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	New York Stock Exchange
Preferred Stock Purchase Rights	

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

TABLE OF CONTENTS

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.

7

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

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.

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

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
Oblig