings no longer indefinitely reinvested.

Liabilities associated with assets held for sale at the end of 2016 related to field abandonment for the Seal field in Canada that was sold in January 2017.

Murphy had commitments for future capital projects of approximately $432.3 million at December 31, 2017 (2016: $585.7 million). These commitments included $197.3 million for field development and future work in Malaysia, $129.4 million for development at Kaybob Duvernay in Canada, $31.8 million for work in the Eagle Ford Shale, $31.3 million for exploration in Mexico, and $8.8 million and $6.3 million for future work commitments offshore Vietnam and Brunei, respectively.

The primary sources of the Company's liquidity are internally generated funds, access to outside financing and working capital. The Company generally uses its internally generated funds to finance its capital and operating expenditures, but it also maintains lines of credit with banks and will borrow as necessary to meet spending requirements. At December 31, 2017, the Company has a $1.1 billion senior unsecured guaranteed credit facility (2016 facility) with a major banking consortium, which now expires in August 2021. At December 31, 2017, the

Company had no outstanding borrowings under the 2016 facility; however, there were $90.7 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 December 31, 2017, the applicable base interest rate would have been 4.875%. At December 31, 2017, the Company was in compliance with all covenants related to the 2016 facility.

On November 17, 2017, the Company entered into the third amendment (Amendment No. 3) to its 2016 facility with, among other parties, JPMorgan Chase Bank, N.A., as administrative agent. Amendment No. 3 extended the maturity date of the Credit Agreement to August 17, 2021, reduced the facility fee on revolving commitments and the interest margin on revolving loans. Amendment No. 3 also limited the consolidated net debt to no more than 4.00 times the last twelve months (LTM) Adjusted EBITDAX. Other covenants include a minimum Adjusted EBITDAX for the LTM of 2.5 times LTM consolidated interest expense, and minimum liquidity from U.S. and other certain subsidiaries equal to or greater than $500 million. Also beginning March 31, 2017, if the Company's total leverage ratio exceeds 3.50 times the Company's LTM Adjusted EBITDAX, the facility will become secured, subject to limitations set forth in the Company's existing notes.

In August 2017, the Company sold $550 million of new notes that bear interest at the rate of 5.75% and mature on August 15, 2025. The Company incurred transaction costs of $8.4 million on the issue of these new notes. The new notes pay interest semi-annually on February 15 and August 15 of each year. The initial interest payment was paid on February 15, 2018. The proceeds of the $550 million notes were used to redeem the Company's 3.50% notes in September 2017. The $550 million 3.50% notes had an original maturity of December 2017.

In August 2016, the Company reduced its then existing $2.0 billion unsecured revolving credit facility (2011 facility) to $630 million (facility has since expired) and entered into a separate $1.2 billion senior unsecured guaranteed credit facility (2016 facility, subsequently reduced to $1.1 billion), with a major banking consortium that originally expired in August 2019, and has subsequently been extended to mature in August 2021. The Company incurred transaction costs of approximately $14.0 million to place the 2016 facility which were included in financing activities in the Consolidated Statement of Cash Flows. Also in August 2016, the Company sold $550 million of notes that bear interest at the rate of 6.875% and mature on August 15, 2024. The proceeds of the $550 million notes were used for general corporate purposes.

The Company has a shelf registration statement on file with the U.S. Securities and Exchange Commission that permits the offer and sale of debt and/or equity securities through October 2018.

Current financing arrangements are set forth more fully in Note F to the consolidated financial statements.

In 2017 the Company's earnings covered fixed charges 1.4 times. In 2016 and 2015 the Company's earnings were inadequate to cover fixed charges by $477.0 million and $3.3 billion, respectively.

Cash and invested cash are maintained in several operating locations outside the United States. At December 31, 2017, cash and cash equivalents held outside the U.S. included $549.3 million (2016: $210 million, including cash temporarily invested in Canadian government securities with greater than 90 day maturities) in Canada and $334.6 million (2016: $262 million) in Malaysia. In addition, approximately $16.6 million of cash was held in the U.K. and has been classified as part of Assets held for sale in the Consolidated Balance Sheets at year-end 2017. In certain cases, the Company could incur cash taxes or other costs should these cash balances be repatriated to the U.S. in future periods. Canada currently collects a 5% withholding tax on any cash repatriated to the U.S. See Note I of the consolidated financial statements for further information regarding potential tax expense that could be incurred upon distribution of foreign earnings back to the United States.

Environmental Matters

Murphy faces various environmental and safety risks that are inherent in exploring for, developing and producing hydrocarbons. To help manage these risks, the Company has established a robust health, safety and environment governance program comprised of a worldwide policy, guiding principles, annual goals and a management system, with appropriate oversight at the business unit, senior leadership and board levels. The Company strives to minimize these risks by continually improving its processes through design, operation and maintenance, and through emergency and oil spill response planning to address any credible and major risks it identifies through impact assessments.

Murphy and other companies in the oil and gas industry are subject to numerous international, national, state, provincial and local environmental and safety laws and regulations. Murphy allocates a portion of its capital expenditure program, as well as its general and administrative budget, to comply with existing and anticipated environmental laws and regulations. These requirements affect virtually all operations of the Company and increase Murphy's overall cost of business, including its capital costs to construct, maintain and upgrade equipment and facilities, and operating costs for ongoing compliance.

The principal environmental laws and regulations to which Murphy is subject address such matters as the generation, storage, handling, use, disposal and remediation of petroleum products, wastewater and hazardous materials, the emission and discharge of such materials to the environment, greenhouse gas emissions, wildlife, habitat and water protection and the placement, operation and decommissioning of production equipment. These laws and regulations also generally require permits for existing operations, as well as the construction or development of new operations. Any violation of applicable environmental laws, regulations or permits can give rise to significant civil and criminal penalties, injunctions, construction bans and delays, and other sanctions.

These laws, regulations and permits have been subject to frequent change and tend to become more stringent over time. The change in the federal administration creates uncertainty in future changes as well as the enforcement of existing laws and regulations. In the United States, the Environmental Protection Agency has implemented requirements to reduce sulfur dioxide, volatile organic compound and hazardous air pollutant air emissions from oil and gas operations, including standards for wells that are hydraulically fractured. Any current or future air emission or other environmental requirements applicable to Murphy's businesses could curtail its operations or otherwise result in operational delays, liabilities and increased costs.

Certain jurisdictions in which the Company operates have required, or are considering requiring, more stringent permitting, chemical disclosure, transparency, water usage, disposal and well construction requirements. Regulators are also becoming increasingly focused on air emissions from the oil and gas industry, including volatile organic compound and methane emissions.

Murphy also could be subject to strict liability for environmental contamination, in various jurisdictions where we operate, including with respect to its current or former properties, operations and waste disposal sites, or those of its predecessors. Contamination has been identified at certain of such sites as a result of which the Company has been required and in the future may be required to remove or remediate previously disposed wastes, clean up contaminated soil, surface water and groundwater, address spills and leaks from pipelines and production equipment, and perform remedial plugging operations. In addition to significant investigation and remediation costs, such matters can result in fines and also give rise to third-party claims for personal injury and property or other environmental damage.

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 Company has retained these liabilities following the sale of the Seal business in January 2017. Following the spill, 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 continues to progress as planned and the Company's insurers were notified. Based on the assessments done to date, the Company recorded $43.9 million in Other expense in the 2015 Consolidated Statements of Operations associated with the estimated costs of remediating the site. The Company has spent $39.7 million from inception to the end of 2017. Further refinements in the estimated total cost to remediate the site are anticipated in future periods including possible fines from regulators. In the first quarter 2018, the Company received $15.0 million in respect to an insurance claim regarding this matter and the outcome of further claims are pending.

Murphy allocates a portion of its capital expenditure program to comply with environmental laws and regulations, and such capital expenditures were approximately $13 million in 2017 (2016: $13 million). This spending is projected to be approximately $15 million in 2018.

Climate Change

Murphy is currently required to report greenhouse gas emissions from certain of its operations and, in British Columbia and Alberta, is subject to a carbon tax on the purchase or use of many carbon-based fuels. Additionally, starting in 2017, a carbon tax applies to certain operations in Alberta. The Canadian Government has announced a proposal that all other provinces and territories implement some form of carbon pricing by 2018. Any limitation on or further regulation of, greenhouse gases (including through a cap and trade system) technology mandate, emissions tax, reporting requirement or other program, could restrict the Company's operations, curtail demand for hydrocarbons generally and/or impose increased costs, including to operate and maintain facilities, install pollution emission controls and administer and manage emissions trading programs.

Safety Matters

The Company is subject to the requirements of the federal Occupational Safety and Health Act (OSHA) and comparable foreign and state laws that regulate the protection of the health and safety of workers. In addition, the OSHA hazard communication standard requires that certain information be maintained about hazardous materials used or produced in Murphy's operations and that this information be provided to employees, state and local government authorities and citizens. The Company believes that its operations are in substantial compliance with applicable safety requirements, including general industry standards, record-keeping requirements and the monitoring of occupational exposure to regulated substances.

Other Matters

Impact of inflation – General inflation was moderate during the last three years in most countries where the Company operates; however, the Company's revenues and capital and operating costs are influenced to a larger extent by specific price changes in the oil and gas and allied industries than by changes in general inflation. Crude oil prices generally reflect the balance between supply and demand, with crude oil prices being particularly sensitive to OPEC production levels and/or attitudes of traders concerning supply and demand in the near future. Prices for oil field goods and services are usually affected by the worldwide prices for crude oil.

Oil and gas prices are generally driven by fundamental demand and supply factors for hydrocarbons, and as such, as demand and supply factors shift, oil and gas prices also shift. Prior to the drop in oil prices in late 2014, the cost for oil field materials and services had generally risen in the preceding years. In 2015-2016 lower oil prices reduced the demand for oil and gas materials and services, which led to significant downward pressure on the cost of these materials and services in 2015 and 2016. In 2017, as oil and gas prices have moved higher, drilling activity has begun to increase, leading to an upward pressure on the cost of oil and gas materials and services. Natural gas prices are also affected by supply and demand, which are often affected by the weather and by the fact that delivery of gas is generally restricted to specific geographic areas. In 2015 and 2016 North American natural gas prices also moved lower, as a result of abundant supply.

As a result of the overall volatility of oil and natural gas prices, it is not possible to predict the Company's future cost of oil field goods and services.

Accounting changes and recent accounting pronouncements

Accounting Principles Adopted

Compensation – Stock Compensation. In March 2016, the Financial Accounting Standards Board (FASB) issued an Accounting Standards Update (ASU) intended to simplify the accounting for share-based payment transactions, including the income tax consequences, classification of awards as either equity or liabilities, and classification within the statement of cash flows. The amendments in this ASU were effective for annual periods beginning after December 15, 2016, and interim periods within those annual periods. The Company adopted this guidance in 2017 and it did not have a material impact on its consolidated financial statements and footnote disclosures as there were no exercises of Company options during the period.

Business Combinations. In January 2017, the FASB issued an ASU to clarify the definition of a business to assist entities in evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses. The standard is intended to narrow the definition of a business by specifying the minimum inputs and processes and by narrowing the definition of outputs. The update is effective for annual periods beginning after December 15, 2017, including interim periods within those periods. The prospective approach is required for adoption and early adoption is permitted for transactions not previously reported in issued financial statements. The Company adopted this guidance in 2017 and it did not have a material impact on its consolidated financial statements and footnote disclosures.

Recent Accounting Pronouncements

Revenue from Contracts with Customers. In May 2014, the FASB issued an ASU to establish a comprehensive new revenue recognition standard for contracts with customers that will supersede most current revenue recognition requirements and industry-specific guidance. The codification was amended through additional ASU's and, as amended, requires an entity to recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration the entity expects to be entitled to in exchange for those goods or services. Additional disclosures will be required to describe the nature, amount, timing and uncertainty of revenue and cash flows from contracts with customers. The Company has performed a review of contracts in each of its revenue streams and has developed accounting policies to address the provisions of the ASU. As a result of this review, the Company's gross revenues and expenses may be impacted based on the determination of whether it is acting as a principal or an agent in certain transactions. The Company adopted the new standard on January 1, 2018, using the modified retrospective method and does not currently expect net earnings, revenues or expenses to be materially impacted. The Company continues to evaluate the impact of this and other provisions of the ASU on related disclosures.

Leases. In February 2016, 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 analyzing its portfolio of contracts to assess the impact future adoption of this ASU may have on its consolidated financial statements.
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 ASU is effective for annual and interim periods beginning after December 15, 2017. The Company anticipates adopting this guidance in the first quarter 2018 and does not believe the application of this ASU will 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 and 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 periods beginning after December 15, 2017 and interim periods within the annual period. Application is retrospective for the presentation of the components of these benefit costs and prospective for the capitalization of only service costs. The Company anticipates adopting this guidance in the first quarter 2018 and does not believe the application of this ASU will have a material impact on its consolidated financial statements.

Compensation – Stock Compensation. In May 2017, 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 anticipates adopting this guidance in the first quarter 2018 and does not believe the application of this ASU will have a material impact on its consolidated financial statements.

Significant accounting policies – In preparing the Company's consolidated financial statements in accordance with U.S. GAAP, management must make a number of estimates and assumptions related to the reporting of assets, liabilities, revenues and expenses and the disclosure of contingent assets and liabilities. Application of certain of the Company's accounting policies requires significant estimates. The most significant of these accounting policies and estimates are described below.

Oil and gas proved reserves – Oil and gas proved reserves are defined by the SEC as those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations before the time at which contracts providing the right to operate expire (unless evidence indicates that renewal is reasonably certain). Proved developed reserves of oil and gas can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared with the cost of a new well, or through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well. Although the Company's engineers are knowledgeable of and follow the guidelines for reserves as established by the SEC, the estimation of reserves requires the engineers to make a significant number of assumptions based on professional judgment. SEC rules require the Company to use a unweighted average of the oil and gas prices in effect at the beginning of each month of the year for determining quantities of proved reserves. These historical prices often do not approximate the average price that the Company expects to receive for its oil and natural gas production in the future. The Company often uses significantly different oil and natural gas price and reserve assumptions when making its own internal economic property evaluations. Changes in oil and gas prices can lead to a decision to start-up or shut-in production, which can lead to revisions to reserves quantities.

Estimated reserves are subject to future revision, certain of which could be substantial, based on the availability of additional information, including: reservoir performance, new geological and geophysical data, additional drilling, technological advancements, price changes and other economic factors. Reserves revisions inherently lead to adjustments of the Company's depreciation rates and the timing of settlement of asset retirement obligations. Downward reserves revisions can also lead to significant impairment expense. The Company cannot predict the type of oil and gas reserves revisions that will be required in future periods.
The Company's proved reserves of crude oil, natural gas liquids and natural gas are presented on pages 106 to 112 of this Form 10-K report. Murphy's estimations for proved reserves were generated through the integration of available geoscience, engineering, and economic data, and commercially available technologies, to establish 'reasonable certainty' of economic producibility. As defined by the SEC, reasonable certainty of proved reserves describes a high-degree of confidence that the quantities will be recovered. In estimating proved reserves, Murphy uses familiar industry-accepted methods for subsurface evaluations, including performance, volumetric, and analog based studies.

Where appropriate, Murphy includes reliable geologic and engineering technology to estimate proved reserves. Reliable geologic and engineering technology is a method or combination of methods that are field-tested and have demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation. This integrated approach increases the quality of and confidence in Murphy's proved reserves estimates, and was utilized in certain undrilled acreage at distances greater than the directly offsetting development spacing areas, and in certain reservoirs developed with the application of improved recovery techniques. Murphy utilized a combination of 3D seismic interpretation, core analysis, wellbore log measurements, well test data, historic production and pressure data, and commercially available seismic processing and numerical reservoir simulation programs. Reservoir parameters from analogous reservoirs were used to strengthen the reserves estimates when available.

See further discussion of proved reserves and changes in proved reserves during the three years ended December 31, 2017 beginning on pages 7 and 107 of this Form 10-K report.

Impairment of long-lived assets – The Company continually monitors its long-lived assets recorded in Property, plant and equipment (PPE) in the Consolidated Balance Sheet to make sure that they are fairly presented. The Company must evaluate its PPE for potential impairment when circumstances indicate that the carrying value of an asset may not be recoverable from future cash flows.

A significant amount of judgment is involved in performing these evaluations since the results are based on estimated future events. Such events include a projection of future oil and natural gas sales prices, an estimate of the amount of oil and natural gas that will be produced from a field, the timing of this future production, future costs to produce the oil and natural gas, future capital, operating and abandonment costs, and future inflation levels.

The need to test a long-lived asset for impairment can be based on several factors, including but not limited to a significant reduction in sales prices for oil and/or natural gas, unfavorable revisions of oil or natural gas reserves, or other changes to contracts, environmental regulations, tax laws or other regulatory changes. All of these factors must be considered when evaluating a property's carrying value for possible impairment.

Due to the volatility of world oil and gas markets, the actual sales prices for oil and natural gas have often been different from the Company's projections.

Estimates of future oil and gas production and sales volumes are based on a combination of proved and risked probable and possible reserves. Although the estimation of reserves and future production is uncertain, the Company believes that its estimates are reasonable; however, there have been cases where actual production volumes were higher or lower than projected and the timing was different than the original projection. The Company adjusts reserves and production estimates as new information becomes available.

The Company generally projects future costs by using historical costs adjusted for both assumed long-term inflation rates and known or expected changes in future operations. Although the projected future costs are considered to be reasonable, at times, costs have been higher or lower than originally estimated.

Based on a review of realized sales prices and costs, estimated futures prices for oil and natural gas, estimates of reserves and relevant regulator environments, the company did not record any impairment expense in 2017.

The Company recorded impairment expense of $95.1 million in 2016 to reduce the carrying value of producing heavy oil properties in Western Canada and the Terra Nova field offshore Canada to their estimated fair value due to significant declines in future oil prices in early 2016.

The Company recorded impairment expense of $2,493.2 million in 2015 to reduce the carrying value of producing offshore properties in Malaysia, producing heavy oil properties in Western Canada and producing and non-producing properties in the Gulf of Mexico to their estimated fair value due to significant declines in future oil and gas prices during 2015.

The fair values were determined by internal discounted cash flow models using estimates of future production, prices from futures exchanges, costs, and a discount rate believed to be consistent with those used by principal market participants in the applicable region.

Income taxes – The Company is subject to income and other similar taxes in all areas in which it operates. When recording income tax expense, certain estimates are required because: (a) income tax returns are generally filed months after the close of its annual accounting period; (b) tax returns are subject to audit by taxing authorities and audits can often take years to complete and settle; (c) future events often impact the timing of when income tax expenses and benefits are recognized by the Company and (d) changes to regulation may be subject to interpretation or clarity from issuing authorities. The Company has deferred tax assets mostly relating to basis differences for property, equipment and inventories, and liabilities for dismantlement and retirement benefit plan obligations and net deferred tax liabilities relating to U.S. basis differences for property equipment and inventories. The Company routinely evaluates all deferred tax assets to determine the likelihood of their realization.

On December 22, 2017, the U.S. enacted into legislation the Tax Cuts and Jobs Act (2017 Tax Act). For the year ended December 31, 2017, the Company recorded tax expense of $274.0 million directly related to the impacts of the 2017 Tax Act. The charge includes the impact of a deemed repatriation of historic foreign earnings and the re-measurement of deferred tax assets and liabilities. Separately, Murphy expects to receive cash refunds or credits of $29.7 million over the next four years relating to Alternative Minimum Tax (AMT) credits generated in earlier years. Murphy continues to assess the impact of this legislation including, among other things, the carry-forward of 2017 net operating losses, refinement of post-1986 accumulated foreign earnings and profits computations, the change to U.S. federal tax rates, the possible limitations on the deductibility of interest expense, the option for expensing of capital expenditures, the migration from a worldwide system of taxation to a territorial system, and the use of new anti-base erosion provisions. The tax expense recorded in 2017 is a reasonable estimate based on published guidance available at this time and considered provisional. The ultimate impact of the 2017 Tax Act may differ from these estimates due to changes in interpretations and assumptions made by the company, as well as additional regulatory guidance that may be issued. The Company's statutory U.S. tax rate will be 21% beginning in 2018, a decrease from the previous rate of 35%.

Accounting for retirement and postretirement benefit plans – Murphy Oil and certain of its subsidiaries maintain defined benefit retirement plans covering most full-time employees. The Company also sponsors health care and life insurance benefit plans covering most retired U.S. employees. The expense associated with these plans is determined by management based on a number of assumptions and with consultation assistance from qualified third-party actuaries. The most important of these assumptions for the retirement plans involve the discount rate used to measure future plan obligations and the expected long-term rate of return on plan assets. For the retiree medical and insurance plans, the most important assumptions are the discount rate for future plan obligations and the health care cost trend rate. Discount rates are based on the universe of high-quality corporate bonds that are available within each country. Cash flow analyses are performed in which a spot yield curve is used to discount projected benefit payment streams for the most significant plans. The discounted cash flows are used to determine an equivalent single rate which is the basis for selecting the discount rate within each country. Expected plan asset returns are based on long-term expectations for asset portfolios with similar investment mix characteristics. Anticipated health care cost trend rates are determined based on prior experience of the Company and an assessment of near-term and long-term trends for medical and drug costs.

Based on bond yields at December 31, 2017, the Company has used a weighted average discount rate of 3.7% at year-end 2017 for the primary U.S. plans. This weighted average discount rate is 0.6% lower than a year earlier, which increased the Company's recorded liabilities for retirement plans compared to a year ago. Although the Company presently assumes a return on plan assets of 6.50% for the primary U.S. plan, it periodically reconsiders the appropriateness of this and other key assumptions. The Company's retirement and postretirement plan expenses in 2018 are expected be $3.0 million higher than 2017 due to higher amortization of actuarial losses at year-end 2017. Cash contributions are anticipated to be $3.2 million higher in 2018. In 2017, the Company paid $24.9 million into various retirement plans and $2.4 million into postretirement plans. In 2018, the Company is expecting to fund payments of approximately $25.1 million into various retirement plans and $5.4 million for postretirement plans. The Company could be required to make additional and more significant funding payments to retirement plans in future years. Future required payments and the amount of liabilities recorded on the balance sheet associated with the plans could be unfavorably affected if the discount rate declines, the actual return on plan assets falls below the assumed return, or the health care cost trend rate increase is higher than expected.

As described above, the Company's retirement and postretirement expenses are sensitive to certain assumptions, primarily related to discount rates and assumed return on plan assets. A 0.5% decline in the discount rate would increase 2018 annual retirement expenses by $0.7 million and decrease postretirement expenses by $0.1 million; and a 0.5% decline in the assumed rate of return on plan assets would increase 2018 retirement expense by $2.8 million.

Legal, environmental and other contingent matters – A provision for legal, environmental and other contingent matters is charged to expense when the loss is probable and the cost can be reasonably estimated. Judgment is often required to determine when expenses should be recorded for legal, environmental and other contingent matters. In addition, the Company often must estimate the amount of such losses. In many cases, management's judgment is based on interpretation of laws and regulations, which can be interpreted differently by regulators and/or courts of law. The Company's management closely monitors known and potential legal, environmental and other contingent matters, and makes its best estimate of the amount of losses and when they should be recorded based on information available to the Company.

Contractual obligations and guarantees – The Company is obligated to make future cash payments under borrowing arrangements, operating leases, purchase obligations primarily associated with existing capital expenditure commitments, and other long-term liabilities. In addition, the Company expects to extend certain operating leases beyond the minimum contractual period. Total payments due after 2017 under such contractual obligations and arrangements are shown in the table below.

	Amount of Obligations				
(Millions of dollars)	Total	2018	2019-2020	2021-2022	After 2022
Debt including current maturities	$ **2,916.4**	9.9	21.4	1,117.4	1,767.7
Operating and other leases	**317.3**	73.7	128.0	89.1	26.5
Capital expenditures, drilling rigs and other	**1,596.3**	332.6	363.1	173.0	727.6
Other long-term liabilities, including debt interest	**2,617.8**	197.4	325.8	371.4	1,723.2
Total	$ **7,447.8**	613.6	838.3	1,750.9	4,245.0

The Company has entered into agreements to lease production facilities for various producing oil fields. In addition, the Company has other arrangements that call for future payments as described in the following section. The Company's share of the contractual obligations under these leases and other arrangements has been included in the table above.

In 2013, the Company entered into a 25-year lease for a semi-floating production system at the Kakap field offshore Sabah, Malaysia. The Company has included the required net lease obligations for this production system as Debt in the contractual obligation table above.

In the normal course of its business, the Company is required under certain contracts with various governmental authorities and others to provide letters of credit that may be drawn upon if the Company fails to perform under those contracts. Total outstanding letters of credit were $179.7 million as of December 31, 2017.

Material off-balance sheet arrangements – The Company occasionally utilizes off-balance sheet arrangements for operational or funding purposes. The most significant of these arrangements at year-end 2017 included operating leases of floating, production, storage and offloading vessel (FPSO) for the Kikeh oil field, drilling contracts for onshore and offshore rigs in various countries, and oil and/or natural gas transportation and processing contracts in the U.S. and Western Canada. The leases call for future monthly net lease payments through 2022 at Kikeh. The U.S. transportation contracts require minimum monthly payments through 2024, while Western Canada processing contracts call for minimum monthly payments through 2035. Future required minimum annual payments under these arrangements are included in the contractual obligation table above. In February 2016, 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 Company anticipates adopting this guidance in the first quarter of 2019 and is currently analyzing its portfolio of contracts to assess the impact future adoption of this ASU may have on its consolidated financial statements.

Outlook

Prices for the Company's primary products are often quite volatile. The price for crude oil is primarily affected by the levels of supply and demand for energy. Anticipated future variances between the predicted demand for crude oil and the projected available supply can lead to significant movement in the price of crude oil. In January 2018, West Texas Intermediate crude oil averaged about $64 for the month and averaged $62 in the first three weeks of February. NYMEX natural gas averaged $3.72 during January 2018. Both of these oil and natural gas prices are above the average prices achieved in 2017. The Company continually monitors the prices for its main products and often alters its operations and spending plans based on these prices.

The Company's capital expenditure budget for 2018 is expected to be $1.06 billion which assumes a West Texas Intermediate oil price of $52 per barrel and Henry Hub natural gas price of $3.00 per thousand cubic feet. Approximately 62% of the total capital is being allocated towards the onshore unconventional businesses with a majority at Eagle Ford Shale. Offshore development expenditures are focused on short-cycle projects that maintain existing assets and other activities expected to increase value-added production in future years. Approximately 10% of the annual budget has been allocated for exploration activities. Capital and other expenditures will be routinely reviewed during 2018 and planned capital expenditures may be adjusted to reflect differences between budgeted and actual cash flow during the year. Capital expenditures may also be affected by asset purchases or sales, which often are not anticipated at the time a budget is prepared. The Company will primarily fund its capital program in 2018 using operating cash flow and available cash, but will supplement funding where necessary using borrowings under available credit facilities. If oil and/or natural gas prices weaken, actual cash flow generated from operations could be reduced such that further capital spending reductions are required and/or borrowings might be required during the year to maintain funding of the Company's ongoing development projects.

The Company currently expects average daily production in 2018 to be between 164,000 and 168,000 barrels of oil equivalent per day. North American onshore unconventional production is expected to be 56% of 2018 production.

The Company has entered into WTI crude oil swap contracts and natural gas forward delivery contracts to manage risk associated with certain U.S. crude oil and Canadian natural gas sales prices as follows:

Commodities	Contract or Location	Dates	Average Volumes per Day	Average Prices
U.S. Oil	West Texas Intermediate	Jan. 2018 – Dec. 2018	21,000 bbls/d	$54.88 per bbl.
Canadian Natural Gas	TCPL–NOVA System	Jan. 2018 – Dec. 2020	59 mmcf/d	C$2.81 per mcf
Canadian Natural Gas	Chicago Gate	Jan. 2018 – Dec. 2018	20 mmcf/d	US$3.51 per mcf

In 2017 the Company observed upward pressure on the cost for oil field goods and services as commodity prices increased. This follows price concessions from many of its vendors that supplied oil field goods and services in 2015 and 2016 during lower commodity prices.

Forward-Looking Statements

This Form 10-K contains forward-looking statements as defined in the Private Securities Litigation Reform Act of 1995. These statements, which express management's current views concerning future events or results, are subject to inherent risks and uncertainties. Factors that could cause actual results to differ materially from those expressed or implied in these forward-looking statements include, but are not limited to, the volatility and level of crude oil and natural gas prices, the level and success rate of Murphy's exploration programs, the Company's ability to maintain production rates and replace reserves, customer demand for Murphy's products, adverse foreign exchange movements, political and regulatory instability, adverse developments in the U.S. or global capital markets, credit markets or economies generally, and uncontrollable natural hazards. For further discussion of risk factors, see Item 1A. Risk Factors, which begins on page 13 of this Annual Report on Form 10-K. Murphy undertakes no duty to publicly update or revise any forward-looking statements.

Item 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The Company is exposed to market risks associated with interest rates, prices of crude oil, natural gas and petroleum products, and foreign currency exchange rates. As described in Note L, Murphy makes use of derivative financial and commodity instruments to manage risks associated with existing or anticipated transactions.

There were commodity transactions in place at December 31, 2017 covering certain future U.S. crude oil sales volumes in 2018. A 10% increase in the respective benchmark price of these commodities would have increased the recorded net liability associated with these derivative contacts by approximately $45.5 million, while a 10% decrease would have decreased the recorded net liability by a similar amount.

Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Information required by this item appears on pages 57 through 118 of this Form 10-K report.

Item 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None

Item 9A. CONTROLS AND PROCEDURES

Under the direction of its principal executive officer and principal financial officer, controls and procedures have been established by Murphy to ensure that material information relating to the Company and its consolidated subsidiaries is made known to the officers who certify the Company's financial reports and to other members of senior management and the Board of Directors.

Based on their evaluation, with the participation of the Company's management, as of December 31, 2017, the principal executive officer and principal financial officer of Murphy Oil Corporation have concluded that the Company's disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934) were effective to ensure that the information required to be disclosed by Murphy Oil Corporation in reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms.

Murphy's management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f). Management has conducted an evaluation of the effectiveness of the Company's internal control over financial reporting based on the criteria set forth in *Internal Control – Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the results of this evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2017. Management's report is included on page 57 of this Form 10-K report. KPMG LLP, an independent registered public accounting firm, has made an independent assessment of the effectiveness of the Company's internal control over financial reporting as of December 31, 2017 and their report is included on page 59 of this Form 10-K report.

There were no changes in the Company's internal controls over financial reporting that occurred during the fourth quarter of 2017 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

Item 9B. OTHER INFORMATION

None

PART III

Item 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Certain information regarding executive officers of the Company is included on page 21 of this Form 10-K report. Other information required by this item is incorporated by reference to the Registrant's definitive Proxy Statement for the Annual Meeting of Stockholders on May 9, 2018 under the captions "Election of Directors" and "Committees."

Murphy Oil has adopted a Code of Ethical Conduct for Executive Management, which can be found under the Corporate Governance and Responsibility tab at www.murphyoilcorp.com. Stockholders may also obtain, free of charge, a copy of the Code of Ethical Conduct for Executive Management by writing to the Company's Secretary at P.O. Box 7000, El Dorado, AR 71731-7000. Any future amendments to or waivers of the Company's Code of Ethical Conduct for Executive Management will be posted on the Company's Website.

Item 11. EXECUTIVE COMPENSATION

Information required by this item is incorporated by reference to Murphy's definitive Proxy Statement for the Annual Meeting of Stockholders on May 9, 2018 under the captions "Compensation Discussion and Analysis" and "Compensation of Directors" and in various compensation schedules.

Item 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Information required by this item is incorporated by reference to Murphy's definitive Proxy Statement for the Annual Meeting of Stockholders on May 9, 2018 under the captions "Security Ownership of Certain Beneficial Owners," "Security Ownership of Management," and "Equity Compensation Plan Information."

Item 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Information required by this item is incorporated by reference to Murphy's definitive Proxy Statement for the Annual Meeting of Stockholders on May 9, 2018 under the caption "Election of Directors."

Item 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Information required by this item is incorporated by reference to Murphy's definitive Proxy Statement for the Annual Meeting of Stockholders on May 9, 2018 under the caption "Audit Committee Report."

PART IV

Item 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a) 1. Financial Statements – The consolidated financial statements of Murphy Oil Corporation and consolidated subsidiaries are located or begin on the pages of this Form 10-K report as indicated below.

2. Financial Statement Schedules

All other financial statement schedules are omitted because either they are not applicable or the required information is included in the consolidated financial statements or notes thereto.

3. Exhibits – The following is an index of exhibits that are hereby filed as indicated by asterisk (*), that are considered furnished rather than filed, or that are incorporated by reference. Exhibits other than those listed have been omitted since they either are not required or are not applicable.

Exhibit No.		Incorporated by Reference to
3.1	Certificate of Incorporation of Murphy Oil Corporation as amended, effective May 11, 2005	Exhibit 3.1 of Murphy's Form 10-K report filed February 28, 2011
3.2	By-Laws of Murphy Oil Corporation as amended effective February 3, 2016	Exhibit 3.2 of Murphy's Form 8-K report filed February 5, 2016

Exhibit No.		Incorporated by Reference to
4.1	Form of Indenture and Form of Supplemental Indenture between Murphy Oil Corporation and SunTrust Bank, as Trustee	Exhibit 4.2 of Murphy's Form 10-K report for the year ended December 31, 2009
4.2	Form of Indenture and First Supplemental Indenture between Murphy Oil Corporation and U.S. Bank National Association, as Trustee	Exhibits 4.1 and 4.2 of Murphy's Form 8-K report filed May 18, 2012
4.3	Second Supplemental Indenture between Murphy Oil Corporation and U.S. Bank National Association, as Trustee	Exhibit 4.1 of Murphy's Form 8-K report filed November 30, 2012.
4.4	5-Year Revolving Credit Agreement dated June 14, 2011	Exhibit 4.1 of Murphy's Form 10-Q report filed August 5, 2014
4.5	Commitment Increase and Maturity Extension Agreement dated May 23, 2013	Exhibit 4.2 of Murphy's Form 10-Q report filed August 5, 2014
4.6	Third Supplemental Indenture dated as of August 17, 2016 between Murphy Oil Corporation and U.S. Bank National Association, as Trustee	Exhibit 4.1 of Murphy's Form 8-K report filed August 17, 2016
4.7	Fourth Supplemental Indenture dated August 18, 2017 between Murphy Oil Corporation and U.S Bank National Association, as Trustee, and Wells Fargo Bank, National Association, as Series Trustee	Exhibit 4.1 of Murphy's Form 8-K report filed August 18, 2017
10.1	2012 Long-Term Incentive Plan	Exhibit A of Murphy's definitive Proxy Statement (Definitive 14A) dated March 29, 2012
10.2	Employee Stock Purchase Plan as amended May 9, 2007	Exhibit 10.3 of Murphy's Form 10-K report for the year ended December 31, 2012
10.3	2008 Stock Plan for Non-Employee Directors, as approved by shareholders on May 14, 2008	Form S-8 report filed February 5, 2009
10.4	2013 Stock Plan for Non-Employee Directors	Exhibit A of Murphy's definitive Proxy Statement (Definitive 14A) dated March 22, 2013
10.5	Non-Qualified Deferred Compensation Plan for Non-Employee Directors	Exhibit 10.6 of Murphy's Form 10-K report for the year ended December 31, 2015
10.6	Tax Matters Agreement, dated August 30, 2013, between Murphy Oil Corporation and Murphy USA Inc.	Exhibit 10.1 of Murphy's Form 8-K report filed September 5, 2013
10.7	Employee Matters Agreement, dated August 30, 2013, between Murphy Oil Corporation and Murphy USA Inc.	Exhibit 10.3 of Murphy's Form 8-K report filed September 5, 2013
10.8	Trademark License Agreement, dated August 30, 2013, between Murphy Oil Corporation and Murphy USA Inc	Exhibit 10.4 of Murphy's Form 8-K report filed September 5, 2013

Exhibit No.		Incorporated by Reference to
10.10	Third Amendment to 5-year Revolving Credit Agreement dated as of August 10, 2016 among Murphy Oil Corporation, Canam Offshore Limited, and Murphy Oil Company Ltd., as borrowers, JPMorgan Chase Bank, N.A., as administrative agent and the lenders party thereto	Exhibit 10.2 of Murphy's Form 8-K report filed August 12, 2016
10.11	Third Amendment to Credit Agreement among Murphy Oil Corporation, Murphy Exploration & Production Company – International and Murphy Oil Company Ltd., as borrowers, JPMorgan Chase Bank, N.A., as administrative agent and the lenders party thereto	Exhibit 10.1 of Murphy's Form 8-K report filed November 20, 2017
*12	Computation of Ratio of Earnings to Fixed Charges	
*21	Subsidiaries of the Registrant	
*23.1	Consent of Independent Registered Public Accounting Firm	
*31.1	Certification required by Rule 13a-14(a) pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	
*31.2	Certification required by Rule 13a-14(a) pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	
*32	Certifications pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	
99.1	Form of employee stock option	Exhibit 99.1 of Murphy's Form 10-K report for the year ended December 31, 2013
99.2	Form of performance-based employee restricted stock unit grant agreement	Exhibit 99.2 of Murphy's Form 10-K report for the year ended December 31, 2014
99.3	Form of employee time-based restricted stock unit grant agreement	Exhibit 99.1 of Murphy's Form 10-Q report filed November 6, 2013
99.4	Form of non-employee director stock option	Exhibit 99.3 of Murphy's Form 10-K report for the year ended December 31, 2010
99.5	Form of non-employee director restricted stock unit award	Exhibit 99.5 of Murphy's Form 10-K report for the year ended December 31, 2008
99.6	Form of non-employee director restricted stock unit award	Exhibit 99.2 of Murphy's Form 10-Q report filed November 6, 2013

Exhibit No.		Incorporated by Reference to
99.7	Form of phantom unit award	Exhibit 99.1 of Murphy’s Form 10-Q report filed November 6, 2012
99.8	Form of stock appreciation right (“SAR”)	Exhibit 99.6 of Murphy’s Form 10-K report for the year ended December 31, 2012 and Exhibit 99.3 of Murphy's Form 10-Q report filed May 7, 2014
99.9	Form of performance-based restricted stock unit-cash grant agreement	Exhibit 99.7 of Murphy’s Form 10-K report for the year ended December 31, 2012
99.10	Form of time-based restricted stock unit grant agreement	Exhibit 99.1 of Murphy's Form 10-Q report filed May 7, 2014
99.11	Form of time-based restricted stock unit-cash grant agreement	Exhibit 99.2 of Murphy's Form 10-Q report filed May 7, 2014
101.INS	XBRL Instance Document	
101.SCH	XBRL Taxonomy Extension Schema Document	
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document	
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document	
101.LAB	XBRL Taxonomy Extension Labels Linkbase Document	
101.PRE	XBRL Taxonomy Extension Presentation Linkbase	

SIGNATURES

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

MURPHY OIL CORPORATION

By /s/ ROGER W. JENKINS Date: February 23, 2018
Roger W. Jenkins, President

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below on February 23, 2018 by the following persons on behalf of the registrant and in the capacities indicated.

/s/ CLAIBORNE P. DEMING Claiborne P. Deming, Chairman and Director	/s/ R. MADISON MURPHY R. Madison Murphy, Director
/s/ ROGER W. JENKINS Roger W. Jenkins, President and Chief Executive Officer and Director (Principal Executive Officer)	/s/ WALENTIN MIROSH Walentin Mirosh, Director
/s/ T. JAY COLLINS T. Jay Collins, Director	/s/ JEFFREY W. NOLAN Jeffrey W. Nolan, Director
/s/ STEVEN A. COSSE Steven A. Cossé, Director	/s/ NEAL E. SCHMALE Neal E. Schmale, Director
/s/ LAWRENCE R. DICKERSON Lawrence R. Dickerson, Director	/s/ LAURA A. SUGG Laura A. Sugg, Director
/s/ ELISABETH W. KELLER Elisabeth W. Keller, Director	/s/ JOHN W. ECKART John W. Eckart, Executive Vice President and Chief Financial Officer (Principal Financial Officer)
/s/ JAMES V. KELLEY James V. Kelley, Director	/s/ CHRISTOPHER D. HULSE Christopher D. Hulse Vice President and Controller (Principal Accounting Officer)

REPORT OF MANAGEMENT – CONSOLIDATED FINANCIAL STATEMENTS

The management of Murphy Oil Corporation is responsible for the preparation and integrity of the accompanying consolidated financial statements and other financial data. The financial statements were prepared in conformity with U.S. generally accepted accounting principles (GAAP) appropriate in the circumstances and include some amounts based on informed estimates and judgments, with consideration given to materiality.

An independent registered public accounting firm, KPMG LLP, has audited the Company's consolidated financial statements in accordance with the standards of the Public Company Accounting Oversight Board and provides an objective, independent opinion about the Company's consolidated financial statements. The Audit Committee of the Board of Directors appoints the independent registered public accounting firm; ratification of the appointment is solicited annually from the shareholders. KPMG LLP's opinion covering the Company's consolidated financial statements can be found on page 58.

The Board of Directors appoints an Audit Committee annually to implement and to support the Board's oversight function of the Company's financial reporting, accounting policies, internal controls and independent registered public accounting firm. This Committee is composed solely of directors who are not employees of the Company. The Committee meets routinely with representatives of management, the Company's audit staff and the independent registered public accounting firm to review and discuss the adequacy and effectiveness of the Company's internal controls, the quality and clarity of its financial reporting, the scope and results of independent and internal audits, and to fulfill other responsibilities included in the Committee's Charter. The independent registered public accounting firm and the Company's audit staff have unrestricted access to the Committee, without management presence, to discuss audit findings and other financial matters.

REPORT OF MANAGEMENT – INTERNAL CONTROL OVER FINANCIAL REPORTING

Management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f). The Company's internal controls have been designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of consolidated financial statements in accordance with U.S. GAAP. All internal control systems have inherent limitations, and therefore, can provide only reasonable assurance with respect to the reliability of financial reporting and preparation of consolidated financial statements.

Management has conducted an evaluation of the effectiveness of the Company's internal control over financial reporting based on the criteria set forth in *Internal Control – Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission in 2013. Based on the results of this evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2017.

KPMG LLP has performed an audit of the Company's internal control over financial reporting and their opinion thereon can be found on page 59.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of Murphy Oil Corporation:
Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of Murphy Oil Corporation and subsidiaries (the "Company") as of December 31, 2017 and 2016, the related consolidated statements of operations, comprehensive income (loss), cash flows, and stockholders' equity for each of the years in the three-year period ended December 31, 2017, and the related notes and financial statement Schedule II – Valuation Accounts and Reserves (collectively, the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2017, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the Company's internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control –Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated February 23, 2018, expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ KPMG LLP

We have served as the Company's auditor since 1952.

Houston, Texas
February 23, 2018

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of Murphy Oil Corporation:

Opinion on Internal Control Over Financial Reporting

We have audited Murphy Oil Corporation and subsidiaries' (the "Company") internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the consolidated balance sheets of the Company as of December 31, 2017 and 2016, the related consolidated statements of operations, comprehensive income (loss), cash flows, and stockholders' equity for each of the years in the three-year period ended December 31, 2017, and the related notes and financial statement Schedule II – Valuation Accounts and Reserves (collectively, the "consolidated financial statements"), and our report dated February 23, 2018 expressed an unqualified opinion on those consolidated financial statements.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Report of Management – Internal Control Over Financial reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control Over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ KPMG LLP
Houston, Texas
February 23, 2018

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

December 31 *(Thousands of dollars)*	**2017**	2016
Assets		
Current assets		
Cash and cash equivalents	$ **964,988**	872,797
Canadian government securities with maturities greater than 90 days at the date of acquisition	–	111,542
Accounts receivable, less allowance for doubtful accounts of $1,605 in 2017 and 2016	**243,472**	357,099
Inventories, at lower of cost or market	**105,127**	127,071
Prepaid expenses	**35,087**	63,604
Assets held for sale	**22,929**	27,070
Total current assets	**1,371,603**	1,559,183
Property, plant and equipment, at cost less accumulated depreciation, depletion and amortization of $12,280,741 in 2017 and $12,607,815 in 2016	**8,220,031**	8,316,188
Deferred income taxes	**211,543**	365,935
Deferred charges and other assets	**57,765**	54,554
Total assets	$ **9,860,942**	10,295,860
Liabilities and Stockholders' Equity		
Current liabilities		
Current maturities of long-term debt	$ **9,902**	569,817
Accounts payable	**595,916**	784,975
Income taxes payable	**44,604**	13,920
Other taxes payable	**23,574**	28,167
Other accrued liabilities	**156,681**	102,777
Liabilities associated with assets held for sale	**3,530**	2,776
Total current liabilities	**834,207**	1,502,432
Long-term debt, including capital lease obligation	**2,906,520**	2,422,750
Deferred income taxes	**159,098**	69,081
Asset retirement obligations	**709,299**	681,528
Deferred credits and other liabilities	**631,627**	617,490
Liabilities associated with assets held for sale	–	85,900
Stockholders' equity		
Cumulative Preferred Stock, par $100, authorized 400,000 shares, none issued	–	–
Common Stock, par $1.00, authorized 450,000,000 shares, issued 195,055,724 shares in 2017 and 2016	**195,056**	195,056
Capital in excess of par value	**917,665**	916,799
Retained earnings	**5,245,242**	5,729,596
Accumulated other comprehensive loss	**(462,243)**	(628,212)
Treasury stock	**(1,275,529)**	(1,296,560)
Total stockholders' equity	**4,620,191**	4,916,679
Total liabilities and stockholders' equity	$ **9,860,942**	10,295,860

See Notes to Consolidated Financial Statements, page 65.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS

Years Ended December 31 *(Thousands of dollars except per share amounts)*		2017	2016 [1]	2015 [1]
Revenues				
Sales and other operating revenues	$	**2,097,695**	1,809,575	2,787,116
Gain on sale of assets		**127,434**	1,663	154,155
Total revenues		**2,225,129**	1,811,238	2,941,271
Costs and Expenses				
Lease operating expenses		**468,323**	559,360	832,306
Severance and ad valorem taxes		**43,618**	43,826	65,794
Exploration expenses, including undeveloped lease amortization		**122,834**	101,861	470,924
Selling and general expenses		**222,766**	265,210	306,663
Depreciation, depletion and amortization		**957,719**	1,054,081	1,619,824
Impairment of assets		–	95,088	2,493,156
Redetermination expense		**15,000**	39,100	–
Accretion of asset retirement obligations		**42,590**	46,742	48,665
Other expense		**30,706**	13,806	360,635
Total costs and expenses		**1,903,556**	2,219,074	6,197,967
Operating income (loss) from continuing operations		**321,573**	(407,836)	(3,256,696)
Other income (loss)				
Interest and other income (loss)		**(67,988)**	62,891	91,809
Interest expense, net		**(181,783)**	(148,170)	(117,375)
Total other loss		**(249,771)**	(85,279)	(25,566)
Income (loss) from continuing operations before income taxes		**71,802**	(493,115)	(3,282,262)
Income tax expense (benefit)		**382,738**	(219,172)	(1,026,490)
Loss from continuing operations		**(310,936)**	(273,943)	(2,255,772)
Loss from discontinued operations, net of income taxes		**(853)**	(2,027)	(15,061)
NET LOSS	$	**(311,789)**	(275,970)	(2,270,833)
LOSS PER COMMON SHARE – BASIC				
Continuing operations	$	**(1.81)**	(1.59)	(12.94)
Discontinued operations		–	(0.01)	(0.09)
Net loss	$	**(1.81)**	(1.60)	(13.03)
LOSS PER COMMON SHARE – DILUTED				
Continuing operations	$	**(1.81)**	(1.59)	(12.94)
Discontinued operations		–	(0.01)	(0.09)
Net loss	$	**(1.81)**	(1.60)	(13.03)
Cash dividends per Common share		**1.00**	1.20	1.40
Average Common shares outstanding (thousands)				
Basic		**172,524**	172,173	174,351
Diluted		**172,524**	172,173	174,351

See Notes to Consolidated Financial Statements, page 65.
[1] Reclassified to conform to current presentation (see Note A).

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

Years Ended December 31 *(Thousands of dollars)*	**2017**	2016	2015
Net loss	**$ (311,789)**	(275,970)	(2,270,833)
Other comprehensive income (loss), net of tax			
Net gain (loss) from foreign currency translation	**171,725**	66,449	(546,705)
Retirement and postretirement benefit plans	**(7,682)**	7,955	10,492
Deferred loss on interest rate hedges reclassified to interest expense.	**1,926**	1,926	1,926
Other comprehensive income (loss)	**165,969**	76,330	(534,287)
COMPREHENSIVE LOSS	**$ (145,820)**	(199,640)	(2,805,120)

See Notes to Consolidated Financial Statements, page 65.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

Years Ended December 31 *(Thousands of dollars)*		**2017**	2016	2015
Operating Activities				
Net loss	$	**(311,789)**	(275,970)	(2,270,833)
Adjustments to reconcile net loss to net cash provided by continuing operations activities:				
Loss from discontinued operations		**853**	2,027	15,061
Depreciation, depletion and amortization		**957,719**	1,054,081	1,619,824
Impairment of assets		**–**	95,088	2,493,156
Amortization of deferred major repair costs		**–**	3,794	7,296
Dry hole costs (credits)		**(4,163)**	15,047	296,845
Amortization of undeveloped leases		**61,776**	43,417	75,312
Accretion of asset retirement obligations		**42,590**	46,742	48,665
Deferred income tax expense (benefit)		**260,420**	(387,843)	(978,030)
Pretax gains from disposition of assets		**(127,434)**	(1,663)	(154,155)
Net (increase) decrease in noncash operating working capital		**136,414**	(38,689)	35,064
Other operating activities, net		**113,289**	44,764	(4,836)
Net cash provided by continuing operations activities		**1,129,675**	600,795	1,183,369
Investing Activities				
Property additions and dry hole costs		**(1,009,667)**	(926,948)	(2,549,736)
Proceeds from sales of property, plant and equipment		**69,506**	1,155,144	423,911
Purchase of investment securities [1]		**(212,661)**	(695,879)	(911,787)
Proceeds from maturity of investment securities [1]		**320,828**	761,000	1,129,139
Other investing activities, net		**–**	(7,230)	(13,648)
Net cash provided (required) by investing activities		**(831,994)**	286,087	(1,922,121)
Financing Activities				
Borrowings of debt		**541,597**	541,444	600,000
Repayments of debt		**(550,000)**	(600,000)	(450,000)
Capital lease obligation payments		**(17,133)**	(10,447)	(10,434)
Purchase of treasury stock		**–**	–	(250,000)
Issue cost of debt facility		**–**	(14,085)	–
Cash dividends paid		**(172,565)**	(206,635)	(244,998)
Other financing activities, net		**(7,116)**	(1,158)	(9,129)
Net cash required by financing activities		**(205,217)**	(290,881)	(364,561)
Cash Flows from Discontinued Operations				
Operating activities		**10,905**	–	(15,005)
Investing activities		**–**	–	5,314
Changes in cash included in current assets held for sale		**(12,505)**	–	192,585
Net increase (decrease) in cash and cash equivalents of discontinued operations		**(1,600)**	–	182,894
Effect of exchange rate changes on cash and cash equivalents		**1,327**	(6,387)	10,294
Net increase (decrease) in cash and cash equivalents		**92,191**	589,614	(910,125)
Cash and cash equivalents at beginning of period		**872,797**	283,183	1,193,308
Cash and cash equivalents at end of period	**$**	**964,988**	872,797	283,183

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

See Notes to Consolidated Financial Statements, page 65.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

Years Ended December 31 *(Thousands of dollars)*	**2017**	2016	2015
Cumulative Preferred Stock – par $100, authorized 400,000 shares, none issued	$ **–**	–	–
Common Stock – par $1.00, authorized 450,000,000 shares at December 31, 2017, 2016 and 2015, issued 195,055,724 shares at December 31, 2017, 2016 and 2015.			
Balance at beginning of year	**195,056**	195,056	195,040
Exercise of stock options	**–**	–	16
Balance at end of period	**195,056**	195,056	195,056
Capital in Excess of Par Value			
Balance at beginning of year	**916,799**	910,074	906,741
Exercise of stock options, including income tax benefits	**–**	(12,017)	(376)
Restricted stock transactions and other	**(26,553)**	(10,078)	(38,415)
Stock-based compensation	**27,496**	29,119	42,322
Other	**(77)**	(299)	(198)
Balance at end of period	**917,665**	916,799	910,074
Retained Earnings			
Balance at beginning of year	**5,729,596**	6,212,201	8,728,032
Net loss for the year	**(311,789)**	(275,970)	(2,270,833)
Cash dividends – $1.00 per share in 2017, $1.20 per share in 2016 and $1.40 per share in 2015	**(172,565)**	(206,635)	(244,998)
Balance at end of period	**5,245,242**	5,729,596	6,212,201
Accumulated Other Comprehensive Loss			
Balance at beginning of year	**(628,212)**	(704,542)	(170,255)
Foreign currency translation gains (losses), net of income taxes	**171,725**	66,449	(546,705)
Retirement and postretirement benefit plans, net of income taxes	**(7,682)**	7,955	10,492
Deferred loss on interest rate hedge reclassified to interest expense, net of income taxes	**1,926**	1,926	1,926
Balance at end of year	**(462,243)**	(628,212)	(704,542)
Treasury Stock			
Balance at beginning of year	**(1,296,560)**	(1,306,061)	(1,086,124)
Purchase of treasury shares	**–**	–	(250,000)
Sale of stock under employee stock purchase plans	**146**	509	491
Awarded restricted stock	**20,885**	8,992	29,572
Balance at end of year – 22,482,851 shares of Common Stock in 2017, 22,853,547 shares of Common Stock in 2016 and 23,021,013 shares of Common Stock in 2015.	**(1,275,529)**	(1,296,560)	(1,306,061)
Total Stockholders' Equity	$ **4,620,191**	4,916,679	5,306,728

See Notes to Consolidated Financial Statements, page 65.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
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 60-64 of the Form 10-K report.

Note A – Significant Accounting Policies

NATURE OF BUSINESS – Murphy Oil Corporation is an international oil and gas company that conducts its business through various operating subsidiaries. The Company produces oil and natural gas in the United States, Canada and Malaysia and conducts oil and natural gas exploration activities worldwide. The Company sold its interest in a Canadian synthetic oil operation in 2016 and its Canadian heavy oil assets in early 2017. In addition, Murphy Oil sold its downstream retail marketing assets in the United Kingdom in 2015. See Notes C and E for more information regarding the sale of these assets.

PRINCIPLES OF CONSOLIDATION – The consolidated financial statements include the accounts of Murphy Oil Corporation and all majority-owned subsidiaries. Undivided interests in oil and gas joint ventures are consolidated on a proportionate basis. Investments in affiliates in which the Company owns from 20% to 50% are accounted for by the equity method. Other investments are generally carried at cost. All significant intercompany accounts and transactions have been eliminated.

Beginning in 2017, certain reclassifications in presentation have been made to the Consolidated Statements of Operations. The Company now presents a separate "Operating income (loss) from continuing operations" subtotal on the Consolidated Statements of Operations. Additionally, "Interest and other income (loss)," which includes foreign exchange gains and losses, has been reclassified from a component of total revenues and is now presented below Operating income (loss) from continuing operations. "Interest expense" and "Capitalized interest" have also been combined into the "Interest expense, net" line item and are now presented below "Operating income (loss) from continuing operations." Previously reported periods have been reclassified to conform to the current period presentation. These reclassifications did not impact previously reported Income (loss) from continuing operations before income taxes, Loss from continuing operations, or Net Loss.

REVENUE RECOGNITION – Revenues from sales of crude oil, natural gas liquids and natural gas are recorded when deliveries have occurred and legal ownership of the commodity transfers to the customer. Revenues from the production of oil and natural gas properties in which Murphy shares an undivided interest with other producers are recognized based on the actual volumes sold by the Company during the period. Natural gas imbalances occur when the Company's actual gas sales volumes differ from its proportional share of production from the well. The company follows the sales method of accounting for these natural gas imbalances. The Company records a liability for gas imbalances when it has sold more than its working interest of gas production and the estimated remaining reserves make it doubtful that partners can recoup their share of production from the field. At December 31, 2017 and 2016, the liabilities for natural gas balancing were immaterial. See Note B for further discussion on revenue recognition.

CASH EQUIVALENTS – Short-term investments, which include government securities and other instruments with government securities as collateral, that are highly liquid and have a maturity of three months or less from the date of purchase are classified as cash equivalents.

MARKETABLE SECURITIES – The Company classifies investments in marketable securities as available-for-sale or held-to-maturity. The Company does not have any investments classified as trading securities. Available-for-sale securities are carried at fair value with the unrealized gain or loss, net of tax, reported in other comprehensive loss. Held-to-maturity securities are recorded at amortized cost. Premiums and discounts are amortized or accreted into earnings over the life of the related available-for-sale or held-to-maturity security. Dividend and interest income is recognized when earned. Unrealized losses considered to be other than temporary are recognized currently in earnings. The cost of securities sold is based on the specific identification method. The fair value of investment securities is determined by available market prices. At December 31, 2016, the Company owned Canadian government securities with maturities greater than 90 days at date of acquisition that had a carrying value of $111.5 million. These securities are readily marketable and could be quickly converted to cash if needed to meet operating cash needs in Canada.

ACCOUNTS RECEIVABLE – At December 31, 2017 and 2016, the Company's accounts receivable primarily consisted of amounts owed to the Company by customers for sales of crude oil and natural gas. The allowance for doubtful accounts is the Company's best estimate of the amount of probable credit losses on these receivables. The Company reviews this allowance for adequacy at least quarterly and bases its assessment on a combination of current information about its customers and historical write-off experience. Any trade accounts receivable balances written off are charged against the allowance for doubtful accounts. The Company has not experienced any significant credit-related losses in the past three years.

INVENTORIES – Amounts included in the Consolidated Balance Sheets include unsold crude oil production and materials and supplies associated with oil and gas production operations. Unsold crude oil production is carried in inventory at the lower of cost, generally applied on a first-in, first-out (FIFO) basis, or market, and includes costs incurred to bring the inventory to its existing condition. Materials and supplies inventories are valued at the lower of average cost or estimated value and generally consist of tubulars and other drilling equipment.

PROPERTY, PLANT AND EQUIPMENT – The Company uses the successful efforts method to account for exploration and development expenditures. Leasehold acquisition costs are capitalized. If proved reserves are found on an undeveloped property, leasehold cost is transferred to proved properties. Costs of undeveloped leases associated with unproved properties are expensed over the life of the leases. Exploratory well costs are capitalized pending determination about whether proved reserves have been found. In certain cases, a determination of whether a drilled exploratory well has found proved reserves cannot be made immediately. This is generally due to the need for a major capital expenditure to produce and/or evacuate the hydrocarbon(s) found. The determination of whether to make such a capital expenditure is usually dependent on whether further exploratory wells find a sufficient quantity of additional reserves. The Company continues to capitalize exploratory well costs in Property, Plant and Equipment 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. The Company reevaluates its capitalized drilling costs at least annually to ascertain whether drilling costs continue to qualify for ongoing capitalization. Other exploratory costs, including geological and geophysical costs, are charged to expense as incurred. Development costs, including unsuccessful development wells, are capitalized. Interest is capitalized on significant development projects that are expected to take one year or more to complete.

Oil and gas properties are evaluated by field for potential impairment. Other properties are evaluated for impairment on a specific asset basis or in groups of similar assets as applicable. An impairment is recognized when the estimated undiscounted future net cash flows of an asset are less than its carrying value. If an impairment occurs, the carrying value of the impaired asset is reduced to fair value. There was no impairment recorded in 2017. During 2016 and 2015, declines in future oil and gas prices provided indications of possible impairments in certain of the Company's producing properties. As a result of management's assessments during 2016, the Company recognized pretax noncash impairments charges of $95.1 million at its Terra Nova field offshore Canada and its Western Canada onshore heavy oil producing properties. In 2015, the Company recognized pretax noncash impairments charges of $2.5 billion to reduce the carrying value of certain producing properties in Malaysia, Western Canada and the Gulf of Mexico to their estimated fair value. See also Note E for further discussion of impairment charges.

The Company records a liability for asset retirement obligations (ARO) equal to the fair value of the estimated cost to retire an asset. The ARO liability is initially recorded in the period in which the obligation meets the definition of a liability, which is generally when a well is drilled or the asset is placed in service. The ARO liability is estimated by the Company's engineers using existing regulatory requirements and anticipated future inflation rates. When the liability is initially recorded, the Company increases the carrying amount of the related long-lived asset by an amount equal to the original liability. The liability is increased over time to reflect the change in its present value, and the capitalized cost is depreciated over the useful life of the related long-lived asset. The Company reevaluates the adequacy of its recorded ARO liability at least annually. Actual costs of asset retirements such as dismantling oil and gas production facilities and site restoration are charged against the related liability. Any difference between costs incurred upon settlement of an asset retirement obligation and the recorded liability is recognized as a gain or loss in the Company's earnings.

Depreciation and depletion of producing oil and gas properties are recorded based on units of production. Unit rates are computed for unamortized exploration drilling and development costs using proved developed reserves; unit rates for unamortized leasehold costs and asset retirement costs are amortized over proved reserves. Proved reserves are estimated by the Company's engineers and are subject to future revisions based on availability of additional information. Additionally, certain natural gas processing facilities and related equipment in Malaysia are being

depreciated on a straight-line basis over their estimated useful life ranging from 20 to 25 years. Gains and losses on asset disposals or retirements are included in net loss as a separate component of revenues.
Turnarounds for coking units at Syncrude Canada Ltd. were scheduled at intervals of two to three years. Turnaround work associated with various other less significant units at Syncrude varied depending on operating requirements and events. Murphy defers turnaround costs incurred and amortizes such costs over the period until the next scheduled turnaround. This amortization is recorded in Lease operating expenses for Syncrude. All other maintenance and repairs are expensed as incurred. Renewals and betterments are capitalized. The Company sold its interest in Syncrude during 2016.

CAPITALIZED INTEREST – Interest associated with borrowings from third parties is capitalized on significant oil and gas development projects when the expected development period extends for one year or more. Interest capitalized is credited in the Consolidated Statements of Operations and is added to the cost of the underlying asset for the development project in Property, plant and equipment in the Consolidated Balance Sheets. Capitalized interest is amortized over the useful life of the asset in the same manner as other development costs.

ENVIRONMENTAL LIABILITIES – A liability for environmental matters is established when it is probable that an environmental obligation exists and the cost can be reasonably estimated. If there is a range of reasonably estimated costs, the most likely amount will be recorded, or if no amount is most likely, the minimum of the range is used. Related expenditures are charged against the liability. Environmental remediation liabilities have not been discounted for the time value of future expected payments. Environmental expenditures that have future economic benefit are capitalized.

INCOME TAXES – The Company accounts for income taxes using the asset and liability method. Under this method, income taxes are provided for amounts currently payable and for amounts deferred as tax assets and liabilities based on differences between the financial statement carrying amounts and the tax bases of existing assets and liabilities. Deferred income taxes are measured using the enacted tax rates that are assumed will be in effect when the differences reverse. The Company routinely assesses the realizability of deferred tax assets based on available evidence including assumptions of future taxable income, tax planning strategies and other pertinent factors. A deferred tax asset valuation allowance is recorded when evidence indicates that it is more likely than not that all or a portion of these deferred tax assets will not be realized in a future period.

Prior to 2017, the Company did not provide U.S. deferred taxes for undistributed earnings of certain foreign subsidiaries when these earnings were considered indefinitely invested. On December 22, 2017 the Tax Cuts and Jobs Act (2017 Tax Act) was enacted which triggered the transitional tax on a deemed repatriation of all past foreign earnings (see Note I) and a provision for this impact has been recorded. Also, deferred tax liabilities are recorded for relevant withholding taxes when undistributed earnings of foreign subsidiaries are not considered indefinitely invested. Under present law, the Company would incur a 5% withholding tax on any earnings repatriated from Canada to the U.S.

The accounting rules for income tax uncertainties permit recognition of income tax benefits only when they are more likely than not to be realized, and then only for the largest amount that is greater than 50% likely of being realized. The Company includes potential penalties and interest for uncertain income tax positions in income tax expense.

FOREIGN CURRENCY – Local currency is the functional currency used for recording operations in Canada and for former refining and marketing activities in the United Kingdom. The U.S. dollar is the functional currency used to record all other operations. Exchange gains or losses from transactions in a currency other than the functional currency are included in earnings. Gains or losses from translating foreign functional currencies into U.S. dollars are included in Accumulated Other Comprehensive Loss in Consolidated Statements of Stockholders' Equity.

DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITIES – The fair value of a derivative instrument is recognized as an asset or liability in the Company's Consolidated Balance Sheets. Upon entering into a derivative contract, the Company may designate the derivative as either a fair value hedge or a cash flow hedge, or decide that the contract is not a hedge for accounting purposes, and thenceforth, recognize changes in the fair value of the contract in earnings. The Company documents the relationship between the derivative instrument designated as a hedge and the hedged items as well as its objective for risk management and strategy for use of the hedging instrument to manage the risk. Derivative instruments designated as fair value or cash flow hedges are linked to specific assets and liabilities or to specific firm commitments or forecasted transactions. The Company assesses at inception and on an ongoing basis whether a derivative instrument accounted for as a hedge is highly effective in offsetting changes in the fair value or cash flows of the hedged item. A derivative that is not a highly effective hedge does not qualify for hedge accounting. The change in the fair value of a qualifying fair value hedge is recorded in earnings along with the gain or loss on the hedged item. The effective portion of the change in the fair value of a qualifying cash flow hedge is recorded in Accumulated other comprehensive loss in the Consolidated Balance Sheets until the hedged item is recognized currently in earnings. If a derivative instrument no longer qualifies as a cash flow hedge and the underlying forecasted transaction is no longer probable of occurring, hedge accounting is discontinued and the gain or loss recorded in Accumulated other comprehensive loss is recognized immediately in earnings.

FAIR VALUE MEASUREMENTS – The Company carries certain assets and liabilities at fair value in its Consolidated Balance Sheets. Fair value is determined using various techniques depending on the availability of observable inputs. Level 1 inputs include quoted prices in active markets for identical assets or liabilities. Level 2 inputs include observable inputs other than quoted prices included within Level 1. Level 3 inputs are unobservable inputs which reflect assumptions about pricing by market participants.

STOCK-BASED COMPENSATION
Equity-Settled Awards – The fair value of awarded stock options, restricted stock units and other stock-based compensation that are settled with Company shares is determined based on a combination of management assumptions and the market value of the Company's common stock. The Company uses the Black-Scholes option pricing model for computing the fair value of equity-settled stock options. The primary assumptions made by management include the expected life of the stock option award and the expected volatility of Murphy's common stock price. The Company uses both historical data and current information to support its assumptions. Stock option expense is recognized on a straight-line basis over the respective vesting period of two or three years. The Company uses a Monte Carlo valuation model to determine the fair value of performance-based restricted stock units that are equity settled and expense is recognized over the three-year vesting period. The fair value of time-lapse restricted stock units is determined based on the price of Company stock on the date of grant and expense is recognized over the vesting period. The Company estimates the number of stock options and performance-based restricted stock units that will not vest and adjusts its compensation expense accordingly. Differences between estimated and actual vested amounts are accounted for as an adjustment to expense when known.

Cash-Settled Awards – The Company accounts for stock appreciation rights (SAR), cash-settled restricted stock units (CRSU) and phantom stock units as liability awards. Expense associated with these awards are recognized over the vesting period based on the latest available estimate of the fair value of the awards, which is generally determined using a Black-Scholes method for SAR, a Monte Carlo method for performance-based CRSU, and the period-end price of the Company's common stock for time-based CRSU and phantom units. When SAR are exercised and when CRSU and phantom units settle, the Company adjusts previously recorded expense to the final amounts paid out in cash for these awards.

PENSION AND OTHER POSTRETIREMENT BENEFIT PLANS – The Company recognizes the funded status (the difference between the fair value of plan assets and the projected benefit obligation) of its defined benefit and other postretirement benefit plans in the Consolidated Balance Sheets. Changes in the funded status which have not yet been recognized in the Consolidated Statement of Operations are recorded net of tax in Accumulated other comprehensive loss. The remaining amounts in Accumulated other comprehensive loss include net actuarial losses and prior service (cost) credit.

NET INCOME (LOSS) PER COMMON SHARE – Basic income (loss) per common share is computed by dividing net income (loss) for each reporting period by the weighted average number of common shares outstanding during the period. Diluted income (loss) per common share is computed by dividing net income (loss) for each reporting period by the weighted average number of common shares outstanding during the period plus the effects of all potentially dilutive common shares. Dilutive securities are not included in the computation of diluted income (loss) per share when a net loss occurs as the inclusion would have the effect of reducing the diluted loss per share.

USE OF ESTIMATES – In preparing the financial statements of the Company in conformity with U.S. generally accepted accounting principles (GAAP), 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.

Note B – New Accounting Principles and Recent Accounting Pronouncements

Accounting Principles Adopted

Compensation – Stock Compensation. In March 2016, the Financial Accounting Standards Board (FASB) issued an Accounting Standards Update (ASU) intended to simplify the accounting for share-based payment transactions, including the income tax consequences, classification of awards as either equity or liabilities, and classification within the statement of cash flows. The amendments in this ASU were effective for annual periods beginning after December 15, 2016, and interim periods within those annual periods. The Company adopted this guidance in 2017 and it did not have a material impact on its consolidated financial statements and footnote disclosures as there were no exercises of Company options during the period.

Business Combinations. In January 2017, the FASB issued an ASU to clarify the definition of a business to assist entities in evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses. The standard is intended to narrow the definition of a business by specifying the minimum inputs and processes and by narrowing the definition of outputs. The update is effective for annual periods beginning after December 15, 2017, including interim periods within those periods. The prospective approach is required for adoption and early adoption is permitted for transactions not previously reported in issued financial statements. The Company adopted this guidance in 2017 and it did not have a material impact on its consolidated financial statements and footnote disclosures.

Recent Accounting Pronouncements

Revenue from Contracts with Customers. In May 2014, the FASB issued an ASU to establish a comprehensive new revenue recognition standard for contracts with customers that will supersede most current revenue recognition requirements and industry-specific guidance. The codification was amended through additional ASU's and, as amended, requires an entity to recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration the entity expects to be entitled to in exchange for those goods or services. Additional disclosures will be required to describe the nature, amount, timing and uncertainty of revenue and cash flows from contracts with customers. The Company has performed a review of contracts in each of its revenue streams and has developed accounting policies to address the provisions of the ASU. As a result of this review, the Company's gross revenues and expenses may be impacted based on the determination of whether it is acting as a principal or an agent in certain transactions. The Company adopted the new standard on January 1, 2018, using the modified retrospective method and does not currently expect net earnings, revenues or expenses to be materially impacted. The Company continues to evaluate the impact of this and other provisions of the ASU on related disclosures.

Leases. In February 2016, 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 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 analyzing its portfolio of contracts to assess the impact future adoption of this ASU may have on its consolidated financial statements.

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 ASU is effective for annual and interim periods beginning after December 15, 2017. The Company anticipates adopting this guidance in the first quarter 2018 and does not believe the application of this ASU will have a material impact on its consolidated financial statements and related footnote disclosures.

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 and 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 periods beginning after December 15, 2017 and interim periods within the annual period. Application is retrospective for the presentation of the components of these benefit costs and prospective for the capitalization of only service costs. The Company anticipates adopting this guidance in the first quarter 2018 and does not believe the application of this ASU will have a material impact on its consolidated financial statements and related footnote disclosures.

Compensation – Stock Compensation. In May 2017, 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 anticipates adopting this guidance in the first quarter 2018 and does not believe the application of this ASU will have a material impact on its consolidated financial statements and related footnote disclosures.

Note C – 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 following table presents the carrying value of the major categories of assets and liabilities of U.K. discontinued refining and marketing operations and Seal operations in Canada reflected as held for sale on the Company's Consolidated Balance Sheets at December 31, 2017 and 2016.

(Thousands of dollars)	**2017**	2016
Current assets		
Cash	**$ 16,631**	4,126
Accounts receivable	**6,298**	22,944
Other	**–**	–
Total current assets held for sale	**$ 22,929**	27,070
Current liabilities		
Accounts payable	**$ 837**	270
Accrued compensation and severance	**–**	–
Refinery decommissioning cost	**2,693**	2,506
Total current liabilities associated with assets held for sale	**$ 3,530**	2,776
Non-current liabilities		
Asset retirement obligation – Seal asset	**$ –**	85,900

The asset retirement obligation at December 31, 2016 relates to well and facility abandonment obligations at the Seal field in Canada which were assumed by the purchasing company upon the completion of the sale in January 2017 (see Note E).

The results of operations associated with discontinued operations are presented in the following table.

(Thousands of dollars)		2017	2016	2015
Revenues	$	854	1,464	381,747
Loss from operations before income taxes	$	(853)	(2,027)	(6,758)
Loss on sale before income taxes		–	–	(4,990)
Total loss from discontinued operations before taxes		(853)	(2,027)	(11,748)
Income tax expense		–	–	3,313
Loss from discontinued operations	$	(853)	(2,027)	(15,061)

Certain reclassifications have been made to 2016 and 2015 Revenues to align with current period presentation (see Note A).

Note D – Inventories

Inventories consisted of the following at December 31, 2017 and 2016.

		December 31,	
		2017	2016
(Thousands of dollars)			
Unsold crude oil	$	20,153	17,146
Materials and supplies		84,974	109,925
	$	105,127	127,071

Note E – Property, Plant and Equipment

		December 31, 2017		December 31, 2016	
(Thousands of dollars)		Cost	Net	Cost	Net
Exploration and production[1]	$	20,329,930	8,120,293 [2]	20,767,772	8,214,740 [2]
Corporate and other		170,842	99,738	156,231	101,448
	$	20,500,772	8,220,031	20,924,003	8,316,188
[1] Includes unproved mineral rights as follows:	$	600,423	198,349	595,138	188,689

[2.] Includes $38,670 in 2017 and $48,053 in 2016 related to administrative assets and support equipment.

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 $48.8 million. Additionally, the buyer assumed the asset retirement obligation of approximately $85.9 million. A $129.0 million pretax gain was reported in 2017 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 transaction was approximately $19.6 million. There were no gains or losses recorded related to the non-core Eagle Ford Shale sales.

In 2016, a Canadian subsidiary of the Company completed the sale of its five percent, non-operated working interest in Syncrude Canada Ltd. (Syncrude) asset to Suncor Energy Inc. (Suncor). The Company received net cash proceeds of $739.1 million and recorded an after-tax gain of $71.7 million associated with the Syncrude divestiture.

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 $7.1 million and $5.1 million of the deferred gain during 2017 and 2016, respectively. The remaining deferred gain of $181.7 million was included as a component of Deferred credits and other liabilities in the Company's Consolidated Balance Sheet as of December 31, 2017.

Acquisition

In 2016, a Canadian subsidiary of Murphy Oil acquired a 70% operated working interest (WI) of Athabasca Oil Corporation's (Athabasca) production, acreage, infrastructure and facilities in the Kaybob Duvernay lands, and a 30% non-operated WI of 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 December 31, 2017, $44.8 million of the carried interest had been paid. The carry is to be paid over a period of up to five years from 2016.

Impairments

During 2016 and 2015, declines in future oil and gas prices led to impairments in certain of the Company's producing properties. During 2016, the Company recorded pretax noncash impairment charges of $95.1 million to reduce the carrying values to their estimated fair values for the Terra Nova field offshore Canada and the Western Canada onshore heavy oil producing properties. In 2015, the Company recognized pretax noncash impairment charges of $2.49 billion to reduce the carrying value of certain offshore producing and non-producing properties in the Gulf of Mexico, producing offshore properties in Malaysia and for Western Canada onshore heavy oil producing properties. The fair values were determined by internal discounted cash flow models using estimates of future production, prices from futures exchanges, costs, and a discount rate believed to be consistent with those used by principal market participants in the applicable region. The following table reflects the recognized impairments for the three years ended December 31, 2017.

	December 31,		
(Thousands of dollars)	**2017**	2016	2015
Gulf of Mexico	$ –	–	328,982
Canada	–	95,088	683,574
Malaysia	–	–	1,480,600
	$ –	95,088	2,493,156

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 owners. The Gumusut-Kakap Unit is operated by another company. In the fourth quarter 2016, the owners 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 taxes) 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 further Unitization Framework Agreement (UFA) between the governments of Brunei and Malaysia, the Company now has a 6.35% interest in the Kakap field in Block K Malaysia as of December 31, 2017. 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 expense of $15.0 million ($9.3 million after tax) related to Company's revised working interest.

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 December 31, 2017, 2016 and 2015, the Company had total capitalized drilling costs pending the determination of proved reserves of $175.6 million, $148.5 million and $130.5 million, respectively. The following table reflects the net changes in capitalized exploratory well costs during the three-year period ended December 31, 2017.

(Thousands of dollars)	**2017**	2016	2015
Beginning balance at January 1	**$ 148,500**	130,514	120,455
Additions pending the determination of proved reserves	**51,488**	17,986	64,578
Reclassifications to proved properties based on the determination of proved reserves	**(15,988)**	–	–
Capitalized exploratory well costs charged to expense	**(8,360)**	–	(54,519)
Ending balance at December 31	**$ 175,640**	148,500	130,514

The capitalized well costs charged to expense in 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 capitalized well costs charged to expense in 2015 included one well in the Gulf of Mexico in which development of the well also could not be justified due to noncommercial hydrocarbon quantities found in the sidetrack and one project in the Gulf of Mexico deemed unlikely to be developed due to low commodity prices.

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 has been capitalized. The projects are aged based on the last well drilled in the project.

	2017			2016			2015		
(Thousands of dollars)	**Amount**	**No. of Wells**	**No. of Projects**	Amount	No. of Wells	No. of Projects	Amount	No. of Wells	No. of Projects
Aging of capitalized well costs:									
Zero to one year	**$ 41,480**	**3**	**2**	$ 20,481	1	1	$ 66,032	7	6
One to two years	**5,812**	**1**	**1**	63,527	5	5	–	–	–
Two to three years	**43,200**	**2**	**2**	–	–	–	57,876	3	–
Three years or more	**85,148**	**7**	**1**	64,492	6	–	6,606	3	–
	$ 175,640	**13**	**6**	$ 148,500	12	6	$ 130,514	13	6

Of the $134.1 million of exploratory well costs capitalized more than one year at December 31, 2017, $70.4 million is in Brunei, $43.2 million is in Vietnam and $20.5 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.

Note F – Financing Arrangements

At December 31, 2017, the Company has a $1.1 billion senior unsecured guaranteed credit facility (2016 facility) with a major banking consortium, which expires in August 2021. At December 31, 2017, the Company had no outstanding borrowings under the 2016 facility; however, there were $90.7 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 December 31, 2017, the applicable base interest rate would have been 4.875%. At December 31, 2017, the Company was in compliance with all covenants related to the 2016 facility.

On November 17, 2017, the Company entered into the third amendment (Amendment No. 3) to the 2016 facility. Among other things, Amendment No. 3 extends the maturity date of the 2016 facility to August 17, 2021, and reduces the facility fee on revolving commitments and the interest margin on revolving loans and increases the total leverage ratio under the financial covenants from ≤ 3.75:1.00 to ≤ 4.00:1.00.

In August 2017, the Company sold $550 million of new notes that bear interest at the rate of 5.75% and mature on August 15, 2025. The Company incurred transaction costs of $8.4 million on the issuance of these new notes. The new notes pay interest semi-annually on February 15 and August 15 of each year. The initial interest payment was paid on February 15, 2018. The proceeds of the $550 million notes were used to redeem the Company's 3.50% notes in September 2017. The 3.50% notes had an original maturity of December 2017.

In August 2016, the Company reduced its then existing $2.0 billion unsecured revolving credit facility (2011 facility) to $630 million (facility has since expired) and entered into a separate $1.2 billion senior unsecured guaranteed credit facility (2016 facility, subsequently reduced to $1.1 billion), with a major banking consortium that originally expired in August 2019, which was subsequently extended to 2021. The Company incurred transaction costs of approximately $14.0 million to place the 2016 facility which were included in financing activities in the Consolidated Statement of Cash Flows. Also in August 2016, the Company sold $550 million of notes that bear interest at the rate of 6.875% and mature on August 15, 2024. The proceeds of the $550 million notes were used for general corporate purposes.

The Company has a shelf registration statement on file with the U.S. Securities and Exchange Commission that permits the offer and sale of debt and/or equity securities through October 2018.

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 $9.9 million and $134.0 million, respectively, associated with this lease at December 31, 2017.

Note G – Long-term Debt

(Thousands of dollars)	December 31, 2017	2016
Notes payable		
3.50% notes, due December 2017	$ -	550,000
4.00% notes, due June 2022	**500,000**	500,000
4.45% notes, due December 2022[1]	**600,000**	600,000
6.875% notes, due August 2024	**550,000**	550,000
5.75% notes, due August 2025	**550,000**	-
7.05% notes, due May 2029	**250,000**	250,000
5.875% notes, due December 2042[1]	**350,000**	350,000
Total notes payable	**2,800,000**	2,800,000
Unamortized debt issuance cost and discount on notes payable	**(27,433)**	(23,835)
Total notes payable, net of unamortized discount	**2,772,567**	2,776,165
Capitalized lease obligation, due through March 2029	**143,855**	216,402
Total debt including current maturities	**2,916,422**	2,992,567
Current maturities	**(9,902)**	(569,817)
Total long-term debt	**$ 2,906,520**	2,422,750

[1] Due to a series of ratings changes by credit agencies, the paying interest rates on the notes due December 2022 and December 2042 decreased from 4.7% to 4.45% and 6.125% to 5.875%, respectively, at December 2017.

The amount of debt repayable over each of the next five years and thereafter are as follows: $9.9 million in 2018, $10.4 million in 2019, $11.0 million in 2020, $11.5 million in 2021, $1.11 billion in 2022 and $1.77 billion thereafter.

Note H – Asset Retirement Obligations

The asset retirement obligations liabilities (ARO) recognized by the Company at December 31, 2017 and 2016 are related to the estimated costs to dismantle and abandon its producing oil and gas properties and related equipment.

A reconciliation of the beginning and ending aggregate carrying amount of the asset retirement obligation for 2017 and 2016 is shown in the following table.

(Thousands of dollars)		**2017**	2016
Balance at beginning of year	**$**	**781,057**	825,312
Accretion expense		**42,590**	46,742
Liabilities incurred		**52,331**	13,690
Revisions of previous estimates		**(47,612)**	(4,511)
Liabilities settled		**(29,111)**	(20,589)
Liabilities assumed by purchaser of oil and gas assets		**(87,456)**	(91,883)
Changes due to translation of foreign currencies		**10,340**	12,296
Balance at end of year		**722,139**	781,057
Liabilities reported as held for sale at end of year[1]		–	(85,900)
Current portion of liability at end of year[2]		**(12,840)**	(13,629)
Noncurrent portion of liability at end of year	**$**	**709,299**	681,528

[1]Liabilities held for sale related to Seal properties in Canada which were sold in January 2017.
[2]Included in Other accrued liabilities on the Consolidated Balance Sheet.

The estimation of future ARO is based on a number of assumptions requiring professional judgment. The Company cannot predict the type of revisions to these assumptions that may be required in future periods due to the availability of additional information such as: prices for oil field services, technological changes, governmental requirements and other factors.

In 2017, revisions of previous estimates primarily reflect the impact of lower rig service rates in the U.S.

Note I – Income Taxes

The components of income (loss) from continuing operations before income taxes for each of the three years presented and income tax expense (benefit) attributable thereto were as follows.

(Thousands of dollars)	**2017**	2016	2015
Income (loss) from continuing operations before income taxes			
United States	$ **(299,349)**	(595,196)	(1,259,268)
Foreign	**371,151**	102,081	(2,022,994)
Total	$ **71,802**	(493,115)	(3,282,262)
Income tax expense (benefit)			
Federal – Current	$ **–**	–	(9,435)
– Deferred	**156,065**	(197,450)	(241,127)
Total Federal	**156,065**	(197,450)	(250,562)
State	**4,230**	13,984	(5,294)
Foreign – Current	**122,318**	146,861	(40,550)
– Deferred	**100,125**	(182,567)	(730,084)
Total Foreign	**222,443**	(35,706)	(770,634)
Total	$ **382,738**	(219,172)	(1,026,490)

The following table reconciles income taxes based on the U.S. statutory tax rate to the Company's income tax expense.

(Thousands of dollars)	**2017**	2016	2015
Income tax expense (benefit) based on the U.S. statutory tax rate	$ **25,131**	(172,590)	(1,148,792)
Revaluation of deferred tax (US tax reform)	**118,004**	–	–
Deferred tax effect of deemed repatriation of foreign invested earnings (U.S. tax reform)	**156,000**	–	–
Deferred tax effect on Canadian earnings no longer indefinitely invested	**65,000**	–	–
Foreign income (loss) subject to foreign tax rates different than the U.S. statutory rate	**12,658**	8,582	49,739
State income taxes, net of federal benefit	**2,438**	9,090	(3,441)
U.S. tax benefit on certain foreign upstream investments	**(32,926)**	(21,336)	(16,939)
Deferred tax on distribution of foreign earnings	**–**	–	188,461
Tax effects on sale of Canadian assets	**–**	(89,473)	–
Tax effects on sale of Malaysian assets	**–**	2,080	(122,559)
Increase in deferred tax asset valuation allowance related to other foreign exploration expenditures	**18,601**	25,734	40,788
Other, net	**17,832**	18,741	(13,747)
Total	$ **382,738**	(219,172)	(1,026,490)

The Tax Cuts and Jobs Act

On December 22, 2017, the U.S. enacted into legislation the Tax Cuts and Jobs Act (2017 Tax Act). For the year ended December 31, 2017, the Company recorded a tax expense of $274.0 million directly related to the impacts of the 2017 Tax Act. The charge includes the impact of a deemed repatriation of foreign earnings and the re-measurement of deferred tax assets and liabilities. Separately, Murphy expects to receive cash refunds or credits of $29.7 million over the next four years relating to Alternative Minimum Tax credits generated in earlier years. Murphy continues to assess the impact of this legislation including, among other things, the carryforward of 2017 net operating losses, refinement of post-1986 accumulated foreign earnings and profits computations, the change to U.S. federal tax rates, the possible limitations on the deductibility of interest expense, the option for expensing of capital expenditures, the migration from a worldwide system of taxation to a territorial system, and the use of new anti-base erosion provisions. The tax expense recorded in 2017 is a reasonable estimate based on published guidance available at this time and is considered provisional. The ultimate impact of the 2017 Tax Act may differ from these estimates due to changes in interpretations and assumptions made by the company, as well as additional regulatory guidance that may be issued. The Company's statutory U.S. federal income tax rate will be 21% beginning in 2018, a decrease from the previous rate of 35%.

As part of the transition of the U.S. tax system to a territorial system, the 2017 Tax Act provides that certain past accumulated undistributed foreign earnings are deemed repatriated. The territorial system is effective January 1, 2018. For financial statement reporting purposes, the Company believes the 2016 tax net operating loss can be carried forward into 2018 and later years to offset U.S. taxable income. The legislation is inconclusive regarding whether the estimated 2017 tax operating loss incurred by the Company prior to the 2017 Tax Act's required deemed repatriation at December 31, 2017 may be excluded from the deemed repatriation tax computation (Internal Revenue Code Section 965(n)).

Based on interpretation and guidance at this time and uncertainty regarding whether the new Section 965(n) election applies to a 2017 loss, the Company's tax provision reflects the estimated 2017 tax operating loss being applied fully against the deemed income inclusion. This results in the inability to carryforward the 2017 tax operating loss and the creation of unused foreign tax credit carryforwards with a limited ten-year life. A full valuation allowance has been provided against these unused foreign tax credits to be carried forward. If the Company had prepared the 2017 tax provision preserving the 2017 tax loss as a carryforward, the unused foreign tax credits would have been available to offset a large portion of the tax resulting from the deemed inclusion of foreign earnings, and the U.S. deferred tax charge would have been reduced by approximately $120.0 million with the $36 million residual balance reclassified from deferred tax to a deemed repatriation tax payable over eight years. In the event the Internal Revenue Service or other guidance subsequently determines that the 2017 tax operating loss can be preserved as a carryforward to subsequent years with a twenty-year life, the Company will adjust its financial statements in future periods.

An analysis of the Company's deferred tax assets and deferred tax liabilities at December 31, 2017 and 2016 showing the tax effects of significant temporary differences follows.

(Thousands of dollars)	**2017**	2016
Deferred tax assets		
Property and leasehold costs	**$ 488,584**	572,481
Liabilities for dismantlements	**98,444**	170,946
Postretirement and other employee benefits	**134,444**	214,288
Alternative minimum tax	**29,710**	29,710
Foreign tax credit carryforwards	**228,159**	33,295
U. S. net operating loss	**272,930**	454,231
Other deferred tax assets	**13,892**	16,541
Total gross deferred tax assets	**1,266,163**	1,491,492
Less valuation allowance	**(476,256)**	(305,389)
Net deferred tax assets	**789,907**	1,186,103
Deferred tax liabilities		
Deferred tax on undistributed foreign earnings	**(65,000)**	–
Accumulated depreciation, depletion and amortization	**(669,638)**	(867,343)
Other deferred tax liabilities	**(2,824)**	(21,908)
Total gross deferred tax liabilities	**(737,462)**	(889,251)
Net deferred tax assets	**$ 52,445**	296,852

In management's judgment, the net deferred tax assets in the preceding table are more likely than not to be realized based on the consideration of deferred tax liability reversals and future taxable income. The valuation allowance for deferred tax assets relates primarily to tax assets arising in foreign tax jurisdictions and foreign tax credit carryforwards; in the judgment of management at the present time, these tax assets are more likely than not unexpected to be realized. The foreign tax credit carryforwards expire in 2018 through 2027. The valuation allowance increased $170.9 million in 2017 primarily due to foreign tax credit carryforwards realized from the deemed repatriation of accumulated undistributed foreign earnings under the 2017 Tax Act. Subsequent reductions of the valuation allowance are expected to be reported as reductions of tax expense assuming no offsetting change in the deferred tax asset.

The Company has an estimated U.S. net operating loss of $1.29 billion at year-end 2017 with a corresponding deferred tax asset of $272.9 million. The Company believes the U.S. net operating loss being carried forward will be utilized in future periods prior to expiration in 2036.

Under present law, if the Company repatriates earnings from Canada to the United States in the future, it would incur a 5% withholding tax on the amounts repatriated. A provision of $65.0 million is recorded in the Company's financial statements for future repatriation of $1.3 billion of Canada's past foreign earnings no longer deemed indefinitely reinvested.

Other Information

The Company currently expects in 2018 to repatriate cash to the U.S. of $700 million of Canada's past earnings not indefinitely invested, which will lead to a tax withholding payment of $35.0 million (provided for as part of the $65.0 million for future repatriation). In December 2015, one of the Company's foreign subsidiaries declared a $2.0 billion dividend payable to its parent. The dividend represented substantially all of the foreign subsidiary's accumulated retained earnings under U.S. GAAP. The foreign subsidiary's dividend was settled with an $800 million cash payment plus issuance of a $1.2 billion note payable to its U.S. parent that was settled in June 2016. The dividend was completed without a U.S. current tax impact due to the utilization of the 2015 U.S. tax net operating loss combined with the shareholder's ability to use foreign tax credits that attached to the dividend. Based on the usage of the 2015 U.S. tax net operating loss, a noncash tax expense of $188.5 million was recorded in 2015, primarily associated with using a U.S. deferred tax asset that without the dividend would otherwise have carried forward to future years.

Uncertain Income Tax Positions

The FASB's rules for accounting for income tax uncertainties clarify the criteria for recognizing uncertain income tax benefits and require additional disclosures about uncertain tax positions. Under current rules the financial statement recognition of the benefit for a tax position is dependent upon the benefit being more likely than not to be sustainable upon examination. If this threshold is met, the tax benefit is then measured and recognized at the largest amount that is greater than 50% likely of being realized upon ultimate settlement. Liabilities associated with uncertain income tax positions are included in Deferred credits and other liabilities in the Consolidated Balance Sheets. A reconciliation of the beginning and ending amount of the consolidated liability for unrecognized income tax benefits during the three years presented is shown in the following table.

(Thousands of dollars)		**2017**	2016	2015
Balance at January 1	**$**	**7,417**	6,631	6,011
Additions for tax positions related to current year		**769**	756	821
Settlements due to lapse of time		**(4,834)**	–	–
Foreign currency translation effect		**85**	30	(201)
Balance at December 31	**$**	**3,437**	7,417	6,631

All additions or settlements to the above liability affect the Company's effective income tax rate in the respective period of change. The Company accounts for any applicable interest and penalties on uncertain tax positions as a component of income tax expense. The Company also had other recorded liabilities as of December 31, 2017, 2016 and 2015 for interest and penalties of $0.1 million, $0.3 million and $0.2 million, respectively, associated with uncertain tax positions. Income tax expense for the years ended December 31, 2017, 2016 and 2015 included net benefits for interest and penalties of $0.2 million, $0.1 million and $0.1 million, respectively, associated with uncertain tax positions.

During the next twelve months, the Company currently expects to add between $1.0 million and $2.0 million to the liability for uncertain taxes for 2018 events. Although existing liabilities could be reduced by settlement with taxing authorities or lapse due to statute of limitations, the Company believes that the changes in its unrecognized tax benefits due to these events will not have a material impact on the Consolidated Statement of Operations during 2018.

The Company's tax returns in multiple jurisdictions are subject to audit by taxing authorities. These audits often take 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 December 31, 2017, the earliest years remaining open for audit and/or settlement in the Company's major taxing jurisdictions are as follows: United States – 2014; Canada – 2012; Malaysia – 2011; and United Kingdom – 2016.

Note J – Incentive Plans

Murphy utilizes cash-based and/or share-based incentive plans to supplement normal salaries as compensation for executive management and certain employees. For share-based awards that qualify for equity accounting, costs are recognized as an expense in the Consolidated Statements of Operations using a grant date fair value-based measurement method over the periods that the awards vest. For share-based awards that are required to be accounted for under liability accounting rules, costs are recognized as expense using a fair value-based measurement method over the vesting period, but expense is adjusted as necessary through the date the award value is finally determined. Total expense for liability awards is ultimately adjusted to the final intrinsic value for the award.

At December 31, 2017, the Company has incentive awards issued to employees under the 2012 Long-Term Incentive Plan (2012 Long-Term Plan) and the 2012 Annual Incentive Plan (2012 Annual Plan). The 2012 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 2012 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 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, performance units, performance shares, dividend equivalents and other stock-based incentives. The 2012 Long-Term Plan expires in 2022. A total of 8.7 million 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. Based on awards made to date, approximately 2.6 million shares remained available for grant under the 2012 Long-Term Plan at December 31, 2017. The Company also has a 2013 Stock Plan for Non-Employee Directors (Director Plan) that permits the issuance of restricted stock, restricted stock units and stock options or a combination thereof to the Company's Non-Employee Directors.

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

(Thousands of dollars)		**2017**	2016	2015
Compensation charged against income (loss) before income tax benefit	**$**	**40,365**	46,300	44,021
Related income tax benefit recognized in income		**5,017**	15,244	13,583

As of December 31, 2017, there were $29.8 million in compensation costs to be expensed over approximately the next two years related to unvested share-based compensation arrangements granted by the Company. Employees receive net shares, after applicable statutory withholding taxes, upon each stock option exercise and restricted stock award. Total income tax benefits realized from tax deductions related to stock option exercises under share-based payment arrangements were immaterial for the year ended December 31, 2015. There were no income tax benefits realized in either 2017 or 2016 due to no stock option exercises during those years.

Share-Settled Awards

STOCK OPTIONS – The Committee fixes the option price of each option granted at no less than fair market value (FMV) on the date of the grant and fixes the option term at no more than seven years from such date. Each option granted to date under the 2012 Long-Term Plan and the 2007 Long-Term Plan has been nonqualified, with a term of seven years and an option price equal to FMV at date of grant. Under these plans, one-half of each grant is generally exercisable after two years and the remainder after three years. For stock options, the number of shares issued upon exercise is reduced for settlement of applicable statutory income tax withholdings owed by the grantee.

The fair value of each option award is estimated on the date of grant using the Black-Scholes pricing model based on the assumptions noted in the following table. Expected volatility is based on historical volatility of the Company's stock and implied volatility on publicly traded at-the-money options on the Company's stock. The Company estimates the expected term of the options granted based on historical option exercise patterns and considers certain groups of employees exhibiting different behavior. The risk-free interest rate for periods within the expected term of the option is based on the U.S. Treasury yield curve in effect at the time of grant.

	2017	2016	2015
Fair value per option grant	**$7.96**	$5.03	$10.97 – $11.08
Assumptions			
Dividend yield	**3.60%**	4.00%	2.40% – 2.50%
Expected volatility	**41.00%**	45.00%	29.00% – 30.00%
Risk-free interest rate	**1.97%**	1.32%	1.34% – 1.60%
Expected life	**5.30 yrs.**	5.20 yrs.	5.30 yrs.

Changes in stock options outstanding during the last three years are presented in the following table.

	Number of Shares	Average Exercise Price
Outstanding at December 31, 2014	5,602,250	$ 57.95
Granted at FMV	991,000	49.67
Exercised	(32,349)	40.80
Forfeited	(1,117,613)	31.99
Outstanding at December 31, 2015	5,443,288	52.93
Granted at FMV	862,000	17.57
Exercised	–	–
Forfeited	(547,853)	44.23
Outstanding at December 31, 2016	5,757,435	48.46
Granted at FMV	**603,000**	**28.51**
Exercised	**–**	**–**
Forfeited	**(1,459,166)**	**49.34**
Outstanding at December 31, 2017	**4,901,269**	**45.74**
Exercisable at December 31, 2014	3,030,105	$ 53.10
Exercisable at December 31, 2015	3,542,352	52.26
Exercisable at December 31, 2016	3,830,535	53.80
Exercisable at December 31, 2017	**3,197,269**	**54.22**

Additional information about stock options outstanding at December 31, 2017 is shown below.

	Options Outstanding			Options Exercisable		
Range of Exercise Prices per Option	No. of Options	Avg. Life Remaining in Years	Aggregate Intrinsic Value	No. of Options	Avg. Life Remaining in Years	Aggregate Intrinsic Value
$17.00 to $30.00	1,320,000	5.5	$ 11,652,680	–	–	$ –
$31.00 to $50.00	823,350	3.9	–	439,350	3.8	–
$51.00 to $65.00	2,757,919	1.6	–	2,757,919	1.6	–
	4,901,269	3.0	$ 11,652,680	3,197,269	1.9	$ –

The total intrinsic value of options exercised during 2015 was $0.2 million. There were no options exercised in both 2017 and 2016 as all awards either had no intrinsic value or were not vested. Intrinsic value is the excess of the market price of stock at date of exercise over the exercise price received by the Company upon exercise. Aggregate intrinsic value is nil when the exercise price of the stock option exceeds the market price of the Company's common stock.

PERFORMANCE-BASED RESTRICTED STOCK UNITS – Performance-based restricted stock units (PRSUS) to be settled in Common shares were granted in each of the last three years under the 2012 Long-Term Plan. Each grant will vest if the Company achieves specific performance objectives at the end of the designated performance period. Additional shares may be awarded if performance objectives are exceeded. If performance goals are not met, PRSUS will not vest, but recognized compensation cost associated with the stock award would not be reversed. For past awards, the performance conditions were based on the Company's total shareholder return over the performance period compared to an industry peer group of companies. During the performance period, PRSUS are subject to transfer restrictions and are subject to forfeiture if a grantee terminates for reasons other than retirement, disability or death. Termination for these three reasons will lead to a pro rata award of amounts earned. No dividends are paid or voting rights exist on awards of PRSUS prior to their settlement.

Changes in PRSUS outstanding for each of the last three years are presented in the following table.

(Number of share units)	**2017**	2016	2015
Outstanding at beginning of year	**992,573**	1,103,986	1,397,040
Granted	**560,000**	394,000	455,000
Awarded	**(272,725)**	(361,096)	(521,800)
Forfeited	**(91,927)**	(144,317)	(226,254)
Outstanding at end of year	**1,187,921**	992,573	1,103,986

The fair value of the equity-settled performance-based awards granted in each year was estimated on the date of grant using a Monte Carlo valuation model. Expected volatility was based on daily historical volatility of the Company's stock price compared to a peer group average over a three-year period. The risk-free interest rate is based on the yield curve of three-year U.S. Treasury bonds and the stock beta was calculated using three years of historical averages of daily stock data for Murphy and the peer group. The assumptions used in the valuation of the performance awards granted in 2017, 2016 and 2015 are presented in the following table.

	2017	2016	2015
Fair value per share at grant date	**$24.10 – $28.28**	$12.21 – $16.34	$44.03 – $48.12
Assumptions			
Expected volatility	**47.00%**	33.00%	26.00%
Risk-free interest rate	**1.46%**	0.93%	0.85%
Stock beta	**1.058**	0.863	0.813
Expected life	**3.0 yrs.**	3.0 yrs.	3.0 yrs.

TIME-LAPSE RESTRICTED STOCK UNITS – Time-lapsed restricted stock units (TRSUS) have been granted to the Company's Non-Employee Directors under the Directors Plan and to certain employees under the 2012 Long-Term Plan. These awards vest on the third anniversary of the date of grant. The fair value of these awards was estimated based on the market value of the Company's stock on the date of grant, which were $28.51 per share in 2017, $17.57 per share in 2016, and $49.67 per share in 2015.

Changes in TRSUS outstanding for each of the last three years are presented in the following table.

(Number of share units)	**2017**	2016	2015
Outstanding at beginning of year	**923,282**	477,244	321,789
Granted	**419,720**	503,555	282,065
Vested and issued	**(217,633)**	(32,092)	(69,610)
Forfeited	**(89,389)**	(25,425)	(57,000)
Outstanding at end of year	**1,035,980**	923,282	477,244

EMPLOYEE STOCK PURCHASE PLAN (ESPP) – The Company had an ESPP under which the Company's Common stock could have been purchased by eligible U.S. and Canadian employees. Each quarter, an eligible employee could have elected to withhold up to 10% of his or her salary to purchase shares of the Company's stock at the end of the quarter at a price equal to 90% of the fair value of the stock as of the first day of the quarter. The ESPP terminated June 30, 2017. Employee stock purchases under the ESPP were 2,564 shares at an average price of $26.85 per share in 2017, 8,962 shares at an average price of $23.41 per share in 2016, and 8,387 shares at an average price of $34.93 per share in 2015. Compensation costs related to the ESPP were estimated based on the value of the 10% discount and the fair value of the option that provided for the refund of participant withholdings, and such expenses were immaterial for all periods presented. The fair value per share issued under the ESPP was approximately $5.34, $2.94, and $5.74 for the years ended December 31, 2017, 2016 and 2015, respectively.

Cash-Settled Awards

The Company has granted stock-based incentive awards to be settled in cash to certain employees in the form of Stock Appreciation Rights (SAR), Performance-based restricted stock units (PRSUC), Time-based restricted stock units (TRSUC) and Phantom units.

SAR awards have terms similar to stock options. PRSUC terms are similar to other performance-based restricted stock awards. TRSUC are generally settled on the third anniversary of the date of grant. Phantom units generally settle three to five years from date of grant. Each award granted is settled, net of applicable income tax withholdings, in cash rather than with Common shares. Total expense recorded in the Consolidated Statements of Operations for all cash-settled stock-based awards was $12.9 million in 2017, $17.2 million in 2016 and $1.6 million in 2015.

The Committee also administers the Company's incentive compensation plans, which provide for annual or periodic cash awards to officers, directors and certain other employees. These cash awards are generally determinable based on the Company achieving specific financial and/or operational objectives. Compensation expense of $30.5 million, $25.8 million and $26.4 million was recorded in 2017, 2016 and 2015, respectively, for these plans.

Note K – Employee and Retiree Benefit Plans

PENSION AND OTHER POSTRETIREMENT PLANS – The Company has defined benefit pension plans that are principally noncontributory and cover most full-time employees. All pension plans are funded except for the U.S. and Canadian nonqualified supplemental plans and the U.S. directors' 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 retired U.S. employees. The health care benefits are contributory; the life insurance benefits are noncontributory.

Upon the disposal of Murphy's former U.K. downstream assets, the Company retained all vested defined benefit pension obligations associated with former employees of this business. No additional benefits will accrue to these former U.K. employees under the Company's retirement plan after the date of their separation from Murphy.

GAAP requires the Company to recognize the overfunded or underfunded status of its defined benefit plans as an asset or liability in its consolidated balance sheet and to recognize changes in that funded status between periods through accumulated other comprehensive loss.

The tables that follow provide a reconciliation of the changes in the plans' benefit obligations and fair value of assets for the years ended December 31, 2017 and 2016 and a statement of the funded status as of December 31, 2017 and 2016.

	Pension Benefits		Other Postretirement Benefits	
(Thousands of dollars)	**2017**	2016	**2017**	2016
Change in benefit obligation				
Obligation at January 1	$ **815,593**	794,589	**106,679**	115,222
Service cost	**8,279**	8,136	**1,601**	1,864
Interest cost	**27,047**	25,185	**3,444**	3,800
Participant contributions	**–**	–	**2,075**	1,278
Actuarial loss (gain)	**60,855**	58,236	**(3,077)**	(10,627)
Medicare Part D subsidy	**–**	–	**318**	510
Exchange rate changes	**18,751**	(30,447)	**46**	20
Benefits paid	**(39,910)**	(40,928)	**(4,810)**	(5,369)
Curtailments	**–**	822	**–**	(19)
Other	**(8,683)**	–	**–**	–
Obligation at December 31	**881,932**	815,593	**106,276**	106,679
Change in plan assets				
Fair value of plan assets at January 1	**519,357**	521,682	**–**	–
Actual return on plan assets	**50,079**	61,860	**–**	–
Employer contributions	**24,918**	8,186	**2,417**	3,581
Participant contributions	**–**	–	**2,075**	1,278
Medicare Part D subsidy	**–**	–	**318**	510
Exchange rate changes	**18,064**	(30,609)	**–**	–
Benefits paid	**(39,910)**	(40,928)	**(4,810)**	(5,369)
Other	**(8,683)**	(834)	**–**	–
Fair value of plan assets at December 31	**563,825**	519,357	**–**	–
Funded status and amounts recognized in the Consolidated Balance Sheets at December 31				
Deferred charges and other assets	**5,905**	7,591	**–**	–
Other accrued liabilities	**(8,856)**	(8,184)	**(5,392)**	(5,267)
Deferred credits and other liabilities	**(315,156)**	(295,643)	**(100,884)**	(101,412)
Funded status and net plan liability recognized at December 31	$ **(318,107)**	(296,236)	**(106,276)**	(106,679)

At December 31, 2017, amounts included in Accumulated other comprehensive loss (AOCL) in the Consolidated Balance Sheets, before reduction for associated deferred income taxes, which have not been recognized in net periodic benefit expense are shown in the following table.

(Thousands of dollars)	Pension Benefits	Other Postretirement Benefits
Net actuarial loss	$ (269,063)	221
Prior service (cost) credit	(5,824)	38
	$ (274,887)	259

Amounts included in AOCL at December 31, 2017 that are expected to be amortized into net periodic benefit expense during 2018 are shown in the following table.

(Thousands of dollars)	Pension Benefits	Other Postretirement Benefits
Net actuarial loss	$ (15,890)	–
Prior service (cost) credit	(1,021)	38
	$ (16,911)	38

The table that follows includes projected benefit obligations, accumulated benefit obligations and fair value of plan assets for plans where the accumulated benefit obligation exceeded the fair value of plan assets.

	Projected Benefit Obligations		Accumulated Benefit Obligations		Fair Value of Plan Assets	
(Thousands of dollars)	**2017**	2016	**2017**	2016	**2017**	2016
Funded qualified plans where accumulated benefit obligation exceeds fair value of plan assets	**$ 691,923**	643,174	**640,230**	599,730	**540,161**	497,894
Unfunded nonqualified and directors' plans where accumulated benefit obligation exceeds fair value of plan assets	**172,364**	156,088	**163,319**	150,780	**–**	–
Unfunded other postretirement plans	**106,276**	106,678	**106,276**	106,678	**–**	–

The table that follows provides the components of net periodic benefit expense for each of the three years ended December 31, 2017.

	Pension Benefits			Other Postretirement Benefits		
(Thousands of dollars)	**2017**	2016	2015	**2017**	2016	2015
Service cost	$ **8,279**	8,136	17,948	**1,601**	1,864	3,180
Interest cost	**27,047**	25,185	33,168	**3,444**	3,800	4,883
Expected return on plan assets	**(28,941)**	(28,154)	(34,016)	**–**	–	–
Amortization of prior service cost (credit)	**1,026**	1,204	1,560	**(74)**	(75)	(82)
Amortization of transitional (asset) liability	**–**	–	(1)	**–**	–	–
Recognized actuarial loss	**16,691**	16,165	15,147	**–**	5	992
	24,102	22,536	33,806	**4,971**	5,594	8,973
Termination benefits expense	**–**	–	8,606	**–**	–	–
Curtailment expense	**–**	822	306	**–**	(19)	–
Net periodic benefit expense	$ **24,102**	23,358	42,718	**4,971**	5,575	8,973

Termination and curtailment expenses in 2016 and 2015 were primarily related to plan amendments made upon early retirement of certain employees during 2016 and 2015.

The preceding tables in this note include the following amounts related to foreign benefit plans.

	Pension Benefits		Other Postretirement Benefits	
(Thousands of dollars)	**2017**	2016	**2017**	2016
Benefit obligation at December 31	$ **222,483**	206,502	**791**	615
Fair value of plan assets at December 31	**212,535**	197,575	**–**	–
Net plan liabilities recognized	**9,948**	8,927	**791**	615
Net periodic benefit expense (benefit)	**194**	(2,244)	**133**	154

The following table provides the weighted-average assumptions used in the measurement of the Company's benefit obligations at December 31, 2017 and 2016 and net periodic benefit expense for 2017 and 2016.

	Benefit Obligations				Net Periodic Benefit Expense			
	Pension Benefits		Other Postretirement Benefits		Pension Benefits		Other Postretirement Benefits	
	December 31		December 31		Year		Year	
	2017	2016	**2017**	2016	**2017**	2016	**2017**	2016
Discount rate	**3.42%**	3.94%	**3.73%**	4.41%	**3.66%**	3.84%	**4.33%**	4.24%
Expected return on plan assets	**5.64%**	5.62%	**–**	–	**5.64%**	5.62%	**–**	–
Rate of compensation increase	**3.52%**	3.52%	**–**	–	**3.52%**	3.52%	**–**	–

The discount rates used for determining the plan obligations and expense are based on the universe of high-quality corporate bonds that are available within each country. Cash flow analyses are performed in which a spot yield curve is used to discount projected benefit payment streams for the most significant plans. The discounted cash flows are used to determine an equivalent single rate which is the basis for selecting the discount rate within each country. Expected plan asset returns are based on long-term expectations for asset portfolios with similar investment mix characteristics. Expected compensation increases are based on anticipated future averages for the Company.

Benefit payments, reflecting expected future service as appropriate, which are expected to be paid in future years from the assets of the plans or by the Company are shown in the following table.

(Thousands of dollars)	Pension Benefits	Other Postretirement Benefits
2018	$ 39,929	6,259
2019	40,236	6,280
2020	41,220	6,357
2021	42,276	6,489
2022	43,554	6,560
2023-2027	227,039	33,971

For purposes of measuring postretirement benefit obligations at December 31, 2017, the future annual rates of increase in the cost of health care were assumed to be 6.7% for 2017 decreasing each year to an ultimate rate of 4.5% in 2038 and thereafter.

Assumed health care cost trend rates have a significant effect on the expense and obligation reported for the postretirement benefit plan. A 1% change in assumed health care cost trend rates would have the following effects.

(Thousands of dollars)	1% Increase	1% Decrease
Effect on total service and interest cost components of net periodic postretirement benefit expense for the year ended December 31, 2017	$ 919	(719)
Effect on the health care component of the accumulated postretirement benefit obligation at December 31, 2017	15,220	(12,277)

During 2017, the Company made contributions of $18.0 million to its domestic defined benefit pension plans, $6.9 million to its foreign defined benefit pension plans and $2.4 million to its domestic postretirement benefits plan. During 2018, Company currently expects to make contributions of $24.4 million to its domestic defined benefit pension plans, $0.6 million to its foreign defined benefit pension plans and $5.4 million to its domestic postretirement benefits plan.

Plan Investments – Murphy Oil Corporation maintains an Investment Policy Statement (Statement) that establishes investment standards related to its funded domestic qualified retirement plan. The Statement specifies that all assets will be held in a Trust sponsored by the Company, which is administrated by a trustee appointed by the Investment Committee (Committee). Members of the Committee are appointed by the Chief Executive Officer of Murphy. The Committee hires Investment Managers to invest trust assets within the guidelines established by the Committee as allowed by the Statement. The investment goals call for a portfolio of assets consisting of equity, fixed income and cash equivalent securities. The primary consideration for investments is the preservation of capital, and investment growth should exceed the rate of inflation. The Committee has directed the asset investment advisors of its benefit plans to maintain a portfolio consisting of both equity and fixed income securities. The Company believes that over time a balanced to slightly heavier weighting of the portfolio in equity securities compared to fixed income securities represents the most appropriate long-term mix for future investment return on assets held by domestic plans. The parameters for asset allocation call for the following minimum and maximum percentages: equity securities of between 40% and 70%; fixed income securities of between 30% and 60%; long/short equity of between 0% and 15%; and cash and equivalents of between 0% and 15%. The Committee is authorized to direct investments within these parameters. Equity investments may include common, preferred and convertible preferred stocks, emerging markets stocks and similar funds, and long/short equity funds. Long/short equity is a strategy invested in a portfolio of long stocks hedged with short sales of stocks and/or stock index options, with the combination of investment intended to produce equity-like returns with lower volatility over the long term. Generally, no more than 10% of an Investment Manager's portfolio is to be held in equity securities of any one issuer, and equity securities should have a minimum market capitalization of $100 million. Equities held in the trust should be listed on the New York or American Stock Exchanges, principal U.S. regional exchanges, major foreign exchanges or quoted in significant over-the-counter markets. Equity or fixed income securities issued by the Company may not be held in the trust. Fixed income securities include maturities greater than one year to maturity. The fixed income portfolio should not exceed an average maturity of 11 years. The portfolio may include investment grade corporate bonds, issues of the U.S. government, its agencies and government sponsored entities, government agency issued collateralized mortgage backed securities, agency issued mortgage backed securities, municipal bonds, asset backed securities, commercial mortgage backed securities and international and emerging markets bond funds. The Committee routinely reviews the investment performance of Investment Managers.

For the U.K. retirement plan, trustees have been appointed by the wholly-owned subsidiary that sponsors the plan for U.K. employees. The trustees have hired a fiduciary investment manager to manage the assets of the plan within the parameters of the Statement of Investment Principles (Statement). The objective of investments is to earn a reasonable return within the allocation strategy permitted in the Statement while limiting the risk for the funded position of the plan. The Statement specifies a strategy with an allocation goal of 60% Delegated growth fund (DGF) equities and 40% Delegated liability fund (DLF). Also, the allocation goal includes interest rate hedge ratio and inflation rate hedge ratio of 100%. Hewitt Risk Management Services Limited (Manager) has discretion to vary the level of interest rate and inflation hedge ratios from the strategic levels. The DGF is diversified by style, strategy and asset class by investing with underlying funds that may include equity funds, fixed income funds, debt funds, currency funds, hedge funds, fund of hedge funds and other collective investment schemes covering a broad range of asset classes and strategies. The DLF aims to provide returns in line with the liabilities of typical pension schemes on an exposure basis in the relevant tenures and instruments (long/short, real/nominal). The DLF holds cash as collateral for the leveraged positions. Small working cash balances are permitted to facilitate daily management of payments and receipts within the plan. The trustee routinely reviews the investment performance of the plan.

For the Canadian retirement plan, the wholly-owned subsidiary that sponsors the plan has a Statement of Investment Policies and Procedures (Policy) applicable to the plan assets. A pension committee appointed by the board of directors of the subsidiary oversees the plan, selects the investment advisors and routinely reviews performance of the asset portfolio. The Policy permits assets to be invested in various Canadian and foreign equity securities, various fixed income securities, real estate, natural resource properties or participation rights and cash. The objective for plan investments is to achieve a total rate of return equal to the long-term interest rate assumption used for the going-concern actuarial funding valuation. The normal allocation for 2017 includes total equity securities of 60% with a range of 55% to 65% of total assets. Fixed income securities have a normal allocation of 35% with a range of 30% to 40%. Cash will normally have an allocation of 5% with a range of 0% to 10%. The Policy calls for diversification norms within the investment portfolios of both equity securities and fixed income securities.

The weighted average asset allocation for the Company's funded pension benefit plans at December 31, 2017 and 2016 are presented in the following table.

	December 31, 2017	December 31, 2016
Equity securities	**60.3 %**	58.4 %
Fixed income securities	**37.2**	39.0
Cash equivalents	**2.5**	2.6
	100.0 %	100.0 %

The Company's weighted average expected return on plan assets was 5.64% in 2017 and the return was determined based on an assessment of actual long-term historical returns and expected future returns for a portfolio with investment characteristics similar to that maintained by the plans. The 5.64% expected return was based on an expected average future equity securities return of 7.15% and a fixed income securities return of 4.26% and is net of average expected investment expenses of 0.60%. Over the last 10 years, the return on funded retirement plan assets has averaged 6.66%.

At December 31, 2017, the fair value measurements of retirement plan assets within the fair value hierarchy are included in the table that follows.

		Fair Value Measurements Using		
(Thousands of dollars)	**Fair Value at December 31, 2017**	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
Domestic Plans				
Equity securities:				
U.S. core equity	**$ 67,343**	**67,343**	–	–
U.S. small/midcap	**24,544**	**24,544**	–	–
Hedged funds and other alternative strategies	**50,522**	–	**12,572**	**37,950**
International commingled trust fund	**83,960**	–	**83,960**	–
Emerging market commingled equity fund	**20,774**	–	**20,774**	–
Fixed income securities:				
U.S. fixed income	**79,890**	–	**79,890**	–
International commingled trust fund	**13,122**	–	**13,122**	–
Emerging market mutual fund	**5,266**	–	**5,266**	–
Cash and equivalents	**5,871**	**5,871**	–	–
Total Domestic Plans	**351,292**	**97,758**	**215,584**	**37,950**
Foreign Plans				
Equity securities funds	**78,666**	–	**78,666**	–
Fixed income securities funds	**103,314**	–	**103,314**	–
Diversified pooled fund	**23,665**	–	**23,665**	–
Cash and equivalents	**6,888**	–	**6,888**	–
Total Foreign Plans	**212,533**	–	**212,533**	–
Total	**$ 563,825**	**97,758**	**428,117**	**37,950**

At December 31, 2016, the fair value measurements of retirement plan assets within the fair value hierarchy are included in the table that follows.

		Fair Value Measurements Using		
(Thousands of dollars)	Fair Value at December 31, 2016	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Domestic Plans				
Equity securities:				
U.S. core equity	$ 61,554	61,554	–	–
U.S. small/midcap	23,103	23,103	–	–
Hedged funds and other alternative strategies	48,113	–	13,999	34,114
International commingled trust fund	67,451	–	67,451	–
Emerging market commingled equity fund	16,006	–	16,006	–
Fixed income securities:				
U.S. fixed income	78,473	–	78,473	–
International commingled trust fund	13,486	–	13,486	–
Emerging market mutual fund	5,775	–	5,775	–
Cash and equivalents	7,821	7,821	–	–
Total Domestic Plans	321,782	92,478	195,190	34,114
Foreign Plans				
Equity securities funds	74,108	–	74,108	–
Fixed income securities funds	97,075	–	97,075	–
Diversified pooled fund	21,463	–	21,463	–
Cash and equivalents	4,929	–	4,929	–
Total Foreign Plans	197,575	–	197,575	–
Total	$ 519,357	92,478	392,765	34,114

The definition of levels within the fair value hierarchy in the tables above is included in Note Q.

For domestic plans, U.S. core and small/midcap equity securities are valued based on daily market prices as quoted on national stock exchanges or in the over-the-counter market. Hedged funds and other alternative strategies funds consist of three investments. One of these investments is valued based on daily market prices as quoted on national stock exchanges, another investment is valued monthly based on net asset value and permits withdrawals semi-annually after a 90-day notice, and the third investment is also valued monthly based on net asset values and has a two-year lock-up period and a 95-day notice following the lock-up period. International equities held in a commingled trust are valued monthly based on prices as quoted on various international stock exchanges. The emerging market commingled equity fund is valued monthly based on net asset value. These commingled equity funds can be withdrawn monthly and have a 10-day notice period. U.S. fixed income securities are valued daily based on bids for the same or similar securities or using net asset values. International fixed income securities held in a commingled trust are valued on a monthly basis using net asset values. The fixed income emerging market mutual fund is valued daily based on net asset value. For foreign plans, the equity securities funds are comprised of U.K. and foreign equity funds valued daily based on fund net asset values. Fixed income securities funds are U.K. securities valued daily at net asset values. The diversified pooled fund is valued daily at net asset value and contains a combination of Canadian and foreign equity securities, Canadian fixed income securities and cash.

The effects of fair value measurements using significant unobservable inputs on changes in Level 3 plan assets are outlined below:

(Thousands of dollars)	Hedged Funds and Other Alternative Strategies
Total at December 31, 2015	$ 33,929
Actual return on plan assets:	
Relating to assets held at the reporting date	185
Relating to assets sold during the period	–
Purchases, sales and settlements	–
Total at December 31, 2016	34,114
Actual return on plan assets:	
Relating to assets held at the reporting date	**3,836**
Relating to assets sold during the period	–
Purchases, sales and settlements	–
Total at December 31, 2017	**$ 37,950**

THRIFT PLANS – Most full-time U.S. employees of the Company may participate in thrift or similar savings plans by allotting up to a specified percentage of their base pay. The Company matches contributions at a stated percentage of each employee's allotment based on years of participation in the plans, with a maximum match of 6%. Amounts charged to expense for these plans were $7.8 million in 2017, $7.4 million in 2016 and $7.6 million in 2015.

Note L – Financial Instruments and Risk Management

DERIVATIVE INSTRUMENTS – 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 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 AOCL until the anticipated transactions occur.

Commodity Purchase Price Risks

The Company is subject to commodity price risk related to crude oil it produces and sells. During the last three years, the Company had West Texas Intermediate (WTI) crude oil price 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 December 31, 2017, the Company had 21,000 barrels per day in WTI crude oil swap financial contracts maturing ratably during 2018 at an average price of $54.88. At December 31, 2017, the fair value of these WTI contracts of $39.1 million was included in Accounts payable in the Consolidated Balance Sheet. The impact of marking to market these commodity derivative contracts reduced the income before income taxes by $34.0 million for the year ended December 31, 2017.

During 2016, the Company had WTI crude oil price swap financial contracts to hedge a portion of its United States production for 2016 and 2017. At December 31, 2016, the Company had 22,000 barrels per day in WTI crude oil swap financial contracts maturing ratably during 2017. At December 31, 2016, the fair value of WTI contracts of $48.9 million was included in Accounts payable in the Consolidated Balance Sheet. The impact of marking to market these commodity derivative contracts increased the loss before income taxes by $47.7 million for the year ended December 31, 2016.

Foreign Currency Exchange Risks

The Company is subject to foreign currency exchange risk associated with operations in countries outside the U.S. At December 31, 2016, short-term derivative instruments were outstanding in Canada for approximately $14.2 million to manage the currency risk of U.S. dollar accounts receivable balances associated with the sale of Canadian crude oil.

At December 31, 2017 and 2016, the fair value of derivative instruments not designated as hedging instruments are presented in the following table. Also shown is the fair value of open foreign currency derivative contracts at December 31, 2016.

	December 31, 2017			December 31, 2016		
(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**	**$**	**(39,093)**	Accounts payable	$	(48,864)
Foreign exchange	–		–	Accounts payable	$	(73)

For the years ended December 31, 2017 and 2016, 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)			
(Thousands of dollars)		**Year Ended December 31,**			
Type of Derivative Contract	**Statement of Operations Locations**	**2017**		2016	
Commodity	**Sales and other operating revenues**	**$**	**9,567**	$	(63,412)
Foreign exchange	**Interest and other income (loss)**		–		26,714
		$	**9,567**	$	(36,698)

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 2012 to match the payment of interest on these notes through 2022. During each of the three years ended December 31, 2017, $3.0 million of the deferred loss on the interest rate swaps was charged to Interest expense in the Consolidated Statements of Operations. The remaining loss (net of tax) deferred on these matured contracts at December 31, 2017 was $8.4 million, which is recorded, net of income taxes of $4.5 million, in Accumulated other comprehensive loss in the Consolidated Balance Sheets. The Company expects to charge approximately $3.0 million of this deferred loss to Interest expense in the Consolidated Statements of Operations during 2018.

CREDIT RISKS – The Company's primary credit risks are associated with trade accounts receivable, cash equivalents and derivative instruments. Trade receivables arise mainly from sales of oil and natural gas in the U.S., Canada and Malaysia, and cost sharing amounts of operating and capital costs billed to partners for oil and natural gas fields operated by Murphy. The credit history and financial condition of potential customers are reviewed before credit is extended, security is obtained when deemed appropriate based on a potential customer's financial condition, and routine follow-up evaluations are made. The combination of these evaluations and the large number of customers tends to limit the risk of credit concentration to an acceptable level. Cash equivalents are placed with several major financial institutions, which limit the Company's exposure to credit risk. The Company controls credit risk on derivatives through credit approvals and monitoring procedures and believes that such risks are minimal because counterparties to the majority of transactions are major financial institutions.

Note M – Stockholders' Equity

Common stock acquired under prior share buyback programs are carried as Treasury stock in the Consolidated Balance Sheets. There were no share repurchases during 2017 or 2016 and no open share buyback programs as of December 31, 2017.

During 2015, the Company repurchased Common Stock under variable term, capped accelerated share repurchase transactions (ASR) as authorized by the Board of Directors. These share repurchases during 2015 were as follows:

	2015
Purchase of Treasury Stock	$ 250,000,000
Shares repurchased	5,967,313

Note N – Earnings per Share

Net loss was used as the numerator in computing both basic and diluted income per Common share for each of the three years ended December 31, 2017. The following table reconciles the weighted-average shares outstanding used for these computations.

(Weighted-average shares)	**2017**	2016	2015
Basic method	**172,524,061**	172,173,012	174,351,227
Dilutive stock options [1]	**–**	–	–
Diluted method	**172,524,061**	172,173,012	174,351,227

[1] Due to a net loss recognized by the Company for the years ended December 31, 2017, 2016 and 2015, no unvested stock awards were included in the computation of diluted earnings per share because the effect would have been antidilutive.

The following table reflects certain options to purchase shares of common stock that were outstanding during the three years ended December 31, 2017, but were not included in the computation of dilutive earnings per share because the incremental shares from the assumed conversion were antidilutive.

	2017	2016	2015
Antidilutive stock options excluded from diluted shares	**4,901,269**	5,757,435	5,443,288
Weighted average price of these options	**$45.74**	$48.46	$52.93

Note O – Other Financial Information

GAIN FROM FOREIGN CURRENCY TRANSACTIONS – Net gains (losses) from foreign currency transactions, including the effects of foreign currency contracts, included in the Consolidated Statements of Operations were $(75.4) million in 2017, $59.7 million in 2016 and $87.9 million in 2015.

Noncash operating working capital (increased) decreased during each of the three years ended December 31, 2017 as shown in the following table.

(Thousands of dollars)	**2017**	2016	2015
Accounts receivable	**$ 114,401**	119,671	297,625
Inventories	**26,883**	(5,171)	(15,340)
Prepaid expenses	**29,570**	149,946	(144,845)
Deferred income tax assets	–	–	3,924
Accounts payable and accrued liabilities	**(51,439)**	(328,078)	(36,887)
Current income tax liabilities	**16,999**	24,943	(69,413)
Net (increase) decrease in noncash operating working capital	**$ 136,414**	(38,689)	35,064
Supplementary disclosures (including discontinued operations):			
Cash income taxes paid, net of refunds	**$ 68,076**	6,707	118,667
Interest paid, net of amounts capitalized of $4,488 in 2017, $4,322 in 2016 and $7,290 in 2015	**147,975**	127,798	110,386
Noncash investing activities, related to continuing operations:			
Asset retirement costs capitalized	**$ 8,509**	13,690	76,775
Decrease in capital expenditure accrual	**99,199**	158,885	462,474

DEEPWATER RIG CONTRACT EXIT COSTS – At year-end 2015, the Company had two deepwater drilling rigs in the Gulf of Mexico under contract that were scheduled to expire in February and November 2016. In the face of low commodity prices, a significant reduction in the Company's overall 2016 capital spending program and lack of interest by working interest partners and others to participate in drilling opportunities in 2016, the Company idled and stacked both rigs during the fourth quarter of 2015. The Company reported a pretax charge to Other expense in 2015 totaling $282.0 million that included both the costs incurred in 2015 when the rigs were idle and stacked together with the remaining day rate commitments due under the contracts in 2016. The contract originally scheduled to expire in November 2016 was terminated by the Company. The Company paid approximately $266.7 million related to these contracts in 2016 and reported a pretax benefit to Other expense in 2017 and 2016 of $6.1 million and $4.3 million, respectively, for the final settlement of the contracts at less than the recorded costs. These amounts are included in Other expense in the Consolidated Statements of Operations.

Note P – Accumulated Other Comprehensive Loss

The components of Accumulated other comprehensive loss on the Consolidated Balance Sheets at December 31, 2017 and December 31, 2016 and the changes during 2017 and 2016 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, 2015	$ (513,004)	(179,260)	(12,278)	(704,542)
2016 components of other comprehensive income (loss):				
Before reclassifications to income	66,449	(3,763)	–	62,686
Reclassifications to income	–	11,718 [1]	1,926 [2]	13,644
Net other comprehensive income	66,449	7,955	1,926	76,330
Balance at December 31, 2016	(446,555)	(171,305)	(10,352)	(628,212)
2017 components of other comprehensive income (loss):				
Before reclassifications to income	**171,725**	**(17,269)**	**–**	**154,456**
Reclassifications to income	**–**	**9,587** [1]	**1,926** [2]	**11,513**
Net other comprehensive income (loss)	**171,725**	**(7,682)**	**1,926**	**165,969**
Balance at December 31, 2017	**$ (274,830)**	**(178,987)**	**(8,426)**	**(462,243)**

1Reclassifications before taxes of $14,821 and $18,036 are included in the computation of net periodic benefit expense in 2017 and 2016, respectively. See Note K for additional information. Related income taxes of $5,234 and $6,318 are included in income tax expense in 2017 and 2016, respectively.
2Reclassifications before taxes of $2,963 are included in Interest expense in both 2017 and 2016. Related income taxes of $1,037 are included in income tax expense in 2017 and 2016. See Note L for additional information.

Note Q – Assets and Liabilities Measured at Fair Value

Fair Values – Recurring

The Company carries certain assets and liabilities at fair value in its Consolidated Balance Sheet. 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 fair value measurements for these assets and liabilities at December 31, 2017 and 2016 are presented in the following table.

	December 31, 2017				December 31, 2016			
(Thousands of dollars)	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
Liabilities:								
Nonqualified employee savings plans	**$ 16,158**	**–**	**–**	**16,158**	13,904	–	–	13,904
Commodity derivative contracts	**–**	**39,093**	**–**	**39,093**	–	48,864	–	48,864
Foreign currency exchange derivative contracts	**–**	**–**	**–**	**–**	–	73	–	73
	$ 16,158	**39,093**	**–**	**55,251**	13,904	48,937	–	62,841

The fair value of West Texas Intermediate (WTI) crude oil contracts in 2017 and 2016 was based on active market quotes for WTI crude oil. The fair value of foreign exchange derivative contracts in 2016 was based on market quotes for similar contracts at the balance sheet date. The income effect of changes in fair value of crude oil derivative contracts is recorded in Sales and other operating revenues 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 December 31, 2017 and 2016.

The following table presents the carrying amounts and estimated fair values of financial instruments held by the Company at December 31, 2017 and 2016. The fair value of a financial instrument is the amount at which the instrument could be exchanged in a current transaction between willing parties. The table excludes cash and cash equivalents, trade accounts receivable, trade accounts payable and accrued expenses, all of which had fair values approximating carrying amounts. The carrying value of Canadian government securities was determined based on cost plus earned interest. The fair value of current and long-term debt was estimated based on rates offered to the Company at that time for debt of the same maturities. The Company has off-balance sheet exposures relating to certain letters of credit. The fair value of these, which represents fees associated with obtaining the instruments, was nominal.

	At December 31,			
	2017		2016	
(Thousands of dollars)	**Carrying Amount**	**Fair Value**	Carrying Amount	Fair Value
Financial assets (liabilities):				
Canadian government securities with maturities greater than 90 days at the date of acquisition	**$ -**	**-**	111,542	111,331
Current and long-term debt	**(2,916,422)**	**(2,993,003)**	(2,992,567)	(2,951,992)

Fair Values – Nonrecurring

As a result of significantly lower commodity prices during 2016, the Company recognized $95.1 million, respectively, in pretax noncash impairment charges related primarily to producing properties. The fair value information associated with these impaired properties is presented in the following table.

	Year Ended December 31, 2016				
	Fair Value				
(*Thousands of dollars*)	Level 1	Level 2	Level 3	Net Book Value Prior to Impairment	Total Pretax (Noncash) Impairment Expense
Assets:					
Impaired proved properties					
Western Canada	$ –	–	71,967	167,055	95,088
	$ –	–	71,967	167,055	95,088

The fair values were determined by internal discounted cash flow models using estimates of future production, prices from futures exchanges, costs and a discount rate believed to be consistent with those used by principal market participants in the applicable region.

Note R – Commitments

The Company leases production and other facilities under operating leases. The most significant operating leases are associated with floating, production, storage and offloading facilities at the Kikeh oil field and a production facility at the West Patricia field. During each of the next five years, expected future net rental payments under all operating leases are approximately $73.7 million in 2018, $65.6 million in 2019, $62.4 million in 2020, $61.3 million in 2021 and $27.8 million in 2022. Rental expense for noncancelable operating leases, including contingent payments when applicable, was $72.6 million in 2017, $77.5 million in 2016, and $111.4 million in 2015. A lease of production equipment at the Kakap field offshore Sabah, Malaysia has been accounted for as a capital lease and is included in long-term debt discussed in Note G.

The Company has entered into contracts to hire various drilling rigs and associated equipment for periods beyond December 31, 2017. These rigs will primarily be utilized for drilling operations in onshore U.S., Canada, Gulf of Mexico, and Vietnam. Future commitments under these contracts, all of which expire by 2020, total $66.6 million. Gulf of Mexico rig contracts are short term in nature and can be terminated within 30 days without cost. A portion of these costs are expected to be borne by other working interest owners as partners of the Company when the wells are drilled. These drilling costs are generally expected to be accounted for as capital expenditures as incurred during the contract periods.

The Company has operating, production handling and transportation service agreements for oil and/or natural gas operations in the U.S. and Western Canada. The U.S. transportation contracts require minimum monthly payments through 2024, while the Western Canada processing contracts call for minimum monthly payments through 2035. Future required minimum monthly payments for the next five years are $57.8 million in 2018, $63.8 million in 2019, $77.9 million in 2020, $91.9 million in 2021 and $78.5 million in 2022. Under certain circumstances, the Company is required to pay additional amounts depending on the actual hydrocarbon quantities processed under the agreement. Total costs incurred under these service arrangements were $53.8 million in 2017, $50.3 million in 2016, and $32.5 million in 2015.

Commitments for capital expenditures were approximately $432.3 million at December 31, 2017, including $197.3 million for field development and future work commitments in Malaysia, $129.4 million for development at Kaybob Duvernay in Canada, $31.8 million for work at Eagle Ford Shale, $31.3 million for exploration cost in Mexico, $24.0 million for costs to develop deepwater U.S. Gulf of Mexico fields, and $8.8 million and $6.3 million for future work commitments in Vietnam and Brazil, respectively.

Note S – 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 increases; 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.

ENVIRONMENTAL MATTERS – 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.

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. Murphy USA Inc. has retained any environmental exposure associated with Murphy's former U.S. marketing operations that were spun-off in August 2013. 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. The Company has not yet established a complete estimate of the costs to remediate the site. Based on the assessments done to date, the Company recorded $43.9 million in Other expense in the 2015 Consolidated Statements of Operations associated with the estimated costs of remediating the site. The Company has spent $39.7 million from inception to the end of 2017. Further refinements in the estimated total cost to remediate the site are anticipated in future periods including possible insurance recoveries. 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. In the first quarter of 2018, the Company received $15.0 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.

LEGAL MATTERS – 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 T – Common Stock Issued and Outstanding

Activity in the number of shares of Common Stock issued and outstanding for the three years ended December 31, 2017 is shown below.

(*Number of shares outstanding*)	**2017**	2016	2015
Beginning of year	**172,202,177**	172,034,711	177,499,513
Stock options exercised [1]	–	–	15,575
Restricted stock awards [1]	**368,132**	158,504	478,549
Employee stock purchase and thrift plans	**2,564**	8,962	8,387
Treasury shares purchased	–	–	(5,967,313)
End of year	**172,572,873**	172,202,177	172,034,711

[1] Shares issued upon exercise of stock options and award of restricted stock are less than the amount reflected in Note J due to withholdings for statutory income taxes owed upon issuance of shares.

Note U – Business Segments

Murphy's reportable segments are organized into geographic areas of operations. The Company's exploration and production activity is subdivided into segments for the United States, Canada, Malaysia and all other countries. Each of these segments derives revenues primarily from the sale of crude oil, condensate, natural gas liquids and/or natural gas. The Company's management evaluates segment performance based on income (loss) from operations, excluding interest income and interest expense.

The Company has several customers that purchase a significant portion of its oil and natural gas production. During 2017, 2016, and 2015, sales to Phillips 66 and affiliated companies represented approximately 14%, 17% and 17%, respectively, of the Company's total sales revenue. Due to the quantity of active oil and natural gas purchasers in the markets where it produces hydrocarbons, the Company does not foresee any difficulty with selling its hydrocarbon production at fair market prices.

The Company completed the sale of its U.K. downstream assets during 2015. For all years presented, assets and liabilities associated with U.K. refining and marketing operations were reported as held for sale in the Consolidated Balance Sheets. These operations have been reported as Discontinued operations for all periods presented in these consolidated financial statements.

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 and other activities, including interest income, miscellaneous gains and losses (including foreign exchange gains and losses), interest expense and unallocated overhead, are shown in the tables to reconcile the business segments to consolidated totals. Certain reclassifications have been made to 2016 and 2015 Corporate Revenue from external customers to align with current period presentation (see Note A). As used in the table on the following page, certain long-lived assets at December 31 exclude investments, noncurrent receivables, deferred tax assets, and goodwill and other intangible assets.

Segment Information

(Millions of dollars)	Exploration and Production United States	Canada[1]	Malaysia	Other	Total E&P
Year ended December 31, 2017					
Segment income (loss)	**$ (2.6)**	**112.5**	**224.2**	**(37.5)**	**296.6**
Revenues from external customers	**953.9**	**485.5**	**781.1**	**–**	**2,220.5** [2]
Interest income	–	–	–	–	–
Interest expense, net of capitalization	–	–	–	–	–
Income tax expense (benefit)	**2.5**	**44.4**	**126.4**	**(36.2)**	**137.1**
Significant noncash charges (credits)					
Depreciation, depletion and amortization	**546.1**	**185.4**	**204.6**	**3.8**	**939.9**
Accretion of asset retirement obligations	**17.4**	**7.9**	**17.3**	**–**	**42.6**
Amortization of undeveloped leases	**60.2**	**1.6**	**–**	**–**	**61.8**
Deferred and noncurrent income taxes	**2.5**	**55.3**	**(3.7)**	**(36.2)**	**17.9**
Additions to property, plant, equipment	**534.8**	**267.6**	**16.0**	**37.6**	**856.0**
Total assets at year-end	**5,186.2**	**1,725.8**	**1,670.1**	**154.2**	**8,736.3**
Year ended December 31, 2016					
Segment income (loss)	$ (205.4)	(35.9)	171.1	(54.7)	(124.9)
Revenues from external customers	685.7	365.3	753.4	0.2	1,804.6
Interest income	–	–	–	–	–
Interest expense, net of capitalization	–	–	–	–	–
Income tax expense (benefit)	(87.9)	(134.3)	85.9	(18.8)	(155.1)
Significant noncash charges (credits)					
Depreciation, depletion and amortization	600.5	203.2	227.7	5.9	1,037.3
Accretion of asset retirement obligations	17.1	13.3	16.3	–	46.7
Amortization of undeveloped leases	38.4	4.5	–	0.5	43.4
Impairment of assets	–	95.1	–	–	95.1
Deferred and noncurrent income taxes	(108.4)	(175.8)	(8.5)	(18.3)	(311.0)
Additions to property, plant, equipment	269.8	361.3	101.4	(1.3)	731.2
Total assets at year-end	5,419.0	1,559.5	2,024.7	115.7	9,118.9
Year ended December 31, 2015					
Segment loss	$ (615.7)	(583.4)	(653.2)	(158.6)	(2,010.9)
Revenues from external customers	1,253.6	549.7	1,131.4	–	2,934.7
Interest income	–	–	–	–	–
Interest expense, net of capitalization	–	–	–	–	–
Income tax expense (benefit)	(337.0)	(188.8)	(567.9)	(17.3)	(1,111.0)
Significant noncash charges (credits)					
Depreciation, depletion and amortization	794.9	261.9	544.9	6.2	1,607.9
Accretion of asset retirement obligations	20.2	12.6	15.9	–	48.7
Amortization of undeveloped leases	59.2	14.4	–	1.8	75.4
Impairment of assets	329.0	683.6	1,480.6	–	2,493.2
Deferred and noncurrent income taxes	(187.7)	(146.0)	(579.2)	(4.6)	(917.5)
Additions to property, plant, equipment	1,263.1	184.9	244.4	39.2	1,731.6
Total assets at year-end	5,717.8	2,460.6	2,537.2	147.7	10,863.3

[1] Includes Synthetic crude operations in 2016 and 2015. This business was sold in June 2016.
[2] Includes a pretax gain of $129.0 million on sale of Seal area heavy oil field sold in January 2017.

Geographic Information

(Millions of dollars)	Certain Long-Lived Assets at December 31 United States	Canada	Malaysia	United Kingdom	Other	Total
2017	**$ 5,050.5**	**1,635.9**	**1,392.3**	**–**	**141.3**	**8,220.0**
2016	5,121.6	1,451.4	1,637.0	–	106.2	8,316.2
2015	5,484.7	2,310.6	1,912.0	–	111.1	9,818.4

Segment Information — Continued

(Millions of dollars)		Corporate and Other	Discontinued Operations	Consolidated Total
Year ended December 31, 2017				
Segment income (loss)	**$**	**(607.5)**	**(0.9)**	**(311.8)**
Revenues from external customers		**4.6**	**–**	**2,225.1**
Interest income		**7.4**	**–**	**7.4**
Interest expense, net of capitalization		**181.8**	**–**	**181.8**
Income tax expense (benefit)		**245.6**	**–**	**382.7**
Significant noncash charges (credits)				
Depreciation, depletion and amortization		**17.8**	**–**	**957.7**
Accretion of asset retirement obligations		**–**	**–**	**42.6**
Amortization of undeveloped leases		**–**	**–**	**61.8**
Deferred and noncurrent income taxes		**242.5**	**–**	**260.4**
Additions to property, plant, equipment		**14.8**	**–**	**870.8**
Total assets at year-end		**1,101.7**	**22.9**	**9,860.9**
Year ended December 31, 2016				
Segment income (loss)	$	(149.1)	(2.0)	(276.0)
Revenues from external customers		6.6	–	1,811.2
Interest income		2.9	–	2.9
Interest expense, net of capitalization		148.2	–	148.2
Income tax expense (benefit)		(64.1)	–	(219.2)
Significant noncash charges (credits)				
Depreciation, depletion and amortization		16.8	–	1,054.1
Accretion of asset retirement obligations		–	–	46.7
Amortization of undeveloped leases		–	–	43.4
Impairment of assets		–	–	95.1
Deferred and noncurrent income taxes		(76.8)	–	(387.8)
Additions to property, plant, equipment		21.9	–	753.1
Total assets at year-end		1,149.9	27.1	10,295.9
Year ended December 31, 2015				
Segment loss	$	(244.9)	(15.0)	(2,270.8)
Revenues from external customers		6.6	–	2,941.3
Interest income		4.0	–	4.0
Interest expense, net of capitalization		117.4	–	117.4
Income tax expense (benefit)		84.5	–	(1,026.5)
Significant noncash charges (credits)				
Depreciation, depletion and amortization		11.9	–	1,619.8
Accretion of asset retirement obligations		–	–	48.7
Amortization of undeveloped leases		–	–	75.4
Impairment of assets		–	–	2,493.2
Deferred and noncurrent income taxes		(60.5)	–	(978.0)
Additions to property, plant, equipment		59.9	–	1,791.5
Total assets at year-end		592.2	38.3	11,493.8

Geographic Information

	Revenues from External Customers for the Year					
(Millions of dollars)		United States	Canada	Malaysia	Other	Total
2017	**$**	**958.3**	**485.7**	**781.1**	**–**	**2,225.1**
2016		692.3	365.3	753.4	0.2	1,811.2
2015		1,260.2	549.7	1,131.4	–	2,941.3

The following unaudited schedules are presented in accordance with required disclosures about Oil and Gas Producing Activities to provide users with a common base for preparing estimates of future cash flows and comparing reserves among companies. Additional background information concerning some of the schedules follows:

SCHEDULE 1 – SUMMARY OF PROVED CRUDE OIL AND SYNTHETIC OIL RESERVES
SCHEDULE 2 – SUMMARY OF PROVED NATURAL GAS LIQUIDS RESERVES
SCHEDULE 3 – SUMMARY OF PROVED NATURAL GAS RESERVES

Reserves of crude oil, synthetic oil, condensate, natural gas liquids and natural gas are estimated by the Company's or independent engineers and are adjusted to reflect contractual arrangements and royalty rates in effect at the end of each year. Many assumptions and judgmental decisions are required to estimate reserves. Reported quantities are subject to future revisions, some of which may be substantial, as additional information becomes available from reservoir performance, new geological and geophysical data, additional drilling, technological advancements, price changes and other economic factors.

Murphy's estimations for proved reserves were generated through the integration of available geoscience, engineering, and economic data and commercially available technologies, to establish 'reasonable certainty' of economic productibility. As defined by the SEC, reasonable certainty of proved reserves describes a high degree of confidence that the quantities will be recovered. In estimating proved reserves, Murphy uses familiar industry-accepted methods for subsurface evaluations, including performance, volumetric and analogue-based studies. Where appropriate, Murphy includes reliable geologic and engineering technology to estimate proved reserves. Reliable geologic and engineering technology is a method or combination of methods that are field tested and have been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation. This integrated approach increases the quality of and confidence in Murphy's proved reserves estimates. The approach was utilized in certain undrilled acreage at distances greater than the directly offsetting development spacing areas and in certain reservoirs developed with the application of improved recovery techniques. Murphy utilized a combination of 3D seismic interpretation, core analysis, wellbore log measurements, well test data, historic production and pressure data and commercially available seismic processing and numerical reservoir simulation programs. Reservoir parameters from analogous reservoirs were used to strengthen the reserves estimates when available.

Prior to its disposition in 2016, Murphy included synthetic crude oil from its 5% interest in the Syncrude project in Alberta, Canada in its proved crude oil reserves. All synthetic oil volumes reported as proved reserves in Schedule 1 are the final synthetic crude oil product.

Production quantities shown are net volumes withdrawn from reservoirs. These may differ from sales quantities due to inventory changes, volumes consumed for fuel and/or shrinkage from extraction of natural gas liquids.

All crude oil and synthetic reserves, natural gas liquids reserves and natural gas reserves are from consolidated subsidiaries and proportionately consolidated joint ventures. The Company has no proved reserves attributable to investees accounted for by the equity method.

All proved reserves in Malaysia are associated with production sharing contracts for Blocks SK 309/311, K and H. Malaysia reserves include oil and gas to be received for both cost recovery and profit provisions under the contract. At December 31, 2017, liquids and natural gas proved reserves associated with the production sharing contracts in Malaysia totaled 52.2 million barrels and 491.3 billion cubic feet (BCF), respectively. At December 31, 2017, approximately 26.7 BCF of natural gas proved reserves in Malaysia relate to fields in Block K for which the Company expects to receive sale proceeds of approximately $0.24 per thousand cubic feet. Sales price for other natural gas produced in Malaysia is based on market-driven prices.

SCHEDULE 6 – STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS RELATING TO PROVED OIL AND GAS RESERVES

GAAP requires calculation of future net cash flows using a 10% annual discount factor, an unweighted average of oil and natural gas prices in effect at the beginning of each month of the year, and year-end costs and statutory tax rates, except for known future changes such as contracted prices and legislated tax rates. On December 22, 2017, the U.S. enacted into legislation the Tax Cuts and Jobs Act (2017 Tax Act); as a result the company's statutory U.S. tax rate will be 21% beginning in 2018, a decrease from the previous rate of 35%.

The reported value of proved reserves is not necessarily indicative of either fair market value or present value of future cash flows because prices, costs and governmental policies do not remain static; appropriate discount rates may vary; and extensive judgment is required to estimate the timing of production. Other logical assumptions would likely have resulted in significantly different amounts.

Schedule 6 also presents the principal reasons for change in the standardized measure of discounted future net cash flows for each of the three years ended December 31, 2017.

Schedule 1 – Summary of Proved Crude Oil and Synthetic Oil Reserves Based on Average Prices for 2014 – 2017

	Crude & Synthetic Oil	Crude Oil				Synthetic Oil [1]
(Millions of barrels)	Total	Total	United States	Canada	Malaysia	Canada
Proved developed and undeveloped crude oil / synthetic oil reserves:						
December 31, 2014	441.8	336.2	204.9	37.4	93.9	105.6
Revisions of previous estimates	5.3	(8.2)	(7.6)	(4.8)	4.2	13.5
Improved recovery	2.4	2.4	–	–	2.4	–
Extensions and discoveries	63.8	63.8	63.8	–	–	–
Sales of properties	(11.0)	(11.0)	–	–	(11.0)	–
Production	(46.1)	(41.8)	(22.2)	(4.7)	(14.9)	(4.3)
December 31, 2015	456.2	341.4	238.9	27.9	74.6	114.8
Revisions of previous estimates	(5.8)	(5.8)	(10.9)	2.5	2.6	–
Extensions and discoveries	11.0	11.0	8.6	–	2.4	–
Purchases of properties	26.3	26.3	–	26.3	–	–
Sales of properties	(121.0)	(7.8)	(4.5)	(3.3)	–	(113.2)
Production	(37.7)	(36.1)	(17.7)	(4.5)	(13.9)	(1.6)
December 31, 2016	329.0	329.0	214.4	48.9	65.7	(0.0)
Revisions of previous estimates	**(6.0)**	**(6.0)**	**(4.7)**	**2.3**	**(3.6)**	**–**
Improved recovery	**2.0**	**2.0**	**–**	**–**	**2.0**	**–**
Extensions and discoveries	**31.6**	**31.6**	**27.2**	**4.4**	**–**	**–**
Purchases of properties	**4.7**	**4.7**	**4.7**	**–**	**–**	**–**
Production	**(33.2)**	**(33.2)**	**(16.9)**	**(4.1)**	**(12.2)**	**–**
December 31, 2017	**328.1**	**328.1**	**224.7**	**51.5**	**51.9**	**–**
Proved developed crude oil/ synthetic oil reserves:						
December 31, 2014	324.1	218.5	106.2	32.4	79.9	105.6
December 31, 2015	326.6	211.8	125.9	23.8	62.1	114.8
December 31, 2016	184.9	184.9	113.9	19.2	51.8	–
December 31, 2017	**185.5**	**185.5**	**126.3**	**21.9**	**37.3**	**–**
Proved undeveloped crude oil reserves:						
December 31, 2014	117.7	117.7	98.7	5.0	14.0	–
December 31, 2015	129.6	129.6	113.0	4.1	12.5	–
December 31, 2016	144.1	144.1	100.5	29.7	13.9	–
December 31, 2017	**142.6**	**142.6**	**98.4**	**29.6**	**14.6**	**–**

[1] All synthetic oil operations were sold in June 2016.

Schedule 1 – Summary of Proved Crude Oil and Synthetic Oil Reserves Based on Average Prices for 2014 – 2017 – Continued

2017 Comments for Proved Crude Oil Reserves Changes

Revisions of previous estimate – The 2017 negative crude oil revision in the U.S. was primarily attributable to the removal of proved undeveloped locations within the 5-year development window as capital was reallocated to higher performing drilling locations within the Company's Eagle Ford Shale fields, partially offset by improved Eagle Ford Shale costs and performance results in the Gulf of Mexico. The positive Canadian oil reserves revisions in 2017 resulted from improved performance at Tupper Montney assets in Western Canada, and offshore Canada fields, Hibernia and Terra Nova. The negative revisions for crude oil reserves in Malaysia were principally attributable to the redetermination of Kakap participation that lowered the Company's entitlement, and higher government entitlement under the terms of the respective production sharing contracts due to higher oil prices, offsetting positive performance revisions at the Company's Sarawak projects.

Improved recovery – The 2017 Malaysia crude oil proved reserve addition was primarily due to favorable impacts for waterflood activity at certain Sarawak oil fields.

Extensions and discoveries – In 2017, proved oil reserves were added in the U.S. for drilling activities in the Eagle Ford Shale concurrent with the reallocation of capital to higher performing drilling areas moving well locations within the 5-year development window for proved undeveloped reserves, and in Canada for drilling activities in the Montney and Duvernay. Proved oil reserves were also added for drilling activities in the U.S. offshore.

Purchases of properties – In 2017, the Company acquired greater working interests in two of its operated Gulf of Mexico fields. In U.S. onshore, the Company acquired acreage in the Permian area of west Texas. Additional Eagle Ford Shale acreage was acquired through joint venture agreements with other operators within its core acreage position.

2016 Comments for Proved Crude Oil and Synthetic Oil Reserves Changes

Revisions of previous estimate – The 2016 negative crude oil revision in the U.S. was primarily attributable to impacts of lower price on Eagle Ford Shale volumes and reduced performance in a particular location, partially offset by improved Eagle Ford Shale costs and drilling results in the Gulf of Mexico. The positive Canadian oil reserves revisions in 2016 resulted from improved Kaybob Duvernay performance and an increase at Terra Nova due to development drilling. The positive revisions for crude oil reserves in Malaysia was attributable to improved performance and lower government entitlement under the terms of the respective production sharing contracts due to lower oil prices, which collectively more than offset a negative revision at Kikeh following updated decline curve analysis.

Extensions and discoveries – In 2016, proved oil reserves were added in the U.S. for drilling activities in the Eagle Ford Shale, and deeper oil-water contacts realized at a field in Malaysia.

Purchases of properties – In 2016, the Company's Canadian subsidiary acquired working interests in the Kaybob Duvernay and liquids rich Placid Montney areas. The crude oil reserves are all associated with the Kaybob Duvernay area.

Sales of properties – In the U.S., proved oil reserves were reduced following the sale of certain non-core Eagle Ford Shale acreage. In Canada, the Company sold its interests in both a heavy oil field and a synthetic oil project.

2015 Comments for Proved Crude Oil and Synthetic Oil Reserves Changes

Revisions of previous estimate – The 2015 negative crude oil revision in the U.S. was primarily attributable to impacts of lower price on Eagle Ford Shale volumes, partially offset by improved Eagle Ford Shale performance, improved Eagle Ford Shale lifting costs, and drilling activity in the Gulf of Mexico. The negative Canadian conventional oil reserves revision in 2015 was result of lower heavy oil prices partially offset by increases at both Hibernia and Terra Nova due to development drilling and lower government royalty effects. The positive synthetic oil revision in the current period is due predominantly to lower government royalty effects due to lower oil prices. The positive revision for crude oil reserves in Malaysia was attributable to improved performance and lower government entitlement under the terms of the respective production sharing contracts due to lower oil prices.

Improved recovery – The 2015 Malaysia crude oil proved reserve addition was primarily due to favorable impacts for waterflood activity at certain Sarawak oil fields.

Extensions and discoveries – In 2015, the U.S. added proved oil reserves primarily for planned drilling activities in the Eagle Ford Shale.

Sales of properties – The proved crude oil reserves reduction in Malaysia was associated with the 2015 sale of 10% of the Company's oil and gas assets in Malaysia.

Schedule 2 – Summary of Proved Natural Gas Liquids (NGL) Reserves Based on Average Prices for 2014 – 2017

(Millions of barrels)	Total	United States	Canada	Malaysia
Proved developed and undeveloped NGL reserves:				
December 31, 2014	30.6	29.1	0.7	0.8
Revisions of previous estimates	2.0	2.2	(0.3)	0.1
Extensions and discoveries	7.6	7.6	–	–
Sales of properties	(0.1)	–	–	(0.1)
Production	(3.7)	(3.5)	–	(0.2)
December 31, 2015	36.4	35.4	0.4	0.6
Revisions of previous estimates	1.6	1.2	0.2	0.2
Extensions and discoveries	2.9	2.8	0.1	–
Purchases of properties	5.1	–	5.1	–
Production	(3.5)	(3.0)	(0.2)	(0.3)
December 31, 2016	42.5	36.4	5.6	0.5
Revisions of previous estimates	**1.3**	**2.0**	**(0.6)**	**(0.1)**
Extensions and discoveries	**7.8**	**7.0**	**0.8**	**–**
Purchases of properties	**0.5**	**0.5**	**–**	**–**
Production	**(3.2)**	**(2.9)**	**(0.2)**	**(0.1)**
December 31, 2017	**48.9**	**43.0**	**5.6**	**0.3**
Proved developed NGL reserves:				
December 31, 2014	17.5	16.5	0.2	0.8
December 31, 2015	21.6	20.7	0.3	0.6
December 31, 2016	22.2	20.8	0.9	0.5
December 31, 2017	**24.6**	**23.3**	**1.0**	**0.3**
Proved undeveloped NGL reserves:				
December 31, 2014	13.1	12.6	0.5	–
December 31, 2015	14.8	14.7	0.1	–
December 31, 2016	20.3	15.6	4.7	–
December 31, 2017	**24.3**	**19.7**	**4.6**	**–**

Schedule 2 – Summary of Proved Natural Gas Liquids (NGL) Reserves Based on Average Prices for 2014 – 2017 – Continued

2017 Comments for Proved Natural Gas Liquids Reserves Changes

Revisions of previous estimates – The positive 2017 NGL proved reserves revision in the U.S. was primarily in the Company's Eagle Ford Shale fields based on an updated shrinkage ratio of liquids rich gas production combined with improved costs, offsetting removal of proved undeveloped locations from within the 5-year development window as capital was reallocated to higher performing drilling locations within the Eagle Ford Shale.

Extensions and discoveries – Proved NGL reserves were added primarily from drilling activities in the Eagle Ford Shale area concurrent with the reallocation of capital to higher performing drilling areas moving well locations within the 5-year development window for proved undeveloped reserves.

Purchase of properties – In U.S., proved NGL reserves were added following the acquisition of acreage in both the Eagle Ford Shale and Permian areas, and increased working interest in two Gulf of Mexico fields.

2016 Comments for Proved Natural Gas Liquids Reserves Changes

Revisions of previous estimates – The positive 2016 NGL proved reserves revision was primarily in the Eagle Ford Shale area based on an updated ratio of oil to gas production.

Extensions and discoveries – Proved NGL reserves were added primarily from drilling activities in the Eagle Ford Shale area.

Purchase of properties – In Canada, proved NGL reserves were added following the acquisition of acreage in both the Kabob Duvernay and liquids rich Placid Montney areas.

2015 Comments for Proved Natural Gas Liquids Reserves Changes

Revisions of previous estimates – The positive 2015 NGL proved reserves revision in the U.S. was primarily in the Eagle Ford Shale area based on improved performance.

Extensions and discoveries – In 2015, the U.S. added NGL reserves primarily for additional drilling activities in the Eagle Ford Shale.

Sales of properties – The Company sold 10% of its oil and gas assets in Malaysia in January 2015.

Schedule 3 – Summary of Proved Natural Gas Reserves Based on Average Prices for 2014 – 2017

(Billions of cubic feet)	Total	United States	Canada	Malaysia
Proved developed and undeveloped natural gas reserves:				
December 31, 2014	1,704.7	226.3	842.8	635.6
Revisions of previous estimates	53.5	(5.2)	18.9	39.8
Improved recovery	1.8	–	–	1.8
Extensions and discoveries	162.9	43.2	119.7	–
Sales of properties	(78.0)	–	–	(78.0)
Production	(156.1)	(31.9)	(71.8)	(52.4)
December 31, 2015	1,688.8	232.4	909.6	546.8
Revisions of previous estimates	43.3	0.1	45.3	(2.1)
Extensions and discoveries	164.2	6.4	120.2	37.6
Purchases of properties	122.3	–	122.3	–
Sales of properties	(2.2)	(0.1)	(2.1)	–
Production	(138.4)	(19.4)	(76.4)	(42.6)
December 31, 2016	1,878.0	219.4	1,118.9	539.7
Revisions of previous estimates	**(5.4)**	**(16.0)**	**19.4**	**(8.8)**
Extensions and discoveries	**190.6**	**32.2**	**156.7**	**1.7**
Purchases of properties	**4.0**	**4.0**	**–**	**–**
Production	**(140.1)**	**(16.3)**	**(82.6)**	**(41.2)**
December 31, 2017	**1,927.1**	**223.3**	**1,212.4**	**491.4**
Proved developed natural gas reserves:				
December 31, 2014	812.1	145.6	467.4	199.1
December 31, 2015	783.5	148.3	453.5	181.7
December 31, 2016	818.1	138.7	498.9	180.5
December 31, 2017	**819.3**	**127.7**	**547.0**	**144.6**
Proved undeveloped natural gas reserves:				
December 31, 2014	892.6	80.7	375.4	436.5
December 31, 2015	905.3	84.1	456.1	365.1
December 31, 2016	1,059.9	80.7	620.0	359.2
December 31, 2017	**1,107.8**	**95.6**	**665.5**	**346.7**

Schedule 3 – Summary of Proved Natural Gas Reserves Based on Average Prices for 2014 – 2017 – Continued

2017 Comments for Proved Natural Gas Reserves Changes

Revisions of previous estimates – In the U.S., the negative natural gas revision was primarily due to shutting in a gas well located in the Gulf of Mexico due to early water break through, and in the Company's Eagle Ford Shale fields proved undeveloped locations were removed from within the 5-year development window as capital was reallocated to higher performing drilling locations within the Eagle Ford Shale. The negative revision for natural gas reserves in Malaysia was primarily attributable to higher government entitlement under the terms of the respective production sharing contracts due to higher gas prices, offsetting positive performance revisions at the Company's Sarawak projects. The 2017 positive natural gas revisions in Canada were attributable to updated well type curves and field performance at the Tupper Montney assets in Western Canada.

Extensions and discoveries – In 2017, the U.S. added natural gas reserves primarily for developmental drilling activities in the Eagle Ford Shale concurrent with the reallocation of capital to higher performing drilling areas moving well locations within the 5-year development window for proved undeveloped reserves, and field development drilling in the Gulf of Mexico. Natural gas reserve additions in Canada were attributable to developmental drilling activities in the Montney and Kaybob Duvernay areas in Western Canada. In Malaysia, proved natural gas reserves were added in Sarawak from field development activities.

Purchase of properties – In the U.S., proved natural gas reserves were added following the acquisition of acreage in both the Eagle Ford Shale and Permian areas, and increased working interest in two Gulf of Mexico fields.

2016 Comments for Proved Natural Gas Reserves Changes

Revisions of previous estimates – The 2016 positive natural gas revisions in Canada were attributable to updated well type curves and field development techniques in both the Montney and Duvernay areas of Western Canada. The negative revision for natural gas reserves in Malaysia was primarily attributable to the removal of Sarawak area proved reserves resulting from the government's decision to delay certain field development plans.

Extensions and discoveries – In 2016, the U.S. added natural gas reserves primarily for developmental drilling activities in the Eagle Ford Shale. Natural gas reserve additions in Canada were attributable to developmental drilling activities in the Tupper area. In Malaysia, proved natural gas reserves were added in Block H as the Permai field was added to the field development plan.

Purchase of properties – In Canada, proved natural gas reserves were added following the acquisition of acreage in both the Kaybob Duvernay and liquids rich Placid Montney areas.

Sales of properties – Proved natural gas reserves were reduced following the sale of certain non-core Eagle Ford Shale acreage in the U.S. and the associated gas related to the sale of a heavy oil field in Canada.

2015 Comments for Proved Natural Gas Reserves Changes

Revisions of previous estimates – The 2015 negative natural gas revision in the U.S. was primarily attributable to performance declines in certain fields in the Gulf of Mexico offset in part by the overall positive performance in the Eagle Ford Shale area. The positive revisions in Canada were attributable to updated well type curves and field development techniques in the Montney area of Western Canada. The positive revision for natural gas reserves in Malaysia was attributable to lower government entitlement under the terms of the respective production sharing contracts due to lower natural gas prices.

Improved recovery – The 2015 Malaysia natural gas proved reserve addition was primarily due to favorable impacts for waterflood activity at certain Sarawak oil fields.

Extensions and discoveries – In 2015, the U.S. added natural gas reserves primarily for planned developmental drilling activities in the Eagle Ford Shale while the gas reserve additions in Canada were attributable to developmental drilling activities in the Tupper area.

Sales of properties – The Company sold 10% of its oil and gas assets in Malaysia in January 2015.

Schedule 4 – Costs Incurred in Oil and Gas Property Acquisition, Exploration and Development Activities

(Millions of dollars)	United States	Canada	Malaysia	Other	Total
Year ended December 31, 2017					
Property acquisition costs					
Unproved	**$ 50.4**	**–**	**–**	**13.0**	**63.4**
Proved	**7.7**	**–**	**–**	**–**	**7.7**
Total acquisition costs	**58.1**	**–**	**–**	**13.0**	**71.1**
Exploration costs [1]	**13.7**	**0.6**	**(8.9)**	**73.8**	**79.2**
Development costs [1]	**508.4**	**273.8**	**35.7**	**1.1**	**819.0**
Total costs incurred	**580.2**	**274.4**	**26.8**	**87.9**	**969.3**
Charged to expense					
Dry hole expense	**(1.9)**	**–**	**0.7**	**(3.0)**	**(4.2)**
Geophysical and other costs	**9.7**	**0.5**	**1.7**	**53.3**	**65.2**
Total charged to expense	**7.8**	**0.5**	**2.4**	**50.3**	**61.0**
Property additions	**$ 572.4**	**273.9**	**24.4**	**37.6**	**908.3**
Year ended December 31, 2016					
Property acquisition costs					
Unproved	$ 18.6	–	–	–	18.6
Proved	–	206.7	–	–	206.7
Total acquisition costs	18.6	206.7	–	–	225.3
Exploration costs [1]	18.5	3.6	6.0	42.0	70.1
Development costs [1]	239.7	165.1	102.9	0.3	508.0
Total costs incurred	276.8	375.4	108.9	42.3	803.4
Charged to expense					
Dry hole expense	0.4	–	4.5	10.2	15.1
Geophysical and other costs	5.7	3.6	0.7	33.4	43.4
Total charged to expense	6.1	3.6	5.2	43.6	58.5
Property additions	$ 270.7	371.8	103.7	(1.3)	744.9
Year ended December 31, 2015					
Property acquisition costs					
Unproved	$ 10.1	2.5	–	–	12.6
Proved	–	–	–	–	–
Total acquisition costs	10.1	2.5 –	–	–	12.6
Exploration costs [1]	166.8	0.7	69.0	135.4	371.9
Development costs [1]	1,375.1	231.5	210.0	2.8	1,819.4
Total costs incurred	1,552.0	234.7	279.0	138.2	2,203.9
Charged to expense					
Dry hole expense	241.3	–	29.7	25.8	296.8
Geophysical and other costs	16.9	0.7	7.9	73.2	98.7
Total charged to expense	258.2	0.7	37.6	99.0	395.5
Property additions	$ 1,293.8	234.0	241.4	39.2	1,808.4

[1] Includes noncash asset retirement costs as follows:

2017					
Exploration costs	**$ –**	**–**	**–**	**–**	**–**
Development costs	**37.6**	**6.3**	**8.4**	**–**	**52.3**
	$ 37.6	**6.3**	**8.4**	**–**	**52.3**
2016					
Exploration costs	$ –	–	–	–	–
Development costs	0.9	10.5	2.3	–	13.7
	$ 0.9	10.5	2.3	–	13.7
2015					
Exploration costs	$ –	–	–	–	–
Development costs	30.7	49.1	(3.0)	–	76.8
	$ 30.7	49.1	(3.0)	–	76.8

Schedule 5 – Results of Operations for Oil and Gas Producing Activities [1]

(*Millions of dollars*)	United States	Canada Conven-tional	Canada Synthetic	Malaysia	Other	Total
Year ended December 31, 2017						
Revenues						
Crude oil and natural gas liquids sales	**$ 913.3**	**203.7**	**–**	**639.9**	**–**	**1,756.9**
Natural gas sales	**37.9**	**155.1**	**–**	**138.2**	**–**	**331.2**
Total oil and gas revenues	**951.2**	**358.8**	**–**	**778.1**	**–**	**2,088.1**
Other operating revenues	**2.7**	**126.7**	**–**	**3.0**	**–**	**132.4**
Total revenues	**953.9**	**485.5**	**–**	**781.1**	**–**	**2,220.5**
Costs and expenses						
Lease operating expenses	**198.5**	**101.1**	**–**	**168.8**	**–**	**468.4**
Severance and ad valorem taxes	**42.2**	**1.5**	**–**	**–**	**–**	**43.7**
Exploration costs charged to expense	**7.8**	**0.5**	**–**	**2.4**	**50.3**	**61.0**
Undeveloped lease amortization	**60.2**	**1.6**	**–**	**–**	**–**	**61.8**
Depreciation, depletion and amortization	**546.1**	**185.4**	**–**	**204.6**	**3.8**	**939.9**
Accretion of asset retirement obligations	**17.4**	**7.9**	**–**	**17.3**	**–**	**42.6**
Redetermination expense	**–**	**–**	**–**	**15.0**	**–**	**15.0**
Selling and general expenses	**61.8**	**28.3**	**–**	**14.0**	**19.6**	**123.7**
Other expenses	**20.0**	**2.3**	**–**	**8.4**	**–**	**30.7**
Total costs and expenses	**954.0**	**328.6**	**–**	**430.5**	**73.7**	**1,786.8**
Results of operations before taxes	**(0.1)**	**156.9**	**–**	**350.6**	**(73.7)**	**433.7**
Income tax expense (benefit)	**2.5**	**44.4**	**–**	**126.4**	**(36.2)**	**137.1**
Results of operations	**$ (2.6)**	**112.5**	**–**	**224.2**	**(37.5)**	**296.6**
Year ended December 31, 2016						
Revenues						
Crude oil and natural gas liquids sales	$ 650.7	171.7	60.7	623.7	–	1,506.8
Natural gas sales	35.1	130.0	–	127.6	–	292.7
Total oil and gas revenues	685.8	301.7	60.7	751.3	–	1,799.5
Other operating revenues	(0.1)	(0.7)	3.6	2.1	0.2	5.1
Total revenues	685.7	301.0	64.3	753.4	0.2	1,804.6
Costs and expenses						
Lease operating expenses	218.6	102.6	69.8	168.4	–	559.4
Severance and ad valorem taxes	37.0	4.3	2.5	–	–	43.8
Exploration costs charged to expense	6.1	3.6	–	5.2	43.6	58.5
Undeveloped lease amortization	38.4	4.5	–	–	0.5	43.4
Depreciation, depletion and amortization	600.5	186.7	16.5	227.7	5.9	1,037.3
Accretion of asset retirement obligations	17.1	10.9	2.4	16.3	–	46.7
Impairment of assets	–	95.1	–	–	–	95.1
Redetermination expense	–	–	–	39.1	–	39.1
Selling and general expenses	68.8	28.6	0.5	15.9	33.6	147.4
Other expenses (benefits)	(7.5)	7.5	–	23.8	(9.9)	13.9
Total costs and expenses	979.0	443.8	91.7	496.4	73.7	2,084.6
Results of operations before taxes	(293.3)	(142.8)	(27.4)	257.0	(73.5)	(280.0)
Income tax expense (benefit)	(87.9)	(58.9)	(75.4)	85.9	(18.8)	(155.1)
Results of operations	$ (205.4)	(83.9)	48.0	171.1	(54.7)	(124.9)

[1] Results exclude corporate overhead, interest and discontinued operations.

Schedule 5 – Results of Operations for Oil and Gas Producing Activities [1] – Continued

(*Millions of dollars*)	United States	Canada Conven-tional	Canada Synthetic	Malaysia	Other	Total
Year ended December 31, 2015						
Revenues						
Crude oil and natural gas liquids sales	$ 1,176.9	181.0	203.0	790.6	–	2,351.5
Natural gas sales	70.4	167.7	–	185.4	–	423.5
Total oil and gas revenues	1,247.3	348.7	203.0	976.0	–	2,775.0
Other operating revenues	6.3	(2.4)	0.4	155.4	–	159.7
Total revenues	1,253.6	346.3	203.4	1,131.4	–	2,934.7
Costs and expenses						
Lease operating expenses	312.0	102.4	166.0	251.9	–	832.3
Severance and ad valorem taxes	55.9	4.8	5.1	–	–	65.8
Exploration costs charged to expense	258.2	0.7	–	37.6	99.0	395.5
Undeveloped lease amortization	59.2	14.4	–	–	1.8	75.4
Depreciation, depletion and amortization	794.9	211.2	50.7	544.9	6.2	1,607.9
Accretion of asset retirement obligations	20.2	7.2	5.4	15.9	–	48.7
Impairment of assets	329.0	683.6	–	1,480.6	–	2,493.2
Selling and general expenses	88.2	25.5	1.0	5.7	56.8	177.2
Other expenses	288.7	43.9	–	15.9	12.1	360.6
Total costs and expenses	2,206.3	1,093.7	228.2	2,352.5	175.9	6,056.6
Results of operations before taxes	(952.7)	(747.4)	(24.8)	(1,221.1)	(175.9)	(3,121.9)
Income tax expense (benefit)	(337.0)	(191.2)	2.4	(567.9)	(17.3)	(1,111.0)
Results of operations	$ (615.7)	(556.2)	(27.2)	(653.2)	(158.6)	(2,010.9)

[1] Results exclude corporate overhead, interest and discontinued operations.

Schedule 6 – Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

(*Millions of dollars*)	United States	Canada	Malaysia	Total
December 31, 2017				
Future cash inflows	**$ 12,885.8**	**4,714.3**	**4,392.0**	**21,992.1**
Future development costs	**(2,079.5)**	**(1,081.7)**	**(632.3)**	**(3,793.5)**
Future production costs	**(4,765.3)**	**(2,507.4)**	**(2,305.0)**	**(9,577.7)**
Future income taxes	**(893.7)**	**(161.1)**	**(232.2)**	**(1,287.0)**
Future net cash flows	**5,147.3**	**964.1**	**1,222.5**	**7,333.9**
10% annual discount for estimated timing of cash flows	**(2,698.2)**	**(394.6)**	**(318.2)**	**(3,411.0)**
Standardized measure of discounted future net cash flows	**$ 2,449.1**	**569.5**	**904.3**	**3,922.9**
December 31, 2016				
Future cash inflows	$ 9,477.9	3,752.7	4,318.7	17,549.3
Future development costs	(1,691.1)	(1,143.6)	(763.8)	(3,598.5)
Future production costs	(3,981.6)	(2,329.7)	(2,661.2)	(8,972.5)
Future income taxes	(118.9)	(81.3)	(73.3)	(273.5)
Future net cash flows	3,686.3	198.1	820.4	4,704.8
10% annual discount for estimated timing of cash flows	(1,799.5)	(95.0)	(230.3)	(2,124.8)
Standardized measure of discounted future net cash flows	$ 1,886.8	103.1	590.1	2,580.0
December 31, 2015				
Future cash inflows	$ 12,373.9	8,922.0	6,143.1	27,439.0
Future development costs	(2,620.5)	(1,145.4)	(957.8)	(4,723.7)
Future production costs	(4,955.4)	(5,892.7)	(3,290.5)	(14,138.6)
Future income taxes	(339.7)	(504.8)	(216.2)	(1,060.7)
Future net cash flows	4,458.3	1,379.1	1,678.6	7,516.0
10% annual discount for estimated timing of cash flows	(2,430.0)	(666.8)	(560.1)	(3,656.9)
Standardized measure of discounted future net cash flows	$ 2,028.3	712.3	1,118.5	3,859.1

Schedule 6 – Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves – Continued

Following are the principal sources of change in the standardized measure of discounted future net cash flows for the years shown.

(Millions of dollars)		2017	2016	2015
Net changes in prices and production costs	$	**2,428.4**	(1,476.1)	(11,365.5)
Net changes in development costs		**(724.4)**	544.9	591.4
Sales and transfers of oil and gas produced, net of production costs		**(1,576.0)**	(1,196.3)	(1,876.9)
Net change due to extensions and discoveries		**807.9**	280.5	1,145.8
Net change due to purchases and sales of proved reserves		**85.9**	(583.4)	(287.4)
Development costs incurred		**802.7**	479.6	1,725.4
Accretion of discount		**270.9**	428.1	1,289.5
Revisions of previous quantity estimates		**(109.5)**	(49.2)	163.3
Net change in income taxes		**(643.0)**	292.8	2,568.3
Net increase (decrease)		**1,342.9**	(1,279.1)	(6,046.1)
Standardized measure at January 1		**2,580.0**	3,859.1	9,905.2
Standardized measure at December 31	$	**3,922.9**	2,580.0	3,859.1

Schedule 7 – Capitalized Costs Relating to Oil and Gas Producing Activities

(Millions of dollars)		United States	Canada	Malaysia	Other	Total
December 31, 2017						
Unproved oil and gas properties	$	**360.9**	**286.8**	**20.5**	**162.1**	**830.3**
Proved oil and gas properties		**9,606.4**	**3,603.4**	**6,139.7**	**–**	**19,349.5**
Gross capitalized costs		**9,967.3**	**3,890.2**	**6,160.2**	**162.1**	**20,179.8**
Accumulated depreciation, depletion and amortization						
Unproved oil and gas properties		**(149.5)**	**(230.7)**	**–**	**(21.8)**	**(402.0)**
Proved oil and gas properties		**(4,893.8)**	**(2,027.9)**	**(4,774.5)**	**–**	**(11,696.2)**
Net capitalized costs	$	**4,924.0**	**1,631.6**	**1,385.7**	**140.3**	**8,081.6**
December 31, 2016						
Unproved oil and gas properties	$	360.8	315.6	47.0	125.6	849.0
Proved oil and gas properties		9,384.6	4,241.6	6,147.8	–	19,774.0
Gross capitalized costs		9,745.4	4,557.2	6,194.8	125.6	20,623.0
Accumulated depreciation, depletion and amortization						
Unproved oil and gas properties		(151.2)	(233.6)	–	(21.8)	(406.6)
Proved oil and gas properties		(4,605.9)	(2,877.2)	(4,566.6)	–	(12,049.7)
Net capitalized costs	$	4,988.3	1,446.4	1,628.2	103.8	8,166.7

Note: Unproved oil and gas properties above include costs and associated accumulated amortization of properties that do not have proved reserves; these costs include mineral interests, uncompleted exploratory wells, and exploratory wells capitalized pending further evaluation.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
SUPPLEMENTAL QUARTERLY INFORMATION (UNAUDITED)

(*Millions of dollars except per share amounts*)		First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year
Year ended December 31, 2017						
Sales and other operating revenues	**$**	**544.7**	**509.7**	**498.3**	**545.0**	**2,097.7**
Income (loss) from continuing operations before income taxes		**154.9**	**(21.9)**	**(63.6)**	**2.4**	**71.8**
Income (loss) from continuing operations		**57.5**	**(17.3)**	**(66.3)**	**(284.8)**	**(310.9)**
Net income (loss)		**58.5**	**(17.6)**	**(65.9)**	**(286.8)**	**(311.8)**
Income (loss) from continuing operations per Common share						
Basic		**0.33**	**(0.10)**	**(0.38)**	**(1.65)**	**(1.81)**
Diluted		**0.33**	**(0.10)**	**(0.38)**	**(1.65)**	**(1.81)**
Net income (loss) per Common share						
Basic		**0.34**	**(0.10)**	**(0.38)**	**(1.66)**	**(1.81)**
Diluted		**0.34**	**(0.10)**	**(0.38)**	**(1.66)**	**(1.81)**
Cash dividend per Common share		**0.25**	**0.25**	**0.25**	**0.25**	**1.00**
Market price of Common Stock [1]						
High		**32.18**	**28.71**	**27.43**	**31.98**	**32.18**
Low		**25.76**	**24.06**	**22.63**	**25.02**	**22.63**
Year ended December 31, 2016						
Sales and other operating revenues	$	429.1	411.2	486.3	483.0	1,809.6
Loss from continuing operations before income taxes		(265.0)	(131.3)	(16.7)	(80.1)	(493.1)
Income (loss) from continuing operations		(199.5)	2.9	(14.6)	(62.8)	(274.0)
Net income (loss)		(198.8)	2.9	(16.2)	(63.9)	(276.0)
Income from continuing operations per Common share						
Basic		(1.16)	0.02	(0.08)	(0.36)	(1.59)
Diluted		(1.16)	0.02	(0.08)	(0.36)	(1.59)
Net income (loss) per Common share						
Basic		(1.16)	0.02	(0.08)	(0.37)	(1.60)
Diluted		(1.16)	0.02	(0.08)	(0.37)	(1.60)
Cash dividend per Common share		0.35	0.35	0.25	0.25	1.20
Market price of Common Stock [1]						
High		26.69	36.24	32.66	34.30	36.24
Low		15.76	23.49	25.14	25.00	15.76

[1] Prices are as quoted on the New York Stock Exchange.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES
SCHEDULE II – VALUATION ACCOUNTS AND RESERVES

(*Millions of dollars*)	Balance at January 1	Charged to Expense	Deductions	Other [1]	Balance at December 31
2017					
Deducted from asset accounts:					
Allowance for doubtful accounts	**$ 1.6**	**–**	**–**	**–**	**1.6**
Deferred tax asset valuation allowance	**305.4**	**18.6**	**–**	**152.3**	**476.3**
2016					
Deducted from asset accounts:					
Allowance for doubtful accounts	$ 1.6	–	–	–	1.6
Deferred tax asset valuation allowance	294.4	25.7	–	(14.7)	305.4
2015					
Deducted from asset accounts:					
Allowance for doubtful accounts	$ 1.6	–	–	–	1.6
Deferred tax asset valuation allowance	306.5	40.8	–	(52.9)	294.4

[1] Amounts in 2017 and 2016 for deferred tax asset valuations are primarily associated with an increase in foreign tax credit carryforwards. The amount in 2015 for deferred tax asset valuation allowance is primarily associated with utilization of foreign tax credit carryforwards.

GLOSSARY

3D seismic

three-dimensional images created by bouncing sound waves off underground rock formations that are used to determine the best places to drill for hydrocarbons

deepwater

offshore location in greater than 1,000 feet of water

downstream

refining and marketing operations

dry hole

an unsuccessful exploration well that is plugged and abandoned, with associated costs written off to expense

exploratory

wildcat and delineation, e.g., exploratory wells

hydrocarbons

organic chemical compounds of hydrogen and carbon atoms that form the basis of all petroleum products

production sharing contract

agreement between extracting company(ies) and a host country regarding each party's share of production after stipulated exploratory and development costs are recovered

synthetic oil

a light, sweet crude oil produced by upgrading bitumen recovered from oil sands

oil sands

tar-like hydrocarbon-bearing substance that occurs naturally in certain areas at the Earth's surface or at relatively shallow depths and which can be recovered, processed and upgraded into a light, sweet synthetic crude oil

operator

the company serving as the manager and often the decision-maker of a drilling or production project

unitization

combining of multiple mineral or leasehold interests to be able to produce from a common reservoir

upstream

oil and natural gas exploration and production operations, including synthetic oil operation

working interest

right to drill and produce oil and gas on the leased acreage, as well as the obligation to pay costs

ABBREVIATIONS

ARO - Asset Retirement Obligation

ASU - Accounting Standards Update

BCF - Billion cubic feet

BOED - Barrel of oil equivalent per day

FASB - Financial Accounting Standards Board

FLNG - Floating Liquified Natural Gas

GAAP - U.S. Generally Accepted Accounting Principles

GK - Gumusut/Kakap

LTM - Last twelve months

MCF - Thousand cubic feet

MMBOE - Million barrels of oil equivalent

MMCF - Million cubic feet

MOCL - Murphy Oil Company Ltd.

NYMEX - New York Mercantile Exchange

OSHA - Occupational Safety and Health Act

QRE - Qualified Reserve Estimators

R&M - Refining and Marketing

SEC - U.S. Securities and Exchange Commission

UFA - Unitization Framework Agreement

WCSB - Western Canadian Sedimentary Basin

WTI - West Texas Intermediate

EXHIBIT 12

Murphy Oil Corporation and Consolidated Subsidiaries
Computation of Ratio of Earnings to Fixed Charges (unaudited)
(Thousands of dollars)

	Years Ended December 31,				
	2017	**2016**	**2015**	**2014**	**2013**
Income (loss) from continuing operations before income taxes	$ 71,802	(493,115)	(3,282,262)	1,252,270	1,472,687
Distributions greater than equity in earnings of affiliates	2,058	6,034	4,104	4,962	5,204
Previously capitalized interest charged to earnings during period	11,106	14,444	27,201	19,760	16,896
Interest and expense on indebtedness, excluding capitalized interest	181,783	148,170	117,375	115,819	71,900
Interest portion of rentals[(1)]	30,317	22,003	26,932	46,528	44,478
Earnings (loss) before provision for taxes and fixed charges	$ 297,066	(302,464)	(3,106,650)	1,439,339	1,611,165
Interest and expense on indebtedness, excluding capitalized interest	181,783	148,170	117,375	115,819	71,900
Capitalized interest	4,488	4,322	7,290	20,605	52,523
Interest portion of rentals[(1)]	30,317	22,003	26,932	46,528	44,478
Total fixed charges	$ 216,588	174,495	151,597	182,952	168,901
Ratio of earnings to fixed charges	1.4	— [(2)]	— [(2)]	7.9	9.5

(1) Calculated as one-third of rentals. Considered a reasonable approximation of interest factor.

(2) Earnings for the years ended December 31, 2016 and 2015 were inadequate to cover fixed charges by $476,959 and $3,258,247, respectively.

MURPHY OIL CORPORATION
SUBSIDIARIES OF THE REGISTRANT AS OF DECEMBER 31, 2017

Exhibit 21

Name of Company	State or Other Jurisdiction of Incorporation	Percentage of Voting Securities Owned by Immediate Parent
Murphy Oil Corporation (REGISTRANT)		
A. Arkansas Oil Company	Delaware	100.0
B. Caledonia Land Company	Delaware	100.0
C. El Dorado Engineering Inc.	Delaware	100.0
1. El Dorado Contractors	Delaware	100.0
D. Marine Land Company	Delaware	100.0
E. Murphy Eastern Oil Company	Delaware	100.0
F. Murphy Exploration & Production Company	Delaware	100.0
1. Mentor Holding Corporation	Delaware	100.0
a. Mentor Excess and Surplus Lines Insurance Company	Delaware	100.0
b. MIRC Corporation	Louisiana	100.0
2. Murphy Building Corporation	Delaware	100.0
3. Murphy Exploration & Production Company – International	Delaware	100.0
a. Canam Offshore Limited	Bahamas	100.0
(1) Canam Brunei Oil Ltd.	Bahamas	100.0
(2) Murphy Peninsular Malaysia Oil Co., Ltd.	Bahamas	100.0
(3) Murphy Sabah Oil Co., Ltd.	Bahamas	100.0
(4) Murphy Sarawak Oil Co., Ltd.	Bahamas	100.0
(5) Murphy Cuu Long Tay Oil Co., Ltd.	Bahamas	100.0
b. El Dorado Exploration, S.A.	Delaware	100.0
c. Murphy Asia Oil Co., Ltd.	Bahamas	100.0
d. Murphy Australia Holdings Pty. Ltd	Western Australia	100.0
(1) Murphy Australia AC/P 57 Oil Pty. Ltd.	Western Australia	100.0
(2) Murphy Australia AC/P 58 Oil Pty. Ltd.	Western Australia	100.0
(3) Murphy Australia EPP43 Oil Pty. Ltd.	Western Australia	100.0
(4) Murphy Australia NT/P80 Oil Pty. Ltd	Western Australia	100.0
(5) Murphy Australia Oil Pty. Ltd.	Western Australia	100.0
(i) Murphy Australia AC/P 36 Oil Pty. Limited	Western Australia	100.0
(6) Murphy Australia WA-408-P Oil Pty. Ltd.	Western Australia	100.0
(7) Murphy Australia WA-423-P Oil Pty. Ltd.	Western Australia	100.0
(8) Murphy Australia WA-476-P Oil Pty. Ltd.	Western Australia	100.0
(9) Murphy Australia WA-481-P Oil Pty. Ltd.	Western Australia	100.0
(10) Murphy Australia AC/P 59 Oil Pty. Ltd.	Western Australia	100.0
e. Murphy Brazil Exploracao e Producao de Petroleo e Gas Ltda. (see company o.(1) below)	Brazil	90.0
f. Murphy Cuu Long Bac Oil Co., Ltd.	Bahamas	100.0
g. Murphy Dai Nam Oil Co., Ltd.	Bahamas	100.0
h. Murphy Equatorial Guinea Oil Co., Ltd.	Bahamas	100.0
i. Murphy Exploration (Alaska), Inc.	Delaware	100.0
j. Murphy Luderitz Oil Co., Ltd.	Bahamas	100.0
k. Murphy Nha Trang Oil Co., Ltd.	Bahamas	100.0
l. Murphy Overseas Ventures Inc.	Delaware	100.0
(1) Murphy Brazil Exploracao e Producao de Petroleo e Gas Ltda. (see company e. above)	Brazil	10.0
m. Murphy Phuong Nam Oil Co., Ltd.	Bahamas	100.0
n. Murphy Semai IV Ltd.	Bahamas	100.0
o. Murphy South Barito, Ltd.	Bahamas	100.0
p. Murphy-Spain Oil Company	Delaware	100.0
q. Murphy West Africa, Ltd.	Bahamas	100.0
r. Murphy Worldwide, Inc.	Delaware	100.0
s. Murphy Offshore Oil Co. Ltd.	Bahamas	100.0

t. Murphy Netherlands Holdings B.V.	Netherlands	100.0
(1) Murphy Netherlands Holdings II B.V.	Netherlands	100.0
(1) Murphy Sur, S. de R. L. de C.V.	Mexico	100.0
4. Murphy Exploration & Production Company – USA	Delaware	100.0
G. Murphy Oil Company Ltd.	Canada	100.0
1. Murphy Canada Exploration Company	NSULCo.[1]	100.0
2. Murphy Canada Holding ULC	AULC[2]	100.0
3. Murphy Canada, Ltd.	Canada	100.0
4. Murphy Finance Company	NSULCo.[1]	100.0
H. New Murphy Oil (UK) Corporation	Delaware	100.0
1. Murphy Petroleum Limited	England	100.0
a. Murco Petroleum Limited	England	100.0

EXHIBIT 23.1

Consent of Independent Registered Public Accounting Firm

The Board of Directors of Murphy Oil Corporation:

We consent to the incorporation by reference in the registration statements (Nos. 333-177206, 333-184286 and 333-192672) on Form S-8 and in the registration statement (No. 333-207463) on Form S-3 of Murphy Oil Corporation of our reports dated February 23, 2018, with respect to the consolidated balance sheets of Murphy Oil Corporation and subsidiaries as of December 31, 2017 and 2016, and the related consolidated statements of operations, comprehensive income (loss), cash flows, and stockholders' equity for each of the years in the three-year period ended December 31, 2017, and the related notes and financial statement Schedule II – Valuation Accounts and Reserves (collectively, the "consolidated financial statements"), and the effectiveness of internal control over financial reporting as of December 31, 2017, which reports appear in the December 31, 2017 annual report on Form 10-K of Murphy Oil Corporation.

/s/ KPMG

Houston, Texas
February 23, 2018

EXHIBIT 31.1

CERTIFICATION PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Roger W. Jenkins, certify that:

1. I have reviewed this annual report on Form 10-K of Murphy Oil Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal controls over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls over financial reporting.

Date: February 23, 2018

/s/ Roger W.Jenkins
Roger W. Jenkins
Principal Executive Officer

**CERTIFICATION PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002**

I, John W. Eckart, certify that:

1. I have reviewed this annual report on Form 10-K of Murphy Oil Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal controls over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls over financial reporting.

Date: February 23, 2018

/s/ John W. Eckart
John W. Eckart
Principal Financial Officer

EXHIBIT 32

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Murphy Oil Corporation (the “Company”) on Form 10-K for the period ended December 31, 2017 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), we, Roger W. Jenkins and John W. Eckart, Principal Executive Officer and Principal Financial Officer, respectively, of the Company, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that to our knowledge:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 23, 2018

/s/ Roger W. Jenkins
Roger W. Jenkins
Principal Executive Officer

/s/ John W. Eckart
John W. Eckart
Principal Financial Officer