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 1-1204

Hess Corporation

(Exact name of Registrant as specified in its charter)

DELAWARE	**13-4921002**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification Number)*
1185 AVENUE OF THE AMERICAS, NEW YORK, N.Y.	**10036**
(Address of principal executive offices)	*(Zip Code)*

(Registrant's telephone number, including area code, is (212) 997-8500)

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

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock (par value $1.00)	**New York Stock Exchange**

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

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

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange 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 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, a smaller reporting company or emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company" and "emerging growth company" in Rule 12b-2 of the Exchange Act:

Large accelerated filer	☑	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 Exchange Act). Yes ☐ No ☑

The aggregate market value of voting stock held by non-affiliates of the Registrant amounted to $17,510,000,000, computed using the outstanding common shares and closing market price on June 29, 2018, the last business day of the Registrant's most recently completed second fiscal quarter.

At January 31, 2019, there were 303,034,262 shares of Common Stock outstanding.

Part III is incorporated by reference from the Proxy Statement for the 2019 annual meeting of stockholders.

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Unless the context indicates otherwise, references to "Hess", the "Corporation", the "Company", "Registrant", "we", "us", "our" and "its" refer to the consolidated business operations of Hess Corporation and its subsidiaries.

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain sections in this Annual Report on Form 10-K, including information incorporated by reference herein, and those made under the captions *Business and Properties*, *Management's Discussion and Analysis of Financial Condition and Results of Operations* and *Quantitative and Qualitative Disclosures about Market Risk* contain "forward-looking" statements, as defined under the Private Securities Litigation Reform Act of 1995. Generally, the words "anticipate," "estimate," "expect," "forecast," "guidance," "could," "may," "should," "would," "believe," "intend," "project," "plan," "predict," "will," "target" and similar expressions identify forward-looking statements, which generally are not historical in nature. Forward-looking statements related to our operations are based on our current understanding, assessments, estimates and projections of relevant factors and reasonable assumptions about the future. Forward-looking statements are subject to certain known and unknown risks and uncertainties that could cause actual results to differ materially from our historical experience and our current projections or expectations of future results expressed or implied by these forward-looking statements. As and when made, we believe that these forward-looking statements are reasonable. However, given these uncertainties, caution should be taken not to place undue reliance on any such forward-looking statements since such statements speak only as of the date when made and there can be no assurance that such forward-looking statements will occur and actual results may differ materially from those contained in any forward-looking statement we make. Except as required by law, we undertake no obligation to publicly update or revise any forward-looking statements, whether because of new information, future events or otherwise. Risk factors that could materially impact future actual results are discussed under *Item 1A. Risk Factors* within this document.

Glossary

Throughout this report, the following company or industry specific terms and abbreviations are used:

Appraisal well – An exploration well drilled to confirm the results of a discovery well, or a well that is used to determine the boundaries of a productive formation.

Bbl – One stock tank barrel, which is 42 United States gallons liquid volume.

Barrel of oil equivalent or Boe – This reflects natural gas reserves converted on the basis of relative energy content of six mcf equals one barrel of oil equivalent (one mcf represents one thousand cubic feet). Barrel of oil equivalence does not necessarily result in price equivalence, as the equivalent price of natural gas on a barrel of oil equivalent basis has been substantially lower than the corresponding price for crude oil over the recent past.

Boepd – Barrels of oil equivalent per day.

Bopd – Barrels of oil per day.

Condensate – A mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that when produced, is in the liquid phase at surface pressure and temperature.

Development well – A well drilled within the proved area of an oil and/or natural gas reservoir with the intent of producing oil and/or natural gas from that area of the reservoir.

Dry hole or dry well – An exploratory or development well that does not find oil or natural gas in commercial quantities.

Exploratory well – A well drilled to find oil or natural gas in an unproved area or find a new reservoir in a field previously found to be productive by another reservoir.

Fractionation – Fractionation is the process by which the mixture of natural gas liquids that results from natural gas processing is separated into the NGL components, such as ethane, propane, butane, isobutane, and natural gasoline, prior to their sale to various petrochemical and industrial end users. Fractionation is accomplished by controlling the temperature of the stream of mixed liquids in order to take advantage of the difference in boiling points of separate products.

Field – An area consisting of a single reservoir or multiple reservoirs all grouped or related to the same individual geological structural feature and/or stratigraphic condition.

FPSO – Floating production, storage, and offloading vessel.

Gross acreage – Acreage in which a working interest is held by the Corporation.

Gross well – A well in which a working interest is held by the Corporation.

Mcf – One thousand cubic feet of natural gas.

Mmcfd – One thousand mcf of natural gas per day.

Net acreage or Net wells – The sum of the fractional working interests owned by us in gross acres or gross wells.

NGLs or Natural gas liquids – Naturally occurring substances that are separated and produced by fractionating natural gas, including ethane, butane, isobutane, propane and natural gasoline. NGLs do not sell at prices equivalent to crude oil.

Non-operated – Projects in which the Corporation has a working interest but does not perform the role of Operator.

OPEC – Organization of Petroleum Exporting Countries.

Operator – The entity responsible for conducting and managing exploration, development, and/or production operations for an oil or gas project.

Participating interest – Reflects the proportion of exploration and production costs each party will bear or the proportion of production each party will receive, as set out in an operating agreement.

Production entitlement – The share of gross production the Corporation is entitled to receive under the terms of a production sharing contract.

Production sharing contract – An agreement between a host government and the owners (or co-owners) of a well or field regarding the percentage of production each party will receive after the parties have recovered a specified amount of capital and operational expenses.

Productive well – A well that is capable of producing hydrocarbons in sufficient quantities to justify commercial exploitation.

Proved properties – Properties with proved reserves.

Proved reserves – In accordance with the Securities and Exchange Commission regulations and practices recognized in the publication of the Society of Petroleum Engineers entitled, *"Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information,"* those quantities of crude oil and condensate, NGLs and natural 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 prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

Proved developed reserves – Proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods or for which the cost of the required equipment is relatively minor compared to the cost of a new well.

Proved undeveloped reserves – Proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

Unproved properties – Properties with no proved reserves.

Working interest – An interest in an oil and gas property that provides the owner of the interest the right to drill for and produce oil and gas on the relevant acreage and requires the owner to pay a share of the costs of drilling and production operations.

Items 1 and 2. Business and Properties

Hess Corporation, incorporated in the State of Delaware in 1920, is a global Exploration and Production (E&P) company engaged in exploration, development, production, transportation, purchase and sale of crude oil, natural gas liquids, and natural gas with production operations located primarily in the United States (U.S.), Denmark, the Malaysia/Thailand Joint Development Area (JDA) and Malaysia. We conduct exploration activities primarily offshore Guyana, Suriname, Canada and in the U.S. Gulf of Mexico. At the Stabroek Block (Hess 30%), offshore Guyana, we have participated in twelve significant discoveries. The Liza Phase 1 development was sanctioned in 2017 and is expected to startup in early 2020 with production reaching up to 120,000 gross bopd. The discovered resources to date on the Stabroek Block are expected to underpin the potential for at least five FPSOs producing more than 750,000 gross bopd by 2025.

Our Midstream operating segment provides fee-based services, including gathering, compressing and processing natural gas and fractionating NGLs; gathering, terminaling, loading and transporting crude oil and NGLs; storing and terminaling propane, and water handling services primarily in the Bakken and Three Forks Shale plays in the Williston Basin area of North Dakota.

See *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations* for further details.

Exploration and Production

Proved Reserves

Proved reserves are calculated using the average price during the twelve-month period ending December 31 determined as an unweighted arithmetic average of the price on the first day of each month within the year, unless prices are defined by contractual agreements, and exclude escalations based on future conditions. Crude oil prices used in the determination of proved reserves at December 31, 2018 were $65.55 per barrel for West Texas Intermediate (WTI) (2017: $51.19) and $72.08 per barrel for Brent (2017: $54.87). Our total proved developed and undeveloped reserves at December 31 were as follows:

	Crude Oil & Condensate		Natural Gas Liquids		Natural Gas		Total Barrels of Oil Equivalent (BOE)	
	2018	2017	2018	2017	2018	2017	2018	2017
	(Millions of bbls)		(Millions of bbls)		(Millions of mcf)		(Millions of bbls)	
Developed								
United States	**266**	239	**85**	87	**432**	526	**423**	414
Europe	**38**	45	**—**	—	**77**	80	**51**	58
Africa	**111**	112	**—**	—	**115**	117	**130**	132
Asia and other	**4**	5	**—**	—	**585**	696	**102**	121
	419	401	**85**	87	**1,209**	1,419	**706**	725
Undeveloped								
United States	**235**	194	**90**	84	**381**	354	**389**	337
Europe	**1**	4	**—**	—	**1**	12	**1**	6
Africa	**15**	16	**—**	—	**13**	7	**17**	17
Asia and other (a)	**44**	44	**—**	—	**211**	149	**79**	69
	295	258	**90**	84	**606**	522	**486**	429
Total								
United States	**501**	433	**175**	171	**813**	880	**812**	751
Europe	**39**	49	**—**	—	**78**	92	**52**	64
Africa	**126**	128	**—**	—	**128**	124	**147**	149
Asia and other (a)	**48**	49	**—**	—	**796**	845	**181**	190
	714	659	**175**	171	**1,815**	1,941	**1,192**	1,154

(a) Asia and other includes proved undeveloped reserves in Guyana of 42 million boe at December 31, 2018 (2017: 45 million boe).

Proved undeveloped reserves were 41% of our total proved reserves at December 31, 2018 on a boe basis (2017: 37%). Proved reserves held under production sharing contracts totaled 7% of our crude oil reserves and 44% of our natural gas reserves at December 31, 2018 (2017: 7% and 44%, respectively).

For additional information regarding our proved oil and gas reserves, see the *Supplementary Oil and Gas Data* to the *Consolidated Financial Statements* presented on pages 82 through 92.

Production

Worldwide crude oil, natural gas liquids, and natural gas net production was as follows:

	2018	2017	2016
Crude oil - Thousands of barrels			
United States			
Bakken	**27,663**	24,439	24,881
Other Onshore (a)	**389**	2,053	3,209
Total Onshore	**28,052**	26,492	28,090
Offshore	**15,026**	14,411	16,649
Total United States	**43,078**	40,903	44,739
Europe			
Norway (a)	—	7,236	8,387
Denmark	**2,231**	2,988	3,636
	2,231	10,224	12,023
Africa			
Equatorial Guinea (a)	—	9,201	11,898
Libya	**6,654**	3,542	387
	6,654	12,743	12,285
Asia			
JDA	**546**	586	616
Malaysia	**851**	289	152
	1,397	875	768
Total	**53,360**	64,745	69,815
Natural gas liquids - Thousands of barrels			
United States			
Bakken	**10,767**	10,107	9,701
Other Onshore (a)	**1,647**	2,972	4,205
Total Onshore	**12,414**	13,079	13,906
Offshore	**1,703**	1,733	1,724
Total United States	**14,117**	14,812	15,630
Europe - Norway (a)	—	340	408
Total	**14,117**	15,152	16,038
Natural gas - Thousands of mcf			
United States			
Bakken	**25,625**	22,621	22,312
Other Onshore (a)	**16,167**	33,478	48,597
Total Onshore	**41,792**	56,099	70,909
Offshore	**24,452**	20,987	23,603
Total United States	**66,244**	77,086	94,512
Europe			
Norway (a)	—	6,739	8,541
Denmark	**2,958**	5,124	7,128
	2,958	11,863	15,669
Asia and Other			
JDA	**68,477**	73,444	68,031
Malaysia (b)	**59,995**	27,225	13,151
Other	**4,288**	—	—
	132,760	100,669	81,182
Total	**201,962**	189,618	191,363
Total Barrels of Oil Equivalent (in millions) (a) (b)	**101**	112	118

(a) In August 2018, the Corporation sold its Utica Assets, onshore U.S. Utica production averaged 9,000 boepd for calendar year 2018 (2017: 19,000 boepd; 2016: 29,000 boepd). In 2017, the Corporation sold its assets in Equatorial Guinea (November), Norway (December), and the Permian, onshore U.S. (August). Permian production averaged 4,000 boepd for calendar year 2017 (2016: 7,000 boepd).

(b) Includes 6,442 thousand mcf of production for 2018 (2017: 4,256 thousand mcf; 2016: 3,624 thousand mcf) from Block PM301 which is unitized into Block A-18 of the JDA.

E&P Operations

At December 31, 2018, our significant E&P assets included the following:

United States

Our production in the U.S. was from onshore properties, principally in the Bakken oil shale play in the Williston Basin of North Dakota (Bakken) and from offshore properties in the Gulf of Mexico.

Onshore:

Bakken: At December 31, 2018, we held approximately 543,000 net acres in the Bakken with varying working interest percentages. During 2018, we operated an average of 4.8 rigs, drilled 121 wells, completed 118 wells, and brought 104 wells on production, bringing the total operated production wells to 1,414 by year-end. During 2018, we transitioned from utilizing sliding sleeve completion designs to plug and perf completions. During 2019, we plan to operate six rigs, drill approximately 170 wells and bring approximately 160 wells on production. From 2019, all production wells will use plug and perf completions, which we expect will allow us to increase peak net production to approximately 200,000 boepd by 2021. We forecast net production for full year 2019 to be in the range of 135,000 boepd to 145,000 boepd, compared to production of 117,000 boepd in 2018.

Offshore:

Gulf of Mexico: At December 31, 2018, we held approximately 75,000 net developed acres, with our production operations principally at the Baldpate (Hess 50%), Conger (Hess 38%), Hack Wilson (Hess 25%), Llano (Hess 50%), Penn State (Hess 50%), Shenzi (Hess 28%), Stampede (Hess 25%) and Tubular Bells (Hess 57%) Fields. At December 31, 2018, we held approximately 270,000 net undeveloped acres, of which leases covering approximately 37,000 acres are due to expire in the next three years.

Production from the Baldpate, Conger, Llano, and Penn State Fields were shut-in following a fire at the third-party operated Enchilada platform in November 2017. In 2018, production restarted at the Baldpate, Llano, and Penn State Fields in the first quarter, and at the Conger Field in the third quarter. At the Hess operated Stampede Field, production commenced in January 2018. In 2019, we plan to drill one production well and two water injection wells at the Stampede Field, one production well at the Llano Field, and one exploration well at the Esox prospect which, if successful, can be tied back into production facilities at the Tubular Bells Field.

Asia

***Malaysia/Thailand Joint Development Area (JDA)*:** At the Carigali Hess operated offshore Block A-18 in the Gulf of Thailand (Hess 50%), no drilling is planned for 2019 as contracted volumes are expected to be met from the booster compression project that came online in 2016.

Malaysia: Our production in Malaysia comes from our interest in Block PM301 (Hess 50%), which is adjacent to and is unitized with Block A-18 of the JDA and our 50% interest in Block PM302 located in the North Malay Basin (NMB), offshore Peninsular Malaysia. Production from full-field development commenced in July 2017. In 2019, we plan to continue the drilling program and development activities.

Europe

Denmark: Production comes from our operated interest in the South Arne Field (Hess 62%). In 2018, we decided to retain our interest in the field after offers received in a previously announced sale process did not meet our value expectations. During 2019, we plan to drill an exploration well on License 06/16, located approximately 19 miles from South Arne.

Africa

Libya: At the onshore Waha concession in Libya, which includes the Defa, Faregh, Gialo, North Gialo and Belhedan Fields (Hess 8%), net production averaged approximately 20,000 boepd in 2018, 10,000 boepd in 2017, and 1,000 boepd in 2016. Production was shut-in by the operator for extended periods in 2016 due to force majeure caused by civil unrest. The Company’s net investment in Libya was approximately $55 million at December 31, 2018.

Other Non-Producing Countries

Guyana: At the Stabroek Block (Hess 30%), which covers approximately 6.6 million acres offshore Guyana, the operator Esso Exploration and Production Guyana Limited has made twelve significant discoveries to date. The first phase of the Liza Field development, which was sanctioned in 2017, is expected to begin producing oil by early 2020. Phase 1 will use the Liza Destiny FPSO to produce up to 120,000 gross bopd. Drilling of development wells in the Liza Field is continuing, subsea equipment is being prepared for installation, and the topside facilities modules have been installed on the Liza Destiny FPSO in Singapore, which is expected to arrive offshore Guyana in the third quarter of 2019. Preparations are also underway for the installation of subsea umbilicals, risers and flowlines at the Liza Field in the spring of 2019.

Phase 2 of the Liza Field development is expected to start production by mid-2022. Pending government and regulatory approvals, project sanction for Phase 2 is expected by the operator in the first quarter of 2019 and will include a second FPSO vessel designed to produce up to 220,000 gross bopd. Project sanction for a third phase of development at the Payara Field is expected in 2019 with first production expected to start up as early as 2023. In addition to the first three phases, development planning is underway for additional FPSOs. The ultimate sizing and timing will be a function of further exploration and appraisal drilling.

The operator is currently utilizing three drillships on the block. The Stena Carron and the Noble Tom Madden, which arrived in the third quarter of 2018, are involved in exploration and appraisal drilling. The Noble Bob Douglas is drilling development wells for Liza Phase 1. In 2018, the following explorations wells were drilled on the Stabroek Block (in chronological order):

Ranger-1: The well, located approximately 60 miles northwest of the Liza discovery, encountered approximately 230 feet of high-quality, oil-bearing carbonate reservoir.

Pacora-1: The well encountered approximately 65 feet of high-quality, oil-bearing sandstone reservoir, and is located approximately four miles west of the Payara-1 well, which was drilled in 2017. The operator plans to integrate this discovery into the Payara Field development.

Liza-5: The well encountered 77 feet of high-quality, oil-bearing sandstone reservoir and is located approximately six miles northwest of the Liza-1 well, which was drilled in 2016.

Sorubim-1: The well did not encounter commercial quantities of hydrocarbons.

Longtail-1: The well encountered approximately 256 feet of high-quality, oil-bearing sandstone reservoir and is located approximately five miles west of the Turbot-1 well, which was drilled in 2017.

Hammerhead-1: The well encountered approximately 197 feet of high-quality, oil-bearing sandstone reservoir and is located approximately 13 miles to the southwest of the Liza-1 well.

Pluma-1: The well encountered approximately 121 feet of high-quality, hydrocarbon-bearing sandstone reservoir and represents the tenth discovery on the Block. The well is located approximately 17 miles south of the Turbot-1 well.

In February 2019, the operator announced the eleventh and twelfth discoveries on the Stabroek Block at the Tilapia-1 and Haimara-1 wells. The Tilapia-1 well encountered approximately 305 feet of high-quality, oil-bearing sandstone reservoir, and is located approximately three miles west of the Longtail-1 well. The Haimara-1 well encountered approximately 207 feet of high-quality, gas condensate-bearing sandstone reservoir, and is located approximately 19 miles east of the Pluma-1 well.

In 2019, additional drilling is planned, including appraisal of the Hammerhead, Ranger and Turbot discoveries, as well as a wider exploration program that will target additional prospects and play types on the block.

In 2018, we acquired a participating interest in the Kaieteur Block (Hess 15%), which is adjacent to the Stabroek Block. The operator, Esso Exploration and Production Guyana Limited, expects to complete a 2D seismic shoot in 2019.

Suriname: We hold a 33% non-operated participating interest in Block 42, offshore Suriname. In 2018, the operator, Kosmos Energy Ltd., completed drilling operations on the Pontoenoe-1 exploration well. Commercial quantities of hydrocarbons were not discovered and well results will be integrated into the ongoing evaluation for future exploration on the block. We also hold a 33% non-operated participating interest in Block 59, offshore Suriname, where the operator ExxonMobil Exploration and Production Suriname B.V. commenced a seismic program in 2018.

Canada: We hold a 50% participating interest in four exploration licenses offshore Nova Scotia. In 2018, the operator, BP Canada, completed drilling of the Aspy exploration well, which did not encounter commercial quantities of hydrocarbons. In January 2019, the partnership relinquished 50% of the Nova Scotia acreage in accordance with the license agreement timeline. The retained acreage of approximately 1.75 million gross acres remains under evaluation. We also hold a 25% participating interest in three BP Canada operated exploration licenses offshore Newfoundland.

Sales Commitments

We have certain long-term contracts with fixed minimum sales volume commitments for natural gas and NGLs production. At the JDA in the Gulf of Thailand, we have annual minimum net sales commitments of approximately 80 billion cubic feet of natural gas per year through 2025 and approximately 40 billion cubic feet per year in 2026 and 2027. At the North Malay Basin development project offshore Peninsular Malaysia, we have annual net sales commitments of approximately 55 billion cubic feet per year through 2024. Our estimated total volume of production subject to these sales commitments is approximately 950 billion cubic feet of natural gas. We also have NGLs minimum delivery commitments, primarily in the Bakken through 2023, of approximately 10 million barrels per year, or approximately 55 million barrels over the remaining life of the contracts.

We have not experienced any significant constraints in satisfying the committed quantities required by our sales commitments, and we anticipate being able to meet future requirements from available proved and probable reserves and projected third-party supply.

Selling Prices and Production Costs

The following table presents our average selling prices and average production costs:

	2018	2017	2016
Average selling prices (a)			
Crude oil - per barrel (including hedging)			
United States			
Onshore	**$ 56.90**	$ 46.04	$ 36.92
Offshore	**62.02**	47.34	37.47
Total United States	**58.69**	46.50	37.13
Europe (b)	**70.08**	55.03	43.33
Africa	**69.64**	53.17	41.88
Asia	**70.42**	56.99	42.98
Worldwide	**60.77**	49.23	39.20
Crude oil - per barrel (excluding hedging)			
United States			
Onshore	**$ 60.64**	$ 46.76	$ 36.92
Offshore	**65.73**	48.15	37.47
Total United States	**62.41**	47.25	37.13
Europe (b)	**70.08**	55.14	43.33
Africa	**69.64**	53.25	41.88
Asia	**70.42**	56.99	42.98
Worldwide	**63.80**	49.75	39.20
Natural gas liquids - per barrel			
United States			
Onshore	**$ 21.29**	$ 17.67	$ 9.18
Offshore	**25.58**	21.34	13.96
Total United States	**21.81**	18.10	9.71
Europe (b)	—	29.04	19.48
Worldwide	**21.81**	18.35	9.95
Natural gas - per mcf			
United States			
Onshore	**$ 2.29**	$ 1.96	$ 1.48
Offshore	**2.68**	2.22	1.99
Total United States	**2.43**	2.03	1.61
Europe (b)	**3.61**	4.42	3.97
Asia and other	**5.07**	4.27	5.31
Worldwide	**4.18**	3.37	3.37
Average production (lifting) costs per barrel of oil equivalent produced (c)			
United States			
Onshore (d)	**$ 22.34**	$ 19.64	$ 18.40
Offshore	**13.80**	11.89	18.88
Total United States	**19.74**	17.42	18.54
Europe (b)	**26.23**	21.95	21.28
Africa	**4.42**	14.40	20.53
Asia and other	**6.16**	7.83	11.91
Worldwide	**15.73**	16.07	18.29

(a) Includes inter-company transfers valued at approximate market prices, primarily onshore U.S., which include certain processing and distribution fees.
(b) In 2017, we sold our assets in Norway. See Note 3, Dispositions in the Notes to Consolidated Financial Statements. The average selling prices in Norway for 2016 were $43.32 per barrel for crude oil (including hedging), $43.32 per barrel for crude oil (excluding hedging), $19.48 per barrel for NGLs and $5.22 per mcf for natural gas. The average production (lifting) costs in Norway were $24.70 per boe in 2016.
(c) Production (lifting) costs consist of amounts incurred to operate and maintain our producing oil and gas wells, related equipment and facilities and transportation costs, including Midstream tariff expense. Lifting costs do not include costs of finding and developing proved oil and gas reserves, production and severance taxes, or the costs of related general and administrative expenses, interest expense and income taxes.
(d) Includes Midstream tariff expense of $13.69 per boe in 2018 (2017: $11.10 per boe; 2016: $9.24 per boe).

Gross and Net Undeveloped Acreage

At December 31, 2018, gross and net undeveloped acreage amounted to:

	Undeveloped Acreage (a)	
	Gross	Net
	(In thousands)	
United States	436	383
South America	14,332	3,943
Europe	169	91
Africa	3,334	272
Asia and other (b)	6,350	2,755
Total (c)	24,621	7,444

(a) Includes acreage held under production sharing contracts.
(b) Includes 5.1 million gross acres (2.1 million net acres) offshore Canada.
(c) At December 31, 2018, 26% of our net undeveloped acreage is scheduled to expire during the next three years pending results of exploration activities. In addition, we relinquished 1.75 million gross acres (0.9 million net acres) offshore Nova Scotia, Canada in January 2019.

Gross and Net Developed Acreage, and Productive Wells

At December 31, 2018 gross and net developed acreage and productive wells amounted to:

	Developed Acreage Applicable to Productive Wells		Productive Wells (a)			
			Oil		Gas	
	Gross	Net	Gross	Net	Gross	Net
	(In thousands)					
United States	953	554	2,693	1,281	29	21
Europe	23	14	19	12	—	—
Africa	9,564	782	1,032	84	9	1
Asia and other	452	226	—	—	118	60
Total	10,992	1,576	3,744	1,377	156	82

(a) Includes multiple completion wells (wells producing from different formations in the same bore hole) totaling 105 gross wells and 61 net wells.

Exploratory and Development Wells

Net exploratory and net development wells completed during the years ended December 31 were:

	Net Exploratory Wells			Net Development Wells		
	2018	2017	2016	2018	2017	2016
Productive wells						
United States	**—**	—	—	**92**	65	83
Europe	**—**	—	—	**—**	1	1
Asia and other	**4**	2	1	**1**	1	—
	4	2	1	**93**	67	84
Dry holes						
United States	**—**	—	1	**—**	—	—
Africa (a)	**—**	—	—	**—**	—	—
Asia and other (b)	**2**	—	1	**—**	—	—
	2	—	2	**—**	—	—
Total	**6**	2	3	**93**	67	84

(a) In 2017, we expensed seven wells in our Deepwater Tano/Cape Three Points Block, offshore Ghana, which were drilled in prior years.
(b) In 2016, we expensed 18 wells relating to our Equus natural gas project, offshore Australia, which were drilled in prior years.

Number of Wells in the Process of Being Drilled

At December 31, 2018, the number of wells in the process of drilling amounted to:

	Gross Wells	Net Wells
United States	112	35
Asia and other	11	4
Total	123	39

Midstream

The Midstream operating segment provides fee-based services, including gathering, compressing and processing natural gas and fractionating NGLs; gathering, terminaling, loading and transporting crude oil and NGLs; storing and terminaling propane, and water handling services primarily in the Bakken and Three Forks Shale plays in the Williston Basin area of North Dakota. In July 2015, we sold a 50% interest in Hess Infrastructure Partners LP (HIP) to Global Infrastructure Partners (GIP) for net cash consideration of approximately $2.6 billion. In April 2017, Hess Midstream Partners LP (the "Partnership"), sold 16,997,000 common units representing limited partner interests at a price of $23 per unit in an initial public offering (IPO) for net proceeds of $365.5 million, of which $350 million was distributed equally to Hess Corporation and GIP.

At December 31, 2018, Hess Corporation and GIP each owned a direct 33.75% limited partner interest in the Partnership and a 50% indirect ownership interest through HIP in the Partnership's general partner, which has a 2% economic interest in the Partnership plus incentive distribution rights. The public unit holders own a 30.5% limited partner interest in the Partnership. In turn, the Partnership owns an approximate 20% controlling interest in the operating companies that comprise our midstream joint venture, while HIP, the 50/50 joint venture between Hess Corporation and GIP, owns the remaining 80%.

The Partnership, HIP and its affiliates, and other minor water handling services wholly-owned by Hess comprise the Midstream operating segment, which currently generates substantially all of its revenues under long-term, fee-based agreements with our E&P operating segment but intends to pursue additional throughput volumes from third-parties in the Williston Basin area. We operate the Midstream assets under various operational and administrative services agreements. In December 2018, we entered into a Memorandum of Understanding with HIP to sell HIP our water handling business for $225 million in cash, subject to customary adjustments. The parties expect to execute definitive agreements and close the transaction in the first quarter of 2019, subject to receipt of regulatory approvals.

At December 31, 2018, Midstream assets included the following:

- *Natural Gas Gathering and Compression:* A natural gas gathering and compression system located primarily in McKenzie, Williams and Mountrail Counties, North Dakota connecting Hess and third-party owned or operated wells to the Tioga Gas Plant and third-party pipeline facilities. This gathering system consists of approximately 1,200 miles of high and low pressure natural gas and NGL gathering pipelines with a current capacity of up to approximately 370 mmcfd, including an aggregate compression capacity of approximately 190 mmcfd. The system also includes the Hawkeye Gas Facility, which contributes approximately 50 mmcfd of the system's current compression capacity.
- *Crude Oil Gathering:* A crude oil gathering system located primarily in McKenzie, Williams and Mountrail Counties, North Dakota, connecting Hess and third-party owned or operated wells to the Ramberg Terminal Facility, the Tioga Rail Terminal and the Johnson's Corner Header System. The crude oil gathering system consists of approximately 400 miles of crude oil gathering pipelines with a current capacity of up to approximately 160,000 bopd. The system also includes the Hawkeye Oil Facility, which contributes approximately 75,000 bopd of the system's current capacity.
- *Tioga Gas Plant:* A natural gas processing and fractionation plant located in Tioga, North Dakota, with a current processing capacity of approximately 250 mmcfd and fractionation capacity of approximately 60,000 boepd.
- *Little Missouri 4:* A natural gas processing plant under construction in McKenzie County, North Dakota, with expected processing capacity of approximately 200 mmcfd. The operator, Targa Resources Corp., estimates the plant will be in service in the second quarter of 2019. The Partnership owns a 50% interest in Little Missouri 4 through a joint venture with Targa Resources Corp. and will be entitled to half of the plant's processing capacity when completed.
- *Mentor Storage Terminal:* A propane storage cavern and rail and truck loading and unloading facility located in Mentor, Minnesota, with approximately 330,000 boe of working storage capacity.
- *Ramberg Terminal Facility:* A crude oil pipeline and truck receipt terminal located in Williams County, North Dakota with a delivery capacity of up to approximately 285,000 bopd of crude oil into an interconnecting pipeline for transportation to the Tioga Rail Terminal and to multiple third-party pipelines and storage facilities.
- *Tioga Rail Terminal:* A 140,000 bopd crude oil and 30,000 boepd NGL rail loading terminal in Tioga, North Dakota that is connected to the Tioga Gas Plant, the Ramberg Terminal Facility and our crude oil gathering system.
- *Crude Oil Rail Cars:* A total of 550 crude oil rail cars, which we operate as unit trains consisting of approximately 100 to 110 crude oil rail cars. These crude oil rail cars have been constructed to DOT-117 standards. In 2018, HIP sold all its remaining older specification crude oil rail cars.
- *Johnson's Corner Header System:* A crude oil pipeline header system located in McKenzie County, North Dakota that receives crude oil by pipeline from Hess and third-parties and delivers crude oil to third-party interstate pipeline systems. The facility has a delivery capacity of approximately 100,000 bopd of crude oil.
- *Water assets:* A produced water gathering system located primarily in McKenzie, Williams and Mountrail Counties, North Dakota, consisting of approximately 150 miles of water gathering pipelines.

<u>Competition and Market Conditions</u>

See *Item 1A. Risk Factors* for a discussion of competition and market conditions.

<u>Other Items</u>

Emergency Preparedness and Response Plans and Procedures

We have in place a series of business and asset-specific emergency preparedness, response and business continuity plans that detail procedures for rapid and effective emergency response and environmental mitigation activities. These plans are maintained, reviewed and updated as necessary to confirm their accuracy and suitability. Where applicable, they are also reviewed and approved by the relevant host government authorities.

Responder training and drills are routinely held worldwide to assess and continually improve the effectiveness of our plans. Our contractors, service providers, representatives from government agencies and, where applicable, joint venture partners participate in the drills to help ensure that emergency procedures are comprehensive and can be effectively implemented.

To complement internal capabilities and to help ensure coverage for our global operations, we maintain membership contracts with a network of local, regional and global oil spill response and emergency response organizations. At the regional and global level, these organizations include Clean Gulf Associates (CGA), Marine Spill Response Corporation (MSRC), Marine Well Containment Company (MWCC), Wild Well Control (WWC), Subsea Well Intervention Service (SWIS) and Oil Spill Response Limited (OSRL). CGA and MSRC are domestic spill response organizations and MWCC provides the equipment and personnel to contain underwater well control incidents in the Gulf of Mexico. WWC provides firefighting, well control and engineering services globally. OSRL is a global response organization and is available, when needed, to assist us with any of our assets. In addition to owning response assets in their own right, the organization maintains business relationships that provide immediate access to additional critical response support services if required. OSRL's response assets include nearly 300 recovery and storage vessels and barges, more than 250 skimmers, over 600,000 feet of boom, 9 capping stacks and significant quantities of dispersants and other ancillary equipment, including aircraft. In addition to external well control and oil spill response support, we have contracts with wildlife, environmental, meteorology, incident management, medical and security resources. If we were to engage these organizations to obtain additional critical response support services, we would fund such services and, where appropriate, seek reimbursement under our insurance coverage, as described below. In certain circumstances, we pursue and enter into mutual aid agreements with other companies and government cooperatives to receive and provide oil spill response equipment and personnel support. We maintain close associations with emergency response organizations through our representation on the Executive Committees of CGA and MSRC, as well as the Board of Directors of OSRL.

We continue to participate in several industry-wide task forces that are studying better ways to assess the risk of and prevent onshore and offshore incidents, access and control blowouts in subsea environments, and improve containment and recovery methods. The task forces are working closely with the oil and gas industry and international government agencies to implement improvements and increase the effectiveness of oil spill prevention, preparedness, response and recovery processes.

Insurance Coverage and Indemnification

We maintain insurance coverage that includes coverage for physical damage to our property, third-party liability, workers' compensation and employers' liability, general liability, sudden and accidental pollution and other coverage. This insurance coverage is subject to deductibles, exclusions and limitations and there is no assurance that such coverage will adequately protect us against liability from all potential consequences and damages.

The amount of insurance covering physical damage to our property and liability related to negative environmental effects resulting from a sudden and accidental pollution event, excluding Atlantic Named Windstorm coverage for which we are self-insured, varies by asset, based on the asset's estimated replacement value or the estimated maximum loss. In the case of a catastrophic event, first party coverage consists of two tiers of insurance. The first $400 million of coverage is provided through an industry mutual insurance group. Above this $400 million threshold, insurance is carried which ranges in value up to $1.11 billion in total, depending on the asset coverage level, as described above. The insurance programs covering physical damage to our property exclude business interruption protection for our E&P operations. Additionally, we carry insurance that provides third-party coverage for general liability, and sudden and accidental pollution, up to $1.08 billion, which coverage under a standard joint operating arrangement would be reduced to our participating interest.

Our insurance policies renew at various dates each year. Future insurance coverage could increase in cost and may include higher deductibles or retentions, or additional exclusions or limitations. In addition, some forms of insurance may become unavailable in the future or unavailable on terms that are deemed economically acceptable.

Generally, our drilling contracts (and most of our other offshore services contracts) provide for a mutual hold harmless indemnity structure whereby each party to the contract (the Corporation and Contractor) indemnifies the other party for injuries or damages to their personnel and property (and, often, those of its contractors/subcontractors) regardless of fault. Variations may include indemnity exclusions to the extent a claim is attributable to the gross negligence and/or willful misconduct of a party. Third-party claims, on the other hand, are generally allocated on a fault basis.

We are customarily responsible for, and indemnify the Contractor against, all claims including those from third-parties, to the extent attributable to pollution or contamination by substances originating from our reservoirs or other property and the Contractor is responsible for and indemnifies us for all claims attributable to pollution emanating from the Contractor's property. Variations may include indemnity exclusions to the extent a claim is attributable to the gross negligence and/or willful misconduct of a party. Additionally, we are generally liable for all of our own losses and most third-party claims associated with catastrophic losses such as damage to reservoirs, blowouts, cratering and loss of hole, regardless of cause, although exceptions for losses attributable to gross negligence and/or willful misconduct do exist. Lastly some offshore services contracts include overall limitations of the Contractor's liability equal to a fixed negotiated amount. Variations may include exclusions of all contractual indemnities from the liability cap.

Under a standard joint operating agreement (JOA), each party is liable for all claims arising under the JOA, to the extent of its participating interest (operator or non-operator). Variations include indemnity exclusions when the claim is based upon the gross negligence and/or willful misconduct of the operator, in which case the operator is solely liable. The parties to the JOA may continue to be jointly and severally liable for claims made by third-parties in some jurisdictions. Further, under some production sharing contracts between a governmental entity and commercial parties, liability of the commercial parties to the government entity is joint and several.

Environmental

Compliance with various existing environmental and pollution control regulations imposed by federal, state, local and foreign governments is not expected to have a material adverse effect on our financial condition or results of operations but increasingly stringent environmental regulations have resulted and will likely continue to result in higher capital expenditures and operating expenses for us and the oil and gas industry in general. We spent approximately $15 million in 2018 for environmental remediation. The level of other expenditures to comply with federal, state, local and foreign country environmental regulations is difficult to quantify as such costs are captured as mostly indistinguishable components of our capital expenditures and operating expenses. For further discussion of environmental matters see *Environment, Health and Safety* in *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations*.

Number of Employees

At December 31, 2018, we had 1,708 employees.

Website Access to Our Reports

We make available free of charge through our website at www.hess.com, our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act, as soon as reasonably practicable after such material is electronically filed with or furnished to the Securities and Exchange Commission. The information on our website is not incorporated by reference in this report. Our Code of Business Conduct and Ethics, Corporate Governance Guidelines, and the charters for the Audit Committee, Compensation and Management Development Committee, and Corporate Governance and Nominating Committee of the Board of Directors are available on our website and are also available free of charge upon request to Investor Relations at our principal executive office. We also file with the New York Stock Exchange (NYSE) an annual certification that our Chief Executive Officer is unaware of any violation of the NYSE's corporate governance standards.

Item 1A. Risk Factors

Our business activities and the value of our securities are subject to significant risks, including the risk factors described below. These risk factors could negatively affect our operations, financial condition, liquidity and results of operations, and as a result, holders and purchasers of our securities could lose part or all of their investments. It is possible that additional risks relating to our securities may be described in a prospectus supplement if we issue securities in the future.

Our business and operating results are highly dependent on the market prices of crude oil, NGLs and natural gas, which can be very volatile. Our estimated proved reserves, revenue, operating cash flows, operating margins, liquidity, financial condition and future earnings are highly dependent on the benchmark market prices of crude oil, NGLs and natural gas, and our associated realized price differentials, which are volatile and influenced by numerous factors beyond our control. The major foreign oil producing countries, including members of OPEC, may exert considerable influence over the supply and price of crude oil and refined petroleum products. Their ability or inability to agree on a common policy on rates of production and other matters may have a significant impact on the oil markets. Other factors include, but are not limited to: worldwide and domestic supplies of and demand for crude oil, NGLs and natural gas, political conditions and events (including instability, changes in governments, armed conflict or economic sanctions) around the world and in particular in crude oil or natural gas producing regions, the cost of exploring for, developing and producing crude oil, NGLs and natural gas, the price and availability of alternative fuels or other forms of energy, the effect of energy conservation and environmental protection efforts and overall economic conditions globally. The sentiment of commodities trading markets as well as other supply and demand factors may also influence the selling prices of crude oil, NGLs and natural gas. Average prices for 2018 were $64.90 per barrel for WTI (2017: $50.85; 2016: $43.47) and $71.69 per barrel for Brent (2017: $54.74; 2016: $45.13). In order to manage the potential volatility of cash flows and credit requirements, we maintain significant 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.

If we fail to successfully increase our reserves, our future crude oil and natural gas production will be adversely impacted. We own or have access to a finite amount of oil and gas reserves, which will be depleted over time. Replacement of oil and gas production and reserves, including proved undeveloped reserves, is subject to successful exploration drilling, development activities, and enhanced recovery programs. Therefore, future oil and gas production is dependent on technical success in finding and developing additional hydrocarbon reserves. Exploration activity involves the interpretation of seismic and other geological and geophysical data, which does not always successfully predict the presence of commercial quantities of hydrocarbons. Drilling risks include unexpected adverse conditions, irregularities in pressure or formations, equipment failure, blowouts and weather interruptions. Future developments may be affected by unforeseen reservoir conditions, which negatively affect recovery factors or flow rates. Reserve replacement can also be achieved through acquisition. Similar risks, however, may be encountered in the production of oil and gas on properties acquired from others. In addition to the technical risks to reserve replacement, replacing reserves and developing future production is also influenced by the price of crude oil and natural gas and costs of drilling and development activities. Lower crude oil and natural gas prices, may have the effect of reducing capital available for exploration and development activity and may render certain development projects uneconomic or delay their completion and may result in negative revisions to existing reserves while increasing drilling and development costs could negatively affect expected economic returns.

There are inherent uncertainties in estimating quantities of proved reserves and discounted future net cash flows, and actual quantities may be lower than estimated. Numerous uncertainties exist in estimating quantities of proved reserves and future net revenues from those reserves. Actual future production, oil and gas prices, revenues, taxes, capital expenditures, operating expenses, and quantities of recoverable oil and gas reserves may vary substantially from those assumed in the estimates and could materially affect the estimated quantities of our proved reserves and the related future net revenues. In addition, reserve estimates may be subject to downward or upward changes based on production performance, purchases or sales of properties, results of future development, prevailing oil and gas prices, production sharing contracts, which may decrease reserves as crude oil and natural gas prices increase, and other factors. Crude oil prices declined in 2016, relative to preceding years, resulting in reductions to our reported proved reserves. In contrast, crude oil prices improved somewhat in 2017 and 2018 resulting in increases to our reported proved reserves. If crude oil prices in 2019 average below prices used to determine proved reserves at December 31, 2018, it could have an adverse effect on our estimates of proved reserve volumes and on the value of our business. See *Crude Oil and Natural Gas Reserves* in *Critical Accounting Policies and Estimates* in *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.*

We do not always control decisions made under joint operating agreements and the parties under such agreements may fail to meet their obligations. We conduct many of our E&P operations through joint operating agreements with other parties under which we may not control decisions, either because we do not have a controlling interest or are not operator under the agreement. There is risk that these parties may at any time have economic, business, or legal interests or goals that are inconsistent with ours, and therefore decisions may be made which are not what we believe is in our best interest. Moreover, parties to these agreements may be unable to meet their economic or other obligations and we may be required to fulfill those obligations alone. In either case, the value of our investment may be adversely affected.

We are subject to changing laws and regulations and other governmental actions that can significantly and adversely affect our business. Federal, state, local, territorial and foreign laws and regulations relating to tax increases and retroactive tax claims, disallowance of tax credits and deductions, expropriation or nationalization of property, mandatory government participation, cancellation or amendment of contract rights, imposition of capital controls or blocking of funds, changes in import and export regulations, reduction of sulfur content in bunker fuel, the imposition of tariffs, limitations on access to exploration and development opportunities, anti-bribery or anti-corruption laws, as well as other political developments may affect our operations and financial results.

We have substantial capital requirements, and we may not be able to obtain needed financing on satisfactory terms, if at all. The exploration, development and production of crude oil and natural gas involves substantial costs, which may not be fully funded from operations. Two of the three major credit rating agencies that rate our debt have assigned an investment grade rating. Although, currently we do not have any borrowings under our long-term credit facility, a ratings downgrade, continued weakness in the oil and gas industry or negative outcomes within commodity and financial markets could adversely impact our access to capital markets by increasing the costs of financing, or by impacting our ability to obtain financing on satisfactory terms, or at all. In addition, a ratings downgrade may require that we issue letters of credit or provide other forms of collateral under certain contractual requirements. Any inability to access capital markets could adversely impact our financial adaptability and our ability to execute our strategy and may also expose us to heightened exposure to credit risk.

Political instability in areas where we operate can adversely affect our business. Some of the international areas in which we operate are politically less stable than other areas and may be subject to civil unrest, conflict, insurgency, corruption, security risks and labor unrest. Political instability and civil unrest in North Africa, South America and the Middle East has affected and may continue to affect our interests in these areas as well as oil and gas markets generally. In addition, geographic territorial border disputes may affect our business in certain areas, such as the border dispute between Guyana and Venezuela over a portion of the Stabroek Block. Political instability exposes our operations to increased risks, including increased difficulty in obtaining required permits and government approvals, enforcing our agreements in those jurisdictions and potential adverse actions by local government authorities. The threat of terrorism around the world also poses additional risks to the operations of the oil and gas industry.

Our oil and gas operations are subject to environmental risks and environmental laws and regulations that can result in significant costs and liabilities. Our oil and gas operations, like those of the industry, are subject to environmental risks such as oil spills, produced water spills, gas leaks and ruptures and discharges of substances or gases that could expose us to substantial liability for pollution or other environmental damage. Our operations are also subject to numerous U.S. federal, state, local and foreign environmental laws and regulations. Non-compliance with these laws and regulations may subject us to administrative, civil or criminal penalties, remedial clean-ups and natural resource damages or other liabilities. In addition, increasingly stringent environmental regulations have resulted and will likely continue to result in higher capital expenditures and operating expenses for us and the oil and gas industry in general. Similarly, we have material legal obligations to dismantle, remove and abandon production facilities and wells that will occur many years in the future, in most cases. These estimates may be impacted by future changes in regulations and other uncertainties.

Concerns have been raised in certain jurisdictions where we have operations concerning the safety and environmental impact of the drilling and development of shale oil and gas resources, particularly hydraulic fracturing, water usage, flaring of associated natural gas and air emissions. While we believe that these operations can be conducted safely and with minimal impact on the environment, regulatory bodies are responding to these concerns and may impose moratoriums and new regulations on such drilling operations that would likely have the effect of prohibiting or delaying such operations and increasing their cost.

Climate change initiatives may result in significant operational changes and expenditures, reduced demand for our products and adversely affect our business. We recognize that climate change is a global environmental concern. Continuing political and social attention to the issue of climate change has resulted in both existing and pending international agreements and national, regional or local legislation and regulatory measures to limit greenhouse gas emissions. These agreements and measures may require, or could result in future legislation and regulatory measures that require, significant equipment modifications, operational changes, taxes, or purchase of emission credits to reduce emission of greenhouse gases from our operations, which may result in substantial capital expenditures and compliance, operating, maintenance and remediation costs. In addition, our production is sold to third parties that produce petroleum fuels, which through normal end user consumption result in the emission of greenhouse gases. Regulatory initiatives to reduce the use of these fuels may reduce demand for crude oil and other hydrocarbons and have an adverse effect on our sales volumes, revenues and margins. The imposition and enforcement of stringent greenhouse gas emissions reduction targets could severely and adversely impact the oil and gas industry and significantly reduce the value of our business. Furthermore, increasing attention to climate change risks has resulted in governmental investigations, and public and private litigation, which could increase our costs or otherwise adversely affect our business. For example, in 2017 certain municipalities and private associations in California, Rhode Island, and Maryland separately filed lawsuits against over 30 fossil fuel producers, including us, for alleged damages purportedly caused by climate change.

Our industry is highly competitive and many of our competitors are larger and have greater resources and more diverse portfolios than we have. The petroleum industry is highly competitive and very capital intensive. We encounter competition from numerous companies, including acquiring rights to explore for crude oil and natural gas. To a lesser extent, we are also in competition with producers of alternative fuels or other forms of energy, including wind, solar and electric power, and in the future, could face increasing competition due to the development and adoption of new technologies. Many competitors, including national oil companies, are larger and have substantially greater resources to acquire and develop oil and gas assets. In addition, competition for drilling services, technical expertise and equipment may affect the availability of technical personnel and drilling rigs, resulting in increased capital and operating costs. Many of our competitors have a more diverse portfolio of assets, which may minimize the impact of adverse events occurring at any one location.

Catastrophic events, whether naturally occurring or man-made, may materially affect our operations and financial conditions. Our oil and gas operations are subject to unforeseen occurrences which have affected us from time to time and which may damage or destroy assets, interrupt operations and have other significant adverse effects. Examples of catastrophic events include hurricanes, fires, explosions, blowouts, pipeline interruptions and ruptures, severe weather, geological events, labor disputes or cyber-attacks. We maintain insurance coverage against many, but not all, potential losses and liabilities in amounts we deem prudent, including for property and casualty losses. There can be no assurance that such insurance will adequately protect us against liability from all potential consequences and damages. Moreover, some forms of insurance may be unavailable in the future or be available only on terms that are deemed economically unacceptable.

Significant time delays between the estimated and actual occurrence of critical events associated with development projects may result in material negative economic consequences. As part of our business, we are involved in large development projects, the completion of which may be delayed beyond what was originally planned. Such examples include, but are not limited to, delays in receiving necessary approvals from project members or regulatory agencies, timely access to necessary equipment, availability of necessary personnel, construction delays, unfavorable weather conditions and equipment failures. This may lead to delays and differences between estimated and actual timing of critical events. These delays could impact our future results of operations and cash flows.

Departures of key members from our senior management team, and/or difficulty in recruiting and retaining adequate numbers of experienced technical personnel, could negatively impact our ability to deliver on our strategic goals. Our future success depends upon the continued service of key members of our senior management team, who play an important role in developing and implementing our strategy. The departure of key members of senior management or an inability to recruit and retain adequate numbers of experienced technical and professional personnel in the necessary locations may prevent us from executing our strategy in full or, in part, which could negatively impact our business.

We are dependent on oilfield service companies for items including drilling rigs, equipment, supplies and skilled labor. An inability or significant delay in securing these services, or a high cost thereof, may result in material negative economic consequences. The availability and cost of drilling rigs, equipment, supplies and skilled labor will fluctuate over time given the cyclical nature of the E&P industry. As a result, we may encounter difficulties in obtaining required services or could face an increase in cost. These consequences may impact our ability to run our operations and to deliver projects on time with the potential for material negative economic consequences.

We manage commodity price and other risks through our risk management function but such activities may impede our ability to benefit from commodity price increases and can expose us to similar potential counterparty credit risk as amounts due from the sale of hydrocarbons. We may enter into additional commodity price hedging arrangements to protect us from commodity price declines. These arrangements may, depending on the instruments used and the level of additional hedges involved, limit any potential upside from commodity price increases. As with accounts receivable from the sale of hydrocarbons, we may be exposed to potential economic loss should a counterparty be unable or unwilling to perform their obligations under the terms of a hedging agreement. In addition, we are exposed to risks related to changes in interest rates and foreign currency values, and may engage in hedging activities to mitigate related volatility.

One of our subsidiaries is the general partner of a publicly traded master limited partnership, Hess Midstream Partners LP. The responsibilities associated with being a general partner expose us to a broader range of legal liabilities. Our control of Hess Midstream Partners LP bestows upon us additional fiduciary duties including, but not limited to, the obligations associated with managing potential conflicts of interests, additional reporting requirements from the Securities and Exchange Commission and the provision of tax information to unit holders of Hess Midstream Partners LP. These heightened duties expose us to additional potential for legal claims that may have a material negative economic impact on our shareholders. Moreover, these increased duties may lead to an increase in compliance costs.

Disruption, failure or cyber security breaches affecting or targeting computer, telecommunications systems, and infrastructure used by the Company may materially impact our business and operations. Computers and telecommunication systems are used to conduct our exploration, development and production activities and have become an integral part of our business. We use these systems to analyze and store financial and operating data and to communicate within our company and with outside business partners. Technical system flaws, power loss, cyber security risks, including cyber or phishing-attacks, unauthorized access, malicious software, data privacy breaches by employees or others with authorized access, ransomware, and other cyber security issues could compromise our computer and telecommunications systems and result in disruptions to our business operations or the access, disclosure or loss of our data and proprietary information. In addition, computers control oil and gas production, processing equipment, and distribution systems globally and are necessary to deliver our production to market. A disruption, failure or a cyber breach of these operating systems, or of the networks and infrastructure on which they rely, could damage critical production, distribution and/or storage assets, delay or prevent delivery to markets, and make it difficult or impossible to accurately account for production and settle transactions. As a result, a disruption, failure or a cyber breach of these operating systems, or of the networks and infrastructure on which they rely and any resulting investigation or remediation costs, litigation or regulatory action could have a material adverse impact on our cash flows and results of operations, reputation and competitiveness. We routinely experience attempts by external parties to penetrate and attack our networks and systems. Although such attempts to date have not resulted in any material breaches, disruptions, financial loss, or loss of business-critical information, our systems and procedures for protecting against such attacks and mitigating such risks may prove to be insufficient in the future and such attacks could have an adverse impact on our business and operations, including damage to our reputation and competitiveness, remediation costs, litigation or regulatory actions. In addition, as technologies evolve and these cyber security attacks become more sophisticated, we may incur significant costs to upgrade or enhance our security measures to protect against such attacks and we may face difficulties in fully anticipating or implementing adequate preventive measures or mitigating potential harm.

Item 1B. Unresolved Staff Comments

None.

Item 3. Legal Proceedings

We, along with many companies that have been or continue to be engaged in refining and marketing of gasoline, have been a party to lawsuits and claims related to the use of methyl tertiary butyl ether (MTBE) in gasoline. A series of similar lawsuits, many involving water utilities or governmental entities, were filed in jurisdictions across the U.S. against producers of MTBE and petroleum refiners who produced gasoline containing MTBE, including us. The principal allegation in all cases was that gasoline containing MTBE was a defective product and that these producers and refiners are strictly liable in proportion to their share of the gasoline market for damage to groundwater resources and are required to take remedial action to ameliorate the alleged effects on the environment of releases of MTBE. The majority of the cases asserted against us have been settled. There are three remaining active cases, filed by Pennsylvania, Rhode Island, and Maryland. In June 2014, the Commonwealth of Pennsylvania filed a lawsuit alleging that we and all major oil companies with operations in Pennsylvania, have damaged the groundwater by introducing thereto gasoline with MTBE. The Pennsylvania suit has been forwarded to the existing MTBE multidistrict litigation pending in the Southern District of New York. In September 2016, the State of Rhode Island also filed a lawsuit alleging that we and other major oil companies damaged the groundwater in Rhode Island by introducing thereto gasoline with MTBE. The suit filed in Rhode Island is proceeding in Federal court. In December 2017, the State of Maryland filed a lawsuit alleging that we and other major oil companies damaged the groundwater in Maryland by introducing thereto gasoline with MTBE. The suit filed in Maryland state court, was served on us in January 2018 and has been removed to Federal court by the defendants.

In September 2003, we received a directive from the New Jersey Department of Environmental Protection (NJDEP) to remediate contamination in the sediments of the Lower Passaic River. The NJDEP is also seeking natural resource damages. The directive, insofar as it affects us, relates to alleged releases from a petroleum bulk storage terminal in Newark, New Jersey we previously owned. We and over 70 companies entered into an Administrative Order on Consent with the Environmental Protection Agency (EPA) to study the same contamination; this work remains ongoing. We and other parties settled a cost recovery claim by the State of New Jersey and also agreed with EPA to fund remediation of a portion of the site. On March 4, 2016, the EPA issued a Record of Decision (ROD) in respect of the lower eight miles of the Lower Passaic River, selecting a remedy that includes bank-to-bank dredging at an estimated cost of $1.38 billion. The ROD does not address the upper nine miles of the Lower Passaic River or the Newark Bay, which may require additional remedial action. In addition, the Federal trustees for natural resources have begun a separate assessment of damages to natural resources in the Passaic River. Given that the EPA has not selected a remedy for the entirety of the Lower Passaic River or the Newark Bay, total remedial costs cannot be reliably estimated at this time. Based on currently known facts and circumstances, we do not believe that this matter will result in a significant liability to us because our former terminal did not store or use contaminants which are of concern in the river sediments and could not have contributed contamination along the river's length. Further, there are numerous other parties who we expect will bear the cost of remediation and damages.

In March 2014, we received an Administrative Order from EPA requiring us and 26 other parties to undertake the Remedial Design for the remedy selected by the EPA for the Gowanus Canal Superfund Site in Brooklyn, New York. The remedy includes dredging of surface sediments and the placement of a cap over the deeper sediments throughout the Canal and in-situ stabilization of certain contaminated sediments that will remain in place below the cap. EPA has estimated that this remedy will cost $506 million; however, the ultimate costs that will be incurred in connection with the design and implementation of the remedy remain uncertain. Our alleged liability derives from our former ownership and operation of a fuel oil terminal and connected ship-building and repair facility adjacent to the Canal. We indicated to EPA that we would comply with the Administrative Order and are currently contributing funding for the Remedial Design based on an interim allocation of costs among the parties. At the same time, we are participating in an allocation process whereby a neutral expert selected by the parties will determine the final shares of the Remedial Design costs to be paid by each of the participants.

On September 28, 2017, we received a general notice letter and offer to settle from the U.S. Environmental Protection Agency relating to Superfund claims for the Ector Drum, Inc. Superfund Site in Odessa, Texas. The EPA and Texas Commission on Environmental Quality (TCEQ) took clean-up and response action at the site commencing in 2014 and concluded in December 2015. The site was determined to have improperly stored industrial waste, including drums with oily liquids. The total clean-up cost incurred by the EPA was approximately $3.5 million. We were invited to negotiate a voluntary settlement for our purported share of the clean-up costs. Our share, if any, is undetermined.

We periodically receive notices from the EPA that we are a "potential responsible party" under the Superfund legislation with respect to various waste disposal sites. Under this legislation, all potentially responsible parties may be jointly and severally liable. For certain sites, such as those discussed above, the EPA's claims or assertions of liability against us relating to these sites have not been fully developed. With respect to the remaining sites, the EPA's claims have been settled, or a proposed settlement is under consideration, in all cases for amounts that are not material. The ultimate impact of these proceedings, and of any related proceedings by private parties, on our business or accounts cannot be predicted at this time due to the large number of other potentially responsible parties and the speculative nature of clean-up cost estimates, but is not expected to be material.

From time to time, we are involved in other judicial and administrative proceedings, including proceedings relating to other environmental matters. We cannot predict with certainty if, how or when such proceedings will be resolved or what the eventual relief, if any, may be, particularly for proceedings that are in their early stages of development or where plaintiffs seek indeterminate damages. Numerous issues may need to be resolved, including through potentially lengthy discovery and determination of important factual matters before a loss or range of loss can be reasonably estimated for any proceeding.

Subject to the foregoing, in management's opinion, based upon currently known facts and circumstances, the outcome of the aforementioned proceedings is not expected to have a material adverse effect on our financial condition, results of operations or cash flows.

Item 4. Mine Safety Disclosures

None.

PART II

Item 5. Market for the Registrant's Common Stock, Related Stockholder Matters and Issuer Purchases of Equity Securities

Stock Market Information

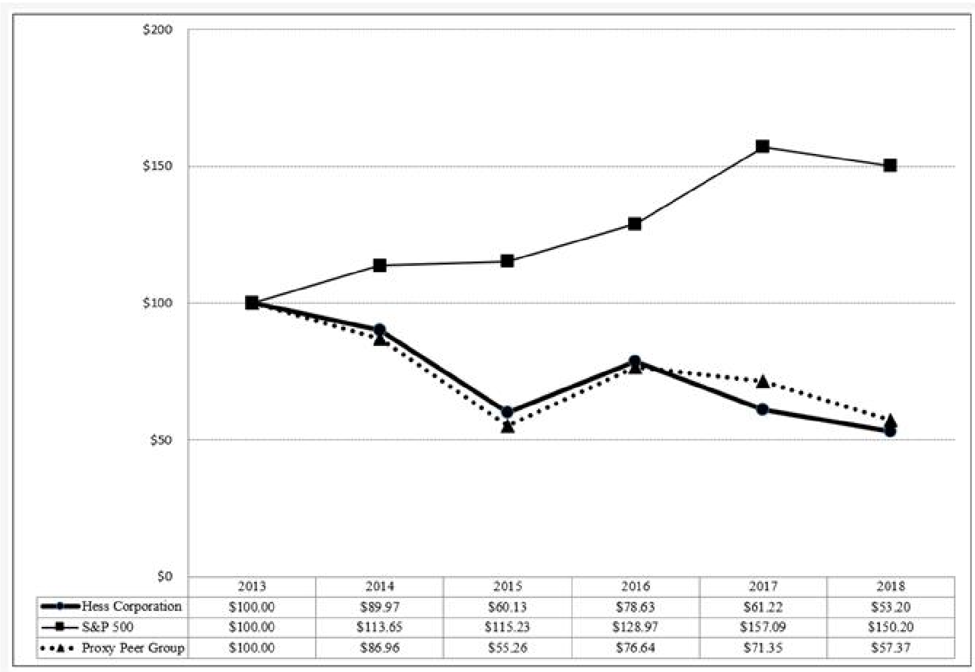
Our common stock is traded principally on the New York Stock Exchange (ticker symbol: HES).

Performance Graph

Set forth below is a line graph comparing the five-year shareholder returns on a $100 investment in our common stock assuming reinvestment of dividends, against the cumulative total returns for the following:

- Standard & Poor's (S&P) 500 Stock Index, which includes us.
- Proxy Peer Group comprising 13 oil and gas peer companies, including us as disclosed in our 2018 Proxy Statement.

Comparison of Five-Year Shareholder Returns
Years Ended December 31,



Holders

At January 31, 2019, there were 3,100 stockholders (based on the number of holders of record) who owned a total of 303,034,262 shares of common stock.

Dividends

In 2018, 2017 and 2016, cash dividends on common stock totaled $1.00 per share per year ($0.25 per quarter).

Share Repurchase Activities

Our share repurchases activities for the year ended December 31, 2018, were as follows:

2018	Total Number of Shares Purchased (a) (b)	Average Price Paid per Share (a)	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs (d)	Maximum Approximate Dollar Value of Shares that May Yet be Purchased Under the Plans or Programs (e) (In millions)
January	607,771	$ 52.30	607,771	$ 998
February	3,670,578	45.76	3,670,578	830
March	3,748,598	48.57	3,708,888	1,650
April (c)	8,039,878	58.49	8,039,878	1,150
May	—	—	—	1,150
June	508,742	58.49	508,742	1,150
July (c)	2,412,545	63.98	2,412,545	950
August	729,203	63.97	729,203	949
September	699,004	70.10	699,004	900
October	505,740	63.27	505,740	868
November	2,130,582	56.79	2,130,582	747
December	2,145,786	45.21	2,145,786	650
Total for 2018	25,198,427	$ 54.84	25,158,717	

(a) Repurchased in open-market transactions. The average price paid per share was inclusive of transaction fees.

(b) Includes 39,710 common shares repurchased in March, all of which were subsequently granted to Directors in accordance with the Non-Employee Directors' Stock Award Plan.

(c) In April 2018, we entered into an accelerated share repurchase program (ASR) with a financial institution to repurchase $500 million of our common stock, in which we received an initial delivery of approximately 8 million shares and upon completion of this transaction in June, we received an additional delivery of approximately 0.5 million shares of our common stock. In July 2018, we entered into an ASR with a financial institution to repurchase $200 million of our common stock, in which we received an initial delivery of approximately 2.4 million shares and upon completion of this transaction in August, we received an additional delivery of approximately 0.7 million shares of our common stock. The transaction price for each ASR was determined by the volume-weighted average price of the shares during the term less a negotiated discount.

(d) Since initiation of the buyback program in August 2013, total shares repurchased through December 31, 2018 amounted to 91.9 million at a total cost of $6.85 billion including transaction fees.

(e) In March 2013, we announced that our Board of Directors approved a stock repurchase program that authorized the purchase of common stock up to a value of $4.0 billion. In May 2014, the share repurchase program was increased to $6.5 billion and in March 2018, it was increased further to $7.5 billion.

Equity Compensation Plans

Following is information related to our equity compensation plans at December 31, 2018.

Plan Category	Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights *	Weighted Average Exercise Price of Outstanding Options, Warrants and Rights	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column*)
Equity compensation plans approved by security holders	5,170,079 (a)	$ 61.91	19,036,450 (b)
Equity compensation plans not approved by security holders (c)	—	—	—

(a) This amount includes 5,170,079 shares of common stock issuable upon exercise of outstanding stock options. This amount excludes 1,063,118 performance share units (PSU) for which the number of shares of common stock to be issued may range from 0% to 200%, based on our total shareholder return (TSR) relative to the TSR of a predetermined group of peer companies over a three-year performance period ending December 31 of the year prior to settlement of the grant. In addition, this amount also excludes 2,881,204 shares of common stock issued as restricted stock pursuant to our equity compensation plans.

(b) These securities may be awarded as stock options, restricted stock, performance share units or other awards permitted under our equity compensation plan.

(c) We have a Non-Employee Director's Stock Award Plan pursuant to which each of our non-employee directors received $175,000 in value of our common stock. These awards are made from shares we have purchased in the open market.

See *Note 11, Share-based Compensation* in the *Notes to Consolidated Financial Statements* for further discussion of our equity compensation plans.

Item 6. Selected Financial Data

The following is a five-year summary of selected financial data that should be read in conjunction with both our *Consolidated Financial Statements* and *Accompanying Notes, and Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations* included elsewhere in this Annual Report:

	2018	2017	2016	2015	2014
	(In millions, except per share amounts)				
Income Statement Selected Financial Data					
Sales and other operating revenues					
Crude oil (a)	**$ 4,960**	$ 4,239	$ 3,639	$ 5,259	$ 9,058
Natural gas liquids (a)	**533**	457	264	244	397
Natural gas (a)	**965**	750	766	1,052	1,247
Other operating revenues (b)	**(135)**	20	93	81	35
Total Sales and other operating revenues	**$ 6,323**	$ 5,466	$ 4,762	$ 6,636	$ 10,737
Income (loss) from continuing operations	**$ (115)**	$ (3,941)	$ (6,076)	$ (2,959)	$ 1,692
Income (loss) from discontinued operations	**—**	—	—	(48)	682
Net income (loss)	**$ (115)**	$ (3,941)	$ (6,076)	$ (3,007)	$ 2,374
Less: Net income (loss) attributable to noncontrolling interests	**167**	133	56	49	57
Net income (loss) attributable to Hess Corporation	**$ (282) (d)**	$ (4,074) (e)	$ (6,132) (f)	$ (3,056) (g)	$ 2,317 (h)
Net Income (Loss) Attributable to Hess Corporation Per Common Share:					
Basic:					
Continuing operations	**$ (1.10)**	$ (13.12)	$ (19.92)	$ (10.61)	$ 5.57
Discontinued operations	**—**	—	—	(0.17)	2.06
Net income (loss) per share	**$ (1.10)**	$ (13.12)	$ (19.92)	$ (10.78)	$ 7.63
Diluted:					
Continuing operations	**$ (1.10)**	$ (13.12)	$ (19.92)	$ (10.61)	$ 5.50
Discontinued operations	**—**	—	—	(0.17)	2.03
Net income (loss) per share	**$ (1.10)**	$ (13.12)	$ (19.92)	$ (10.78)	$ 7.53
Balance Sheet Selected Financial Data					
Total assets	**$ 21,433**	$ 23,112	$ 28,621	$ 34,157	$ 38,372
Total debt (c)	**$ 6,672**	$ 6,977	$ 6,806	$ 6,592	$ 5,952
Total equity	**$ 10,888**	$ 12,354	$ 15,591	$ 20,401	$ 22,320
Dividends Per Share					
Dividends per share of common stock	**$ 1.00**	$ 1.00	$ 1.00	$ 1.00	$ 1.00

(a) Represents sales of Hess net production and purchased third-party volumes.

(b) Commencing with the adoption of Accounting Standards Codification (ASC) 606, Revenue from Contracts with Customers, using the modified retrospective method effective January 1, 2018, gains (losses) on commodity derivatives are included within Other operating revenue. Prior to January 1, 2018, gains (losses) on commodity derivatives were included within Crude oil revenues. See Note 1, Nature of Operations, Basis of Presentation and Summary of Accounting Policies in the Notes to Consolidated Financial Statements.

(c) At December 31, 2018 includes debt from our Midstream operating segment of $981 million that is non-recourse to Hess Corporation (2017: $980 million; 2016: $733 million; 2015: $704 million; 2014: $0).

(d) Includes after-tax charges of $221 million related to exit costs, settlement of legal claims related to a former downstream interest, and a loss from debt extinguishment. These charges were, partially offset by a noncash $91 million income tax benefit primarily relating to intraperiod income tax allocation requirements resulting from changes in fair value of our 2019 crude oil hedging program, and gains totaling $24 million related to asset sales.

(e) Includes after-tax impairment charges of $2,250 million (Gulf of Mexico and Norway), an after-tax dry hole and lease impairment charge of $280 million (Ghana), a combined after-tax loss of $91 million related to asset sales (Norway, Equatorial Guinea and Permian), and after-tax charges of $52 million primarily for de-designated crude oil hedging contracts and other exit costs.

(f) Includes noncash charges of $3,749 million to establish valuation allowances on deferred tax assets following a three-year cumulative loss and after-tax charges of $894 million primarily for dry hole and other exploration expenses, loss on debt extinguishment, offshore rig costs, severance, and impairment of older specification rail cars.

(g) Includes total after-tax charges of $1,943 million, including noncash charges of $1,483 million to write-off all goodwill associated with our Exploration and production operating segment.

(h) Includes after-tax income of $1,589 million relating to net gains on asset sales and income from the partial liquidation of last-in, first-out (LIFO) inventories, partially offset by after-tax charges totaling $580 million for dry hole expenses, charges associated with termination of lease contracts, severance and other exit costs, income tax restructuring charges and other charges.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion should be read together with the *Consolidated Financial Statements* and the *Notes to Consolidated Financial Statements*, which are included in this Form 10-K in Item 8, the information set forth in *Risk Factors* under Item 1A.

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Overview

Hess Corporation, incorporated in the State of Delaware in 1920, is a global Exploration and Production (E&P) company engaged in exploration, development, production, transportation, purchase and sale of crude oil, natural gas liquids, and natural gas with production operations located primarily in the United States (U.S.), Denmark, the Malaysia/Thailand Joint Development Area (JDA) and Malaysia. We conduct exploration activities primarily offshore Guyana, Suriname, Canada and in the U.S. Gulf of Mexico. At the Stabroek Block (Hess 30%), offshore Guyana, we have participated in twelve significant discoveries. The Liza Phase 1 development was sanctioned in 2017 and is expected to startup in early 2020 with production reaching up to 120,000 gross bopd. The discovered resources to date on the Stabroek Block are expected to underpin the potential for at least five FPSOs producing more than 750,000 gross bopd by 2025.

Our Midstream operating segment provides fee-based services, including gathering, compressing and processing natural gas and fractionating NGLs; gathering, terminaling, loading and transporting crude oil and NGLs; storing and terminaling propane, and water handling services primarily in the Bakken and Three Forks Shale plays in the Williston Basin area of North Dakota.

In 2018, we completed the sale of our joint venture interests in the Utica shale play in eastern Ohio, onshore U.S., and during 2017 we sold our interests in Equatorial Guinea, Norway and our enhanced oil recovery assets in the Permian Basin, onshore U.S. These sales, which generated total proceeds of approximately $3.5 billion, are consistent with our strategy to high grade our portfolio by divesting lower return, mature assets to invest in higher return assets, primarily in Guyana and the Bakken, and to provide returns to shareholders. During 2018, we repurchased $1.38 billion of common stock (2017: $120 million), repaid debt of $633 million, and paid dividends of $345 million. At December 31, 2018, we had cash and cash equivalents of $2.6 billion excluding Midstream.

Outlook

We project our E&P capital and exploratory expenditures will be approximately $2.9 billion in 2019. Capital investment for our Midstream operations is expected to be approximately $330 million. Oil and gas production in 2019 is forecast to be in the range of 270,000 boepd to 280,000 boepd excluding Libya, up from 248,000 boepd in 2018, excluding Libya and assets sold. We have purchased crude oil put options for calendar year 2019 that establish a WTI monthly floor price of $60 per barrel for 95,000 bopd.

Net cash provided by operating activities was $1,939 million in 2018, compared to $945 million in 2017, while capital expenditures for 2018 and 2017 were $2,180 million and $1,973 million, respectively. Based on current forward strip crude oil prices for 2019, we expect cash flow from operating activities and cash and cash equivalents existing at December 31, 2018 will be sufficient to fund our capital investment program and dividends through the end of 2019.

Consolidated Results

Net loss attributable to Hess Corporation was $282 million in 2018 (2017: $4,074 million; 2016: $6,132 million). Excluding items affecting comparability of earnings between periods summarized on page 26, the adjusted net loss was $176 million in 2018 (2017: $1,401 million; 2016: $1,489 million). Annual production averaged 277,000 boepd in 2018 (2017: 306,000 boepd; 2016: 322,000 boepd). Total proved reserves were 1,192 million boe at December 31, 2018 (2017: 1,154 million boe; 2016: 1,109 million boe).

Significant 2018 Activities

The following is an update of significant E&P activities during 2018:

Producing E&P assets:

- In North Dakota, net production from the Bakken oil shale play averaged 117,000 boepd (2017: 105,000 boepd). During 2018, we operated an average of 4.8 rigs, drilled 121 wells, completed 118 wells, and brought on production 104 wells. During 2018, we transitioned from utilizing sliding sleeve completion designs to plug and perf completions. During 2019, we plan to operate six rigs, drill approximately 170 wells and bring approximately 160 wells on production. From 2019, all production wells will use plug and perf completions, which we expect will allow us to increase peak net production to approximately 200,000 boepd by 2021. We forecast net production for full year 2019 to be in the range of 135,000 boepd to 145,000 boepd.

- In the Gulf of Mexico, net production averaged 57,000 boepd (2017: 54,000 boepd). The increase in production was primarily due to the Stampede and Penn State Fields, partially offset by the impact of downtime from a planned well workover at the Tubular Bells Field, the shutdown at the third-party operated Enchilada platform, and natural field decline. We forecast Gulf of Mexico net production for full year 2019 to be in the range of 65,000 boepd to 70,000 boepd.

- In the Gulf of Thailand, net production from Block A-18 of the JDA averaged 36,000 boepd for the year (2017: 37,000 boepd), including contribution from unitized acreage in Malaysia, while net production from North Malay Basin averaged 27,000 boepd for the year (2017: 11,000 boepd). Production from the North Malay Basin full-field development project commenced in July 2017. During 2018 we drilled three production wells at North Malay Basin, and plan to continue the drilling program and development activities in 2019.

  We forecast Gulf of Thailand net production for full year 2019 to be in the range of 60,000 boepd and 65,000 boepd.

- In Denmark, we announced that we decided to retain our interest in the Hess operated offshore South Arne Field after offers received in a previously announced sale process did not meet our value expectations. During 2019, we plan to drill an exploration well on License 06/16, located approximately 19 miles from South Arne.

Other E&P assets:

- Offshore Guyana, at the Stabroek Block (Hess 30%), the operator, Esso Exploration and Production Guyana Limited progressed the first phase of the Liza Field development, which was sanctioned in 2017. The Liza Phase 1 development, which is expected to begin producing oil by early 2020 will use the Liza Destiny FPSO to produce up to 120,000 gross bopd. Drilling of development wells in the Liza Field is continuing, subsea equipment is being prepared for installation, and the topside facilities modules have been installed on the Liza Destiny FPSO in Singapore, which is expected to arrive offshore Guyana in the third quarter of 2019. Preparations are also underway for the installation of subsea umbilicals, risers and flowlines at the Liza Field in the spring of 2019.

  Phase 2 of the Liza Field development is expected to start production by mid-2022. Pending government and regulatory approvals, project sanction for Phase 2 is expected by the operator in the first quarter of 2019 and will include a second FPSO vessel designed to produce up to 220,000 gross bopd. Project sanction for a third phase of development at the Payara Field is expected in 2019 with first production expected to start up as early as 2023. In addition to the first three phases, development planning is underway for additional FPSOs. The ultimate sizing and timing will be a function of further exploration and appraisal drilling.

  The operator is currently utilizing three drillships on the block. The Stena Carron and the Noble Tom Madden, which arrived in the third quarter of 2018, are involved in exploration and appraisal drilling. The Noble Bob Douglas is drilling development wells for Liza Phase 1. In 2018, the following explorations wells were drilled on the Stabroek Block (in chronological order):

  Ranger-1: The well, located approximately 60 miles northwest of the Liza discovery, encountered approximately 230 feet of high-quality, oil-bearing carbonate reservoir.

  Pacora-1: The well encountered approximately 65 feet of high-quality, oil-bearing sandstone reservoir, and is located approximately four miles west of the Payara-1 well, which was drilled in 2017. The operator plans to integrate this discovery into the Payara Field development.

  Liza-5: The well encountered 77 feet of high-quality, oil-bearing sandstone reservoir and is located approximately six miles northwest of the Liza-1 well, which was drilled in 2016.

Sorubim-1: The well did not encounter commercial quantities of hydrocarbons.

Longtail-1: The well encountered approximately 256 feet of high-quality, oil-bearing sandstone reservoir and is located approximately five miles west of the Turbot-1 well, which was drilled in 2017.

Hammerhead-1: The well encountered approximately 197 feet of high-quality, oil-bearing sandstone reservoir and is located approximately 13 miles to the southwest of the Liza-1 well.

Pluma-1: The well encountered approximately 121 feet of high-quality, hydrocarbon-bearing sandstone reservoir and represents the tenth discovery on the Block. The well is located approximately 17 miles south of the Turbot-1 well.

In February 2019, the operator announced the eleventh and twelfth discoveries on the Stabroek Block at the Tilapia-1 and Haimara-1 wells. The Tilapia-1 well encountered approximately 305 feet of high-quality, oil-bearing sandstone reservoir, and is located approximately three miles west of the Longtail-1 well. The Haimara-1 well encountered approximately 207 feet of high-quality, gas condensate-bearing sandstone reservoir, and is located approximately 19 miles east of the Pluma-1 well.

- At Block 42 (Hess - 33%), offshore Suriname, the operator, Kosmos Energy Ltd., completed drilling operations on the Pontoenoe-1 exploration well. Commercial quantities of hydrocarbons were not discovered and well results will be integrated into the ongoing evaluation for future exploration on the block. Total well costs charged to exploration expenses were $33 million.

- In Canada, offshore Nova Scotia (Hess - 50%), the operator, BP Canada, completed drilling of the Aspy exploration well, which did not encounter commercial quantities of hydrocarbons. Total well costs charged to exploration expenses were $120 million.

The following is an update of significant Midstream activities during 2018:

- In December 2018, we entered into a Memorandum of Understanding with HIP to sell HIP our water handling business for $225 million in cash, subject to customary adjustments. The parties expect to execute definitive agreements and close the transaction in the first quarter of 2019, subject to receipt of regulatory approvals.

Liquidity and Capital and Exploratory Expenditures

In 2018, net cash provided by operating activities was $1,939 million (2017: $945 million; 2016: $795 million). At December 31, 2018, consolidated cash and cash equivalents were $2,694 million (2017: $4,847 million), consolidated debt was $6,672 million (2017: $6,977 million), and our consolidated debt to capitalization ratio was 38.0% (2017: 36.1%).

Capital and exploratory expenditures were as follows (in millions):

	2018	2017	2016
E&P Capital and Exploratory Expenditures			
United States			
Bakken	**$ 967**	$ 624	$ 429
Other Onshore	**43**	30	46
Total Onshore	**1,010**	654	475
Offshore	**368**	702	735
Total United States	**1,378**	1,356	1,210
South America	**423**	242	144
Europe	**8**	142	65
Asia and other	**260**	307	452
E&P - Capital and Exploratory Expenditures	**$ 2,069**	$ 2,047	$ 1,871

Exploration expenses charged to income included in E&P capital and exploratory expenditures above were:

	2018	2017	2016
United States	**$ 106**	$ 90	$ 93
International	**54**	105	140
Total Exploration Expenses Charged to Income included above	**$ 160**	$ 195	$ 233

	2018	2017	2016
Midstream Capital Expenditures			
Midstream - Capital Expenditures (a)	**$ 271**	$ 121	$ 283

(a) Excludes equity investments of $67 million in 2018.

In 2019, we project our E&P capital and exploratory expenditures will be approximately $2.9 billion.

Consolidated Results of Operations

Results by Segment:

The after-tax income (loss) by major operating activity is summarized below:

	2018	2017	2016
	(In millions, except per share amounts)		
Net Income (Loss) Attributable to Hess Corporation:			
Exploration and Production	**$ 51**	$ (3,653)	$ (4,964)
Midstream	**120**	42	42
Corporate, Interest and Other	**(453)**	(463)	(1,210)
Total	**$ (282)**	$ (4,074)	$ (6,132)
Net Income (Loss) Attributable to Hess Corporation Per Common Share - Diluted (a)	**$ (1.10)**	$ (13.12)	$ (19.92)

(a) Calculated as net income (loss) attributable to Hess Corporation less preferred stock dividends, divided by weighted average number of diluted shares.

In the following discussion and elsewhere in this report, the financial effects of certain transactions are disclosed on an after-tax basis. Management reviews segment earnings on an after-tax basis and uses after-tax amounts in its review of variances in segment earnings. Management believes that after-tax amounts are a preferable method of explaining variances in earnings, since they show the entire effect of a transaction rather than only the pre-tax amount. After-tax amounts are determined by applying the income tax rate in each tax jurisdiction to pre-tax amounts.

Items Affecting Comparability of Earnings Between Periods:

The following table summarizes items of income (expense) that are included in net income (loss) and affect comparability of earnings between periods. The items in the table below are explained on pages 31 through 35.

	2018	2017	2016
	(In millions)		
Items Affecting Comparability of Earnings Between Periods, After Income Taxes:			
Exploration and Production	**$ (86)**	$ (2,609)	$ (3,699)
Midstream	**—**	(34)	(21)
Corporate, Interest and Other	**(20)**	(30)	(923)
Total	**$ (106)**	$ (2,673)	$ (4,643)

The following table reconciles reported net income (loss) attributable to Hess Corporation and adjusted net income (loss):

	2018	2017	2016
	(In millions)		
Net income (loss) attributable to Hess Corporation	**$ (282)**	$ (4,074)	$ (6,132)
Less: Total items affecting comparability of earnings between periods	**(106)**	(2,673)	(4,643)
Adjusted Net Income (Loss) Attributable to Hess Corporation	**$ (176)**	$ (1,401)	$ (1,489)

Adjusted net income (loss) attributable to Hess Corporation presented in this report is a non-GAAP financial measure, which we define as reported net income (loss) attributable to Hess Corporation excluding items identified as affecting comparability of earnings between periods. Management uses adjusted net income (loss) to evaluate the Corporation's operating performance and believes that investors' understanding of our performance is enhanced by disclosing this measure, which excludes certain items that management believes are not directly related to ongoing operations and are not indicative of future business trends and operations. This measure is not, and should not be viewed as, a substitute for U.S. GAAP net income (loss).

The following table presents the pre-tax amount of items affecting comparability of income (expense) by financial statement line item in the *Statement of Consolidated Income* on page 48. The items in the table below are explained on pages 31 through 35.

	Before Income Taxes		
	2018	**2017**	**2016**
		(In millions)	
Total Items Affecting Comparability of Earnings Between Periods, Pre-Tax:			
Sales and other operating revenues	**$ —**	$ (22)	$ —
Gains (losses) on asset sales, net	**24**	(98)	27
Operating costs and expenses	**(19)**	—	(164)
Exploration expenses, including dry holes and lease impairment	**(3)**	(280)	(1,029)
General and administrative expenses	**(130)**	(11)	(1)
Loss on debt extinguishment	**(53)**	—	(148)
Depreciation, depletion and amortization	**(16)**	(19)	—
Impairment	**—**	(4,203)	(67)
Total	**$ (197)**	$ (4,633)	$ (1,382)

Comparison of Results

Exploration and Production

Following is a summarized statement of income for our E&P operations:

	2018	**2017**	**2016**
		(In millions)	
Revenues and Non-Operating Income			
Sales and other operating revenues	**$ 6,323**	$ 5,460	$ 4,755
Gains (losses) on asset sales, net	**27**	(39)	27
Other, net	**53**	(1)	16
Total revenues and non-operating income	**6,403**	5,420	4,798
Costs and Expenses			
Marketing, including purchased oil and gas	**1,833**	1,335	1,128
Operating costs and expenses	**941**	1,248	1,658
Production and severance taxes	**171**	119	101
Midstream tariffs	**648**	543	497
Exploration expenses, including dry holes and lease impairment	**362**	507	1,442
General and administrative expenses	**258**	224	236
Depreciation, depletion and amortization	**1,748**	2,736	3,113
Impairment	**—**	4,203	—
Total costs and expenses	**5,961**	10,915	8,175
Results of Operations Before Income Taxes	**442**	(5,495)	(3,377)
Provision (benefit) for income taxes	**391**	(1,842)	1,587
Net Income (Loss) Attributable to Hess Corporation	**$ 51**	$ (3,653)	$ (4,964)

Excluding the E&P items affecting comparability of earnings between periods in the table on page 31, the changes in E&P results are primarily attributable to changes in selling prices, production and sales volumes, marketing expenses, cash operating costs, Midstream tariffs, depreciation, depletion and amortization, exploration expenses and income taxes, as discussed below.

Selling Prices: Average worldwide realized crude oil selling prices, including hedging, were 23% higher in 2018 compared to the prior year, primarily due to the increase in Brent and WTI crude oil prices. In addition, realized worldwide selling prices for NGLs increased in 2018 by 19% and worldwide natural gas prices increased in 2018 by 24%, compared to the prior year. In total, higher realized selling prices improved 2018 financial results by approximately $700 million after income taxes, compared with 2017. Our average selling prices were as follows:

	2018	2017	2016
Crude Oil - Per Barrel (Including Hedging)			
United States			
Onshore	**$ 56.90**	$ 46.04	$ 36.92
Offshore	**62.02**	47.34	37.47
Total United States	**58.69**	46.50	37.13
Europe	**70.08**	55.03	43.33
Africa	**69.64**	53.17	41.88
Asia	**70.42**	56.99	42.98
Worldwide	**60.77**	49.23	39.20
Crude Oil - Per Barrel (Excluding Hedging)			
United States			
Onshore	**$ 60.64**	$ 46.76	$ 36.92
Offshore	**65.73**	48.15	37.47
Total United States	**62.41**	47.25	37.13
Europe	**70.08**	55.14	43.33
Africa	**69.64**	53.25	41.88
Asia	**70.42**	56.99	42.98
Worldwide	**63.80**	49.75	39.20
Natural Gas Liquids - Per Barrel			
United States			
Onshore	**$ 21.29**	$ 17.67	$ 9.18
Offshore	**25.58**	21.34	13.96
Total United States	**21.81**	18.10	9.71
Europe	**—**	29.04	19.48
Worldwide	**21.81**	18.35	9.95
Natural Gas - Per Mcf			
United States			
Onshore	**$ 2.29**	$ 1.96	$ 1.48
Offshore	**2.68**	2.22	1.99
Total United States	**2.43**	2.03	1.61
Europe	**3.61**	4.42	3.97
Asia and other	**5.07**	4.27	5.31
Worldwide	**4.18**	3.37	3.37

(a) Selling prices in the United States are adjusted for certain processing and distribution fees included in Marketing expenses. Excluding these fees Worldwide selling prices for 2018 would be $63.77 per barrel for crude oil (including hedging), $66.80 per barrel for crude oil (excluding hedging), $22.00 per barrel for NGLs and $4.25 per mcf for natural gas.

Net realized losses from crude oil hedging contracts reduced Sales and other operating revenues by $183 million ($183 million after income taxes) in 2018, and $59 million ($59 million after income taxes) in 2017. There were no crude oil hedge contracts in 2016. We have purchased crude oil put options for calendar year 2019 that establish a WTI monthly floor price of $60 per barrel on 95,000 bopd for $116 million, which will be amortized on a straight-line basis during 2019.

Production Volumes: Our daily worldwide net production was as follows:

	2018	2017	2016
		(In thousands)	
Crude Oil - Barrels			
United States			
Bakken	**76**	67	68
Other Onshore	**1**	6	9
Total Onshore	**77**	73	77
Offshore	**41**	39	45
Total United States	**118**	112	122
Europe	**6**	28	33
Africa	**18**	35	34
Asia	**4**	2	2
Worldwide	**146**	177	191
Natural Gas Liquids - Barrels			
United States			
Bakken	**29**	28	27
Other Onshore	**5**	8	11
Total Onshore	**34**	36	38
Offshore	**5**	5	5
Total United States	**39**	41	43
Europe	—	1	1
Worldwide	**39**	42	44
Natural Gas - Mcf			
United States			
Bakken	**70**	62	61
Other Onshore	**44**	92	133
Total Onshore	**114**	154	194
Offshore	**67**	57	64
Total United States	**181**	211	258
Europe	**8**	33	43
Asia and other	**364**	276	222
Worldwide	**553**	520	523
Barrels of Oil Equivalent	**277**	306	322
Crude oil and natural gas liquids as a share of total production	**67%**	72%	73%

In 2019, we expect net production, excluding Libya, to average between 270,000 boepd and 280,000 boepd, compared to full year pro forma 2018 net production, excluding Libya and assets sold, of 248,000 boepd.

Production variances related to 2018, 2017 and 2016 are summarized as follows:

United States: Bakken net production was higher in 2018, compared to 2017, primarily due to increased drilling activity and improved well performance in the current year. The year-on-year decline in U.S. other onshore production in 2018 and 2017 reflects the sale of our interests in the Utica shale play in August 2018 and the sale of our Permian assets in August 2017. Total U.S. offshore oil production was higher in 2018, compared to 2017, primarily due to the Stampede and Penn State Fields, partially offset by the impact of downtime from a planned well workover at the Tubular Bells Field, the shutdown at the third-party operated Enchilada platform, and natural field decline. Total offshore production was lower in 2017, compared to 2016, due to shut-in production from the fire at the third-party operated Enchilada platform and natural field decline, partially offset by higher production from the Tubular Bells Field. Production from Utica averaged 9,000 boepd for calendar year 2018 (2017: 19,000 boepd; 2016: 29,000 boepd). Production from the Permian averaged net 4,000 boepd for calendar year 2017 (2016: 7,000 boepd).

Europe: Total net production was lower in 2018 compared to 2017, primarily due to the sale of our interests in Norway in December 2017. Crude oil and natural gas production was lower in 2017 compared to 2016, primarily due to natural field decline. Production in Norway averaged 24,000 boepd in 2017 (2016: 28,000 boepd).

Africa: Crude oil production was lower in 2018 compared to 2017, primarily reflecting the sale of Equatorial Guinea in November 2017, partially offset by higher production in Libya. Crude oil production in 2017 was comparable to 2016, as lower volumes from Equatorial Guinea were offset by higher production in Libya. Production in Equatorial Guinea averaged 25,000 boepd in 2017 (2016: 33,000 boepd). Production in Libya was 20,000 boepd in 2018 (2017: 10,000 boepd; 2016: 1,000 boepd).

Asia: Natural gas production was higher in 2018, compared to 2017, and in 2017, compared to 2016, primarily due to first production at the North Malay Basin full-field development in July 2017.

Sales Volumes: The impact of lower sales volumes, primarily due to asset sales, decreased after-tax results by approximately $150 million in 2018, compared to 2017. Worldwide sales volumes from Hess net production, excluding sales volumes of crude oil, NGLs and natural gas purchased from third-parties, were as follows:

	2018	2017	2016
		(In thousands)	
Crude oil - barrels	**52,742**	63,367	72,462
Natural gas liquids - barrels	**14,019**	15,152	16,055
Natural gas - mcf	**202,041**	190,089	191,482
Barrels of Oil Equivalent	**100,435**	110,201	120,431
Crude oil - barrels per day	**144**	173	198
Natural gas liquids - barrels per day	**39**	42	44
Natural gas - mcf per day	**553**	520	523
Barrels of Oil Equivalent Per Day	**275**	302	329

Marketing, including purchased oil and gas: Marketing expense is mainly comprised of costs to purchase crude oil, NGLs and natural gas from our partners in Hess operated wells or other third-parties, primarily in the U.S., and transportation and other distribution costs for U.S. marketing activities. The increases in 2018, compared to 2017, and in 2017, compared to 2016, primarily reflect the impact of higher benchmark crude oil prices on the cost of purchased volumes.

Cash Operating Costs: Cash operating costs, consisting of operating costs and expenses, production and severance taxes and E&P general and administrative expenses, decreased by $221 million in 2018, compared to the prior year (2017: $404 million decrease versus 2016). The decrease in 2018, compared to 2017, is primarily due to asset sales and cost savings initiatives, partially offset by higher production taxes in the Bakken. The decrease in 2017, compared to 2016, is due to lower workover expenses, lease operating and employee costs, partially offset by higher production taxes in the Bakken. Operating costs in 2016 include higher workover costs to replace failed subsurface valves in the Gulf of Mexico.

Midstream Tariffs Expense: Tariffs expense in 2018 increased, compared to 2017, primarily due to higher throughput volumes and water disposal activity in 2018, partially offset by lower costs from our former business in the Permian. Tariffs expense in 2017 increased, compared to 2016, primarily due to higher shortfall fees in 2017. For 2019, we estimate Midstream tariffs expense to be in the range of $750 million to $775 million.

Depreciation, Depletion and Amortization: Depreciation, depletion and amortization (DD&A) costs decreased by $988 million in 2018, compared to 2017, primarily due to the sale of assets which had higher DD&A rates than the portfolio average, a lower DD&A rate at the Bakken due to year-end 2017 proved reserve additions, and the impact of prior year asset impairments. DD&A costs decreased by $377 million in 2017, compared to 2016, primarily due to lower production and an improved portfolio average DD&A rate due to the production mix.

Unit costs: Unit cost per boe information is based on total E&P production volumes and excludes items affecting comparability of earnings as disclosed below. Actual and forecast unit costs are as follows:

	Actual			Forecast range (a)
	2018	2017	2016	2019
Cash operating costs (b)	**$ 12.66**	$ 14.27	$ 15.56	$13.00 — $14.00
DD&A (c)	**17.14**	24.53	26.40	18.00 — 19.00
Total Production Unit Costs	**$ 29.80**	$ 38.80	$ 41.96	$31.00 — $33.00

(a) Forecast information excludes any contribution from Libya and items affecting comparability of earnings.
(b) Excluding items affecting comparability of earnings and Libya, cash operating costs per boe for 2018 were $13.32 (2017: $14.56; 2016: $15.45).
(c) Excluding items affecting comparability of earnings and Libya, DD&A per boe for 2018 were $18.29 (2017: $25.29; 2016: $26.48).

Exploration Expenses: Exploration expenses, including items affecting comparability of earnings described below, were as follows:

	2018	2017	2016
	(In millions)		
Exploratory dry hole costs (a)	**$ 165**	$ 268	$ 1,064
Exploration lease and other impairment	**37**	44	145
Geological and geophysical expense and exploration overhead	**160**	195	233
	$ 362	$ 507	$ 1,442

(a) In 2018, we recorded dry hole costs associated with the Aspy well, offshore Nova Scotia, Canada, the Pontoenoe-1 well, offshore Suriname, and the Sorubim-1 well on the Stabroek Block, offshore Guyana. In 2017, we recorded dry hole costs associated with our former interests in Ghana. In 2016, we recorded dry hole costs associated with our former interests in Australia and three exploration wells in the Gulf of Mexico.

Exploration expenses were lower in 2018, compared to 2017, primarily due to lower dry hole expense and lower geologic and seismic costs. Exploration expenses were lower in 2017, compared to 2016, primarily due to lower dry hole expense, leasehold impairment expense, geologic and seismic costs, and employee expenses. See items affecting comparability of earnings between periods described below. For 2019, we estimate exploration expenses, excluding dry hole expense, to be in the range of $200 million to $220 million.

Income Taxes: The E&P income tax provision was an expense of $391 million in 2018 (2017: $1,842 million benefit; 2016: $1,587 million expense). Excluding items affecting comparability between periods, the E&P income tax provision was an expense of $391 million in 2018 (2017: $95 million expense; 2016: $948 million benefit). The provision in 2018 compared to 2017, and 2017 compared to 2016, reflects higher production from Libya and lower deferred tax benefits on losses. Commencing in 2017, we are generally not recognizing deferred tax benefit or expense in certain countries, primarily the U.S., Denmark (hydrocarbon tax only), Malaysia and Guyana, while we maintain valuation allowances against net deferred tax assets in these jurisdictions in accordance with the requirements of U.S. accounting standards. See E&P items affecting comparability of earnings below and *Critical Accounting Policies and Estimates – Income Taxes* beginning on page 39.

Actual and forecast effective tax rates are as follows:

	Actual			Forecast range
	2018 %	2017 %	2016 %	2019 %
Effective income tax benefit (expense) rate	**(88)**	34	(47)	N/A
Adjusted effective income tax benefit (expense) rate (a)	**60**	7	42	0 to (4)

(a) Excludes any contribution from Libya and items affecting comparability of earnings.

Items Affecting Comparability of Earnings Between Periods: Reported E&P earnings include the following items affecting comparability of income (expense) before and after income taxes:

	Before Income Taxes			After Income Taxes		
	2018	2017	2016	2018	2017	2016
	(In millions)					
Gains (losses) on asset sales, net	**$ 24**	$ (41)	$ 27	**$ 24**	$ (57)	$ 17
Exit costs and other	**(110)**	—	(26)	**(110)**	—	(17)
Impairment	**—**	(4,203)	—	**—**	(2,250)	—
Dry hole, lease impairment and other exploration expenses	**—**	(280)	(1,021)	**—**	(280)	(745)
Noncash charges on de-designated crude oil collars	**—**	(22)	—	**—**	(22)	—
Income tax adjustments	**—**	—	—	**—**	—	(2,869)
Offshore rig cost	**—**	—	(105)	**—**	—	(66)
Inventory write-off	**—**	—	(39)	**—**	—	(19)
	$ (86)	$ (4,546)	$ (1,164)	**$ (86)**	$ (2,609)	$ (3,699)

The pre-tax amounts of E&P items affecting comparability of income (expense) as presented in the *Statement of Consolidated Income* are as follows:

	Before Income Taxes		
	2018	2017	2016
		(In millions)	
Sales and other operating revenues	**$ —**	$ (22)	$ —
Gains (losses) on asset sales, net	**24**	(41)	27
Operating costs and expenses	**(19)**	—	(162)
Exploration expenses, including dry holes and lease impairment	**(3)**	(280)	(1,029)
General and administrative expenses	**(72)**	—	—
Depreciation, depletion and amortization	**(16)**	—	—
Impairment	**—**	(4,203)	—
	$ (86)	$ (4,546)	$ (1,164)

2018:

- *Gains (losses) on asset sales, net:* We recorded a pre-tax gain of $14 million ($14 million after income taxes) associated with the sale of our interests in the Utica shale play in eastern Ohio and a pre-tax gain of $10 million ($10 million after income taxes) associated with the sale of our interests in Ghana.
- *Exit costs and other:* We incurred noncash pre-tax charges of $73 million ($73 million after income taxes) in connection with vacated office space. In addition, we recorded a pre-tax severance charge of $37 million ($37 million after income taxes), related to a cost reduction program undertaken to reflect the reduced scale of our business following significant asset sales in 2017.

2017:

- *Gains (losses) on asset sales, net:* We recognized a pre-tax gain of $486 million ($486 million after income taxes) related to the sale of our assets in Equatorial Guinea, and a pre-tax gain of $330 million ($314 million after income taxes) related to the sale of our enhanced oil recovery assets in the Permian Basin. We also incurred a pre-tax loss of $857 million ($857 million after income taxes) on the sale of our interests in Norway. The loss included the recognition of $900 million in earnings for cumulative translation adjustments previously reflected within accumulated other comprehensive income. See *Note 3, Dispositions* in the *Notes to Consolidated Financial Statements*.
- *Impairment:* We recorded a noncash impairment charge related to our interests in Norway totaling $2,503 million pre-tax ($550 million after income taxes) in the third quarter prior to the sale of our interests in the fourth quarter. In addition, we recognized pre-tax impairment charges to reduce the carrying value of our interests in the Stampede Field by $1,095 million ($1,095 million after income taxes), and the Tubular Bells Field by $605 million ($605 million after income taxes) primarily because of a lower long-term crude oil price outlook. The Stampede Field had significant capitalized exploration and appraisal costs that were incurred on a 100% working interest basis on the Pony discovery prior to unitizing into the Stampede project. See *Note 13, Impairment* in the *Notes to Consolidated Financial Statements*.
- *Dry hole, lease impairment and other exploration expenses:* We recorded a pre-tax charge of $280 million ($280 million after income taxes) to fully impair the carrying value of our interest at the Hess operated offshore Deepwater Tano/Cape Three Points license, offshore Ghana (Hess 50% license interest) as a result of management's decision in the fourth quarter of 2017 to not develop the previously discovered fields. These costs were incurred in periods prior to 2017.
- *Noncash charges on de-designated crude oil collars:* We recorded a pre-tax charge of $22 million ($22 million after income taxes) related to certain crude oil collars not designated as cash flow hedges. The de-designation was a result of production downtime caused by a fire at the third-party operated Enchilada platform in the Gulf of Mexico during the fourth quarter.

2016:

- *Dry hole, lease impairment and other exploration expenses:* We recorded a pre-tax charge of $938 million ($693 million after income taxes) to write-off all previously capitalized wells and other project related costs for our Equus natural gas project, offshore the North West Shelf of Australia, following the decision to defer further development of the project. In addition, we recorded a pre-tax charge of $83 million ($52 million after income taxes) to write-off the previously capitalized Sicily-1 exploration well based on our decision not to pursue the project. These costs were incurred in periods prior to 2016.

- *Gains on asset sale, net:* We recognized a pre-tax gain of $27 million ($17 million after income taxes) related to the sale of undeveloped onshore acreage in the U.S.
- *Income taxes:* We recorded a non-cash charge of $2,920 million to establish valuation allowances against net deferred tax assets at December 31, 2016, as required under application of the accounting standards following a three-year cumulative loss. This deferred tax charge had no impact on the Corporation's cash flows or its underlying tax positions. In addition, we recorded a tax benefit of $51 million related to the resolution of certain international tax matters.
- *Offshore rig cost:* We recognized a pre-tax charge of $105 million ($66 million after income taxes) related to an offshore drilling rig.
- *Inventory write-off:* We incurred a pre-tax charge of $39 million ($19 million after income taxes) to write off surplus materials and supplies inventory.
- *Exit costs and other:* We recorded exit and other costs of $26 million ($17 million after income taxes), which primarily relates to employee severance as part of a cost reduction program.

Midstream

Following is a summarized statement of income for our Midstream operations, which include results for a gas plant and associated CO_2 assets in the Permian Basin (through August 2017) and water handling services in North Dakota that are wholly-owned by Hess:

	2018	2017	2016
		(In millions)	
Revenues and Non-Operating Income			
Sales and other operating revenues	**$ 713**	$ 617	$ 569
Losses on asset sales, net	**—**	(51)	—
Other, net	**6**	—	—
Total revenues and non-operating income	**719**	566	569
Costs and Expenses			
Operating costs and expenses	**193**	195	218
General and administrative expenses	**14**	16	20
Depreciation, depletion and amortization	**127**	123	121
Impairment	**—**	—	67
Interest expense	**60**	26	19
Total costs and expenses	**394**	360	445
Results of Operations Before Income Taxes	**325**	206	124
Provision (benefit) for income taxes (a)	**38**	31	26
Net income (loss)	**287**	175	98
Less: Net income (loss) attributable to noncontrolling interests (b)	**167**	133	56
Net Income (Loss) Attributable to Hess Corporation	**$ 120**	$ 42	$ 42

(a) The provision for income taxes in the Midstream segment in 2018 and 2017 is presented before consolidating its operations with other U.S. activities of the Company and prior to evaluating realizability of net U.S. deferred taxes. An offsetting impact is presented in the E&P segment.
(b) The partnership is not subject to tax and, therefore, the noncontrolling interest's share of net income is a pre-tax amount.

Sales and other operating revenues in 2018 increased, compared to 2017, primarily due to higher throughput volumes and water disposal activity in 2018, partially offset by prior year activity associated with our former Permian assets that were sold in August 2017. Sales and other operating revenues in 2017 increased, compared to 2016, primarily due to higher shortfall fees earned, and higher tariff rates and throughput volumes, partially offset by lower rail export revenue associated with third-party rail charges and the sale of our Permian assets in August 2017.

Operating costs and expenses in 2018 reflect increased activity related to produced water disposal services and lower costs from our former Permian assets versus the prior year. Operating costs and expenses were lower in 2017 compared to 2016, primarily due to lower third-party rail charges and the sale of our Permian assets in August 2017. DD&A expenses were higher in 2018 compared to 2017, primarily due to pipeline assets that were brought into service in the current year.

The increase in interest expense in 2018, compared to 2017, and 2017, compared to 2016, reflects higher borrowings by Hess Infrastructure Partners LP.

For 2019, we estimate net income attributable to Hess Corporation from the Midstream segment to be in the range of $170 million to $180 million.

Items Affecting Comparability of Earnings Between Periods: We recognized a pre-tax loss of $57 million ($34 million after income taxes and noncontrolling interest) in 2017 related to the sale of our Midstream assets in the Permian Basin. Midstream results in 2016 included a pre-tax charge of $67 million ($21 million after income taxes and noncontrolling interest) to impair older specification rail cars.

Corporate, Interest and Other

The following table summarizes Corporate, Interest and Other expenses:

	2018	2017	2016
		(In millions)	
Corporate and other expenses (excluding items affecting comparability)	**$ 97**	$ 160	$ 131
Interest expense	**359**	385	380
Less: Capitalized interest	**(20)**	(86)	(61)
Interest expense, net	**339**	299	319
Corporate, Interest and Other expenses before income taxes	**436**	459	450
Provision (benefit) for income taxes	**(3)**	(26)	(163)
Net Corporate, Interest and Other expenses after income taxes	**433**	433	287
Items affecting comparability of earnings between periods, after income taxes	**20**	30	923
Total Corporate, Interest and Other Expenses After Income Taxes	**$ 453**	$ 463	$ 1,210

Corporate and other expenses, excluding items affecting comparability, were lower in 2018, compared to 2017, primarily due to lower employee related costs, non-service pension costs and legal fees. Corporate and other expenses, excluding items affecting comparability, were higher in 2017, compared to 2016, primarily due to higher legal costs, increased pension settlement charges in 2017, and the recognition of a nonrecurring gain of $8 million in 2016. In 2019, after-tax Corporate and other expenses, excluding items affecting comparability of earnings between periods, are estimated to be in the range of $105 million to $115 million.

Interest expense was lower in 2018, compared to 2017, due to lower average borrowings. Capitalized interest was lower in 2018, compared to 2017, primarily due to the Stampede Field commencing production in January 2018. Interest expense was higher in 2017, compared to 2016, primarily due to slightly higher average borrowings. Capitalized interest expense was higher in 2017, compared to 2016, due to increased activity at the Hess operated Stampede development project and sanction of the Liza Field Phase 1 development project during 2017. In 2019 after-tax interest expense, net is estimated to be in the range of $315 million to $325 million.

Excluding items affecting comparability of earnings between periods, the benefit for income taxes is lower in 2018 and 2017, compared to 2016, due to us generally not recognizing deferred tax benefit or expense in the U.S. while we maintain valuation allowances against net deferred tax assets in accordance with the requirements of U.S. accounting standards. This accounting treatment commenced on December 31, 2016. See items affecting comparability of earnings below and *Critical Accounting Policies and Estimates – Income Taxes* beginning on page 39.

Items Affecting Comparability of Earnings Between Periods: Corporate, Interest and Other results included the following items affecting comparability of income (expense) before and after income taxes:

2018:

- *Loss on debt extinguishment:* We recorded a pre-tax charge of $53 million ($53 million after income taxes) related to the premium paid for debt repurchases. See *Note 8, Debt*, in the *Notes to Consolidated Financial Statements.*
- *Exit costs and other:* We recorded a pre-tax charge of $58 million ($58 million after income taxes) resulting from the settlement of legal claims related to former downstream interests.
- *Income tax:* We recorded an allocation of noncash income tax benefit of $91 million to offset the recognition of a noncash income tax expense recorded in other comprehensive income resulting primarily from changes in fair value of our 2019 crude oil hedging program, as required under accounting standards.

2017:

- *Exit costs and other:* We recorded a pre-tax charge of $30 million ($30 million after income taxes) in connection with vacated office space, of which $11 million is included in General and administrative expenses and $19 million is included in Depreciation, depletion and amortization in the *Statement of Consolidated Income*.

2016:

- *Income tax:* We recorded a non-cash charge of $829 million to establish valuation allowances against net deferred tax assets at December 31, 2016, as required under application of the accounting standards following a three-year cumulative loss. This deferred tax charge had no impact on the Corporation's cash flows or its underlying tax positions.
- *Loss on debt extinguishment:* We recorded a pre-tax charge of $148 million ($92 million after income taxes) related to the repurchase and redemption of notes to complete a debt refinancing.
- *Exit costs and other:* We recorded exit and other costs of $3 million ($2 million after income taxes), which primarily relates to employee severance.

Liquidity and Capital Resources

The following table sets forth certain relevant measures of our liquidity and capital resources at December 31:

	2018	2017
	(In millions, except ratio)	
Cash and cash equivalents (a)	**$ 2,694**	$ 4,847
Current maturities of long-term debt	**67**	580
Total debt (b)	**6,672**	6,977
Total equity	**10,888**	12,354
Debt to capitalization ratio (c)	**38.0%**	36.1%

(a) Includes $109 million of cash attributable to our Midstream Segment, at December 31, 2018 (2017: $356 million).
(b) Includes $981 million of debt outstanding from HIP at December 31, 2018 (2017: $980 million) that is non-recourse to Hess Corporation.
(c) Total debt as a percentage of the sum of total debt plus equity.

Cash Flows

The following table sets forth a summary of our cash flows:

	2018	2017	2016
		(In millions)	
Net cash provided by (used in):			
Operating activities	**$ 1,939**	$ 945	$ 795
Investing activities	**(1,566)**	1,358	(2,090)
Financing activities	**(2,526)**	(188)	1,311
Net Increase (Decrease) in Cash and Cash Equivalents	**$ (2,153)**	$ 2,115	$ 16

***Operating Activities*:** In 2018, net cash provided by operating activities increased, compared to 2017, primarily due to higher benchmark crude oil prices and lower operating costs, partially offset by lower production volumes largely due to asset sales. In 2017, operating cash flows increased, compared to 2016, primarily due to higher benchmark crude oil prices and lower operating costs, partially offset by lower production volumes.

Changes in working capital in 2018 reduced cash by $186 million (2017: $780 million reduction; 2016: $47 million reduction), primarily from premiums on crude oil hedge contracts and abandonment expenditures. Changes in working capital in 2017 included increased accounts receivable due to higher crude oil prices, abandonment expenditures, premiums on crude oil hedge contracts, pension contributions, contract termination payments for an offshore drilling rig, and crude oil delivered as line fill.

Investing Activities: Total addition to property, plant and equipment were $2,097 million in 2018 (2017: $1,937 million; 2016: $2,251 million). The increase in Additions to property, plant and equipment in 2018, compared to 2017, is primarily related to increased expenditures in the Bakken, offshore Guyana, offshore Canada and in our Midstream segment, primarily offset by the impact of prior year asset sales and reduced development expenditure in both the Gulf of Mexico and Malaysia. In 2017, Additions to property, plant and equipment were lower, compared to 2016, primarily due to lower development expenditures at North Malay Basin, partially offset by increased investments in Bakken and Guyana in 2017. In 2018, Midstream equity investments in its 50/50 joint venture with Targa Resources were $67 million. Proceeds from the sale of assets of $607 million in 2018 (2017: $3,296 million; 2016: $140 million) include the divestiture of our joint venture interests in the Utica shale play in eastern Ohio, and our share of proceeds from the sale and lease-back transaction of the North Malay Basin floating storage and offloading vessel.

Financing Activities: Repayments of debt were $633 million in 2018 (2017: $459 million; 2016: $1,455 million) while borrowings of debt with maturities in excess of 90 days were $800 million in 2017 and $1,496 million in 2016. We settled common stock purchases in the amount of $1,365 million in 2018 (2017: $110 million). Common and preferred stock dividends paid were $345 million in 2018 (2017: $363 million; 2016: $350 million). In 2017, Hess Midstream Partners LP received proceeds of $365.5 million from the issuance of common units in an initial public offering, of which $350 million was distributed equally to Hess Corporation and GIP. Net outflows to noncontrolling interests were $211 million in 2018 (2017: $243 million net outflow; 2016: $23 million net outflow). In 2016, we issued 28,750,000 shares of common stock and depositary shares representing 575,000 shares of 8% Series A Mandatory Convertible Preferred Stock for total net proceeds of $1.64 billion.

Future Capital Requirements and Resources

At December 31, 2018, Hess Corporation, had $2.6 billion in cash and cash equivalents, excluding Midstream, and total liquidity, including available committed credit facilities, of approximately $7.0 billion. The Corporation has no significant near-term debt maturities. We have purchased crude oil put options for calendar year 2019 that establish a WTI monthly floor price of $60 per barrel for 95,000 bopd.

Net production in 2019 is forecast to be in the range of 270,000 boepd to 280,000 boepd, excluding Libya, and we expect our 2019 E&P capital and exploratory expenditures will be approximately $2.9 billion. Based on current forward strip crude oil prices for 2019, we expect cash flow from operating activities and cash and cash equivalents existing at December 31, 2018, will be sufficient to fund our capital investment program and dividends through the end of 2019.

The table below summarizes the capacity, usage, and available capacity of our borrowing and letter of credit facilities at December 31, 2018:

	Expiration Date	Capacity	Borrowings	Letters of Credit Issued	Total Used	Available Capacity
				(In millions)		
Hess Corporation						
Revolving credit facility - Hess Corporation (a)	January 2021	$ 4,000	$ —	$ —	$ —	$ 4,000
Committed lines	Various (b)	445	—	29	29	416
Uncommitted lines	Various (b)	255	—	255	255	—
Total - Hess Corporation		$ 4,700	$ —	$ 284	$ 284	$ 4,416
Midstream						
Revolving credit facility - HIP (c)	November 2022	$ 600	$ —	$ —	$ —	$ 600
Revolving credit facility - Hess Midstream Partners LP (d)	March 2021	300	—	—	—	300
Total - Midstream		$ 900	$ —	$ —	$ —	$ 900

(a) In January 2020, the capacity reduces to $3.7 billion.
(b) Committed and uncommitted lines have expiration dates throughout 2019.
(c) This credit facility may only be utilized by HIP and is non-recourse to Hess Corporation.
(d) This credit facility may only be utilized by Hess Midstream Partners LP and is non-recourse to Hess Corporation.

The Corporation's $4.0 billion syndicated revolving credit facility expires in January 2021, with commitments of $3.7 billion available for the final year. Borrowings on the facility will generally bear interest at 1.30% above the London Interbank Offered Rate (LIBOR). The interest rate will be higher if our credit rating is lowered. The facility contains a financial covenant that limits the amount of the total borrowings on the last day of each fiscal quarter to 60% of the Corporation's total capitalization, defined as total debt plus stockholders' equity. At December 31, 2018, Hess Corporation had no outstanding borrowings or letters of credit under this facility and was in compliance with this financial covenant.

We had $284 million in letters of credit outstanding at December 31, 2018 (2017: $246 million), which primarily relate to our international operations. See also *Note 21, Financial Risk Management Activities* in the *Notes to Consolidated Financial Statements*.

We also have a shelf registration under which we may issue additional debt securities, warrants, common stock or preferred stock.

At December 31, 2018, HIP has $800 million of senior secured syndicated credit facilities maturing November 2022, consisting of a $600 million 5-year revolving credit facility and a drawn $200 million 5-year Term Loan A facility. The revolving credit facility can be used for borrowings and letters of credit to fund the joint venture's operating activities and capital expenditures. Borrowings under the 5-year Term Loan A facility will generally bear interest at LIBOR plus an applicable margin ranging from 1.55% to 2.50%, while the applicable margin for the 5-year syndicated revolving credit facility ranges from 1.275% to 2.000%. The interest rate is subject to adjustment based on HIP's leverage ratio, which is calculated as total debt to Earnings Before Interest, Taxes, Depreciation and Amortization (EBITDA). If HIP obtains an investment grade credit rating, as defined in the amended credit agreement, pricing levels will be based on the credit ratings in effect from time to time. The credit facilities contain financial covenants that generally require a leverage ratio of no more than 5.0 to 1.0 for the prior four fiscal quarters and an interest coverage ratio, which is calculated as EBITDA to cash interest expense, of no less than 2.25 to 1.0 for the prior four fiscal quarters. The amended credit agreement includes a secured leverage ratio test not to exceed 3.75 to 1.00 for so long as the facilities remain secured. HIP is in compliance with these financial covenants at December 31, 2018. Outstanding borrowings under this credit facility are non-recourse to Hess Corporation. At December 31, 2018, HIP's revolving credit facility was undrawn and borrowings under the Term Loan A facility amounted to $197.5 million, excluding deferred issuance costs. The credit facilities are secured by first-priority perfected liens on substantially all of HIP's and certain of its wholly-owned subsidiaries' directly owned assets, including its equity interests in certain subsidiaries, subject to customary exclusions.

Hess Midstream Partners LP (the "Partnership") has a $300 million 4-year senior secured syndicated revolving credit facility that became available for utilization at completion of its initial public offering in April 2017. The credit facility can be used for borrowings and letters of credit to fund operating activities and capital expenditures of the Partnership and expires March 2021. Borrowings on the credit facility will generally bear interest at LIBOR plus an applicable margin of 1.275%. The interest rate is subject to adjustment based on the Partnership's leverage ratio, which is calculated as total debt to EBITDA. If the Partnership obtains credit ratings, pricing levels will be based on the credit ratings in effect from time to time. The Partnership is subject to customary covenants in the credit agreement, including financial covenants that generally require a leverage ratio of no more than 4.5 to 1.0 for the prior four fiscal quarters. The credit facility is secured by first priority perfected liens on substantially all directly owned assets of the Partnership and its wholly-owned subsidiaries, including equity interests in subsidiaries, subject to certain customary exclusions. Outstanding borrowings under this credit facility are non-recourse to Hess Corporation. At December 31, 2018, this facility was undrawn.

Credit Ratings

Two of the three major credit rating agencies that rate the Corporation's debt have assigned an investment grade rating. At December 31, 2018, we have investment grade credit ratings from Standard and Poor's Ratings Services (BBB-) and Fitch Ratings (BBB-). Moody's Investors Service has rated our debt at Ba1. The consequence of lower credit ratings is an increase in interest rates and facility fees on our credit facilities and the potential for additional required collateral under operating agreements, which are not material.

At December 31, 2018, HIP's senior unsecured debt is rated BB+ by Standard and Poor's Ratings Services, Ba3 by Moody's Investors Service, and BB by Fitch Ratings.

Contractual Obligations and Contingencies

The following table shows aggregate information about certain contractual obligations at December 31, 2018:

		Payments Due by Period			
	Total	2019	2020 and 2021	2022 and 2023	Thereafter
			(In millions)		
Total Debt (excludes interest) (a)	$ 6,672	$ 67	$ 66	$ 192	$ 6,347
Operating Leases (b) (c)	902	355	221	128	198
Purchase Obligations:					
Capital expenditures (c)	1,069	443	551	75	—
Operating expenses (c)	433	219	99	61	54
Transportation and related contracts (c)	1,050	212	401	336	101
Asset retirement obligations	857	116	75	36	630
Other liabilities	518	121	93	84	220

(a) We anticipate cash payments for interest of $401 million for 2019, $775 million for 2020-2021, $752 million for 2022-2023, and $3,912 million thereafter for a total of $5,840 million. These interest payments reflect our contractual obligations at December 31, 2018.
(b) On January 1, 2019, we will adopt ASC 842, Leases, which will result in operating lease commitments greater than one year being reflected on our Consolidated Balance Sheet. See Note 1, Nature of Operations, Basis of Presentation and Summary of Accounting Policies, in the Notes to Consolidated Financial Statements for further details.
(c) Comprises obligations where we, as operator, have contracted directly with suppliers.

Capital expenditures represent amounts that we were contractually committed at December 31, 2018, including the portion of our planned capital expenditure program for 2019. Obligations for operating expenses include commitments for oil and gas production expenses, seismic purchases and other normal business expenses. Other liabilities reflect contractually committed obligations in the *Consolidated Balance Sheet* at December 31, 2018, including pension plan liabilities and estimates for uncertain income tax positions. The Corporation and certain of its subsidiaries lease drilling rigs, support vessels, office space and other assets for varying periods under leases accounted for as operating leases.

Off-Balance Sheet Arrangements

At December 31, 2018, we had $284 million in letters of credit. See also *Note 19, Guarantees, Contingencies and Commitments* in the *Notes to Consolidated Financial Statements*.

Foreign Operations

We conduct E&P activities outside the U.S., principally in the Joint Development Area of Malaysia/Thailand and Malaysia, Denmark, Libya, Guyana, Suriname, and Canada. Therefore, we are subject to the risks associated with foreign operations, including political risk, tax law changes, currency risk, corruption, and acts of terrorism. See *Item 1A. Risk Factors* for further details.

Critical Accounting Policies and Estimates

Accounting policies and estimates affect the recognition of assets and liabilities in the *Consolidated Balance Sheet* and revenues and expenses in the *Statement of Consolidated Income*. The accounting methods used can affect net income, equity and various financial statement ratios. However, our accounting policies generally do not change cash flows or liquidity.

Accounting for Exploration and Development Costs: E&P activities are accounted for using the successful efforts method. Costs of acquiring unproved and proved oil and gas leasehold acreage, including lease bonuses, brokers' fees and other related costs are capitalized. Annual lease rentals, exploration expenses and exploratory dry hole costs are expensed as incurred. Costs of drilling and equipping productive wells, including development dry holes, and related production facilities are capitalized.

The costs of exploratory wells that find oil and gas reserves are capitalized pending determination of whether proved reserves have been found. Exploratory drilling costs remain capitalized after drilling is completed if (1) the well has found a sufficient quantity of reserves to justify completion as a producing well and (2) sufficient progress is being made in assessing the reserves and the economic and operational viability of the project. If either of those criteria is not met, or if there is substantial doubt about the economic or operational viability of the project, the capitalized well costs are charged to expense. Indicators of sufficient progress in assessing reserves, and the economic and operating viability of a project include: commitment of project personnel, active negotiations for sales contracts with customers, negotiations with governments, operators and contractors and firm plans for additional drilling and other factors.

Crude Oil and Natural Gas Reserves: The determination of estimated proved reserves is a significant element in arriving at the results of operations of E&P activities. The estimates of proved reserves affect well capitalizations, the unit of production depreciation rates of proved properties and wells and equipment, as well as impairment testing of oil and gas assets.

For reserves to be booked as proved they must be determined with reasonable certainty to be economically producible from known reservoirs under existing economic conditions, operating methods and government regulations. In addition, government and project operator approvals must be obtained and, depending on the amount of the project cost, senior management or the Board of Directors must commit to fund the project. We maintain our own internal reserve estimates that are calculated by technical staff that work directly with the oil and gas properties. Our technical staff updates reserve estimates throughout the year based on evaluations of new wells, performance reviews, new technical data and other studies. To provide consistency throughout the Corporation, standard reserve estimation guidelines, definitions, reporting reviews and approval practices are used. The internal reserve estimates are subject to internal technical audits and senior management review. We also engage an independent third-party consulting firm to audit approximately 80% of our total proved reserves each year.

Proved reserves are calculated using the average price during the twelve-month period ending December 31 determined as an unweighted arithmetic average of the price on the first day of each month within the year, unless prices are defined by contractual agreements, excluding escalations based on future conditions. As discussed in *Item 1A. Risk Factors*, crude oil prices are volatile which can have an impact on our proved reserves. If crude oil prices in 2019 are at levels below that used in determining 2018 proved reserves, we may recognize negative revisions to our December 31, 2019 proved undeveloped reserves. In addition, we may recognize negative revisions to proved developed reserves, which can vary significantly by asset due to differing operating cost structures. Conversely, price increases in 2019 above those used in determining 2018 proved reserves could result in positive revisions to proved developed and proved undeveloped reserves at December 31, 2019. It is difficult to estimate the magnitude of any potential net negative or positive change in proved reserves at December 31, 2019, due to numerous currently unknown factors, including 2019 crude oil prices, any revisions based on 2019 reservoir performance, and the levels to which industry costs will change in response to movements in commodity prices. A 10% change in proved developed and proved undeveloped reserves at December 31, 2018 would result in an approximate $200 million pre-tax change in depreciation, depletion, and amortization expense for 2019 based on projected production volumes. See the *Supplementary Oil and Gas Data* on pages 82 through 92 in the accompanying financial statements for additional information on our oil and gas reserves.

Midstream Joint Venture: We consolidate the activities of our 50/50 joint venture HIP, which qualifies as a variable interest entity (VIE) under U.S. generally accepted accounting principles. We have concluded that we are the primary beneficiary of the VIE, as defined in the accounting standards, since we have the power through our 50% ownership to direct those activities that most significantly impact the economic performance of HIP, and are obligated to absorb losses or have the right to receive benefits that could potentially be significant to HIP. This conclusion was based on a qualitative analysis that considered HIP's governance structure, the commercial agreements between HIP and us, and the voting rights established between the members, which provide us the ability to control the operations of HIP.

Impairment of Long-lived Assets: We review long-lived assets, including oil and gas fields, for impairment whenever events or changes in circumstances indicate that the carrying amounts may not be recovered. Long-lived assets are tested based on identifiable cash flows that are largely independent of the cash flows of other assets and liabilities. If the carrying amounts of the long-lived assets are not expected to be recovered by estimated undiscounted future net cash flows, the assets are impaired and an impairment loss is recorded. The amount of impairment is determined based on the estimated fair value of the assets generally determined by discounting anticipated future net cash flows, an income valuation approach, or by a market-based valuation approach, which are Level 3 fair value measurements.

In the case of oil and gas fields, the present value of future net cash flows is based on management's best estimate of future prices, which is determined with reference to recent historical prices and published forward prices, applied to projected production volumes and discounted at a risk-adjusted rate. The projected production volumes represent reserves, including probable reserves, expected to be produced based on a stipulated amount of capital expenditures. The production volumes, prices and timing of production are consistent with internal projections and other externally reported information. Oil and gas prices used for determining asset impairment will generally differ from those used in the standardized measure of discounted future net cash flows, since the standardized measure requires the use of historical twelve-month average prices.

Our impairment tests of long-lived E&P producing assets are based on our best estimates of future production volumes (including recovery factors), selling prices, operating and capital costs, the timing of future production and other factors, which are updated each time an impairment test is performed. While crude oil prices in 2018 were higher than the last few years, we could experience an asset impairment in the future if the projected production volumes from oil and gas fields decrease, crude oil and natural gas selling prices decline significantly for an extended period or future estimated capital and operating costs increase significantly.

Impairment of Goodwill: Goodwill is tested for impairment annually on October 1st or when events or circumstances indicate that the carrying amount of the goodwill may not be recoverable. We conduct the goodwill test at a reporting unit level, which is defined in accounting standards as an operating segment or one level below an operating segment. The reporting unit or units used in an evaluation and measurement of goodwill for impairment testing are determined from several factors, including the manner in which the business is managed. At December 31, 2018, our Midstream operating segment had goodwill of $360 million that resulted from an allocation from our E&P segment upon the formation of the Midstream segment in 2015. Our E&P segment has no goodwill at December 31, 2018.

To determine whether an indicator of impairment exists, the fair value of a reporting unit is compared with its carrying amount, including goodwill. If the fair value of the reporting unit exceeds its carrying value, goodwill is not impaired. If the carrying value of the reporting unit exceeds its fair value, an impairment charge would be recorded for the excess of the carrying value over fair value, limited by the amount of goodwill allocated to the reporting unit.

Fair value for the Midstream operating segment is based on a market approach, whereby the market capitalization of Hess Midstream Partners, LP's (the Partnership), which represents an approximate 20% economic interest in the operating companies that comprise the Midstream segment, is adjusted to an amount equal to a 100% economic interest in the operating companies based on the Partnership's stock price at the time of the impairment test. Other adjustments made to compute fair value include estimating the fair value of other minor Midstream assets not owned by the Partnership and long-term debt held directly by HIP.

Income Taxes: Judgments are required in the determination and recognition of income tax assets and liabilities in the financial statements. These judgments include the requirement to only recognize the financial statement effect of a tax position when management believes that it is more likely than not, that based on the technical merits, the position will be sustained upon examination.

We have net operating loss carryforwards or credit carryforwards in multiple jurisdictions and have recorded deferred tax assets for those losses and credits. Additionally, we have deferred tax assets due to temporary differences between the book basis and tax basis of certain assets and liabilities. Regular assessments are made as to the likelihood of those deferred tax assets being realized. If, when tested under the relevant accounting standards, it is more likely than not that some or all of the deferred tax assets will not be realized, a valuation allowance is recorded to reduce the deferred tax assets to the amount that is expected to be realized.

The accounting standards require the evaluation of all available positive and negative evidence giving weight based on the evidence's relative objectivity. In evaluating potential sources of positive evidence, we consider the reversal of taxable temporary differences, taxable income in carryback and carryforward periods, the availability of tax planning strategies, the existence of appreciated assets, estimates of future taxable income, and other factors. Estimates of future taxable income are based on assumptions of oil and gas reserves, selling prices, and other subjective operating assumptions that are consistent with internal business forecasts. In evaluating potential sources of negative evidence, we consider a cumulative loss in recent years, any history of operating losses or tax credit carryforwards expiring unused, losses expected in early future years, unsettled circumstances that, if unfavorably resolved, would adversely affect future operations and profit levels on a continuing basis in future years, and carryback or carryforward periods that are so brief that it would limit realization of tax benefits if a significant deductible temporary difference is expected to reverse in a single year. Due to a sustained low commodity price environment, we remained in a three-year cumulative consolidated loss position at December 31, 2018. A three-year cumulative consolidated loss constitutes objective negative evidence to which the accounting standards require we assign significant weight relative to subjective evidence such as our estimates of future taxable income. We are generally not recognizing deferred tax benefit or expense in certain countries, primarily the U.S., Denmark (hydrocarbon tax only), Malaysia, and Guyana, while we maintain valuation allowances against net deferred tax assets in these jurisdictions.

At December 31, 2018, the *Consolidated Balance Sheet* reflects a $4,877 million valuation allowance against the net deferred tax assets for multiple jurisdictions based on the evaluation of the accounting standards described above. The amount of the deferred tax asset considered realizable, however, could be adjusted if estimates of future taxable income change or if objective negative evidence in the form of cumulative losses is no longer present and additional weight is given to subjective evidence such as expected future growth.

Asset Retirement Obligations: We have material legal obligations to remove and dismantle long-lived assets and to restore land or seabed at certain E&P locations. In accordance with generally accepted accounting principles, we recognize a liability for the fair value of required asset retirement obligations. In addition, the fair value of any legally required conditional asset retirement obligation is recorded if the liability can be reasonably estimated. We capitalize such costs as a component of the carrying amount of the underlying assets in the period in which the liability is incurred. In subsequent periods, the liability is accreted, and the asset is depreciated over the useful life of the related asset. We estimate the fair value of these obligations by discounting projected future payments that will be required to satisfy the obligations. In determining these estimates, we are required to make several assumptions and judgments related to the scope of dismantlement, timing of settlement, interpretation of legal requirements, inflationary factors and discount rate. In addition, there are other external factors, which could significantly affect the ultimate settlement costs for these obligations including changes in environmental regulations and other statutory requirements, fluctuations in industry costs and foreign currency exchange rates and advances in technology. As a result, our estimates of asset retirement obligations are subject to revision due to the factors described above. Changes in estimates prior to settlement result in adjustments to both the liability and related asset values, unless the field has ceased production, in which case changes are recognized in our *Consolidated Statement of Income*. See Note 9, *Asset Retirement Obligations*.

Retirement Plans: We have funded non-contributory defined benefit pension plans, an unfunded supplemental pension plan and an unfunded postretirement medical plan. We recognize the net change in the funded status of the projected benefit obligation for these plans in the *Consolidated Balance Sheet*.

The determination of the obligations and expenses related to these plans are based on several actuarial assumptions. These assumptions represent estimates made by us, some of which can be affected by external factors. The most significant assumptions relate to:

Discount rate used for measuring the present value of future plan obligations: The discount rate used to estimate our projected benefit obligation is based on a portfolio of high-quality, fixed income debt instruments with maturities that approximate the expected payment of plan obligations. At December 31, 2018, a 0.25% decrease in the discount rate assumption would increase projected benefit obligations by approximately $100 million and forecasted 2019 annual benefit expense by approximately $5 million. The increase in the projected benefit obligation would decrease the funded status of our pension plans, but any decrease in the funded status would be partially mitigated by increases in the fair value of fixed income investments in the asset portfolio.

Expected long-term rates of returns on plan assets: The expected return on plan assets is developed from the expected future returns for each asset category, weighted by the target allocation of pension assets to that asset category. The future expected return assumptions for individual asset categories are largely based on inputs from various investment experts regarding their future return expectations for particular asset categories. At December 31, 2018, a 0.25% decrease in the expected long-term rates of returns on plan assets assumption would increase forecasted 2019 annual benefit expense by approximately $5 million.

Other assumptions include the rate of future increases in compensation levels and participant mortality level.

Derivatives: We utilize derivative instruments, including futures, forwards, options and swaps, individually or in combination to mitigate our exposure to fluctuations in the prices of crude oil and natural gas, as well as changes in interest and foreign currency exchange rates. All derivative instruments are recorded at fair value in our *Consolidated Balance Sheet*. Our policy for recognizing the changes in fair value of derivatives varies based on the designation of the derivative. The changes in fair value of derivatives that are not designated as hedges are recognized currently in earnings. Derivatives may be designated as hedges of expected future cash flows or forecasted transactions (cash flow hedges), or hedges of changes in fair value of recognized assets and liabilities or of unrecognized firm commitments (fair value hedges). Changes in fair value of derivatives that are designated as cash flow hedges are recorded as a component of other comprehensive income (loss). Amounts included in Accumulated other comprehensive income (loss) for cash flow hedges are reclassified into earnings in the same period that the hedged item is recognized in earnings. Changes in fair value of derivatives designated as fair value hedges are recognized currently in earnings. The change in fair value of the related hedged commitment is recorded as an adjustment to its carrying amount and recognized currently in earnings.

Fair Value Measurements: We use various valuation approaches in determining fair value for financial instruments, including the market and income approaches. Our fair value measurements also include non-performance risk and time value of money considerations. Counterparty credit is considered for receivable balances, and our credit is considered for accrued liabilities.

We also record certain nonfinancial assets and liabilities at fair value when required by generally accepted accounting principles. These fair value measurements are recorded in connection with business combinations, qualifying non-monetary exchanges, the initial recognition of asset retirement obligations and any impairment of long-lived assets, equity method investments or goodwill.

We determine fair value in accordance with the fair value measurements accounting standard which established a hierarchy for the inputs used to measure fair value based on the source of the inputs, which generally range from quoted prices for identical instruments in a principal trading market (Level 1) to estimates determined using related market data (Level 3), including discounted cash flows and other unobservable data. Measurements derived indirectly from observable inputs or from quoted prices from markets that are less liquid are considered Level 2. When Level 1 inputs are available within a particular market, those inputs are selected for determination of fair value over Level 2 or 3 inputs in the same market. Multiple inputs may be used to measure fair value; however, the level of fair value assigned for each physical derivative and financial asset or liability is based on the lowest significant input level within this fair value hierarchy.

Environment, Health and Safety

Our long-term vision and values provide a foundation for how we do business and define our commitment to meeting high standards of corporate citizenship and creating a long lasting positive impact on the communities where we do business. Our strategy is reflected in our environment, health, safety and social responsibility (EHS & SR) policies and by a management system framework that helps protect our workforce, customers and local communities. Our management systems are intended to promote internal consistency, adherence to policy objectives and continual improvement in EHS & SR performance. Improved performance may, in the short-term, increase our operating costs and could also require increased capital expenditures to reduce potential risks to our assets, reputation and license to operate. In addition to enhanced EHS & SR performance, improved productivity and operational efficiencies may be realized from investments in EHS & SR. We have programs in place to evaluate regulatory compliance, audit facilities, train employees, prevent and manage risks and emergencies and to generally meet corporate EHS & SR goals and objectives.

We recognize that climate change is a global environmental concern. We assess, monitor and take measures to reduce our carbon footprint at existing and planned operations. We are committed to complying with all Greenhouse Gas (GHG) emissions mandates and the responsible management of GHG emissions at our facilities.

We will have continuing expenditures for environmental assessment and remediation. Sites where corrective action may be necessary include onshore E&P facilities, sites from discontinued operations where we retained liability and, although not currently significant, “Superfund” sites where we have been named a potentially responsible party.

We accrue for environmental assessment and remediation expenses when the future costs are probable and reasonably estimable. At December 31, 2018, our reserve for estimated remediation liabilities was approximately $80 million. We expect that existing reserves for environmental liabilities will adequately cover costs to assess and remediate known sites. Our remediation spending was approximately $15 million in 2018 (2017: $15 million; 2016: $10 million). The amount of other expenditures incurred to comply with federal, state, local and foreign country environmental regulations is difficult to quantify as such costs are captured as mostly indistinguishable components of our capital expenditures and operating expenses.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

In the normal course of our business, we are exposed to commodity risks related to changes in the prices of crude oil, natural gas liquids, and natural gas as well as changes in interest rates and foreign currency values. In the disclosures that follow, financial risk management activities refer to the mitigation of these risks through hedging activities.

Controls: We maintain a control environment under the direction of our Chief Risk Officer. Controls over instruments used in financial risk management activities include volumetric and term limits. Our Treasury department is responsible for administering and monitoring foreign exchange rate and interest rate hedging programs using similar controls and processes, where applicable. Hedging strategies are reviewed annually by the Audit Committee of the Board of Directors.

Instruments: We primarily use forward commodity contracts, foreign exchange forward contracts, futures, swaps, and options in our risk management activities. These contracts are generally widely traded instruments with standardized terms. The following describes these instruments and how we use them:

- *Swaps:* We use financially settled swap contracts with third-parties as part of our financial risk management activities. Cash flows from swap contracts are determined based on underlying commodity prices or interest rates and are typically settled over the life of the contract.
- *Forward Foreign Exchange Contracts:* We enter into forward contracts, primarily for the British Pound, which commit us to buy or sell a fixed amount of British Pound at a predetermined exchange rate on a future date.
- *Exchange Traded Contracts:* We may use exchange traded contracts, including futures, on a number of different underlying energy commodities. These contracts are settled daily with the relevant exchange and may be subject to exchange position limits.
- *Options:* Options on various underlying energy commodities include exchange traded and third-party contracts and have various exercise periods. As a seller of options, we receive a premium at the outset and bear the risk of unfavorable changes in the price of the commodity underlying the option. As a purchaser of options, we pay a premium at the outset and have the right to participate in the favorable price movements in the underlying commodities.

Financial Risk Management Activities

At December 31, 2018, outstanding total debt, excluding capital leases, was substantially comprised of fixed rate debt instruments with a carrying value of $6,403 million and a fair value of $6,225 million. A 15% increase or decrease in interest rates would decrease or increase the fair value of our fixed rate debt by approximately $480 million or $550 million, respectively. Any changes in interest rates do not impact cash outflows associated with fixed rate interest payments or settlement of debt principal, unless a debt instrument is repurchased prior to maturity.

At December 31, 2018, we have outstanding WTI crude oil put contracts for calendar year 2019 with a WTI monthly floor price of $60 per barrel for 95,000 bopd. At December 31, 2018, an assumed 10% increase in the forward WTI crude oil prices used in determining the fair value of our crude oil put contracts would reduce the fair value of these derivatives instruments by approximately $120 million, while an assumed 10% decrease in the same WTI crude oil prices would increase the fair value of these derivative instruments by approximately $140 million.

We have outstanding foreign exchange contracts with a total notional amount of $16 million at December 31, 2018 that are used to reduce our exposure to fluctuating foreign exchange rates for various currencies. The change in fair value of foreign exchange contracts from a 10% weakening of the U.S. Dollar exchange rate is estimated to be a loss of less than $5 million at December 31, 2018.

See *Note 21, Financial Risk Management Activities*, in the *Notes to Consolidated Financial Statements* for further details.

Item 8. Financial Statements and Supplementary Data

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES
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* *Schedules have been omitted because of the absence of the conditions under which they are required or because the required information is presented in the financial statements or the notes thereto.*

Management’s Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f). Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting, as required by Section 404 of the Sarbanes-Oxley Act, based on the framework in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework). Based on our evaluation, management concluded that our internal control over financial reporting was effective as of December 31, 2018.

The Corporation’s independent registered public accounting firm, Ernst & Young LLP, has audited the effectiveness of the Corporation’s internal control over financial reporting as of December 31, 2018, as stated in their report, which is included herein.

By	/s/ John P. Rielly John P. Rielly Senior Vice President and Chief Financial Officer	By	/s/ John B. Hess John B. Hess Chief Executive Officer

February 21, 2019

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
Hess Corporation

Opinion on Internal Control over Financial Reporting

We have audited Hess Corporation and consolidated subsidiaries' (the "Corporation") internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). In our opinion, Hess Corporation and consolidated subsidiaries maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheets of the Corporation as of December 31, 2018 and 2017, the related statements of consolidated income, comprehensive income, cash flows and equity for each of the three years in the period ended December 31, 2018, and the related notes and our report dated February 21, 2019 expressed an unqualified opinion thereon.

Basis for Opinion

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

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects.

Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control over Financial Reporting

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

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

/s/ Ernst & Young LLP
New York, New York
February 21, 2019

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
Hess Corporation

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Hess Corporation and consolidated subsidiaries (the "Corporation") as of December 31, 2018 and 2017, the related statements of consolidated income, comprehensive income, cash flows and equity for each of the three years in the period ended December 31, 2018, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the consolidated financial position of the Corporation at December 31, 2018 and 2017, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2018, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Corporation's internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework), and our report dated February 21, 2019 expressed an unqualified opinion thereon.

Basis for Opinion

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

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

/s/ Ernst & Young LLP
We have served as the Corporation's auditor since 1971
New York, New York
February 21, 2019

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES

CONSOLIDATED BALANCE SHEET

	December 31, 2018	December 31, 2017
	(In millions, except share amounts)	
Assets		
Current Assets:		
Cash and cash equivalents	**$ 2,694**	$ 4,847
Accounts receivable:		
From contracts with customers	**771**	677
Joint venture and other	**230**	347
Inventories	**245**	232
Other current assets	**519**	54
Total current assets	**4,459**	6,157
Property, plant and equipment:		
Total — at cost	**33,222**	32,504
Less: Reserves for depreciation, depletion, amortization and lease impairment	**17,139**	16,312
Property, plant and equipment — net	**16,083**	16,192
Goodwill	**360**	360
Deferred income taxes	**21**	21
Other assets	**510**	382
Total Assets	**$ 21,433**	$ 23,112
Liabilities		
Current Liabilities:		
Accounts payable	**$ 495**	$ 435
Accrued liabilities	**1,560**	1,337
Taxes payable	**81**	83
Current maturities of long-term debt	**67**	580
Total current liabilities	**2,203**	2,435
Long-term debt	**6,605**	6,397
Deferred income taxes	**421**	429
Asset retirement obligations	**741**	753
Other liabilities and deferred credits	**575**	744
Total Liabilities	**10,545**	10,758
Equity		
Hess Corporation stockholders' equity:		
Preferred stock, par value $1.00; Authorized — 20,000,000 shares:		
Series A 8% Cumulative Mandatory Convertible; $1,000 per share liquidation preference; Issued — 574,997 shares (2017: 575,000)	**1**	1
Common stock, par value $1.00; Authorized — 600,000,000 shares:		
Issued — 291,434,534 shares (2017: 315,053,615)	**291**	315
Capital in excess of par value	**5,386**	5,824
Retained earnings	**4,257**	5,597
Accumulated other comprehensive income (loss)	**(306)**	(686)
Total Hess Corporation stockholders' equity	**9,629**	11,051
Noncontrolling interests	**1,259**	1,303
Total equity	**10,888**	12,354
Total Liabilities and Equity	**$ 21,433**	$ 23,112

The consolidated financial statements reflect the successful efforts method of accounting for oil and gas exploration and production activities.

See accompanying Notes to Consolidated Financial Statements.

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES

STATEMENT OF CONSOLIDATED INCOME

	Years Ended December 31, 2018	2017	2016
	(In millions, except per share amounts)		
Revenues and Non-Operating Income			
Sales and other operating revenues	**$ 6,323**	$ 5,466	$ 4,762
Gains (losses) on asset sales, net	**32**	(86)	23
Other, net	**111**	11	54
Total revenues and non-operating income	**6,466**	5,391	4,839
Costs and Expenses			
Marketing, including purchased oil and gas	**1,771**	1,267	1,063
Operating costs and expenses	**1,134**	1,443	1,876
Production and severance taxes	**171**	119	101
Exploration expenses, including dry holes and lease impairment	**362**	507	1,442
General and administrative expenses	**473**	422	414
Interest expense	**399**	325	338
Loss on debt extinguishment	**53**	—	148
Depreciation, depletion and amortization	**1,883**	2,883	3,244
Impairment	**—**	4,203	67
Total costs and expenses	**6,246**	11,169	8,693
Income (Loss) Before Income Taxes	**220**	(5,778)	(3,854)
Provision (benefit) for income taxes	**335**	(1,837)	2,222
Net Income (Loss)	**(115)**	(3,941)	(6,076)
Less: Net income (loss) attributable to noncontrolling interests	**167**	133	56
Net Income (Loss) Attributable to Hess Corporation	**(282)**	(4,074)	(6,132)
Less: Preferred stock dividends	**46**	46	41
Net Income (Loss) Attributable to Hess Corporation Common Stockholders	**$ (328)**	$ (4,120)	$ (6,173)
Net Income (Loss) Attributable to Hess Corporation Per Common Share			
Basic	**$ (1.10)**	$ (13.12)	$ (19.92)
Diluted	**$ (1.10)**	$ (13.12)	$ (19.92)
Weighted Average Number of Common Shares Outstanding (Diluted)	**298.2**	314.1	309.9
Common Stock Dividends Per Share	**$ 1.00**	$ 1.00	$ 1.00

See accompanying Notes to Consolidated Financial Statements.

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES

STATEMENT OF CONSOLIDATED COMPREHENSIVE INCOME

	Years Ended December 31, 2018	2017	2016
	(In millions)		
Net Income (Loss)	**$ (115)**	$ (3,941)	$ (6,076)
Other Comprehensive Income (Loss):			
Derivatives designated as cash flow hedges			
Effect of hedge (gains) losses reclassified to income	**173**	18	—
Income taxes on effect of hedge (gains) losses reclassified to income	**—**	—	—
Net effect of hedge (gains) losses reclassified to income	**173**	18	—
Change in fair value of cash flow hedges	**330**	(156)	—
Income taxes on change in fair value of cash flow hedges	**(86)**	—	—
Net change in fair value of cash flow hedges	**244**	(156)	—
Change in derivatives designated as cash flow hedges, after taxes	**417**	(138)	—
Pension and other postretirement plans			
(Increase) reduction in unrecognized actuarial losses	**29**	35	(155)
Income taxes on actuarial changes in plan liabilities	**(6)**	—	20
(Increase) reduction in unrecognized actuarial losses, net	**23**	35	(135)
Amortization of net actuarial losses	**41**	77	60
Income taxes on amortization of net actuarial losses	**—**	—	(21)
Net effect of amortization of net actuarial losses	**41**	77	39
Change in pension and other postretirement plans, after taxes	**64**	112	(96)
Foreign currency translation adjustment			
Foreign currency translation adjustment	**—**	144	56
Asset disposition	**—**	900	—
Change in foreign currency translation adjustment	**—**	1,044	56
Other Comprehensive Income (Loss)	**481**	1,018	(40)
Comprehensive Income (Loss)	**366**	(2,923)	(6,116)
Less: Comprehensive income (loss) attributable to noncontrolling interests	**167**	133	56
Comprehensive Income (Loss) Attributable to Hess Corporation	**$ 199**	$ (3,056)	$ (6,172)

See accompanying Notes to Consolidated Financial Statements.

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES

STATEMENT OF CONSOLIDATED CASH FLOWS

	Year Ended December 31,		
	2018	2017	2016
		(In millions)	
Cash Flows from Operating Activities			
Net income (loss)	**$ (115)**	$ (3,941)	$ (6,076)
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities			
(Gains) losses on asset sales, net	**(32)**	86	(23)
Depreciation, depletion and amortization	**1,883**	2,883	3,244
Impairment	**—**	4,203	67
Exploratory dry hole costs	**165**	268	1,064
Exploration lease and other impairment	**37**	44	145
Stock compensation expense	**72**	86	73
Noncash (gains) losses on commodity derivatives, net	**182**	97	—
Provision (benefit) for deferred income taxes and other tax accruals	**(120)**	(2,001)	2,200
Loss on debt extinguishment	**53**	—	148
Changes in operating assets and liabilities			
(Increase) decrease in accounts receivable	**(138)**	(340)	96
(Increase) decrease in inventories	**(12)**	(64)	77
Increase (decrease) in accounts payable and accrued liabilities	**88**	(44)	(87)
Increase (decrease) in taxes payable	**(2)**	(34)	9
Changes in other operating assets and liabilities	**(122)**	(298)	(142)
Net cash provided by (used in) operating activities	**1,939**	945	795
Cash Flows from Investing Activities			
Additions to property, plant and equipment - E&P	**(1,854)**	(1,788)	(1,974)
Additions to property, plant and equipment - Midstream	**(243)**	(149)	(277)
Payments for Midstream equity investments	**(67)**	—	—
Proceeds from asset sales, net of cash sold	**607**	3,296	140
Other, net	**(9)**	(1)	21
Net cash provided by (used in) investing activities	**(1,566)**	1,358	(2,090)
Cash Flows from Financing Activities			
Net borrowings (repayments) of debt with maturities of 90 days or less	**—**	(153)	43
Debt with maturities of greater than 90 days			
Borrowings	**—**	800	1,496
Repayments	**(633)**	(459)	(1,455)
Proceeds from issuance of Hess Midstream Partnership LP units	**—**	366	—
Proceeds from issuance of preferred stock	**—**	—	557
Proceeds from issuance of common stock	**—**	—	1,087
Common stock acquired and retired	**(1,365)**	(110)	—
Cash dividends paid	**(345)**	(363)	(350)
Noncontrolling interests, net	**(211)**	(243)	(23)
Other, net	**28**	(26)	(44)
Net cash provided by (used in) financing activities	**(2,526)**	(188)	1,311
Net Increase (Decrease) in Cash and Cash Equivalents	**(2,153)**	2,115	16
Cash and Cash Equivalents at Beginning of Year	**4,847**	2,732	2,716
Cash and Cash Equivalents at End of Year	**$ 2,694**	$ 4,847	$ 2,732

See accompanying Notes to Consolidated Financial Statements.

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES

STATEMENT OF CONSOLIDATED EQUITY

	Mandatory Convertible Preferred Stock	Common Stock	Capital in Excess of Par Value	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Hess Stockholders' Equity	Noncontrolling Interests	Total Equity
					(In millions)			
Balance at December 31, 2015	$ —	$ 286	$ 4,127	$ 16,637	$ (1,664)	$ 19,386	$ 1,015	$ 20,401
Net income (loss)	—	—	—	(6,132)	—	(6,132)	56	(6,076)
Other comprehensive income (loss)	—	—	—	—	(40)	(40)	—	(40)
Stock issuance	1	29	1,577	—	—	1,607	—	1,607
Share-based compensation activity, including income taxes	—	2	69	—	—	71	—	71
Dividends on preferred stock	—	—	—	(41)	—	(41)	—	(41)
Dividends on common stock	—	—	—	(317)	—	(317)	—	(317)
Noncontrolling interests, net	—	—	—	—	—	—	(14)	(14)
Balance at December 31, 2016	$ 1	$ 317	$ 5,773	$ 10,147	$ (1,704)	$ 14,534	$ 1,057	$ 15,591
Cumulative effect of adoption of new accounting standards	—	—	2	(39)	—	(37)	—	(37)
Net income (loss)	—	—	—	(4,074)	—	(4,074)	133	(3,941)
Other comprehensive income (loss)	—	—	—	—	1,018	1,018	—	1,018
Share-based compensation activity	—	1	92	—	—	93	—	93
Dividends on preferred stock	—	—	—	(46)	—	(46)	—	(46)
Dividends on common stock	—	—	—	(317)	—	(317)	—	(317)
Common stock acquired and retired	—	(3)	(43)	(74)	—	(120)	—	(120)
Hess Midstream Partners LP units issuance	—	—	—	—	—	—	356	356
Noncontrolling interests, net	—	—	—	—	—	—	(243)	(243)
Balance at December 31, 2017	$ 1	$ 315	$ 5,824	$ 5,597	$ (686)	$ 11,051	$ 1,303	$ 12,354
Cumulative effect of adoption of new accounting standards	—	—	—	101	(101)	—	—	—
Net income (loss)	—	—	—	(282)	—	(282)	167	(115)
Other comprehensive income (loss)	—	—	—	—	481	481	—	481
Share-based compensation activity	—	1	103	—	—	104	—	104
Dividends on preferred stock	—	—	—	(46)	—	(46)	—	(46)
Dividends on common stock	—	—	—	(299)	—	(299)	—	(299)
Common stock acquired and retired	—	(25)	(541)	(814)	—	(1,380)	—	(1,380)
Noncontrolling interests, net	—	—	—	—	—	—	(211)	(211)
Balance at December 31, 2018	$ 1	$ 291	$ 5,386	$ 4,257	$ (306)	$ 9,629	$ 1,259	$ 10,888

See accompanying Notes to Consolidated Financial Statements.

1. Nature of Operations, Basis of Presentation and Summary of Accounting Policies

Unless the context indicates otherwise, references to "Hess", "the Corporation", "Registrant", "we", "us" and "our" refer to the consolidated business operations of Hess Corporation and its affiliates.

Nature of Business: Hess Corporation, incorporated in the State of Delaware in 1920, is a global Exploration and Production (E&P) company engaged in exploration, development, production, transportation, purchase and sale of crude oil, natural gas liquids, and natural gas with production operations located primarily in the United States (U.S.), Denmark, the Malaysia/Thailand Joint Development Area (JDA) and Malaysia. We conduct exploration activities primarily offshore Guyana, Suriname, Canada and in the U.S. Gulf of Mexico. At the Stabroek Block (Hess 30%), offshore Guyana, we have participated in twelve significant discoveries and sanctioned in 2017 the first phase of development of the block.

Our Midstream operating segment provides fee-based services, including gathering, compressing and processing natural gas and fractionating NGLs; gathering, terminaling, loading and transporting crude oil and NGLs; storing and terminaling propane, and water handling services primarily in the Bakken and Three Forks Shale plays in the Williston Basin area of North Dakota.

Basis of Presentation and Principles of Consolidation: The consolidated financial statements include the accounts of Hess Corporation and entities in which we own more than a 50% voting interest. We also consolidate Hess Infrastructure Partners LP (HIP), a variable interest entity, based on our conclusion that we have the power through our 50% ownership to direct those activities that most significantly impact the economic performance of HIP, and are obligated to absorb losses or have the right to receive benefits that could potentially be significant to HIP. Our undivided interests in unincorporated oil and gas E&P ventures are proportionately consolidated. Investments in affiliated companies, 20% to 50% owned and where we have the ability to influence the operating or financial decisions of the affiliate, are accounted for using the equity method.

In 2018, we adopted Accounting Standards Codification (ASC) Topic, ASC 606, *Revenue from Contracts with Customers*, using the modified retrospective method. Accordingly, the required disclosures under *ASC 606* were provided only for the current period. The adoption of this standard did not affect the timing of revenue recognition for our uncompleted contracts at January 1, 2018, and as a result, no cumulative effect adjustment to *Retained earnings* was recognized. *Accounts receivables from contracts with customers* is presented separately in the *Consolidated Balance Sheet* with the prior year balance recast to conform to the current period presentation. In addition, as the adoption of ASC 606 did not affect previous conclusions regarding our involvement as a principal versus agent in contracts with customers, there were no changes in presentation to the *Statement of Consolidated Income*.

In 2018, we adopted Accounting Standards Update (ASU) 2017-07, *Compensation – Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost*. This ASU contains a provision that prohibits the capitalization of the non-service cost components of net periodic benefit cost when constructing or producing an asset. This provision was applied prospectively effective January 1, 2018. The ASU contains another provision requiring that non-service cost components of net periodic benefit cost be presented separately from the service cost component in the *Statement of Consolidated Income*. We elected the practical expedient allowing the use of amounts previously disclosed in the notes to our Consolidated Financial Statements as the basis for the required retrospective application of this provision, as capitalization of non-service cost components of net periodic benefit cost was not material. For the years ended December 31, 2017 and 2016, the retrospective application resulted in the reclassification of net expense totaling $14 million and $5 million, respectively to *Other, net* from *Operating costs and expenses* and *General and administrative expenses* in our *Statement of Consolidated Income*.

In 2018, we adopted ASU 2017-12, *Derivatives and Hedging – Targeted Improvements to Accounting for Hedging Activities*. This ASU makes certain targeted improvements to simplify the application of the existing hedge accounting guidance. The adoption of this ASU resulted in an increase to *Retained earnings* and a decrease in *Accumulated other comprehensive income (loss)* of $1 million in our *Consolidated Balance Sheet* in order to remove the cumulative effect of hedging ineffectiveness previously recognized in earnings for contracts designated as hedging instruments that were outstanding at January 1, 2018.

In 2018, the FASB issued ASU 2018-02, *Income Statement – Reporting Comprehensive Income (Topic 220): Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income*. This ASU allows the reclassification of stranded income tax effects within *Accumulated other comprehensive income (loss)* to *Retained earnings* that resulted from the enactment of U.S. Federal income tax reform, commonly referred to as the U.S. Tax Cuts and Jobs Act ("Act"). Specifically, this ASU provides entities the option to reclassify the stranded income tax effects resulting from the reduction to the corporate income tax rate from the Act upon adoption of this ASU, instead of upon liquidation of the individual items (or of the underlying portfolio of items). This ASU is effective for us beginning in the first quarter of 2019, with early adoption permitted. We elected to adopt this ASU effective October 1, 2018. The adoption resulted in an increase to *Retained earnings* and a decrease to *Accumulated other comprehensive income (loss)* of $100 million in our *Consolidated Balance Sheet*.

In 2018, we adopted ASU 2016-18, *Statement of Cash Flows (Topic 230): Restricted Cash (a consensus of the FASB Emerging Issues Task Force)*. This ASU requires the total change in cash and cash equivalents and restricted cash be reflected on the statement of cash flows. A reconciliation to the balance sheet is also required when cash and cash equivalents and restricted cash are not separately presented on the balance sheet or are presented in more than one financial statement line item on the balance sheet. The adoption of this ASU did not have a material impact on our *Statement of Consolidated Cash Flows*.

In 2018, we adopted ASU 2016-15, *Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments (a consensus of the FASB Emerging Issues Task Force)*. This ASU is intended to reduce diversity in practice in how certain transactions are classified in the statement of cash flows. The guidance addresses eight specific classification issues for which current guidance is either unclear or is non-specific. The requirement that fees paid to third-parties and premiums incurred relating to the repayment of debt be classified as financing cash outflows is among the classification issues addressed by this ASU. The adoption of this ASU did not have a material impact on our *Statement of Consolidated Cash Flows.*

In 2017, the FASB issued ASU 2017-04, *Intangibles – Goodwill and Other – Simplifying the Test for Goodwill Impairment*. This ASU modifies the concept of goodwill impairment from a condition that exists when the carrying amount of goodwill exceeds its implied fair value to a condition that exists when the carrying amount of the reporting unit exceeds its fair value. Thus, an entity should recognize an impairment charge for the amount by which the carrying amount of a reporting unit exceeds its fair value, limited by the amount of goodwill allocated to the reporting unit. This ASU is effective for us beginning in the first quarter of 2020, with early adoption permitted. We elected to adopt this ASU effective October 1, 2018, and the adoption had no impact on our Consolidated Financial Statements.

Estimates and Assumptions: In preparing financial statements in conformity with U.S. generally accepted accounting principles (GAAP), management makes estimates and assumptions that affect the reported amounts of assets and liabilities in the *Consolidated Balance Sheet* and revenues and expenses in our *Statement of Consolidated Income*. Actual results could differ from those estimates. Estimates made by management include oil and gas reserves, asset and other valuations, depreciable lives, pension liabilities, legal and environmental obligations, asset retirement obligations and income taxes.

Revenue Recognition: See *Note 2, Revenue*.

Exploration and Development Costs: E&P activities are accounted for using the successful efforts method. Costs of acquiring unproved and proved oil and gas leasehold acreage, including lease bonuses, brokers' fees and other related costs are capitalized. Annual lease rentals, exploration expenses and exploratory dry hole costs are expensed as incurred. Costs of drilling and equipping productive wells, including development dry holes, and related production facilities are capitalized.

The costs of exploratory wells that find oil and gas reserves are capitalized pending determination of whether proved reserves have been found. Exploratory drilling costs remain capitalized after drilling is completed if (1) the well has found a sufficient quantity of reserves to justify completion as a producing well and (2) sufficient progress is being made in assessing the reserves and the economic and operational viability of the project. If either of those criteria is not met, or if there is substantial doubt about the economic or operational viability of a project, the capitalized well costs are charged to expense. Indicators of sufficient progress in assessing reserves and the economic and operating viability of a project include commitment of project personnel, active negotiations for sales contracts with customers, negotiations with governments, operators and contractors, firm plans for additional drilling and other factors.

Depreciation, Depletion and Amortization: We record depletion expense for acquisition costs of proved properties using the units of production method over proved oil and gas reserves. Depreciation and depletion expense for oil and gas production facilities and wells is calculated using the units of production method over proved developed oil and gas reserves. Provisions for impairment of undeveloped oil and gas leases are based on periodic evaluations and other factors. Depreciation of all other plant and equipment is determined on the straight-line method based on estimated useful lives.

Capitalized Interest: Interest from external borrowings is capitalized on material projects using the weighted average cost of outstanding borrowings until the project is substantially complete and ready for its intended use, which for oil and gas assets is at first production from the field. Capitalized interest is depreciated over the useful lives of the assets in the same manner as the depreciation of the underlying assets.

Impairment of Long-lived Assets: We review long-lived assets, including oil and gas fields, for impairment whenever events or changes in circumstances indicate that the carrying amounts may not be recovered. If the carrying amounts of the long-lived assets are not expected to be recovered by estimated undiscounted future net cash flows, the assets are impaired and an impairment loss is recorded. The amount of impairment is determined based on the estimated fair value of the assets generally determined by discounting anticipated future net cash flows, an income valuation approach, or by a market-based valuation approach, which are Level 3 fair value measurements. In the case of oil and gas fields, the present value of future net cash flows is based on management's best estimate of future prices, which is determined with reference to recent historical prices and published forward prices, applied to projected production volumes and discounted at a risk-adjusted rate. The projected production volumes represent reserves, including probable reserves, expected to be produced based on a projected amount of capital expenditures. The production volumes, prices and timing of production are consistent with internal projections and other externally reported information. Oil and gas prices used for determining asset impairment will generally differ from those used in the standardized measure of discounted future net cash flows reported in *Supplementary Oil and Gas Data*, since the standardized measure requires the use of historical twelve-month average prices.

Impairment of Goodwill: Goodwill is tested for impairment annually on October 1st or when events or circumstances indicate that the carrying amount of the goodwill may not be recoverable. To determine whether an indicator of impairment exists, the fair value of a reporting unit is compared with its carrying amount, including goodwill. If the fair value of the reporting unit exceeds its carrying value, goodwill is not impaired. If the carrying value of the reporting unit exceeds its fair value, an impairment charge would be recorded for the excess of the carrying value over fair value, limited by the amount of goodwill allocated to the reporting unit. At December 31, 2018, goodwill of $360 million relates to the Midstream operating segment.

Cash and Cash Equivalents: Cash and cash equivalents primarily comprises cash on hand and on deposit, as well as highly liquid investments that are readily convertible into cash and have maturities of three months or less when acquired.

Inventories: Unsold crude oil and NGLs are valued at the lower of cost or net realizable value. Cost is determined based on the average cost of production. Materials and supplies are valued at cost. Obsolete or surplus materials identified during periodic reviews are valued at the lower of cost or estimated net realizable value.

Income Taxes: Deferred income taxes are determined using the liability method. We have net operating loss carryforwards or credit carryforwards in multiple jurisdictions and have recorded deferred tax assets for those losses and credits. Additionally, we have deferred tax assets due to temporary differences between the book basis and tax basis of certain assets and liabilities. Regular assessments are made as to the likelihood of those deferred tax assets being realized. If, when tested under the relevant accounting standards, it is more likely than not that some or all of the deferred tax assets will not be realized, a valuation allowance is recorded to reduce the deferred tax assets to the amount that is expected to be realized. The accounting standards require the evaluation of all available positive and negative evidence giving weight based on the evidence's relative objectivity. In evaluating potential sources of positive evidence, we consider the reversal of taxable temporary differences, taxable income in carryback and carryforward periods, the availability of tax planning strategies, the existence of appreciated assets, estimates of future taxable income, and other factors. In evaluating potential sources of negative evidence, we consider a cumulative loss in recent years, any history of operating losses or tax credit carryforwards expiring unused, losses expected in early future years, unsettled circumstances that, if unfavorably resolved, would adversely affect future operations and profit levels on a continuing basis in future years, and carryback or carryforward periods that are so brief that it would limit realization of tax benefits if a significant deductible temporary difference is expected to reverse in a single year. We assign cumulative historical losses significant weight in the evaluation of realizability relative to more subjective evidence such as forecasts of future income. In addition, we recognize the financial statement effect of a tax position only when management believes that it is more likely than not, that based on the technical merits, the position will be sustained upon examination. We are no longer indefinitely reinvested with respect to the book in excess of tax basis in the investment in our foreign subsidiaries. Because of U.S. tax reform we expect that the future reversal of such temporary differences will occur free of material taxation. We classify interest and penalties associated with uncertain tax positions as income tax expense. We account for the U.S. tax effect of global intangible low-taxed income earned by foreign subsidiaries in the period that such income is earned. We utilize the aggregate approach for releasing disproportionate income tax effects from *Accumulated other comprehensive income (loss)*.

Asset Retirement Obligations: We have material legal obligations to remove and dismantle long-lived assets and to restore land or the seabed at certain E&P locations. We initially recognize a liability for the fair value of legally required asset retirement obligations in the period in which the retirement obligations are incurred, and capitalize the associated asset retirement costs as part of the carrying amount of the long-lived assets. In subsequent periods, the liability is accreted, and the asset is depreciated over the useful life of the related asset. Fair value is determined by applying a credit adjusted risk-free rate to the undiscounted expected future abandonment expenditures, which represent Level 3 inputs in the fair value hierarchy defined under *Fair Value Measurements* below. Changes in estimates prior to settlement result in adjustments to both the liability and related asset values, unless the field has ceased production, in which case changes are recognized in the *Statement of Consolidated Income*.

Retirement Plans: We recognize the funded status of defined benefit postretirement plans in the *Consolidated Balance Sheet*. The funded status is measured as the difference between the fair value of plan assets and the projected benefit obligation. We recognize the net changes in the funded status of these plans in the year in which such changes occur. Actuarial gains and losses in excess of 10% of the greater of the benefit obligation or the market value of assets are amortized over the average remaining service period of active employees or the remaining average expected life if a plan's participants are predominantly inactive.

Derivatives: We utilize derivative instruments for financial risk management activities. In these activities, we may use futures, forwards, options and swaps, individually or in combination, to mitigate our exposure to fluctuations in prices of crude oil and natural gas, as well as changes in interest and foreign currency exchange rates.

All derivative instruments are recorded at fair value in our *Consolidated Balance Sheet*. Our policy for recognizing the changes in fair value of derivatives varies based on the designation of the derivative. The changes in fair value of derivatives that are not designated as hedges are recognized currently in earnings. Derivatives may be designated as hedges of expected future cash flows or forecasted transactions (cash flow hedges), or hedges of changes in fair value of recognized assets and liabilities or of unrecognized firm commitments (fair value hedges). Changes in fair value of derivatives that are designated as cash flow hedges are recorded as a component of other comprehensive income (loss). Amounts included in Accumulated other comprehensive income (loss) for cash flow hedges are reclassified into earnings in the same period that the hedged item is recognized in earnings. Changes in fair value of derivatives designated as fair value hedges are recognized currently in earnings. The change in fair value of the related hedged commitment is recorded as an adjustment to its carrying amount and recognized currently in earnings.

Fair Value Measurements: We use various valuation approaches in determining fair value for financial instruments, including the market and income approaches. Our fair value measurements also include non-performance risk and time value of money considerations. Counterparty credit is considered for receivable balances, and our credit is considered for accrued liabilities. We also record certain nonfinancial assets and liabilities at fair value when required by GAAP. These fair value measurements are recorded in connection with business combinations, qualifying nonmonetary exchanges, the initial recognition of asset retirement obligations and any impairment of long-lived assets, equity method investments or goodwill. We determine fair value in accordance with the fair value measurements accounting standard which established a hierarchy for the inputs used to measure fair value based on the source of the inputs, which generally range from quoted prices for identical instruments in a principal trading market (Level 1) to estimates determined using related market data (Level 3), including discounted cash flows and other unobservable data. Measurements derived indirectly from observable inputs or from quoted prices from markets that are less liquid are considered Level 2. When Level 1 inputs are available within a particular market, those inputs are selected for determination of fair value over Level 2 or 3 inputs in the same market. Multiple inputs may be used to measure fair value; however, the level of fair value assigned for each physical derivative and financial asset or liability is based on the lowest significant input level within this fair value hierarchy.

Details on the methods and assumptions used to determine the fair values are as follows:

Fair value measurements based on Level 1 inputs: Measurements that are most observable are based on quoted prices of identical instruments obtained from the principal markets in which they are traded. Closing prices are both readily available and representative of fair value. Market transactions occur with sufficient frequency and volume to assure liquidity.

Fair value measurements based on Level 2 inputs: Measurements derived indirectly from observable inputs or from quoted prices from markets that are less liquid are considered Level 2. Measurements based on Level 2 inputs include over-the-counter derivative instruments that are priced on an exchange traded curve, but have contractual terms that are not identical to exchange traded contracts.

Fair value measurements based on Level 3 inputs: Measurements that are least observable are estimated from related market data, determined from sources with little or no market activity for comparable contracts or are positions with longer durations. Fair values determined using discounted cash flows and other unobservable data are also classified as Level 3.

Netting of Financial Instruments: We generally enter into master netting arrangements to mitigate legal and counterparty credit risk. Master netting arrangements are generally accepted overarching master contracts that govern all individual transactions with the same counterparty entity as a single legally enforceable agreement. The U.S. Bankruptcy Code provides for the enforcement of certain termination and netting rights under certain types of contracts upon the bankruptcy filing of a counterparty, commonly known as the "safe harbor" provisions. If a master netting arrangement provides for termination and netting upon the counterparty's bankruptcy, these rights are generally enforceable with respect to "safe harbor" transactions. If these arrangements provide the right of offset and our intent and practice is to offset amounts in the case of such a termination, our policy is to record the fair value of derivative assets and liabilities on a net basis. In the normal course of business, we rely on legal and credit risk mitigation clauses providing for adequate credit assurance as well as close-out netting, including two-party netting and single counterparty multilateral netting. As applied to us, "two-party netting" is the right to net amounts owing under safe harbor transactions between a single defaulting counterparty entity and a single Hess entity, and "single counterparty multilateral netting" is the right to net amounts owing under safe harbor transactions among a single defaulting counterparty entity and multiple Hess entities. We are reasonably assured that these netting rights would be upheld in a bankruptcy proceeding in the U.S. in which the defaulting counterparty is a debtor under the U.S. Bankruptcy Code.

Share-based Compensation: We account for share-based compensation under the fair value method of accounting. The fair value of all share-based compensation is recognized over the service period for the entire award, whether the award was granted with ratable or cliff vesting, net of actual forfeitures. We estimate fair value at the date of grant using a Black-Scholes valuation model for employee stock options and a Monte Carlo simulation model for performance share units. Fair value of restricted stock is based on the market value of the underlying shares at the date of grant.

Foreign Currency Translation: The U.S. Dollar is the functional currency (primary currency in which business is conducted) for our foreign operations. Adjustments resulting from remeasuring monetary assets and liabilities that are denominated in a currency other than the functional currency are recorded in Other, net in the *Statement of Consolidated Income*. For our former operations in Norway that did not use the U.S. Dollar as the functional currency, adjustments resulting from translating foreign currency assets and liabilities into U.S. Dollars were recorded in the *Consolidated Balance Sheet* in a separate component of equity titled Accumulated other comprehensive income (loss) prior to the disposition. See *Note 3, Dispositions*.

Maintenance and Repairs: Maintenance and repairs are expensed as incurred. Capital improvements are recorded as additions in Property, plant and equipment.

Environmental Expenditures: We accrue and expense the undiscounted environmental costs necessary to remediate existing conditions related to past operations when the future costs are probable and reasonably estimable. At year-end 2018, our reserve for estimated remediation liabilities was approximately $80 million. Environmental expenditures that increase the life or efficiency of property or reduce or prevent future adverse impacts to the environment are capitalized.

New Accounting Pronouncements: In February 2016, the FASB issued ASU 2016-02, *Leases*, as a new ASC Topic, ASC 842. The new standard supersedes ASC 840 and will require the recognition of right-of-use assets and lease liabilities for all leases with lease terms greater than one year, including leases currently treated as operating leases under ASC 840. ASC 842 is effective for us beginning in the first quarter of 2019. We have elected to adopt ASC 842 using the modified retrospective method which allows application of the new standard prospectively from the date of adoption with a cumulative effect adjustment, if any, recorded to *Retained Earnings* at the date of adoption. Accordingly, comparative financial statements for periods prior to the adoption date of ASC 842 will not be affected. In addition, we have elected to apply a number of practical expedients permitted by the ASU, including not needing to reassess: (i) whether existing contracts are (or contain) leases, (ii) whether the lease classification for existing leases would differ under ASC 842, (iii) whether initial direct costs incurred for existing leases are capitalizable under ASC 842, and (iv) land easements that were not previously accounted for as leases under ASC 840. We have completed our implementation plan to adopt ASU 842, but we continue to monitor standard setting activity and our internal controls to comply with the accounting and disclosure requirements. Upon adoption on January 1, 2019, we expect to recognize operating and finance lease obligations totaling approximately $1.2 billion, of which approximately $390 million of liabilities at December 31, 2018, are included in the *Consolidated Balance Sheet*. We enter into various leases in the normal course of business primarily for drilling rigs, a floating storage and offloading vessel, support vessels, and office space.

In June 2016, the FASB issued ASU 2016-13, *Financial Instruments – Credit Losses*. This ASU makes changes to the impairment model for trade receivables, net investments in leases, debt securities, loans and certain other instruments. The standard requires the use of a forward-looking "expected loss" model compared to the current "incurred loss" model. This ASU is effective for us beginning in the first quarter of 2020, with early adoption permitted beginning in the first quarter of 2019. We are currently assessing the impact of the ASU on our Consolidated Financial Statements.

2. Revenue

Revenue from contracts with customers on a disaggregated basis in 2018 was as follows (in millions):

	Exploration and Production					Midstream	Eliminations	Total
	United States	Europe	Africa	Asia	E&P Total			
Sales of our net production volumes:								
Crude oil revenue	$ 2,832	$ 153	$ 434	$ 104	$ 3,523	$ —	$ —	$ 3,523
Natural gas liquids revenue	308	—	—	—	308	—	—	308
Natural gas revenue	176	11	21	651	859	—	—	859
Sales of purchased oil and gas	1,661	—	93	14	1,768	—	—	1,768
Intercompany revenue	—	—	—	—	—	713	(713)	—
Total revenues from contracts with customers	4,977	164	548	769	6,458	713	(713)	6,458
Other operating revenues (a)	(135)	—	—	—	(135)	—	—	(135)
Total sales and other operating revenues	$ 4,842	$ 164	$ 548	$ 769	$ 6,323	$ 713	$ (713)	$ 6,323

(a) Includes gains (losses) on commodity derivatives.

Exploration and Production

The E&P segment recognizes revenue from the sale of crude oil, NGLs, and natural gas as performance obligations under contracts with customers are satisfied. Our responsibilities to deliver each unit of quantity of crude oil, NGL, and natural gas under these contracts represent separate, distinct performance obligations. These performance obligations are satisfied at the point in time control of each unit of quantity transfers to the customer. Generally, the control of each unit of quantity transfers to the customer upon the transfer of legal title at the point of physical delivery. Pricing is variable and is determined with reference to a particular market or pricing index, plus or minus adjustments reflecting quality or location differentials.

For long-term international natural gas contracts with ship-or-pay provisions, our obligation to stand-ready to provide a minimum volume over each commitment period represents separate, distinct performance obligations. Penalties owed against future deliveries of natural gas due to delivery of volumes below minimum delivery commitments are recognized as reductions to revenue in the commitment period when the shortfall occurs. Long-term international natural gas contracts may also contain take-or-pay provisions whereby the customer is required to pay for volumes not taken that are below the minimum volume commitment, but the customer has certain make-up rights to receive shortfall volumes in subsequent periods. Shortfall payments received from customers when volumes purchased are below the minimum volume commitment are deferred upon receipt as a contract liability. Revenue is recognized at the earlier of when we deliver the make-up volumes in subsequent periods or when it becomes remote that the customer will exercise their make-up rights.

Certain crude oil, NGL, and natural gas volumes are purchased by Hess from third-parties, including working interest partners and royalty owners in certain Hess-operated properties, before they are sold to customers. Where control over the crude oil, NGLs, or natural gas transfers to Hess before the volumes are transferred to the customer, revenue and the associated cost of purchased volumes are presented on a gross basis in the *Statement of Consolidated Income* within *Sales and other operating revenues* and *Marketing, including purchased oil and gas*, respectively. Where control of crude oil, NGLs, or natural gas is not transferred to Hess, revenue is presented net of the associated cost of purchased volumes within *Sales and other operating revenues* in the *Statement of Consolidated Income*.

Contract types

The following is a summary of contract types for our E&P segment:

Crude oil, NGLs, and natural gas – United States (U.S.): Contracts with customers for the sale of U.S. crude oil, NGLs, and natural gas primarily include those contracts that involve the short-term sale of volumes during a specified period, and those contracts that automatically renew on a periodic basis until either party cancels. We have certain long-term contracts with customers for the sale of U.S. natural gas and NGLs that have remaining durations of less than ten years. Contracts may specify a fixed volume for delivery subject to tolerance thresholds or may specify a percentage of production to be delivered from a particular location. Pricing is determined with reference to a particular market or pricing index, plus or minus adjustments reflecting quality or location differentials.

Crude oil – International: Contracts with customers for the sale of international crude oil involve the short-term sale of volumes during a specified period. These contracts specify a fixed volume for delivery subject to tolerance thresholds. Pricing is determined with reference to a particular market or pricing index, plus or minus adjustments reflecting quality or location differentials, shortly after control of the volumes transfers to the customer.

Natural gas – International: Contracts with customers for the sale of natural gas are in the form of natural gas sales agreements with government entities that have durations that are aligned with the durations of production sharing contracts or other contractual arrangements with host governments. Pricing is determined using contractual formulas that are based on the price of alternative fuels as obtained from price indices and other factors. These contracts also specify a minimum volume we are obligated to make available during specified periods within the contract term and may specify minimum volumes the customer is obligated to purchase during specified periods within the contract term. If we do not deliver the volume properly nominated by the customer, the customer is entitled to a price discount on future volumes equivalent to the shortfall delivery. Under certain international natural gas sales agreements, if the customer purchases natural gas volumes below the minimum volume commitment, the customer is required to pay us for the shortfall volumes and may receive make-up volumes in subsequent periods at no additional cost.

Revenue from sale of third-party purchased volumes: Crude oil, NGLs, and natural gas are purchased by Hess from third-parties, including working interest partners and royalty owners in certain Hess-operated properties, before they are sold to customers. The types of contracts with customers for the sale of third-party purchased volumes are the same as those described above.

Contract Balances

Our right to receive or collect payment from the customer is aligned with the timing of revenue recognition except in situations when we receive shortfall payments under contracts with take-or-pay provisions with customer make-up rights or where we recognize a liability for price discounts owed against future deliveries as a result of not shipping minimum volume commitments. At December 31, 2018 and 2017, there were no contract assets or contract liabilities, respectively.

Generally, we receive payments from customers on a monthly basis, shortly after the physical delivery of the crude oil, NGLs, or natural gas. In 2018, we did not recognize any impairment losses on receivables arising from contracts with customers.

Transaction Price Allocated to Remaining Performance Obligations

The transaction price allocated to our wholly unsatisfied performance obligations on uncompleted contracts is variable. Further, many of our contracts with customers have durations of less than twelve months. Accordingly, we have elected under the provisions of *ASC 606* the exemption from disclosure of revenue recognizable in future periods as these performance obligations are satisfied.

Sales-based Taxes

We exclude sales-based taxes that are collected from customers from the transaction price in our contracts with customers. Accordingly, revenue from contracts with customers is net of sales-based taxes that are collected from customers and remitted to taxing authorities.

Midstream

Our Midstream segment provides gathering, compression, processing, fractionation, storage, terminaling, loading and transportation, and water handling services.

The Midstream segment has multiple long-term, fee-based commercial agreements with a marketing subsidiary of Hess, each generally with an initial ten-year term that can be extended for an additional ten-year term at the unilateral right of our Midstream segment. These contracts have minimum volumes the customer is obligated to provide each calendar quarter. The minimum volume commitments are subject to fluctuation based on nominations covering substantially all of our E&P segment's production and projected third-party volumes that will be purchased in the Bakken. As the minimum volume commitments are subject to fluctuation, and as these contracts contain fee inflation escalators and fee recalculation mechanisms, substantially all of the transaction price at contract inception is variable. The Midstream segment also provides water handling services to a subsidiary of Hess for an agreed-upon fee per barrel or the reimbursement of third-party fees.

The Midstream segment's responsibilities to provide each of the above services for each year under each of the commercial agreements are considered separate, distinct performance obligations. Revenue is recognized for each performance obligation under these commercial agreements over-time as services are rendered using the output method, measured using the amount of volumes serviced during the period. The Midstream segment has elected the practical expedient under the provisions of *ASC 606* to recognize revenue in the amount it is entitled to invoice. If the commercial agreements have take-or-pay provisions, the Midstream segment's responsibility to stand-ready to service a minimum volume over each quarterly commitment period represent separate, distinct performance obligations. Shortfall payments received under take-or-pay provisions are recognized as revenue in the calendar quarter the shortfall occurs as the customer does not have make-up rights beyond the calendar quarter end of the quarterly commitment period. All revenues, receivables, and contract balances arising from the commercial agreements between the Midstream segment and the Hess marketing subsidiary that is the counterparty to the commercial agreements are eliminated upon consolidation.

3. Dispositions

2018: We completed the sale of our joint venture interests in the Utica shale play in eastern Ohio in August for proceeds of $396 million, after normal closing adjustments, and recognized a pre-tax gain of $14 million ($14 million after income taxes). In addition, we completed the sale of our interests in Ghana for total consideration of $100 million, consisting of a $25 million payment that was received at closing and a further payment of $75 million that is payable to us upon the buyer receiving government approval for a Plan of Development on the Deepwater Tano Cape Three Points Block. The receipt of proceeds at closing resulted in a pre-tax gain of $10 million ($10 million after income taxes).

2017: We completed the sale of our enhanced oil recovery assets in the Permian Basin in August for proceeds of $597 million, after normal closing adjustments, and recognized a pre-tax gain of $273 million ($280 million attributable to Hess Corporation after income taxes and noncontrolling interest). This sale transaction included both upstream and midstream assets resulting in an after-tax gain of $314 million allocated to the E&P segment, and an after-tax loss of $34 million allocated to the Midstream segment. In November, we completed the sale of our interests in Equatorial Guinea for proceeds of $449 million, after normal closing adjustments, which resulted in a pre-tax gain of $486 million ($486 million after income taxes). In December, we completed the sale of our interests in the Valhall and Hod assets, offshore Norway for proceeds of $2,056 million, after normal closing adjustments, which resulted in a pre-tax loss of $857 million ($857 million after income taxes). This loss includes a recognition in earnings of $900 million for cumulative translation adjustments that were previously reflected within *Accumulated Other Comprehensive Income (Loss)* in *Stockholders' Equity*. We also sold certain U.S. onshore assets for proceeds totaling approximately $194 million and recognized net pre-tax gains totaling $12 million ($12 million after income taxes).

Pre-tax income (loss) associated with our interests in Equatorial Guinea and Norway, excluding the financial statement impacts resulting from the asset sales in 2017, were as follows for the three years ended December 31:

	2018	2017	2016
		(In millions)	
Equatorial Guinea (a)	**$ —**	$ 69	$ (95)
Norway (b)	**—**	(55)	(195)
Income (Loss) from Continuing Operations Before Income Taxes	**$ —**	$ 14	$ (290)

(a) Pre-tax income for 2017 excludes the gain of $486 million related to sale of our assets in November 2017.
(b) Pre-tax loss for 2017 excludes the loss of $857 million related to sale of our assets in December 2017. In addition, the 2017 loss excludes a pre-tax impairment charge of $2,503 million associated with the disposition.

2016: We sold miscellaneous non-core assets during the year for proceeds totaling approximately $100 million and recognized net pre-tax gains totaling $23 million ($14 million after income taxes).

The asset sales in 2018 and 2017 high grade our portfolio by divesting of lower return, mature assets to invest in higher return assets, primarily in Guyana and the Bakken, and to fund purchases of common stock and retirement of debt in 2018.

4. Inventories

Inventories at December 31 were as follows:

	2018	2017
	(In millions)	
Crude oil and natural gas liquids	**$ 74**	$ 59
Materials and supplies	**171**	173
Total Inventories	**$ 245**	$ 232

5. Property, Plant and Equipment

Property, plant and equipment at December 31 were as follows:

	2018	2017
	(In millions)	
Exploration and Production		
Unproved properties	**$ 394**	$ 520
Proved properties	**3,124**	3,162
Wells, equipment and related facilities	**26,173**	25,550
	29,691	29,232
Midstream	**3,492**	3,219
Corporate and Other	**39**	53
Total — at cost	**33,222**	32,504
Less: Reserves for depreciation, depletion, amortization and lease impairment	**17,139**	16,312
Property, Plant and Equipment — Net	**$ 16,083**	$ 16,192

Capitalized Exploratory Well Costs: The following table discloses the amount of capitalized exploratory well costs pending determination of proved reserves at December 31, and the changes therein during the respective years:

	2018	2017	2016
		(In millions)	
Balance at January 1	**$ 304**	$ 597	$ 1,415
Additions to capitalized exploratory well costs pending the determination of proved reserves	**128**	116	79
Reclassifications to wells, facilities and equipment based on the determination of proved reserves	**—**	(165)	—
Capitalized exploratory well costs charged to expense	**(14)**	(268)	(897)
Dispositions and other	**—**	24	—
Balance at December 31	**$ 418**	$ 304	$ 597
Number of Wells at December 31	**24**	12	17

During the three years ended December 31, 2018, additions to capitalized exploratory well costs primarily related to drilling at the Stabroek Block offshore Guyana. Other drilling activity included the Bunga prospect in Malaysia during 2018 and in the Gulf of Mexico during 2016. Reclassifications to wells, facilities and equipment based on the determination of proved reserves primarily related to the sanction of the first phase of Liza Field development, offshore Guyana in 2017.

Capitalized exploratory well costs charged to expense include the following:

2018: In Canada, offshore Nova Scotia (Hess 50% participating interest), the operator, BP Canada, completed drilling of the Aspy exploration well, which did not encounter commercial quantities of hydrocarbons. As a result, we expensed well costs totaling $120 million of which $106 million were incurred and expensed in 2018.

2017: In Ghana, at the Hess operated offshore Deepwater Tano/Cape Three Points license (Hess 50% license interest), management determined in the fourth quarter of 2017 that it would not develop the previously discovered fields. As a result, we recorded a charge of $268 million to write-off previously capitalized exploration wells.

2016: At the Hess-operated Equus natural gas project, offshore the North West Shelf of Australia in the fourth quarter of 2016, we terminated a joint front-end engineering study with a third-party natural gas liquefaction joint venture and notified the Australian government of our intent to defer the project. As a result, we expensed all well costs associated with the project, including an exploration well completed in the second quarter of 2016, totaling $830 million. These properties were sold in 2017. In the second quarter of 2016, we expensed costs associated with two exploration wells at the non-operated Sicily project in the Gulf of Mexico where hydrocarbons were encountered but we decided not to pursue the project due to the low commodity price environment and the limited time remaining on the leases. We also expensed the cost of an unsuccessful exploration well at the non-operated Melmar project in the Gulf of Mexico, where noncommercial quantities of hydrocarbons were encountered.

The preceding table excludes exploratory dry hole costs of $151 million in 2018 (2017: $0 million; 2016: $167 million), which were incurred and subsequently expensed in the same year. In 2018, these costs are associated with the Aspy well, offshore Nova Scotia, Canada, the Pontoenoe-1 well, offshore Suriname, the Sorubim-1 well on the Stabroek Block, offshore Guyana, and the Bunga Teruntum-1 well in North Malay Basin.

Exploratory well costs capitalized for greater than one year following completion of drilling were $267 million at December 31, 2018, separated by year of completion as follows (in millions):

2017	$	97
2016		—
2015		166
2014		—
2013		4
	$	267

Gulf of Mexico: Approximately 45% of the capitalized well costs in excess of one year relates to the appraisal of the northern portion of the Shenzi Field (Hess 28% participating interest) in the Gulf of Mexico, where hydrocarbons were encountered in the fourth quarter of 2015. Following exploration and appraisal drilling activities completed by the operator in prior years on adjacent blocks to the north of our Shenzi blocks, the operator is planning to acquire 3D seismic in 2019 for use in development planning of the northern portion of the Shenzi Field.

Guyana: Approximately 35% of the capitalized well costs in excess of one year relates to the Liza-4, Payara-1, Payara-2 and Snoek-1 wells on the Stabroek Block, offshore Guyana (Hess 30%), where hydrocarbons were encountered. The operator plans to integrate the Liza-4 discovery into the second phase of development, which is expected to commence production by mid-2022. The operator plans to integrate the Payara-1 and Payara-2 discoveries into the third phase of development, which is expected to commence production as early as 2023. The Snoek discovery is expected to produce into the Liza Phase 1 FPSO under a subsequent phase of development.

JDA: Approximately 15% of the capitalized well costs in excess of one year relates to the JDA in the Gulf of Thailand (Hess 50%) where hydrocarbons were encountered in three successful exploration wells drilled in the western part of Block A-18. The operator has submitted a development plan concept to the regulator to facilitate commercial negotiations for an extension of the existing gas sales contract to include development of the western part of the Block.

Malaysia: Approximately 5% of the capitalized well costs in excess of one year relates to North Malay Basin, offshore Peninsular Malaysia (Hess 50%), where hydrocarbons were encountered in one successful exploration well drilled in the fourth quarter of 2015. In 2018, we completed four exploration wells and are conducting subsurface evaluations for consideration in future phases of field development.

6. Hess Infrastructure Partners LP

On July 1, 2015, we sold a 50% interest in Hess Infrastructure Partners LP (HIP) to Global Infrastructure Partners (GIP) for net cash consideration of approximately $2.6 billion. HIP and its affiliates primarily comprise our Midstream operating segment. The Midstream operating segment currently generates substantially all of its revenues under long-term, fee-based agreements with our E&P operating segment and intends to pursue additional throughput volumes from third-parties in the Williston Basin area. We operate the Midstream assets and operations, including routine and emergency maintenance and repair services under various operational and administrative services agreements.

The tariff agreements between our E&P operating segment and the Midstream entities became effective on January 1, 2014 and are 10-year, fee-based commercial agreements, with HIP having the sole option to renew the agreements for an additional 10-year term. These agreements include minimum volume commitments based on dedicated production, inflation escalators and fee recalculation mechanisms. The Midstream segment has minimal direct commodity price exposure, and the E&P segment retains ownership of the crude oil, natural gas or NGLs processed, terminaled, stored or transported by the Midstream segment.

We consolidate the activities of HIP, a 50/50 joint venture between Hess Corporation and GIP, which qualifies as a variable interest entity (VIE) under U.S. GAAP. We have concluded that we are the primary beneficiary of the VIE, as defined in the accounting standards, since we have the power, through our 50% ownership, to direct those activities that most significantly impact the economic performance of HIP. This conclusion was based on a qualitative analysis that considered HIP's governance structure, the commercial agreements between HIP and us, and the voting rights established between the members, which provide us the ability to control the operations of HIP.

At December 31, 2018, HIP liabilities totaling $1,105 million (2017: $1,065 million) are on a nonrecourse basis to Hess Corporation, while HIP assets available to settle the obligations of HIP included Cash and cash equivalents totaling $109 million (2017: $356 million) and Property, plant and equipment, net totaling $2,664 million (2017: $2,520 million).

7. Hess Midstream Partners LP – Initial Public Offering

In April 2017, Hess Midstream Partners LP (the "Partnership"), sold 16,997,000 common units representing limited partner interests at a price of $23 per unit in an initial public offering (IPO) for net proceeds of $365.5 million, of which $350 million was distributed equally to Hess Corporation and GIP.

The Partnership owns an approximate 20% controlling interest in the operating companies that comprise our midstream joint venture, while HIP, the 50/50 joint venture between Hess Corporation and GIP, owns the remaining 80%. Hess Corporation and GIP each own a direct 33.75% limited partner interest in the Partnership and a 50% indirect ownership interest through HIP in the Partnership's general partner, which has a 2% economic interest in the Partnership plus incentive distribution rights. The public unit holders own a 30.5% limited partner interest in the Partnership.

8. Debt

Total debt at December 31 consisted of the following:

	2018	2017
	(In millions)	
Debt - Hess Corporation:		
Fixed-rate public notes:		
8.1% due 2019	**$ —**	$ 349
3.5% due 2024	**298**	297
4.3% due 2027	**992**	991
7.9% due 2029	**463**	500
7.3% due 2031	**627**	679
7.1% due 2033	**537**	596
6.0% due 2040	**740**	740
5.6% due 2041	**1,234**	1,234
5.8% due 2047	**493**	493
Total fixed-rate public notes	**5,384**	5,879
Capital lease obligations	**269**	—
Financing obligations associated with floating production system	**40**	118
Fair value adjustments - interest rate hedging	**(2)**	—
Total Debt - Hess Corporation	**$ 5,691**	$ 5,997
Debt - Midstream:		
Fixed-rate notes: 5.6% due 2026 - HIP	**$ 787**	$ 785
Term loan A facility - HIP	**194**	195
Total Debt - Midstream	**$ 981**	$ 980
Total Debt:		
Current maturities of long-term debt	**$ 67**	$ 580
Long-term debt	**6,605**	6,397
Total Debt	**$ 6,672**	$ 6,977

At December 31, 2018, the maturity profile of total debt was as follows:

	Total	Hess Corporation	Midstream
		(In millions)	
2019	$ 67	$ 56	$ 11
2020	32	17	15
2021	34	18	16
2022	171	19	152
2023	21	21	—
Thereafter	6,347	5,560	787
Total debt (excluding interest)	$ 6,672	$ 5,691	$ 981

Debt – Hess Corporation:

Fixed-rate public notes:

At December 31, 2018, Hess Corporation's fixed-rate public notes had a gross principal amount of $5,438 million (2017: $5,938 million) and a weighted average interest rate of 5.9% (2017: 6.0%). Our long-term debt agreements, including the revolving credit facility, contain financial covenants that restrict the amount of total borrowings and secured debt. The most restrictive of these covenants allow us to borrow up to an additional $3,098 million of secured debt at December 31, 2018. Capitalized interest was $20 million in 2018 (2017: $86 million; 2016: $61 million).

In 2018, we paid $553 million to redeem $350 million principal amount of 8.125% notes due 2019 and to purchase other notes with a carrying value of $150 million. As a result, we recorded total losses on debt extinguishment of $53 million in 2018 (2017: $0 million; 2016: $148 million). Concurrent with the redemption of the 2019 notes, we terminated interest rate swaps with a notional amount of $350 million.

Capital lease:

In 2018, we entered into a sale and lease-back arrangement for a floating storage and offloading vessel (FSO) to handle produced condensate at North Malay Basin, offshore Peninsular Malaysia (Hess operated – 50%). Pursuant to the sale agreement, we received total proceeds of approximately $260 million, including our partner's share of the proceeds which is reported in *Accounts Payable* on our *Consolidated Balance Sheet.* No gain or loss was recognized from the sale transaction. The lease agreement is for 16 years with four consecutive twelve-month renewal options that may be exercised at our discretion. At December 31, 2018, the carrying value of the lease asset is $264 million and the carrying value of the lease obligation is $269 million, which represents 100% of the present value of future minimum lease payments, of which $15 million is included in *Current maturities of long-term debt* and $254 million is included in *Long-term debt* on our *Consolidated Balance Sheet*. As the payments under the lease agreement become due, we will bill our partner their proportionate share for reimbursement pursuant to the terms of our joint operating agreement.

Credit facility:

Hess Corporation's $4 billion syndicated revolving credit facility expires in January 2021, with commitments of $3.7 billion available for the final year. Borrowings on the facility will generally bear interest at 1.30% above the London Interbank Offered Rate (LIBOR). The interest rate will be higher if our credit rating is lowered. The facility contains a financial covenant that limits the amount of the total borrowings on the last day of each fiscal quarter to 60% of the Corporation's total capitalization, defined as total debt plus stockholders' equity. At December 31, 2018, Hess Corporation had no outstanding borrowings or letters of credit under this facility and was in compliance with this financial covenant.

Other outstanding letters of credit at December 31 were as follows:

	2018	**2017**
	(In millions)	
Committed lines (a)	**$ 29**	$ 29
Uncommitted lines (a)	**255**	217
Total	**$ 284**	$ 246

(a) At December 31, 2018, committed and uncommitted lines have expiration dates throughout 2019.

Debt - Midstream:

Our Midstream segment holds the following non-recourse debt:

Hess Infrastructure Partners (HIP):

In November 2017, HIP issued $800 million of 5.625% senior notes, due in February 2026 and concurrently amended its senior unsecured credit facilities. HIP used a portion of the proceeds from the note issuance to repay borrowings under HIP's credit facilities and to fund a distribution to the partners. Under the amended credit facilities, the 5-year Term Loan A facility was reduced to $200 million and the 5-year syndicated revolving credit facility increased to $600 million from $400 million previously, with the maturity of both facilities extended to November 2022. The amended facilities are secured by first-priority perfected liens on substantially all of HIP's and certain of its wholly-owned subsidiaries' directly owned assets, including its equity interests in certain subsidiaries, subject to customary exclusions. The 5-year syndicated revolving credit facility is expected to continue to fund the joint venture's operating activities and capital expenditures. Borrowings under the 5-year Term Loan A facility will generally bear interest at LIBOR plus an applicable margin ranging from 1.55% to 2.50%, while the applicable margin for the 5-year syndicated revolving credit facility ranges from 1.275% to 2.000%. The interest rate continues to be subject to adjustment based on the joint venture's leverage ratio, which is calculated as total debt to Earnings Before Interest, Taxes, Depreciation and Amortization (EBITDA). If HIP obtains an investment grade credit rating, as defined in the amended credit agreement, pricing levels will be based on the credit ratings in effect from time to time. The joint venture is subject to customary covenants in the credit agreement that include financial covenants that generally require a leverage ratio of no more than 5.0 to 1.0 for the prior four fiscal quarters and an interest coverage ratio, which is calculated as EBITDA to cash interest expense, of no less than 2.25 to 1.0 for the prior four fiscal quarters. The amended credit agreement includes a secured leverage ratio test not to exceed 3.75 to 1.00 for so long as the facilities remain secured. HIP is in compliance with all debt covenants at December 31, 2018, and its financial covenants do not currently impact its ability to issue indebtedness to fund future capital expenditures. At December 31, 2018, HIP's revolving credit facility was undrawn and borrowings under the Term Loan A facility amounted to $197.5 million, excluding deferred issuance costs.

Hess Midstream Partners (the Partnership):

The Partnership has a $300 million 4-year senior secured syndicated revolving credit facility through March 2021 that can be used for borrowings and letters of credit to fund operating activities and capital expenditures of the Partnership. Borrowings on the credit facility will generally bear interest at LIBOR plus an applicable margin of 1.275%. The interest rate is subject to adjustment based on the Partnership's leverage ratio, which is calculated as total debt to EBITDA. If the Partnership obtains credit ratings, pricing levels will be based on the credit ratings in effect from time to time. The Partnership is subject to customary covenants in the credit agreement, including financial covenants that generally require a leverage ratio of no more than 4.5 to 1.0 for the prior four fiscal quarters. The credit facility is secured by first priority perfected liens on substantially all directly owned assets of the Partnership and its wholly-owned subsidiaries, including equity interests in subsidiaries, subject to certain customary exclusions. Outstanding borrowings under this credit facility are non-recourse to Hess Corporation. At December 31, 2018, this facility was undrawn.

9. Asset Retirement Obligations

The following table describes changes to and maturity of our asset retirement obligations:

	2018	2017
	(In millions)	
Balance at January 1	**$ 801**	$ 2,128
Liabilities incurred	**68**	62
Liabilities settled or disposed of	**(46)**	(1,464)
Accretion expense	**37**	97
Revisions of estimated liabilities	**1**	(54)
Foreign currency remeasurement	**(4)**	32
Balance at December 31	**$ 857**	$ 801
Total Asset Retirement Obligations at December 31:		
Current portion of asset retirement obligations	**$ 116**	$ 48
Long-term asset retirement obligations	**741**	753
Total at December 31	**$ 857**	$ 801

The liabilities incurred in 2018 include $25 million related to acquired participating interests. The liabilities settled or disposed of in 2017 primarily relate to the sale of our interests in Norway and Equatorial Guinea. The fair value of sinking fund deposits that are legally restricted for purposes of settling asset retirement obligations, which are reported in non-current Other assets in the *Consolidated Balance Sheet*, was $148 million at December 31, 2018 (2017: $118 million).

10. Retirement Plans

We have funded noncontributory defined benefit pension plans for a significant portion of our employees. In addition, we have an unfunded supplemental pension plan covering certain employees, which provides incremental payments that would have been payable from our principal pension plans, were it not for limitations imposed by income tax regulations. The plans provide defined benefits based on years of service and final average salary. Additionally, we maintain an unfunded postretirement medical plan that provides health benefits to certain qualified retirees from ages 55 through 65. The measurement date for all retirement plans is December 31.

The following table summarizes the benefit obligations, the fair value of plan assets, and the funded status of our pension and postretirement medical plans:

	Funded Pension Plans		Unfunded Pension Plan		Postretirement Medical Plan	
	2018	2017	**2018**	2017	**2018**	2017
			(In millions)			
Change in Benefit Obligation						
Balance at January 1,	**$ 2,765**	$ 2,560	**$ 249**	$ 256	**$ 87**	$ 84
Service cost	**30**	36	**12**	13	**2**	4
Interest cost	**84**	93	**7**	9	**3**	3
Actuarial (gains) loss (a)	**(237)**	138	**(29)**	10	**(24)**	3
Benefit payments (b)	**(110)**	(113)	**(19)**	(39)	**(7)**	(7)
Plan curtailments	**(10)**	(3)	**(4)**	—	**(2)**	—
Plan amendments	**4**	—	**—**	—	**—**	—
Foreign currency exchange rate changes	**(34)**	54	**—**	—	**—**	—
Balance at December 31, (c)	**2,492**	2,765	**216**	249	**59**	87
Change in Fair Value of Plan Assets						
Balance at January 1,	**$ 2,732**	$ 2,284	**$ —**	$ —	**$ —**	$ —
Actual return on plan assets	**(77)**	351	**—**	—	**—**	—
Employer contributions	**59**	158	**19**	39	**7**	7
Benefit payments (b)	**(110)**	(113)	**(19)**	(39)	**(7)**	(7)
Foreign currency exchange rate changes	**(36)**	52	**—**	—	**—**	—
Balance at December 31,	**2,568**	2,732	**—**	—	**—**	—
Funded Status (Plan assets greater (less) than benefit obligations) at December 31,	**$ 76**	$ (33)	**$ (216)**	$ (249)	**$ (59)**	$ (87)
Unrecognized Net Actuarial (Gains) Losses	**$ 778**	$ 789	**$ 47**	$ 84	**$ (32)**	$ (10)

(a) The change in discount rate in 2018 resulted in total actuarial gains of approximately $235 million (2017: $170 million of actuarial losses).
(b) Benefit payments include lump-sum settlement payments of approximately $32 million in 2018 (2017: $57 million).
(c) At December 31, 2018, the accumulated benefit obligation for the funded and unfunded defined benefit pension plans was $2,424 million and $171 million, respectively (2017: $2,679 million and $190 million, respectively).

Amounts recognized in the *Consolidated Balance Sheet* at December 31 consisted of the following:

	Funded Pension Plans		Unfunded Pension Plan		Postretirement Medical Plan	
	2018	2017	**2018**	2017	**2018**	2017
			(In millions)			
Noncurrent assets	**$ 76**	$ 22	**$ —**	$ —	**$ —**	$ —
Current liabilities	**—**	—	**(30)**	(18)	**(9)**	(11)
Noncurrent liabilities	**—**	(55)	**(186)**	(231)	**(50)**	(76)
Pension assets / (accrued benefit liability)	**$ 76**	$ (33)	**$ (216)**	$ (249)	**$ (59)**	$ (87)
Accumulated other comprehensive loss, pre-tax (a)	**$ 778**	$ 789	**$ 47**	$ 84	**$ (32)**	$ (10)

(a) The after-tax deficit reflected in Accumulated other comprehensive income (loss) was $581 million at December 31, 2018 (2017: $548 million deficit).

The net periodic benefit cost for funded and unfunded pension plans, and the postretirement medical plan, is as follows:

	Pension Plans			Postretirement Medical Plan		
	2018	2017	2016	2018	2017	2016
	(In millions)					
Service cost	**$ 42**	$ 49	$ 60	**$ 2**	$ 4	$ 4
Interest cost	**91**	102	107	**3**	3	3
Expected return on plan assets	**(194)**	(168)	(166)	**—**	—	—
Amortization of unrecognized net actuarial losses (gains)	**39**	58	60	**(2)**	—	—
Settlement loss	**4**	19	—	**—**	—	—
Curtailment gain	**—**	—	—	**(2)**	—	—
Special termination benefit recognized	**—**	—	1	**—**	—	—
Net Periodic Benefit Cost (a)	**$ (18)**	$ 60	$ 62	**$ 1**	$ 7	$ 7

(a) Net non-service pension costs are included in Other, net in the Statement of Consolidated Income. In 2018, net non-service pension costs amounted to income of $61 million (2017: $14 million of expense; 2016: $5 million of expense).

In 2018, we recorded curtailment gains of $14 million to *Accumulated other comprehensive Income (loss)* and $2 million to the *Statement of Consolidated Income* following workforce reductions. In connection with this curtailment, as required under accounting standards, we remeasured our U.S. retirement plans and recorded a total decrease of $125 million in the Corporation's U.S. post retirement liabilities. This reduction was primarily driven by a change in weighted average discount rates used to measure the liabilities. There was no change to the weighted average expected long-term rate of return on plan assets.

For the full year 2019, we forecast pension service costs for our pension and postretirement medical plans to be approximately $40 million and net non-service pension costs of approximately $40 million of income, which is comprised of interest cost of approximately $95 million, amortization of unrecognized net actuarial losses of approximately $45 million, and estimated expected return on plan assets of approximately $180 million.

Assumptions:

The weighted average actuarial assumptions used to determine Benefit obligations at December 31 and Net periodic benefit cost for the three years ended December 31 for our funded and unfunded pension plans were as follows:

	2018	2017	2016
Benefit Obligations:			
Discount rate	**3.9%**	3.3%	3.7%
Rate of compensation increase	**3.8%**	4.5%	4.6%
Net Periodic Benefit Cost:			
Discount rate			
Service cost	**3.9%**	3.7%	4.1%
Interest cost	**3.3%**	3.7%	4.1%
Expected return on plan assets	**7.2%**	7.3%	7.4%
Rate of compensation increase	**4.5%**	4.6%	4.5%

The actuarial assumptions used to determine Benefit obligations at December 31 for the postretirement medical plan were as follows:

	2018	2017	2016
Discount rate	**3.9%**	3.2%	3.5%
Initial health care trend rate	**6.9%**	7.3%	7.7%
Ultimate trend rate	**4.5%**	4.5%	4.5%
Year in which ultimate trend rate is reached	**2038**	2038	2038

The assumptions used to determine net periodic benefit cost for each year were established at the end of each previous year while the assumptions used to determine benefit obligations were established at each year-end. The net periodic benefit cost and the actuarial present value of benefit obligations are based on actuarial assumptions that are reviewed on an annual basis. The discount rate is developed based on a portfolio of high-quality, fixed income debt instruments with maturities that approximate the expected payment of plan obligations. Beginning in 2018, we have elected to use a split discount rate approach for all of our retirement plans. This involves the continued use of a single weighted-average discount rate in the calculation of the projected benefit obligation, and separate discount rates for each projected benefit payment in the calculation of service cost and interest cost. In contrast, historically, a single weighted-average discount rate was used in both the calculation of the projected benefit obligation, and service cost and interest cost.

The overall expected return on plan assets is developed from the expected future returns for each asset category, weighted by the target allocation of pension assets to that asset category. The future expected return assumptions for individual asset categories are largely based on inputs from various investment experts regarding their future return expectations for particular asset categories.

Our investment strategy is to maximize long-term returns at an acceptable level of risk through broad diversification of plan assets in a variety of asset classes. Asset classes and target allocations are determined by our investment committee and include domestic and foreign equities, fixed income, and other investments, including hedge funds, real estate and private equity. Investment managers are prohibited from investing in securities issued by us unless indirectly held as part of an index strategy. The majority of plan assets are highly liquid, providing ample liquidity for benefit payment requirements. The current target allocations for plan assets are 50% equity securities, 30% fixed income securities (including cash and short-term investment funds) and 20% to all other types of investments. Asset allocations are rebalanced on a periodic basis throughout the year to bring assets to within an acceptable range of target levels.

Fair value:

The following tables provide the fair value of the financial assets of the funded pension plans at December 31, 2018 and 2017 in accordance with the fair value measurement hierarchy described in *Note 1, Nature of Operations, Basis of Presentation and Summary of Accounting Policies*.

	Level 1	Level 2	Level 3	Net Asset Value (d)	Total
			(In millions)		
December 31, 2018					
Cash and Short-Term Investment Funds	**$ 3**	**$ 47**	**$ —**	**$ —**	**$ 50**
Equities:					
U.S. equities (domestic)	**654**	**—**	**—**	**—**	**654**
International equities (non-U.S.)	**92**	**29**	**—**	**288**	**409**
Global equities (domestic and non-U.S.)	**2**	**203**	**—**	**—**	**205**
Fixed Income:					
Treasury and government issued (a)	**—**	**240**	**—**	**—**	**240**
Government related (b)	**—**	**37**	**—**	**—**	**37**
Mortgage-backed securities (c)	**—**	**159**	**—**	**27**	**186**
Corporate	**—**	**272**	**—**	**31**	**303**
Other:					
Hedge funds	**—**	**—**	**—**	**135**	**135**
Private equity funds	**—**	**—**	**—**	**170**	**170**
Real estate funds	**49**	**—**	**61**	**50**	**160**
Diversified commodities funds	**—**	**19**	**—**	**—**	**19**
Total investments	**$ 800**	**$ 1,006**	**$ 61**	**$ 701**	**$ 2,568**
December 31, 2017					
Cash and Short-Term Investment Funds	$ 32	$ 69	$ —	$ —	$ 101
Equities:					
U.S. equities (domestic)	789	—	—	—	789
International equities (non-U.S.)	104	34	—	296	434
Global equities (domestic and non-U.S.)	2	238	—	—	240
Fixed Income:					
Treasury and government issued (a)	—	271	—	—	271
Government related (b)	—	34	1	—	35
Mortgage-backed securities (c)	—	139	1	26	166
Corporate	—	182	—	6	188
Other:					
Hedge funds	—	—	—	187	187
Private equity funds	—	—	—	140	140
Real estate funds	63	—	2	92	157
Diversified commodities funds	—	24	—	—	24
Total investments	$ 990	$ 991	$ 4	$ 747	$ 2,732

(a) *Includes securities issued and guaranteed by U.S. and non-U.S. governments.*
(b) *Primarily consists of securities issued by governmental agencies and municipalities.*
(c) *Comprised of U.S. residential and commercial mortgage-backed securities.*
(d) *Includes certain investments that have been valued using the net asset value practical expedient, and therefore have not been categorized in the fair value hierarchy. The inclusion of such amounts in the above table is intended to aid reconciliation of investments categorized in the fair value hierarchy to total pension plan assets.*

The following describes the financial assets of the funded pension plans:

Cash and short-term investment funds **-** Consists of cash on hand and short-term investment funds that provide for daily investments and redemptions. Cash on hand is classified as Level 1 and short-term investment funds are classified as Level 2.

Equities **-** Consists of individually held or commingled funds of U.S. and International equity securities. Equity securities, which are individually held and are traded actively on exchanges, are classified as Level 1. Commingled funds, consisting primarily of equity securities, are valued using the net asset value (NAV) per fund share derived from quoted prices in active markets of the underlying securities. These funds are classified as Level 2 where they have readily determinable fair values, otherwise they are classified under the NAV practical expedient.

Fixed income investments **-** Consists of securities issued by the U.S. government, non-U.S. governments, governmental agencies, municipalities and corporations, and agency and non-agency mortgage-backed securities. This investment category also includes commingled investment funds that invest in fixed income securities. Individual fixed income securities are generally priced based on evaluated prices from independent pricing services, which are monitored and provided by the third-party custodial firm responsible for safekeeping plan assets. Individual fixed income securities are classified as Level 2. Certain fixed income investments are commingled funds that are valued at the NAV per fund share derived indirectly from observable inputs or from quoted prices in less liquid markets of the underlying securities. These funds are classified as Level 2 where they have readily determinable fair values, otherwise they are classified under the NAV practical expedient.

Other investments **-** Consists of exchange-traded real estate investment trust securities, which are classified as Level 1. Commingled funds and limited partnership investments in hedge funds, private equity and real estate funds are valued at the NAV per fund share derived using information provided by fund managers which include various inputs such as discounted future cash flows, market based comparable data and independent appraisals from third parties. These funds are classified as Level 2 or 3 where they have readily determinable fair values, otherwise they are classified under the NAV practical expedient.

The following tables provide changes in financial assets that are measured at fair value based on Level 3 inputs that are held by institutional funds classified as:

	Fixed Income	Real Estate Funds	Total
		(In millions)	
Balance at January 1, 2017	$ 2	$ 8	$ 10
Actual return on plan assets	—	—	—
Purchases, sales or other settlements	1	(6)	(5)
Net transfers in (out) of Level 3	(1)	—	(1)
Balance at December 31, 2017	2	2	4
Actual return on plan assets	**—**	**1**	**1**
Purchases, sales or other settlements	**(2)**	**58**	**56**
Net transfers in (out) of Level 3	**—**	**—**	**—**
Balance at December 31, 2018	**$ —**	**$ 61**	**$ 61**

Contributions and estimated future benefit payments:

We expect to contribute approximately $40 million to our funded pension plans in 2019.

Estimated future benefit payments by the funded and unfunded pension plans, and the postretirement medical plan, which reflect expected future service, are as follows (in millions):

2019	$ 142
2020	139
2021	135
2022	139
2023	140
Years 2024 to 2028	722

We also have several defined contribution plans for certain eligible employees. Employees may contribute a portion of their compensation to these plans and we match a portion of the employee contributions. We recorded expense of $19 million in 2018 for contributions to these plans (2017: $22 million; 2016: $25 million).

11. Share-based Compensation

We have established and maintain a Long-term Incentive Plan (LTIP), as amended, for the granting of restricted common shares (Restricted stock), performance share units (PSUs) and stock options to our employees. At December 31, 2018, the total number of authorized common stock under the LTIP, as amended, was 51.5 million shares, of which we have 19.0 million shares available for issuance. Share-based compensation expense consisted of the following:

	2018	2017	2016
		(In millions)	
Restricted stock	**$ 40**	$ 56	$ 45
Stock options	**10**	9	7
Performance share units	**22**	21	21
Share-based compensation expense before income taxes	**$ 72**	$ 86	$ 73
Income tax benefit on share-based compensation expense	**$ —**	$ 1	$ 28

Based on share-based compensation awards outstanding at December 31, 2018, unearned compensation expense, before income taxes, will be recognized in future years as follows (in millions): 2019: $57, 2020: $30 and 2021: $6.

Our share-based compensation plans can be summarized as follows:

Restricted stock:

Restricted stock generally vests equally on an annual basis over a three-year term and are valued based on the prevailing market price of our common stock on the date of grant. The following is a summary of restricted stock award activity in 2018:

	Shares of Restricted Common Stock	Weighted - Average Price on Date of Grant
	(In thousands, except per share amounts)	
Outstanding at January 1, 2018	3,202	$ 54.04
Granted	1,258	50.78
Vested (a)	(1,099)	65.80
Forfeited	(480)	50.63
Outstanding at December 31, 2018	2,881	$ 48.70

(a) In 2018, restricted stock with fair values of $54 million were vested (2017: $37 million; 2016: $41 million).

PSUs:

PSUs generally vest three years from the date of grant and are valued based on the prevailing market price of our common stock on the date of grant. The number of shares of common stock to be issued under a PSU agreement is based on a comparison of the Corporation's total shareholder return (TSR) to the TSR of a predetermined group of peer companies over a three-year performance period ending December 31 of the year prior to settlement of the grant. Payouts of the performance share awards will range from 0% to 200% of the target awards based on the Corporation's TSR ranking within the peer group. Dividend equivalents for the performance period will accrue on performance shares, but will only be paid out on earned shares after the performance period. The following is a summary of PSU activity in 2018:

	Performance Share Units	Weighted - Average Fair Value on Date of Grant
	(In thousands, except per share amounts)	
Outstanding at January 1, 2018	1,146	$ 58.78
Granted	278	59.65
Vested (a)	(313)	76.64
Forfeited	(48)	53.62
Outstanding at December 31, 2018	1,063	$ 53.98

(a) In 2018, PSU's with fair value of $9 million were vested (2017: $10 million; 2016: $15 million).

The following weighted average assumptions were utilized to estimate the fair value of PSU awards:

	2018	2017	2016
Risk free interest rate	**2.39%**	1.55%	0.96%
Stock price volatility	**0.400**	0.387	0.329
Contractual term in years	**3.0**	3.0	3.0
Grant date price of Hess common stock	**$ 48.48**	$ 51.03	$ 44.31

Stock options:

Stock options vest over three years from the date of grant, have a 10-year term, and the exercise price equals market price of the common stock on the date of grant. The following is a summary of stock options activity in 2018:

	Number of options (In thousands)	Weighted Average Exercise Price per Share	Weighted Average Remaining Contractual Term
Outstanding at January 1, 2018	6,482	$ 66.84	3.6 years
Granted	683	48.48	
Exercised	(564)	55.84	
Forfeited	(1,431)	80.23	
Outstanding at December 31, 2018	5,170	$ 61.91	4.3 years

At December 31, 2018, there were 5.2 million outstanding stock options (3.9 million exercisable) with a weighted average remaining contractual life of 4.3 years (2.9 years for exercisable options) and an aggregated intrinsic value of 0 (0 for exercisable options).

The following weighted average assumptions were utilized to estimate the fair value of stock options:

	2018	2017	2016
Risk free interest rate	**2.74%**	2.17%	1.47%
Stock price volatility	**0.322**	0.333	0.326
Dividend yield	**2.06%**	1.96%	2.26%
Expected life in years	**6.0**	6.0	6.0
Weighted average fair value per option granted	**$ 13.69**	$ 14.51	$ 11.33

In estimating the fair value of PSUs and stock options, the risk-free interest rate is based on the vesting period of the award and is obtained from published sources. The stock price volatility is determined from the historical stock prices of the Corporation using the expected term.

12. Exit and Disposal Costs

In 2018, we incurred severance expense of $38 million (2017: $18 million; 2016: $55 million) and paid accrued severance costs of $40 million (2017: $48 million; 2016: $52 million). The severance expenses incurred during the three-year period resulted from asset sales and cost savings initiatives in response to low crude oil prices. Severance charges were based on amounts incurred under ongoing severance arrangements or other statutory requirements, plus amounts earned under enhanced benefit arrangements. We recognized the expense associated with the enhanced benefits ratably over the estimated service period required for the employee to earn the benefit upon termination. We also recorded charges for vacated office space of $73 million in 2018 (2017: $14 million).

At December 31, 2018, we had accrued liabilities for severance costs of $4 million (2017: $6 million) and accrued liabilities for exit cost provisions of $85 million (2017: $28 million). Accrued severance costs are expected to be paid in 2019, and accrued exit costs will be paid over the next several years.

13. Impairment

2017: In the third quarter, we recognized a pre-tax charge of $2,503 million ($550 million after income taxes) to impair the carrying value of our interests in Norway based on an anticipated sale of the asset, which closed in the fourth quarter of 2017. See *Note 3, Dispositions*. In the fourth quarter, we recognized pre-tax impairment charges to reduce the carrying value of our interests in the Stampede Field by $1,095 million ($1,095 million after income taxes), and the Tubular Bells Field by $605 million ($605 million after income taxes) primarily as a result of a lower long-term crude oil price outlook. The Stampede Field had significant capitalized exploration and appraisal costs that were incurred on a 100% working interest basis on the Pony discovery prior to unitizing into the Stampede project. The fourth quarter impairment charges were based on a total fair value estimate of approximately $1.1 billion that was determined using internal projected discounted cash flows. The determination of projected discounted cash flows depended on estimates of oil and gas reserves, future prices, operating costs, capital expenditures, discount rate and timing of future net cash flows.

2016: We recorded a pre-tax impairment charge of $67 million ($21 million after income taxes and noncontrolling interest) to impair older specification rail cars in our Midstream segment based on estimated salvage values, which approximated fair value.

Each of the valuation methods used in the determination of the impairment charges above represent Level 3 fair value measurements.

14. Income Taxes

The provision (benefit) for income taxes consisted of:

	2018	2017	2016 (a)
		(In millions)	
United States			
Federal			
Current	**$ 1**	$ (23)	$ (27)
Deferred taxes and other accruals	**(74)**	(6)	1,948
State	**(45)**	—	23
	(118)	(29)	1,944
Foreign			
Current (b)	**455**	179	36
Deferred taxes and other accruals	**(2)**	(1,987)	235
	453	(1,808)	271
Total	**335**	(1,837)	2,215
Adjustment of deferred taxes for foreign income tax law changes	**—**	—	7
Total Provision (Benefit) For Income Taxes	**$ 335**	$ (1,837)	$ 2,222

(a) Includes charges of $3,749 million to establish valuation allowances on net deferred tax assets.
(b) Primarily comprised of Libya in 2018 and 2017.

Income (loss) before income taxes consisted of the following:

	2018	2017	2016
		(In millions)	
United States (a)	**$ (219)**	$ (2,784)	$ (2,431)
Foreign	**439**	(2,994)	(1,423)
Total Income (Loss) Before Income Taxes	**$ 220**	$ (5,778)	$ (3,854)

(a) Includes substantially all of our interest expense, corporate expense and the results of commodity hedging activities.

The difference between our effective income tax rate and the U.S. statutory rate is reconciled below:

	2018	2017	2016
U.S. statutory rate	**21.0 %**	35.0 %	35.0 %
Effect of foreign operations (a)	**141.2**	17.4	4.6
State income taxes, net of Federal income tax	**(18.9)**	—	1.9
Change in enacted tax laws (b)	**—**	(23.6)	(0.2)
Valuation allowance adjustment with tax law change (b)	**—**	23.6	—
Rate differential on U.S. loss	**—**	(4.1)	—
Gains on asset sales, net	**—**	(2.2)	—
Impairment	**—**	—	(2.1)
Valuation allowance on current year operations	**55.2**	(14.9)	—
Valuation allowance against previously benefitted deferred tax assets	**—**	0.1	(97.3)
Noncontrolling interest in partnership	**(15.9)**	0.8	0.5
Intraperiod allocation	**(37.3)**	—	—
Equity compensation shortfall	**6.3**	(0.3)	—
Other	**0.8**	—	(0.1)
Total	**152.4 %**	31.8 %	(57.7) %

(a) The variance in effective income tax rates attributable to the effect of foreign operations primarily resulted from the mix of income among high, primarily Libya, and low tax rate jurisdictions.
(b) The enactment of the U.S. Tax Cuts and Jobs Act provided for a decrease in the corporate tax rate to 21% from 35% and a change to a territorial tax regime, resulting in a net $1,336 million reduction to our U.S. net deferred tax asset at December 31, 2017, with a corresponding reduction in the previously established U.S. valuation allowance.

The components of deferred tax liabilities and deferred tax assets at December 31 were as follows:

	2018	2017
	(In millions)	
Deferred Tax Liabilities		
Property, plant and equipment and investments	**$ (853)**	$ (629)
Other	**(77)**	(24)
Total Deferred Tax Liabilities	**(930)**	(653)
Deferred Tax Assets		
Net operating loss carryforwards	**4,239**	4,029
Tax credit carryforwards	**134**	138
Property, plant and equipment and investments	**416**	746
Accrued compensation, deferred credits and other liabilities	**232**	283
Asset retirement obligations	**225**	212
Other	**161**	36
Total Deferred Tax Assets	**5,407**	5,444
Valuation allowances (a)	**(4,877)**	(5,199)
Total deferred tax assets, net of valuation allowances	**530**	245
Net Deferred Tax Assets (Liabilities)	**$ (400)**	$ (408)

(a) *In 2018, the valuation allowance decreased by $322 million (2017: decrease of $251 million; 2016: increase of $3,872).*

In the *Consolidated Balance Sheet*, deferred tax assets and liabilities are netted by taxing jurisdiction and are recorded at December 31 as follows:

	2018	2017
	(In millions)	
Deferred income taxes (long-term asset)	**$ 21**	$ 21
Deferred income taxes (long-term liability)	**(421)**	(429)
Net Deferred Tax Assets (Liabilities)	**$ (400)**	$ (408)

At December 31, 2018, we have recognized a gross deferred tax asset related to net operating loss carryforwards of $4,239 million before application of valuation allowances. The deferred tax asset is comprised of $1,382 million attributable to foreign net operating losses which begin to expire in 2025, $2,386 million attributable to U.S. Federal operating losses which begin to expire in 2035, and $471 million attributable to losses in various U.S. states which begin to expire in 2019. The deferred tax asset attributable to foreign net operating losses, net of valuation allowances, is $12 million. A full valuation allowance is established against the deferred tax asset attributable to U.S. Federal and state net operating losses. At December 31, 2018, we have U.S. Federal, state and foreign alternative minimum tax credit carryforwards of $49 million, which can be carried forward indefinitely, and approximately $15 million of other business credit carryforwards. The deferred tax asset attributable to these credits, net of valuation allowances, is $1 million. A full valuation allowance is established against our foreign tax credit carryforwards of $70 million, which begin to expire in 2019.

At December 31, 2018, the Balance Sheet reflects a $4,877 million valuation allowance against the net deferred tax assets for multiple jurisdictions based on application of the relevant accounting standards. Hess continues to maintain a full valuation allowance against its deferred tax assets in the U.S., Denmark (hydrocarbon tax only), Malaysia, and Guyana. Management assesses the available positive and negative evidence to estimate whether sufficient future taxable income will be generated to permit the use of deferred tax assets. The cumulative loss incurred over the three-year period ending December 31, 2018 constitutes significant objective negative evidence. Such objective negative evidence limits our ability to consider subjective positive evidence, such as our projections of future taxable income, resulting in the recognition of a valuation allowance against the net deferred tax assets for these jurisdictions. The amount of the deferred tax asset considered realizable, however, could be adjusted if estimates of future taxable income change or if objective negative evidence in the form of cumulative losses is no longer present and additional weight can be given to subjective evidence.

The Company completed its review of previously recorded provisional income tax amounts related to the U.S. Tax Cuts and Jobs Act (“Act”) and concluded that additional information, interpretation and guidance that became available during the twelve-month measurement period did not alter the Company’s accounting as reported in its Consolidated Financial Statements as of December 31, 2017. There were no adjustments deemed necessary in the period ended December 31, 2018.

Below is a reconciliation of the gross beginning and ending amounts of unrecognized tax benefits:

	2018	2017	2016
		(In millions)	
Balance at January 1	**$ 205**	$ 424	$ 604
Additions based on tax positions taken in the current year	**19**	14	19
Additions based on tax positions of prior years	**36**	4	113
Reductions based on tax positions of prior years	**(78)**	(147)	(274)
Reductions due to settlements with taxing authorities	**(10)**	(85)	(27)
Reductions due to lapses in statutes of limitation	**(4)**	(5)	(11)
Balance at December 31	**$ 168**	$ 205	$ 424

The December 31, 2018 balance of unrecognized tax benefits includes $7 million that, if recognized, would impact our effective income tax rate. Over the next 12 months, it is reasonably possible that the total amount of unrecognized tax benefits could decrease between $2 million and $8 million due to settlements with taxing authorities or other resolutions, as well as lapses in statutes of limitation. At December 31, 2018, our accrued interest and penalties related to unrecognized tax benefits is $3 million (2017: $23 million).

We file income tax returns in the U.S. and various foreign jurisdictions. We are no longer subject to examinations by income tax authorities in most jurisdictions for years prior to 2005.

15. Basic and Diluted Earnings Per Common Share

The Net income (loss) and weighted average number of common shares used in basic and diluted earnings per share computation were as follows:

	2018	2017	2016
		(In millions)	
Net Income (Loss) Attributable to Hess Corporation Common Stockholders:			
Net income (loss)	**$ (115)**	$ (3,941)	$ (6,076)
Less: Net income (loss) attributable to noncontrolling interests	**167**	133	56
Less: Preferred stock dividends	**46**	46	41
Net income (loss) attributable to Hess Corporation Common Stockholders	**$ (328)**	$ (4,120)	$ (6,173)
Weighted Average Number of Common Shares Outstanding:			
Basic	**298.2**	314.1	309.9
Effect of dilutive securities			
Restricted common stock	**—**	—	—
Stock options	**—**	—	—
Performance share units	**—**	—	—
Mandatory Convertible Preferred stock	**—**	—	—
Diluted	**298.2**	314.1	309.9
Net Income (Loss) Attributable to Hess Corporation per Common Share:			
Basic	**$ (1.10)**	$ (13.12)	$ (19.92)
Diluted	**$ (1.10)**	$ (13.12)	$ (19.92)
Antidilutive shares excluded from the computation of diluted shares:			
Restricted common stock	**2.9**	3.3	3.3
Stock options	**5.5**	6.4	6.9
Performance share units	**1.1**	0.6	0.9
Common shares from conversion of preferred stock	**12.7**	12.8	11.2

16. Common and Preferred Stock

The following table provides the changes in our outstanding common shares:

	2018	2017	2016
		(In millions)	
Balance at January 1	**315.1**	316.5	286.0
Shares issued	**—**	—	28.8
Activity related to restricted stock awards, net	**0.8**	0.8	1.1
Stock options exercised	**0.6**	0.2	0.2
PSU vested	**0.1**	0.2	0.4
Shares repurchased	**(25.2)**	(2.6)	—
Balance at December 31	**291.4**	315.1	316.5

Common and Preferred Stock Issuance:

In February 2016, we issued 28,750,000 shares of common stock and depositary shares representing 575,000 shares of 8% Series A Mandatory Convertible Preferred Stock (Convertible Preferred Stock), par value $1 per share, with a liquidation preference of $1,000 per share, for total net proceeds of approximately $1.6 billion after deducting underwriting discounts, commissions, and offering expenses. The dividends on the Convertible Preferred Stock are payable on a cumulative basis. Unless converted earlier, each share of Convertible Preferred Stock will automatically convert into between 21.822 shares and 25.642 shares of our common stock based on the volume weighted average share price ("VWAP") over a period of twenty-consecutive trading days ending January 28, 2019, subject to anti-dilution adjustments. See *Note 15, Basic and Diluted Earnings Per Common Share* and *Note 22, Subsequent Event.*

We also entered into capped call transactions on 12.55 million covered shares that were expected generally to reduce the potential dilution to our common stock upon conversion of the Convertible Preferred Stock if the VWAP for any individual day during the period of twenty consecutive trading days ending January 28, 2019 exceeded $45.83 per share, subject to anti-dilution adjustments. On any day during the twenty consecutive trading days ending January 28, 2019, if the daily VWAP is between $45.83 and $53.625, the value of the capped call transactions for that day will be the proportionate covered shares multiplied by the difference between the VWAP for that day and $45.83. The number of common shares to be delivered by the counterparties to us will be the sum of each daily calculation during the twenty-consecutive trading day period. The premium paid for the capped call transactions was $37 million, which was recorded against *Capital in excess of par* in the *Statement of Consolidated Equity*. See *Note 22, Subsequent Event.*

Common Stock Repurchase Plan:

In 2018, we repurchased 25.2 million shares of our common stock (2017: 2.6 million shares) for $1,380 million (2017: $120 million), at an average cost per share of $54.85 (2017: $45.67). There were no repurchases in 2016. At December 31, 2018, we are authorized, but not required, to purchase additional common stock up to a value of $650 million.

Common stock dividends:

In 2018, 2017 and 2016, cash dividends declared on common stock totaled $1.00 per share ($0.25 per quarter).

17. Supplementary Cash Flow Information

The following information supplements the *Statement of Consolidated Cash Flows*:

	2018	2017	2016
		(In millions)	
Cash Flows from Operating Activities			
Interest paid	**$ (394)**	$ (314)	$ (338)
Net income taxes (paid) refunded	**(463)**	(210)	132
Cash Flows from Investing Activities			
Capital expenditures incurred - E&P	**$ (1,909)**	$ (1,852)	$ (1,638)
Increase (decrease) in related liabilities	**55**	64	(336)
Additions to property, plant and equipment - E&P	**$ (1,854)**	$ (1,788)	$ (1,974)
Capital expenditures incurred - Midstream	**$ (271)**	$ (121)	$ (283)
Increase (decrease) in related liabilities	**28**	(28)	6
Additions to property, plant and equipment - Midstream	**$ (243)**	$ (149)	$ (277)

18. Leased Assets

We and certain of our subsidiaries lease drilling rigs, support vessels, office space and other assets for varying periods under contractual obligations accounted for as operating leases. Operating lease expenses for drilling rigs used to drill development wells and successful exploration wells are capitalized. At December 31, 2018, future minimum rental payments applicable to non-cancelable operating leases with remaining terms in excess of one year (other than oil and gas property leases) are as follows (in millions):

2019	$ 355
2020	156
2021	65
2022	64
2023	64
Remaining years	198
Total Minimum Lease Payments	902
Less: Income from subleases	114
Net Minimum Lease Payments	$ 788

Rental expense was as follows:

	2018	2017	2016
		(In millions)	
Total rental expense	**$ 154**	$ 123	$ 106
Less: Income from subleases	**8**	10	5
Net Rental Expense	**$ 146**	$ 113	$ 101

19. Guarantees, Contingencies and Commitments

Guarantees and Contingencies

We are subject to loss contingencies with respect to various claims, lawsuits and other proceedings. A liability is recognized in our consolidated financial statements when it is probable that a loss has been incurred and the amount can be reasonably estimated. If the risk of loss is probable, but the amount cannot be reasonably estimated or the risk of loss is only reasonably possible, a liability is not accrued; however, we disclose the nature of those contingencies. We cannot predict with certainty if, how or when existing claims, lawsuits and proceedings will be resolved or what the eventual relief, if any, may be, particularly for proceedings that are in their early stages of development or where plaintiffs seek indeterminate damages. Numerous issues may need to be resolved, including through lengthy discovery, conciliation and/or arbitration proceedings, or litigation before a loss or range of loss can be reasonably estimated. Subject to the foregoing, in management's opinion, based upon currently known facts and circumstances, the outcome of such lawsuits, claims and proceedings, including the matters described below, is not expected to have a material adverse effect on our financial condition. However, we could incur judgments, enter into settlements, or revise our opinion regarding the outcome of certain matters, and such developments could have a material adverse effect on our results of operations in the period in which the amounts are accrued and our cash flows in the period in which the amounts are paid.

We, along with many companies that have been or continue to be engaged in refining and marketing of gasoline, have been a party to lawsuits and claims related to the use of methyl tertiary butyl ether (MTBE) in gasoline. A series of similar lawsuits, many involving water utilities or governmental entities, were filed in jurisdictions across the U.S. against producers of MTBE and petroleum refiners who produced gasoline containing MTBE, including us. The principal allegation in all cases was that gasoline containing MTBE was a defective product and that these producers and refiners are strictly liable in proportion to their share of the gasoline market for damage to groundwater resources and are required to take remedial action to ameliorate the alleged effects on the environment of releases of MTBE. The majority of the cases asserted against us have been settled. There are three remaining active cases, filed by Pennsylvania, Rhode Island, and Maryland. In June 2014, the Commonwealth of Pennsylvania filed a lawsuit alleging that we and all major oil companies with operations in Pennsylvania, have damaged the groundwater by introducing thereto gasoline with MTBE. The Pennsylvania suit has been forwarded to the existing MTBE multidistrict litigation pending in the Southern District of New York. In September 2016, the State of Rhode Island also filed a lawsuit alleging that we and other major oil companies damaged the groundwater in Rhode Island by introducing thereto gasoline with MTBE. The suit filed in Rhode Island is proceeding in Federal court. In December 2017, the State of Maryland filed a lawsuit alleging that we and other major oil companies damaged the groundwater in Maryland by introducing thereto gasoline with MTBE. The suit filed in Maryland state court, was served on us in January 2018 and has been removed to Federal court by the defendants.

In September 2003, we received a directive from the New Jersey Department of Environmental Protection (NJDEP) to remediate contamination in the sediments of the Lower Passaic River. The NJDEP is also seeking natural resource damages. The directive, insofar as it affects us, relates to alleged releases from a petroleum bulk storage terminal in Newark, New Jersey we previously owned. We and over 70 companies entered into an Administrative Order on Consent with the Environmental Protection Agency (EPA) to study the same contamination; this work remains ongoing. We and other parties settled a cost recovery claim by the State of New Jersey and also agreed with EPA to fund remediation of a portion of the site. On March 4, 2016, the EPA issued a Record of Decision (ROD) in respect of the lower eight miles of the Lower Passaic River, selecting a remedy that includes bank-to-bank dredging at an estimated cost of $1.38 billion. The ROD does not address the upper nine miles of the Lower Passaic River or the Newark Bay, which may require additional remedial action. In addition, the Federal trustees for natural resources have begun a separate assessment of damages to natural resources in the Passaic River. Given that the EPA has not selected a remedy for the entirety of the Lower Passaic River or the Newark Bay, total remedial costs cannot be reliably estimated at this time. Based on currently known facts and circumstances, we do not believe that this matter will result in a significant liability to us because our former terminal did not store or use contaminants which are of concern in the river sediments and could not have contributed contamination along the river's length. Further, there are numerous other parties who we expect will bear the cost of remediation and damages.

In March 2014, we received an Administrative Order from EPA requiring us and 26 other parties to undertake the Remedial Design for the remedy selected by the EPA for the Gowanus Canal Superfund Site in Brooklyn, New York. The remedy includes dredging of surface sediments and the placement of a cap over the deeper sediments throughout the Canal and in-situ stabilization of certain contaminated sediments that will remain in place below the cap. EPA has estimated that this remedy will cost $506 million; however, the ultimate costs that will be incurred in connection with the design and implementation of the remedy remain uncertain. Our alleged liability derives from our former ownership and operation of a fuel oil terminal and connected ship-building and repair facility adjacent to the Canal. We indicated to EPA that we would comply with the

Administrative Order and are currently contributing funding for the Remedial Design based on an interim allocation of costs among the parties. At the same time, we are participating in an allocation process whereby a neutral expert selected by the parties will determine the final shares of the Remedial Design costs to be paid by each of the participants.

On September 28, 2017, we received a general notice letter and offer to settle from the U.S. Environmental Protection Agency relating to Superfund claims for the Ector Drum, Inc. Superfund Site in Odessa, Texas. The EPA and Texas Commission on Environmental Quality (TCEQ) took clean-up and response action at the site commencing in 2014 and concluded in December 2015. The site was determined to have improperly stored industrial waste, including drums with oily liquids. The total clean-up cost incurred by the EPA was approximately $3.5 million. We were invited to negotiate a voluntary settlement for our purported share of the clean-up costs. Our share, if any, is undetermined.

From time to time, we are involved in other judicial and administrative proceedings, including proceedings relating to other environmental matters. We cannot predict with certainty if, how or when such proceedings will be resolved or what the eventual relief, if any, may be, particularly for proceedings that are in their early stages of development or where plaintiffs seek indeterminate damages. Numerous issues may need to be resolved, including through potentially lengthy discovery and determination of important factual matters before a loss or range of loss can be reasonably estimated for any proceeding.

Subject to the foregoing, in management's opinion, based upon currently known facts and circumstances, the outcome of the aforementioned proceedings is not expected to have a material adverse effect on our financial condition, results of operations or cash flows.

Unconditional Purchase Obligations and Commitments

The following table shows aggregate information for certain unconditional purchase obligations and commitments at December 31, 2018, which are not included elsewhere within these *Consolidated Financial Statements*:

		Payments Due by Period			
	Total	2019	2020 and 2021	2022 and 2023	Thereafter
			(In millions)		
Capital expenditures	$ 1,069	$ 443	$ 551	$ 75	$ —
Operating expenses	433	219	99	61	54
Transportation and related contracts	1,050	212	401	336	101

20. Segment Information

We currently have two operating segments, Exploration and Production (E&P) and Midstream. The E&P operating segment explores for, develops, produces, purchases and sells crude oil, NGLs and natural gas. Production operations over the three years ended December 31, 2018 were primarily in the United States (U.S.), Denmark, the JDA and Malaysia, and from divested assets, including Equatorial Guinea (until November 2017) and Norway (until December 2017). The Midstream operating segment provides fee-based services including crude oil and natural gas gathering, processing of natural gas and the fractionation of NGLs, transportation of crude oil by rail car, terminaling and loading crude oil and NGLs, storing and terminaling propane, and water handling services primarily in the Bakken shale play of North Dakota. All unallocated costs are reflected under Corporate, Interest and Other.

The following table presents operating segment financial data (in millions):

	Exploration and Production	Midstream	Corporate, Interest and Other	Eliminations	Total
2018					
Sales and Other Operating Revenues - Third-parties	**$ 6,323**	**$ —**	**$ —**	**$ —**	**$ 6,323**
Intersegment Revenues	**—**	**713**	**—**	**(713)**	**—**
Sales and Other Operating Revenues	**$ 6,323**	**$ 713**	**$ —**	**$ (713)**	**$ 6,323**
Net Income (Loss) Attributable to Hess Corporation	**$ 51**	**$ 120**	**$ (453)**	**$ —**	**$ (282)**
Interest Expense	**—**	**60**	**339**	**—**	**399**
Depreciation, Depletion and Amortization	**1,748**	**127**	**8**	**—**	**1,883**
Provision (Benefit) for Income Taxes (a)	**391**	**38**	**(94)**	**—**	**335**
Investment in Affiliates	**126**	**67**	**—**	**—**	**193**
Identifiable Assets	**16,109**	**3,285**	**2,039**	**—**	**21,433**
Capital Expenditures	**1,909**	**271**	**—**	**—**	**2,180**
2017					
Sales and Other Operating Revenues - Third-parties	$ 5,460	$ 6	$ —	$ —	$ 5,466
Intersegment Revenues	—	611	—	(611)	—
Sales and Other Operating Revenues	$ 5,460	$ 617	$ —	$ (611)	$ 5,466
Net Income (Loss) Attributable to Hess Corporation	$ (3,653)	$ 42	$ (463)	$ —	$ (4,074)
Interest Expense	—	26	299	—	325
Depreciation, Depletion and Amortization	2,736	123	24	—	2,883
Impairment	4,203	—	—	—	4,203
Provision (Benefit) for Income Taxes (a)	(1,842)	31	(26)	—	(1,837)
Investment in Affiliates	134	—	—	—	134
Identifiable Assets	15,613	3,329	4,170	—	23,112
Capital Expenditures	1,852	121	—	—	1,973
2016					
Sales and Other Operating Revenues - Third-parties	$ 4,755	$ 7	$ —	$ —	$ 4,762
Intersegment Revenues	—	562	—	(562)	—
Sales and Other Operating Revenues	$ 4,755	$ 569	$ —	$ (562)	$ 4,762
Net Income (Loss) Attributable to Hess Corporation	$ (4,964)	$ 42	$ (1,210)	$ —	$ (6,132)
Interest Expense	—	19	319	—	338
Depreciation, Depletion and Amortization	3,113	121	10	—	3,244
Impairment	—	67	—	—	67
Provision (Benefit) for Income Taxes	1,587	26	609	—	2,222
Capital Expenditures	1,638	283	—	—	1,921

(a) *The provision for income taxes in the Midstream segment in 2018 and 2017 is presented before consolidating its operations with other U.S. activities of the Company and prior to evaluating realizability of net U.S. deferred taxes. An offsetting impact is presented in the E&P segment.*

The following table presents financial information by major geographic area:

	United States	Europe	Africa	Asia and Other Countries	Corporate, Interest and other	Total
			(In millions)			
2018						
Sales and Other Operating Revenues	**$ 4,842**	**$ 164**	**$ 548**	**$ 769**	**$ —**	**$ 6,323**
Net Income (Loss) Attributable to Hess Corporation	**131**	**42**	**36**	**(38)**	**(453)**	**(282)**
Depreciation, Depletion and Amortization	**1,424**	**37**	**19**	**395**	**8**	**1,883**
Provision (Benefit) for Income Taxes	**(25)**	**15**	**430**	**9**	**(94)**	**335**
Identifiable Assets	**13,250**	**1,033**	**395**	**4,716**	**2,039**	**21,433**
Property, Plant and Equipment (Net)	**11,653**	**906**	**355**	**3,154**	**15**	**16,083**
Capital Expenditures	**1,543**	**8**	**9**	**620**	**—**	**2,180**
2017						
Sales and Other Operating Revenues	$ 3,692	$ 629	$ 675	$ 470	$ —	$ 5,466
Net Income (Loss) Attributable to Hess Corporation	(2,433)	(1,383)	259	(54)	(463)	(4,074)
Depreciation, Depletion and Amortization	1,942	381	263	273	24	2,883
Impairment	1,700	2,503	—	—	—	4,203
Provision (Benefit) for Income Taxes	—	(1,999)	197	(9)	(26)	(1,837)
Identifiable Assets	13,640	1,024	428	3,850	4,170	23,112
Property, Plant and Equipment (Net)	11,894	946	365	2,964	23	16,192
Capital Expenditures	1,387	141	30	415	—	1,973
2016						
Sales and Other Operating Revenues	$ 3,085	$ 610	$ 601	$ 466	$ —	$ 4,762
Net Income (Loss) Attributable to Hess Corporation	(2,353)	(439)	(355)	(1,775)	(1,210)	(6,132)
Depreciation, Depletion and Amortization	2,133	502	375	224	10	3,244
Impairment	67	—	—	—	—	67
Provision (Benefit) for Income Taxes	411	243	244	715	609	2,222
Capital Expenditures	1,400	59	10	452	—	1,921

21. Financial Risk Management Activities

In the normal course of our business, we are exposed to commodity risks related to changes in the prices of crude oil and natural gas as well as changes in interest rates and foreign currency values. In the disclosures that follow, corporate financial risk management activities refer to the mitigation of these risks through hedging activities. We maintain a control environment for all of our financial risk management activities under the direction of our Chief Risk Officer. Our Treasury department is responsible for administering foreign exchange rate and interest rate hedging programs using similar controls and processes, where applicable. Hedging strategies are reviewed annually by the Audit Committee of the Board of Directors.

Corporate Financial Risk Management Activities: Financial risk management activities include transactions designed to reduce risk in the selling prices of crude oil or natural gas we produce or by reducing our exposure to foreign currency or interest rate movements. Generally, futures, swaps or option strategies may be used to fix the forward selling price of a portion of our crude oil or natural gas production. Forward contracts may also be used to purchase certain currencies in which we conduct business with the intent of reducing exposure to foreign currency fluctuations. At December 31, 2018, these forward contracts relate to the British Pound. Interest rate swaps may be used to convert interest payments on certain long-term debt from fixed to floating rates.

Gross notional amounts of both long and short positions are presented in the volume tables beginning below. These amounts include long and short positions that offset in closed positions and have not reached contractual maturity. Gross notional amounts do not quantify risk or represent assets or liabilities of the Corporation, but are used in the calculation of cash settlements under the contracts.

The gross notional amounts of outstanding financial risk management derivative contracts related to WTI instruments as of the dates shown below were as follows:

	December 31, 2018	December 31, 2017
Calendar year program	**2019**	2018
Instrument type	**Puts**	Collars
Crude oil volumes (millions of barrels)	**34.7**	42.0
Ceiling price	**N/A**	$ 65
Floor price	**$ 60**	$ 50

At December 31, 2017, we had WTI crude oil price collars for calendar year 2018 with a monthly floor price of $50 per barrel and a monthly ceiling price of $65 per barrel for 115,000 bopd. In the first quarter of 2018, we bought back the WTI $65 call options within the crude oil price collars for the period of May 1, 2018 through December 31, 2018. In 2018, we purchased WTI put options for calendar year 2019 with a WTI monthly floor price of $60 per barrel for 95,000 bopd.

The gross notional amounts of outstanding financial risk management derivative contracts, excluding commodity contracts, were as follows:

	December 31, 2018	December 31, 2017
	(In millions)	
Foreign exchange	**$ 16**	$ 52
Interest rate swaps	**$ 100**	$ 450

The table below reflects the gross and net fair values of risk management derivative instruments and their respective financial statement caption in the *Consolidated Balance Sheet*:

	Assets	Liabilities
	(In millions)	
December 31, 2018		
Derivative Contracts Designated as Hedging Instruments		
Commodity - Other current assets	**$ 484**	**$ —**
Interest rate - Other liabilities and deferred credits (noncurrent)	**—**	**(2)**
Total derivative contracts designated as hedging instruments	**484**	**(2)**
Gross fair value of derivative contracts	**484**	**(2)**
Master netting arrangements	**—**	**—**
Net Fair Value of Derivative Contracts	**$ 484**	**$ (2)**
December 31, 2017		
Derivative Contracts Designated as Hedging Instruments		
Commodity - Accounts payable	$ —	$ (7)
Interest rate - Other assets (noncurrent) and Accounts payable	—	(4)
Total derivative contracts designated as hedging instruments	—	(11)
Derivative Contracts Not Designated as Hedging Instruments		
Commodity - Accounts payable	—	(2)
Foreign exchange - Accounts receivable: Joint venture and other	1	—
Total derivative contracts not designated as hedging instruments	1	(2)
Gross fair value of derivative contracts	1	(13)
Master netting arrangements	—	—
Net Fair Value of Derivative Contracts	$ 1	$ (13)

All fair values above are based on Level 2 inputs.

Impact on statement of consolidated income from derivative contracts designated as hedging instruments:

Crude oil derivatives: In 2018, crude oil price hedging contracts decreased Sales and other operating revenues by $161 million (2017: decrease of $34 million; 2016: $0). At December 31, 2018, pre-tax deferred gains in Accumulated other comprehensive income (loss) related to outstanding crude oil price hedging contracts were $365 million, of which all will be reclassified into earnings during the next 12 months as the hedged crude oil sales are recognized in earnings.

Interest rate swaps designated as fair value hedges: At December 31, 2018, we had interest rate swaps with gross notional amounts of $100 million (2017: $450 million), which were designated as fair value hedges and relate to debt where we have converted interest payments on certain long-term debt from fixed to floating rates. During 2018, we terminated interest rate swaps with a gross notional amount of $350 million and paid $3 million (2017: $0; 2016: $5 million proceeds). See *Note 8, Debt*. Changes in the fair value of interest rate swaps and the hedged fixed-rate debt are recorded in *Interest expense* in the *Statement of Consolidated Income*. In 2018, the change in fair value of interest rate swaps was an increase in the derivative liability of $1 million (2017: $4 million increase in liability; 2016: $6 million increase in asset) with a corresponding adjustment in the carrying value of the hedged fixed-rate debt.

Interest rate swaps designated as cash flow hedges: During 2017, HIP entered into interest rate swaps with gross notional amounts totaling $553 million to convert interest payments on certain long-term debt from floating to fixed rates before settling these instruments for a payment of $3 million as part of the refinancing that occurred later in the year. See *Note 8, Debt*.

Impact on statement of consolidated income from derivative contracts not designated as hedging instruments:

Crude oil collars: In 2018, noncash adjustments to de-designated crude oil price hedging contracts decreased Sales and other operating revenues by $22 million (2017: decrease of $25 million).

Foreign exchange: Total foreign exchange gains and losses were a loss of $5 million in 2018 (2017: gain of $15 million; 2016: gain of $26 million) and are reported in *Other, net* in Revenues and non-operating income in the *Statement of Consolidated Income.* A component of foreign exchange gains or losses is the result of foreign exchange derivative contracts that are not designated as hedges, which amounted to a loss of $2 million in 2018 (2017: gain of $3 million; 2016: gain of $62 million).

After-tax foreign currency translation adjustments included in the *Statement of Consolidated Comprehensive Income* amounted to gains of $144 million in 2017 and $56 million in 2016. In 2017, $900 million of cumulative currency translation losses were recognized in earnings as a result of the sale of our assets in Norway. See *Note 3, Dispositions*.

Credit Risk: We are exposed to credit risks that may at times be concentrated with certain counterparties, groups of counterparties or customers. Accounts receivable are generated from a diverse domestic and international customer base. At December 31, 2018, our Accounts receivable were concentrated with the following counterparty industry segments: Financial Institutions — 34%, Integrated companies — 24%, Independent E&P companies — 22%, National oil companies — 7% Refining and marketing companies — 5%, Storage and transportation companies — 3%, and Others — 5%. We reduce risk related to certain counterparties, where applicable, by using master netting arrangements and requiring collateral, generally cash or letters of credit.

At December 31, 2018, we had outstanding letters of credit totaling $284 million (2017: $246 million).

Fair Value Measurement: At December 31, 2018, outstanding total debt, excluding capital leases, was substantially comprised of fixed rate debt instruments with a carrying value of $6,403 million and a fair value of $6,225 million, based on Level 2 inputs in the fair value measurement hierarchy. We also have short-term financial instruments, primarily cash equivalents, accounts receivable and accounts payable, for which the carrying value approximated fair value at December 31, 2018 and December 31, 2017.

22. Subsequent Event

On January 31, 2019, the 8.00% Series A Mandatory Convertible Preferred Stock (Preferred Stock) automatically converted into shares of common stock at a rate of 21.822 shares of common stock per share of Preferred Stock. In total, the Preferred Stock was converted into approximately 12.5 million shares of common stock. In connection with the Preferred Stock offering in 2016, the Company entered into capped call transactions to reduce the potential dilution to the Company’s common stock upon conversion of the Preferred Stock, subject to a cap. The Company received approximately 0.9 million shares of common stock upon settlement of the capped call transactions. As a result, the net number of common shares issued by the Company upon conversion of the Preferred Stock was approximately 11.6 million shares.

SUPPLEMENTARY OIL AND GAS DATA (UNAUDITED)

The *Supplementary Oil and Gas Data* that follows is presented in accordance with ASC 932, *Disclosures about Oil and Gas Producing Activities,* and includes (1) costs incurred, capitalized costs and results of operations relating to oil and gas producing activities, (2) net proved oil and gas reserves and (3) a standardized measure of discounted future net cash flows relating to proved oil and gas reserves, including a reconciliation of changes therein.

During the three-year period ended December 31, 2018, we produced crude oil, NGLs and natural gas principally in the United States (U.S.), Europe (Norway until December 2017 and Denmark), Africa (Equatorial Guinea until November 2017 and Libya) and Asia and Other (the Malaysia/Thailand Joint Development Area (JDA), and Malaysia). Exploration activities were also conducted, or are planned, in certain of these areas as well as additional countries. See *Note 3, Dispositions* in the *Notes to Consolidated Financial Statements*.

Costs Incurred in Oil and Gas Producing Activities

For the Years Ended December 31	Total	United States	Europe (b)	Africa	Asia and Other
			(In millions)		
2018					
Property acquisitions					
Unproved	**$ 51**	**$ 43**	**$ —**	**$ —**	**$ 8**
Proved	**43**	**43**	**—**	**—**	**—**
Exploration	**442**	**111**	**—**	**—**	**331**
Production and development capital expenditures (a)	**1,577**	**1,239**	**(7)**	**9**	**336**
2017					
Property acquisitions					
Unproved	$ 46	$ 46	$ —	$ —	$ —
Proved	—	—	—	—	—
Exploration	322	94	1	—	227
Production and development capital expenditures (a)	1,687	1,160	146	40	341
2016					
Property acquisitions					
Unproved	$ 11	$ 11	$ —	$ —	$ —
Proved	—	—	—	—	—
Exploration	491	211	6	(2)	276
Production and development capital expenditures (a)	1,181	999	(64)	(58)	304

(a) Includes an increase of $44 million for asset retirement obligations related to net accruals and revisions in 2018 (2017: $8 million increase; 2016: $188 million decrease).
(b) Costs incurred in oil and gas producing activities in Norway, including net accruals and revisions for asset retirement obligations, amounted to a net credit of $19 million for the year ended December 31, 2016.

Capitalized Costs Relating to Oil and Gas Producing Activities

	At December 31, 2018	At December 31, 2017
	(In millions)	
Unproved properties	**$ 394**	$ 520
Proved properties	**3,124**	3,162
Wells, equipment and related facilities	**26,173**	25,550
Total costs	**29,691**	29,232
Less: Reserve for depreciation, depletion, amortization and lease impairment	**16,361**	15,654
Net Capitalized Costs	**$ 13,330**	$ 13,578

Results of Operations for Oil and Gas Producing Activities

The results of operations shown below exclude non-oil and gas producing activities, primarily gains (losses) on sales of oil and gas properties, sales of purchased crude oil, NGLs and natural gas, interest expense and non-operating income. Therefore, these results are on a different basis than the net income (loss) from E&P operations reported in Management's Discussion and Analysis of Financial Condition and Results of Operations and in *Note 20, Segment Information* in the *Notes to Consolidated Financial Statements*.

For the Years Ended December 31	Total	United States	Europe (b)	Africa	Asia and Other
			(In millions)		
2018					
Sales and Other Operating Revenues	**$ 4,515**	**$ 3,141**	**$ 164**	**$ 455**	**$ 755**
Costs and Expenses					
Operating costs and expenses	**941**	**697**	**71**	**32**	**141**
Production and severance taxes	**171**	**165**	**—**	**—**	**6**
Midstream tariffs	**648**	**648**	**—**	**—**	**—**
Exploration expenses, including dry holes and lease impairment	**362**	**119**	**—**	**1**	**242**
General and administrative expenses	**258**	**230**	**22**	**—**	**6**
Depreciation, depletion and amortization	**1,748**	**1,297**	**37**	**19**	**395**
Total Costs and Expenses	**4,128**	**3,156**	**130**	**52**	**790**
Results of Operations Before Income Taxes	**387**	**(15)**	**34**	**403**	**(35)**
Provision (benefit) for income taxes	**337**	**(63)**	**14**	**376**	**10**
Results of Operations	**$ 50**	**$ 48**	**$ 20**	**$ 27**	**$ (45)**
2017					
Sales and Other Operating Revenues	$ 4,128	$ 2,335	$ 628	$ 700	$ 465
Costs and Expenses					
Operating costs and expenses	1,250	652	275	186	137
Production and severance taxes	119	116	—	1	2
Midstream tariffs	543	543	—	—	—
Exploration expenses, including dry holes and lease impairment	507	106	1	280	120
General and administrative expenses	225	208	10	4	3
Depreciation, depletion and amortization	2,736	1,819	381	263	273
Impairment	4,203	1,700	2,503	—	—
Total Costs and Expenses	9,583	5,144	3,170	734	535
Results of Operations Before Income Taxes	(5,455)	(2,809)	(2,542)	(34)	(70)
Provision (benefit) for income taxes	(1,873)	(47)	(2,014)	197	(9)
Results of Operations	$ (3,582)	$ (2,762)	$ (528)	$ (231)	$ (61)
2016					
Sales and Other Operating Revenues	$ 3,628	$ 2,056	$ 597	$ 519	$ 456
Costs and Expenses					
Operating costs and expenses	1,662	920	321	249	172
Production and severance taxes	101	94	1	—	6
Midstream tariffs	497	497	—	—	—
Exploration expenses, including dry holes and lease impairment	1,442	342	6	—	1,094
General and administrative expenses	232	215	1	7	9
Depreciation, depletion and amortization	3,113	2,012	502	375	224
Total Costs and Expenses	7,047	4,080	831	631	1,505
Results of Operations Before Income Taxes	(3,419)	(2,024)	(234)	(112)	(1,049)
Provision (benefit) for income taxes (a)	1,549	379	208	244	718
Results of Operations	$ (4,968)	$ (2,403)	$ (442)	$ (356)	$ (1,767)

(a) Includes charges to establish valuation allowances against net deferred tax assets amounting to $2,920 million. The charge is attributed to the geographic region in which the operations occurred that gave rise to the net deferred tax asset (United States - $1,144 million, Europe - $486 million, Africa - $249 million and Asia & Other - $1,041 million).

(b) Results of operations for oil and gas producing activities in Norway for the year ended December 31, 2016 (in millions) were as follows:

Sales and Other Operating Revenues	*$ 419*
Costs and Expenses	
Operating costs and expenses	*252*
Production and severance taxes	*—*
General and administrative expenses	*6*
Depreciation, depletion and amortization	*362*
Total Costs and Expenses	*620*
Results of Operations Before Income Taxes	*(201)*
Provision (benefit) for income taxes	*(157)*
Results of Operations	*$ (44)*

Proved Oil and Gas Reserves

Our proved oil and gas reserves are calculated in accordance with the Securities and Exchange Commission (SEC) regulations and the requirements of the Financial Accounting Standards Board. Proved oil and gas reserves are quantities, which by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from known reservoirs under existing economic conditions, operating methods and government regulations. Our estimation of net recoverable quantities of liquid hydrocarbons and natural gas is a highly technical process performed by our internal teams of geoscience and reservoir engineering professionals. Estimates of reserves were prepared by the use of appropriate geologic, petroleum engineering, and evaluation principles and techniques that are in accordance with practices generally recognized by the petroleum industry as presented in the publication of the Society of Petroleum Engineers entitled “Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (Revision as of February 19, 2007).” The method or combination of methods used in the analysis of each reservoir is based on the maturity of the reservoir, the completeness of the subsurface data available at the time of the estimate, the stage of reservoir development and the production history. Where applicable, reliable technologies may be used in reserve estimation, as defined in the SEC regulations. These technologies, including computational methods, must have been field tested and demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation. In order for reserves to be classified as proved, any required government approvals must be obtained and depending on the cost of the project, either senior management or the Board of Directors must commit to fund the development. Our proved reserves are subject to certain risks and uncertainties, which are discussed in *Item 1A. Risk Factors* of this Form 10-K.

Internal Controls

The Corporation maintains internal controls over its oil and gas reserve estimation processes, which are administered by our Global Reserves group and our Chief Financial Officer. Estimates of reserves are prepared by technical staff who work directly with the oil and gas properties using industry standard reserve estimation principles, definitions and methodologies. Each year, reserve estimates of the Corporation’s assets are subject to internal technical audits and reviews. In addition, an independent third-party reserve engineer reviews and audits a significant portion of the Corporation’s reported reserves (see pages 85 through 90). Reserve estimates are reviewed by senior management and the Board of Directors.

Qualifications

The person primarily responsible for overseeing the preparation of the Corporation’s oil and gas reserves during 2018 was Mr. Kenneth Kosco, Senior Manager, Global Reserves. Mr. Kosco is a member of the Society of Petroleum Engineers and has 30 years of experience in the oil and gas industry with a BS degree in Petroleum Engineering. His experience has been primarily focused on oil and gas subsurface understanding and reserves estimation in both domestic and international areas. Mr. Kosco is responsible for the Corporation’s Global Reserves group, which is the internal organization responsible for establishing the policies and processes used within the operating units to estimate reserves and perform internal technical reserve audits and reviews.

Reserves Audit

We engaged the consulting firm of DeGolyer and MacNaughton (D&M) to perform an audit of the internally prepared reserve estimates on certain fields aggregating 80% of 2018 year-end reported reserve quantities on a barrel of oil equivalent basis (2017: 80%). The purpose of this audit was to provide additional assurance on the reasonableness of internally prepared reserve estimates and compliance with SEC regulations. The D&M letter report, dated February 6, 2019, on the Corporation’s estimated oil and gas reserves was prepared using standard geological and engineering methods generally recognized in the petroleum industry. D&M is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world for over 70 years. D&M’s letter report on the Corporation’s December 31, 2018 oil and gas reserves is included as an exhibit to this Form 10-K. While the D&M report should be read in its entirety, the report concludes that for the properties reviewed by D&M, the total net proved reserve estimates prepared by Hess and audited by D&M, in the aggregate, differed by less than 1% (2017: 4%) of total audited net proved reserves on a barrel of oil equivalent basis. The report also includes among other information, the qualifications of the technical person primarily responsible for overseeing the reserve audit.

Crude Oil Prices Used to Estimate Proved Reserves

Proved reserves are calculated using the average price during the twelve-month period before December 31 determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within the year, unless prices are defined by contractual agreements, excluding escalations based on future conditions. Crude oil prices used in the determination of proved reserves at December 31, 2018 were $65.55 per barrel for WTI (2017: $51.19; 2016: $42.68) and $72.08 per barrel for Brent (2017: $54.87; 2016: $44.45). New York Mercantile Exchange (NYMEX) natural gas prices used were $3.01 per mcf in 2018 (2017: $3.03; 2016: $2.54).

At December 31, 2018, spot prices for WTI oil closed at $45.41 per barrel. If crude oil prices during 2019 average below those used in determining 2018 proved reserves, we may recognize negative revisions to our proved reserves at December 31, 2019, which can vary significantly by asset due to differing cost structures. Conversely, if crude oil prices in 2019 remain above those used in determining 2018 proved reserves, we could recognize positive revisions to our proved reserves at December 31, 2019. It is difficult to estimate the magnitude of any potential negative or positive change in proved reserves at December 31, 2019, due to a number of factors that are currently unknown, including 2019 crude oil prices, any revisions based on 2019 reservoir performance, and the levels to which industry costs will change in response to movements in commodity prices.

Following are the Corporation's proved reserves:

	Crude Oil & Condensate (Millions of bbls)					Natural Gas Liquids (Millions of bbls)			
	United States	Europe (b)	Africa	Asia & Other	Total	United States	Europe (b)	Asia & Other	Total
Net Proved Reserves									
At January 1, 2016	346	203	172	5	726	74	27	—	101
Revisions of previous estimates (a)	42	(14)	2	1	31	23	(19)	—	4
Extensions, discoveries and other additions	12	33	—	—	45	5	—	—	5
Sales of minerals in place	—	—	—	—	—	—	—	—	—
Production	(45)	(12)	(12)	(1)	(70)	(16)	—	—	(16)
At December 31, 2016	355	210	162	5	732	86	8	—	94
Revisions of previous estimates (a)	13	5	(6)	—	12	56	—	—	56
Extensions, discoveries and other additions	127	2	—	45	174	50	—	—	50
Sales of minerals in place	(21)	(158)	(15)	—	(194)	(6)	(8)	—	(14)
Production	(41)	(10)	(13)	(1)	(65)	(15)	—	—	(15)
At December 31, 2017	433	49	128	49	659	171	—	—	171
Revisions of previous estimates (a)	**(3)**	**(10)**	**(2)**	**(2)**	**(17)**	**(14)**	—	—	**(14)**
Extensions, discoveries and other additions	**114**	**2**	**7**	**2**	**125**	**39**	—	—	**39**
Purchase of minerals in place	**3**	—	—	—	**3**	**1**	—	—	**1**
Sales of minerals in place	**(3)**	—	—	—	**(3)**	**(8)**	—	—	**(8)**
Production	**(43)**	**(2)**	**(7)**	**(1)**	**(53)**	**(14)**	—	—	**(14)**
At December 31, 2018	**501**	**39**	**126**	**48**	**714**	**175**	—	—	**175**
Net Proved Developed Reserves									
At January 1, 2016	253	114	148	5	520	51	12	—	63
At December 31, 2016	245	116	138	5	504	59	3	—	62
At December 31, 2017	239	45	112	5	401	87	—	—	87
At December 31, 2018	**266**	**38**	**111**	**4**	**419**	**85**	—	—	**85**
Net Proved Undeveloped Reserves									
At January 1, 2016	93	89	24	—	206	23	15	—	38
At December 31, 2016	110	94	24	—	228	27	5	—	32
At December 31, 2017	194	4	16	44	258	84	—	—	84
At December 31, 2018	**235**	**1**	**15**	**44**	**295**	**90**	—	—	**90**

(a) *Revisions resulting from the impact of price changes in production sharing contracts reduced proved crude oil and condensate reserves in 2018 by 3 million, primarily in Guyana. (2017: 0 million barrels; 2016: 1 million barrels increase).*

(b) *Our Norwegian operations were sold in 2017. Crude oil and condensate and NGLs proved reserves in Norway for 2016 were as follows:*

	Crude Oil & Condensate (Millions of bbls)	*Natural Gas Liquids (Millions of bbls)*
At January 1, 2016	*171*	*27*
Revisions of previous estimates	*(2)*	*(19)*
Extensions, discoveries and other additions	*4*	*—*
Sales of minerals in place	*—*	*—*
Production	*(8)*	*—*
At December 31,2016	*165*	*8*
Net Proved Developed Reserves at December 31, 2016	*75*	*3*
Net Proved Undeveloped Reserves at December 31, 2016	*90*	*5*

	Natural Gas					Total				
	United States	Europe (c)	Africa	Asia & Other	Total	United States	Europe (c)	Africa	Asia & Other	Total
	(Millions of mcf)					(Millions of boe)				
Net Proved Reserves										
At January 1, 2016	505	234	148	667	1,554	504	269	197	116	1,086
Revisions of previous estimates (a)	116	(38)	(3)	160	235	84	(39)	1	28	74
Extensions, discoveries and other additions	73	41	—	—	114	29	40	—	—	69
Sales of minerals in place	—	—	—	—	—	—	—	—	—	—
Production (b)	(104)	(17)	(2)	(83)	(206)	(78)	(15)	(12)	(15)	(120)
At December 31, 2016	590	220	143	744	1,697	539	255	186	129	1,109
Revisions of previous estimates (a)	171	31	(2)	28	228	97	10	(6)	5	106
Extensions, discoveries and other additions	219	7	—	176	402	214	3	—	74	291
Sales of minerals in place	(18)	(153)	(15)	—	(186)	(29)	(192)	(18)	—	(239)
Production (b)	(82)	(13)	(2)	(103)	(200)	(70)	(12)	(13)	(18)	(113)
At December 31, 2017	880	92	124	845	1,941	751	64	149	190	1,154
Revisions of previous estimates (a)	**(24)**	**(14)**	**1**	**(21)**	**(58)**	**(21)**	**(12)**	**(3)**	**(5)**	**(41)**
Extensions, discoveries and other additions	**177**	**3**	**8**	**104**	**292**	**183**	**3**	**8**	**19**	**213**
Purchase of minerals in place	—	—	—	—	—	**4**	—	—	—	**4**
Sales of minerals in place	**(145)**	—	—	—	**(145)**	**(35)**	—	—	—	**(35)**
Production (b)	**(75)**	**(3)**	**(5)**	**(132)**	**(215)**	**(70)**	**(3)**	**(7)**	**(23)**	**(103)**
At December 31, 2018	**813**	**78**	**128**	**796**	**1,815**	**812**	**52**	**147**	**181**	**1,192**
Net Proved Developed Reserves										
At January 1, 2016	368	123	137	643	1,271	365	147	171	112	795
At December 31, 2016	404	125	132	739	1,400	371	140	160	128	799
At December 31, 2017	526	80	117	696	1,419	414	58	132	121	725
At December 31, 2018	**432**	**77**	**115**	**585**	**1,209**	**423**	**51**	**130**	**102**	**706**
Net Proved Undeveloped Reserves										
At January 1, 2016	137	111	11	24	283	139	122	26	4	291
At December 31, 2016	186	95	11	5	297	168	115	26	1	310
At December 31, 2017	354	12	7	149	522	337	6	17	69	429
At December 31, 2018	**381**	**1**	**13**	**211**	**606**	**389**	**1**	**17**	**79**	**486**

(a) Revisions resulting from the impact of price changes in production sharing contracts reduced proved natural gas reserves in 2018 by 22 million mcf (2017: 22 million mcf decrease; 2016: 12 million mcf increase).
(b) Natural gas production in 2018 includes 13 million mcf used for fuel (2017: 11 million mcf; 2016: 15 million mcf).
(c) Natural gas and Total proved reserves in Norway for 2016 were as follows:

	Natural Gas (Millions of mcf)	*Total (Millions of boe)*
At January 1, 2016	*191*	*230*
Revisions of previous estimates	*(26)*	*(25)*
Extensions, discoveries and other additions	*4*	*5*
Sales of minerals in place	*—*	*—*
Production	*(9)*	*(10)*
At December 31, 2016	*160*	*200*
Net Proved Developed Reserves at December 31, 2016	*72*	*90*
Net Proved Undeveloped Reserves at December 31, 2016	*88*	*110*

Extensions, discoveries and other additions ('Additions')

2018: Total Additions were 213 million boe, of which 6 million boe (3 million barrels of crude oil and 18 million mcf of natural gas) related to proved developed reserves. Additions to proved developed reserves were primarily from drilling activity in the Bakken shale play in North Dakota. Additions to proved undeveloped reserves were 207 million boe (122 million barrels of crude oil, 39 million barrels of NGLs and 274 million mcf of natural gas) and are discussed in further detail on page 89.

2017: Total Additions were 291 million boe, of which 11 million boe (4 million barrels of crude oil, 1 million barrels of NGLs and 37 million mcf of natural gas) related to proved developed reserves. Additions to proved developed reserves were primarily from drilling activity in the Bakken and North Malay Basin. Additions to proved undeveloped reserves were 280 million boe (170 million barrels of crude oil, 49 million barrels of NGLs and 365 million mcf of natural gas) and are discussed in further detail on page 89.

2016: Total Additions were 69 million boe, of which 45 million boe (34 million barrels of crude oil, 2 million barrels of NGLs and 55 million mcf of natural gas) related to proved developed reserves. Additions to proved developed reserves were primarily from drilling activity in the Bakken and from a 20-year extension to the license for the South Arne Field, offshore Denmark, which extends expiry to 2047. Additions to proved undeveloped reserves were 24 million boe (11 million barrels of crude oil, 3 million barrels of NGLs and 59 million mcf of natural gas) and are discussed in further detail on page 89.

Revisions of previous estimates

2018: Total revisions of previous estimates amounted to a net decrease of 41 million boe, of which revisions of proved developed reserves amounted to a net increase of 3 million boe (crude oil - 4 million barrels increase, NGLs - 4 million barrels decrease and natural gas - 20 million mcf increase). Revisions to proved developed reserves primarily relate to the Bakken. Revisions associated with proved undeveloped reserves are discussed in further detail on page 89.

2017: Total revisions of previous estimates amounted to a net increase of 106 million boe, of which revisions of proved developed reserves amounted to a net increase of 126 million boe (41 million barrels of crude oil, 44 million barrels of NGLs and 243 million mcf of natural gas). Revisions to proved developed reserves from the Bakken amounted to 85 million boe with approximately 55% resulting from improved reservoir performance, and the remaining 45% resulting from higher prices and an improved cost structure. The Gulf of Mexico and Utica had positive revisions to proved developed reserves totaling 16 million boe due to improved reservoir performance, while higher crude oil prices resulted in revisions to proved developed reserves of 15 million boe in Denmark and Utica. Revisions associated with proved undeveloped reserves are discussed in further detail on page 89.

2016: Total revisions of previous estimates amounted to a net increase of 74 million boe, of which net positive revisions increased proved reserves by 103 million boe (54 million barrels of crude oil, 5 million barrels of NGLs and 265 million mcf of natural gas) and negative revisions associated with lower crude oil prices reduced proved reserves by 29 million boe (23 million barrels of crude oil, 1 million barrels of NGLs and 30 million mcf of natural gas). Total revisions of proved developed reserves amounted to a net increase of 41 million boe (5 million barrels decrease of crude oil, 7 million barrels increase of NGLs and 235 million mcf increase of natural gas) reflecting improved expected recoveries in the Bakken, completion of incremental development activities at the North Malay Basin, partially offset by negative revisions at the Valhall Field offshore Norway due to changes in estimated recoveries of NGLs and natural gas, and negative price revisions mostly related to crude oil reserves. Revisions associated with proved undeveloped reserves are discussed in further detail on page 89.

Sales of minerals in place ('Asset sales')

2018: Assets sales primarily include our former interests in the Utica Basin of Ohio.

2017: Assets sales primarily include our former interests in Norway, Equatorial Guinea, and our enhanced oil recovery assets in the Permian Basin.

Proved Undeveloped Reserves

Following are the Corporation's proved undeveloped reserves:

	United States	Europe	Africa	Asia & Other	Total
			(Millions of boe)		
Net Proved Undeveloped Reserves					
At January 1, 2016	139	122	26	4	291
Revisions of previous estimates	50	(14)	—	(3)	33
Extensions, discoveries and other additions	13	11	—	—	24
Transfers to proved developed reserves	(34)	(4)	—	—	(38)
Sales of minerals in place	—	—	—	—	—
At December 31, 2016	168	115	26	1	310
Revisions of previous estimates	(8)	(3)	(9)	—	(20)
Extensions, discoveries and other additions	209	3	—	68	280
Transfers to proved developed reserves	(32)	—	—	—	(32)
Sales of minerals in place	—	(109)	—	—	(109)
At December 31, 2017	337	6	17	69	429
Revisions of previous estimates	**(22)**	**(7)**	**(6)**	**(9)**	**(44)**
Extensions, discoveries and other additions	**178**	**2**	**8**	**19**	**207**
Transfers to proved developed reserves	**(97)**	**—**	**(2)**	**—**	**(99)**
Sales of minerals in place	**(7)**	**—**	**—**	**—**	**(7)**
At December 31, 2018	**389**	**1**	**17**	**79**	**486**

Extensions, discoveries and other additions ('Additions')

2018: In the United States, additions from the Bakken shale play in North Dakota were 168 million boe, of which approximately 40% of the change results from additional planned wells to be drilled in the next five years, approximately 35% results from performance associated with improved well completion designs, and approximately 25% results from other changes, primarily the impact of higher crude oil prices. Additions in the Gulf of Mexico were 10 million boe due to additional planned drilling at the Tubular Bells Field. Additions in Asia include 11 million boe at North Malay Basin and 8 million boe at the JDA relating to additional planned wells to be drilled within the next five years.

2017: In the United States, additions from the Bakken were 180 million boe, of which approximately 70% resulted from higher crude oil prices that increased the percentage of proved undeveloped wells in our planned five-year drilling program compared to the prior year. The remaining 30% of Bakken additions reflect the expected improved recovery in future wells from changes in well completion design and reservoir performance. Additions from the Stampede Field in the Gulf of Mexico were 21 million boe, due to completion of further development activities. At the Stabroek Block, offshore Guyana, additions of 45 million boe were recognized for project sanction of the first phase of the Liza Field development. Other international additions were primarily at North Malay Basin due to higher prices.

2016: In the United States, additions were at the Utica shale play in Ohio as result of changes in well design that improved both well economics and recoverability, and at the Bakken due to drilling plans. In Europe, additions were primarily from a 20-year extension to the license for the South Arne Field, offshore Denmark, which extends expiry to 2047.

Revisions of previous estimates

2018: Negative reserve revisions in the United States totaling 22 million boe, primarily resulted from optimizing drilling plans at the Bakken. Negative reserve revisions in international assets primarily resulted from updates in drilling plans in Denmark and North Malay Basin, and the impact of crude oil price changes on our PSC in Guyana.

2017: Total negative reserve revisions of 20 million boe, primarily relate to changes in drilling plans in Libya and lower reserves at certain fields in the Gulf of Mexico and Denmark.

2016: Total positive reserve revisions were 33 million boe. Technical revisions increased reserves by 44 million boe and were primarily from an improved well design at the Bakken, which was partially offset by negative revisions at the Valhall Field offshore Norway due to changes in expected recoveries of NGLs and natural gas. Negative revisions resulting from lower commodity prices totaled 11 million boe and were primarily in the Bakken.

Transfers to proved developed reserves ('Transfers')

2018: Transfers from proved undeveloped reserves included 75 million boe in the Bakken shale play associated with drilling activity, and 22 million boe at the Stampede Field in the Gulf of Mexico where first production was achieved in 2018.

2017: Transfers from proved undeveloped reserves included 24 million boe in the Bakken and 8 million boe at the Penn State Field in the Gulf of Mexico associated with drilling activity.

2016: Transfers from proved undeveloped reserves included 21 million boe in the Bakken and 13 million boe at the Tubular Bells and Conger Fields in the Gulf of Mexico associated with drilling activity.

In 2018, capital expenditures of $1,070 million were incurred to convert proved undeveloped reserves to proved developed reserves (2017: $527 million; 2016: $589 million).

Projects that have proved reserves, which have been classified as undeveloped for a period in excess of five years, total 6 million boe, or 1% of total proved reserves at December 31, 2018. Most of the proved undeveloped reserves in excess of five years relate to Libya.

Production Sharing Contracts

The Corporation's proved reserves include crude oil and natural gas reserves relating to long-term agreements with governments or authorities in which the Corporation has the legal right to produce or has a revenue interest in the production. Proved reserves from these production sharing contracts for each of the three years ended December 31, 2018 are presented separately below, as well as volumes produced and received during 2018, 2017 and 2016 from these production sharing contracts.

	Crude Oil					Natural Gas				
	United States	Europe	Africa	Asia & Other (a)	Total	United States	Europe	Africa	Asia & Other (a)	Total
			(Millions of bbls)					(Millions of mcf)		
Production Sharing Contracts										
Proved Reserves										
At December 31, 2016	—	—	24	5	29	—	—	15	744	759
At December 31, 2017	—	—	—	49	49	—	—	—	845	845
At December 31, 2018	**—**	**—**	**—**	**48**	**48**	**—**	**—**	**—**	**796**	**796**
Production										
2016	—	—	12	1	13	—	—	2	83	85
2017	—	—	9	1	10	—	—	2	103	105
2018	**—**	**—**	**—**	**1**	**1**	**—**	**—**	**—**	**132**	**132**

(a) Asia and Other includes Guyana proved undeveloped reserves of 40 million barrels of oil and 11 million mcf of natural gas at December 31, 2018 and 43 million barrels of oil and 11 million mcf of natural gas at December 31, 2017.

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

Future net cash flows are calculated by applying prescribed oil and gas selling prices used in determining year-end reserve estimates (adjusted for price changes provided by contractual arrangements) to estimated future production of proved oil and gas reserves, less estimated future development and production costs, which are based on year-end costs and existing economic assumptions. Future income tax expenses are computed by applying the appropriate year-end statutory tax rates to the pre-tax net cash flows, as well as including the effect of tax deductions and tax credits and allowances relating to the Corporation's proved oil and gas reserves. Future net cash flows are discounted at the prescribed rate of 10%.

The prices used for the discounted future net cash flows in 2018 were $65.55 per barrel for WTI (2017: $51.19; 2016: $42.68) and $72.08 per barrel for Brent (2017: $54.87; 2016: $44.45) and do not include the effects of commodity hedges. New York Mercantile Exchange (NYMEX) natural gas prices used were $3.01 per mcf in 2018 (2017: $3.03; 2016: $2.54). Selling prices have in the past, and can in the future, fluctuate significantly. As a result, selling prices used in the disclosure of future net cash flows may not be representative of future selling prices. In addition, the discounted future net cash flow estimates do not include exploration expenses, interest expense or corporate general and administrative expenses. The amount of tax deductions, credits, and allowances relating to the Corporation's proved oil and gas reserves can change year to year due to factors including changes in proved reserves, variances in actual pre-tax cash flows from forecasted pre-tax cash flows in historical periods, and the impact to year-end carryforward tax attributes associated with deducting in the Corporation's income tax returns exploration expenses, interest expense, and corporate general and administrative expenses that are not contemplated in the standardized measure computations. The future net cash flow estimates could be materially different if other assumptions were used.

At December 31	Total	United States	Europe (a)	Africa	Asia & Other
			(In millions)		
2018					
Future revenues	**$ 50,948**	**$ 31,460**	**$ 3,036**	**$ 9,183**	**$ 7,269**
Less:					
Future production costs	**13,636**	**9,718**	**1,311**	**678**	**1,929**
Future development costs	**8,427**	**6,132**	**449**	**301**	**1,545**
Future income tax expenses	**10,950**	**2,641**	**246**	**7,496**	**567**
	33,013	**18,491**	**2,006**	**8,475**	**4,041**
Future net cash flows	**17,935**	**12,969**	**1,030**	**708**	**3,228**
Less: Discount at 10% annual rate	**7,285**	**5,437**	**444**	**359**	**1,045**
Standardized Measure of Discounted Future Net Cash Flows	**$ 10,650**	**$ 7,532**	**$ 586**	**$ 349**	**$ 2,183**
2017					
Future revenues	$ 36,746	$ 20,834	$ 2,958	$ 7,154	$ 5,800
Less:					
Future production costs	13,042	8,802	1,501	782	1,957
Future development costs	6,748	4,601	553	330	1,264
Future income tax expenses	6,379	444	137	5,485	313
	26,169	13,847	2,191	6,597	3,534
Future net cash flows	10,577	6,987	767	557	2,266
Less: Discount at 10% annual rate	4,221	2,904	272	307	738
Standardized Measure of Discounted Future Net Cash Flows	$ 6,356	$ 4,083	$ 495	$ 250	$ 1,528
2016					
Future revenues	$ 32,814	$ 13,035	$ 10,283	$ 6,907	$ 2,589
Less:					
Future production costs	14,054	6,639	5,091	1,440	884
Future development costs	8,635	2,910	4,348	992	385
Future income tax expenses	2,450	—	(2,064) (b)	4,406	108
	25,139	9,549	7,375	6,838	1,377
Future net cash flows	7,675	3,486	2,908	69	1,212
Less: Discount at 10% annual rate	3,650	1,288	2,072	40	250
Standardized Measure of Discounted Future Net Cash Flows	$ 4,025	$ 2,198	$ 836	$ 29	$ 962

(a) The standardized measure of discounted future net cash flows relating to proved reserves in Norway for 2016 (in millions) were as follows:

Future revenues	*$ 8,188*
Less:	
Future production costs	*4,004*
Future development costs	*3,931*
Future income tax expenses (b)	*(2,112)*
	5,823
Future net cash flows	*2,365*
Less: Discount at 10% annual rate	*1,969*
Standardized Measure of Discounted Future Net Cash Flows	*$ 396*

(b) The Petroleum Tax Act provides for compensation by the Norwegian government to a company upon cessation of its E&P activities on the Norwegian Continental Shelf in an amount equal to the tax values of unutilized tax losses and certain other tax attributes, including dismantlement expenditures incurred after production has ceased that would qualify for compensation at an effective tax rate of 78%. Due to the low crude oil price used in the 2016 computation, future income taxes reflect cash inflows for Norway of $2.1 billion on an undiscounted basis. The corresponding present value reflected in the Standardized Measure of Discounted Future Net Cash Flows at December 31, 2016 is $70 million.

Changes in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

For the Years Ended December 31	2018	2017	2016
		(In millions)	
Standardized Measure of Discounted Future Net Cash Flows at January 1	**$ 6,356**	$ 4,025	$ 7,190
Changes during the year:			
Sales and transfers of oil and gas produced during the year, net of production costs	**(2,755)**	(2,216)	(1,368)
Development costs incurred during the year	**1,533**	1,679	1,369
Net changes in prices and production costs applicable to future production	**7,076**	2,330	(4,284)
Net change in estimated future development costs	**(1,119)**	(568)	(76)
Extensions and discoveries (including improved recovery) of oil and gas reserves, less related costs	**2,129**	1,282	338
Revisions of previous oil and gas reserve estimates	**(630)**	644	376
Net purchases (sales) of minerals in place, before income taxes	**(83)**	116	—
Accretion of discount	**929**	603	779
Net change in income taxes	**(2,662)**	(709)	1,331
Revision in rate or timing of future production and other changes	**(124)**	(830)	(1,630)
Total	**4,294**	2,331	(3,165)
Standardized Measure of Discounted Future Net Cash Flows at December 31	**$ 10,650**	$ 6,356	$ 4,025

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES
SELECTED QUARTERLY FINANCIAL DATA (UNAUDITED)

Following are selected quarterly results of operations (unaudited):

	2018			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In millions, except per share amounts)			
Sales and other operating revenues	**$ 1,346**	**$ 1,534**	**$ 1,793**	**1,650**
Gross profit (loss) (a)	**$ 244**	**$ 310**	**$ 500**	**310**
Net income (loss)	**(65)**	**(87)**	**3**	**34**
Less: Net income (loss) attributable to noncontrolling interests	**41**	**43**	**45**	**38**
Net income (loss) attributable to Hess Corporation	**(106)**	**(130)**	**(42)**	**(4)**
Less: Preferred stock dividends	**11**	**12**	**11**	**12**
Net income (loss) attributable to Hess Corporation common stockholders	**$ (117)** (b)	**$ (142)** (c)	**(53)** (d)	**(16)** (e)
Net income (loss) attributable to Hess Corporation per common share:				
Basic	**$ (0.38)**	**$ (0.48)**	**(0.18)**	**(0.05)**
Diluted	**$ (0.38)**	**$ (0.48)**	**(0.18)**	**(0.05)**

	2017			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In millions, except per share amounts)			
Sales and other operating revenues	$ 1,258	$ 1,197	$ 1,348	$ 1,663
Gross profit (loss) (a)	$ (68)	$ (201)	$ (2,632)	$ (1,548)
Net income (loss)	(296)	(417)	(593)	(2,635)
Less: Net income (loss) attributable to noncontrolling interests	28	32	31	42
Net income (loss) attributable to Hess Corporation	(324)	(449)	(624)	(2,677)
Less: Preferred stock dividends	12	11	11	12
Net income (loss) attributable to Hess Corporation common stockholders	$ (336)	$ (460)	$ (635) (f)	$ (2,689) (g)
Net income (loss) attributable to Hess Corporation per common share:				
Basic	$ (1.07)	$ (1.46)	$ (2.02)	$ (8.57)
Diluted	$ (1.07)	$ (1.46)	$ (2.02)	$ (8.57)

(a) Gross profit represents Sales and other operating revenues, less Marketing expenses, Operating costs and expenses, Production and severance taxes, Depreciation, depletion and amortization and Impairment.

(b) Includes a net after-tax severance charge of $37 million ($37 million pre-tax), an after-tax charge of $27 million ($27 million pre-tax) relating to the premium paid for the retirement of debt, and a noncash income tax benefit of $30 million to offset a noncash income tax expense recognized in other comprehensive income, resulting from a reduction in our pension liabilities.

(c) Includes an after-tax gain of $10 million ($10 million pre-tax) associated with the sale of our interests in Ghana, an after-tax charge of $26 million ($26 million pre-tax) relating to the premium paid for the retirement of debt, and an after-tax charge of $58 million ($58 million pre-tax) resulting from the settlement of legal claims related to former downstream interests.

(d) Includes an after-tax gain of $14 million ($14 million pre-tax) associated with the sale of our interests in the Utica shale play in eastern Ohio, noncash after-tax charges of $73 million ($73 million pre-tax) in connection with vacated office space, and an allocation of noncash income tax expense of $12 million to offset the recognition of a noncash income tax benefit recorded in other comprehensive income resulting from changes in fair value of our 2019 crude oil hedging program.

(e) Includes a noncash income tax benefit of $73 million to offset the recognition of a noncash income tax expense recorded in other comprehensive income primarily resulting from changes in fair value of our 2019 crude oil hedging program.

(f) Includes an after-tax impairment charge of $550 million ($2,503 million pre-tax) associated with the expected sale of our interests in Norway and an after-tax gain of $280 million ($280 million pre-tax) related to the sale of our Permian assets.

(g) Includes an after-tax impairment charge of $1,700 million ($1,700 million pre-tax) associated with certain Gulf of Mexico assets, an after-tax charge of $280 million to fully impair the carrying value of our interests in Ghana ($280 million pre-tax), and a net $371 million after-tax loss related to sales of our interests in Norway and Equatorial Guinea ($371 million pre-tax).

The results of operations for the periods reported herein should not be considered as indicative of future operating results.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

Based upon their evaluation of the Corporation's disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) as of December 31, 2018, John B. Hess, Chief Executive Officer, and John P. Rielly, Chief Financial Officer, concluded that these disclosure controls and procedures were effective as of December 31, 2018.

There was no change in internal controls over financial reporting identified in the evaluation required by paragraph (d) of Rules 13a-15 or 15d-15 in the quarter ended December 31, 2018 that has materially affected, or is reasonably likely to materially affect, internal controls over financial reporting.

Management's report on internal control over financial reporting and the attestation report on the Corporation's internal controls over financial reporting are included in *Item 8. Financial Statements and Supplementary Data* of this annual report on Form 10-K.

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

Information relating to Directors is incorporated herein by reference to "Election of Directors" from the Corporation's definitive proxy statement for the 2019 annual meeting of stockholders.

The Corporation has adopted a Code of Business Conduct and Ethics applicable to the Corporation's directors, officers (including the Corporation's principal executive officer and principal financial officer) and employees. The Code of Business Conduct and Ethics is available on the Corporation's website. In the event that we amend or waive any of the provisions of the Code of Business Conduct and Ethics that relate to any element of the code of ethics definition enumerated in Item 406(b) of Regulation S-K, we intend to disclose the same on the Corporation's website at www.hess.com.

Information relating to the audit committee is incorporated herein by reference to "Election of Directors" from the Corporation's definitive proxy statement for the 2019 annual meeting of stockholders.

Executive Officers of the Corporation

The following table presents information as of February 21, 2019 regarding executive officers of the Corporation:

Name	Age	Office Held* and Business Experience	Year Individual Became an Executive Officer
John B. Hess	64	*Chief Executive Officer and Director* Mr. Hess has been Chief Executive Officer of the Corporation since 1995 and employed by the Corporation since 1977. He has over 40 years of experience in the oil and gas industry.	1983
Gregory P. Hill	57	*Chief Operating Officer, Executive Vice President and President, Exploration and Production* Mr. Hill has been Chief Operating Officer since 2014 and President of the Corporation's worldwide Exploration and Production business since joining the Corporation in January 2009. Prior to joining the Corporation, Mr. Hill spent 25 years at Royal Dutch Shell and its affiliates in a variety of operations, engineering, technical and managerial roles in Asia-Pacific, Europe and the United States.	2009
Timothy B. Goodell	61	*Senior Vice President, General Counsel and Corporate Secretary* Mr. Goodell has been the Senior Vice President and General Counsel of the Corporation since 2009 and Corporate Secretary since 2016. Prior to joining the Corporation in 2009, he was a partner at the law firm of White & Case, LLP where he spent 25 years.	2009
John P. Rielly	56	*Senior Vice President and Chief Financial Officer* Mr. Rielly has been the Senior Vice President and Chief Financial Officer of the Corporation since 2004. Mr. Rielly previously served as Vice President and Controller of the Corporation from 2001 to 2004. Prior to joining the Corporation in 2001, he was a Partner at Ernst & Young, LLP where he was employed for 16 years.	2002
Andrew Slentz	57	*Senior Vice President, Human Resources* Mr. Slentz has been Senior Vice President, Human Resources of the Corporation since April 2016. Prior to joining the Corporation, Mr. Slentz served as Executive Vice President of Administration and Human Resources at Peabody Energy since 2010. Mr. Slentz has over 25 years in human resources experience at large international public companies.	2016
Richard Lynch	60	*Senior Vice President, Technology and Services* Mr. Lynch has been Senior Vice President, Technology and Services of the Corporation since 2018. Mr. Lynch previously was Senior Vice President Global Developments, Drilling and Completions. Prior to joining Hess in 2014, Mr. Lynch spent over 30 years in well delivery and operations, as well as project and asset management, with BP plc and ARCO.	2018
Michael R. Turner	59	*Senior Vice President, Global Production* Mr. Turner has been Senior Vice President, Global Production of the Corporation since 2017. He previously served as Senior Vice President, Onshore. Prior to joining the Corporation in 2009, Mr. Turner spent 28 years with Royal Dutch Shell and its affiliates in a variety of production leadership positions around the world.	2014
Barbara Lowery-Yilmaz	62	*Senior Vice President, Exploration* Ms. Lowery-Yilmaz has been the Senior Vice President, Exploration of the Corporation since August 2014. Ms. Lowery-Yilmaz has over 30 years of oil and gas industry experience in exploration and technology with BP plc and its affiliates including senior leadership roles.	2014

** All officers referred to herein hold office in accordance with the By-laws until the first meeting of directors in connection with the annual meeting of stockholders of the Registrant and until their successors shall have been duly chosen and qualified. Each of said officers was elected to the office opposite their name on June 5, 2018.*

Except for Mr. Lynch, Ms. Lowery-Yilmaz and Mr. Slentz, each of the above officers has been employed by the Corporation or its affiliates in various managerial and executive capacities for more than five years. Prior to joining the Corporation, Mr. Lynch served in senior positions at BP plc, most recently as Vice President Global Wells Organizations, overseeing all upstream activities associated with drilling and completion, intervention and well integrity. Ms. Lowery-Yilmaz served in senior executive positions in Exploration and Production at BP plc. Mr. Slentz served in senior executive positions in human resources at Peabody Energy and its affiliates.

Item 11. Executive Compensation

Information relating to executive compensation is incorporated herein by reference to "Election of Directors—Executive Compensation and Other Information," from the Corporation's definitive proxy statement for the 2019 annual meeting of stockholders.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Information pertaining to security ownership of certain beneficial owners and management is incorporated herein by reference to "Election of Directors—Ownership of Voting Securities by Certain Beneficial Owners" and "Election of Directors—Ownership of Equity Securities by Management" from the Corporation's definitive proxy statement for the 2019 annual meeting of stockholders.

See Equity Compensation Plans in *Item 5. Market for the Registrant's Common Stock, Related Stockholder Matters and Issuer Purchases of Equity Securities* for information pertaining to securities authorized for issuance under equity compensation plans.

Item 13. Certain Relationships and Related Transactions, and Director Independence

Information relating to this item is incorporated herein by reference to "Election of Directors" from the Corporation's definitive proxy statement for the 2019 annual meeting of stockholders.

Item 14. Principal Accounting Fees and Services

Information relating to this item is incorporated herein by reference to "Ratification of Selection of Independent Auditors" from the Corporation's definitive proxy statement for the 2019 annual meeting of stockholders.

PART IV

Item 15. Exhibits, Financial Statement Schedules

(a) 1. and 2. Financial statements and financial statement schedules

The financial statements filed as part of this Annual Report on Form 10-K are listed in the accompanying index to financial statements and schedules in *Item 8. Financial Statements and Supplementary Data*.

All other financial statement schedules required under SEC rules that are not included in this Annual Report on Form 10-K, are omitted either because they are not applicable or the required information is contained in *Item 8. Financial Statements and Supplementary Data*.

3. Exhibits

The exhibits required to be filed pursuant to Item 15(b) of Form 10-K are listed in the Exhibit Index filed herewith, which Exhibit Index is incorporated herein by reference.

3(1)	Restated Certificate of Incorporation of Registrant, including amendment thereto dated May 3, 2006 incorporated by reference to Exhibit 3(1) of Registrant's Form 10-Q for the three months ended June 30, 2006.
3(2)	Certificate of Amendment to Restated Certificate of Incorporation of Registrant, dated May 22, 2013, incorporated by reference to Exhibit 3(1) of Form 8-K of Registrant filed on May 22, 2013.
3(3)	Certificate of Amendment to Restated Certificate of Incorporation of Registrant, effective May 12, 2014, incorporated by reference to Exhibit 3(1) of Form 8-K of Registrant filed on May 13, 2014.
3(4)	By-laws of Registrant incorporated by reference to Exhibit 3(2) of Form 8-K of Registrant filed on November 9, 2015.
4(1)	Five-Year Credit Agreement, dated as of January 21, 2015, as amended and restated as of December 1, 2017, among Hess Corporation, the subsidiaries party thereto, the lenders party thereto and JPMorgan Chase Bank, N.A., as administrative agent, incorporated by reference to Exhibit 10(1) of Form 8-K of Registrant filed on December 7, 2017.
4(2)	Indenture dated as of October 1, 1999, between Registrant and The Chase Manhattan Bank, as Trustee, incorporated by reference to Exhibit 4(1) of Form 10-Q of Registrant for the three months ended September 30, 1999.
4(3)	First Supplemental Indenture, dated as of October 1, 1999, between Registrant and The Chase Manhattan Bank, as Trustee, relating to Registrant's $7\frac{3}{8}$% Notes due 2009 and $7\frac{7}{8}$% Notes due 2029, incorporated by reference to Exhibit 4(2) of Form 10-Q of Registrant for the three months ended September 30, 1999.
4(4)	Prospectus Supplement, dated August 8, 2001, to Prospectus dated July 27, 2001 relating to Registrant's 5.30% Notes due 2004, 5.90% Notes due 2006, 6.65% Notes due 2011 and 7.30% Notes due 2031, incorporated by reference to Registrant's prospectus filed pursuant to Rule 424(b)(2) under the Securities Act of 1933, as amended, on August 9, 2001.
4(5)	Prospectus Supplement, dated February 28, 2002, to Prospectus dated July 27, 2001 relating to Registrant's 7.125% Notes due 2033, incorporated by reference to Registrant's prospectus filed pursuant to Rule 424(b)(4) under the Securities Act of 1933, as amended, on March 1, 2002.
4(6)	Indenture dated as of March 1, 2006, between Registrant and The Bank of New York Mellon, as successor to JP Morgan Chase Bank, N.A., as Trustee, including form of Note, incorporated by reference to Exhibit 4 to Registrant's Form S-3ASR filed on March 1, 2006.
4(7)	Form of 6.00% Note due 2040, incorporated by reference to Exhibit 4(1) to Form 8-K of Registrant filed on December 15, 2009.
4(8)	Form of 5.60% Note due 2041, incorporated by reference to Exhibit 4(1) to Form 8-K of Registrant filed on August 12, 2010.
4(9)	Form of 3.50% Note due 2024, incorporated by reference to Exhibit 4(3) to Form 8-K of Registrant filed on June 25, 2014.

4(10)	Form of 4.30% Note due 2027, incorporated by reference to Exhibit 4(1) to Form 8-K of Registrant filed on September 28, 2016.
4(11)	Form of 5.80% Note due 2047, incorporated by reference to Exhibit 4(2) to Form 8-K of Registrant filed on September 28, 2016.
	Other instruments defining the rights of holders of long-term debt of Registrant and its consolidated subsidiaries are not being filed since the total amount of securities authorized under each such instrument does not exceed 10% of the total assets of Registrant and its subsidiaries on a consolidated basis. Registrant agrees to furnish to the Securities and Exchange Commission a copy of any instruments defining the rights of holders of long-term debt of Registrant and its subsidiaries upon request.
10(1)*	Annual Cash Incentive Plan description incorporated by reference to Item 5.02 of Form 8-K of Registrant filed on March 6, 2018.
10(2)*	Financial Counseling Program description incorporated by reference to Exhibit 10(6) of Form 10-K of Registrant for the fiscal year ended December 31, 2004.
10(3)*	Hess Corporation Savings and Stock Bonus Plan incorporated by reference to Exhibit 10(7) of Form 10-K of Registrant for the fiscal year ended December 31, 2006.
10(4)*	Hess Corporation Pension Restoration Plan, dated January 19, 1990, incorporated by reference to Exhibit 10(9) of Form 10-K of Registrant for the fiscal year ended December 31, 1989. (P)
10(5)*	Amendment, dated December 31, 2006, to Hess Corporation Pension Restoration Plan, incorporated by reference to Exhibit 10(10) of Form 10-K of Registrant for the fiscal year ended December 31, 2006.
10(6)*	Letter Agreement, dated May 17, 2001, between Registrant and John P. Rielly relating to Mr. Rielly's participation in the Hess Corporation Pension Restoration Plan, incorporated by reference to Exhibit 10(18) of Form 10-K of Registrant for the fiscal year ended December 31, 2002.
10(7)*	Amended and Restated 2008 Long-term Incentive Plan, incorporated by reference to exhibit 10(1) of Form 8-K of the Registrant filed on May 12, 2015.
10(8)*	Forms of Awards under Registrant's 2008 Long-term Incentive Plan, incorporated by reference to Exhibit 10(14) of Form 10-K of Registrant for the fiscal year ended December 31, 2009.
10(9)*	Form of Performance Award Agreement under Registrant's 2008 Long-term Incentive Plan incorporated by reference to Exhibit 10(2) of Form 8-K of Registrant filed on March 13, 2012.
10(10)*	Form of Restricted Stock Award Agreement under Registrant's Amended and Restated 2008 Long-term Incentive Plan, incorporated by reference to Exhibit 10(2) of Form 10-Q of Registrant for the three months ended March 31, 2015.
10(11)*	Form of Performance Award Agreement for the three-year period ending December 31, 2017 under Registrant's Amended and Restated 2008 Long-term Incentive Plan, incorporated by reference to Exhibit 10(3) of Form 10-Q of Registrant for the three months ended March 31, 2015.
10(12)*	Compensation program description for non-employee directors, incorporated by reference to Item 1.01 of Form 8-K of Registrant filed on January 4, 2007.
10(13)*	Form of Amended and Restated Change in Control Termination Benefits Agreement, dated as of May 29, 2009, incorporated by reference to Exhibit 10(1) of Form 10-Q of Registrant for the three months ended June 30, 2009. A substantially identical agreement (differing only in the signatories thereto) was entered into between Registrant and John B. Hess.
10(14)*	Amended and Restated Change in Control Termination Benefits Agreement, dated as of May 29, 2009, between Registrant and John P. Rielly, incorporated by reference to Exhibit 10(17) of Form 10-K of Registrant for the fiscal year ended December 31, 2009. Substantially identical agreements (differing only in the signatories thereto) were entered into between Registrant and other executive officers (including the named executive officers, other than Michael Turner and John B. Hess).

10(15)	Form of Change in Control Termination Benefits Agreement, dated as of August 3, 2015, between the Registrant and Michael R. Turner, incorporated by reference to Exhibit 10(3) of Form 10-Q of Registrant for the three months ended June 30, 2015. Substantially identical agreements (differing only in the signatories thereto) were entered into between the Registrant and four other senior officers.
10(16)*	Agreement between Registrant and Gregory P. Hill, relating to Mr. Hill's compensation and other terms of employment, incorporated by reference to Item 5.02 of Form 8-K of Registrant filed January 7, 2009.
10(17)*	Agreement between Registrant and Timothy B. Goodell, relating to Mr. Goodell's compensation and other terms of employment, incorporated by reference to Exhibit 10(20) of Registrant's Form 10-K for the fiscal year ended December 31, 2009.
10(18)*	Deferred Compensation Plan of Registrant, dated December 1, 1999, incorporated by reference to Exhibit 10(16) of Form 10-K of Registrant for the fiscal year ended December 31, 1999.
10(19)*	Hess Corporation 2017 Long-Term Incentive Plan, incorporated by reference to Exhibit 10(1) of Form 8-K of Registrant filed on June 13, 2017.
10(20)*	Form of Restricted Stock Award Agreement under the 2017 Long-Term Incentive Plan, incorporated by reference to Exhibit 10(1) of Form 10-Q of Registrant for the three months ended March 31, 2018.
10(21)*	Form of Stock Option Agreement under the 2017 Long-Term Incentive Plan, incorporated by reference to Exhibit 10(2) of Form 10-Q of Registrant for the three months ended March 31, 2018.
10(22)*	Form of Performance Award Agreement under the 2017 Long-Term Incentive Plan, incorporated by reference to Exhibit 10(3) of Form 10-Q of Registrant for the three months ended March 31, 2018.
21	Subsidiaries of Registrant.
23(1)	Consent of Ernst & Young LLP, Independent Registered Public Accounting Firm, dated February 21, 2019.
23(2)	Consent of DeGolyer and MacNaughton dated February 21, 2019.
31(1)	Certification required by Rule 13a-14(a) (17 CFR 240.13a-14(a)) or Rule 15d-14(a) (17 CFR 240.15d-14(a)).
31(2)	Certification required by Rule 13a-14(a) (17 CFR 240.13a-14(a)) or Rule 15d-14(a) (17 CFR 240.15d-14(a)).
32(1)	Certification required by Rule 13a-14(b) (17 CFR 240.13a-14(b)) or Rule 15d-14(b) (17 CFR 240.15d-14(b)) and Section 1350 of Chapter 63 of Title 18 of the United States Code (18 U.S.C. 1350).
32(2)	Certification required by Rule 13a-14(b) (17 CFR 240.13a-14(b)) or Rule 15d-14(b) (17 CFR 240.15d-14(b)) and Section 1350 of Chapter 63 of Title 18 of the United States Code (18 U.S.C. 1350).
99(1)	Letter report of DeGolyer and MacNaughton, Independent Petroleum Engineering Consulting Firm, dated February 6, 2019, on proved reserves audit as of December 31, 2018 of certain properties attributable to Registrant.
101(INS)	XBRL Instance Document
101(SCH)	XBRL Schema Document
101(CAL)	XBRL Calculation Linkbase Document
101(LAB)	XBRL Labels Linkbase Document
101(PRE)	XBRL Presentation Linkbase Document
101(DEF)	XBRL Definition Linkbase Document

** These exhibits relate to executive compensation plans and arrangements.*

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on the 21st day of February 2019.

HESS CORPORATION
(Registrant)

By /s/ JOHN P. RIELLY
(John P. Rielly)
Senior Vice President and
Chief Financial Officer

POWER OF ATTORNEY

Each person whose signature appears below constitutes and appoints John B. Hess, Timothy B. Goodell and John P. Rielly or any of them, his true and lawful attorneys-in-fact and agents, with full power of substitution and resubstitution, for him and in his name, place and stead, in any and all capacities, to sign any and all amendments to Annual Report on Form 10-K, and to file the same, with all exhibits thereto, and other documents in connection therewith with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and to perform each and every act and thing requisite and necessary to be done in and about the premises, as fully and to all intents and purposes as he might or would do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents or any of them, or their or his substitute or substitutes, may lawfully do or cause to be done by virtue hereof.

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

Signature	Title	Date
/s/ JOHN B. HESS **John B. Hess**	Director and Chief Executive Officer (Principal Executive Officer)	February 21, 2019
/s/ JAMES H. QUIGLEY **James H. Quigley**	Director and Chairman of the Board	February 21, 2019
/s/ RODNEY F. CHASE **Rodney F. Chase**	Director	February 21, 2019
/s/ TERRENCE J. CHECKI **Terrence J. Checki**	Director	February 21, 2019
/s/ LEONARD S. COLEMAN JR. **Leonard S. Coleman Jr.**	Director	February 21, 2019
/s/ EDITH E. HOLIDAY **Edith E. Holiday**	Director	February 21, 2019
/s/ DR. RISA LAVIZZO-MOUREY **Dr. Risa Lavizzo-Mourey**	Director	February 21, 2019
/s/ MARC S. LIPSCHULTZ **Marc S. Lipschultz**	Director	February 21, 2019
/s/ DAVID MCMANUS **David McManus**	Director	February 21, 2019
/s/ DR. KEVIN O. MEYERS **Dr. Kevin O. Meyers**	Director	February 21, 2019
/s/ FREDRIC G. REYNOLDS **Fredric G. Reynolds**	Director	February 21, 2019
/s/ JOHN P. RIELLY **John P. Rielly**	Senior Vice President and Chief Financial Officer (Principal Financial and Accounting Officer)	February 21, 2019
/s/ WILLIAM G. SCHRADER **William G. Schrader**	Director	February 21, 2019

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES

SUBSIDIARIES OF THE REGISTRANT

Name of Company	Registrant ownership %	Jurisdiction
Hess Asia Holdings Inc	100	Cayman Islands
Hess Bakken Investments II L.L.C.	100	Delaware
Hess Bakken Investments III L.L.C.	100	Delaware
Hess Bakken Investments IV L.L.C.	100	Delaware
Hess Bakken Processing L.L.C.	47	Delaware
Hess Canada Oil and Gas ULC	100	Canada
Hess Capital Corporation S.a.r.l.	100	Luxembourg
Hess Capital Limited	100	Cayman Islands
Hess Capital Services Corporation	100	Delaware
Hess Canada (Aspy) Exploration Limited	100	Cayman Islands
Hess Canada Exploration Limited	100	Cayman Islands
Hess Capital Services L.L.C.	100	Delaware
Hess Denmark Aps	100	Denmark
Hess Equatorial Guinea Investments Limited	100	Cayman Islands
Hess Exploration and Production Malaysia B.V.	100	The Netherlands
Hess Energy Exploration Limited	100	Delaware
Hess Exploration & Production Holdings Limited	100	Delaware
Hess Finance	100	England & Wales
Hess GOM Deepwater L.L.C.	100	Delaware
Hess GOM Exploration L.L.C.	100	Delaware
Hess Gulf of Mexico Ventures L.L.C.	100	Delaware
Hess Guyana Exploration (Liza) Limited	100	Cayman Islands
Hess Guyana Exploration Limited	100	Cayman Islands
Hess Holdings EG Limited	100	Cayman Islands
Hess Holdings West Africa Limited	100	Cayman Islands
Hess Hungary Finance KFT	100	Hungary
Hess (Indonesia-VIII) Holdings Limited	100	Cayman Islands
Hess Infrastructure Partners LP	50	Delaware
Hess International Holdings Corporation	100	Delaware
Hess International Holdings Limited	100	Cayman Islands
Hess International Receivables Limited	100	Cayman Islands
Hess Libya Exploration Limited	100	Cayman Islands
Hess Libya (Waha) Limited	100	Cayman Islands
Hess Limited	100	England & Wales
Hess Llano L.L.C	100	Delaware
Hess Middle East New Ventures Limited	100	Cayman Islands
Hess Midstream Partners LP	35	Delaware
Hess Midstream Partners GP LP	50	Delaware
Hess (Netherlands) Oil & Gas Holdings C.V.	100	The Netherlands
Hess New Ventures Exploration Limited	100	Cayman Islands
Hess North Dakota Export Logistics L.L.C.	47	Delaware
Hess North Dakota Export Logistics Holdings L.L.C.	47	Delaware
Hess North Dakota Export Logistics Operations LP	47	Delaware
Hess North Dakota Pipelines L.L.C.	47	Delaware
Hess North Dakota Pipelines Holdings L.L.C.	47	Delaware

Name of Company	Registrant ownership %	Jurisdiction
Hess North Dakota Pipelines Operations LP	47	Delaware
Hess NWE Holdings Limited	100	England & Wales
Hess Ohio Developments, L.L.C.	100	Delaware
Hess Ohio Holdings Corporation	100	Delaware
Hess Ohio Sub-Holdings L.L.C.	100	Delaware
Hess Oil and Gas Holdings Inc.	100	Cayman Islands
Hess Oil Company of Thailand (JDA) Limited	100	Cayman Islands
Hess Services UK Limited	100	England & Wales
Hess Shenzi L.L.C.	100	Delaware
Hess Stampede L.L.C.	100	Delaware
Hess Tank Cars L.L.C.	50	Delaware
Hess Tank Cars II L.L.C.	50	Delaware
Hess Tank Cars Holdings II L.L.C.	50	Delaware
Hess TGP Finance Company L.L.C.	100	Delaware
Hess TGP Holdings L.L.C.	47	Delaware
Hess TGP Operations LP	47	Delaware
Hess Tioga Gas Plant L.L.C.	47	Delaware
Hess Trading Corporation	100	Delaware
Hess Tubular Bells L.L.C.	100	Delaware
Hess West Africa Holdings Limited	100	Cayman Islands
HIH C.V.	100	The Netherlands

Each of the foregoing subsidiaries conducts business under the name listed. The above list does not include 47 subsidiary holding companies (20 domestic and 27 non-U.S.) that would otherwise be reported except that they are ultimately 100% owned by the Registrant and, as their line of business, fulfill similar roles to those holding companies separately identified in the above list. In addition, we have excluded subsidiaries associated with divested assets, discontinued activities and those that when considered in the aggregate as a single subsidiary, would not constitute a significant subsidiary.

Exhibit 23(1)

Consent of Independent Registered Public Accounting Firm

We consent to the incorporation by reference in the following Registration Statements:

(1) Registration Statement (Form S-8 No. 333-43569) pertaining to the Hess Corporation Employees' Savings Plan,

(2) Registration Statement (Form S-8 No. 333-150992) pertaining to the Hess Corporation Amended and Restated 2008 Long-Term Incentive Plan and the Hess Corporation 2017 Long-Term Incentive Plan,

(3) Registration Statement (Form S-8 No. 333-167076) pertaining to the Hess Corporation Amended and Restated 2008 Long-Term Incentive Plan and the Hess Corporation 2017 Long-Term Incentive Plan,

(4) Registration Statement (Form S-8 No. 333-181704) pertaining to the Hess Corporation Amended and Restated 2008 Long-Term Incentive Plan and the Hess Corporation 2017 Long-Term Incentive Plan,

(5) Registration Statement (Form S-8 No. 333-204929) pertaining to the Hess Corporation Amended and Restated 2008 Long-Term Incentive Plan and the Hess Corporation 2017 Long-Term Incentive Plan,

(6) Registration Statement (Form S-8 No. 333-219113) pertaining to the Hess Corporation 2017 Long-Term Incentive Plan, and

(7) Registration Statement (Form S-3 No. 333-223279) of Hess Corporation;

of our reports dated February 21, 2019, with respect to the consolidated financial statements of Hess Corporation and the effectiveness of internal control over financial reporting of Hess Corporation included in this Annual Report (Form 10-K) of Hess Corporation for the year ended December 31, 2018.

/s/ Ernst & Young LLP
New York, New York
February 21, 2019

Exhibit 23(2)

DEGOLYER AND MACNAUGHTON
5001 SPRING VALLEY ROAD
SUITE 800 EAST
DALLAS, TEXAS 75244

February 21, 2019

Hess Corporation
1185 Avenue of the Americas
New York, New York 10036

Ladies and Gentlemen:

We hereby consent to the use of the name DeGolyer and MacNaughton, to references to DeGolyer and MacNaughton as an independent petroleum engineering consulting firm, to references to our third-party letter report dated February 6, 2019, containing our opinion on the estimated proved reserves, as of December 31, 2018 attributable to certain properties that Hess Corporation has represented that it owns (our "Report") under the heading "Proved Oil and Gas Reserves-Reserves Audit," and to the inclusion of our Report as an exhibit in Hess Corporation's Annual Report on Form 10-K for the year ended December 31, 2018. We also consent to all such references, including under the heading "Experts," and to the incorporation by reference of our Report in the Registration Statements filed by Hess Corporation on Form S-3 (No. 333-223-279) and Form S-8 (No. 333-43569, No. 333-150992, No. 333-167076, No. 333-181704, No. 333-204929 and No. 333-219113).

Very truly yours,

By /s/ DeGolyer and MacNaughton

DEGOLYER AND MACNAUGHTON
Texas Registered Engineering Firm F-716

Exhibit 31(1)

I, John B. Hess, certify that:

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

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

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

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

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

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

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

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

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

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

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

By /s/ John B. Hess
John B. Hess
Chief Executive Officer

Date: February 21, 2019

Exhibit 31(2)

I, John P. Rielly, certify that:

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

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

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

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

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

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

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

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

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

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

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

By /s/ John P. Rielly
John P. Rielly
Senior Vice President and
Chief Financial Officer

Date: February 21, 2019

Exhibit 32(1)

CERTIFICATION PURSUANT TO

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

In connection with the Annual Report of Hess Corporation (the Corporation) on Form 10-K for the period ended December 31, 2018 as filed with the Securities and Exchange Commission on the date hereof (the Report), I, John B. Hess, Chief Executive Officer of the Corporation, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

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

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

By /s/ John B. Hess
John B. Hess
Chief Executive Officer

Date: February 21, 2019

Exhibit 32(2)

CERTIFICATION PURSUANT TO

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

In connection with the Annual Report of Hess Corporation (the Corporation) on Form 10-K for the period ended December 31, 2018 as filed with the Securities and Exchange Commission on the date hereof (the Report), I, John P. Rielly, Senior Vice President and Chief Financial Officer of the Corporation, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

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

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

By /s/ John P. Rielly
John P. Rielly
Senior Vice President and
Chief Financial Officer

Date: February 21, 2019

Exhibit 99.1

DeGolyer and MacNaughton
5001 Spring Valley Road
Suite 800 East
Dallas, Texas 75244

February 6, 2019

Board of Directors
Hess Corporation
1185 Avenue of the Americas
New York, New York 10036

Ladies and Gentlemen:

Pursuant to your request, this report of third party presents an independent evaluation, as of December 31, 2018, of the net proved oil, condensate, natural gas liquids (NGL), and gas reserves of certain selected properties in which Hess Corporation (Hess) has represented it holds an interest to determine the reasonableness of Hess' estimates. This evaluation was completed on February 6, 2019. Hess has represented to us that these properties account for approximately 80.3 percent on a net equivalent barrel basis of Hess' net proved reserves, as of December 31, 2018, and that the net proved reserves estimates have been prepared in accordance with the reserves definitions of Rules 4-10(a) (1)–(32) of Regulation S–X of the Securities and Exchange Commission (SEC) of the United States. We have reviewed information provided to us by Hess that it represents to be Hess' estimates of the net reserves, as of December 31, 2018, for the same properties as those which we evaluated. This report was prepared in accordance with guidelines specified in Item 1202 (a)(8) of Regulation S–K and is to be used for inclusion in certain SEC filings by Hess.

Reserves estimates included herein are expressed as net reserves as represented by Hess. Gross reserves are defined as the total estimated petroleum remaining to be produced from these properties after December 31, 2018. Net reserves are defined as that portion of the gross reserves attributable to the interests held by Hess after deducting all interests held by others.

Certain properties in which Hess has represented that it holds an interest are subject to the terms of production sharing contracts (PSC). The terms of these PSCs generally allow for working interest participants to be reimbursed for portions of capital costs and operating expenses and to share in the profits. The reimbursements and profit proceeds are converted to a barrel of oil equivalent or standard cubic foot of gas equivalent by dividing by product prices to estimate the "entitlement quantities." These entitlement quantities are equivalent in principle to net reserves and are used to calculate an equivalent net share, termed an "entitlement interest." In this report, Hess' net reserves or interest for the properties subject to these PSCs is the entitlement based on Hess' working interest.

Estimates of reserves should be regarded only as estimates that may change as production history and additional information become available. Not only are such estimates based on that information which is currently available, but such estimates are also subject to the uncertainties inherent in the application of judgmental factors in interpreting such information.

Information used in the preparation of this report was obtained from Hess. In the preparation of this report we have relied, without independent verification, upon such information furnished by Hess with respect to the property interests being evaluated, production from such properties, current costs of operation and development, current prices for production, agreements relating to current and future operations and sale of production, and various other information and data that were accepted as represented. A field examination of the properties was not considered necessary for the purposes of this report.

Definition of Reserves

Petroleum reserves estimated by Hess included in this report are classified as proved. Only proved reserves have been evaluated for this report. Reserves classifications used by Hess in this report are in accordance with the reserves definitions of Rules 4–10(a) (1)–(32) of Regulation S–X of the SEC. Reserves are judged to be economically producible in future years from known reservoirs under existing economic and operating conditions and assuming continuation of current regulatory practices using conventional production methods and equipment. In the analyses of production-decline curves, reserves were estimated only to the limit of economic rates of production under existing economic and operating conditions using prices and costs consistent with the effective date of this report, including consideration of changes in existing prices provided only by contractual arrangements but not including escalations based upon future conditions. The petroleum reserves are classified as follows:

Proved oil and gas reserves – 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, from known reservoirs, and under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes: (A) The area identified by drilling and limited by fluid contacts, if any; and, (B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and, (B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic and operating conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12 month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Developed oil and gas reserves – Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Undeveloped oil and gas reserves – Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time.

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in Rule 4-10(a)(2) of Regulation S-X, or by other evidence using reliable technology establishing reasonable certainty.

Methodology and Procedures

Estimates of reserves were prepared by the use of appropriate geologic, petroleum engineering, and evaluation principles and techniques that are in accordance with the reserves definitions of Rules 4–10(a) (1)–(32) of Regulation S–X of the SEC and with practices generally recognized by the petroleum industry as presented in the publication of the Society of Petroleum Engineers entitled "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (Revision as of February 19, 2007)" and in Monograph 3 and Monograph 4 published by the Society of Petroleum Evaluation Engineers. The method or combination of methods used in the analysis of each reservoir was tempered by experience with similar reservoirs, stage of development, quality and completeness of basic data, and production history.

Based on the current stage of field development, production performance, the development plans provided by Hess, and analyses of areas offsetting existing wells with test or production data, reserves were classified as proved.

Hess has represented that its senior management is committed to the development plan provided by Hess and that Hess has the financial capability to execute the development plan, including the drilling and completion of wells and the installation of equipment and facilities.

A performance-based methodology integrating the appropriate geology and petroleum engineering data was utilized for the evaluation of all reserves categories. Performance-based methodology primarily includes (1) production diagnostics, (2) decline-curve analysis, and (3) model-based analysis (if necessary, based on availability of data). Production diagnostics include data quality control, identification of flow regimes, and characteristic well performance behavior. Analysis was performed for all well groupings (or type-curve areas).

Characteristic rate-decline profiles from diagnostic interpretation were translated to modified hyperbolic rate profiles, including one or multiple b-exponent values followed by an exponential decline. Based on the availability of data, model-based analysis may be integrated to evaluate long-term decline behavior, the impact of dynamic reservoir and fracture parameters on well performance, and complex situations sourced by the nature of unconventional reservoirs. The methodology used for the analysis was tempered by experience with similar reservoirs, stage of development, quality and completeness of basic data, production history, and the appropriate reserves definitions.

When applicable, the volumetric method was used to estimate the original oil in place (OOIP) and original gas in place (OGIP). Structure maps were prepared to delineate each reservoir, and isopach maps were constructed to estimate reservoir volume. Electrical logs, radioactivity logs, core analyses, and other available data were used to prepare these maps as well as to estimate representative values for porosity and water saturation. When adequate data were available and when circumstances justified, material-balance methods were used to estimate OOIP or OGIP.

Estimates of ultimate recovery were obtained after applying recovery factors to OOIP and OGIP. These recovery factors were based on consideration of the type of energy inherent in the reservoirs, analyses of the petroleum, the structural positions of the properties, and the production histories. When applicable, material balance and other engineering methods were used to estimate recovery factors based on an analysis of reservoir performance, including production rate, reservoir pressure, and reservoir fluid properties.

For depletion-type reservoirs or those whose performance disclosed a reliable decline in producing-rate trends or other diagnostic characteristics, reserves were estimated by the application of appropriate decline curves or other performance relationships. In the analyses of production-decline curves, reserves were estimated only to the limits of economic production as defined under the Definition of Reserves heading of this report or the expiration of the fiscal agreement, as appropriate.

In certain cases, reserves were estimated by incorporating elements of analogy with similar wells or reservoirs for which more complete data were available.

In the evaluation of non-producing and undeveloped reserves, type-well analysis was performed using well data from analogous reservoirs for which more complete historical performance data were available.

Data provided by Hess from wells drilled through December 31, 2018 and made available for this evaluation were used to prepare the reserves estimates herein. These reserves estimates were based on consideration of monthly production data available only through August 2018. Estimated cumulative production, as of December 31, 2018, was deducted from the estimated gross ultimate recovery to estimate gross reserves. This required that production be estimated for up to 4 months.

Oil and condensate reserves estimated herein are to be recovered by normal field separation. NGL reserves estimated herein include C5+ and liquefied petroleum gas (LPG), which consists primarily of propane and butane fractions. NGL reserves are the result of low-temperature plant processing. Oil, condensate, and NGL reserves reported herein are expressed in thousands of barrels (10^3bbl) In these estimates, 1 barrel equals 42 United States gallons. For reporting purposes, oil and condensate reserves have been estimated separately and are presented herein as a summed quantity.

Gas quantities estimated herein are expressed as fuel gas and marketable gas. Marketable gas is defined as the total gas produced from the reservoir after reduction for shrinkage resulting from field separation; processing, including removal of the nonhydrocarbon gas to meet pipeline specifications; and flare and other losses but not from fuel usage. Fuel gas is the gas consumed in operation and is included in marketable gas and estimated herein as reserves. Gas reserves estimated herein are reported as marketable gas. Gas reserves estimated herein are expressed at a temperature base of 60 degrees Fahrenheit (°F) and at a pressure base of 14.7 pounds per square inch absolute (psia). Gas reserves presented in this report are expressed in millions of cubic feet (10^6ft^3).

Gas quantities are identified by the type of reservoir from which the gas will be produced. Nonassociated gas is gas at initial reservoir conditions with no oil present in the reservoir. Associated gas includes both gas-cap gas and solution gas. Gas-cap gas is gas at initial reservoir conditions and is in communication with an underlying oil zone. Solution gas is gas dissolved in oil at initial reservoir conditions. Gas quantities estimated herein include both associated and nonassociated gas.

At the request of Hess, marketable gas reserves estimated herein were converted to oil equivalent using an energy equivalent factor of 6,000 cubic feet of gas per 1 barrel of oil equivalent. This conversion factor was provided by Hess.

Primary Economic Assumptions

This report has been prepared using initial prices, expenses, and costs provided by Hess in United States dollars (U.S.$). Future prices were estimated using guidelines established by the SEC and the Financial Accounting Standards Board (FASB). The following economic assumptions were used for estimating the reserves reported herein:

Oil and Condensate Prices

Hess has represented that the oil and condensate prices were based on a 12-month average price (reference price), calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, unless prices are defined by contractual arrangements. The 12-month average reference prices used were U.S.$65.55 per barrel for West Texas Intermediate and U.S.$72.08 per barrel for Brent. Hess supplied appropriate differentials by field to the relevant reference prices and the prices were held constant thereafter. The volume-weighted average oil and condensate price for the fields evaluated was U.S.$63.87 per barrel.

NGL Prices

Hess has represented that the NGL prices were based on a 12 month average price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, unless prices are defined by contractual arrangements. These prices were held constant over the lives of the properties. The volume-weighted average NGL price for the fields evaluated was U.S.$8.10 per barrel.

Gas Prices

Hess has represented that gas prices were based on reference prices, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12 month period prior to the end of the reporting period, unless prices are defined by contractual arrangements. The 12-month average reference price for NYMEX was U.S.$3.01 per thousand cubic feet and the UK International Petroleum Exchange reference price was U.S.$7.79 per million British thermal units. The gas prices were adjusted for each property using differentials to the NYMEX or UK International Petroleum Exchange reference prices furnished by Hess and held constant thereafter. The volume-weighted average gas price for the fields evaluated was U.S.$2.39 per thousand cubic feet.

Operating Expenses, Capital Costs, and Abandonment Costs

Estimates of operating expenses, provided by Hess and based on current expenses, were held constant for the lives of the properties. Future capital expenditures were estimated using 2018 values, provided by Hess, and were not adjusted for inflation. In certain cases, future expenditures, either higher or lower than current expenditures, may have been used because of anticipated changes in operating conditions, but no general escalation that might result from inflation was applied. Abandonment costs, which are those costs associated with the removal of equipment, plugging of the wells, and reclamation and restoration associated with the abandonment, were provided by Hess and were not adjusted for inflation. Operating expenses, capital costs, and abandonment costs were considered, as appropriate, in determining the economic viability of the developed non-producing and undeveloped reserves.

In our opinion, the information relating to estimated proved reserves of oil, condensate, natural gas liquids, and gas contained in this report has been prepared in accordance with Paragraphs 932-235-50-4, 932-235-50-6, 932-235-50-7, and 932 235-50-9 of the Accounting Standards Update 932-235-50, Extractive Industries – Oil and Gas (Topic 932): Oil and Gas Reserve Estimation and Disclosures (January 2010) of the Financial Accounting Standards Board and Rules 4–10(a) (1)–(32) of Regulation S–X and Rules 302(b), 1201, and 1202(a) (1), (2), (3), (4), (8) of Regulation S–K of the Securities and Exchange Commission; provided, however, that estimates of proved developed and proved undeveloped reserves are not presented at the beginning of the year.

To the extent the above-enumerated rules, regulations, and statements require determinations of an accounting or legal nature, we, as engineers, are necessarily unable to express an opinion as to whether the above-described information is in accordance therewith or sufficient therefor.

Summary of Conclusions

Hess has represented that its estimated net proved reserves attributable to the evaluated properties were based on the definition of proved reserves of the SEC. The Hess net proved reserves attributable to these properties, as of December 31, 2018, and which represent approximately 80.3 percent of total Hess net reserves on a net equivalent barrel basis, are summarized as follows, expressed in millions of barrels (10^6bbl), billions of cubic feet (10^9ft^3), and millions of barrels of oil equivalent (10^6boe):

Estimated by Hess
Net Proved Reserves as of December 31, 2018

	Oil and Condensate (10^6bbl)	NGL (10^6bbl)	Marketable Gas (10^9ft^3)	Oil Equivalent (10^6boe)
United States	477	169	724	766
Europe	39	0	78	52
Asia and Other	8	0	785	139
Total	**524**	**169**	**1,587**	**957**

Notes:

1. Marketable gas reserves estimated herein were converted to oil equivalent using an energy equivalent factor of 6,000 cubic feet of gas per 1 barrel of oil equivalent.
2. Totals may vary due to rounding.
3. Net proved fuel gas reserves included as a portion of marketable gas reserves were estimated to be 162 10^9ft^3.

In comparing the detailed net proved reserves estimates by field prepared by DeGolyer and MacNaughton and by Hess, differences have been found, both positive and negative, resulting in an aggregate difference of less than 1 percent when compared on the basis of net equivalent barrels. It is DeGolyer and MacNaughton's opinion that the total net proved reserves estimates prepared by Hess, as of December 31, 2018, on the properties evaluated and referred to above, when compared on the basis of net equivalent barrels, do not differ materially from those prepared by DeGolyer and MacNaughton.

Hess' oil and gas reserves have been estimated assuming the continuation of the current regulatory environment. Foreign oil-producing countries, including members of the Organization of Petroleum Exporting Countries (OPEC), may impose production quotas which limit the supply of oil that can be produced. Generally, these production quotas affect the timing of production, rather than the total volume of oil or gas reserves estimated.

Changes in the regulatory environment by host governments may affect the operating environment and oil and gas reserves estimates of industry participants. Such regulatory changes could include increased mandatory government participation in producing contracts, changes in royalty terms, cancellation or amendment of contract rights, or expropriation or nationalization of property. While the oil and gas industry is subject to regulatory changes that could affect an industry participant's ability to recover its reserves, neither we nor Hess are aware of any such governmental actions which restrict the recovery of the December 31, 2018, estimated reserves.

DeGolyer and MacNaughton is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1936. DeGolyer and MacNaughton does not have any financial interest, including stock ownership, in Hess. Our fees were not contingent on the results of our evaluation. This letter report has been prepared at the request of Hess. DeGolyer and MacNaughton has used all data, procedures, assumptions and methods that it considers necessary to prepare this report.

Submitted,

/s/ DeGolyer and MacNaughton
DeGOLYER and MacNAUGHTON
Texas Registered Engineering Firm F-716

/s/ Thomas C. Pence, P.E.
Thomas C. Pence, P.E.
Senior Vice President
DeGolyer and MacNaughton

[SEAL]

CERTIFICATE of QUALIFICATION

I, Thomas C. Pence, Petroleum Engineer with DeGolyer and MacNaughton, 5001 Spring Valley Road, Suite 800 East, Dallas, Texas, 75244 U.S.A., hereby certify:

1. That I am a Senior Vice President of DeGolyer and MacNaughton, which firm did prepare the report of third party dated February 6, 2019, on the proved reserves evaluation of certain properties attributable to Hess Corporation, and that I, as Senior Vice President, was responsible for the preparation of this report of third party.

2. That I attended Texas A&M University, and that I graduated with a Bachelor of Science degree in Petroleum Engineering in 1982; that I am a Registered Professional Engineer in the State of Texas; that I am a member of the Society of Petroleum Engineers and that I have in excess of 36 years of experience in oil and gas reservoir studies and reserves evaluations.

/s/ Thomas C. Pence, P.E.

[SEAL]

Thomas C. Pence, P.E.
Senior Vice President
DeGolyer and MacNaughton