MURPHY OIL CORP /DE
Form 10-K
February 27, 2019

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2018

OR

TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to

Commission file number 1-8590

MURPHY OIL CORPORATION

(Exact name of registrant as specified in its charter)

Delaware	71-0361522
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification Number)
300 Peach Street, P.O. Box 7000, El Dorado, Arkansas	71731-7000
(Address of principal executive offices)	(Zip Code)

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 every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). 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, 2018) – $5,528,315,891.

Number of shares of Common Stock, $1.00 Par Value, outstanding at January 31, 2019 was 173,058,829.

Documents incorporated by reference:

Portions of the Registrant’s definitive Proxy Statement relating to the Annual Meeting of Stockholders on May 8, 2019 have been incorporated by reference in Part III herein.

MURPHY OIL CORPORATION

2018 FORM 10-K

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PART I

Item 1. BUSINESS

Summary

Murphy Oil Corporation is a global 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), corporate risk management activities 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 focused on oil and gas exploration and production activities.

At December 31, 2018, Murphy had 1,108 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 38, 71 through 73, 101 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, with the most significant of these including Houston in Texas, Calgary in Alberta, and Kuala Lumpur in Malaysia.

During 2018, 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, Brazil, 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 2018 was in the United States, Canada, Malaysia and Brunei.

Unless otherwise indicated, all references to the Company's offshore U.S. and total oil, natural gas liquids and natural gas production and sales volumes, and proved reserves references include a noncontrolling interest in MP Gulf of Mexico, LLC (MP GOM; see further details below and in the Management's Discussion and Analysis section).

Murphy's worldwide 2018 production on a barrel of oil equivalent basis (six thousand cubic feet of natural gas equals one barrel of oil) was 172,172 barrels of oil equivalent per day, an increase of 5.3% compared to 2017.

See Management's Discussion and Analysis section for further details on 2018 production and sales volume.

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 Gulf of Mexico. The Company produced approximately 58,200 barrels of crude oil and gas liquids per day and approximately 46 MMCF of natural gas per day in the U.S. in 2018. These amounts represented 57.2% of the Company's total worldwide oil and gas liquids and 10.9% of worldwide natural gas production volumes.

Offshore

On November 30, 2018, Murphy Expro USA and Petrobras America Inc. (PAI), a subsidiary of Petróleo Brasileiro S.A., closed a transaction among Murphy, PAI and MP Gulf of Mexico, LLC (MP GOM), a subsidiary of Murphy. The transaction had an effective date of October 1, 2018. Under the terms of the transaction, Murphy paid cash consideration of $794.6 million and transferred a 20% interest in MP GOM to PAI. Murphy could also owe additional contingent consideration up to $150 million if certain sales thresholds are exceeded beginning in 2019 through 2025. PAI and Murphy contributed all of their Gulf of Mexico producing assets and Murphy contributed its interest in the Medusa Spar LLC to MP GOM. Following closing of the transaction, MP GOM is owned 80% by Murphy and 20% by PAI. Throughout this 10K report, unless stated otherwise, financial and operational metrics relating to MP GOM include PAI's 20% noncontrolling interest in MP GOM. 100% of revenues, costs, assets, liabilities and cash flows of MP GOM are fully consolidated in the financial statements.

During 2018, approximately 34% of total U.S. hydrocarbon production was produced at fields in the Gulf of Mexico. Approximately 91% of Gulf of Mexico production in 2018 was derived from seven fields, including Dalmatian, Medusa, Kodiak, Front Runner, Thunder Hawk, St. Malo and Chinook. Through MP GOM, including the noncontrolling interest, the Company now holds a 70% operated 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, a 62.5% operated interest in the Front Runner field in Green Canyon Blocks 338/339, a 62.5% operated interest in the Thunder Hawk field in Mississippi Canyon Block 734, a 100% interest in Cascade and Cottonwood, a 66.6% operated interest in Chinook Walker Ridge 425/469, a 25% non-operated interest in St Malo Walker Ridge 633/634/677/678, and a 11.5% non-operated interest in Lucius.

Total daily production in the Gulf of Mexico in 2018 was 19,800 barrels of liquids and approximately 14 MMCF of natural gas. At December 31, 2018, Murphy had total proved reserves for Gulf of Mexico fields of 132.9 million barrels of oil and gas liquids and 53.9 billion cubic feet of natural gas.

Onshore

The Company holds rights to approximately 135 thousand gross acres in South Texas in the Eagle Ford Shale unconventional oil and gas play. Total 2018 production in the Eagle Ford area was 38,200 barrels of oil and liquids per day and approximately 32 MMCF per day of natural gas. On a barrel of oil equivalent basis, Eagle Ford production accounted for 66% of total U.S. production volumes in 2018. At December 31, 2018, the Company's proved reserves for the U.S. Onshore business totaled 241.2 million barrels of liquids and 255.2 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 (operated) and liquids rich Placid Montney (non-operated) lands also in the WCSB and two non-operated assets – the Hibernia and Terra Nova fields offshore Newfoundland in the Jeanne d'Arc Basin.

Onshore

The Company has approximately 94 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 2018, the Company entered into a further commitment, commencing November 2020 for an additional 200 MMCFD.

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, both in Alberta. The Company has approximately 349 thousand gross acres of Kaybob and Placid mineral rights.

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

Daily production in 2018 in the WCSB averaged 6,800 barrels of liquids and approximately 266 MMCF of natural gas, an increase of 84.7% and 17.7% versus 2017, respectively. Total WCSB proved liquids and natural gas reserves at December 31, 2018, were approximately 43.3 million barrels and 1.4 trillion cubic feet, respectively.

Offshore

Murphy has a 6.5% working interest in Hibernia Main and a 4.3% working interest in Hibernia South Extension, while at Terra Nova the Company's working interest is 10.475%. Oil production in 2018 was approximately 6,700 barrels of oil per day for the two offshore Canada fields. Total proved oil reserves at December 31, 2018 for the two fields were approximately 17.6 million barrels of liquids and 12.3 billion cubic feet of natural gas.

Malaysia

In Malaysia, the Company has majority interests in seven 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 2.6 million gross acres.

Sarawak

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 12,700 barrels of liquids per day were produced in 2018 at Blocks SK 309/311.

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 (with extension options), but allows the Company to deliver higher sales volumes as requested. The Company's net share of volumes is sold via this contract.

Total net natural gas sales volume offshore Sarawak was approximately 104 MMCF per day during 2018.

Total proved reserves at December 31, 2018 for Blocks SK 309/311 were 10.7 million barrels of liquids and approximately 117.7 billion cubic feet (BCF), respectively.

Other Sarawak

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. This interest expired in June 2018.

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 Company currently has a gas holding area for a gas field that will expire in August 2021.

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 SK 314A to complete the remaining fourth and fifth exploration commitment wells which is currently scheduled for 2019.

Block K

The Company's working interest in the Kakap field in Block K is 6.35%, following a series of unitization and redeterminations.

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 parties. 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 relation to this matter, 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, of which $17.3 million remains as a liability at the end of 2018. 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.

In 2017, following a further Unitization Framework Agreement (UFA) between the governments of Brunei and Malaysia the Company has a 6.35% interest in the Kakap field in Block K Malaysia. The UFA unitized the Gumusut/Kakap (GK) and Geronggong/Jagus East fields effective November 23, 2017. The Company has recorded an estimated redetermination expense of $26.3 million ($16.3 million after taxes) related to the Company's revised working interest, all of which remains as a liability at the end of 2018.

The Siakap oil field was developed as a unitized area with the Petai field operated 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 16,700 barrels per day during 2018.

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 2018 totaled 6 MMCF per day.

Total proved reserves booked in Block K at the end of 2018 were 40.0 million barrels of liquids and about 26.1 billion cubic feet of natural gas.

Block H

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 2018 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, 2018, total natural gas proved reserves for Block H were approximately 324.4 billion cubic feet.

Block P

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.

Brunei

The Company has a working interest of 8.05% in Block CA-1 and a 30% working interest in Block CA-2.

On November 23, 2017, both the governments of Brunei and Malaysia signed a UFA (see Malaysia section above) which resulted in Jagus East discovery in Block CA-1 forming part of a unitized field with the GK Unit in Malaysia.

Following this unitization, the Company's working interest in the Brunei section of the Kakap field was adjusted and on July 4, 2018 a participation agreement was signed which finalized the Company's working interest of 8.05%.

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 2018.

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.

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 Northern Australia. Acquisition of multiclient 3D seismic commenced over the permitted area in December 2017 and was completed in December 2018. The permit covers approximately 165 thousand acres and expires in June 2019 with an option to extend.

In March 2015, Murphy was awarded the AC/P59 license, another acreage position in the Vulcan Basin with 60% interest and operatorship. The block covers approximately 288 thousand gross acres. The acquisition of multiclient 3D seismic commenced in 2016 and was completed in 2017. The permit expires in 2022 with an option to renew.

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 with an option to renew.

In October 2013, Murphy was awarded the EPP43 license in the Ceduna Basin, offshore South Australia, with 50% interest & operatorship. The block covers approximately 4.1 million acres. Acquisition of multiclient 3D seismic commenced over the permit in 2016 and the fully processed seismic was received in 2017. The first exploration period of the permit expires in 2021 with an option to renew.

In November 2007, Murphy signed a farm in agreement to acquire 40% of AC/P36, in the Browse Basin, offshore northern Australia in the Territory of Ashmore and Cartier Islands. The block covers approximately 482 thousand gross acres. Murphy currently holds a non-operated 50% interest and is carried for the existing exploration commitments. The permit is in its first renewal period which currently expires in 2020 with a further option to renew.

Vietnam

The Company holds a 65% working interest in Blocks 144 and 145, a 60% interest in Block 11-2/11 and a 40% interest in Block 15-1/05.

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 remaining commitment of the acquisition, processing and interpretation of six hundred square kilometers (600 km2) of 3D seismic is tentatively scheduled for 2020.

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 which has been fulfilled with the first exploration well drilled in 2016 and the second and third wells drilled in 2017.

In August 2015, the Company signed a farm-in agreement to acquire 35% of Block 15-1/05 and in 2018 became the operator and increased its working interest to 40%. The exploration phase expired in December 2018 and is extended until December 2019. The exploration license calls for one exploration well commitment, which is planned to be drilled in 2019. The Lac Da Trang (LDT) 1X exploration well, the last remaining commitment of the PSC, is scheduled to commence in 2019. Effective January 11, 2019, the Declaration of Commercial Discovery of the Lac Da Vang (LDV) project was approved. First oil from LDV is currently planned by the end of 2021.

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. 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 commitment to drill one exploration well which is planned for early 2019.

Brazil

The Company now holds an interest in 6 blocks in Brazil (SEAL-M-351, SEAL-M-428, SEAL-M-430, SEAL-M-501, SEAL-M-503 and SEAL-M-573). ExxonMobil has a 50% working interest and is the operator of the blocks, Murphy has a 20% working interest and QGEP holds a 30% working interest.

In 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. Subsequent to the farm-in, Murphy and its co-venturers were the high bidder in Brazil's Round 14 lease sale, for leases which are adjacent to SEAL-M-351 and SEAL-M-428.

In 2018, the co-venturer's were the successful bidders on blocks 430 and 573.

Murphy's total acreage position in Brazil is 746,000 gross acres over the six blocks, offsetting several major Petrobras discoveries, with no well commitments.

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. In May 2017, Ecuador instituted a proceeding in the Netherlands district court located in The Hague to set aside the award. Murphy filed an opposition and settled for $26.0 million, which was received in 2018.

Proved Reserves

Total proved reserves for crude oil, natural gas liquids and natural gas as of December 31, 2018 are presented in the following table.

	Proved Reserves		
	Crude Oil	Natural Gas Liquids	Natural Gas
Proved Developed Reserves:	(MMBBL)		(BCF)
United States	189.0	24.9	198.3
Canada	23.3	1.7	595.0
Malaysia	37.0	0.7	128.3
Total proved developed reserves 1	249.3	27.3	921.6
Proved Undeveloped Reserves:			
United States	137.5	22.7	110.7
Canada	31.7	4.2	771.4
Malaysia	14.0	–	339.9
Total proved undeveloped reserves 2	183.2	26.9	1,222.0
Total proved reserves 3	432.5	54.2	2,143.6

1 Includes proved developed reserves of 19.1 MMBBL oil, 0.8 MMBBL NGLs, and 8.2 BCF natural gas for Total and United States attributable to the noncontrolling interest in MP GOM.

2 Includes proved undeveloped reserves of 6.4 MMBBL oil, 0.3 MMBBL NGLs, and 2.6 BCF natural gas for Total and United States attributable to the noncontrolling interest in MP GOM.

3 Includes total proved reserves of 25.5 MMBBL oil, 1.1 MMBBL NGLs, and 10.8 BCF natural gas for Total and United States attributable to the noncontrolling interest in MP GOM.

Murphy Oil's total proved reserves and proved undeveloped reserves increased during 2018 as presented in the table below:

	Total	Total Proved

(Millions of oil equivalent barrels) 1	Proved Reserves	Undeveloped Reserves
Beginning of year	698.3	351.7
Revisions of previous estimates	(21.7)	(43.7)
Extensions and discoveries	122.5	115.2
Improved recovery	0.9	0.9
Conversions to proved developed reserves	–	(40.9)
Purchases of properties	106.8	30.5
Production	(62.8)	–
End of year 2	844.0	413.7

1 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.

2 Includes 28.4 MMBOE and 7.1 MMBOE for total proved and proved undeveloped reserves, respectively, attributable to the noncontrolling interest in MP GOM.

During 2018, Murphy's total proved reserves increased by 145.7 million barrels of oil equivalent (mmboe). The increase in reserves principally relates to continued development in the Eagle Ford Shale area of South Texas and the Tupper Montney gas area of Western Canada that added 42.6 MMBOE and 39.0 MMBOE, respectively, as well as improved performance in Malaysia which added 12.0 MMBOE. In addition, Murphy added 97.0 MMBOE of total proved reserves as a result of the MP GOM transaction.

Proved Reserves (Contd.)

Murphy's total proved undeveloped reserves at December 31, 2018 increased 62.0 MMBOE from a year earlier. The proved undeveloped reserves reported in the table as extensions and discoveries during 2018 were predominantly attributable to three areas: the Eagle Ford Shale area of South Texas and the Western Canada areas of Tupper Montney and Kaybob Duvernay. Each 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 removing locations in lower performing areas of Western Canada and the Eagle Ford Shale. The majority of the proved undeveloped reserves migration to the proved developed category are attributable to drilling in the Eagle Ford Shale, Kaybob Duvernay, and Tupper Montney.

The Company spent approximately $824 million in 2018 to convert proved undeveloped reserves to proved developed reserves. The Company expects to spend approximately $1,300 million in 2019, $1,200 million in 2020 and $900 million in 2021 to move currently undeveloped proved reserves to the developed category. The anticipated level of spending in 2019 primarily includes drilling and development in the Eagle Ford Shale, Kaybob Duvernay, Tupper Montney, and Gulf of Mexico areas.

At December 31, 2018, proved reserves are included for several development projects, including oil developments at the Eagle Ford Shale in South Texas; Kaybob Duvernay in Western Canada; deepwater Gulf of Mexico; and the Kakap and Kikeh fields, offshore Sabah in Malaysia; and natural gas developments in Tupper Montney and offshore Sabah in Block H and Kikeh in Malaysia. Total proved undeveloped reserves associated with various development projects at December 31, 2018 were approximately 413.7 MMBOE, which represent 49% 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 two undeveloped locations that exceed this five-year window. Total reserves associated with the two locations amount to less than 1% of the Company's total proved reserves at year-end 2018. 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 from initial booking to be completely developed is deepwater Block H, offshore Malaysia. Project timing is pending timing of completion of the Floating Liquefied Natural Gas Facility (FLNG) which is ongoing and expected to be on production in 2020. The FLNG will be operated by Malaysia's national oil company, PETRONAS. The Block H development project represents approximately 6% of the Company's total proved reserves at year-end 2018.

Murphy Oil's Reserves Processes and Policies

As per the SEC, proved oil and gas reserves are "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." The SEC has defined reasonable certainty for proved reserves, as a "high degree of confidence that the quantities will be recovered." Proved reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change. Moreover, estimates of proved reserves may be revised as a result of future operations, effects of regulation by governmental agencies or geopolitical or economic risks. Therefore, the proved reserves included in this report are estimates only and should not be construed as being exact quantities, and if recovered, could be more or less than the estimated amounts.

Murphy has established both internal and external controls for estimating proved reserves that follows the guidelines set forth by the SEC for oil and gas reporting. Certain qualified technical personnel of Murphy from the various exploration and production offices are responsible for the preparation of proved reserve estimates and these technical representatives provide the necessary information and maintain the data as well as the documentation for all properties.

Murphy Oil's Reserves Processes and Policies (Contd.)

The Murphy proved reserves is then consolidated and reported through the Corporate Reserves group. Murphy's General Manager of Corporate Reserves (Reserves Manager) leads the Corporate Reserves group that also includes Corporate reserve engineers and support staff in which all are independent of the Company's oil and gas operational management and technical personnel. The Reserves Manager was new to Murphy in 2018 and has over 18 years of industry experience. He has a Bachelor of Science and a Master of Science degree in Petroleum Engineering as well as a Master of Business Administration. The Reserves Manager is also a licensed Professional Engineer in the State of Texas. The Reserves Manager reports to the Chief Financial Officer and makes annual presentations to the Board of Directors about the Company's reserves. The Reserves Manager and the Corporate reserve engineers review and discuss reserves estimates directly with the Company's technical staff in order to make every effort to ensure compliance with the rules and regulations of the SEC. The Reserves Manager coordinates and oversees the third-party audits which 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. Internal audits may also be performed by the Reserves 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 also 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 as a result of having sufficient educational background, professional training, and professional experience to enable him or her to exercise prudent professional judgment. Larger offices of the Company also employ a Regional Reserves Coordinator (RRC) who supervises the local QREs. The RRC is usually a senior QRE who has the primary responsibility for coordinating and submitting reserves information to senior management.

QRE qualification requires a minimum of five years of practical experience in petroleum engineering or petroleum production geology, with at least three years 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. 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.

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 documentation stating that, in their opinion, the reserves have been calculated, reviewed, documented, and reported in compliance with SEC regulations. When reserves calculations are completed by technical personnel with the support of the QREs and appropriately reviewed by RRCs, the Corporate reserves engineers and the Reserves Manager, the conclusions are reviewed and approved with the heads of the Company's exploration and production business units and other senior management on an annual basis. The Company's Controller's department is responsible for preparing and filing reserves schedules within the Form 10-K report.

To ensure accuracy and security of reported reserves, the proved reserves estimates are coordinated in industry-standard software with access controls for approved users. In addition, Murphy complies with audit controls concerning the various business processes related to reserves.

The estimated proved reserves reported in this Form 10-K report are prepared by Murphy's internal employees. Murphy engaged both Ryder Scott Company, L.P. (Ryder Scott) and McDaniel & Associates Consultants Ltd. (McDaniel) to perform a reserves audit of 54.3% and 9.4% of the Company's total proved reserves, respectively. In addition, Ryder Scott provided a proved reserve report for the Petrobras GOM properties which represented 11.5% of the company total proved reserves.

Murphy Oil's Reserves Processes and Policies (Contd).

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 103 through 110 of this Form 10-K report. Also, Murphy currently has no oil and gas reserves from non-traditional sources. 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, 2018 are shown on pages 30 through 31 and 33 of this Form 10-K report.

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.

Supplemental disclosures relating to oil and gas producing activities are reported on pages 101 through 116 of this Form 10-K report.

At December 31, 2018, 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	105	95	66	59	171	154
– Gulf of Mexico	101	43	450	250	551	293
Total United States	206	138	516	309	722	447
Canada – Onshore	105	83	482	348	587	431
– Offshore	101	8	43	2	144	10
Total Canada	206	91	525	350	731	441
Malaysia	257	149	2,417	1,210	2,674	1,359
Mexico	–	–	636	191	636	191
Brazil	–	–	1,120	224	1,120	224
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	669	378	21,947	10,770	22,616	11,148

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

Scheduled expirations in 2019 include 415 thousand net acres in Block AC/P58 in Australia; 125 thousand net acres in Western Canada; 9 thousand net acres in the United States; and 19 thousand net acres in the Gulf of Mexico.

Acreage currently scheduled to expire in 2020 include 93 thousand net acres in Western Canada; 37 thousand net acres in Block 351 in Brazil; 37 thousand net acres in Block 428 in Brazil; 18 thousand net acres in the United States; and 3 thousand acres in the Gulf of Mexico.

Scheduled expirations in 2021 include 39 thousand net acres in Western Canada; 1 thousand net acres in the United States; and 12 thousand acres in the Gulf of Mexico.

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, 2018.

	Oil Wells		Gas Wells	
	Gross	Net	Gross	Net
Country				
United States	979	811	8	4
Canada	43	24	415	339
Malaysia	93	48	55	33
Totals	1,115	883	478	376

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
2018										
Exploration	0.5	0.4	-	-	-	-	-	-	0.5	0.4
Development	46.6	-	28.1	-	-	-	-	-	74.7	-
2017										
Exploration	-	-	-	-	-	-	-	-	-	-
Development	68.7	-	27.2	-	-	-	-	-	95.9	-
2016										
Exploration	-	-	-	-	-	0.7	-	-	-	0.7

Development	51.5	-	7.0	-	3.0	-	-	-	61.5	-

Murphy's drilling wells in progress at December 31, 2018 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 all located in the Eagle Ford Shale area of South Texas.

	Exploration		Development		Total	
Country	Gross	Net	Gross	Net	Gross	Net
United States	-	-	25.0	20.6	25.0	20.6
Totals	-	-	25.0	20.6	25.0	20.6

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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 38 and 39.

Website Access to SEC Reports

Murphy Oil's internet Website address is http://www.murphyoilcorp.com. The 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.

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 variable factors impacting 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 were volatile in 2018. Crude oil prices in 2018 were higher than those in years 2015 to 2017, but were significantly lower than prices in 2013 and 2014. 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 $65 in 2018, compared to $51 in 2017, $43 per barrel in 2016 and $49 per barrel in 2015. The closing price for WTI at the end of 2018 was approximately $45 per barrel. Certain U.S. and Canadian crude oils and all crude oil produced in Malaysia, are generally priced from 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 the Malaysian Crude Oil Selling Price.

The average New York Mercantile Exchange (NYMEX) natural gas sales price was $3.12 in 2018, compared with $2.96 per million British Thermal Units (MMBTU) in 2017, $2.48 per MMBTU in 2016 and $2.61 per MMBTU in 2015. The closing price for NYMEX natural gas as of December 31, 2018, was $2.94 per MMBTU. In recent years, certain natural gas production offshore Sarawak have been sold 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 also has exposure to the Canadian benchmark natural gas price, AECO, which averaged $1.16 MMBTU in 2018. The Company has entered into certain forward fixed price contracts as detailed in the Outlook section on page 45.

The Company cannot predict how changes in the sales prices of oil and natural gas will affect the results of operations in future periods. In 2018, the Company hedged 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. The Company markets a portion of Canadian gas production to locations which sell at a premium to AECO and through physical forward sales.

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

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 a portion of the Company’s proved reserves uneconomic, which in turn could lead to the removal of certain of the Company’s 2018 year-end reported proved oil reserves in future periods. These reserve reductions could be significant.

· In order to manage the potential volatility of cash flows and credit requirements, we maintain appropriate bank credit facilities. An inability to access, renew or replace such credit facilities or access other sources of funding as they mature would negatively impact our liquidity.

· 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, from time to time, 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's Information Technology environment may be exposed to cyber threats

In recent years the Oil and Gas industry has become increasingly dependent on digital technologies to conduct certain exploration, development, and production activities. We depend on these technologies to estimate quantities of oil and gas reserves, process and record financial and operating data, analyze seismic and drilling information, communicate with our employees and third party partners, and conduct many of our activities.

Maintaining the security of the technology and preventing unauthorized access is critical given increasing global threats from cybercrime. The Company's approach focuses on cyber risk assessment, asset protection, eradicating security vulnerabilities, security education and security awareness. In the Oil and Gas industry, there are cyber intrusion attempts every day. As the sophistication of cyber attacks continues to evolve, we may be required to dedicate additional resources to continue to modify or enhance our protective measures, or to investigate and remediate any vulnerabilities to cyber attacks.

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. 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 since 2014, the Company reduced its exploration program and this may reduce the rate at which it is able to replace reserves. In 2018, the Company entered into a transaction among Murphy, PAI and MP Gulf of Mexico, LLC (MP GOM), whereby the Company through its interest in MP GOM acquired an 80% interest in PAI Gulf of Mexico producing Assets (Cascade, Chinook, Lucius, St. Malo, Cottonwood, South Marsh Island, Northwestern, and South Hadrian fields) and its interests in exploration blocks in the U.S. Gulf of Mexico to MP GOM.

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 101 through 110 have been prepared according to the Securities and Exchange (SEC) guidelines 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.

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, 2018, and including noncontrolling interests, approximately 42% 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 114 and 115 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 in recent years, the Company has reduced its exploration program from pre-2015 levels. In 2018, two exploration wells were drilled in the US Gulf of Mexico with a 50% commercial success rate. The Company's 2019 planned exploratory drilling program includes four wells, two of which are in the US Gulf of Mexico, one well in Vietnam, and one well offshore 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 operations are subject to numerous environmental and occupational health and safety laws and regulations at the international, federal, provincial, state, tribal, and local levels. These laws and associated requirements can impose operational controls and/or siting constraints on our business. These laws and regulations can result in capital and operating expenditures.

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 occurs thousands of feet below the surface and creates fractures in the rock formation within the reservoir which enhances migration of oil and natural gas to the wellbore. The Company primarily uses this technique in the Eagle Ford Shale in South Texas and in Western Canada. 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 various aspects of 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. Once new laws and/or regulations have been enacted and adopted, the costs of compliance are appraised.

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 used 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 instituted 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 groundwater contamination, including from petroleum constituents or hydraulic fracturing chemical additives. Ineffective containment of surface spillage and surface or groundwater 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 wastewater 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 wastewater, or any further restrictions placed on wastewater, 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, in 2017 subsequently withdrew 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. 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. In November 2018, the Company entered into a $1.6 billion revolving credit facility (the “New Revolving Credit Facility”). The New Revolving Credit Facility is a senior unsecured guaranteed facility and will expire in November 2023. This replaces the previous $1.1 billion facility.

The Company’s ability to obtain additional financing is also affected by the Company’s debt credit ratings and competition for available debt financing. A ratings downgrade could materially and adversely impact the Company’s ability to access debt markets, increase the borrowing cost under the Company’s credit facility and the cost of future debt, and potentially require the Company to post additional letters of credit or other forms of collateral for certain obligations.

See Note H for information regarding the Company's outstanding debt and other commitments as of December 31, 2018 and the terms associated therewith.

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, generally reduce worldwide demand for these energy commodities, which can lead to reduced prices for oil and natural gas. An abundant recoverable supply of crude oil in recent years also led to a decline in worldwide oil prices from pre-2015 levels. Lower prices for crude oil, NGL and natural gas inevitably lead to lower earnings for the Company. The volatile, and at times low, crude oil price environment in recent years 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 and 2018 (compared to 2015 to 2016) 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 2018, approximately 16% of the Company's total production was at fields operated by others, while at December 31, 2018, approximately 14% 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.

In 2018, Murphy Oil's net income included a favorable income tax adjustment of $135.7 million related to the 2017 Tax Act enacted on December 22, 2017. The $135.7 million adjustment, primarily related to the reinstatement of a deferred tax asset for 2017 net operating losses, which in 2017, was assumed utilized against the deemed repatriation.

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.

As of December 31, 2018, approximately 15% 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 factors 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. Some of the Company's offshore fields are in the U.S. Gulf of Mexico, where hurricanes and tropical storms can lead 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.

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 ($875 million for Gulf of Mexico claims), all or part of which could apply 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 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. 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, 2018.

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 101 to 115 and in Note G – 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, 2019 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 57; President and Chief Executive Officer since August 2013. Mr. Jenkins served as Chief Operating Officer from June 2012 to August 2013.

David R. Looney – Age 62; Chief Financial Officer and Executive Vice President since March 2018. Mr. Looney joined the Company following a broad range of leadership roles at both offshore deepwater Gulf of Mexico and U.S. onshore unconventional exploration and production companies.

Eugene T. Coleman – Age 60; Executive Vice President, Exploration and Business Development since September 2018. Mr. Coleman has also served as Executive Vice President, Offshore of the Company's exploration and production subsidiary from 2011 to 2017. As previously announced, Mr. Coleman has elected to retire from the Company effective February 28, 2019.

Michael K. McFadyen – Age 51; Executive Vice President, Offshore since September 2018. Mr. McFadyen has also served as Executive Vice President, Onshore of the Company's exploration and production subsidiary from 2011 to 2017.

Eric M. Hambly – Age 44; Executive Vice President, Onshore since September 2018. Mr. Hambly served as Senior Vice President, U.S. Onshore from 2016 to September 2018.

Walter K. Compton – Age 56; Executive Vice President and General Counsel since February 2014. Mr. Compton was Senior Vice President and General Counsel from March 2011 to February 2014.

Kelly L. Whitley – Age 53; Vice President, Investor Relations and Communications since July 2015.

Thomas J. Mireles – Age 46; Senior Vice President, Technical Services (Health, Safety, Environment, Information Technology and Procurement) since September 2018. Mr. Mireles also served as the Senior Vice President, Eastern Hemisphere from 2016 to September 2018.

Maria A. Martinez – Age 44; Vice President, Human Resources & Administration since September 2018. Ms. Martinez was the Vice President, Human Resources from 2013 to September 2018.

E. Ted Botner – Age 54; Vice President, Law and Secretary since March 2015. Mr. Botner was Secretary and Manager, Law from August 2013 to March 2015.

John B. Gardner – Age 50; Vice President and Treasurer since March 2015. Mr. Gardner served as Treasurer from August 2013 to March 2015.

Kelli M. Hammock – Age 47; Senior Vice President, Special Projects since September 2018. Ms. Hammock served as Senior Vice President, Administration from February 2014 to September 2018.

Christopher D. Hulse – Age 40, Vice President and Controller since June 2017. Mr. Hulse was Vice President, Finance, Onshore from September 2015 to June 2017.

Barry F.R. Jeffery – Age 60; 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.

Louis W. Utsch – Age 53; Vice President, Tax since January 2018. Mr. Utsch joined the Company following over 20 years of corporate tax experience at Big Four accounting firms as well as more than a decade of work experience in the oil and natural gas industry.

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 2,324 stockholders of record as of December 31, 2018. Information on dividends per share by quarter for 2018 and 2017 are reported on page 116 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, 2013 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 included 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.

		2013	2014	2015	2016	2017	2018
Murphy Oil Corporation	$	100	80	37	54	55	43
S&P 500 Index		100	114	115	129	157	150
Peer Group		100	87	54	77	68	49

Item 6. SELECTED FINANCIAL DATA

(Thousands of dollars except per share data)							
Results of Operations for the Year		2018	2017	2016	2015	2014	
Revenue from sales to customers	$	2,586,627	2,078,548	1,862,891	2,787,116	5,288,933	
Net cash provided by continuing operations		1,219,396	1,128,075	600,795	1,183,369	3,048,639	
Income (loss) from continuing operations		423,008	(310,936)	(273,943)	(2,255,772)	1,024,973	
Net income (loss) attributable to Murphy		411,094	(311,789)	(275,970)	(2,270,833)	905,611	
Cash dividends – diluted		173,044	172,565	206,635	244,998	236,371	
Per Common share – diluted							
Income (loss) from continuing operations	$	2.37	(1.81)	(1.59)	(12.94)	5.69	
Net income (loss) attributable to Murphy		2.36	(1.81)	(1.60)	(13.03)	5.03	
Average common shares outstanding (thousands) – diluted		174,209	172,974	172,173	174,351	180,071	
Cash dividends per Common share		1.00	1.00	1.20	1.40	1.33	
Capital Expenditures for the Year 1							
Continuing operations							
Exploration and production	$	1,959,400	960,870	789,721	2,127,197	3,742,541	2
Corporate and other		27,900	14,821	21,740	59,886	14,453	
		1,987,300	975,691	811,461	2,187,083	3,756,994	
Discontinued operations		–	–	–	159	12,349	
	$	1,987,300	975,691	811,461	2,187,242	3,769,343	
Financial Condition at December 31							
Current ratio		1.04	1.64	1.04	0.83	1.02	
Working capital (deficit)	$	33,756	537,396	56,751	(277,396)	76,155	
Net property, plant and equipment		9,757,564	8,220,031	8,316,188	9,818,365	13,331,047	
Total assets		11,052,587	9,860,942	10,295,860	11,493,812	16,742,307	
Long-term debt 2		3,227,134	2,906,520	2,422,750	3,040,594	2,536,238	
Murphy shareholders' equity		4,829,299	4,620,191	4,916,679	5,306,728	8,573,434	
Per share		27.91	26.77	28.55	30.85	48.30	
Long-term debt – percent of capital employed 3		40.1	38.6	33.0	36.4	22.8	
Stockholder and Employee Data at December 31							
Common shares outstanding (thousands)		173,059	172,573	172,202	172,035	177,500	
Number of stockholders of record		2,324	2,506	2,588	2,713	2,556	

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. 2018 includes $794.6 million capital expenditures in relation to the MP GOM transaction.

2 Long-term debt includes noncurrent capital lease obligations.

3 Long-term debt – percent of capital employed is calculated as total long-term debt at the balance sheet date divided by the sum of total long-term debt plus total Murphy shareholders’ 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 2018 were as follows:

- Income from continuing operations before income taxes of $432.3 million (2017: $71.8 million)
- Entered into an oil-weighted Gulf of Mexico transaction with Petrobras (see Business Review for further details)
- Produced 172,175 barrels of oil equivalent (BOE) per day (170,945 excluding noncontrolling interest, NCI)
- Achieved an overall lease operating expense per BOE of $8.86 (2017: $7.89)
- Excluding acquisitions, replaced 166% of total proved reserves (2017: 123%)
- Preserved balance sheet strength with approximately 35% net debt to total capital 1 (37% excluding NCI)

Throughout this section, the term, 'excluding noncontrolling interest' or 'excluding NCI' refers to amounts attributable to Murphy.

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 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 2018 liquids represented 59% of total hydrocarbons produced on an energy equivalent basis. In 2019, the Company's ratio of hydrocarbon production represented by liquids is expected to be 67%. When oil-price linked natural gas in Malaysia is combined with oil production, the Company's 2019 total expected production is approximately 75% linked to the price of oil. If the prices for crude oil and natural gas are lower in 2019 or beyond, this will have an unfavorable impact on the Company's operating profits. The Company, from time to time, may choose to use a variety of commodity hedge instruments to reduce commodity price risk, including forward sale fixed financial swaps and long-term fixed-price physical commodity sales.

Oil prices strengthened in 2018 compared to the 2017 period. The sales price of a barrel of West Texas Intermediate (WTI) crude oil averaged $64.77 in 2018, $50.95 in 2017, and $43.32 in 2016. The sales price of a barrel of Platts Dated Brent crude oil increased to $71.04 in 2018, following averages of $54.28 per barrel in 2017 and $43.69 per barrel in 2016. The WTI index increased approximately 27% over the prior year while Dated Brent experienced a 31% increase in 2018.

During 2018 the discount for WTI crude compared to Dated Brent increased compared to the prior year. The average WTI to Dated Brent discount was $6.27 per barrel during 2018, $3.33 per barrel during 2017 and $0.37 per barrel in 2016. In early 2019, Dated Brent has been trading at a similar premium to WTI as 2018 average levels. Crude oil prices in early 2019 were below the 2018 average prices.

The NYMEX natural gas price per million British Thermal Units (MMBTU) averaged $3.12 in 2018, $2.96 in 2017 and $2.48 in 2016. The 2018 NYMEX natural gas price was approximately in line with 2017. 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. On an energy equivalent basis, the market continued to discount North American natural gas and NGL compared to crude oil in 2018. Natural gas prices in North America in 2019 have thus far been below the average 2018 levels.

1 Total capital is calculated as equity plus long-term debt less cash.

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.

		Years Ended December 31,		
(Millions of dollars, except EPS)		2018	2017	2016
Income (loss) from continuing operations before income taxes	$	432.3	71.8	(493.1)
Net income (loss) attributable to Murphy	$	411.1	(311.8)	(276.0)
Diluted EPS		2.36	(1.81)	(1.60)
Income (loss) from continuing operations attributable to Murphy	$	414.6	(310.9)	(274.0)
Diluted EPS		2.37	(1.81)	(1.59)
Loss from discontinued operations	$	(3.5)	(0.9)	(2.0)
Diluted EPS		(0.01)	-	(0.01)

Results of continuing operations before taxes in 2018 were improved versus 2017. In 2018, income from continuing operations attributable to Murphy of $414.6 million ($2.37 per diluted share) increased from a loss of $310.9 million ($1.81 per diluted share) in 2017. Murphy Oil's net income in 2018 included a favorable income tax adjustment of $135.7 million related to the 2017 Tax Act enacted on December 22, 2017. The $135.7 million adjustment, primarily related to the reinstatement of a deferred tax asset for 2017 net operating losses, which in 2017, was assumed utilized against the deemed repatriation.

The results for 2018 were also favorably impacted by higher revenues (due to higher realized oil and natural gas sales prices and volumes), higher other operating income (vs 2017 other operating expense), lower foreign exchange losses, and lower exploration expenses; partially offset by losses on crude contracts, lower gain on sale of assets, higher lease operating expenses and higher depreciation.

In 2018 the Company's discontinued operations incurred a loss of $3.5 million.

Murphy Oil's net loss in 2017 vs 2016 was 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.

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.

Results in 2016 included a $71.7 million after-tax gain on sale of the Company’s five percent interest in Syncrude. In 2016, the Company’s refining and marketing operations generated a loss of $2.5 million, which led to overall losses from discontinued operations in each year.

Segment Results – In the following table, the Company's results of operations for the three years ended December 31, 2018, are presented by segment. More detailed reviews of operating results for the Company's exploration and production and other activities follow the table.

A summary of Net Income is presented in the following table.

(Millions of dollars)	2018	2017	2016
Exploration and production – continuing operations			
United States	$ 242.9	(8.9)	(164.2)
Canada	51.1	112.5	(35.9)
Malaysia	269.5	224.2	171.1
Other	(16.6)	(37.5)	(54.7)
Total exploration and production – continuing operations	546.9	290.3	(83.7)
Corporate and other	(123.9)	(601.2)	(190.3)
Income (loss) from continuing operations	423.0	(310.9)	(274.0)
Loss from discontinued operations	(3.5)	(0.9)	(2.0)
Net income (loss) including noncontrolling interest	419.5	(311.8)	(276.0)
Net income attributable to noncontrolling interest	8.4	-	-
Net income (loss) attributable to Murphy	$ 411.1	(311.8)	(276.0)

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

(Millions of dollars)	2018	2017	2016
United States – Oil and gas liquids	$ 1,245.3	903.7	714.1
– Natural gas	42.9	37.9	35.1
Canada – Conventional oil and gas liquids	291.2	203.7	171.7
– Synthetic oil	–	–	60.7
– Natural gas	147.6	155.1	130.0
Malaysia – Oil and gas liquids	708.8	639.9	623.7
– Natural gas	144.7	138.2	127.6

Other	6.1	–	–
Total oil and gas revenues	$ 2,586.6	2,078.5	1,862.9

Exploration and Production

Please refer to Schedule 5 – Results of Operations for Oil and Gas Producing Activities in the Supplemental Oil and Gas Information section for supporting tables.

2018 vs 2017

Exploration and production (E&P) continuing operations recorded a profit of $546.9 million in 2018 compared to a profit of $290.3 million in 2017 and a loss of $83.7 million in 2016. The results for 2018 were favorably impacted by higher revenues due to higher realized oil and natural gas sales prices and volumes, lower gain on sale of assets, lower other exploration expenses, and lower other operating expenses, partially offset by higher lease operating expenses, higher depreciation expense, non-recurring impairment expense in 2018 and higher taxes.

Crude oil price realizations averaged $64.30 per barrel in the current year compared to $51.34 per barrel in 2017, a price increase of 25% year over year. U.S. natural gas realized price per thousand cubic feet (MCF) averaged $2.54 in the current year compared to $2.33 per MCF in 2017, a price increase of 9% year over year. Canada natural gas realized price per MCF averaged US$1.52 in the current year compared to US$1.88 per MCF in 2016, a price decrease of 20% year over year. Oil and gas production costs, including associated production taxes, on a per-unit basis, were $9.69 in 2018 (2017: $8.63), which together with higher oil and natural gas volumes sold, resulted in $96.2 million higher costs in 2018.

Exploration and Production (Contd.)

2018 vs 2017(Contd.)

United States E&P operations reported earnings of $242.9 million in 2018 compared to a net loss of $8.9 million in 2017. Results were $251.8 million favorable in the 2018 period compared to the 2017 period due to higher revenues ($345.3 million), lower depreciation ($26.6 million), and lower G&A ($12.8 million), partially offset by higher lease operating expenses ($32.0 million), higher dry hole costs ($17.9 million, primarily related to the write-off of the King Cake well in the Gulf of Mexico), an impairment charge related to select Midland properties ($20.0 million), and higher income taxes ($68.9 million). Higher revenues were primarily due to higher realized prices and contribution from new volumes from the MP GOM transaction, while lower depreciation expense was due primarily to lower rates and lower volumes sold at Eagle Ford Shale. Higher lease operating expenses were principally a result of higher costs at Front Runner (due to 2017 Clipper well acquisition) and Kodiak work-over costs in the U.S. Gulf of Mexico business. Higher exploration expenditures are principally a result of data acquisition costs in the U.S Gulf of Mexico business.

Canadian E&P operations reported earnings of $51.1 million in 2018 compared to earnings of $112.5 million in the 2017 period. Results were unfavorable $61.4 million due to 2017 including a pretax gain of $132.4 million (after tax: $96.0 million) related to the sale of Seal heavy oil assets in Canada in January 2017. Adjusting for the impact of gain on sale of assets, Canadian results of operations improved $34.6 million in the 2018 period compared to the 2017 period due to higher revenue ($85.5 million), and insurance proceeds ($21.3 million), partially offset by higher lease operating expense ($21.7 million), higher depreciation ($47.1 million) and higher taxes ($6.5 million). Higher revenues were a result of both higher volumes at the Tupper, Kaybob and Placid assets and higher realized crude prices. Insurance proceeds related to cash received in relation to the spill at the now divested Seal asset. Higher taxes (excluding the Seal gain in 2017) are the result of higher net earnings. Higher lease operating expenses and depreciation are a result of higher volumes sold.

Malaysia E&P operations reported earnings of $269.5 million in 2018, compared to earnings of $224.2 million in 2017. Results were favorable by $45.3 million due to higher revenues ($73.1 million), lower depreciation ($6.0 million), and lower redetermination/unitization expense ($3.7 million), partially offset by higher lease operating expenses ($33.3 million), and higher taxes ($16.9 million). Higher revenues are principally due to higher realized prices, partially offset by lower volumes sold. Lower depreciation is due to lower volumes sold. Lower other expenses are due to the cost of a rig exit recorded in 2017. Higher lease operating expenses are due to higher platform, onshore facility and sub-sea maintenance costs. The higher taxes are due to higher pre-tax profits. The redetermination/unitization charges (in both years) relates to the executed unitization agreement for the Gumusut-Kakap (GK) and Geronggong/Jagus East fields originally signed in Q4 2017. Also, in the third quarter of 2018, the Brunei working interest income was recorded as a result of signing the Brunei participation agreement (see below).

Other international E&P operations reported a loss from continuing operations of $16.6 million in 2018 compared to a loss of $37.5 million in the 2017 period. The loss was $20.9 million lower in the 2018 period versus 2017 primarily due to the recording of past profits ($21.6 million) relating to the working interest in Block CA1 in Brunei, and lower exploration costs ($16.2 million), partially offset by lower tax benefits on investments in foreign areas ($18.2 million). The Brunei income follows the signing of the Brunei participation agreement on July 4, 2018, which enables the Company the right to claim its proportional share of revenue since inception as well as the obligation to settle the related past operating and capital expenditure costs since inception. In addition, ongoing current Brunei revenue is now being reported.

2017 vs 2016

Exploration and production (E&P) continuing operations recorded a profit of $290.3 million in 2017 compared to a loss of $83.7 million in 2016. The results for 2017 were favorably impacted by higher revenues due to higher realized oil and natural gas liquid sales prices, lower lease operating expenses, lower depreciation expense, lower redetermination expenses, lower dry hole costs, and higher taxes, partially offset by no repeat of the impairment expense in 2016.

Crude oil price realizations averaged $51.21 per barrel in 2017 compared to $42.38 per barrel in 2016, a price increase of 21% year over year. WTI crude oil averaged 18% more in 2017 compared to 2016. In 2017, U.S. natural gas realized price per thousand cubic feet (MCF) averaged $2.49 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 2017 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.

Exploration and Production (Contd.)

2017 vs 2016 (Contd.)

United States E&P operations reported a net loss of $8.9 million in 2017 compared to a net loss of $164.2 million in 2016. Results were $155.3 million favorable in the 2017 period compared to the 2016 period due to higher revenues ($195.2 million) and lower depreciation ($54.4 million), and lower lease operating expenses ($20.1 million), partially offset by exploration costs ($23.5 million) and higher taxes ($64.9 million). Higher revenues were primarily due to higher realized prices, while lower depreciation expense was due primarily to lower rates and lower volumes sold at Eagle Ford Shale. Lower lease operating expenses were principally a result of continued management effort to reduce costs in the Company's U.S. Onshore business. Higher exploration costs were due to higher lease amortization and higher taxes resulted from higher profits.

Canadian E&P operations reported earnings of $112.5 million in 2017 compared to losses of $35.9 million in the 2016 period. Results were favorable $148.4 million due to 2017 including a pretax gain of $132.4 million (after tax: $96.0 million) related to the sale of Seal heavy oil assets in Canada in January 2017. Adjusting for the impact of gain on sale of assets, Canadian results of operations improved $54.2 million in the 2017 period compared to the 2016 period due to lower lease operating expense ($71.3 million), lower depreciation expense ($17.8 million), and no repeat of the 2016 impairment charge on the Company's Terra Nova field and Seal heavy oil field in Western Canada ($95.1 million), partially offset by lower revenues ($12.2 million) and higher taxes ($142.3 million). Lower lease operating expenses and lower depreciation expense were principally the result of the disposal of the Syncrude asset in mid-2016.

Malaysia E&P operations reported earnings of $224.2 million in 2017, compared to earnings of $171.1 million in 2016. Results were favorable by $53.1 million due to higher revenues ($27.7 million), lower depreciation ($23.1 million), and lower redetermination/unitization expense ($24.1 million), partially offset by higher taxes ($40.5 million). Higher revenues are principally due to higher realized prices, partially offset by lower volumes sold. Lower depreciation was a result of lower volumes produced at Block K (as a result of natural field decline).

Other international E&P operations reported a loss from continuing operations of $37.5 million in 2017 compared to a loss of $54.7 million in the 2016 period. The loss was $17.2 million lower in the 2017 period versus 2016 primarily due to 2017 tax benefits on investments in foreign areas ($32.9 million).

The following table contains hydrocarbons produced for the three years ended December 31, 2018.

Barrels per day unless otherwise noted		2018	2017	2016
Net crude oil and condensate				
United States	Onshore	31,787	34,649	35,858
	Gulf of Mexico 1	18,702	11,551	12,372
Canada	Onshore	5,690	3,004	1,046
	Offshore	6,701	8,091	8,737
	Heavy 2	–	150	2,766
	Synthetic 2	–	–	4,637
Malaysia	Sarawak	11,942	12,674	13,365
	Block K	16,734	20,312	24,619
Brunei		558	–	–
Total net crude oil and condensate		92,114	90,431	103,400
Net natural gas liquids				
United States	Onshore	6,578	6,867	6,929
	Gulf of Mexico 1	1,147	947	1,302
Canada	Onshore	1,073	508	210
Malaysia	Sarawak	792	829	786
Total net natural gas liquids		9,590	9,151	9,227
Net natural gas sold – thousands of cubic feet per day				
United States	Onshore	31,832	32,629	35,789
	Gulf of Mexico 1	14,356	11,901	17,242
Canada	Onshore	266,416	226,218	208,682
Malaysia	Sarawak	104,457	104,616	106,380
	Block K	5,766	8,358	10,070
Total net natural gas - thousands of cubic feet per day		422,827	383,722	378,163
Total net hydrocarbons including noncontrolling interest 3		172,175	163,536	175,654
Less noncontrolling interest				
Net crude oil and condensate – barrels per day		1,134	–	–
Net natural gas liquids – barrels per day		24	–	–

Net natural gas – thousands of cubic feet per day	430	–	–
Net BOE produced attributable to noncontrolling interest 3	1,230	–	–
Total net hydrocarbons excluding noncontrolling interest 3	170,945	163,536	175,654
Estimated net hydrocarbon reserves - million equivalent barrels 3,4	844.0	698.3	684.5

1 2018 includes net volumes attributable to a noncontrolling interest in MP GOM.

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. Production in this table includes production for these sold interests through the date of disposition.

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

4 At December 31, 2018, includes 28.4 MMBOE relating to noncontrolling interest.

The following table contains hydrocarbons sold for the three years ended December 31, 2018.

Barrels per day unless otherwise noted		2018	2017	2016
Net crude oil and condensate				
United States	Onshore	31,787	34,649	35,858
	Gulf of Mexico 1	17,729	11,551	12,372
Canada	Onshore	5,690	3,004	1,046
	Offshore	6,884	7,525	8,886
	Heavy 2	–	150	2,766
	Synthetic 2	–	–	4,637
Malaysia	Sarawak	12,401	12,454	12,464
	Block K	17,025	19,867	24,376
Brunei		233	–	–
Total net crude oil and condensate		91,749	89,200	102,405
Net natural gas liquids				
United States	Onshore	6,578	6,867	6,929
	Gulf of Mexico 1	1,147	947	1,302
Canada	Onshore	1,073	508	210
Malaysia	Sarawak	786	1,048	720
Total net natural gas liquids		9,584	9,370	9,161
Net natural gas sold – thousands of cubic feet per day				
United States	Onshore	31,832	32,629	35,789
	Gulf of Mexico 1	14,356	11,901	17,242
Canada	Onshore	266,416	226,218	208,682
Malaysia	Sarawak	104,457	104,616	106,380
	Block K	5,766	8,358	10,070
Total net natural gas - thousands of cubic feet per day		422,827	383,722	378,163
Total net hydrocarbons including noncontrolling interest 3		171,804	162,524	174,593
Less noncontrolling interest				
Net crude oil and condensate – barrels per day		940	–	–
Net natural gas liquids – barrels per day		24	–	–
Net natural gas – thousands of cubic feet per day		430	–	–
Net BOE sold attributable to noncontrolling interest 3		1,036	–	–
Total net hydrocarbons excluding noncontrolling interest 3		170,768	162,524	174,593

1 2018 includes net volumes attributable to a noncontrolling interest in MP GOM.

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. Production in this table includes production for these sold interests through the date of disposition.

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

The Company's reported total crude oil and condensate production averaged 92,114 barrels per day in 2018, compared to 90,431 barrels per day in 2017 and 103,400 barrels per day in 2016. The 2018 crude oil production level was 2% higher than 2017. Crude oil production in the United States totaled 50,489 barrels per day (which includes 1,134 barrels per day relating to noncontrolling interest) in 2018, up from 46,200 barrels per day in 2017. The increase in U.S. crude oil production year over year was primarily due to new drilling and the acquisition of properties relating to the MP GOM transaction. Crude oil volumes produced offshore Eastern Canada totaled 6,701 barrels per day in 2018, down from 8,091 barrels per day in the previous year. Crude oil production offshore Sarawak decreased from 12,674 barrels per day in 2017 to 11,942 barrels per day in 2018. Block K in Malaysia had crude oil production of 16,734 barrels per day in 2018, down from 20,312 barrels per day in 2017. Lower oil production in 2018 in Malaysia was primarily attributable to natural well decline at most fields.

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 produced natural gas liquids (NGL) of 9,590 barrels per day in 2018, largely in line with 9,151 barrels per day produced in 2017. Eighty-one percent of the Company's NGL production in 2018 was derived from the Gulf of Mexico and Eagle Ford Shale areas in the U.S.

The Company's NGL production of 9,151 barrels per day in 2017 was 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 the Gulf of Mexico and Eagle Ford Shale areas in the U.S.

Worldwide sales of natural gas averaged 422.8 million cubic feet (MMCF) per day in 2018 compared to 383.7 MMCF per day in 2017. The 2018 increase in natural gas sales volumes is attributable to an 18% increase in natural gas production in Canada, primarily in Tupper and Placid areas as well as increase in gas production in the Gulf of Mexico in U.S.

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 Eagle Ford Shale areas in United States.

The following table contains the weighted average sales prices including transportation cost deduction for the three years ended December 31, 2018.

			2018	2017	2016
Weighted average Exploration and Production sales prices 1					
Crude oil and condensate – dollars per barrel					
United States	Onshore	$	67.08	50.49	42.11
	Gulf of Mexico		62.36	49.24	41.63
Canada 2	Onshore		50.87	46.68	42.01
	Offshore		68.02	53.39	43.12
Malaysia 3	Sarawak		62.38	53.26	46.02
	Block K		65.44	52.72	45.27
Brunei			71.48	–	–
Natural gas liquids – dollars per barrel					
United States	Onshore		22.21	17.70	11.51
	Gulf of Mexico		24.54	19.57	12.84
Canada 2	Onshore		37.44	25.00	20.63
Malaysia 3	Sarawak		69.04	51.00	38.30
Natural gas – dollars per thousand cubic feet					
United States	Onshore		2.44	2.49	1.88
	Gulf of Mexico		2.77	2.49	1.92
Canada 2	Onshore		1.52	1.97	1.72
Malaysia 3	Sarawak		3.78	3.55	3.21
	Block K		0.24	0.24	0.25

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.

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

(Dollars per equivalent barrel)	2018	2017	2016
United States – Eagle Ford Shale			
Lease operating expense	$ 8.84	7.35	9.10
Severance and ad valorem taxes	3.20	2.46	2.07
Depreciation, depletion and amortization (DD&A) expense	24.54	25.64	25.83
United States – Gulf of Mexico			
Lease operating expense	11.39	13.71	9.28
Severance and ad valorem taxes	–	–	0.02
DD&A expense	16.50	20.20	23.06
Canada – Onshore			
Lease operating expense	4.52	4.95	5.26
Severance and ad valorem taxes	0.06	0.10	0.30
DD&A expense	10.61	9.92	10.61
Canada – Offshore			
Lease operating expense	15.21	9.61	8.58
DD&A expense	13.68	12.95	11.08
Malaysia – Sarawak			
Lease operating expense	8.12	5.24	5.41
DD&A expense	8.65	8.09	8.68
Malaysia – Block K			
Lease operating expense	16.97	14.13	11.23
DD&A expense	15.52	14.60	13.60
Total oil and gas operations			
Lease operating expense	8.86	7.89	8.75
Severance and ad valorem taxes	0.83	0.74	0.69
DD&A expense	15.50	15.85	16.24
Total oil and gas operations – excluding noncontrolling interest			
Lease operating expense	8.88	7.89	8.75
Severance and ad valorem taxes	0.83	0.74	0.69
DD&A expense	15.23	15.85	16.24

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Results of Operations (Contd.)

Corporate

2018 vs 2017

Corporate activities, which include interest income and expense, foreign exchange effects, realized and unrealized gains/losses on crude oil contracts and corporate overhead not allocated to operating functions, reported a net loss of $123.9 million in 2018 compared to a loss of $601.2 million in 2017. The $477.3 million favorable variance in 2018 was primarily due to a credit to income tax expense of $135.7 million primarily related to an IRS interpretation of the 2017 Tax Act (versus a charge in 2017 of $274.0 million), lower foreign exchange losses ($66.4 million), and income related to an Ecuador arbitration settlement ($26.0 million), partially offset by losses on crude contracts used to hedge price risk ($42.0 million) versus a loss in the prior period ($9.5 million), lower other tax credits ($18.2 million), and higher G&A expense ($6.9 million). Further, the 2017 period included a deferred tax charge of $65.2 million associated with the estimated tax consequence of future repatriation of Malaysian and Canadian earnings that were deemed no longer indefinitely invested.

2017 vs 2016

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.

Financial Condition

Cash Provided by Operating Activities

Net cash provided by continuing operating activities was $1,219.4 million in 2018 compared to $1,128.1 million in 2017. The $91.3 million improvement in cash provided by continuing operations activities in 2018 was primarily attributable to higher revenues from higher prices and higher volumes ($508.1 million), offset by higher cash taxes paid as a result of repatriating cash from Canada, current tax payments in Malaysia ($62.9 million), payments made on hedge (crude contracts to mitigate price risk) losses ($75.9 million). Changes in operating working capital from continuing operations decreased cash by $169.8 million during 2018, compared to increasing cash by $136.4 million in 2017.

Cash flow provided by continuing operations was $527.3 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.

The total reductions of operating cash flows for interest paid during the three years ended December 31, 2018, 2017, and 2016 were $167.8 million, $147.9 million and $127.8 million, respectively.

Cash Used in Investing Activities

Cash used for property additions and dry holes, which includes amounts expensed, were $1,102.8 million and $1,009.7 million in 2018 and 2017, respectively. The increase is due to higher development drilling activities in Eagle Ford Shale and Kaybob Duvernay. Cash used for acquisition of oil properties was $794.6 million, attributable to the MP GOM acquisition.

The accrual basis of capital expenditures were as follows:

	Year Ended December 31,		
(Millions of dollars)	2018	2017	2016
Capital Expenditures			
Exploration and production	$ 1,959.4	960.9	789.8
Corporate	27.9	14.8	21.7
Total capital expenditures	$ 1,987.3	975.7	811.5

A reconciliation of property additions and dry hole costs in the Consolidated Statements of Cash Flows to total capital expenditures for continuing operations follows.

	Year Ended December 31,		
(Millions of dollars)	2018	2017	2016
Property additions and dry hole costs per cash flow statements	$ 1,102.8	1,009.7	926.9
Acquisition of oil properties	794.6	-	-
Geophysical and other exploration expenses	43.2	65.2	43.4
Capital expenditure accrual changes and other	46.7	(99.2)	(158.8)
Total capital expenditures	$ 1,987.3	975.7	811.5

Proceeds from sales of property and equipment generated cash of $1.4 million in 2018 compared to $69.5 million in 2017 primarily relating to the proceeds from the sale of the Seal field in Western Canada and the sale of certain non-core assets of Eagle Ford Shale in South Texas in 2017. Proceeds from sales of assets generated $1.16 billion in 2016 as a result of the sale of Syncrude and natural gas processing and sales pipeline assets that support natural gas fields in the Tupper area in Canada.

Cash Provided by and Use by Financing Activities

During 2018, the Company borrowed $325.0 million on its revolving credit facility to partially fund the MP GOM transaction.

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 in cash during 2016 to repay long-term debt under its revolving credit facility.

Total cash dividends to shareholders amounted to $173.0 million in 2018, $172.6 million in 2017, and $206.6 million in 2016.

Financial Condition (Contd.)

At the end of 2018, working capital (total current assets less total current liabilities) amounted to $33.8 million (2017: $537.4 million). The total working capital decrease in 2018 is primarily attributable to lower cash (due to the MP GOM transaction, $469.6 million cash impact) and inventory balances offset by higher accounts receivable and prepaid expenses.

Cash and cash equivalents at the end of 2018 totaled $387.4 million (2017: $965.0 million). The decrease in 2018 is primarily related to the use of cash on hand to fund the MP GOM acquisition. Cash and cash equivalents at the end of 2017 totaled $965.0 million (2016: $872.8 million). The increase in 2017 was 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.

Cash and invested cash are maintained in several operating locations outside the United States. At December 31, 2018, Cash and cash equivalents held outside the U.S. included U.S dollar equivalents of approximately $175.1 million (2017: $549.3 million) in Canada and $27.4 million (2017: $334.6 million) in Malaysia. In addition, approximately $17.2 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 2018. 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 earnings repatriated to the U.S. See Note J 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.

At December 31, 2018, long-term debt of $3,227.1 million was $320.6 million higher than year-end 2017, principally as a result of borrowing on the revolving credit facility to partially fund the MP GOM acquisition ($325.0 million). Long-term debt at year-end 2017 was $483.8 million higher than year-end 2016, principally as a result of the issuance of $550 million notes in August 2017 that bear a rate of 5.75% and mature in August 2025. A summary of capital employed at December 31, 2018 and 2017 follows.

	December 31, 2018			December 31, 2017		
(Millions of dollars)	Amount	%		Amount	%	
Capital employed						
Long-term debt	$ 3,227.1	38.3	%	$ 2,906.5	38.6	%
Total equity	5,197.6	61.7	%	4,620.2	61.4	%
Total capital employed	8,424.7	100.0	%	$ 7,526.7	100.0	%
Total capital employed excluding noncontrolling interest	$ 8,056.4	n/a		7,526.7	n/a	

Stockholders' equity was $5.20 billion at the end of 2018 (2017: $4.62 billion; 2016: $4.92 billion). Stockholders' equity increased in 2018 primarily due to net income earned and the addition of noncontrolling interest as part of the MP GOM transaction. Stockholders' equity declined in 2017 primarily due to the net loss incurred and cash dividends paid on common stock. A summary of transactions in stockholders' equity accounts is presented in the Consolidated Statements of Stockholders' Equity on page 59 of this Form 10-K report.

Other significant changes in Murphy's balance sheet at the end of 2018, compared to 2017 are discussed below.

Deferred income tax assets increased $148.1 million to $359.6 million (2017: $211.5 million) principally as a result of the favorable 2018 IRS interpretation of the impact of the 2017 Tax Act which resulted in the reinstatement of deferred tax assets relating to 2017 net operating losses.

Deferred income tax liabilities decreased $29.2 million to $129.9 million (2017: $159.1 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 liability position to a net deferred tax asset position, due to the 2018 IRS interpretation of the impact of the 2017 Tax Act.

Long-term asset retirement obligations increased $318.1 million to $1,027.4 million, principally due to increased obligations associated with the MP GOM transaction.

Financial Condition (Contd.)

Murphy had commitments for capital expenditures of approximately $383.1 million at December 31, 2018 (2017: $432.3 million). These commitments included $165.2 million for costs to develop deepwater U.S. Gulf of Mexico fields including new fields acquired as part of the MP GOM transaction, $103.0 million for field development and future work commitments in Malaysia, $60.0 million for development at Kaybob Duvernay in Canada, $31.4 million for work at Eagle Ford Shale, $14.7 million for exploration cost in Mexico, and $8.8 million for future work commitments in Vietnam.

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, 2018, the Company has a $1.6 billion senior unsecured guaranteed credit facility (2018 facility) with a major banking consortium, which expires in November 2023.

At December 31, 2018, the Company had outstanding borrowings of $325.0 million under the 2018 facility and $24.7 million of outstanding letters of credit, which reduce the borrowing capacity of the 2018 facility. Borrowings under the 2018 facility bear interest at rates, based, at the Company's option, on the "Alternate Base Rate" of interest in effect plus the "ABR Spread" or the "Adjusted LIBOR Rate," which is a periodic fixed rate based on LIBOR with a term equivalent to the interest period for such borrowing, plus the "Eurodollar Spread." The "Alternate Base Rate" of interest is the highest of (i) the Wall Street Journal prime rate, (ii) the New York Federal Reserve Bank Rate plus 0.50%, and (iii) one-month LIBOR plus 1.00%. The "Eurodollar Spread" ranges from 1.075% to 2.10% per annum based upon the Corporation's senior unsecured long-term debt securities credit ratings (the "Credit Ratings"). A facility fee accrues and is payable quarterly in arrears at a rate ranging from 0.175% to 0.40% per annum (based upon the Company's Credit Ratings) on the aggregate commitments under the 2018 facility. At December 31, 2018, the interest rate in effect on borrowings under the facility was 3.831%. At December 31, 2018, the Company was in compliance with all covenants related to the 2018 facility.

Current financing arrangements are outlined in more detail in Note H to the consolidated financial statements.

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 environmental 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.

Environmental Matters (Contd.)

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, a 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 2015, the Company's subsidiary in Canada identified a leak or leaks at an infield condensate transfer pipeline at the Seal field in a remote area of Alberta. The pipeline was immediately shut down and the Company's emergency response plan was activated. In cooperation with local governmental regulators, and with the assistance of qualified consultants, an investigation and remediation plan is progressing as planned and the Company's insurers were notified. Based on the assessments done to date, the Company recorded $43.9 million in Other expense during 2015 and a further $3.8 million in 2018 associated with the estimated costs of remediating the site. The Company has spent $44.7 million from inception to December 31, 2018. Further refinements in the estimated total cost to remediate the site may occur in future periods. The Company retained the responsibility for this remediation upon sale of the Seal field in 2017. As of December 31, 2018, the Company has a remaining accrued liability of $3.0 million associated with this event. In 2018, the Company received $25.0 million in respect to an insurance claim regarding this matter and the outcome of further insurance claims by the Company is pending.

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 future. Prices for oil field goods and services are usually affected by the worldwide prices for crude oil.

Following the drop in oil prices in late 2014, 2015-2016 experienced reduced demand for oil and gas materials and services, which led to downward pressure on the cost of these materials and services in 2015 and 2016. In 2017 and 2018, as oil and gas prices have moved higher, drilling activity has begun to increase, leading to 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.

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 – see Note B

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 an 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.

Other Matters (Contd.)

Significant accounting policies (contd.)

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, 2018 beginning on pages 7 and 101 of this Form 10-K report.

Property, Plant & Equipment - 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.

In 2018, the Company recorded an impairment expense of $20.0 million to reduce the carrying value of select Midland properties to its net recoverable value.

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.

Other Matters (Contd.)

Significant accounting policies (contd.)

Property, Plant & Equipment – business combinations – The Company may acquire assets and assume liabilities in transactions accounted for as business combinations, such as the MP GOM transaction with PAI in 2018. In connection with a business combination, the acquiring company must allocate the cost of the acquisition to assets acquired and liabilities assumed, based on fair values as of the acquisition date. Any excess of the purchase price over amounts assigned to assets and liabilities is recorded as goodwill. The amount of goodwill or gain on bargain purchase recorded in any particular business combination can vary significantly depending upon the values attributed to assets acquired and liabilities assumed.

Significant assumptions are involved in determining the fair value of assets acquired and liabilities assumed, such as the fair values assigned to proved and unproved crude oil and natural gas properties. In most cases, sufficient market data is not available regarding the fair values of proved and unproved properties, and the Company prepares estimates of such properties based on the fair value of associated crude oil, natural gas and NGL reserves. The primary assumptions used to arrive at estimates of future net cash flows are reserves quantities, commodity prices, and capital and operating costs. For estimated proved reserves, the future net cash flows are discounted using a market-based weighted average cost of capital rate determined at the time of the acquisition. The market-based weighted average cost of capital rate is subjected to additional project-specific risking factors. To compensate for the inherent risk of estimating and valuing unproved reserves, the discounted future net cash flows of probable and possible reserves are reduced by additional risk-weighting factors.

Estimated deferred taxes are based on available information concerning the tax basis of assets acquired and liabilities assumed and loss carryforwards at the acquisition date, although such estimates may change in the future as additional information becomes known.

Beginning in the fourth quarter of 2018, Murphy reports 100% of the sales volumes, revenues, costs, assets and liabilities including the 20% noncontrolling interest (NCI), of the new Gulf of Mexico transaction (MP GOM) with Petrobras Americas Inc (PAI), in accordance with accounting for noncontrolling interest as prescribed by ASC 810-10-45.

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 regulations may be subject to different interpretations and require future clarification 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.

In 2018, Murphy Oil's net income included a favorable income tax adjustment of $135.7 million related to the 2017 Tax Act enacted on December 22, 2017. The $135.7 million adjustment, primarily related to the reinstatement of a deferred tax asset for 2017 net operating losses, which in 2017, was assumed utilized against the deemed repatriation.

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.

Accounting for retirement and postretirement benefit plans – Murphy Oil and certain of its subsidiaries maintain defined benefit retirement plans covering certain 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 estimated 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, 2018, the Company has used a weighted average discount rate of 4.4 % at year-end 2018 for the primary U.S. plans. This weighted average discount rate is 0.7% higher than prior year, which decreased the Company's recorded liabilities for retirement plans compared to a year ago. Although the Company presently assumes a return on plan assets of 6.0% 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 2019 are expected to be $1.7 million higher than 2018 primarily due to increased amortization of the interest cost component. Cash contributions are anticipated to be $4.8 million higher in 2019. In 2018, the Company paid $24.5 million into various retirement plans and $3.1 million into postretirement plans. In 2019, the Company is expecting to fund payments of approximately $27.3 million into various retirement plans and $5.1 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 2019 annual retirement expenses by $2.0 million and decrease postretirement expenses by $0.3 million; and a 0.5% decline in the assumed rate of return on plan assets would increase 2018 retirement expense by $2.4 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 plans, and other long-term liabilities. Total payments due after 2018 under such contractual obligations and arrangements are shown in the table below.

	Amount of Obligations				
(Millions of dollars)	Total	2019	2020-2021	2022-2023	After 2023
Debt including current maturities	$ 3,237.9	10.6	22.9	1,445.4	1,759.0
Operating and other leases	401.7	188.6	150.8	43.2	19.1
Capital expenditures, drilling rigs and other	2,060.2	516.4	314.8	259.9	969.1
Other long-term liabilities, including debt interest	2,810.0	162.0	476.5	347.6	1,823.9
Total	$ 8,509.8	877.6	965.0	2,096.1	4,571.1

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, along with its partners, 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 $181.2 million as of December 31, 2018.

Material off-balance sheet arrangements – The Company occasionally utilizes lease arrangements for operational or funding purposes where the commitment may not be recorded on the balance sheet. The most significant of these arrangements at year-end 2017 included operating leases of floating, production, storage and offloading vessel (FPSO) for the Kikeh and Cascade/Chinook oil fields, 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 of 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 2019, West Texas Intermediate crude oil averaged about $51.55 for the month and averaged $54.45 in the first three weeks of February. NYMEX natural gas averaged $3.07 during January 2019. Both of these oil and natural gas prices are below the average prices achieved in 2018. 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 2019 is expected to be between $1.25 and $1.45 billion (excluding noncontrolling interest of $48 million). Capital and other expenditures will be routinely reviewed during 2019 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 2019 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 2019 to be between 215,000 and 223,000 barrels of oil equivalent per day (including noncontrolling interest of 13,000 BOEPD).

The Company has entered into natural gas forward delivery contracts to manage risk associated with certain Canadian natural gas sales prices as follows:

Area	Commodity	Type	Volumes (MMcf/d)	Price (CAD /Mcf)	Remaining Period Start Date	End Date
Montney	Natural Gas	Fixed price forward sales at AECO	59	C$2.81	1/1/2019	12/31/2020

Area	Commodity	Type	Volumes (MMcf/d)	Price (USD/MMBtu)		Remaining Period Start Date	End Date
Montney	Natural Gas	Fixed price forward sales at AECO	10	$	4.19	1/1/2019	3/31/2019
Montney	Natural Gas	Fixed price forward sales at AECO	10	$	3.85	1/1/2019	3/31/2019
Montney	Natural Gas	Fixed price forward sales at Dawn	10	$	4.20	1/1/2019	3/31/2019

In 2018 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 filed goods and services in prior periods of 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 M, Murphy makes use of derivative financial and commodity instruments to manage risks associated with existing or anticipated transactions.

There were no commodity transactions in place at December 31, 2018 covering certain future U.S. crude oil sales volumes in 2019.

Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Information required by this item appears on pages 52 through 117 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, 2018, 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, 2018. Under guidelines established by the SEC, companies are permitted to exclude acquisitions from their assessment of internal controls over financial reporting during the first year of an acquisition while integrating the acquired business. As noted in Management’s report, included on page 52 of this Form 10-K report, our assessment of, and conclusion on, the effectiveness of internal control over financial reporting did not include the internal controls of assets acquired in the MP GOM transaction on November 30, 2018. 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, 2018 and their report is included on page 54 of this Form 10-K report.

Other than noted above, there were no changes in the Company’s internal controls over financial reporting that occurred during the fourth quarter of 2018 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 8, 2019 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 8, 2019 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 8, 2019 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 8, 2019 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 8, 2019 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 the Indicated Filing by Murphy Oil Corporation
*2.1	Contribution Agreement dated as of October 10, 2018 among Murphy Exploration & Production Company – USA, Petrobras America Inc. and MP Gulf of Mexico, LLC	
3.1	Certificate of Incorporation of Murphy Oil Corporation, as amended effective May 11, 2005	Exhibit 3.1 to Form 10-K for the year ended December 31, 2010
3.2	By-Laws of Murphy Oil Corporation, as amended effective February 3, 2016	Exhibit 3.2 to Form 8-K filed February 5, 2016
4.1	Indenture dated as of May 4, 1999 between Murphy Oil Corporation and Suntrust Bank, Nashville, N.A., as trustee	Exhibit 4.2 to Form 10-K for the year ended December 31, 2004
4.2	Supplemental Indenture dated as of May 4, 1999 between Murphy Oil Corporation and Suntrust Bank, Nashville, N.A., as trustee, relating to 7.05% Notes due 2029	Exhibit 4.2 to Form 10-K for the year ended December 31, 2004
4.3	Indenture dated as of May 18, 2012 between Murphy Oil Corporation and U.S. Bank National Association, as trustee	Exhibit 4.1 to Form 8-K filed May 18, 2012
4.4	First Supplemental Indenture dated as of May 18, 2012, between Murphy Oil Corporation and U.S. Bank National Association, as trustee, relating to 4.00% Notes due 2022	Exhibit 4.2 to Form 8-K filed May 18, 2012

4.5	Second Supplemental Indenture dated as of November 30, 2012, between Murphy Oil Corporation and U.S. Bank National Association, as trustee, relating to 3.70% Notes due 2022 and 5.125% notes due 2042	Exhibit 4.1 to Form 8-K filed November 30, 2012
4.6	Third Supplemental Indenture dated as of August 17, 2016, between Murphy Oil Corporation and U.S. Bank National Association, as trustee, relating to 6.875% Notes due 2024	Exhibit 4.1 to Form 8-K filed August 17, 2016
4.7	Fourth Supplemental Indenture dated as of August 18, 2017, between Murphy Oil Corporation and U.S. Bank National Association, as trustee, relating to 5.75% Notes due 2025	Exhibit 4.1 to Form 8-K filed August 18, 2017
10.1	Credit Agreement dated as of August 10, 2016 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 to Form 8-K filed August 12, 2016
10.2	Third Amendment dated as of November 17, 2017 to Credit Agreement dated as of August 10, 2016 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 to Form 8-K filed November 20, 2017
10.3	Fourth Amendment dated as of October 10, 2018 to Credit Agreement dated as of August 10, 2016 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 to Form 8-K filed October 11, 2018
*10.4	Credit Agreement dated as of November 28, 2018 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	
10.5	2007 Long-Term Incentive Plan	Exhibit 10.1 of Murphy's Form 8-K report filed April 24, 2007
10.6	Form of employee stock option (2007 Long-Term Plan)	Exhibits 99.1 and 99.2 of Murphy's Form 10-Q report filed August 6, 2012
10.7	Murphy Oil Corporation 2012 Long-Term Incentive Plan	Exhibit A to definitive proxy statement filed March 29, 2012
10.8	Form of employee stock option (2012 Long-Term Plan)	Exhibit 99.1 to Form 10-K for the year ended December 31, 2013
10.9	Form of employee performance-based restricted stock unit grant agreement (2012 Long-Term Plan)	Exhibit 99.2 to Form 10-K for the year ended December 31, 2014
10.10	Form of stock appreciation right (2012 Long-Term Plan)	Exhibit 99.3 to Form 10-Q filed May 7, 2014
10.11	Form of employee time-based restricted stock unit grant agreement (2012 Long-Term Plan)	Exhibit 99.1 to Form 10-Q filed May 7, 2014
10.12	Form of employee time-based restricted stock unit-cash grant agreement (2012 Long-Term Plan)	Exhibit 99.2 to Form 10-Q filed May 7, 2014
10.13	Murphy Oil Corporation 2018 Long-Term Incentive Plan	Exhibit B to definitive proxy statement filed

		March 23, 2018
*10.14	Form of employee performance-based restricted stock unit – stock settled grant agreement (2018 Long-Term Plan)	
*10.15	Form of employee time-based restricted stock unit – stock settled 3-year grant agreement (2018 Long-Term Plan)	
*10.16	Form of employee time-based restricted stock unit – stock settled 5-year grant agreement (2018 Long-Term Plan)	

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10.17	Murphy Oil Corporation 2013 Stock Plan for Non-Employee Directors	Exhibit A to definitive proxy statement filed March 22, 2013
10.18	Form of non-employee director restricted stock unit award (2013 NED Plan)	Exhibit 99.2 to Form 10-Q filed November 6, 2013
10.19	Murphy Oil Corporation 2018 Stock Plan for Non-Employee Directors	Exhibit A to definitive proxy statement filed March 23, 2018
*10.20	Form of non-employee director restricted stock unit award – stock settled grant agreement (2018 NED Plan)	
10.21	Murphy Oil Corporation Non-Qualified Deferred Compensation Plan for Non-Employee Directors	Exhibit 10.6 to Form 10-K for the year ended December 31, 2015
10.22	Tax Matters Agreement dated as of August 30, 2013, between Murphy Oil Corporation and Murphy USA Inc.	Exhibit 10.1 to Form 8-K filed September 5, 2013
10.23	Employee Matters Agreement dated as of August 30, 2013, between Murphy Oil Corporation and Murphy USA Inc.	Exhibit 10.3 to Form 8-K filed September 5, 2013
10.24	Trademark License Agreement dated as of August 30, 2013, between Murphy Oil Corporation and Murphy USA Inc.	Exhibit 10.4 to Form 8-K filed September 5, 2013
*21.1	Subsidiaries of Murphy Oil Corporation	
*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	
*32.1	Certifications pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	
*99.1	Ryder Scott reserves audit report for Eagle Ford Shale, Gulf of Mexico, and Malaysia	
*99.2	Ryder Scott reserves audit report for MP GOM JV	
*99.3	McDaniel independent audit report for Canada Onshore and Offshore proved crude oil and natural gas reserves	
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 27, 2019
Roger W. Jenkins, President

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below on February 27, 2019 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/ DAVID R. LOONEY David R. Looney, 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 53.

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, 2018.

Our assessment of, and conclusion on, the effectiveness of internal control over financial reporting did not include the internal controls of assets acquired in the MP GOM transaction on November 30, 2018. The assets acquired represent 15% of total consolidated assets and revenue from the acquired assets represent 2% of total consolidated revenue. We are in the process of integrating process and internal controls over financial reporting.

KPMG LLP has performed an audit of the Company's internal control over financial reporting and their opinion thereon can be found on page 54.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Stockholders and Board of Directors
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, 2018 and 2017, 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, 2018, and the related notes and financial statement Schedule II (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, 2018 and 2017, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2018, 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, 2018, 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 27, 2019 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 27, 2019

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Stockholders and Board of Directors

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, 2018, 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, 2018, 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, 2018 and 2017, 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, 2018, and the related notes and financial statement Schedule II (collectively, the consolidated financial statements), and our report dated February 27, 2019 expressed an unqualified opinion on those consolidated financial statements.

The Company acquired assets in MP Gulf of Mexico, LLC (the Acquired Business) during 2018, and management excluded from its assessment of the effectiveness of the Company's internal control over financial reporting as of December 31, 2018, the Acquired Business' internal control over financial reporting associated with total assets of $1.6 billion and total revenues of $56 million included in the consolidated financial statements of the Company as of and for the year ended December 31, 2018. Our audit of internal control over financial reporting of the Company also excluded an evaluation of the internal control over financial reporting of the Acquired Business.

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 27, 2019

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

December 31 (Thousands of dollars)	2018	2017
Assets		
Current assets		
Cash and cash equivalents	$ 387,373	964,988
Accounts receivable, less allowance for doubtful accounts of $1,605 in 2018 and 2017	331,859	243,472
Inventories	87,911	105,127
Prepaid expenses	51,724	35,087
Assets held for sale	20,947	22,929
Total current assets	879,814	1,371,603
Property, plant and equipment, at cost less accumulated depreciation, depletion and amortization of $13,065,751 in 2018 and $12,280,741 in 2017	9,757,564	8,220,031
Deferred income taxes	359,644	211,543
Deferred charges and other assets	55,565	57,765
Total assets	$ 11,052,587	9,860,942
Liabilities and Stockholders' Equity		
Current liabilities		
Current maturities of long-term debt	$ 10,583	9,902
Accounts payable	596,071	595,916
Income taxes payable	31,605	44,604
Other taxes payable	19,387	23,574
Other accrued liabilities	185,648	156,681
Liabilities associated with assets held for sale	2,764	3,530
Total current liabilities	846,058	834,207
Long-term debt, including capital lease obligation	3,227,134	2,906,520
Deferred income taxes	129,894	159,098
Asset retirement obligations	1,027,423	709,299
Deferred credits and other liabilities	624,436	631,627
Equity		
Cumulative Preferred Stock, par $100, authorized 400,000 shares, none issued	–	–
Common Stock, par $1.00, authorized 450,000,000 shares, issued 195,076,924 shares in 2018 and 195,055,724 in 2017	195,077	195,056
Capital in excess of par value	979,642	917,665
Retained earnings	5,513,529	5,245,242
Accumulated other comprehensive loss	(609,787)	(462,243)
Treasury stock	(1,249,162)	(1,275,529)

Murphy Shareholders' Equity	4,829,299	4,620,191
Noncontrolling interest	368,343	–
Total equity	5,197,642	4,620,191
Total liabilities and stockholders' equity	$ 11,052,587	9,860,942

See Notes to Consolidated Financial Statements, page 60.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

Years Ended December 31 (Thousands of dollars except per share amounts)	2018	2017 1	2016 1
Revenues			
Revenue from sales to customers	$ 2,586,627	2,078,548	1,862,891
(Loss) gain on crude contracts	(41,975)	9,566	(63,412)
Gain on sale of assets and other income	25,951	137,015	11,759
Total revenues	2,570,603	2,225,129	1,811,238
Costs and Expenses			
Lease operating expenses	555,894	468,323	559,360
Severance and ad valorem taxes	52,072	43,618	43,826
Exploration expenses, including undeveloped lease amortization	103,977	122,834	101,861
Selling and general expenses	216,024	203,573	246,277
Depreciation, depletion and amortization	971,901	957,719	1,054,081
Impairment of assets	20,000	–	95,088
Redetermination expense	11,332	15,000	39,100
Accretion of asset retirement obligations	44,559	42,590	46,742
Other (income) expense	(34,873)	30,706	13,806
Total costs and expenses	1,940,886	1,884,363	2,200,141
Operating income (loss) from continuing operations	629,717	340,766	(388,903)
Other income (loss)			
Interest and other income (loss)	(15,775)	(87,181)	43,958
Interest expense, net	(181,604)	(181,783)	(148,170)
Total other loss	(197,379)	(268,964)	(104,212)
Income (loss) from continuing operations before income taxes	432,338	71,802	(493,115)
Income tax expense (benefit)	9,330	382,738	(219,172)
Income (loss) from continuing operations	423,008	(310,936)	(273,943)
Loss from discontinued operations, net of income taxes	(3,522)	(853)	(2,027)
Net income (loss) including noncontrolling interest	419,486	(311,789)	(275,970)
Less: Net income attributable to noncontrolling interest	8,392	–	–
NET INCOME (LOSS) ATTRIBUTABLE TO MURPHY	$ 411,094	(311,789)	(275,970)
INCOME (LOSS) PER COMMON SHARE – BASIC			
Continuing operations	$ 2.39	(1.81)	(1.59)
Discontinued operations	(0.01)	–	(0.01)
Net income (loss)	$ 2.38	(1.81)	(1.60)

INCOME (LOSS) PER COMMON SHARE – DILUTED			
Continuing operations	$ 2.37	(1.81)	(1.59)
Discontinued operations	(0.01)	–	(0.01)
Net income (loss)	$ 2.36	(1.81)	(1.60)
Cash dividends per Common share	1.00	1.00	1.20
Average Common shares outstanding (thousands)			
Basic	172,974	172,524	172,173
Diluted	174,209	172,524	172,173

See Notes to Consolidated Financial Statements, page 60.

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

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MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

Years Ended December 31 (Thousands of dollars)	2018	2017	2016
Net income (loss) including noncontrolling interest	$ 419,486	(311,789)	(275,970)
Other comprehensive income (loss), net of tax			
Net gain (loss) from foreign currency translation	(145,022)	171,725	66,449
Retirement and postretirement benefit plans	29,110	(7,682)	7,955
Deferred loss on interest rate hedges reclassified to interest expense.	2,342	1,926	1,926
Reclassification of certain tax effects to retained earnings	(30,237)	–	–
Other	(3,737)	–	–
Other comprehensive income (loss)	(147,544)	165,969	76,330
COMPREHENSIVE INCOME (LOSS)	$ 271,942	(145,820)	(199,640)

See Notes to Consolidated Financial Statements, page 60.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

Years Ended December 31 (Thousands of dollars)	2018	2017	2016
Operating Activities			
Net income (loss) including noncontrolling interest	$ 419,486	(311,789)	(275,970)
Adjustments to reconcile net loss to net cash provided by continuing operations activities:			
Loss from discontinued operations	3,522	853	2,027
Depreciation, depletion and amortization	971,901	957,719	1,054,081
Impairment of assets	20,000	–	95,088
Amortization of deferred major repair costs	–	–	3,794
Dry hole costs (credits)	20,624	(4,163)	15,047
Amortization of undeveloped leases	40,177	61,776	43,417
Accretion of asset retirement obligations	44,559	42,590	46,742
Deferred income tax expense (benefit)	(183,680)	260,420	(387,843)
Pretax gains from disposition of assets	(54)	(127,434)	(1,663)
Net (increase) decrease in noncash operating working capital	(169,808)	136,414	(38,689)
Other operating activities, net	52,669	111,689	44,764
Net cash provided by continuing operations activities	1,219,396	1,128,075	600,795
Investing Activities			
Acquisition of oil properties	(794,623)	–	–
Property additions and dry hole costs	(1,102,805)	(1,009,667)	(926,948)
Proceeds from sales of property, plant and equipment	1,383	69,506	1,155,144
Purchase of investment securities 1	–	(212,661)	(695,879)
Proceeds from maturity of investment securities 1	–	320,828	761,000
Other investing activities, net	–	–	(7,230)
Net cash provided (required) by investing activities	(1,896,045)	(831,994)	286,087
Financing Activities			
Borrowings of debt	325,000	541,597	541,444
Repayments of debt	–	(550,000)	(600,000)
Capital lease obligation payments	(9,750)	(17,133)	(10,447)
Issue cost of debt facility	(6,366)	–	(14,085)
Cash dividends paid	(173,044)	(172,565)	(206,635)
Other financing activities, net	(8,076)	(7,116)	(1,158)
Net cash required by financing activities	127,764	(205,217)	(290,881)
Effect of exchange rate changes on cash and cash equivalents	(28,730)	1,327	(6,387)
Net increase (decrease) in cash and cash equivalents	(577,615)	92,191	589,614
Cash and cash equivalents at beginning of period	964,988	872,797	283,183
Cash and cash equivalents at end of period	$ 387,373	964,988	872,797

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

See Notes to Consolidated Financial Statements, page 60.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

Years Ended December 31 (Thousands of dollars)	2018	2017	2016
Cumulative Preferred Stock – par $100, authorized 400,000 shares, none issued	$ –	–	–
Common Stock – par $1.00, authorized 450,000,000 shares at December 31, 2018, 2017 and 2016, issued 195,076,924 shares at December 31, 2018 and 195,055,724 at December 31, 2017 and 2016.			
Balance at beginning of year	195,056	195,056	195,056
Exercise of stock options	21	–	–
Balance at end of period	195,077	195,056	195,056
Capital in Excess of Par Value			
Balance at beginning of year	917,665	916,799	910,074
Exercise of stock options, including income tax benefits	(362)	–	(12,017)
Restricted stock transactions and other	(33,920)	(26,553)	(10,078)
Stock-based compensation	27,920	27,496	29,119
Fair value increase in common controlled assets	68,339	–	–
Other	–	(77)	(299)
Balance at end of period	979,642	917,665	916,799
Retained Earnings			
Balance at beginning of year	5,245,242	5,729,596	6,212,201
Net income (loss) for the year attributable to Murphy	411,094	(311,789)	(275,970)
Reclassification of certain tax effects from accumulated other comprehensive loss	30,237	–	–
Cash dividends	(173,044)	(172,565)	(206,635)
Balance at end of period	5,513,529	5,245,242	5,729,596
Accumulated Other Comprehensive Loss			
Balance at beginning of year	(462,243)	(628,212)	(704,542)
Foreign currency translation gains (losses), net of income taxes	(145,022)	171,725	66,449
Retirement and postretirement benefit plans, net of income taxes	29,110	(7,682)	7,955
Deferred loss on interest rate hedge reclassified to interest expense, net of income taxes	2,342	1,926	1,926
Reclassification of certain tax effects to retained earnings	(30,237)	–	–
Other	(3,737)	–	–
Balance at end of year	(609,787)	(462,243)	(628,212)
Treasury Stock			
Balance at beginning of year	(1,275,529)	(1,296,560)	(1,306,061)
Sale of stock under employee stock purchase plans	–	146	509
Awarded restricted stock	26,367	20,885	8,992

Balance at end of year – 22,018,095 shares of Common Stock in 2018, 22,482,851 shares of Common Stock in 2017, and 22,853,547 shares of Common Stock in 2016	(1,249,162)	(1,275,529)	(1,296,560)
Murphy Shareholders' Equity	4,829,299	4,620,191	4,916,679
Noncontrolling Interest			
Balance at beginning of year	–	–	–
Acquisition	359,951	–	–
Net income attributable to noncontrolling interest	8,392	–	–
Distributions to noncontrolling Interest Owners	0	–	–
Balance at end of year	368,343	–	–
Total Equity	$ 5,197,642	4,620,191	4,916,679

See Notes to Consolidated Financial Statements, page 60.

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 55-59 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 primarily 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. See Notes E and G 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. Beginning in the fourth quarter of 2018, Murphy reports 100% of the sales volume, revenues, costs, assets and liabilities including the 20% noncontrolling interest (NCI), of the new Gulf of Mexico transaction (MP GOM) with Petrobras Americas Inc (PAI), in accordance with accounting for noncontrolling interest as prescribed by ASC 810-10-45 (see Note D). 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; the amount of revenue recognized reflects the consideration expected in exchange for those commodities. The Company measures revenue based on consideration specified in a contract and excludes taxes and other amounts collected on behalf of third parties. Revenues from the production of oil and natural gas properties in which Murphy shares in the undivided interest with other producers are recognized based on the actual volumes sold by the Company during the period. Revenue is presented as the Company’s share net of certain costs associated with generation of Revenue. Examples of costs that reduce revenue include transportation, gathering, compression, and processing fees in U.S. and Canada, as well as certain required payments associated with production sharing contracts (PSCs) and export taxes in Malaysia. 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, 2018 and 2017, the liabilities for natural gas balancing were immaterial. Gains and losses on asset disposals or retirements are included in net income/(loss) as a component of revenues. 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.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – Continued

Note A – Significant Accounting Policies (Contd.)

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 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.

ACCOUNTS RECEIVABLE – At December 31, 2018 and 2017, 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 undeveloped property, the 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 major capital expenditure to produce and/or evacuate the hydrocarbon(s) found. The determination of whether to make such capital expenditure is usually dependent on whether further exploratory or appraisal 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. As a result of management's assessments during 2018, the Company recognized a pretax, noncash impairment charge of $20.0 million at select Midland properties. There were no impairments recorded during 2017. In 2016, charges of $95.1 million at its Terra Nova field offshore Canada and its Western Canada onshore heavy oil producing properties were reported. See also Note G 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.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – Continued

Note A – Significant Accounting Policies (Contd.)

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 development drilling and completion costs using proved developed reserves and acquisition costs are amortized over proved reserves. Proved reserves are estimated by the Company's engineers and are subject to future revisions based on the 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.

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 J) 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 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 the use of the hedging instrument to manage the risk. Derivative instruments designated as fair value or cash flow hedges are linked to

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – Continued

Note A – Significant Accounting Policies (Contd.)

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. See Note Q.

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. See Note K.

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. See Note L.

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.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – Continued

Note B – New Accounting Principles and Recent Accounting Pronouncements

Accounting Principles Adopted

Revenue from Contracts with Customers. In May 2014, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2014-09, which established a comprehensive model of accounting for revenue arising from contracts with customers that superseded most revenue recognition requirements and industry-specific guidance. Under the new standard, the Company recognizes revenue when it transfers control of the commodity to customers in an amount that reflects the consideration the Company expects to be entitled to in exchange for the commodity. Additional disclosures are required to describe the nature, amount, timing and uncertainty of revenue and cash flows from contracts with customers. The Company adopted the new standard in the first quarter of 2018 using the modified retrospective method. The Company performed a review of contracts in each of its revenue streams and implemented accounting policies and internal controls to address the requirements of the ASU. Prior to January 1, 2018, the Company followed the sales method of revenue recognition under Accounting Standards Codification (ASC) Topic 605 and recorded revenue when deliveries occurred, and legal ownership of the commodity transferred to the customer.

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

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

Compensation – Retirement Benefits. In March 2017, the FASB issued ASU 2017-07 requiring that the service cost component of pension and postretirement benefit costs be presented in the same line item as other current employee compensation costs and other components of those benefit costs be presented separately from the service cost component outside a subtotal of income from operations, if presented. The update also requires that only the service cost component of pension and postretirement benefit cost is eligible for capitalization. The update is effective for annual and interim periods beginning after December 15, 2017. The Company elected to apply the practical expedient, which allows us to reclassify amounts disclosed previously in the retirement benefits note as the basis for applying retrospective presentation for comparative periods. The Company adopted the standard in the first quarter of 2018 and it did not have a material impact on its consolidated financial statements.

Compensation – Stock Compensation. In May 2017, the FASB issued ASU 2017-09 which amends the scope of modification accounting for share-based payment arrangements and provides guidance on the type of changes to the terms and conditions of share-based payment awards to which an entity would be required to apply modification accounting. The update is effective for annual periods beginning after December 15, 2017 and interim periods within the annual period. The Company adopted this accounting standard in the first quarter of 2018 and it did not have a material impact on its consolidated financial statements.

Statement of Operations – Reporting Comprehensive Income. In February 2018, the FASB issued ASU 2018-02, which allows a reclassification from accumulated other comprehensive income to retained earnings for stranded tax effects resulting from the Tax Cuts and Jobs Act. The Company elected to early adopt this accounting standard during the first quarter of 2018 and recorded discrete adjustments from accumulated other comprehensive income to retained earnings of $28.4 million related to retirement and postretirement obligations and $1.8 million related to the deferred loss on interest rate derivative hedges. The adoption of this ASU will have no future impact.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – Continued

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

Accounting Principles Adopted (Contd).

In August 2018, the U.S. Securities and Exchange Commission (SEC) adopted the final rule under SEC Release No. 33-10532 Disclosure Update and Simplification, to eliminate or modify certain disclosure rules that are redundant, outdated, or duplicative of U.S. GAAP or other regulatory requirements. Among other changes, the amendments eliminated the annual requirement to disclose the high and low trading prices of our common stock and the ratio of earnings to fixed charges. In addition, the amendments provide that disclosure requirements related to the analysis of shareholders' equity are expanded for interim financial statements. An analysis of the changes in each caption of shareholders' equity presented in the balance sheet must be provided in a note or separate statement, as well as the amount of dividends per share for each class of shares. This rule was effective on November 5, 2018; and the expanded interim disclosure requirements for changes in shareholders' equity will be effective for the Company for our quarterly reporting beginning March 31, 2019.

Recent Accounting Pronouncements

Leases. In February 2016, the FASB established Topic 842 (the new standard) by issuing ASU 2016-02 to increase transparency and comparability among companies. The new standard requires lease benefits and corresponding lease liabilities to be recorded on the balance sheet and requires disclosing key information about leasing arrangements. The main difference between previous Generally Accepted Accounting Principles (GAAP) and the requirements of the new standard, is the recognition of right-of-use (ROU) assets and lease liabilities for certain leases. Entities will now be required to recognize operating leases alongside finance leases (formerly referred to as capital leases), with the distinction affecting the classification of expense recognition. The new standard also calls for disclosures regarding leasing arrangements and costs, to provide a more comprehensive insight into an entity’s leasing activities.

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 adopted this guidance in the first quarter of 2019 effective as of January 1, 2019. A modified retrospective transition approach is required upon adoption, with the new standard being applied to all leases at the date of initial application. We expect to take certain practical expedients that allow our initial date of application to coincide with the effective date, such that the new standard is applied prospectively on January 1, 2019 (relief option). Therefore, financial information and disclosures related to prior periods will neither be updated nor recast and will not reflect the new requirements.

Further, the new standard also provides other practical expedients that an entity may elect, at its option, to facilitate a more efficient transition. We expect to elect the main ‘package of practical expedients,’ allowing entities not to reassess lease conclusions made under previous GAAP (primarily related to lease identification and classification). We currently expect to elect the short-term lease recognition exemption for all leases that qualify.

We expect the new standard will have a material effect on our financial statements. Reviews indicate the impact will be generated primarily from ROU assets and lease liabilities related to an operating lease of a gas processing plant and floating, platform, storage, and off-take vessels. As required by the standard, previously deferred gains related to a sale-leaseback transaction will be transferred to equity upon transition, lowering liabilities but increasing retained earnings by approximately $160 million (see Note G). For all asset classes, preliminary estimates suggest operating leases could add approximately $800 million, representing the present value of remaining minimum lease payments. These estimates are provisional. Additional changes may arise due to the finalization of policies and elections made to the volume of leases recognized and revisions made to anticipated lease terms. We do not expect the standard to have an impact on our underlying liquidity or our debt-covenant compliance under our existing agreements.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – Continued

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

Recent Accounting Pronouncements (Contd.)

Compensation – Stock Compensation. In June 2018, the FASB issued ASU 2018-07 which supersedes existing guidance for equity-based payments to nonemployees and expands the scope of guidance for stock compensation to include all share-based payment arrangements related to the acquisition of goods and services from both nonemployees and employees. As a result, the same guidance that provides for employee share-based payments, including most of its requirements related to classification and measurement, applies to nonemployee share-based payment arrangements. The ASU is effective for financial statements issued for annual periods beginning after December 15, 2018 and interim periods within those annual periods. Early adoption is permitted. The Company adopted this guidance for the first quarter of 2019 and it is not expected to have a material impact on its consolidated financial statements.

Fair Value Measurement. In August 2018, the FASB issued ASU 2018-13 which modifies disclosure requirements related to fair value measurement. The amendments in this ASU are effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2019. Implementation on a prospective or retrospective basis varies by specific disclosure requirement. Early adoption is permitted. The standard also allows for early adoption of any removed or modified disclosures upon issuance of this ASU while delaying adoption of the additional disclosures until their effective date. The Company is currently assessing the potential impact of this ASU to its consolidated financial statements.

Compensation-Retirement Benefits-Defined Benefit Plans-General. In August 2018, the FASB issued ASU 2018-14 that modifies the disclosure requirements for employers that sponsor defined benefit pension or other postretirement plans. For public companies, the amendments in this ASU are effective for fiscal years beginning after December 15, 2020, with early adoption permitted, and is to be applied on a retrospective basis to all periods presented. The Company is currently assessing the potential impact of this ASU to its consolidated financial statements.

Note C – Revenue from Contracts with Customers

Nature of Goods and Services

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

For operated oil and gas production where the non-operated working interest owner does not take-in-kind its proportionate interest in the produced commodity, the Company acts as an agent for the working interest owner and recognizes revenue only for its own share of the commingled production. The exception to this is the reporting of the noncontrolling interest in MP GOM as prescribed by ASC 810-10-45.

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

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

Malaysia- In Malaysia, the Company has interests in seven separate PSCs. The Company serves as the operator of all these areas except for the unitized Gumusut-Kakap field. Crude oil contracts in Malaysia share similar features of largely fixed cargo quantities and variable index-based pricing, and revenue is typically recognized as the same time of vessel load. Malaysia also has three long term Gas Sales Agreements (GSA) with terms until the end of the field life, economic life, or PSC term.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – Continued

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

Disaggregation of Revenue

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

For the years ended December 31, 2018, 2017, and 2016 the Company recognized $2.6 billion, $2.1 billion, and 1.9 billion, respectively, from contracts with customers for the sales of oil, natural gas liquids and natural gas.

		For the Year Ended December 31,		
(Thousands of dollars)		2018	2017	2016
Net crude oil and condensate revenue				
United States – Onshore	$	778,198	644,023	508,045
– Offshore 1		403,523	208,984	172,022
Canada – Onshore		105,651	51,013	92,605
– Offshore		170,895	147,230	138,425
Malaysia – Sarawak		282,370	241,774	209,751
– Block K		406,653	378,401	403,912
Other		6,079	–	–
Total crude oil and condensate revenue		2,153,369	1,671,425	1,524,760
Net natural gas liquids revenue				
United States – Onshore		53,335	43,804	28,316
– Offshore 1		10,269	6,894	5,781
Canada – Onshore		14,657	5,450	1,351
Malaysia – Sarawak		19,798	19,733	10,001
Total natural gas liquids revenue		98,059	75,881	45,449
Net natural gas revenue				
United States – Onshore		28,335	27,460	24,281
– Offshore 1		14,525	10,480	10,839
Canada – Onshore		147,613	155,125	129,968
Malaysia – Sarawak		144,222	137,479	126,975
– Block K		504	698	619
Total natural gas revenue		335,199	331,242	292,682
Total revenue from contracts with customers		2,586,627	2,078,548	1,862,891
Gain (loss) on crude contracts		(41,975)	9,566	(63,412)
Other operating income		25,897	9,581	10,096
Gain on sale of assets		54	127,434	1,663
Total revenue	$	2,570,603	2,225,129	1,811,238

1 2018 includes revenue attributable to noncontrolling interest in MP GOM, effective November 30, 2018.

Contract Balances and Asset Recognition

As of December 31, 2018, and December 31, 2017, receivables from contracts with customers, net of royalties and associated payables, on the balance sheet, were $263.0 million and $203.4 million, respectively. Payment terms for the Company’s sales vary across contracts and geographical regions, with the majority of the cash receipts required within 30 days of billing. Based on historical collections and ability of customers to pay, the Company did not recognize any impairment losses on receivables or contract assets arising from customer contracts during the reporting periods.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – Continued

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

The Company has not entered into any upstream oil and gas sale contracts that have financing components as of December 31, 2018.

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

Performance Obligations

The Company recognizes oil and gas revenue when it satisfies a performance obligation by transferring control over a commodity to a customer and considers each unit of measure, of the specified commodity, to represent a distinct performance obligation. The pricing for the Company's sales contracts is typically market or index-based based. The Company has elected the direct allocation exception and therefore the variable consideration is allocated to each single performance obligation in the contract. As a result, there is no price allocation to unsatisfied performance obligations for delivery of a commodity in subsequent periods.

The Company has applied the exemption to not report any unsatisfied performance obligation related to contracts with terms of less than one year.

As at December 31, 2018, the Company had the following sales contracts in place with terms greater than one year:

Current Long-Term Contracts Outstanding at December 31, 2018

Location	Commodity	End Date	Description	Approximate Volumes
U.S.	Oil	Q3 2019	Fixed quantity delivery in Eagle Ford	4,000 BOED
U.S.	Oil	Q4 2021	Fixed quantity delivery in Eagle Ford	17,000 BOED
U.S.	Gas and NGL	Q2 2026	Deliveries from dedicated acreage in Eagle Ford	As produced
Canada	Gas	Q4 2020	Contracts to sell natural gas at Alberta AECO fixed prices	59 MMCFD
Canada	Gas	Q4 2020	Contracts to sell natural gas at USD Index pricing	60 MMCFD
Canada	Gas	Q4 2024		30 MMCFD

			Contracts to sell natural gas at USD Index pricing	
Canada	Gas	Q4 2026	Contracts to sell natural gas at USD Index pricing	38 MMCFD

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MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – Continued

Note D – Acquisition

In December 2018, the Company announced the completion of a transaction with Petrobras Americas Inc. (PAI) which became effective October 1, 2018. Through this transaction, Murphy acquired all PAI's producing Gulf of Mexico assets along with certain blocks that hold deep exploration rights. This transaction added production of approximately 50,000 BOED (including noncontrolling interest, NCI) along with approximately 97 MMBOE (including NCI) of proven reserves at December 31, 2018. See Supplemental Oil and Gas Information (Unaudited), below for discussion of proved reserves acquired.

Under the terms of the transaction, Murphy paid cash consideration of $794.6 million and transferred a 20% interest in MP Gulf of Mexico, LLC (MP GOM), a subsidiary of Murphy, to PAI. Murphy could also owe additional contingent consideration up to $150 million if certain sales thresholds are exceeded beginning in 2019 through 2025. Both companies contributed all of their current producing Gulf of Mexico assets into MP GOM. Following closing of the transaction, MP GOM is owned 80% by Murphy and 20% by PAI, with Murphy overseeing the operations.

The following tables contain the preliminary purchase price allocation at fair value:

(Thousands of dollars)	
Cash consideration paid to PAI	$ 794,623
Fair value of net assets contributed	166,797
Fair value of contingent consideration	52,540
Noncontrolling interest in acquired assets	253,490
Total purchase consideration	$ 1,267,450

(Thousands of dollars)	
Fair value of Property, Plant, and Equipment	$ 1,617,052
Other assets	10,041
Less: Asset retirement obligations	(359,643)
Total net assets	$ 1,267,450

The fair value measurements of crude oil and natural gas properties and asset retirement obligations are based on inputs that are not observable in the market and therefore represent Level 3 inputs. The fair values of crude oil and natural gas properties and asset retirement obligations were measured using valuation techniques that convert expected future cash flows to a single discounted amount. Significant inputs to the valuation of crude oil and natural gas properties included estimates of: (i) proved, probable, and possible reserves; (ii) production rates and related development timing; (iii) future operating and development costs; (iv) future commodity prices; and (v) a market-based weighted average discount rate. These inputs required significant judgments and estimates by management at the time of the valuation and are the most sensitive and may be subject to change.

Certain data necessary to complete the purchase price allocation is not yet available, and includes, but is not limited to, analysis of the underlying tax basis of the PAI assets acquired and liabilities assumed and the final purchase price adjustments to be settled in 2019. We expect to complete the purchase price allocation during the 12-month period following the acquisition date, during which time the value of the assets and liabilities may be revised as appropriate.

Results of Operations

The results of operations attributable to the acquired PAI assets are included in our Consolidated Statement of Operations beginning on December 1, 2018. Murphy generated additional revenues of $56.7 million and pre-tax income of $36.5 million related to the acquired assets from the period December 1, 2018 to December 31, 2018.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – Continued

Note D – Acquisition (Contd.)

Pro Forma Financial Information

The following pro forma condensed combined financial information was derived from historical financial statements of Murphy and PAI and gives effect to the transaction as if it had occurred on January 1, 2017. The information below reflects pro forma adjustments based on available information and certain assumptions that we believe are reasonable, including depletion of PAI fair-valued proved crude oil and natural gas properties. The pro forma condensed combined financial information was also adjusted to exclude acquisition-related costs of $6.2 million incurred by Murphy. The pro forma results of operations do not include any cost savings or other synergies that we expect to realize from the transaction or any estimated costs that have been or will be incurred by us to integrate the PAI assets. The pro forma condensed combined financial information has been included for comparative purposes and is not necessarily indicative of the results that might have occurred had the transaction taken place on January 1, 2017; furthermore, the financial information is not intended to be a projection of future results.

	Years Ended December 31,		
(Thousands of dollars, except per share amounts)		2018	2017
Revenues	$	2,825,169	2,816,458
Net Income Attributable to Murphy		603,231	(224,860)
Net Income Attributable to Murphy per Common Share			
Basic	$	3.49	(1.30)
Diluted		3.46	(1.30)

Note E – Discontinued Operations and Assets Held for Sale

The Company has accounted for its former U.K. and U.S. refining and marketing operations as discontinued operations for all periods presented.

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

(Thousands of dollars)	2018	2017
Current assets		
Cash	$ 17,219	16,631
Accounts receivable	3,728	6,298
Total current assets held for sale	$ 20,947	22,929
Current liabilities		
Accounts payable	$ 106	837
Refinery decommissioning cost	2,658	2,693
Total current liabilities associated with assets held for sale	$ 2,764	3,530

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

(Thousands of dollars)	2018	2017	2016
Revenues	$ 6	854	1,464
Loss from operations before income taxes	$ (3,522)	(853)	(2,027)
Loss on sale before income taxes	–	–	–
Total loss from discontinued operations before taxes	(3,522)	(853)	(2,027)
Income tax expense	–	–	–
Loss from discontinued operations	$ (3,522)	(853)	(2,027)

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – Continued

Note F – Inventories

Inventories consisted of the following at December 31, 2018 and 2017.

	December 31,	
	2018	2017
(Thousands of dollars)		
Unsold crude oil	$ 25,205	20,153
Materials and supplies	62,706	84,974
	$ 87,911	105,127

Note G – Property, Plant and Equipment

	December 31, 2018		December 31, 2017	
(Thousands of dollars)	Cost	Net	Cost	Net
Exploration and production1	$ 22,629,844	9,654,945 2	20,329,930	8,120,293 2
Corporate and other	193,471	102,619	170,842	99,738
	$ 22,823,315	9,757,564	20,500,772	8,220,031
1 Includes unproved mineral rights as follows:	$ 512,025	144,912	600,423	198,349

2. Includes $32,071 in 2018 and $38,670 in 2017 related to administrative assets and support equipment.

Divestments

In 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 17 years in the Canadian operating segment. The Company amortized approximately $7.6 million and $7.1 million of the deferred gain during 2018 and 2017, respectively. The remaining deferred gain of $160.2 million was included as a component of Deferred credits and other liabilities in the Company's Consolidated Balance Sheet as of December 31, 2018.

Acquisition

In 2018, a wholly owned subsidiary, Murphy Exploration & Production Company - USA, entered into a definitive agreement with Petrobras America Inc. (PAI), a subsidiary of Petrobras. The transaction was comprised of all of the Gulf of Mexico producing assets from Murphy and PAI with Murphy overseeing the operations. Both companies contributed all their current producing Gulf of Mexico assets to MP Gulf of Mexico, LLC, a subsidiary of Murphy, which following closing of the transaction is owned 80% by Murphy and 20% by PAI. The transaction excludes exploration blocks from Murphy. However, PAI's blocks that hold deep exploration rights were part of the transaction. Murphy paid net cash consideration of $794.6 million at closing, after adjustments provided for in the sale and purchase agreement. Additionally, PAI received a 20% interest in MP GOM and will earn an additional contingent consideration up to $150 million if certain price and production thresholds are exceeded beginning in 2019 through 2025. Also, Murphy will carry $50 million of PAI costs in the St. Malo Field if certain enhanced oil recovery projects are undertaken.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – Continued

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

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, 2018, $102.0 million of the carried interest had been paid. The carry is to be paid over a period through 2020.

Impairments

During 2018, underperforming wells led to impairments in certain of the Company's US Onshore properties. In 2018 the Company recorded a pretax noncash impairment charge of $20 million to reduce the carrying values to their estimated fair values at select Midland properties. During 2016, 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.

The following table reflects the recognized impairments for the three years ended December 31, 2018.

	December 31,		
(Thousands of dollars)	2018	2017	2016
US Onshore (Midland)	$ 20,000	–	–
Canada	–	–	95,088
Malaysia	–	–	–
	$ 20,000	–	95,088

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 partial payment, the remaining redetermination liability of $17.3 million was included as a component of Other current liabilities in the Company's Consolidated Balance Sheet as of December 30, 2018.

In 2017, following a further Unitization Framework Agreement (UFA) between the governments of Brunei and Malaysia, the Company has a 6.35% interest in the Kakap field in Block K Malaysia. The UFA unitized the Gumusut/Kakap (GK) and Geronggong/Jagus East fields effective November 23, 2017. In the fourth quarter 2017, the Company recorded an estimated redetermination expense of $15.0 million ($9.3 million after tax) related to Company's revised working interest, which was included as a component of Other current liabilities in the Company's Consolidated Balance Sheet as of December 31, 2018.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – Continued

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

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, 2018, 2017 and 2016, the Company had total capitalized drilling costs pending the determination of proved reserves of $229.1 million, $175.6 million and $148.5 million, respectively. The following table reflects the net changes in capitalized exploratory well costs during the three-year period ended December 31, 2018.

(Thousands of dollars)	2018	2017	2016
Beginning balance at January 1	$ 175,640	148,500	130,514
Additions pending the determination of proved reserves	60,179	51,488	17,986
Reclassifications to proved properties based on the determination of proved reserves	(2,214)	(15,988)	–
Capitalized exploration well costs charged to expense	(4,521)	(8,360)	–
Ending balance at December 31	$ 229,084	175,640	148,500

The capitalized well costs charged to expense during 2018 included the Julong East well in Block CA-1, offshore Brunei in which further development of the well has not been sanctioned by the operator and the contract term for development sanctions has now been reached. This well was originally drilled in 2012. The capitalized well costs charged to expense 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 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.

	2018			2017			2016		
(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	$ 61,096	1	1	$ 41,480	3	2	$ 20,481	1	1
One to two years	40,523	3	2	5,812	1	1	63,527	5	5
Two to three years	–	–	–	43,200	2	2	–	–	–
Three years or more	127,465	6	3	85,148	7	1	64,492	6	–
	$ 229,084	10	6	$ 175,640	13	6	$ 148,500	12	6

Of the $167.9 million of exploratory well costs capitalized more than one year at December 31, 2018, $55.8 million is in Brunei, $63.5 million is in Vietnam, $27.4 million in the U.S., and $21.2 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.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – Continued

Note H – Financing Arrangements and Long-Term Debt

As of December 31, 2018, the Company has a $1.6 billion revolving credit facility (2018 facility). The 2018 facility is a senior unsecured guaranteed facility which expires in November 2023 and it replaced the $1.1 billion senior unsecured guaranteed credit facility (2016 facility). At December 31, 2018, the Company had outstanding borrowings of $325.0 million under the 2018 facility and $24.7 million of outstanding letters of credit, which reduce the borrowing capacity of the 2018 facility. Borrowings under the 2018 facility bear interest at rates, based, at the Company's option, on the "Alternate Base Rate" of interest in effect plus the "ABR Spread" or the "Adjusted LIBOR Rate," which is a periodic fixed rate based on LIBOR with a term equivalent to the interest period for such borrowing, plus the "Eurodollar Spread." The "Alternate Base Rate" of interest is the highest of (i) the Wall Street Journal prime rate, (ii) the New York Federal Reserve Bank Rate plus 0.50%, and (iii) one-month LIBOR plus 1.00%. The "Eurodollar Spread" ranges from 1.075% to 2.10% per annum based upon the Corporation's senior unsecured long-term debt securities credit ratings (the "Credit Ratings"). A facility fee accrues and is payable quarterly in arrears at a rate ranging from 0.175% to 0.40% per annum (based upon the Company's Credit Ratings) on the aggregate commitments under the 2016 facility. At December 31, 2018, the interest rate in effect on borrowings under the facility was 3.831%. At December 31, 2018, the Company was in compliance with all covenants related to the 2018 facility.

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 Company pays 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.

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 (finance lease under ASC 842), and payments under the agreement are to be made over a 15-year period through March 2029. Current maturities of long-term debt and long-term debt on the Consolidated Balance Sheet included $10.6 million and $125.8 million, respectively, associated with this lease at December 31, 2018.

	December 31,	
(Thousands of dollars)	2018	2017
Notes payable		
4.00% notes, due June 2022	$ 500,000	500,000
4.45% notes, due December 20221	600,000	600,000
6.875% notes, due August 2024	550,000	550,000
5.75% notes, due August 2025	550,000	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		(23,627)	(27,433)
Total notes payable, net of unamortized discount		2,776,373	2,772,567
Capitalized lease obligation, due through March 2029		136,344	143,855
Total debt including current maturities		2,912,717	2,916,422
Senior Unsecured Revolving Credit Facility		325,000	-
Current maturities		(10,583)	(9,902)
Total long-term debt	$	3,227,134	2,906,520

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, in 2017 and remained through 2018.

The amount of debt repayable over each of the next five years and thereafter are as follows: ‘$10.6 million in 2019, $11.2 million in 2020, $11.7 million in 2021, $1.1 billion in 2022, $337.9 million in 2023 and $1.76 billion thereafter.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – Continued

Note I – Asset Retirement Obligations

The asset retirement obligations liabilities (ARO) recognized by the Company at December 31, 2018 and 2017 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 2018 and 2017 is shown in the following table.

(Thousands of dollars)	2018	2017
Balance at beginning of year	$ 722,139	781,057
Accretion expense	44,559	42,590
Liabilities incurred	13,886	52,331
Liabilities assumed from PAI	359,643	–
Revisions of previous estimates	(24,959)	(47,612)
Liabilities settled	(23,398)	(29,111)
Liabilities assumed by purchaser of oil and gas assets	–	(87,456)
Changes due to translation of foreign currencies	(8,966)	10,340
Balance at end of year	1,082,904	722,139
Current portion of liability at end of year[1]	(55,481)	(12,840)
Noncurrent portion of liability at end of year	$ 1,027,423	709,299

1Included 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 reflected the impact of lower rig service rates in the U.S.

Liabilities assumed from PAI in 2018 primarily represent obligations assumed as part of the MP GOM acquisition (see Note D).

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – Continued

Note J – 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)	2018	2017	2016
Income (loss) from continuing operations before income taxes			
United States	$ 14,907	(299,349)	(595,196)
Foreign	417,431	371,151	102,081
Total	$ 432,338	71,802	(493,115)
Income tax expense (benefit)			
Federal – Current	$ (9,765)	–	-
– Deferred	(131,200)	156,065	(197,450)
Total Federal	(140,965)	156,065	(197,450)
State	3,299	4,230	13,984
Foreign – Current	202,775	122,318	146,861
– Deferred	(55,779)	100,125	(182,567)
Total Foreign	146,996	222,443	(35,706)
Total	$ 9,330	382,738	(219,172)

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

(Thousands of dollars)	2018	2017	2016
Income tax expense (benefit) based on the U.S. statutory tax rate	$ 90,791	25,131	(172,590)
Revaluation of deferred tax (US tax reform)	–	118,004	–
Tax impact of deemed repatriation of foreign invested earnings (U.S. tax reform)	(135,700)	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	72,007	12,658	8,582
State income taxes, net of federal benefit	2,607	2,438	9,090
U.S. tax benefit on certain foreign upstream investments	(14,702)	(32,926)	(21,336)

Tax effects on sale of Canadian assets	–	–	(89,473)
Tax effects on sale of Malaysian assets	–	–	2,080
Increase in deferred tax asset valuation allowance related to other foreign exploration expenditures	3,283	18,601	25,734
Other, net	(8,956)	17,832	18,741
Total	$ 9,330	382,738	(219,172)

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – Continued

Note J – Income Taxes (Contd.)

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 provisional tax expense of $274.0 million directly related to the impacts of the 2017 Tax Act. The charge included the impact of a deemed repatriation of foreign earnings and the re-measurement of deferred tax assets and liabilities. During 2018, the Company completed the accounting for the income tax effects related to the 2017 Tax Act before the end of the measurement period. The Company revised the provisional amount recorded in 2017 and recognized a favorable income tax adjustment of $135.7 million primarily related to the reinstatement of a deferred tax asset for 2017 net operating losses, which in 2017 was assumed utilized against the deemed repatriation. This reinstatement followed April 2, 2018 Internal Revenue Service guidance related to the Section 965(n) election. This guidance allowed the Company to preserve the 2017 tax net operating loss as a carryforward and allowed previously unused foreign tax credits to be credited against all but $26 million of current income tax on the deemed inclusion of foreign earnings. The $26 million tax is further reduced by $16 million of post-2017 foreign tax credits allowed to be carried back as an offset, which results in a net $10.1 million tax on the deemed repatriation. This tax is fully offset by $29.7 million of AMT credit carryforwards to 2017, with half of the $19.6 million remainder expected to be refunded in late 2019, and the balance to be refunded or available to offset future U.S. income tax obligations over the next four years.

An analysis of the Company's deferred tax assets and deferred tax liabilities at December 31, 2018 and 2017 showing the tax effects of significant temporary differences follows.

(Thousands of dollars)	2018	2017
Deferred tax assets		
Property and leasehold costs	$ 491,660	488,584
Liabilities for dismantlements	88,075	98,444
Postretirement and other employee benefits	113,826	134,444
Alternative minimum tax	9,765	29,710
Foreign tax credit carryforwards	–	228,159
U. S. net operating loss	496,629	272,930
Other deferred tax assets	19,974	13,892
Total gross deferred tax assets	1,219,929	1,266,163
Less valuation allowance	(213,815)	(476,256)
Net deferred tax assets	1,006,114	789,907
Deferred tax liabilities		
Deferred tax on undistributed foreign earnings	(5,000)	(65,000)

Accumulated depreciation, depletion and amortization	(742,562)	(669,638)
Other deferred tax liabilities	(28,802)	(2,824)
Total gross deferred tax liabilities	(776,364)	(737,462)
Net deferred tax assets	$ 229,750	52,445

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 relate primarily to tax assets arising in foreign tax jurisdictions that in the judgment of management at the present time are more likely than not unexpected to be realized. The valuation allowance decreased $262 million in 2018 primarily due to a decrease in foreign tax credit carryforwards. 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 $2.36 billion at year-end 2018 with a corresponding deferred tax asset of $496.6 million. The Company believes the U.S. net operating loss being carried forward will be utilized in future periods prior to expirations in 2036 and 2037.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – Continued

Note J – Income Taxes (Contd.)

Other Information

During 2018 the Company repatriated $1.2 billion to the U.S. and paid $60 million of related Canadian withholding tax. $1.3 billion was reflected on the Company's December 31, 2017 balance sheet as earnings not permanently reinvested, with an accompanying $65.0 million liability. Currently the Company considers $100.0 million of Canada's past foreign earnings not permanently reinvested, with an accompanying $5.0 million liability. At December 31, 2018, $1.2 billion of past foreign earnings are considered permanently reinvested. The Company closely and routinely monitors these reinvestment positions considering underlying facts and circumstances pertinent to our business and the future operation of the company.

Uncertain Income Tax Positions

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)	2018	2017	2016
Balance at January 1	$ 3,437	7,417	6,631
Additions for tax positions related to current year	454	769	756
Settlements due to lapse of time	(988)	(4,834)	–
Foreign currency translation effect	–	85	30
Balance at December 31	$ 2,903	3,437	7,417

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, 2018, 2017 and 2016 for interest and penalties of $0.2 million, $0.1 million and $0.3 million, respectively, associated with uncertain tax positions. Income tax expense for the years ended December 31, 2018, 2017 and 2016 included net benefits for interest and penalties of $0.1 million, $0.2 million and $0.1 million, respectively, associated with uncertain tax positions.

During the next twelve months, the Company currently expects to add between $0.2 million and $1.0 million to the liability for uncertain taxes for 2019 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 2019.

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, 2018, the earliest years remaining open for audit and/or settlement in the Company’s major taxing jurisdictions are as follows: United States – 2015; Canada – 2013; Malaysia – 2012; and United Kingdom – 2017.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – Continued

Note K – Incentive Plans

Murphy utilizes cash-based and/or share-based incentive awards 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 the Company's annual stockholders' meeting held on May 9, 2018, shareholders approved replacement of the 2012 Long-Term Incentive Plan (2012 Long-Term Plan) with the 2018 Long-Term Incentive Plan (2018 Long-Term Plan). The 2018 Long-Term Plan authorizes the Committee to make grants of the Company's Common Stock to employees in the same form as the 2012 Long-Term Plan. The new plan can be found in the Company's Definitive Proxy statement (Definitive 14A) dated March 23, 2018. All awards on or after May 9, 2018 will be made under the 2018 Long-Term Plan.

The Company currently has outstanding incentive awards issued to certain employees under the 2017 Annual Incentive Plan, the 2012 Long-Term Plan and the 2018 Long-Term Plan. The 2017 Annual Plan authorizes the Executive Compensation Committee (the Committee) to establish specific performance goals associated with annual cash awards that may be earned by officers, executives and certain other employees. Cash awards under the 2017 Annual Plan are determined based on the Company's actual financial and operating results as measured against the performance goals established by the Committee.

The 2018 Long-Term Plan and the 2012 Long-term Plan authorize 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 2018 Long-Term Plan expires in 2028. A total of 6.75 million shares are issuable during the life of the 2018 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, 3.4 million shares are available for grant under the 2018 Long-Term Plan at December 31, 2018. In 2018, the Company's shareholders approved the 2018 Stock Plan for Non-Employee Directors (2018 NED 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.

The Company generally expects to issue treasury shares to satisfy future stock option exercises and vesting of restricted stock and restricted stock units.

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

(Thousands of dollars)	2018	2017	2016
Compensation charged against income (loss) before income tax benefit	$ 34,467	40,365	46,300
Related income tax benefit recognized in income	4,383	5,017	15,244

As of December 31, 2018, there were $46.5 million in compensation costs to be expensed over approximately the next five 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, 2018. There were no income tax benefits realized in either 2017 or 2016 due to no stock option exercises during those years.

Equity-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 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.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – Continued

Note K – Incentive Plans (Contd.)

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. In 2018, in light of a shift in the peer group compensation practices, the Company ceased the inclusion of stock options and stock appreciation rights as a part of the long-term incentive compensation mix.

	2018	2017	2016
Fair value per option grant	N/A	$7.96	$5.03
Assumptions			
Dividend yield	N/A	3.60%	4.00%
Expected volatility	N/A	41.00%	45.00%
Risk-free interest rate	N/A	1.97%	1.32%
Expected life	N/A	5.30 yrs.	5.20 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, 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
Granted at FMV	–	–
Exercised	(72,000)	17.57
Forfeited	(834,674)	53.36
Outstanding at December 31, 2018	3,994,595	44.66
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
Exercisable at December 31, 2018	3,182,345	49.10

Additional information about stock options outstanding at December 31, 2018 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	1,131,500	4.5	$ 3,719,263	319,250	4	$ 1,859,631
$31.00 to $50.00	817,350	2.9	–	817,350	2.9	–
$51.00 to $65.00	2,045,745	1.0	–	2,045,745	1.0	–
	3,994,595	2.4	$ 3,719,263	3,182,345	1.8	$ 1,859,631

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – Continued

Note K – Incentive Plans (Contd.)

The total intrinsic value of options exercised during 2018 was $1 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 (PSUs) 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, PSUs 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, PSUs 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 PSUs prior to their settlement.

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

(Number of stock units)	2018	2017	2016
Outstanding at beginning of year	1,187,921	992,573	1,103,986
Granted	905,500	560,000	394,000
Vested and issued	(311,866)	(272,725)	(361,096)
Forfeited	(121,138)	(91,927)	(144,317)
Outstanding at end of year	1,660,417	1,187,921	992,573

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 2018, 2017 and 2016 are presented in the following table.

	2018	2017	2016
Fair value per share at grant date	$22.99 - $30.56	$24.10 – $28.28	$12.21 – $16.34
Assumptions			
Expected volatility	48.00%	47.00%	33.00%
Risk-free interest rate	2.30%	1.46%	0.93%
Stock beta	1.103	1.058	0.863
Expected life	3.0 yrs.	3.0 yrs.	3.0 yrs.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – Continued

Note K – Incentive Plans (Contd.)

TIME-BASED RESTRICTED STOCK UNITS – Time-based restricted stock units (RSUs) have been granted to the Company’s Non-Employee Directors under the 2013 NED Plan and to certain employees under the 2012 Long-Term Plan and 2018 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 $25.69 to $28.43 per share in 2018, $28.51 per share in 2017, and $17.57 per share in 2016.

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

(Number of share units)	2018	2017	2016
Outstanding at beginning of year	1,035,980	923,282	477,244
Granted	823,803	419,720	503,555
Vested and issued	(233,456)	(217,633)	(32,092)
Forfeited	(87,473)	(89,389)	(25,425)
Outstanding at end of year	1,538,854	1,035,980	923,282

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. The plan ceased to operate in 2017. 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. Employee stock purchases under the ESPP were 2,564 shares at an average price of $26.85 per share in 2017 and 8,962 shares at an average price of $23.41 per share in 2016. 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 and $2.94 for the years ended December 31, 2017 and 2016, 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 (CPSU), Time-based restricted stock units

(CRSU) and Phantom units.

SAR awards have terms similar to stock options. CPSU terms are similar to other performance-based restricted stock awards (PSUs). CRSUs generally settle 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 $6.5 million in 2018, $12.9 million in 2017 and $17.2 million in 2016.

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 million, $30.5 million and $25.8 million was recorded in 2018, 2017 and 2016, respectively, for these plans.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – Continued

Note L – 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, 2018 and 2017 and a statement of the funded status as of December 31, 2018 and 2017.

	Pension Benefits		Other Postretirement Benefits	
(Thousands of dollars)	2018	2017	2018	2017
Change in benefit obligation				
Obligation at January 1	$ 881,932	815,593	106,276	106,679
Service cost	8,994	8,279	1,965	1,601
Interest cost	26,168	27,047	3,427	3,444
Participant contributions	–	–	2,104	2,075
Actuarial loss (gain)	(57,378)	60,855	(13,778)	(3,077)
Medicare Part D subsidy	–	–	325	318
Exchange rate changes	(12,742)	18,751	(67)	46
Benefits paid	(41,132)	(39,910)	(5,473)	(4,810)
Prior Service Cost	737	–	–	–
Other	(28,934)	(8,683)	–	–

Obligation at December 31		777,645	881,932	94,779	106,276
Change in plan assets					
Fair value of plan assets at January 1		563,825	519,357	–	–
Actual return on plan assets		(18,951)	50,079	–	–
Employer contributions		24,357	24,918	3,044	2,417
Participant contributions		–	–	2,104	2,075
Medicare Part D subsidy		–	–	325	318
Exchange rate changes		(12,071)	18,064	–	–
Benefits paid		(41,132)	(39,910)	(5,473)	(4,810)
Other		(28,934)	(8,683)	–	–
Fair value of plan assets at December 31		487,094	563,825	–	–
Funded status and amounts recognized in the Consolidated Balance Sheets at December 31					
Deferred charges and other assets		11,039	5,905	–	–
Other accrued liabilities		(9,175)	(8,856)	(5,101)	(5,392)
Deferred credits and other liabilities		(292,415)	(315,156)	(89,678)	(100,884)
Funded status and net plan liability recognized at December 31	$	(290,551)	(318,107)	(94,779)	(106,276)

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – Continued

Note L – Employee and Retiree Benefit Plans (Contd.)

At December 31, 2018, 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	$ (239,030)	13,969
Prior service (cost) credit	(5,568)	–
	$ (244,598)	13,969

Amounts included in AOCL at December 31, 2018 that are expected to be amortized into net periodic benefit expense during 2019 are shown in the following table.

(Thousands of dollars)	Pension Benefits	Other Postretirement Benefits
Net actuarial loss	$ (14,117)	(391)
Prior service (cost) credit	(956)	–
	$ (15,073)	(391)

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)	2018	2017	2018	2017	2018	2017
Funded qualified plans where accumulated benefit obligation exceeds fair value of plan assets	$ 457,446	691,923	447,793	640,230	316,543	540,161

Unfunded nonqualified and directors' plans where accumulated benefit obligation exceeds fair value of plan assets	158,228	172,364	150,586	163,319	–	–
Unfunded other postretirement plans	94,808	106,276	94,808	106,276	–	–

The table that follows provides the components of net periodic benefit expense for each of the three years ended December 31, 2018.

	Pension Benefits			Other Postretirement Benefits		
(Thousands of dollars)	2018	2017	2016	2018	2017	2016
Service cost	$ 8,994	8,279	8,136	1,965	1,601	1,864
Interest cost	26,168	27,047	25,185	3,427	3,444	3,800
Expected return on plan assets	(29,236)	(28,941)	(28,154)	–	–	–
Amortization of prior service cost (credit)	1,021	1,026	1,204	(38)	(74)	(75)
Amortization of transitional (asset) liability	–	–	–	–	–	–
Recognized actuarial loss	21,893	16,691	16,165	–	–	5
	28,840	24,102	22,536	5,354	4,971	5,594
Termination benefits expense	–	–	–	–	–	–
Curtailment expense	–	–	822	–	–	(19)
Net periodic benefit expense	$ 28,840	24,102	23,358	5,354	4,971	5,575

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MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – Continued

Note L – Employee and Retiree Benefit Plans (Contd.)

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

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

	Pension Benefits		Other Postretirement Benefits	
(Thousands of dollars)	2018	2017	2018	2017
Benefit obligation at December 31	$ 173,860	222,483	812	791
Fair value of plan assets at December 31	170,551	212,535	–	–
Net plan liabilities recognized	3,309	9,948	812	791
Net periodic benefit expense (benefit)	3,983	194	146	133

The following table provides the weighted-average assumptions used in the measurement of the Company's benefit obligations at December 31, 2018 and 2017 and net periodic benefit expense for 2018 and 2017.

	Benefit Obligations				Net Periodic Benefit Expense			
	Pension Benefits December 31		Other Postretirement Benefits December 31		Pension Benefits Year		Other Postretirement Benefits Year	
	2018	2017	2018	2017	2018	2017	2018	2017
Discount rate	4.07%	3.42%	3.73%	3.73%	3.54%	3.66%	4.32%	4.33%
Expected return on plan assets	5.37%	5.64%	–	–	5.37%	5.64%	–	–
Rate of compensation increase	3.28%	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	$ 37,266	5,754
2019	37,565	5,839
2020	38,606	5,994
2021	39,660	6,130
2022	39,908	6,171
2023-2027	207,633	32,109

For purposes of measuring postretirement benefit obligations at December 31, 2018, the future annual rates of increase in the cost of health care were assumed to be 6.5% for 2018 decreasing each year to an ultimate rate of 4.5% in 2038 and thereafter.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – Continued

Note L – Employee and Retiree Benefit Plans (Contd.)

Assumed health care cost trend rates have a significant effect on the expense and obligation reported for the postretirement benefit plan. A one percent 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, 2018	$ 1,049	(813)
Effect on the health care component of the accumulated postretirement benefit obligation at December 31, 2018	12,656	(10,350)

During 2018, the Company made contributions of $23.7 million to its domestic defined benefit pension plans, $0.8 million to its foreign defined benefit pension plans and $3.0 million to its domestic postretirement benefits plan. During 2019, Company currently expects to make contributions of $26.7 million to its domestic defined benefit pension plans, $0.6 million to its foreign defined benefit pension plans and $5.1 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.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – Continued

Note L – Employee and Retiree Benefit Plans (Contd.)

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 2019 includes total equity securities of 42% with a range of 37% to 47% of total assets. Fixed income securities have a normal allocation of 56% with a range of 51% to 61%. Cash will normally have an allocation of 2% 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, 2018 and 2017 are presented in the following table.

	December 31,	
	2018	2017
Equity securities	56.0 %	60.3 %
Fixed income securities	42.2	37.2
Cash equivalents	1.8	2.5
	100.0 %	100.0 %

The Company’s weighted average expected return on plan assets was 5.42% in 2018 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 5.42% expected return was based on an expected average future equity securities return of 6.97% and a fixed income securities return of 3.44% 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 7.71%.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – Continued

Note L – Employee and Retiree Benefit Plans (Contd.)

At December 31, 2018, 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, 2018	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	$ 62,105	62,105	–	–
U.S. small/midcap	19,436	19,436	–	–
Hedged funds and other alternative strategies	45,844	–	10,789	35,055
International commingled trust fund	63,089	–	63,089	–
Emerging market commingled equity fund	15,355	–	15,355	–
Fixed income securities:				
U.S. fixed income	87,526	–	87,526	–
International commingled trust fund	13,274	–	13,274	–
Emerging market mutual fund	4,570	–	4,570	–
Cash and equivalents	5,344	5,344	–	–
Total Domestic Plans	316,543	86,885	194,603	35,055
Foreign Plans				
Equity securities funds	67,165	–	67,165	–
Fixed income securities funds	89,417	–	89,417	–
Diversified pooled fund	10,762	–	10,762	–
Cash and equivalents	3,207	–	3,207	–
Total Foreign Plans	170,551	–	170,551	–
Total	$ 487,094	86,885	365,154	35,055

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – Continued

Note L – Employee and Retiree Benefit Plans (Contd.)

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

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. Hedge 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.

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MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – Continued

Note L – Employee and Retiree Benefit Plans (Contd.)

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, 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
Actual return on plan assets:	
Relating to assets held at the reporting date	(2,921)
Relating to assets sold during the period	–
Purchases, sales and settlements	–
Total at December 31, 2018	$ 35,029

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 the Company's match to these plans were $5.2 million in 2018, $7.8 million in 2017 and $7.4 million in 2016.

Note M – 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, 2018, the Company had no open WTI crude oil swap financial contracts. 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.

Foreign Currency Exchange Risks

The Company is subject to foreign currency exchange risk associated with operations in countries outside the U.S. The Company had no foreign currency exchange short-term derivative instruments outstanding as of December 31, 2018 and 2017.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – Continued

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

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

	December 31, 2018		December 31, 2017	
(Thousands of dollars)	Asset (Liability) Derivatives		Asset (Liability) Derivatives	
Type of Derivative Contract	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Commodity	Accounts receivable	$ 3,837	Accounts payable	$ (39,093)

For the years ended December 31, 2018, 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	2018	2017	2016
Commodity	(Loss) gain on crude contracts	$ (41,975)	9,566	(63,412)
Foreign exchange	Interest and other income (loss)	–	–	26,714
		$ (41,975)	9,566	(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 May 2012 to match the payment of interest on these notes through 2022. During each of the three years ended December 31, 2018, $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, 2018 was $7.9 million, which is recorded, net of income taxes of $2.1 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 2019.

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.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – Continued

Note N – Earnings per Share

Net income (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, 2018. The following table reconciles the weighted-average shares outstanding used for these computations.

(Weighted-average shares)	2018	2017	2016
Basic method	172,974,491	172,524,061	172,173,012
Dilutive stock options 1	1,234,274	–	–
Diluted method	174,208,765	172,524,061	172,173,012

1 Due to a net loss recognized by the Company for the years ended December 31, 2017 and 2016, 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, 2018, but were not included in the computation of dilutive earnings per share because the incremental shares from the assumed conversion were antidilutive.

	2018	2017	2016
Antidilutive stock options excluded from diluted shares	3,942,296	4,901,269	5,757,435
Weighted average price of these options	$46.77	$45.74	$48.46

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 $(7.8) million in 2018, $(75.4) million in 2017 and $59.7 million in 2016.

Noncash operating working capital (increased) decreased during each of the three years ended December 31, 2018 as shown in the following table.

(Thousands of dollars)	2018	2017	2016
Accounts receivable	$ (89,070)	114,401	119,671
Inventories	12,216	26,883	(5,171)
Prepaid expenses	(17,341)	29,570	149,946
Deferred income tax assets	–	–	-
Accounts payable and accrued liabilities	(51,769)	(51,439)	(328,078)
Current income tax liabilities	(23,844)	16,999	24,943
Net (increase) decrease in noncash operating working capital	$ (169,808)	136,414	(38,689)
Supplementary disclosures (including discontinued operations):			
Cash income taxes paid, net of refunds	$ 129,296	68,076	6,707
Interest paid, net of amounts capitalized of $5,258 in 2018, $4,488 in 2017 and $4,322 in 2016	167,750	147,975	127,798
Noncash investing activities, related to continuing operations:			
Asset retirement costs capitalized	$ 353,436	8,509	13,690
Decrease (increase) in capital expenditure accrual	(42,467)	99,199	158,885

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – Continued

Note O – Other Financial Information (Contd.)

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, 2018 and December 31, 2017 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, 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	171,725	(7,682)	1,926	165,969
Balance at December 31, 2017	(274,830)	(178,987)	(8,426)	(462,243)
2018 components of other comprehensive income (loss):				
Before reclassifications to income	(145,022)	(16,839)	(1,815)	(163,676)
Reclassifications to income	–	13,790 [1]	2,342 [2]	16,132
Net other comprehensive income (loss)	(145,022)	(3,049)	527	(147,544)
Balance at December 31, 2018	$ (419,852)	(182,036)	(7,899)	(609,787)

[1] Reclassifications before taxes of $17,313 and $14,821 are included in the computation of net periodic benefit expense in 2018 and 2017, respectively. See Note L for additional information. Related income taxes of $3,523 and $5,234 are included in income tax expense in 2018 and 2017, respectively.

[2] Reclassifications before taxes of $2,963 are included in Interest expense in both 2018 and 2017. Related income taxes of $622 and $1,037 are included in income tax expense in 2018 and 2017. See Note M 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.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – Continued

Note Q – Assets and Liabilities Measured at Fair Value (Contd.)

The fair value measurements for these assets and liabilities at December 31, 2018 and 2017 are presented in the following table.

	December 31, 2018				December 31, 2017			
(Thousands of dollars)	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets:								
Commodity derivative contracts	$ –	3,837	–	3,837	–	–	–	–
	$ –	3,837	–	3,837	–	–	–	–
Liabilities:								
Nonqualified employee savings plans	$ 13,845	–	–	13,845	16,158	–	–	16,158
Contingent consideration	–	–	47,730	47,730	–	–	–	–
Commodity derivative contracts	–	–	–	–	–	39,093	–	39,093
	$ 13,845	–	47,730	61,575	16,158	39,093	–	55,251

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's contingent consideration liability (as further described in Note D) is measured at fair value on a recurring basis and is categorized as Level 3 in the fair value hierarchy. The contingent consideration is valued using a Monte Carlo simulation model, which used the following assumptions as of December 31, 2018: (i) the remaining expected life of 7 years, (ii) West Texas Intermediate forward strip pricing with historical volatility of 30.0%, and (iii) a risk-free interest rate of 2.752%. The income effect of changes in the fair value of the contingent consideration is recorded in Other (income) expense in the Consolidated Statements of Operations.

The fair value of West Texas Intermediate (WTI) crude oil contracts in 2018 and 2017 was based on active market quotes for WTI crude oil. The income effect of changes in fair value of crude oil derivative contracts is recorded in Gain (loss) on crude contracts in the Consolidated Statements of Operations, while the effects of changes in fair value of foreign exchange derivative contracts is recorded in Interest and other income (loss).

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, 2018 and 2017.

The following table presents the carrying amounts and estimated fair values of financial instruments held by the Company at December 31, 2018 and 2017. 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 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.

	December 31,			
	2018		2017	
(Thousands of dollars)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Financial assets (liabilities):				
Current and long-term debt	$ (3,237,717)	(3,003,388)	(2,916,422)	(2,993,003)

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – Continued

Note Q – Assets and Liabilities Measured at Fair Value (Contd.)

Fair Values – Nonrecurring

In 2018, as a result of our assessment of market value and our expected recoverable value of select Midland properties in the U.S., the Company recognized a pretax noncash impairment charge of $20.0 million.

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 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 fair value information associated with these impaired properties is presented in the following table.

	Year Ended December 31,				
(Thousands of dollars)	Fair Value Level 1	Level 2	Level 3	Net Book Value Prior to Impairment	Total Pretax (Noncash) Impairment Expense
2018					
Assets:					
Impaired proved properties					
United States Midland	$ –	–	37,690	57,690	20,000
2016					
Assets:					
Impaired proved properties					
Western Canada	$ –	–	71,967	167,055	95,088

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, the West Patricia field and the Gulf of Mexico Cascade Chinook facility. During each of the next five years, expected future net rental payments under all operating leases are approximately $188.6 million in 2019, $88.9 million in 2020, $61.9 million in 2021, $27.6 million in 2022 and $15.6 million in 2023. Rental expense for noncancelable operating leases, including contingent payments when applicable, was $75.3 million in 2018, $72.6 million in 2017, and $77.5 million in 2016. 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 H.

The Company has entered into contracts to hire various drilling rigs and associated equipment for periods beyond December 31, 2018. These rigs will primarily be utilized for drilling operations in onshore U.S., Canada, and the Gulf of Mexico. Future commitments under these contracts, all of which expire by 2020, total $57.9 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.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – Continued

Note R – Commitments (Contd.)

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. Onshore and Gulf of Mexico transportation contracts require minimum monthly payments through 2024, while the Western Canada processing contracts call for minimum monthly payments through 2045. Future required minimum monthly payments for the next five years are $116.8 million in 2019, $128.0 million in 2020, $145.3 million in 2021, $136.2 million in 2022 and $123.7 million in 2023. 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 $52.2 million in 2018, $53.8 million in 2017, and $50.3 million in 2016.

Commitments for capital expenditures were approximately $383.1 million at December 31, 2018, including $165.2 million for costs to develop deepwater U.S. Gulf of Mexico fields including new fields acquired as part of the MP GOM transaction, $103.0 million for field development and future work commitments in Malaysia, $60.0 million for development at Kaybob Duvernay in Canada, $31.4 million for work at Eagle Ford Shale, $14.7 million for exploration cost in Mexico, and $8.8 million for future work commitments in Vietnam.

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.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – Continued

Note S – Contingencies (Contd.)

In 2015, the Company's subsidiary in Canada identified a leak or leaks at an infield condensate transfer pipeline at the Seal field in a remote area of Alberta. The pipeline was immediately shut down and the Company's emergency response plan was activated. In cooperation with local governmental regulators, and with the assistance of qualified consultants, an investigation and remediation plan is progressing as planned and the Company's insurers were notified. Based on the assessments done to date, the Company recorded $43.9 million in Other expense during 2015 and a further $3.8 million in 2018 associated with the estimated costs of remediating the site. The Company has spent $44.7 million from inception to December 31, 2018.

Further refinements in the estimated total cost to remediate the site may occur in future periods. The Company retained the responsibility for this remediation upon sale of the Seal field in 2017. As of December 31, 2018, the Company has a remaining accrued liability of $3.0 million associated with this event. In 2018, the Company received $25.0 million in respect to an insurance claim regarding this matter and the outcome of further insurance claims by the Company is pending.

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

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, 2018 is shown below.

(Number of shares outstanding)	2018	2017	2016
Beginning of year	172,572,873	172,202,177	172,034,711
Stock options exercised 1	21,200	–	–
Restricted stock awards 1	464,756	368,132	158,504

Employee stock purchase and thrift plans	–	2,564	8,962
Treasury shares purchased	–	–	–
End of year	173,058,829	172,572,873	172,202,177

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

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – Continued

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 2018, 2017, and 2016, sales to Phillips 66 and affiliated companies represented approximately 12%, 14% 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, other gains and losses (including foreign exchange gains/losses, and realized/unrealized gains/losses on crude oil contracts), interest expense and unallocated overhead, are shown in the tables to reconcile the business segments to consolidated totals. As used in the table on the following page, certain long-lived assets at December 31 exclude investments, noncurrent receivables, deferred tax assets, and other intangible assets.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – Continued

Segment Information	Exploration and Production				
	United				Total
(Millions of dollars)	States	Canada1	Malaysia	Other	E&P
Year ended December 31, 2018					
Segment income (loss)	$ 242.9	51.1	269.5	(16.6)	546.9
Revenues from external customers	1,289.6	438.6	854.2	22.2	2,604.6 2
Interest income	–	–	–	–	–
Interest expense, net of capitalization	–	–	–	0.2	0.2
Income tax expense (benefit)	68.1	14.5	143.3	(25.3)	200.6
Significant noncash charges (credits)					
Depreciation, depletion and amortization	519.5	232.4	198.6	3.5	954.0
Accretion of asset retirement obligations	19.5	7.7	17.4	–	44.6
Amortization of undeveloped leases	36.8	0.8	–	2.5	40.1
Impairment of assets	20.0	–	–	–	20.0
Deferred and noncurrent income taxes	68.1	16.5	(0.5)	(25.7)	58.4
Additions to property, plant, equipment	1,343.5	373.8	138.6	15.9	1,871.8
Total assets at year-end	6,342.9	1,711.9	1,670.2	188.1	9,913.1
Year ended December 31, 2017					
Segment income (loss)	$ (8.9)	112.5	224.2	(37.5)	290.3
Revenues from external customers	944.3	485.5	781.1	–	2,210.9
Interest income	–	–	–	–	–
Interest expense, net of capitalization	–	–	–	–	–
Income tax expense (benefit)	(0.8)	44.4	126.4	(36.2)	133.8
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 loss	$ (164.2)	(35.9)	171.1	(54.7)	(83.7)
Revenues from external customers	749.1	365.3	753.4	0.2	1,868.0
Interest income	–	–	–	–	–
Interest expense, net of capitalization	–	–	–	–	–
Income tax expense (benefit)	(65.7)	(134.3)	85.9	(18.8)	(132.9)
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

1 Includes Synthetic crude operations in 2016. 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	Certain Long-Lived Assets at December 31					
(Millions of dollars)	United States	Canada	Malaysia	United Kingdom	Other	Total
2018	$ 6,634.3	1,644.6	1,325.4	–	153.3	9,757.6
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

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – Continued

Segment Information — Continued

(Millions of dollars)	Corporate and Other	Discontinued Operations	Consolidated Total
Year ended December 31, 2018			
Segment income (loss)	$ (123.9)	(3.5)	419.5
Revenues from external customers	(34.0)	–	2,570.6
Interest income	8.0	–	8.0
Interest expense, net of capitalization	181.4	–	181.6
Income tax expense (benefit)	(191.3)	–	9.3
Significant noncash charges (credits)			
Depreciation, depletion and amortization	17.9	–	971.9
Accretion of asset retirement obligations	–	–	44.6
Amortization of undeveloped leases	–	–	40.1
Deferred and noncurrent income taxes	(242.1)	–	(183.7)
Additions to property, plant, equipment	22.7	–	1,894.5
Total assets at year-end	1,118.5	20.9	11,052.5
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 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

Geographic Information	Revenues from External Customers for the Year				
(Millions of dollars)	United States	Canada	Malaysia	Other	Total
2018	$ 1,297.5	438.5	854.3	(19.7)	2,570.6
2017	958.3	485.7	781.1	–	2,225.1
2016	692.3	365.3	753.4	0.2	1,811.2

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED)

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 RESERVES

SCHEDULE 2 – SUMMARY OF PROVED NATURAL GAS LIQUIDS RESERVES

SCHEDULE 3 – SUMMARY OF PROVED NATURAL GAS RESERVES

Reserves of crude 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. Reserve estimates and future cash flows are based on the average market prices for sales of oil and gas on the first calendar day of each month during the year. The average prices used for 2018 were $65.56 per barrel for NYMEX crude oil (WTI), and $3.10 per Mcf for natural gas (Henry Hub). The average prices used for 2017 were $51.34 per barrel for NYMEX crude oil (WTI), and $2.98 per Mcf for natural gas (Henry Hub). 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 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 common 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 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 five percent 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 the extraction of natural gas liquids.

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

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED) – Continued

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, 2018, liquids and natural gas proved reserves associated with the production sharing contracts in Malaysia totaled 51.7 million barrels and 468.2 billion cubic feet (BCF), respectively. At December 31, 2018, approximately 26.1 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 was 21% 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, 2018.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED) – Continued

Schedule 1 – Summary of Proved Crude Oil Reserves Based on Average Prices for 2015 – 2018

	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, 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	–
Revisions of previous estimates	(15.3)	(15.3)	(15.0)	(8.0)	7.7	–
Improved recovery	0.8	0.8	–	–	0.8	–
Extensions and discoveries	58.9	58.9	42.9	16.0	–	–
Purchases of properties	93.6	93.6	92.3	–	1.3	–
Production	(33.6)	(33.6)	(18.4)	(4.5)	(10.7)	–
December 31, 2018 2	432.5	432.5	326.5	55.0	51.0	–
Proved developed crude oil/ synthetic oil reserves:						
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	–
December 31, 2018 3	249.3	249.3	189.0	23.3	37.0	–
Proved undeveloped crude oil reserves:						
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	–
December 31, 2018 4	183.2	183.2	137.5	31.7	14.0	–

1 All synthetic oil operations were sold in June 2016.

2 Includes total proved reserves of 25.5 MMBO for Total and United States attributable to the noncontrolling interest in MP GOM.

3 Includes proved developed reserves of 19.1 MMBO for Total and United States attributable to the noncontrolling interest in MP GOM.

4 Includes proved undeveloped reserves of 6.4 MMBO for Total and United States attributable to the noncontrolling interest in MP GOM.

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MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED) – Continued

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

for 2015 – 2018 – Continued

2018 Comments for Proved Crude Oil Reserves Changes

Revisions of previous estimates – The 2018 negative crude oil revision in the U.S. was primarily attributable to revised type curves and the removal of proved undeveloped locations outside the 5-year development window. The negative Canadian oil reserves revisions in 2018 resulted from removing locations in lower performing areas of the Kaybob Duvernay as well as locations removed in Hibernia Offshore Canada due to updated operator development plans. The positive revisions for crude oil reserves in Malaysia were principally attributable to continued development in Kakap field and improved performance in South Acis field.

Improved recovery – The 2018 Malaysia crude oil proved reserve addition was due to favorable impacts from gas lift activity at the Kikeh field.

Extensions and discoveries – In 2018, proved oil reserves were added in the U.S. for drilling activities in the Eagle Ford Shale, and in Canada for drilling activities in the Kaybob Duvernay. Proved oil reserves were also added for drilling activities in the U.S. offshore.

Purchases of properties – In 2018, the Company acquired producing assets from PAI, which were contributed to MP GOM, for which Murphy owns 80% of the associated assets and oversees operations. In addition, the Company acquired partial ownership in the Jagus East field in Brunei.

2017 Comments for Proved Crude Oil Reserves Changes

Revisions of previous estimates – 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 estimates – 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.

2016 Comments for Proved Crude Oil and Synthetic Oil Reserves Changes (Contd.)

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.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED) – Continued

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

for 2015 – 2018

(Millions of barrels)	Total	United States	Canada	Malaysia
Proved developed and undeveloped NGL reserves:				
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	–
Purchase 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
Revisions of previous estimates	(6.2)	(5.3)	(1.6)	0.7
Extensions and discoveries	12.0	9.7	2.3	–
Purchases of properties	3.0	3.0	–	–
Production	(3.5)	(2.8)	(0.4)	(0.3)
December 31, 2018 1	54.2	47.6	5.9	0.7
Proved developed NGL reserves:				
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
December 31, 2018 2	27.3	24.9	1.7	0.7
Proved undeveloped NGL reserves:				
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	–
December 31, 2018 3	26.9	22.7	4.2	–

1 Includes total proved reserves of 1.1 MMBBL for Total and United States attributable to the noncontrolling interest in MP GOM.

2 Includes proved developed reserves of 0.8 MMBBL for Total and United States attributable to the noncontrolling interest in MP GOM.

3 Includes proved undeveloped reserves of 0.3 MMBBL for Total and United States attributable to the noncontrolling interest in MP GOM.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED) – Continued

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

for 2015 – 2018 – Continued

2018 Comments for Proved Natural Gas Liquids Reserves Changes

Revisions of previous estimates – The negative 2018 NGL proved reserves revision in the U.S. was primarily in the Company's Eagle Ford Shale fields based on removal of proved undeveloped locations outside the 5-year development window. The negative Canadian NGL reserves revisions in 2018 resulted from removing locations in lower performing areas of the Kaybob Duvernay. The positive revisions for NGL reserves in Malaysia were principally attributable to improved performance for gas fields offshore Sarawak.

Extensions and discoveries – In 2018, proved NGL reserves were added in the U.S. for drilling activities in the Eagle Ford Shale, and in Canada for drilling activities in the Kaybob Duvernay.

Purchases of properties – In 2018, the Company acquired producing assets from PAI, which were contributed to MP GOM, for which Murphy owns 80% of the associated assets and oversees operations.

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.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED) – Continued

Schedule 3 – Summary of Proved Natural Gas Reserves Based on Average Prices for 2015 – 2018

(Billions of cubic feet)	Total	United States	Canada	Malaysia
Proved developed and undeveloped natural gas reserves:				
December 31, 2015	1,688.8	232.4	909.6	546.8
Revisions of previous estimates	43.3	0.1	45.3	(2.1)
Improved recovery	164.2	6.4	120.2	37.6
Extensions and discoveries	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
Revisions of previous estimates	(1.8)	37.6	(51.2)	11.8
Improved recovery	0.6	–	–	0.6
Extensions and discoveries	310.3	44.7	261.0	4.6
Purchases of properties	61.7	20.3	41.4	–
Production	(154.3)	(16.9)	(97.2)	(40.2)
December 31, 2018 1	2,143.6	309.0	1,366.4	468.2
Proved developed natural gas reserves:				
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
December 31, 2018 2	921.6	198.3	595.0	128.3
Proved undeveloped natural gas reserves:				
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
December 31, 2018 3	1,222.0	110.7	771.4	339.9

1 Includes total proved reserves of 10.8 BCF for Total and United States attributable to the noncontrolling interest in MP GOM.

2 Includes proved developed reserves of 8.2 BCF for Total and United States attributable to the noncontrolling interest in MP GOM.

3 Includes proved undeveloped reserves of 2.6 BCF for Total and United States attributable to the noncontrolling interest in MP GOM.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED) – Continued

Schedule 3 – Summary of Proved Natural Gas Reserves Based on Average Prices for 2015 – 2018 – Continued

2018 Comments for Proved Natural Gas Reserves Changes

Revisions of previous estimates – In 2018, the U.S. positive natural gas revision was primarily due to drilling within the Eagle Ford Shale. The 2018 negative natural gas revisions in Canada resulted from removing locations in lower performing areas of the Kaybob Duvernay asset partially offset by positive performance revisions in the Tupper Montney asset. The positive revision for natural gas reserves in Malaysia was primarily attributable to positive performance revisions at the Company's Sarawak projects offset somewhat by negative Block H revisions attributable to higher government entitlement under the terms of the respective production sharing contracts due to higher gas prices.

Improved recovery – The 2018 Malaysia natural gas proved reserve addition was due to favorable impacts from gas lift activity at the Kikeh field.

Extensions and discoveries – In 2018, 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 Montney and Kaybob Duvernay areas in Western Canada. In Malaysia, proved natural gas reserves were added in the Merapuh field in Sarawak from field development activities.

Purchases of properties – In 2018, the Company acquired producing assets from PAI, which were contributed to MP GOM, for which Murphy owns 80% of the associated assets and overseas operations. In addition, the Company acquired acreage in Tupper Montney in Western Canada.

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.

2016 Comments for Proved Natural Gas Reserves Changes (Contd.)

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.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED) – Continued

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, 2018					
Property acquisition costs					
Unproved	$ 2.8	–	–	0.2	3.0
Proved	794.3	–	–	–	794.3
Total acquisition costs	797.1	–	–	0.2	797.3
Exploration costs 1	88.1	0.6	2.2	35.1	126.0
Development costs 1	853.7	373.8	145.9	16.6	1,390.0
Total costs incurred	1,738.9	374.4	148.1	51.9	2,313.3
Charged to expense					
Dry hole expense	16.0	–	0.1	4.5	20.6
Geophysical and other costs	13.4	0.6	2.1	31.3	47.4
Total charged to expense	29.4	0.6	2.2	35.8	68.0
Property additions	$ 1,709.5	373.8	145.9	16.1	2,245.3
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

1 Includes noncash asset retirement costs as follows:

2018						
Exploration costs	$	–	–	–	–	–
Development costs		366.0	–	7.3	0.2	373.5
	$	366.0	–	7.3	0.20	373.5
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

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MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED) – Continued

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

(Millions of dollars)	United States	Canada	Malaysia	Other	Total
Year ended December 31, 2018					
Revenues					
Crude oil and natural gas liquids sales	$ 1,245.3	291.2	708.8	6.1	2,251.4
Natural gas sales	42.9	147.6	144.7	–	335.2
Total oil and gas revenues	1,288.2	438.8	853.5	6.1	2,586.6
Other operating revenues	1.4	(0.2)	0.7	16.1	18.0
Total revenues	1,289.6	438.6	854.2	22.2	2,604.6
Costs and expenses					
Lease operating expenses	230.5	122.6	202.1	0.7	555.9
Severance and ad valorem taxes	50.9	1.2	–	–	52.1
Exploration costs charged to expense	29.4	0.6	2.2	31.6	63.8
Undeveloped lease amortization	36.8	0.8	–	2.5	40.1
Depreciation, depletion and amortization	519.5	232.4	198.6	3.5	954.0
Accretion of asset retirement obligations	19.5	7.7	17.4	–	44.6
Impairment of assets	20.0	–	–	–	20.0
Redetermination expense	–	–	11.3	–	11.3
Selling and general expenses	49.0	26.8	10.8	23.5	110.1
Other expenses (benefits)	23.0	(19.1)	(1.0)	2.3	5.2
Total costs and expenses	978.6	373.0	441.4	64.1	1,857.1
Results of operations before taxes	311.0	65.6	412.8	(41.9)	747.5
Income tax expense (benefit)	68.1	14.5	143.3	(25.3)	200.6
Results of operations	$ 242.9	51.1	269.5	(16.6)	546.9
Year ended December 31, 2017					
Revenues					
Crude oil and natural gas liquids sales	$ 903.7	203.7	639.9	–	1,747.3
Natural gas sales	37.9	155.1	138.2	–	331.2
Total oil and gas revenues	941.6	358.8	778.1	–	2,078.5
Other operating revenues	2.7	126.7	3.0	–	132.4
Total revenues	944.3	485.5	781.1	–	2,210.9
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	(9.7)	156.9	350.6	(73.7)	424.1
Income tax expense (benefit)	(0.8)	44.4	126.4	(36.2)	133.8
Results of operations	$ (8.9)	112.5	224.2	(37.5)	290.3

1 Results exclude corporate overhead, interest and discontinued operations. 2018 includes noncontrolling interest in MP GOM.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED) – Continued

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

(Millions of dollars)	United States	Canada Conven-tional	Synthetic	Malaysia	Other	Total
Year ended December 31, 2016						
Revenues						
Crude oil and natural gas liquids sales	$ 714.1	171.7	60.7	623.7	–	1,570.2
Natural gas sales	35.1	130.0	–	127.6	–	292.7
Total oil and gas revenues	749.2	301.7	60.7	751.3	–	1,862.9
Other operating revenues	(0.1)	(0.7)	3.6	2.1	0.2	5.1
Total revenues	749.1	301.0	64.3	753.4	0.2	1,868.0
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	54.0	28.2	0.5	15.4	33.6	131.7
Other expenses	7.3	7.9	–	24.3	(9.9)	29.6
Total costs and expenses	979.0	443.8	91.7	496.4	73.7	2,084.6
Results of operations before taxes	(229.9)	(142.8)	(27.4)	257.0	(73.5)	(216.6)
Income tax expense (benefit)	(65.7)	(58.9)	(75.4)	85.9	(18.8)	(132.9)
Results of operations	$ (164.2)	(83.9)	48.0	171.1	(54.7)	(83.7)

1 Results exclude corporate overhead, interest and discontinued operations.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED) – Continued

Schedule 6 – Standardized Measure of Discounted Future Net Cash Flows Relating to

Proved Oil and Gas Reserves 1

(Millions of dollars)	United States	Canada	Malaysia	Total
December 31, 2018				
Future cash inflows	$ 23,473.9	5,437.5	5,511.6	34,423.0
Future development costs	(3,279.1)	(1,362.7)	(517.4)	(5,159.2)
Future production costs	(7,279.5)	(2,693.0)	(2,813.4)	(12,785.9)
Future income taxes	(2,216.5)	(236.4)	(472.0)	(2,924.9)
Future net cash flows	10,698.8	1,145.4	1,708.8	13,553.0
10% annual discount for estimated timing of cash flows	(4,295.4)	(531.4)	(446.3)	(5,273.1)
Standardized measure of discounted future net cash flows	$ 6,403.4	614.0	1,262.5	8,279.9
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

1 2018 includes noncontrolling interest in MP GOM.

MURPHY OIL CORPORATION AND CONSOLIDATED SUBSIDIARIES

SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED) – Continued

Schedule 6 – Standardized Measure of Discounted Future Net Cash Flows Relating to

Proved Oil and Gas Reserves – Continued 1

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

(Millions of dollars)	2018	2017	2016
Net changes in prices and production costs	$ 2,972.6	2,428.4	(1,476.1)
Net changes in development costs	(1,891.1)	(724.4)	544.9
Sales and transfers of oil and gas produced, net of production costs	(1,978.6)	(1,576.0)	(1,196.3)
Net change due to extensions and discoveries	1,930.3	807.9	280.5
Net change due to purchases and sales of proved reserves	3,152.4	85.9	(583.4)
Development costs incurred	1,017.3	802.7	479.6
Accretion of discount	469.5	270.9	428.1
Revisions of previous quantity estimates	(347.8)	(109.5)	(49.2)
Net change in income taxes	(967.6)	(643.0)	292.8
Net increase (decrease)	4,357.0	1,342.9	(1,279.1)
Standardized measure at January 1	3,922.9	2,580.0	3,859.1
Standardized measure at December 31	$ 8,279.9	3,922.9	2,580.0

1 2018 includes noncontrolling interest in MP GOM.

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

(Millions of dollars)	United States	Canada	Malaysia	Other	Total
December 31, 2018					
Unproved oil and gas properties	$ 394.2	250.0	21.2	176.9	842.3
Proved oil and gas properties	11,678.3	3,693.0	6,263.5	–	21,634.8
Gross capitalized costs	12,072.5	3,943.0	6,284.7	176.9	22,477.1

Accumulated depreciation, depletion and amortization					
Unproved oil and gas properties	(129.3)	(213.5)	–	(25.4)	(368.2)
Proved oil and gas properties	(5,433.7)	(2,088.8)	(4,963.5)	–	(12,486.0)
Net capitalized costs	$ 6,509.5	1,640.7	1,321.2	151.5	9,622.9
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

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, 2018 1					
Revenue from contracts with customers	$ 606.9	655.2	659.8	664.7	2,586.6
Income (loss) from continuing operations before income taxes	97.0	82.3	146.8	106.2	432.3
Income (loss) from continuing operations	168.7	45.9	95.8	112.6	423.0
Net income including noncontrolling interest	168.3	45.5	93.9	111.8	419.5
Net income attributable to Murphy	168.3	45.5	93.9	103.4	411.1
Income (loss) from continuing operations per Common share					
Basic	0.98	0.26	0.55	0.60	2.39
Diluted	0.97	0.26	0.55	0.59	2.37
Net income (loss) per Common share					
Basic	0.97	0.26	0.54	0.60	2.38
Diluted	0.96	0.26	0.54	0.59	2.36
Cash dividend per Common share	0.25	0.25	0.25	0.25	1.00
Year ended December 31, 2017					
Revenue from contracts with customers	$ 509.0	477.6	511.2	580.5	2,078.5
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) attributable to Murphy	58.5	(17.6)	(65.9)	(286.8)	(311.8)
Income 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

1 2018 includes noncontrolling interest in MP GOM.

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
2018					
Deducted from asset accounts:					
Allowance for doubtful accounts	$ 1.6	–	–	–	1.6
Deferred tax asset valuation allowance	476.3	3.3	–	(265.9)	213.7
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

1Amounts in 2017 and 2016 for deferred tax asset valuations are primarily associated with an increase in foreign tax credit carryforwards. The amount in 2018 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

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

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

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

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 to pay costs