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, 2016

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**
Depositary Shares, each representing 1/20th interest in a share of 8% Series A Mandatory Convertible Preferred 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 submitted electronically and posted on its Corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☑ No ☐

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

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

Large accelerated filer	☑	Accelerated filer	☐	Non-accelerated filer	☐	Smaller reporting company	☐
				(Do not check if a smaller reporting company)			

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 $16,770,000,000, computed using the outstanding common shares and closing market price on June 30, 2016, the last business day of the Registrant's most recently completed second fiscal quarter.

At December 31, 2016, there were 316,523,200 shares of Common Stock outstanding.

Part III is incorporated by reference from the Proxy Statement for the 2017 annual meeting of stockholders.

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Unless the context indicates otherwise, references to “Hess”, the “Corporation”, “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,” “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. Forward-looking statements are subject to certain risks and uncertainties that could cause actual results to differ materially from our historical experience and our current projections or expectations. As and when made, we believe that these forward-looking statements are reasonable. However, 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. We are not obligated to publicly update or revise any forward-looking statements, whether as a result 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 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. See the average selling prices in the table on page 9.

Boepd – Barrels of oil equivalent per day.

Bopd – Barrels of oil per day.

Carried interest – An interest in an oil and gas property where the carrying party agrees to pay for all or part of development and operating costs of another party. The carrying party may then recover a specified amount of costs from the other party's share of any hydrocarbon revenues.

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 – Exploratory or development well that does not produce oil or 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.

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

Fractionation – Fractionation is the process by which the mixture of NGLs 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.

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 found in natural gas, including ethane, butane, isobutane, propane and natural gasoline that can be collectively removed from produced natural gas, separated into these substances and sold. Natural gas liquids do not sell at prices equivalent to crude oil. See the average selling prices in the table on page 9.

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 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 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, Equatorial Guinea, the Malaysia/Thailand Joint Development Area (JDA), Malaysia, and Norway. The Bakken Midstream operating segment, which was established in the second quarter of 2015, provides fee-based services, including gathering, compressing and processing natural gas and fractionating natural gas liquids, or NGLs; gathering, terminaling, loading and transporting crude oil and NGLs; and storing and terminaling propane, 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, excluding escalations based on future conditions. Crude oil prices used in the determination of proved reserves at December 31, 2016 were $42.68 per barrel for WTI (2015: $50.13) and $44.45 per barrel for Brent (2015: $55.10).

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)	
	2016	2015	2016	2015	2016	2015	2016	2015
	(Millions of bbls)		(Millions of bbls)		(Millions of mcf)		(Millions of bbls)	
Developed								
United States	**245**	253	**59**	51	**404**	368	**371**	365
Europe (a)	**116**	114	**3**	12	**125**	123	**140**	147
Africa	**138**	148	**—**	—	**132**	137	**160**	171
Asia	**5**	5	**—**	—	**739**	643	**128**	112
	504	520	**62**	63	**1,400**	1,271	**799**	795
Undeveloped								
United States	**110**	93	**27**	23	**186**	137	**168**	139
Europe (a)	**94**	89	**5**	15	**95**	111	**115**	122
Africa	**24**	24	**—**	—	**11**	11	**26**	26
Asia	**—**	—	**—**	—	**5**	24	**1**	4
	228	206	**32**	38	**297**	283	**310**	291
Total								
United States	**355**	346	**86**	74	**590**	505	**539**	504
Europe (a)	**210**	203	**8**	27	**220**	234	**255**	269
Africa	**162**	172	**—**	—	**143**	148	**186**	197
Asia	**5**	5	**—**	—	**744**	667	**129**	116
	732	726	**94**	101	**1,697**	1,554	**1,109**	1,086

(a) Proved reserves in Norway, which represented 18% of our total proved reserves at December 31, 2016 (2015: 21%), were as follows:

	Crude Oil & Condensate		*Natural Gas Liquids*		*Natural Gas*		*Total Barrels of Oil Equivalent (BOE)*	
	2016	*2015*	*2016*	*2015*	*2016*	*2015*	*2016*	*2015*
	(Millions of bbls)		*(Millions of bbls)*		*(Millions of mcf)*		*(Millions of bbls)*	
Developed	***75***	*86*	***3***	*12*	***72***	*84*	***90***	*112*
Undeveloped	***90***	*85*	***5***	*15*	***88***	*107*	***110***	*118*
Total	***165***	*171*	***8***	*27*	***160***	*191*	***200***	*230*

Proved undeveloped reserves were 28% of our total proved reserves at December 31, 2016 on a boe basis (2015: 27%). Proved reserves held under production sharing contracts totaled 4% of our crude oil reserves and 45% of our natural gas reserves at December 31, 2016 (2015: 5% 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 84 through 94.

Production

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

	2016	2015	2014
Crude oil	**(Thousands of barrels)**		
United States			
Bakken	**24,881**	29,579	23,997
Other Onshore	**3,209**	3,814	3,587
Total Onshore	**28,090**	33,393	27,584
Offshore	**16,649**	20,391	18,702
Total United States	**44,739**	53,784	46,286
Europe			
Norway	**8,387**	9,985	9,275
Denmark	**3,636**	3,981	3,994
	12,023	13,966	13,269
Africa			
Equatorial Guinea	**11,898**	15,881	15,869
Libya	**387**	20	1,410
Algeria	**—**	2,589	2,364
	12,285	18,490	19,643
Asia			
JDA and Other	**768**	809	1,030
	768	809	1,030
Total	**69,815**	87,049	80,228

	2016	2015	2014
	(Thousands of barrels)		
Natural gas liquids			
United States			
Bakken	**9,701**	7,438	3,759
Other Onshore	**4,205**	4,215	2,376
Total Onshore	**13,906**	11,653	6,135
Offshore	**1,724**	2,258	2,283
Total United States	**15,630**	13,911	8,418
Europe - Norway	**408**	499	501
Asia	**—**	—	10
Total	**16,038**	14,410	8,929

	2016	2015	2014
Natural gas		(Thousands of mcf)	
United States			
Bakken	**22,312**	23,214	14,612
Other Onshore	**48,597**	39,929	17,091
Total Onshore	**70,909**	63,143	31,703
Offshore	**23,603**	31,751	28,426
Total United States	**94,512**	94,894	60,129
Europe			
Norway	**8,541**	9,973	8,951
Denmark	**7,128**	5,588	4,184
	15,669	15,561	13,135
Asia and Other			
JDA	**68,031**	83,900	80,941
Malaysia (a)	**13,151**	18,994	21,916
Other	**—**	—	11,031
	81,182	102,894	113,888
Total	**191,363**	213,349	187,152
Total Barrels of Oil Equivalent (in millions)	**118**	137	120

(a) Includes 3,624 thousand mcf of production for 2016 (2015: 5,321 thousand mcf; 2014: 7,435 thousand mcf) from Block PM301 which is unitized into the JDA.

E&P Operations

A description of our significant E&P operations is as follows:

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, the Utica Basin of Ohio and the Permian Basin of Texas and from offshore properties in the Gulf of Mexico.

Onshore:

Bakken: At December 31, 2016, we held 577,000 net acres in the Bakken with varying working interest percentages. During 2016, we operated an average of 3.3 rigs, drilled 71 wells, completed 92 wells, and brought on production 100 wells, bringing the total operated production wells to 1,272. Drilling and completion costs per operated well averaged $4.8 million in 2016, down 17% from 2015. In 2016, we also increased our standard well design to a 50-stage completion from the previous 35-stage completion. The improved efficiency of our drilling operations can largely be attributed to application of our lean manufacturing capabilities. During 2017, we plan to increase our rig count to six rigs from two rigs, for an average of 3.5 rigs, to drill approximately 80 wells and to bring approximately 75 wells on production. Net production for full year 2017 is forecast to be in the range of 95,000 boepd to 105,000 boepd. With the building rig count we expect our Bakken production in the fourth quarter of 2017 to average between 105,000 boepd and 110,000 boepd, which would represent an increase of approximately 15% from the first quarter to the fourth quarter.

Utica: We own a 50% working interest in approximately 45,000 net acres in the wet gas area of the Utica Basin of Ohio. During 2016, a total of 6 wells were drilled, 6 wells were completed and 14 wells were brought on production. In March 2016, we and our joint venture partner released the remaining Hess operated rig. At December 31, 2016, we had 5 wells drilled but not completed on a single well pad. We do not plan to drill any wells in 2017.

Permian: We operate and hold a 34% interest in the Seminole-San Andres Unit in the Permian Basin.

Offshore: At December 31, 2016, we held interests in 76 blocks in the deepwater Gulf of Mexico. Our production offshore in the Gulf of Mexico was principally from the Baldpate (Hess 50%), Conger (Hess 38%), Hack Wilson (Hess 25%), Llano (Hess 50%), Penn State (Hess 50%), Shenzi (Hess 28%) and Tubular Bells (Hess 57%) fields. In addition, we are operator of the Stampede development project (Hess 25%). At December 31, 2016, we held approximately 190,000 net undeveloped acres, of which leases covering approximately 85,000 acres are due to expire in the next three years.

A description of our significant operations in the Gulf of Mexico is as follows:

Conger: At this Hess operated field, we drilled and brought online an additional production well during the year. In addition, one well was shut-in for an extended period in 2016 in order to replace a subsurface valve.

Penn State: At this Hess operated field, we intend to drill one production well in 2017.

Shenzi: At this BHP Billiton Petroleum operated field, drilling continued during 2016 with the completion of a water injection well. In 2017, the operator plans to defer further drilling activity.

Tubular Bells: At this Hess operated field, we brought online a fifth production well and one water injector well, completing the initial drilling campaign. Three wells were shut-in for an extended period in 2016 due to subsurface valve failures. These valves have since been replaced and we are pursuing our options to recover damages for these valve failures.

Stampede: At this Hess operated project in the Green Canyon area of the Gulf of Mexico, the co-owners sanctioned the field development and committed to two deepwater drilling rigs in 2014. In 2016, the topsides deck was installed on the hull, and fabrication and pre-commissioning of the topsides continues according to plan. We also completed installation of subsea equipment at both drill centers in the field, drilled one development well, and commenced drilling on one water injector well. First production from the field is targeted for 2018, and is expected to ramp up to a net rate of approximately 15,000 boepd.

Europe

Norway: In 2016, Aker BP assumed operatorship from BP of the offshore Valhall Field (Hess 64%). During 2016, well abandonment activities were conducted as part of a multi-year program that will continue into 2017. In 2017, the operator plans to drill two production wells from the existing platform rig, of which one well is expected to be completed in the fourth quarter. In 2017, net production is expected to average between 25,000 boepd to 30,000 boepd.

Denmark: At the Hess operated offshore South Arne Field (Hess 62%), we completed drilling of a previously sanctioned eleven well multi-year program. In addition, the Danish government awarded a 20-year extension to the South Arne Field license, extending expiry to 2047.

Africa

Equatorial Guinea: At the Hess operated offshore Block G (Hess 85% paying interest, national oil company of Equatorial Guinea 5% carried interest), we have production from the Okume and Ceiba Fields. In 2016, there were no drilling operations and there are no plans for drilling in 2017.

Ghana: At the Hess operated offshore Deepwater Tano/Cape Three Points license (Hess 50% license interest), we have drilled seven successful exploration wells on the block since 2011. In May 2013, we submitted appraisal plans for each of the seven discoveries, which comprise both oil and natural gas, to the Ghanaian government for approval. Five appraisal plans have been approved. In 2014, we drilled three successful appraisal wells. Well results continue to be evaluated and development planning is progressing. The government of Côte d'Ivoire has challenged the maritime border between it and the country of Ghana, which includes a portion of our Deepwater Tano/Cape Three Points license. We are unable to proceed with development of this license until there is a resolution of this matter, which may also impact our ability to develop the license. The International Tribunal for Law of the Sea is expected to render a final ruling on the maritime border dispute in 2017. Under terms of our license and subject to resolution of the border dispute, we have declared commerciality for four discoveries, including the Pecan Field in March 2016, which would be the primary development hub for the block. We are continuing to work with the government on how best to progress work on the block given the maritime border dispute. See *Capitalized Exploratory Well Costs* in *Note 4, Property, Plant and Equipment* in the *Notes to Consolidated Financial Statements* for details of wells capitalized at December 31, 2016.

Libya: At the onshore Waha concession in Libya, which include the Defa, Faregh, Gialo, North Gialo and Belhedan Fields (Hess 8%), the operator has shut in production for extended periods over the last three years due to force majeure caused by civil unrest. The national oil company of Libya lifted force majeure in September 2016 and production recommenced in October 2016. Net production averaged 1,000 bopd in 2016, zero in 2015, and 4,000 bopd in 2014. We have after-tax net book value in our Libyan operations of approximately $135 million and total proved reserves of 159 million boe at December 31, 2016.

Asia and Other

***Malaysia/Thailand Joint Development Area (JDA)*:** At the Carigali Hess operated offshore Block A-18 in the Gulf of Thailand (Hess 50%), the operator continued development drilling and completed installation and commissioning of a major booster compression project in 2016. No drilling is planned for 2017 as contracted volumes are expected to be met as a result of the booster compression project.

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 Blocks PM302, PM325 and PM326B located in the North Malay Basin (NMB), offshore Peninsular Malaysia, where we operate a multi-phase natural gas development project. In 2016, we completed the installation of three remote wellhead platforms and the jacket of the central processing platform. We also achieved mechanical completion of the central processing platform topsides and transport to the field via a heavy lift vessel is planned for the first quarter of 2017. We expect net production from NMB to increase from 26 million cubic feet per day in 2016 to approximately 165 million cubic feet per day following the completion of full field development in the third quarter of 2017.

Australia: At the WA-390-P and WA-474-P blocks (Hess 100%) in the Carnarvon Basin, offshore Western Australia (also known as Equus) covering approximately 658,000 acres, we have drilled 13 natural gas discoveries and 6 appraisal wells. 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 government of Australia of our intent to defer further development of the project. As a result, we recognized an after-tax charge of $693 million to expense capitalized exploratory well costs and other project related costs.

Guyana: At the Esso Exploration and Production Guyana Limited operated offshore Stabroek Block (Hess 30% participating interest), the operator announced a significant oil discovery at the Liza-1 well in 2015. During 2016, the operator completed a 17,000 square kilometer 3D seismic acquisition on the Stabroek Block and drilled the Liza-2 and Liza-3 wells, both of which encountered hydrocarbons. Pre-development planning and appraisal activities are underway and we expect to be in a position to sanction the first phase of the Liza development in mid-2017 with first production expected in 2020. At the Skipjack prospect 25 miles northwest of the Liza discovery, the operator completed the drilling of an exploration well, which was unsuccessful and expensed. In November 2016, the operator commenced drilling of the Payara-1 exploration well, located approximately 10 miles northwest of the Liza discovery, and in January 2017 announced results confirming the well as a second oil discovery on the block. In 2017, the operator plans to drill a well at the Snoek exploration prospect, a Liza-4 appraisal well, and a Payara-2 appraisal well. In addition, the operator will evaluate additional exploration opportunities on the broader Stabroek block.

Suriname: In 2016 we acquired a 33% non-operated participating interest in the Kosmos Energy Ltd. operated Block 42 contract area, offshore Suriname, which is located in the Guyana-Suriname basin. The operator completed a 6,500 square kilometer 3D seismic shoot in January 2017.

Canada: At the four BP operated exploration licenses offshore Nova Scotia (Hess 50% participating interest), the operator expects to drill its first exploration well in 2018.

Sales Commitments

We have certain long-term contracts with fixed minimum sales volume commitments for natural gas and natural gas liquids production. At the JDA in the Gulf of Thailand, we have annual minimum net sales commitments of approximately 70 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 Malaysia, we have annual net sales commitments of approximately 50 billion cubic feet per year from completion of full field development which is expected in the third quarter of 2017 through 2024. The Corporation’s estimated total volume of production subject to sales commitments over the remaining term of the contracts is approximately 1.1 trillion cubic feet of natural gas. We also have natural gas liquids minimum delivery commitments, primarily in the Bakken through 2023, of approximately 10 million barrels per year, or approximately 70 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:

	2016	2015	2014
Average selling prices (a)			
Crude oil - per barrel (including hedging)			
United States			
Onshore	**$ 36.92**	$ 42.67	$ 81.89
Offshore	**37.47**	46.21	95.05
Total United States	**37.13**	44.01	87.21
Europe (b)	**43.33**	55.10	104.21
Africa	**41.88**	53.89	97.31
Asia	**42.98**	52.74	89.71
Worldwide	**39.20**	47.85	92.59
Crude oil - per barrel (excluding hedging)			
United States			
Onshore	**$ 36.92**	$ 41.22	$ 81.89
Offshore	**37.47**	46.21	92.22
Total United States	**37.13**	43.11	86.06
Europe (b)	**43.33**	52.37	99.20
Africa	**41.88**	51.57	93.70
Asia	**42.98**	52.74	89.71
Worldwide	**39.20**	46.37	90.20
Natural gas liquids - per barrel			
United States			
Onshore	**$ 9.18**	$ 9.18	$ 28.92
Offshore	**13.96**	14.40	30.40
Total United States	**9.71**	10.02	29.32
Europe (b)	**19.48**	24.59	52.66
Worldwide	**9.95**	10.52	30.59
Natural gas - per mcf			
United States			
Onshore	**$ 1.48**	$ 1.64	$ 3.18
Offshore	**1.99**	2.03	3.79
Total United States	**1.61**	1.77	3.47
Europe (b)	**3.97**	6.72	10.00
Asia	**5.31**	5.97	6.94
Worldwide	**3.37**	4.16	6.04
Average production (lifting) costs per barrel of oil equivalent produced (c)			
United States			
Onshore	**$ 18.75**	$ 18.68	$ 20.90
Offshore	**18.88**	7.03	5.06
Total United States	**18.79**	14.80	14.60
Europe (b)	**21.28**	23.61	28.93
Africa	**20.53**	23.12	22.41
Asia and other	**11.91**	8.34	9.11
Worldwide	**18.45**	16.17	16.86

(a) Includes inter-company transfers valued at approximate market prices and, primarily onshore United States, is adjusted for certain processing and distribution fees.

(b) 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 natural gas liquids and $5.22 per mcf for natural gas (2015: $54.89, $52.15, $24.59 and $8.58, respectively; 2014: $105.35, $100.34, $52.13 and $12.22, respectively). The average production (lifting) costs in Norway were $24.70 per barrel of oil equivalent in 2016 (2015: $25.81; 2014: $33.52).

(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 Bakken 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.

Gross and Net Undeveloped Acreage

At December 31, 2016 gross and net undeveloped acreage amounted to:

	Undeveloped Acreage (a)	
	Gross	Net
	(In thousands)	
United States	481	369
Europe	169	91
Africa	3,831	521
Asia and other	13,483	5,758
Total (b)	17,964	6,739

(a) Includes acreage held under production sharing contracts.
(b) At December 31, 2016, licenses covering approximately 5% of our net undeveloped acreage held are scheduled to expire during the next three years pending the results of exploration activities.

Gross and Net Developed Acreage, and Productive Wells

At December 31, 2016 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	1,293	827	2,822	1,365	177	84
Europe (b)	102	59	73	46	—	—
Africa	9,629	833	767	94	—	—
Asia and other	356	178	—	—	83	44
Total	11,380	1,897	3,662	1,505	260	128

(a) Includes multiple completion wells (wells producing from different formations in the same bore hole) totaling 93 gross wells and 55 net wells.
(b) Gross and net developed acreage in Norway was approximately 57 thousand and 36 thousand, respectively. Gross and net productive oil wells in Norway were 52 and 33, respectively.

Exploratory and Development Wells

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

	Net Exploratory Wells			Net Development Wells		
	2016	2015	2014	2016	2015	2014
Productive wells						
United States	**—**	—	8	**83**	181	202
Europe	**—**	—	—	**1**	5	4
Africa	**—**	—	2	**—**	—	4
Asia and other	**—**	3	—	**—**	1	4
	—	3	10	**84**	187	214
Dry holes						
United States	**1**	—	1	**—**	—	—
Europe	**—**	—	—	**—**	—	—
Africa	**—**	1	—	**—**	—	—
Asia and other (a)	**1**	5	3	**—**	—	—
	2	6	4	**—**	—	—
Total	**2**	9	14	**84**	187	214

(a) 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, 2016 the number of wells in the process of drilling amounted to:

	Gross Wells	Net Wells
United States	17	10
Asia and other	15	7
Total	32	17

Bakken Midstream

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. HIP and its affiliates primarily comprise the Bakken Midstream operating segment which provides fee-based services. The Bakken Midstream operating segment generates substantially all of its revenues by charging fees for gathering, compressing and processing natural gas and fractionating natural gas liquids, or NGLs; gathering, terminaling, loading and transporting crude oil and NGLs; and storing and terminaling propane, primarily in the Bakken and Three Forks Shale plays in the Williston Basin area of North Dakota. The Bakken Midstream operating segment 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 Bakken Midstream assets and operations under various operational and administrative services agreements.

Bakken Midstream assets include 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 1,211 miles of high and low pressure natural gas and NGL gathering pipelines with a current capacity of up to 345 mmcfd, including an aggregate compression capacity of 174 mmcfd. The system also includes the Hawkeye Gas Facility, which contributes 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, when completed, the Johnson's Corner Header System. The crude oil gathering system consists of approximately 365 miles of crude oil gathering pipelines with a current capacity of up to 161,000 bopd. The system also includes the Hawkeye Oil Facility, which contributes 76,000 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 250 mmcfd and fractionation capacity of 60,000 boepd.
- *Mentor Storage Terminal.* A propane storage cavern and rail and truck loading and unloading facility located in Mentor, Minnesota, with approximately 328,000 boe of working storage capacity.
- *Ramberg Terminal Facility.* A crude oil pipeline and truck receipt terminal located in Williams County, North Dakota that is capable of delivering up to 282,000 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. During the summer of 2016, Hess piloted five third-party NGL unit trains consisting of 60 NGL rail cars that originated at the Tioga Rail Terminal.
- *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, with the exception of electronically controlled pneumatic brakes which, if required, can be added at a later date, prior to the regulation deadline, for minimal cost. In addition, HIP also has 956 older specification crude oil rail cars that are capable of being upgraded to the most recent DOT-117 safety standards. In 2016, we recorded an impairment charge against these older specification rail cars. See *Note 6, Impairment* in *Notes to Consolidated Financial Statements*.
- *Johnson's Corner Header System.* We are currently constructing the Johnson's Corner Header System, a crude oil pipeline header system located in McKenzie County, North Dakota that will receive crude oil by pipeline from Hess and third parties and deliver crude oil to third-party interstate pipeline systems. At commissioning, the facility will have a delivery capacity of approximately 100,000 bopd of crude oil. We expect the Johnson's Corner Header System to enter into service in 2017.

HIP owns 100% of Hess Midstream Partners LP, which was formed to own, operate, develop and acquire a diverse set of midstream assets to provide fee-based services to both Hess Corporation and third party customers as a publicly traded master limited partnership upon the future completion of an initial public offering of limited partnership units. Hess Midstream Partners LP filed an amendment to its registration statement on Form S-1 on February 13, 2017. The assets to be held by Hess Midstream Partners LP at the time of its initial public offering are expected to include a 20% economic interest in Hess North Dakota Pipelines Operations LP (owner of the natural gas gathering and compression and crude oil gathering systems), a 20% economic interest in Hess TGP Operations LP (owner of the Tioga gas plant), a 20% economic interest in

Hess North Dakota Export Logistics Operations LP (owner of the Tioga rail terminal, Ramberg terminal facility and 550 crude oil rail cars), and a 100% interest in Hess Mentor Storage Holdings LLC (owner of the Mentor storage terminal).

Beginning January 1, 2017, Hess's Midstream segment will include our interest in a Permian gas plant in West Texas and related CO_2 assets, and water handling assets in North Dakota as a result of organizational changes to the management of the assets. These assets are wholly-owned by the Corporation and are not included in our HIP joint venture.

Divested Downstream Businesses

In 2013, we announced several initiatives to continue our transformation from an integrated energy company into a more geographically focused pure play E&P company. The transformation plan included fully exiting the Corporation's Marketing and Refining (M&R) business, including its terminal, retail, energy marketing and energy trading operations, as well as the permanent shutdown of refining operations at its Port Reading, NJ facility. See *Note 9, Discontinued Operations* in *Notes to Consolidated Financial Statements*.

HOVENSA LLC (HOVENSA), a 50/50 joint venture between the Corporation's subsidiary, Hess Oil Virgin Islands Corp. (HOVIC), and a subsidiary of Petroleos de Venezuela S.A. (PDVSA), had previously shut down its U.S. Virgin Islands refinery in 2012 and filed a voluntary petition for relief under Chapter 11 of the United States Bankruptcy Code in the United States District Court of the Virgin Islands in September 2015. In January 2016, a sale of HOVENSA's terminal and refinery assets to Limetree Bay Terminals, LLC was completed and the Bankruptcy Court entered an order confirming HOVENSA's Chapter 11 plan of liquidation (the "Liquidation Plan"). Under the Liquidation Plan, HOVENSA established a liquidating trust to distribute certain assets and sale proceeds to its creditors, established an environmental response trust to administer to HOVENSA's remaining environmental obligations and to conduct an orderly wind-down of its remaining activities. See *Note 10, HOVENSA LLC* in *Notes to Consolidated Financial Statements*.

Competition and Market Conditions

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

Other Items

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 risk appropriate and are maintained, reviewed and updated as necessary to confirm their accuracy and suitability. Where appropriate, 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 anywhere in the world. 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. These owned 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 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 a number of 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 $3.19 billion in total, depending on the asset coverage level, as described above. 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 (regardless of cause, including gross negligence and willful misconduct) and the Contractor is responsible for and indemnifies us for all claims attributable to pollution emanating from the Contractor’s property. 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 the value of the contract or a fixed amount.

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 $10 million in 2016 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, 2016, we had 2,304 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, natural gas liquids 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, natural gas liquids 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, natural gas liquids and natural gas, political conditions and events (including instability, changes in governments, or armed conflict) around the world and in particular in crude oil or natural gas producing regions, the cost of exploring for, developing and producing crude oil, natural gas liquids 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, natural gas liquids and natural gas. Average prices for 2016 were $43.47 per barrel for WTI (2015: $48.76; 2014: $92.91) and $45.13 per barrel for Brent (2015: $53.60; 2014: $99.45). 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. Persistent lower crude oil and natural gas prices, such as those currently prevailing, 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 significantly in 2015 and to a lesser extent in 2016 resulting in reductions to our reported proved reserves. If crude oil prices in 2017 average below prices used to determine proved reserves at December 31, 2016, it could have an adverse effect on our estimated proved reserves and 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, limitations on access to exploration and development opportunities, anti-bribery or anti-corruption laws, as well as other political developments may affect our operations.

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. For example, in 2016, we had a significant net loss and, if commodity prices remain low through 2017, we are forecasting a net loss for 2017. Two of the three major credit rating agencies that rate our debt have assigned an investment grade rating. In February 2016, Standard and Poor's Ratings Services (S&P) lowered our investment grade credit rating one notch to BBB- with stable outlook and Moody's Investors Service (Moody's) lowered our credit rating to Ba1 with stable outlook, which is below investment grade. In December 2016, Fitch Ratings (Fitch) lowered our investment grade credit rating one notch to BBB- with stable outlook. In February 2017, S&P re-affirmed our investment grade credit rating of BBB- with stable outlook. Although, currently we do not have any borrowings under our long-term credit facility, further ratings downgrades, 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, further ratings downgrades 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, and the partners with whom we operate, are politically less stable than other areas and partners and may be subject to civil unrest, conflict, insurgency, geographic territorial border disputes, corruption, security risks and labor unrest. Political and civil unrest in North Africa and the Middle East has affected and may affect our operations in these areas as well as oil and gas markets generally. 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 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 used to produce petroleum fuels, which through normal customer use may 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.

Our industry is highly competitive and many of our competitors are larger and have greater resources than we have. The petroleum industry is highly competitive and very capital intensive. We encounter competition from numerous companies in each of our activities, including acquiring rights to explore for crude oil and natural gas. Many competitors, including national oil companies, are larger and have substantially greater resources. We are also in competition with producers of other forms of energy. Increased competition for worldwide oil and gas assets could significantly increase the cost of acquiring 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.

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 risks include hurricanes, fires, explosions, blowouts, such as the third-party accident at the Macondo prospect, pipeline interruptions and ruptures, severe weather, geological events, labor disputes or cyber-attacks. Although we maintain insurance coverage against 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. We are involved in several large development projects and the completion of those projects may be delayed beyond what was originally anticipated. 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. The derivation and monitoring of successful strategies and related policies may be negatively impacted by the departure of key members of senior management. Moreover, an inability to recruit and retain adequate numbers of experienced technical and professional personnel in the necessary locations may prohibit us from executing our strategy in full or, in part, with a commensurate impact on shareholder value.

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 impacts amounts due from the sale of hydrocarbons. We may enter into commodity price hedging arrangements to protect us from commodity price declines. These arrangements may, depending on the instruments used and the level of increases involved, limit any potential upside from commodity price increases. As with accounts receivable 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.

Cyber-attacks targeting computer, telecommunications systems, and infrastructure used by the oil and gas industry 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. Cyber-attacks could compromise our computer and telecommunications systems and result in disruptions to our business operations or the 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 cyber-attack against these operating systems, or 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 cyber-attack could have a material adverse impact on our cash flows and results of operations. 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, 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. In addition, as technologies evolve and these attacks become more sophisticated, we may incur significant costs to upgrade or enhance our security measures to protect against such attacks.

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 is a defective product and that these parties 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. In June 2014, the Commonwealth of Pennsylvania and the State of Vermont each filed independent lawsuits alleging that we and all major oil companies with operations in each respective state, have damaged the groundwater in those states by introducing thereto gasoline with MTBE. The Pennsylvania suit has been removed to Federal court and has been forwarded to the existing MTBE multidistrict litigation pending in the Southern District of New York. The suit filed in Vermont is proceeding there in a state court. In September 2016, the State of Rhode Island also filed a lawsuit in Federal court alleging that we and other major oil companies damaged the groundwater in Rhode Island by introducing thereto gasoline with MTBE. An action brought by the Commonwealth of Puerto Rico was settled in conjunction with the Bankruptcy Court's confirmation of HOVENSA's Liquidation Plan, which is described below. The remaining open matters are not expected to have a material adverse effect on our financial condition.

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. In April 2014, the EPA issued a Focused Feasibility Study (FFS) proposing to conduct bank-to-bank dredging of the lower eight miles of the Lower Passaic River at an estimated cost of $1.7 billion. 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, 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, 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 there are numerous other parties who we expect will share in the cost of remediation and damages and our former terminal did not store or use contaminants which are of the greatest concern in the river sediments and could not have contributed contamination along most of the river's length.

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 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 neutral experts selected by the parties will determine the final shares of the Remedial Design costs to be paid by each of the participants. The parties have not yet addressed the allocation of costs associated with implementing the remedy that is currently being designed. This matter is not expected to have a material adverse effect on our financial condition.

On January 18, 2017, we entered into a Consent Decree with the North Dakota Department of Health resolving alleged non-compliance with North Dakota's air pollution laws and provisions of the federal Clean Air Act. Pursuant to the Consent Decree, we are required to implement corrective actions, including implementation of a leak detection and repair program, at most of our existing facilities in North Dakota. We were assessed a base penalty of $922,000, which is subject to adjustment based on the date we complete corrective actions required under the terms of the Consent Decree. We made an initial penalty payment of $55,000 during the first quarter of 2017.

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.

We are from time to time 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 such 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). High and low sales prices were as follows:

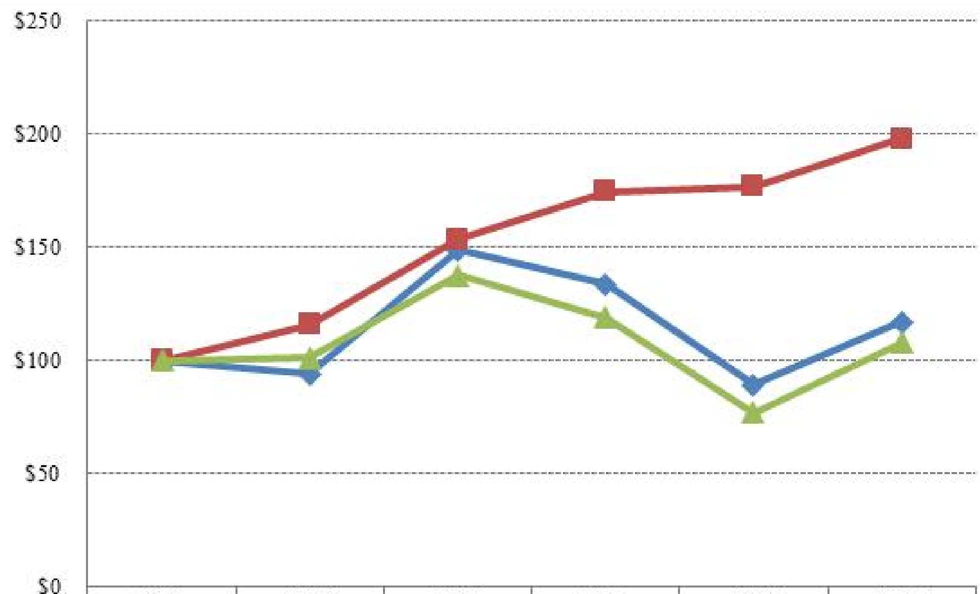
Quarter Ended	2016 High	2016 Low	2015 High	2015 Low
March 31	**$ 54.83**	**$ 32.41**	$ 77.63	$ 63.81
June 30	**63.76**	**49.52**	79.00	64.84
September 30	**61.54**	**45.37**	67.18	47.84
December 31	**65.56**	**46.06**	64.08	47.04

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 the Corporation.
- Proxy Peer Group comprising 13 oil and gas peer companies, including the Corporation (as disclosed in our 2016 Proxy Statement).

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



	2011	2012	2013	2014	2015	2016
Hess Corporation	$100.00	$93.96	$148.61	$133.71	$89.37	$116.86
S&P 500	$100.00	$115.98	$153.51	$174.47	$176.88	$197.98
Proxy Peer Group	$100.00	$101.22	$137.80	$119.19	$77.01	$108.04

Holders

At December 31, 2016, there were 3,428 stockholders (based on the number of holders of record) who owned a total of 316,523,200 shares of common stock.

Dividends

In 2016, 2015 and 2014, cash dividends on common stock totaled $1.00 per share per year ($0.25 per quarter).

Share Repurchase Activities

Our share repurchase activities for the year ended December 31, 2016, were as follows:

2016	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 (c)	Maximum Approximate Dollar Value of Shares that May Yet be Purchased Under the Plans or Programs (d) (In millions)
January	—	$ —	—	$ 1,150
February	—	—	—	1,150
March	42,972	44.23	—	1,150
April	—	—	—	1,150
May	—	—	—	1,150
June	—	—	—	1,150
July	—	—	—	1,150
August	—	—	—	1,150
September	1,083	47.00	—	1,150
October	—	—	—	1,150
November	—	—	—	1,150
December	—	—	—	1,150
Total for 2016	44,055	$ 44.30	—	

(a) Repurchased in open-market transactions. The average price paid per share was inclusive of transaction fees.
(b) Includes 42,972 common shares repurchased at a price of $44.23 per common share on the open market in March, which were subsequently granted to Directors in accordance with the Non-Employee Directors' Stock Award Plan. In addition, includes 1,083 common shares repurchased at a price of $47.00 per common share on the open market in September, which were subsequently granted to a new Director in accordance with the Non-Employee Directors' Stock Award Plan.
(c) Since initiation of the buyback program in August 2013, total shares repurchased through December 31, 2016 amounted to 64.1 million at a total cost of $5.4 billion (including transaction fees).
(d) 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.

Equity Compensation Plans

Following is information related to our equity compensation plans at December 31, 2016.

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	6,591,944 (a)	$ 67.15	10,551,300 (b)
Equity compensation plans not approved by security holders (c)	—	—	—

(a) This amount includes 6,591,944 shares of common stock issuable upon exercise of outstanding stock options. This amount excludes 1,015,379 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 3,100,659 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 our non-employee directors received in aggregate $2 million in value of our common stock. These awards are made from shares we have purchased in the open market.

See *Note 13, Share-based Compensation* in *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:

	2016	2015	2014	2013	2012
		(In millions, except per share amounts)			
Income Statement Selected Financial Data					
Sales and other operating revenues					
Crude oil	**$ 3,639**	$ 5,259	$ 9,058	$ 9,998	$ 10,229
Natural gas liquids	**264**	244	397	457	573
Natural gas	**766**	1,052	1,247	1,394	1,394
Other operating revenues	**93**	81	35	56	49
Total Sales and other operating revenues	**$ 4,762**	$ 6,636	$ 10,737	$ 11,905	$ 12,245
Income (loss) from continuing operations	**$ (6,076)**	$ (2,959)	$ 1,692	$ 4,036	$ 1,808
Income (loss) from discontinued operations	—	(48)	682	1,186	255
Net income (loss)	**$ (6,076)**	$ (3,007)	$ 2,374	$ 5,222	$ 2,063
Less: Net income (loss) attributable to noncontrolling interests*	**56**	49	57	170	38
Net income (loss) attributable to Hess Corporation	**$ (6,132) (a)**	$ (3,056) (b)	$ 2,317 (c)	$ 5,052 (d)	$ 2,025 (e)
Net Income (Loss) Attributable to Hess Corporation Per Common Share:					
Basic:					
Continuing operations	**$ (19.92)**	$ (10.61)	$ 5.57	$ 11.47	$ 5.29
Discontinued operations	—	(0.17)	2.06	3.54	0.69
Net income (loss) per share	**$ (19.92)**	$ (10.78)	$ 7.63	$ 15.01	$ 5.98
Diluted:					
Continuing operations	**$ (19.92)**	$ (10.61)	$ 5.50	$ 11.33	$ 5.26
Discontinued operations	—	(0.17)	2.03	3.49	0.69
Net income (loss) per share	**$ (19.92)**	$ (10.78)	$ 7.53	$ 14.82	$ 5.95
Balance Sheet Selected Financial Data					
Total assets	**$ 28,621**	$ 34,157	$ 38,372	$ 42,482	$ 43,187
Total debt	**$ 6,806**	$ 6,592	$ 5,952	$ 5,765	$ 8,076
Total equity	**$ 15,591**	$ 20,401	$ 22,320	$ 24,784	$ 21,203
Dividends Per Share					
Dividends per share of common stock	**$ 1.00**	$ 1.00	$ 1.00	$ 0.70	$ 0.40

* *Includes noncontrolling interests associated with both continuing and discontinued operations.*

(a) *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.*

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

(c) *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.*

(d) *Includes after-tax income of $4,060 million relating to net gains on asset sales, Denmark's enacted changes to the hydrocarbon income tax law and income from the partial liquidation of LIFO inventories, partially offset by after-tax charges totaling $900 million for asset impairments, dry hole expenses, severance and other exit costs, income tax charges, refinery shutdown costs, and other charges.*

(e) *Includes after-tax income of $661 million relating to gains on asset sales and income from the partial liquidation of LIFO inventories, partially offset by after-tax charges totaling $634 million for asset impairments, dry hole expenses, income taxes and other charges.*

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

Overview

Hess Corporation 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, Equatorial Guinea, the Malaysia/Thailand Joint Development Area (JDA), Malaysia, and Norway. The Bakken Midstream operating segment, which was established in the second quarter of 2015, provides fee-based services, including gathering, compressing and processing natural gas and fractionating natural gas liquids, or NGLs; gathering, terminaling, loading and transporting crude oil and NGLs; and storing and terminaling propane, primarily in the Bakken and Three Forks Shale plays in the Williston Basin area of North Dakota.

Response to Low Oil Prices

In 2016 our industry continued to face a challenging commodity price environment leading to further reductions in capital investment compared with 2015. Our realized crude oil selling prices, including hedging, were $39.20 per barrel in 2016 (2015: $47.85; 2014: $92.59). In response, we improved operating efficiency across our portfolio and reduced our E&P capital and exploratory expenditures during 2016 to $1.9 billion, a decrease of over 50% compared to the same period in 2015, which partially contributed to our lower 2016 oil and gas production levels.

In addition to improving our operating efficiency and reducing our capital and exploratory expenditures, we proactively took other steps in 2016 to preserve the strength of our balance sheet and improve liquidity, including issuing equity securities and executing a debt refinancing transaction. 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, for total net proceeds of $1.6 billion. In the third quarter of 2016, we initiated a debt refinancing transaction by issuing $1 billion of 4.30% notes due in 2027 and $500 million of 5.80% notes due in 2047 with proceeds used primarily to purchase higher-coupon bonds and redeem near-term maturities. At December 31, 2016, we had $2.7 billion in cash and cash equivalents and total liquidity including available committed credit facilities of approximately $7.3 billion.

We project our E&P capital and exploratory expenditures will be approximately $2.25 billion in 2017 as we plan to increase from two rigs to six rigs in the Bakken over the course of 2017. Capital expenditures for our Midstream operations are expected to be approximately $190 million. Oil and gas production in 2017 is forecast to be in the range of 300,000 boepd to 310,000 boepd excluding any contribution from Libya. As a result of reduced capital expenditures in 2016 and a high level of planned maintenance in the second quarter of 2017, we forecast our production to decline during the first half of 2017 and then increase in the third and fourth quarters of the year with the start-up of North Malay Basin and a new well at the Penn State Field in the Gulf of Mexico expected in the third quarter and production increases as a result of the rig ramp up in the Bakken.

In 2016, we realized a net operating cash flow deficit (cash flow from operating activities less cash flows from investing activities) of $1,295 million. Forward strip crude oil prices for 2017 are higher than average prices for 2016, and as a result, we forecast a smaller net operating cash flow deficit in 2017. We expect to fund our net operating cash flow deficit (including capital expenditures) for the full year of 2017 with cash on hand. Due to the low commodity price environment, we may take any of the following steps, or a combination thereof, to improve our liquidity and financial position: reduce our planned capital program and other cash outlays, borrow from our committed credit facilities, issue debt or equity securities, and pursue asset sales.

Consolidated Results

Net loss attributable to Hess Corporation was $6,132 million in 2016 and $3,056 million in 2015. In 2014, net income attributable to Hess Corporation was $2,317 million. Excluding items affecting comparability summarized on page 27, the adjusted net loss was $1,489 million in 2016 and $1,113 million in 2015. Adjusted net income in 2014 was $1,308 million. Annual production averaged 322,000 boepd in 2016, 375,000 boepd in 2015, and 329,000 boepd in 2014. Total proved reserves were 1,109 million boe, 1,086 million boe, and 1,431 million boe at December 31, 2016, 2015, and 2014, respectively. Lower crude oil prices in 2015 resulted in negative revisions of 234 million boe at December 31, 2015, primarily related to proved undeveloped reserves.

Significant 2016 Activities

The following is an update of significant E&P activities during 2016:

Producing E&P assets:

- In North Dakota, net production from the Bakken oil shale play averaged 105,000 boepd (2015: 112,000 boepd), with the decrease from the prior-year period primarily due to reduced drilling activity in response to low oil prices. During 2016, we operated an average of 3.3 rigs, drilled 71 wells, completed 92 wells, and brought on production 100 wells, bringing the total operated production wells to 1,272 at December 31, 2016. Drilling and completion costs per operated well averaged $4.8 million in 2016, down 17% from 2015. In 2016, we also increased our standard well design to a 50-stage completion from the previous 35-stage completion. During 2017, we plan to increase our rig count to six rigs from two rigs, for an average of 3.5 rigs, to drill approximately 80 wells and bring approximately 75 wells on production. Net production for full year 2017 is forecast to be in the range of 95,000 boepd and 105,000 boepd. With the building rig count we expect our Bakken production in the fourth quarter of 2017 to average between 105,000 boepd and 110,000 boepd, which would represent a growth rate of approximately 15% from the first quarter to the fourth quarter.
- In the Gulf of Mexico, net production averaged 61,000 boepd (2015: 77,000 boepd). The decrease in production was the result of unplanned well downtime at the Tubular Bells Field (Hess 57%) due to subsurface valve failures in three wells, unplanned downtime at the Conger Field (Hess 38%) due to a failed subsurface valve in one well, and natural decline. Well workovers were conducted to replace the subsurface valves in the three wells at the Tubular Bells Field and in the well at the Conger Field, which caused an increase in workover expense for the year. In addition, we brought online a fifth production well and one water injection well at Tubular Bells during the year. In 2017, Gulf of Mexico production is forecast to average approximately 65,000 boepd.
- At the Valhall Field offshore Norway, net production averaged 28,000 boepd (2015: 33,000 boepd), with the decrease from the prior year primarily due to lower drilling activity, natural field decline and a planned shutdown. Net production from the Valhall Field is forecast to average between 25,000 boepd and 30,000 boepd in 2017. In 2017, the operator plans to drill two production wells from the existing platform rig, of which one well is expected to be completed in the fourth quarter. The operator plans to continue a multi-year well abandonment program.
- At Block A-18 of the JDA, the operator, Carigali Hess Operating Company, continued drilling production wells and completed commissioning of its booster compression project in the third quarter of 2016. Production averaged 206 mmcfd (2015: 255 mmcfd), including contribution from unitized acreage in Malaysia, with the decrease from prior-year primarily due to lower entitlement and downtime associated with commissioning of the new booster compression project. Production from the JDA is forecast to average approximately 210 mmcfd in 2017.
- In the North Malay Basin (NMB), net production from the Early Production System averaged 26 mmcfd (2015: 40 mmcfd). In 2016, we completed the installation of three remote wellhead platforms and the jacket of the central processing platform. We also achieved mechanical completion of the central processing platform topsides and transport to the field via a heavy lift vessel is planned for the first quarter of 2017. The full field development project is planned for completion in the third quarter of 2017, after which net production is expected to increase to 165 mmcfd.
- At the South Arne Field, offshore Denmark, we completed drilling of an eleven well multi-year program early in 2016. Net production averaged 13,000 boepd (2015: 13,000 boepd). In the fourth quarter, the Danish government awarded a 20 year extension to the South Arne Field license, extending expiry to 2047. Net production is forecast to average approximately 12,000 boepd in 2017.
- In the Utica shale, we drilled and completed 6 wells and brought 14 wells onto production before suspending drilling activities during the first quarter of 2016 in response to low commodity prices. Net production increased to 29,000 boepd in 2016 (2015: 24,000 boepd) and is expected to average between 15,000 boepd and 20,000 boepd in 2017.
- In Equatorial Guinea, net production was 33,000 boepd in 2016 down from 43,000 boepd in 2015 due to lower drilling activity and natural field decline. Net production in 2017 is expected to average approximately 25,000 boepd.
- In Libya, civil and political unrest has largely interrupted production and crude oil export capability in 2016. At the Waha fields (Hess 8%), the operator recommenced production in October 2016 following the lifting of force majeure by the national oil company of Libya. Net production from the Waha fields averaged 1,000 boepd for the year.

Other E&P assets:

- At the Hess operated Stampede development project (Hess 25%) in the Green Canyon area of the Gulf of Mexico, the topsides deck was installed on the hull and fabrication and pre-commissioning of topsides continue as planned. We also completed installation of subsea equipment at both drill centers in the field, drilled one development well, and commenced drilling on one water injector well. In 2017, we plan to install the tension leg platform and topsides, complete the sub-sea installation and continue our drilling operations with introduction of a second drilling rig. First production from the field is targeted for 2018, and is expected to ramp up to a net rate of approximately 15,000 boepd.
- In Guyana, at the offshore Stabroek Block (Hess 30%), the operator, Esso Exploration and Production Guyana Limited, completed a 3D seismic acquisition program covering approximately 17,000 square kilometers on the block and drilled two successful appraisal wells at the Liza discovery. The Liza-2 well was drilled to a total depth of 17,963 feet and encountered more than 190 feet of oil-bearing sandstone reservoirs in the Upper Cretaceous formations and included an extended drill stem test. The Liza-3 well was drilled to a total depth of 18,098 feet and encountered 210 feet of the same oil-bearing reservoirs encountered in other Liza wells. Pre-development planning and appraisal activities are underway and we expect to be in a position to sanction the first phase of the Liza development in mid-2017 with first production expected in 2020.

  In 2016, the operator also drilled the Payara-1 exploration well at the Payara prospect, located approximately 10 miles northwest of the Liza discovery, and encountered more than 95 feet of oil-bearing sandstone reservoirs. At the Skipjack prospect 25 miles northwest of the Liza discovery, the operator completed the drilling of an exploration well, which was unsuccessful and expensed. In 2017, the operator plans to drill a well at the Snoek exploration prospect, a Liza-4 appraisal well, and a Payara-2 appraisal well. In addition, the operator will evaluate additional exploration opportunities on the broader Stabroek block.
- At the Equus project on Block WA-390-P in the offshore Carnarvon Basin of Australia, we were awarded a retention lease through 2021 covering certain areas within the WA-390-P License which include our Equus discoveries. In addition, we also completed drilling of an exploration commitment well at the WA-474-P License which is adjacent to Block WA-390-P. 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 government of Australia of our intent to defer further development of the project. As a result, we recognized an after-tax charge of $693 million ($938 million pre-tax) to expense all previously capitalized exploratory well costs and other project related costs.
- In Ghana, we continued development planning and subsurface evaluation. The government of Côte d'Ivoire has challenged the maritime border between it and the country of Ghana, which includes a portion of our Deepwater Tano/Cape Three Points license. We are unable to proceed with development of this license until there is a resolution of this matter, which may also impact our ability to develop the license. The International Tribunal for Law of the Sea is expected to render a final ruling on the maritime border dispute in 2017. Under terms of our license and subject to resolution of the border dispute, we have declared commerciality for four discoveries, including the Pecan Field in March 2016, which would be the primary development hub for the block. We are continuing to work with the government on how best to progress work on the block given the maritime border dispute. See *Capitalized Exploratory Well Costs* in *Note 4, Property, Plant and Equipment* in the *Notes to Consolidated Financial Statements.*
- At the non-operated Sicily prospect, in the Keathley Canyon area of the deepwater Gulf of Mexico, where two exploration wells discovered hydrocarbons, we decided in 2016 not to pursue the project due to the low oil price environment and the limited time remaining on the leases. The costs of both wells were expensed in 2016.
- At the non-operated Melmar prospect in the Alaminos Canyon area of the deepwater Gulf of Mexico, the operator completed drilling of an exploration well in 2016, where noncommercial quantities of hydrocarbons were encountered and well costs were expensed.

The following is an update of significant Bakken Midstream activities during 2016:

- We continued to progress the construction of facilities and the reconfiguration of pipelines in McKenzie and Williams counties that are expected to increase throughput capacity for crude oil and natural gas originating from south of the Missouri River for transporting north to our natural gas processing and crude oil and natural gas liquids logistics assets in Tioga and Ramberg and multiple third-party pipelines.

Liquidity, and Capital and Exploratory Expenditures

Net cash provided by operating activities was $795 million in 2016 (2015: $1,981 million; 2014: $4,457 million). At December 31, 2016, cash and cash equivalents were $2,732 million (2015: $2,716 million) and total debt was $6,806 million (2015: $6,592 million). Our consolidated debt to capitalization ratio at December 31, 2016 was 30.4% (2015: 24.4%).

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

	2016	2015	2014
E&P Capital and Exploratory Expenditures			
United States			
Bakken	**$ 429**	$ 1,308	$ 1,854
Other Onshore	**53**	332	725
Total Onshore	**482**	1,640	2,579
Offshore	**735**	923	765
Total United States	**1,217**	2,563	3,344
Europe	**65**	298	540
Africa	**10**	161	435
Asia and other	**586**	1,020	986
E&P - Capital and Exploratory Expenditures (a)	**$ 1,878**	$ 4,042	$ 5,305

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

	2016	2015	2014
United States	**$ 93**	$ 132	$ 125
International	**140**	157	207
Total Exploration Expenses Charged to Income included above	**$ 233**	$ 289	$ 332

(a) In 2014, the above table excludes capital expenditures of $431 million related to our discontinued operations, and includes corporate capital expenditures of $53 million.

	2016	2015	2014
Bakken Midstream Capital Expenditures			
Bakken Midstream - Capital Expenditures	**$ 276**	$ 296	$ 301

We plan to invest approximately $2.25 billion on E&P capital and exploratory expenditures and approximately $190 million in Midstream capital expenditures in 2017. Beginning January 1, 2017, Hess's Midstream segment will include our interest in a Permian gas plant in West Texas and related CO_2 assets, and water handling assets in North Dakota. These assets are wholly owned by the Corporation and are not included in our Hess Infrastructure Partners joint venture.

Consolidated Results of Operations

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

	2016	2015	2014
	(In millions, except per share amounts)		
Net Income (Loss) Attributable to Hess Corporation:			
Exploration and Production	**$ (4,963)**	$ (2,717)	$ 2,086
Bakken Midstream	**41**	86	10
Corporate, Interest and Other	**(1,210)**	(377)	(404)
Income (loss) from continuing operations	**(6,132)**	(3,008)	1,692
Discontinued operations	**—**	(48)	625
Total	**$ (6,132)**	$ (3,056)	$ 2,317
Net Income (Loss) per Common Share - Diluted (a):			
Continuing operations	**$ (19.92)**	$ (10.61)	$ 5.50
Discontinued operations	**—**	(0.17)	2.03
Net Income (Loss) Attributable to Hess Corporation Per Common Share - Diluted	**$ (19.92)**	$ (10.78)	$ 7.53

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

The following table summarizes, on an after-tax basis, items of income (expense) that are included in net income (loss) and affect comparability between periods. The items in the table below are explained on pages 32 through 36.

Items Affecting Comparability of Earnings Between Periods

	2016	2015	2014
	(In millions)		
Exploration and Production	**$ (3,699)**	$ (1,851)	$ 542
Bakken Midstream	**(21)**	—	—
Corporate, Interest and Other	**(923)**	(44)	(74)
Discontinued operations	**—**	(48)	541
Total Items Affecting Comparability of Earnings Between Periods	**$ (4,643)**	$ (1,943)	$ 1,009

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.

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

	2016	2015	2014
	(In millions)		
Net income (loss) attributable to Hess Corporation	**$ (6,132)**	$ (3,056)	$ 2,317
Less: Total items affecting comparability of earnings between periods	**(4,643)**	(1,943)	1,009
Adjusted Net Income (Loss) Attributable to Hess Corporation	**$ (1,489)**	$ (1,113)	$ 1,308

"Adjusted net income (loss)" 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).

Comparison of Results

Exploration and Production

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

	2016	2015	2014
		(In millions)	
Revenues and Non-Operating Income			
Sales and other operating revenues	**$ 4,762**	$ 6,636	$ 10,737
Gains on asset sales, net	**26**	31	817
Other, net	**17**	(61)	(46)
Total revenues and non-operating income	**4,805**	6,606	11,508
Costs and Expenses			
Cost of products sold (excluding items shown separately below)	**1,095**	1,409	1,826
Operating costs and expenses	**1,697**	1,764	1,815
Production and severance taxes	**101**	146	275
Bakken Midstream tariffs	**478**	449	212
Exploration expenses, including dry holes and lease impairment	**1,442**	881	840
General and administrative expenses	**235**	317	325
Depreciation, depletion and amortization	**3,132**	3,852	3,140
Impairment	**—**	1,616	—
Total costs and expenses	**8,180**	10,434	8,433
Results of Operations Before Income Taxes	**(3,375)**	(3,828)	3,075
Provision (benefit) for income taxes	**1,588**	(1,111)	989
Net Income (Loss) Attributable to Hess Corporation	**$ (4,963)**	$ (2,717)	$ 2,086

Excluding the E&P items affecting comparability of earnings between periods in the table on page 32, the changes in E&P earnings are primarily attributable to changes in selling prices, production and sales volumes, cost of products sold, cash operating costs, depreciation, depletion and amortization, Bakken Midstream tariffs, exploration expenses and income taxes, as discussed below.

Selling Prices: Average realized crude oil selling prices, including hedging, were 18% lower in 2016 compared to the prior year, primarily due to the declines in Brent and WTI crude oil prices. In addition, realized selling prices for natural gas liquids and natural gas declined in 2016 by 5% and 19%, respectively, compared to the prior year. In total, lower realized selling prices reduced 2016 financial results by approximately $440 million after income taxes compared with 2015. Our average selling prices were as follows:

	2016	2015	2014
Crude Oil - Per Barrel (Including Hedging)			
United States			
Onshore	**$ 36.92**	$ 42.67	$ 81.89
Offshore	**37.47**	46.21	95.05
Total United States	**37.13**	44.01	87.21
Europe	**43.33**	55.10	104.21
Africa	**41.88**	53.89	97.31
Asia	**42.98**	52.74	89.71
Worldwide	**39.20**	47.85	92.59
Crude Oil - Per Barrel (Excluding Hedging)			
United States			
Onshore	**$ 36.92**	$ 41.22	$ 81.89
Offshore	**37.47**	46.21	92.22
Total United States	**37.13**	43.11	86.06
Europe	**43.33**	52.37	99.20
Africa	**41.88**	51.57	93.70
Asia	**42.98**	52.74	89.71
Worldwide	**39.20**	46.37	90.20
Natural Gas Liquids - Per Barrel			
United States			
Onshore	**$ 9.18**	$ 9.18	$ 28.92
Offshore	**13.96**	14.40	30.40
Total United States	**9.71**	10.02	29.32
Europe	**19.48**	24.59	52.66
Worldwide	**9.95**	10.52	30.59
Natural Gas - Per Mcf			
United States			
Onshore	**$ 1.48**	$ 1.64	$ 3.18
Offshore	**1.99**	2.03	3.79
Total United States	**1.61**	1.77	3.47
Europe	**3.97**	6.72	10.00
Asia	**5.31**	5.97	6.94
Worldwide	**3.37**	4.16	6.04

Crude oil price hedging contracts increased E&P Sales and other operating revenues by $126 million ($79 million after income taxes) in 2015 and $193 million ($121 million after income taxes) in 2014. There were no crude oil hedge contracts in 2016.

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

	2016	2015	2014
		(In thousands)	
Crude Oil - Barrels			
United States			
Bakken	**68**	81	66
Other Onshore	**9**	10	10
Total Onshore	**77**	91	76
Offshore	**45**	56	51
Total United States	**122**	147	127
Europe	**33**	38	36
Africa	**34**	51	54
Asia	**2**	2	3
Worldwide	**191**	238	220
Natural Gas Liquids - Barrels			
United States			
Bakken	**27**	20	10
Other Onshore	**11**	12	7
Total Onshore	**38**	32	17
Offshore	**5**	6	6
Total United States	**43**	38	23
Europe	**1**	1	1
Worldwide	**44**	39	24
Natural Gas - Mcf			
United States			
Bakken	**61**	64	40
Other Onshore	**133**	109	47
Total Onshore	**194**	173	87
Offshore	**64**	87	78
Total United States	**258**	260	165
Europe	**43**	43	36
Asia	**222**	282	312
Worldwide	**523**	585	513
Barrels of Oil Equivalent	**322**	375	329
Crude oil and natural gas liquids as a share of total production	**73%**	74%	74%

We expect total net production to average between 300,000 boepd and 310,000 boepd in 2017, excluding any contribution from Libya. Our production has been decreasing the last several quarters as a result of reducing our capital expenditures to manage in the lower price environment. We expect our production will continue to decline in the first half of 2017 as a result of this reduced spend and a high level of planned maintenance at four of our offshore assets in the second quarter. We forecast production to average between 290,000 boepd and 300,000 boepd in the first quarter and between 270,000 boepd and 280,000 boepd in the second quarter. Production is then forecast to increase in the third quarter with the start-up of North Malay Basin and a new well at the Penn State Field in the Gulf of Mexico to between 305,000 boepd and 315,000 boepd. We expect our production will continue to grow in the fourth quarter as Bakken production increases as a result of the rig ramp up and the first new Valhall well comes online. Fourth quarter production is forecast to average between 330,000 boepd and 340,000 boepd.

Production variances related to 2016, 2015 and 2014 can be summarized as follows:

United States: Onshore crude oil production was lower in 2016 compared to 2015, primarily due to reduced drilling activity in the Bakken shale play in response to low oil prices, while the increase in natural gas liquids production was primarily due to greater processed volumes at the Tioga gas plant. Onshore natural gas production was higher in 2016 compared to 2015, primarily due to a higher number of wells being on production in the Utica shale play relative to the prior year. Total offshore production was lower in 2016 compared to 2015, primarily due to subsurface valve failures in three wells at the Tubular Bells Field, a shut-in well to replace a subsurface valve at the Conger Field, extended planned shutdowns on third-party hosted production facilities at the Tubular Bells and Conger Fields, and natural field decline. Onshore crude oil and natural gas liquids production was higher in 2015 compared to 2014, primarily due to continued drilling in the Bakken oil shale play, while the increase in natural gas production was primarily attributable to the Bakken and the Utica shale. Offshore production increased in 2015 relative to 2014 as higher production from the Tubular Bells Field, which came online in November 2014, was offset primarily by lower production from the Llano, Conger and Shenzi Fields.

Europe: Crude oil production was lower in 2016 compared to 2015, primarily due to lower drilling activity, natural field decline and a planned shutdown at the Valhall Field, offshore Norway. Crude oil and natural gas production was higher in 2015 compared to 2014, primarily due to less facility downtime and new wells at the Valhall Field in 2015.

Africa: Crude oil production in Africa was lower in 2016 compared to 2015, as a result of reduced drilling activity in Equatorial Guinea and the sale of our Algeria asset in the fourth quarter of 2015, where net production for 2015 amounted to 7,000 boepd. Crude oil production in Africa was lower in 2015 compared to 2014, due to Libyan production being shut-in. Force majeure declared by the national oil company of Libya was lifted in September 2016 and net production averaged 1,000 boepd in 2016.

Asia: Natural gas production was lower in 2016, compared to 2015, primarily due to the planned shutdown of production facilities at the JDA in 2016 to commission the booster compressor project and from lower production entitlement. Natural gas production was lower in 2015 compared to 2014 primarily due to asset sales partially offset by higher production at the JDA as a result of higher facility uptime.

Sales Volumes: The impact of lower sales volumes decreased after-tax results by approximately $540 million in 2016 compared to 2015. Our worldwide sales volumes were as follows:

	2016	2015	2014
		(In thousands)	
Crude oil - barrels	**72,462**	85,344	80,869
Natural gas liquids - barrels	**16,055**	14,400	8,793
Natural gas - mcf	**191,482**	213,195	187,381
Barrels of Oil Equivalent	**120,431**	135,277	120,892
Crude oil - barrels per day	**198**	234	222
Natural gas liquids - barrels per day	**44**	39	24
Natural gas - mcf per day	**523**	584	513
Barrels of Oil Equivalent Per Day	**329**	371	331

Cost of Products Sold: Cost of products sold is mainly comprised of costs relating to the purchases of crude oil, natural gas liquids and natural gas from our partners in Hess operated wells or other third-parties, as well as rail transportation fees from our Bakken Midstream operating segment. The decrease in Cost of products sold in 2016 compared to 2015, and in 2015 compared to 2014, principally reflects the decline in crude oil prices.

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 $194 million in 2016 compared with the prior year (2015: $188 million decrease versus 2014). The decrease in 2016 compared to 2015 is due to lower production and ongoing cost reduction efforts, and lower production taxes in the Bakken. Operating costs in 2016 include higher workover costs to replace failed subsurface valves in the Gulf of Mexico. The decrease in 2015 compared to 2014 is due to cost reductions across the portfolio and lower production taxes in the Bakken, which were partially offset by higher operating costs at Tubular Bells where production commenced in the fourth quarter of 2014.

Bakken Midstream Tariffs Expense: Tariffs expense in 2016 increased versus 2015 primarily due to increased oil gathering tariffs and minimum volume deficiency payments related to rail export services in 2016, partially offset by lower gas volumes processed through the Tioga gas plant. Higher tariff expense in 2015 compared with 2014 primarily reflects higher volumes processed through the Tioga gas plant which was shut down during the first quarter of 2014 to complete a plant expansion and refurbishment project. For 2017, we estimate Midstream tariffs expense, which will include tariffs associated with our interests in a Permian gas plant in West Texas and related CO_2 assets and water handling assets in North Dakota, to be in the range of $520 million to $550 million.

Depreciation, Depletion and Amortization: Depreciation, depletion and amortization (DD&A) costs decreased by $720 million in 2016 from 2015. The decrease resulted from lower production and an improved portfolio average DD&A rate due to the production mix. Higher production in 2015 from the Bakken, Tubular Bells and Utica fields, which had higher DD&A rates per barrel than the portfolio average, were the primarily drivers for the increase in DD&A costs in 2015 compared to 2014.

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

	Actual			Forecast range
	2016	**2015**	**2014**	**2017 (a)**
Cash operating costs	**$ 15.87**	$ 15.69	$ 20.01	$15.00 — $16.00
Depreciation, depletion and amortization costs	**26.57**	28.14	26.10	24.00 — 25.00
Total Production Unit Costs	**$ 42.44**	$ 43.83	$ 46.11	$39.00 — $41.00

(a) Forecasted amounts assume no contribution from Libya.

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

	2016	2015	2014
		(In millions)	
Exploratory dry hole costs	**$ 1,064**	$ 410	$ 301
Exploratory lease and other impairment	**145**	182	207
Geological and geophysical expense and exploration overhead	**233**	289	332
	$ 1,442	$ 881	$ 840

Exploration expenses were higher in 2016 compared to 2015 primarily due to higher dry hole expense partially offset by lower leasehold impairment expense, geologic and seismic costs, and employee expenses. Exploration expenses were higher in 2015 compared to 2014 due to higher dry hole costs, partially offset by lower leasehold impairment expense, geologic and seismic costs, and employee expenses. See items affecting comparability of earnings between periods described below. For 2017, we estimate exploration expenses, excluding dry hole expense, to be in the range of $250 million to $270 million.

Income Taxes: The E&P income tax provision was an expense of $1,588 million in 2016, a benefit of $1,111 million in 2015 and an expense of $989 million in 2014. The income tax expense recognized in 2016, despite pre-tax losses, is the result of deferred income tax charges to establish valuation allowances on net deferred tax assets. Excluding the impact of these charges and other items affecting comparability of earnings between periods provided below and Libya, the effective income tax rates for E&P operations amounted to a benefit of 42% in 2016 (2015: 46% benefit; 2014: 37% charge). Based on current strip crude oil prices, we are forecasting a pre-tax loss for 2017. The E&P effective tax rate, excluding items affecting comparability of earnings between periods and Libyan operations, is expected to be a benefit in the range of 17% to 21%, which is lower than the comparable effective tax rate in 2016 due to our not recognizing a deferred tax benefit or expense commencing in 2017 in the U.S., Denmark (hydrocarbon tax only), and Malaysia until such time that deferred tax assets are re-established in these jurisdictions. See E&P items affecting comparability of earnings below and *Critical Accounting Policies and Estimates – Income Taxes* on page 42.

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

	Before Income Taxes			After Income Taxes		
	2016	**2015**	**2014**	**2016**	**2015**	**2014**
			(In millions)			
Income tax	**$ —**	$ —	$ —	**$ (2,869)**	$ 101	$ (48)
Dry hole, lease impairment and other exploration expenses	**(1,021)**	(518)	(304)	**(745)**	(301)	(173)
Offshore rig cost	**(105)**	—	—	**(66)**	—	—
Inventory write-off	**(39)**	(87)	—	**(19)**	(58)	—
Exit costs and other	**(26)**	(44)	(28)	**(17)**	(37)	(11)
Impairments	**—**	(1,616)	—	**—**	(1,566)	—
Gain on asset sales, net	**27**	28	801	**17**	10	774
	$ (1,164)	$ (2,237)	$ 469	**$ (3,699)**	$ (1,851)	$ 542

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

	Before Income Taxes		
	2016	**2015**	**2014**
		(In millions)	
Gains on asset sales, net	**$ 27**	$ 28	$ 801
Other, net	**—**	(14)	—
Cost of products sold	**—**	(39)	(18)
Operating costs and expenses	**(162)**	(51)	—
Exploration expenses, including dry holes and lease impairment	**(1,029)**	(518)	(304)
General and administrative expenses	**—**	(27)	(10)
Impairment	**—**	(1,616)	—
	$ (1,164)	$ (2,237)	$ 469

2016:

- *Income taxes:* We recorded a non-cash charge of $2,920 million to establish valuation allowances against net deferred tax assets as of December 31, 2016, as required under application of the accounting standards following a three-year cumulative loss. This deferred tax charge has no cash flow impact and the Corporation's underlying tax position remains unchanged. In addition, we recorded a tax benefit of $51 million related to the resolution of certain international tax matters.
- *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.
- *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 pre-tax exit and other costs of $26 million ($17 million after income taxes), which primarily relates to employee severance.
- *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 United States.

2015:

- *Impairment:* We recorded noncash goodwill impairment charges totaling $1,483 million pre-tax ($1,483 million after income taxes), representing all goodwill of our E&P segment, due to the decline in crude oil prices. In addition, we recorded a pre-tax charge of $133 million ($83 million after income taxes) associated with our legacy conventional North Dakota assets.
- *Dry hole, lease impairment and other exploration expenses:* We recognized a pre-tax charge of $190 million ($86 million after income taxes) to write-off an exploration well, associated leasehold expenses and other costs related to the Dinarta Block in the Kurdistan Region of Iraq following the decision of the Corporation and its partner to relinquish the block and exit operations in the region. In offshore Ghana, we expensed previously capitalized well costs of $182 million ($117 million after income taxes) primarily associated with natural gas discoveries due to insufficient progress on appraisal negotiations with the regulator. In offshore Australia, we expensed previously capitalized well costs of $62 million ($45 million after income taxes) associated with discovered resources that we determined would not be included in the development concept for the Equus project. In addition, we recorded pre-tax charges totaling $84 million ($53 million after income taxes) primarily to impair exploration leases in the Gulf of Mexico.
- *Exit costs and other:* We recognized pre-tax charges totaling $21 million ($21 million after income taxes) associated with terminated international office space and incurred charges of $23 million ($16 million after income taxes) related to employee severance and other expenses.
- *Inventory write-off:* We incurred a pre-tax charge of $48 million ($30 million after income taxes) to write off

surplus drilling materials based on future drilling plans and recognized a pre-tax charge of $39 million ($28 million after income taxes) to reduce crude oil inventories to their net realizable value.

- *Gains on asset sales, net:* We completed the sale of approximately 13,000 acres of Utica dry gas acreage for consideration of approximately $120 million. This transaction resulted in a pre-tax gain of $49 million ($31 million after income taxes). We also completed the sale of our producing assets in Algeria in December 2015 and recognized a pre-tax loss of $21 million ($21 million after income taxes).
- *Income taxes:* In 2015, we recorded net tax benefits totaling $101 million, comprised primarily of $154 million to recognize a deferred tax benefit from a legal entity restructuring, $50 million benefit from receiving approval for an international investment incentive and a $112 million charge to recognize a partial valuation allowance against foreign deferred tax assets.

2014:

- *Gains on asset sales, net:* We completed the sale of our producing assets in Thailand, 77,000 net acres of Utica dry gas acreage, including related wells and facilities, and an exploration asset in the United Kingdom North Sea. These divestitures generated total cash proceeds of $1,933 million and total pre-tax gains of $801 million ($774 million after income taxes). At the time of sale, these assets were producing at an aggregate net rate of approximately 19,000 boepd.
- *Dry hole, lease impairment and other exploration expenses:* We recorded dry hole and other exploration expenses for the write-off of a previously capitalized exploration well in the western half of Block 469 in the Gulf of Mexico of $169 million ($105 million after income taxes) and other charges totaling $135 million pre-tax ($68 million after income taxes) to write-off leasehold acreage in the Paris Basin of France, the Shakrok Block in Kurdistan and our interest in a natural gas exploration project, offshore Sabah, Malaysia.
- *Exit costs and other:* We recorded pre-tax severance and other exit costs of $28 million ($11 million after income taxes) resulting from our transformation to a more focused pure play E&P company.
- *Income taxes:* We recorded an income tax charge of $48 million for remeasurement of deferred taxes resulting from legal entity restructurings.

Bakken Midstream

Following is a summarized income statement of our Bakken Midstream operations:

	2016	2015	2014
		(In millions)	
Revenues and Non-Operating Income			
Total revenues and non-operating income	**$ 510**	$ 564	$ 319
Costs and Expenses			
Operating costs and expenses	**183**	265	219
General and administrative expenses	**17**	14	11
Depreciation, depletion and amortization	**102**	88	70
Impairments	**67**	—	—
Interest expense	**19**	10	2
Total costs and expenses	**388**	377	302
Results of Operations Before Income Taxes	**122**	187	17
Provision (benefit) for income taxes	**25**	52	7
Net income (loss)	**97**	135	10
Less: Net income (loss) attributable to noncontrolling interests (a)	**56**	49	—
Net Income (Loss) Attributable to Hess Corporation	**$ 41**	$ 86	$ 10

(a) The partnership is not subject to tax and, therefore, the noncontrolling interest's share of net income is a pre-tax amount.

Total revenues and non-operating income in 2016 decreased from 2015, primarily as a result of lower rail export revenue associated with third-party rail charges, partially offset by recognition of deferred minimum volume deficiency payments earned. Total revenues and non-operating income in 2015 improved from 2014 mainly due to higher throughput volumes at the Tioga gas plant.

Operating costs and expenses were lower in 2016 compared to 2015 primarily due to a decrease in third-party rail charges. Operating costs and expenses were higher in 2015 compared to 2014 mainly due to an increase in third-party operating and maintenance expense. DD&A expenses were higher in 2016 compared to 2015, primarily due to capital expenditures on gathering pipelines and railcars that were placed in service. DD&A expenses were higher in 2015 compared with 2014, primarily due to a full year's usage of the Tioga gas plant in 2015, which was shut down during the first quarter of 2014 in connection with a large-scale expansion, refurbishment and optimization project.

The increase in interest expense in 2016 and 2015 reflects borrowings by Hess Infrastructure Partners LP subsequent to its formation on July 1, 2015.

For 2017, we estimate net income attributable to Hess Corporation from the Midstream segment, excluding items affecting comparability of earnings between periods, to be in the range of $70 million to $90 million. In 2017, the Midstream segment will include our interests in a Permian gas plant in West Texas and related CO_2 assets, and water handling assets in North Dakota in addition to assets that comprise our current Bakken Midstream segment.

Items Affecting Comparability of Earnings Between Periods: Bakken Midstream 2016 results 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:

	2016	2015	2014
		(In millions)	
Corporate and other expenses (excluding items affecting comparability)	**$ 131**	$ 219	$ 217
Interest expense	**380**	376	397
Less: Capitalized interest	**(61)**	(45)	(76)
Interest expense, net	**319**	331	321
Corporate, Interest and Other expenses before income taxes	**450**	550	538
Provision (benefit) for income taxes	**(163)**	(217)	(208)
Net Corporate, Interest and Other expenses after income taxes	**287**	333	330
Items affecting comparability of earnings between periods, after-tax	**923**	44	74
Total Corporate, Interest and Other Expenses After Income Taxes	**$ 1,210**	$ 377	$ 404

Corporate and other expenses, excluding items affecting comparability, were lower in 2016 compared to 2015, primarily due to reductions in employee costs, professional fees, and other general and administrative expenses, and the benefit of higher interest income and non-operating income. Corporate and other expenses for 2014 include a pre-tax gain of $13 million ($8 million after income taxes) related to the disposition of our 50% interest in a joint venture involved in the construction of an electric generating facility in Newark, New Jersey. Excluding the gain, 2015 costs are down compared to 2014 primarily due to lower employee costs and other expenses. In 2017 pre-tax corporate expenses, excluding items affecting comparability of earnings between periods, are estimated to be in the range of $140 million to $150 million.

Interest expense was comparable in 2016 compared to 2015, but capitalized interest expense increased over the same period with 2016 reflecting increased activity at the Hess operated Stampede development project. Interest expense was lower in 2015 compared to 2014, as lower interest rates offset higher average borrowings. Capitalized interest was also lower in 2015 compared to 2014 due to the cessation of capitalized interest on the Tubular Bells Field upon first production in the fourth quarter of 2014. In 2017 pre-tax interest expense, net is estimated to be in the range of $295 million to $305 million.

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:

2016:

- *Income tax:* We recorded a non-cash charge of $829 million to establish valuation allowances against net deferred tax assets as of December 31, 2016, as required under application of the accounting standards following a three-year cumulative loss. This deferred tax charge has no cash flow impact and the Corporation's underlying tax position remains unchanged.
- *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. See *Note 12, Debt,* in the *Notes to Consolidated Financial Statements.*

- *Exit costs and other:* We recorded pre-tax exit and other costs of $3 million ($2 million after income taxes), which primarily relates to employee severance.

2015:

- *HOVENSA LLC:* We recorded a pre-tax charge of $76 million ($49 million after income taxes) associated with debtor-in-possession financing provided to HOVENSA LLC and the estimated liability resulting from its bankruptcy resolution.
- *Other:* We recorded a pre-tax gain of $20 million ($13 million after income taxes) from the sale of land and incurred exit costs of $6 million pre-tax ($4 million after income taxes).

2014:

- *Impairment:* We recorded a pre-tax charge of $84 million ($52 million after income taxes) to reduce the carrying value of our equity investment in the Bayonne Energy Center to fair value.
- *Other:* We incurred severance charges of $19 million pre-tax ($12 million after income taxes) and exit related costs of $15 million pre-tax ($10 million after income taxes).

Discontinued Operations – Items Affecting Comparability of Earnings Between Periods

Discontinued operations attributable to Hess Corporation incurred a net loss of $48 million in 2015 compared to a net income of $625 million in 2014. Discontinued operations included ownership of an energy trading partnership through February 2015 and retail marketing through September 2014.

In September 2014, we completed the sale of our retail business for cash proceeds of approximately $2.8 billion. This transaction resulted in a pre-tax gain of $954 million ($602 million after income taxes). During 2014, we recorded pre-tax gains of $275 million ($171 million after income taxes) relating to the liquidation of last-in, first-out (LIFO) inventories associated with the divested downstream operations. In addition, we recorded pre-tax charges totaling $308 million ($202 million after income taxes) in 2014 for impairments, environmental matters, severance and exit related activities associated with the divestiture of downstream operations. We also recognized in 2014 a pre-tax charge of $115 million ($72 million after income taxes) related to the termination of lease contracts and the purchase of 180 retail gasoline stations in preparation for the sale of the retail operations.

Liquidity and Capital Resources

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

	2016	2015
	(In millions, except ratio)	
Cash and cash equivalents	**$ 2,732**	$ 2,716
Current maturities of long-term debt	**112**	86
Total debt (a)	**6,806**	6,592
Total equity	**15,591**	20,401
Debt to capitalization ratio (b)	**30.4%**	24.4%

(a) Includes $733 million of debt outstanding from our Bakken Midstream joint venture at December 31, 2016 (2015: $704 million) that is non-recourse to Hess Corporation.
(b) 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:

	2016	2015	2014
		(In millions)	
Cash Flows From Operating Activities:			
Cash provided by (used in) operating activities - continuing operations	**$ 795**	$ 2,016	$ 4,504
Cash provided by (used in) operating activities - discontinued operations	**—**	(35)	(47)
Net cash provided by (used in) operating activities	**795**	1,981	4,457
Cash Flows From Investing Activities:			
Additions to property, plant and equipment - E&P	**(1,979)**	(3,956)	(4,867)
Additions to property, plant and equipment - Bakken Midstream	**(272)**	(365)	(347)
Proceeds from asset sales	**140**	50	2,978
Other, net	**21**	(44)	(192)
Cash provided by (used in) investing activities - continuing operations	**(2,090)**	(4,315)	(2,428)
Cash provided by (used in) investing activities - discontinued operations	**—**	109	2,436
Net cash provided by (used in) investing activities	**(2,090)**	(4,206)	8
Cash Flows From Financing Activities:			
Cash provided by (used in) financing activities - continuing operations	**1,311**	2,497	(3,828)
Cash provided by (used in) financing activities - discontinued operations	**—**	—	(7)
Net cash provided by (used in) financing activities	**1,311**	2,497	(3,835)
Net Increase (Decrease) in Cash and Cash Equivalents from Continuing Operations	**16**	198	(1,752)
Net Increase (Decrease) in Cash and Cash Equivalents from Discontinued Operations	**—**	74	2,382
Net Increase (Decrease) in Cash and Cash Equivalents	**$ 16**	$ 272	$ 630

***Operating Activities*:** Net cash provided by operating activities was $795 million in 2016, $1,981 million in 2015 and $4,457 million in 2014, primarily reflecting declining benchmark crude oil prices and changes in production volumes.

Investing Activities: The decrease in Additions to property, plant and equipment in 2016, as compared to 2015, is primarily due to reduced drilling activity (Bakken, Utica, Norway, Denmark and Equatorial Guinea) and reduced development expenditures (Tubular Bells, North Malay Basin and the JDA). The decrease in Additions to property, plant and equipment in 2015, as compared to 2014, is primarily due to reduced drilling activity (Bakken, Utica, Norway and Equatorial Guinea), reduced development expenditures at Tubular Bells and the JDA, and lower exploratory drilling activity (Ghana and Kurdistan). These reductions were offset by 2015 activity related to development activities at Stampede in the Gulf of Mexico and exploration drilling activity in the Gulf of Mexico and Guyana, and full field development at North Malay Basin.

Total proceeds from the sale of assets related to continuing operations amounted to $140 million in 2016 (2015: $50 million; 2014: $2,978 million). In 2014, we completed asset sales of our dry gas acreage in the Utica shale play, our assets in Thailand, the Pangkah Field, offshore Indonesia, and our interests in two power plant joint ventures. In 2014, net cash provided by investing activities from discontinued operations included proceeds of $2.8 billion from the sale of the retail business. In addition, we acquired our partners' 56% interest in WilcoHess, a retail gasoline joint venture, for approximately $290 million and we incurred capital expenditures of $105 million related to the acquisition of previously leased retail gasoline stations.

Financing Activities: In 2016, total borrowings were $1.54 billion and total repayments of debt were $1.46 billion. In the first quarter of 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. In 2015, we received net cash consideration of approximately $2.6 billion from the sale of a 50% interest in our Bakken Midstream business. Upon formation of the joint venture, HIP issued $600 million of debt under a Term Loan A facility. The proceeds from the debt were distributed equally to the partners. We purchased common stock under our $6.5 billion Board authorized stock repurchase plan of $142 million in 2015 and $3,715 million in 2014. Common and preferred stock dividends paid were $350 million in 2016 (2015: $287 million; 2014: $303 million).

Future Capital Requirements and Resources

At December 31, 2016, we had $2.7 billion in cash and cash equivalents and total liquidity, including available committed credit facilities, of approximately $7.3 billion. Cash and cash equivalents held outside of the U.S., which we have the ability to repatriate without triggering a U.S. cash tax liability, amounted to $287 million at December 31, 2016.

Net production in 2017 is forecast to be in the range of 300,000 boepd to 310,000 boepd, excluding any contribution from Libya and we expect our 2017 E&P capital and exploratory expenditures will be approximately $2.25 billion. Based on current forward strip crude oil prices for 2017, which are higher than 2016 prices, we forecast a smaller net loss and net operating cash flow deficit (including capital expenditures) in 2017 compared to 2016. We expect to fund our projected net operating cash flow deficit (including capital expenditures) through 2017 with cash on hand. Due to the low commodity price environment, we may take any of the following steps, or a combination thereof, to improve our liquidity and financial position: further reduce our planned capital program and other cash outlays, borrow from our committed credit facilities, issue debt or equity securities, and pursue asset sales.

The table below summarizes the capacity, usage, and available capacity of our borrowing and letter of credit facilities at December 31, 2016:

	Expiration Date	Capacity	Borrowings	Letters of Credit Issued	Total Used	Available Capacity
				(In millions)		
Revolving credit facility - Hess Corporation	January 2020	$ 4,000	$ —	$ —	$ —	$ 4,000
Revolving credit facility - HIP(a)	July 2020	400	153	—	153	247
Committed lines	Various (b)	575	—	1	1	574
Uncommitted lines	Various (b)	187	—	187	187	—
Total		$ 5,162	$ 153	$ 188	$ 341	$ 4,821

(a) This credit facility may only be utilized by HIP and is non-recourse to Hess Corporation.
(b) Committed and uncommitted lines have expiration dates through 2018.

Hess Corporation has a $4.0 billion syndicated revolving credit facility expiring in January 2020. Borrowings on the facility will generally bear interest at 1.3% 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 65% of the Corporation's total capitalization, defined as total debt plus stockholders' equity. As of December 31, 2016, Hess Corporation had no outstanding borrowings under this facility and was in compliance with this financial covenant.

We had $188 million in letters of credit outstanding at December 31, 2016 (2015: $113 million), which primarily relate to our international operations. See also *Note 24, Financial Risk Management Activities* in the *Notes to Consolidated Financial Statements.*

HIP has a $400 million 5-year syndicated revolving credit facility, which can be used for borrowings and letters of credit to fund the joint venture's operating activities and capital expenditures. Borrowings generally bear interest at the LIBOR plus an applicable margin ranging from 1.10% to 1.70%. 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 credit ratings, pricing levels will be based on the credit ratings in effect from time to time. The credit facility contains 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 interest expense, of no less than 2.25 to 1.0 for the prior four fiscal quarters. HIP is in compliance with these financial covenants at December 31, 2016.

At December 31, 2016, borrowings under HIP's revolving credit facility, which are non-recourse to Hess Corporation, amounted to $153 million. HIP also has a five-year Term Loan A loan facility with outstanding borrowings of $585 million, excluding deferred issuance costs, which is also non-recourse to Hess Corporation.

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

Credit Ratings

Two of the three major credit rating agencies that rate our debt have assigned an investment grade rating. In February 2016, Standard and Poor's Ratings Services (S&P) lowered our investment grade credit rating one notch to BBB- with stable outlook and Moody's Investors Service (Moody's) lowered our credit rating to Ba1 with stable outlook, which is below investment grade. In December 2016, Fitch Ratings (Fitch) lowered our investment grade credit rating one notch to BBB- with stable outlook. In February 2017, S&P re-affirmed our investment grade credit rating of BBB- with stable outlook. 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. As of December 31, 2016, based on our current credit ratings, we may be required to issue additional collateral in the form of letters of credit up to approximately $270 million. If Fitch or S&P were to reduce their rating on our unsecured debt below investment grade, we estimate that we could be required to issue additional letters of credit up to $200 million as of December 31, 2016.

Contractual Obligations and Contingencies

The following table shows aggregate information about certain contractual obligations at December 31, 2016:

		Payments Due by Period			
	Total	**2017**	**2018 and 2019**	**2020 and 2021**	**Thereafter**
			(In millions)		
Total Debt (excludes interest) (a)	$ 6,806	$ 112	$ 571	$ 598	$ 5,525
Operating Leases	1,631	376	726	191	338
Purchase Obligations:					
Capital expenditures	708	632	76	—	—
Operating expenses	497	393	76	18	10
Transportation and related contracts	1,560	182	457	433	488
Asset retirement obligations	2,128	216	479	191	1,242
Other liabilities	983	140	157	145	541

(a) We anticipate cash payments for interest of $397 million for 2017, $760 million for 2018-2019, $670 million for 2020-2021, and $4,514 million thereafter for a total of $6,341 million.

Capital expenditures represent amounts that were contractually committed at December 31, 2016, including the portion of our planned capital expenditure program for 2017. 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, 2016, including pension plan liabilities and estimates for uncertain income tax positions.

The Corporation and certain of its subsidiaries, lease drilling rigs, office space and other assets for varying periods under leases accounted for as operating leases.

Off-Balance Sheet Arrangements

At December 31, 2016, we have $27 million in letters of credit for which we are contingently liable. See also *Note 21, Guarantees, Contingencies and Commitments* in the *Notes to Consolidated Financial Statements*.

Foreign Operations

We conduct exploration and production activities outside the U.S., principally in Europe (Norway and Denmark), Africa (Equatorial Guinea, Libya, and Ghana), Asia (Joint Development Area of Malaysia/Thailand and Malaysia), Australia, South America (Guyana and Suriname) and Canada. Therefore, we are subject to the risks associated with foreign operations, including political risk, corruption, acts of terrorism, tax law changes and currency risk. 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. In production operations, costs of injected CO_2 for tertiary recovery are expensed as incurred.

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 exploration and production 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 and goodwill.

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. For example, the average WTI crude oil price used in the determination of proved reserves at December 31, 2016, 2015, and 2014 was $42.68, $50.13, and $94.42 per barrel, respectively. The lower prices for 2016 and 2015 relative to 2014 resulted in negative revisions to our proved reserves at December 31, 2016 of 29 million boe (2015: 234 million boe). If crude oil prices in 2017 are at levels below that used in determining 2016 proved reserves, we may recognize further negative revisions to our December 31, 2016 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 2017 above those used in determining 2016 proved reserves could result in positive revisions to proved developed and proved undeveloped reserves at December 31, 2017. It is difficult to estimate the magnitude of any potential net negative or positive change in proved reserves as of December 31, 2017, due to a number of factors that are currently unknown, including 2017 crude oil prices, any revisions based on 2017 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, 2016 would result in an approximate $300 million pre-tax change in depreciation, depletion, and amortization expense for 2017. See the *Supplementary Oil and Gas Data* on pages 84 through 94 in the accompanying financial statements for additional information on our oil and gas reserves.

Bakken Midstream Joint Venture: On July 1, 2015, we sold a 50% interest in HIP to GIP for net cash consideration of approximately $2.6 billion. We consolidate the activities of 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 impairments 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. We could have impairments 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. As a result of the extended period of low crude oil prices, we tested our oil and gas properties for impairment. See *Note 6, Impairment* in the *Notes to Consolidated Financial Statements*.

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 based on a two-step process. The goodwill test is conducted 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 to be used in an evaluation and measurement of goodwill for impairment testing are determined from a number of factors, including the manner in which the business is managed. Prior to the second quarter of 2015, we had one operating segment, E&P consisting of two reporting units, Offshore and Onshore which reflected the manner in which performance was assessed by the Operating segment manager. In the second quarter of 2015 we established a second operating segment, Bakken Midstream, which previously was part of the Onshore reporting unit. Prior to the formation of the Bakken Midstream operating segment the Offshore reporting unit had allocated goodwill of $1,098 million while the Onshore reporting unit had allocated goodwill of $760 million. Upon formation of the Bakken Midstream operating segment, we allocated $375 million of goodwill from the Onshore reporting unit to the Bakken Midstream operating segment based on the relative fair values of the Bakken Midstream business and the remainder of the Onshore reporting unit. There was no change to the composition of the Offshore reporting unit.

In step one of the impairment test, 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, we perform step two to determine possible impairment by comparing the implied fair value of goodwill with the carrying amount. The implied fair value of goodwill is determined by assuming the reporting unit is purchased at fair value with assets and liabilities of the reporting unit being reflected at fair value in the same manner as the accounting prescribed for a business combination. The resulting excess of fair value of the reporting unit over the amounts assigned to the reporting unit's assets and liabilities represents the implied fair value of goodwill. If the implied fair value of goodwill is less than its carrying amount, an impairment loss would be recorded.

Our fair value estimate of each reporting unit is the sum of the anticipated discounted cash flows of producing assets and known development projects and an estimated market premium to reflect the market price an acquirer would pay for potential synergies including cost savings, access to new business opportunities, enterprise control and increased market share. The determination of the fair value of each reporting unit depends on estimates about oil and gas reserves, future prices, timing of future net cash flows and market premiums. We also consider the relative market valuation of similar peer companies, and other market data if available, in determining fair value of a reporting unit. In addition, a qualitative reconciliation of our market capitalization to the fair value of the reporting units used in the goodwill impairment test is performed as of the testing date to assess reasonableness of the reporting unit fair values.

Significant extended declines in crude oil and natural gas prices or reduced reserve estimates could lead to a decrease in the fair value of a reporting unit that could result in failing step one and potentially result in an impairment of goodwill based on the outcome of step two. If a reporting unit fails step one, it is possible that the implied fair value of goodwill in step two exceeds its carrying value due to one or more assets of the reporting unit having a fair value below its carrying value.

As there are significant differences in the way long-lived assets and goodwill are evaluated and measured for impairment testing, there may be impairments of individual assets that would not cause an impairment of the goodwill assigned at the reporting unit level or there could be an impairment of goodwill without a corresponding impairment of an underlying asset.

In the second quarter of 2015, we performed impairment tests on the Offshore and Onshore reporting units in accordance with accounting standards for goodwill immediately prior to creation of the Bakken Midstream operating segment. No impairment resulted from this assessment. In addition, accounting standards require that following a reorganization, allocated goodwill should be tested for impairment. We also performed impairment tests on the allocated goodwill for the Bakken Midstream and the Onshore reporting unit at June 30, 2015. Goodwill allocated to the Bakken Midstream operating segment passed the impairment test but the goodwill allocated to the Onshore reporting unit did not pass the impairment test. As a result, we recorded a noncash pre-tax charge of $385 million ($385 million after income taxes) in the second quarter of 2015 to reflect the Onshore reporting unit's goodwill at its implied fair value of zero based on a hypothetical purchase price allocation as stipulated in the accounting standards.

As a result of the decline in crude oil prices in the fourth quarter of 2015, we performed an impairment test at December 31, 2015 on the Offshore reporting unit and determined its goodwill was impaired. We recorded a pre-tax impairment charge of $1,098 million ($1,098 million after income taxes) to reflect the Offshore reporting unit's goodwill at its implied fair value of zero based on a hypothetical purchase price allocation as stipulated in the accounting standards.

Effective January 1, 2017, as part of a reorganization of our E&P business, the Onshore and Offshore reporting units were combined within the E&P operating segment, which had no goodwill at December 31, 2016. This reorganization had no impact on the composition of the Bakken Midstream operating segment. We expect that the benefits of our remaining goodwill totaling $375 million assigned to the Bakken Midstream operating segment will be recovered based on market conditions at December 31, 2016.

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 experienced a three-year cumulative consolidated loss as of December 31, 2016. 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.

As of December 31, 2016, the *Consolidated Balance Sheet* reflects a $5,450 million valuation allowance against the net deferred tax assets for multiple jurisdictions based on the evaluation of the accounting standards described above, with $3,749 million recorded in the fourth quarter of 2016 related primarily to the U.S., Denmark (hydrocarbon tax only), and Malaysia. 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. We do not provide for deferred U.S. income taxes for that portion of undistributed earnings of foreign subsidiaries that are indefinitely reinvested in foreign operations.

Asset Retirement Obligations: We have material legal obligations to remove and dismantle long-lived assets and to restore land or seabed at certain exploration and production 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. In order to measure these obligations, we estimate the fair value of the obligations by discounting the 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.

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, the most significant of which relate to the discount rate for measuring the present value of future plan obligations; expected long-term rates of return on plan assets; the rate of future increases in compensation levels, and participant mortality assumptions. These assumptions represent estimates made by us, some of which can be affected by external factors. For example, 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, while 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. Changes in these assumptions can have a material impact on the amounts reported in our financial statements.

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 firm commitments (fair value hedges). The effective portion of changes in fair value of derivatives that are designated as cash flow hedges is 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. The ineffective portion of changes in fair value of derivatives designated as cash flow hedges is recorded currently 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 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 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 exploration and production facilities, sites from discontinued operations as to which 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, 2016, 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 $10 million in 2016 (2015: $13 million; 2014: $12 million). 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.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

As discussed in *Note 24, Financial Risk Management Activities*, in the *Notes to Consolidated Financial Statements*, 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, 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 to affect 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 and Danish Krone which commit us to buy or sell a fixed amount of these currencies 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

We have outstanding foreign exchange contracts with a total notional amount of $785 million at December 31, 2016 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 approximately $5 million at December 31, 2016.

At December 31, 2016, our outstanding long-term debt of $6,806 million, including current maturities, had a fair value of $7,548 million. A 15% increase or decrease in the rate of interest would decrease or increase the fair value of debt by approximately $510 million or $580 million, respectively.

We have no outstanding commodity price hedges at December 31, 2016.

Item 8. Financial Statements and Supplementary Data

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES
INDEX TO FINANCIAL STATEMENTS AND SCHEDULE

* *Schedules other than Schedule II 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, 2016.

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, 2016, as stated in their report, which is included herein.

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

February 23, 2017

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
Hess Corporation

We have audited Hess Corporation and consolidated subsidiaries' (the "Corporation") internal control over financial reporting as of December 31, 2016, 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). 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 conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). 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.

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.

In our opinion, Hess Corporation and consolidated subsidiaries maintained, in all material respects, effective internal control over financial reporting as of December 31, 2016, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet of Hess Corporation and consolidated subsidiaries as of December 31, 2016 and 2015, and the related statements of consolidated income, comprehensive income, cash flows and equity for each of the three years in the period ended December 31, 2016 of Hess Corporation and consolidated subsidiaries, and our report dated February 23, 2017 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
New York, New York
February 23, 2017

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
Hess Corporation

We have audited the accompanying consolidated balance sheets of Hess Corporation and consolidated subsidiaries (the "Corporation") as of December 31, 2016 and 2015, and the related statements of consolidated income, comprehensive income, cash flows and equity for each of the three years in the period ended December 31, 2016. Our audits also included the financial statement schedule listed in the Index at Item 8. These financial statements and schedule are the responsibility of the Corporation's management. Our responsibility is to express an opinion on these financial statements and schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Hess Corporation and consolidated subsidiaries at December 31, 2016 and 2015, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2016, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related financial statement schedule, when considered in relation to the consolidated financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Hess Corporation's internal control over financial reporting as of December 31, 2016, 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 23, 2017 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
New York, New York
February 23, 2017

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES

CONSOLIDATED BALANCE SHEET

	December 31, 2016	December 31, 2015
	(In millions, except share amounts)	
Assets		
Current Assets:		
Cash and cash equivalents	$ **2,732**	$ 2,716
Accounts receivable		
Trade	**940**	847
Other	**86**	312
Inventories	**323**	399
Other current assets	**195**	130
Total current assets	**4,276**	4,404
Property, plant and equipment:		
Total — at cost	**46,907**	46,826
Less: Reserves for depreciation, depletion, amortization and lease impairment	**23,312**	20,474
Property, plant and equipment — net	**23,595**	26,352
Goodwill	**375**	375
Deferred income taxes	**59**	2,653
Other assets	**316**	373
Total Assets	$ **28,621**	$ 34,157
Liabilities		
Current Liabilities:		
Accounts payable	$ **433**	$ 457
Accrued liabilities	**1,609**	1,997
Taxes payable	**97**	88
Current maturities of long-term debt	**112**	86
Total current liabilities	**2,251**	2,628
Long-term debt	**6,694**	6,506
Deferred income taxes	**1,144**	1,334
Asset retirement obligations	**1,912**	2,158
Other liabilities and deferred credits	**1,029**	1,130
Total Liabilities	**13,030**	13,756
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 — 575,000 shares (2015: nil)	**1**	—
Common stock, par value $1.00; Authorized — 600,000,000 shares		
Issued — 316,523,200 shares (2015: 286,045,586)	**317**	286
Capital in excess of par value	**5,773**	4,127
Retained earnings	**10,147**	16,637
Accumulated other comprehensive income (loss)	**(1,704)**	(1,664)
Total Hess Corporation stockholders' equity	**14,534**	19,386
Noncontrolling interests	**1,057**	1,015
Total equity	**15,591**	20,401
Total Liabilities and Equity	$ **28,621**	$ 34,157

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, 2016	2015	2014
	(In millions, except per share amounts)		
Revenues and Non-Operating Income			
Sales and other operating revenues	**$ 4,762**	$ 6,636	$ 10,737
Gains on asset sales, net	**23**	51	823
Other, net	**59**	(126)	(121)
Total revenues and non-operating income	**4,844**	6,561	11,439
Costs and Expenses			
Cost of products sold (excluding items shown separately below)	**1,063**	1,294	1,719
Operating costs and expenses	**1,880**	2,029	2,034
Production and severance taxes	**101**	146	275
Exploration expenses, including dry holes and lease impairment	**1,442**	881	840
General and administrative expenses	**415**	557	588
Interest expense	**338**	341	323
Loss on debt extinguishment	**148**	—	—
Depreciation, depletion and amortization	**3,244**	3,955	3,224
Impairment	**67**	1,616	—
Total costs and expenses	**8,698**	10,819	9,003
Income (Loss) from Continuing Operations Before Income Taxes	**(3,854)**	(4,258)	2,436
Provision (benefit) for income taxes	**2,222**	(1,299)	744
Income (Loss) from Continuing Operations	**(6,076)**	(2,959)	1,692
Income (Loss) from Discontinued Operations, Net of Income Taxes	**—**	(48)	682
Net Income (Loss)	**(6,076)**	(3,007)	2,374
Less: Net income (loss) attributable to noncontrolling interests	**56**	49	57
Net Income (Loss) Attributable to Hess Corporation	**(6,132)**	(3,056)	2,317
Less: Preferred stock dividends	**41**	—	—
Net Income (Loss) Applicable to Hess Corporation Common Stockholders	**$ (6,173)**	$ (3,056)	$ 2,317

	2016	2015	2014
Net Income (Loss) Attributable to Hess Corporation Per Common Share			
Basic:			
Continuing operations	**$ (19.92)**	$ (10.61)	$ 5.57
Discontinued operations	**—**	(0.17)	2.06
Net Income (Loss) Per Common Share	**$ (19.92)**	$ (10.78)	$ 7.63
Diluted:			
Continuing operations	**$ (19.92)**	$ (10.61)	$ 5.50
Discontinued operations	**—**	(0.17)	2.03
Net Income (Loss) Per Common Share	**$ (19.92)**	$ (10.78)	$ 7.53
Weighted Average Number of Common Shares Outstanding (Diluted)	**309.9**	283.6	307.7
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

	2016	2015	2014
	Years Ended December 31, (In millions)		
Net Income (Loss)	**$ (6,076)**	$ (3,007)	$ 2,374
Other Comprehensive Income (Loss):			
Derivatives designated as cash flow hedges			
Effect of hedge (gains) losses reclassified to income	**—**	(118)	(137)
Income taxes on effect of hedge (gains) losses reclassified to income	**—**	44	51
Net effect of hedge (gains) losses reclassified to income	**—**	(74)	(86)
Change in fair value of cash flow hedges	**—**	121	128
Income taxes on change in fair value of cash flow hedges	**—**	(45)	(48)
Net change in fair value of cash flow hedges	**—**	76	80
Change in derivatives designated as cash flow hedges, after taxes	**—**	2	(6)
Pension and other postretirement plans			
(Increase) reduction in unrecognized actuarial losses	**(155)**	17	(534)
Income taxes on actuarial changes in plan liabilities	**20**	4	186
(Increase) reduction in unrecognized actuarial losses, net	**(135)**	21	(348)
Amortization of net actuarial losses	**60**	92	56
Income taxes on amortization of net actuarial losses	**(21)**	(31)	(18)
Net effect of amortization of net actuarial losses	**39**	61	38
Recognition of accumulated actuarial losses - HOVENSA	**—**	15	—
Income taxes on recognition of accumulated actuarial losses - HOVENSA	**—**	(9)	—
Recognition of accumulated actuarial losses, net of taxes - HOVENSA	**—**	6	—
Change in pension and other postretirement plans, after taxes	**(96)**	88	(310)
Foreign currency translation adjustment			
Foreign currency translation adjustment	**56**	(344)	(756)
Change in foreign currency translation adjustment	**56**	(344)	(756)
Other Comprehensive Income (Loss)	**(40)**	(254)	(1,072)
Comprehensive Income (Loss)	**(6,116)**	(3,261)	1,302
Less: Comprehensive income (loss) attributable to noncontrolling interests	**56**	49	57
Comprehensive Income (Loss) Attributable to Hess Corporation	**$ (6,172)**	$ (3,310)	$ 1,245

See accompanying Notes to Consolidated Financial Statements.

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES

STATEMENT OF CONSOLIDATED CASH FLOWS

	Years Ended December 31, 2016	2015	2014
	(In millions)		
Cash Flows From Operating Activities			
Net income (loss)	**$ (6,076)**	$ (3,007)	$ 2,374
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities			
(Gains) losses on asset sales, net	**(23)**	(51)	(823)
Depreciation, depletion and amortization	**3,244**	3,955	3,224
Impairment	**67**	1,616	—
Loss from equity affiliates	**—**	25	84
Exploratory dry hole costs	**1,064**	410	301
Exploration lease and other impairment	**145**	182	207
Stock compensation expense	**73**	97	87
Provision (benefit) for deferred income taxes and other tax accruals	**2,200**	(1,319)	270
Loss on extinguishment of debt	**148**	—	—
(Income) loss from discontinued operations, net of income taxes	**—**	48	(682)
Changes in operating assets and liabilities			
(Increase) decrease in accounts receivable	**96**	841	(199)
(Increase) decrease in inventories	**77**	29	62
Increase (decrease) in accounts payable and accrued liabilities	**(87)**	(424)	79
Increase (decrease) in taxes payable	**9**	(222)	(108)
Changes in other operating assets and liabilities	**(142)**	(164)	(372)
Cash provided by (used in) operating activities - continuing operations	**795**	2,016	4,504
Cash provided by (used in) operating activities - discontinued operations	**—**	(35)	(47)
Net cash provided by (used in) operating activities	**795**	1,981	4,457
Cash Flows From Investing Activities			
Additions to property, plant and equipment - E&P	**(1,979)**	(3,956)	(4,867)
Additions to property, plant and equipment - Bakken Midstream	**(272)**	(365)	(347)
Proceeds from asset sales	**140**	50	2,978
Other, net	**21**	(44)	(192)
Cash provided by (used in) investing activities - continuing operations	**(2,090)**	(4,315)	(2,428)
Cash provided by (used in) investing activities - discontinued operations	**—**	109	2,436
Net cash provided by (used in) investing activities	**(2,090)**	(4,206)	8
Cash Flows From Financing Activities			
Net borrowings (repayments) of debt with maturities of 90 days or less	**43**	110	—
Debt with maturities of greater than 90 days			
Borrowings	**1,496**	600	598
Repayments	**(1,455)**	(67)	(590)
Proceeds from issuance of preferred stock	**557**	—	—
Proceeds from issuance of common stock	**1,087**	—	—
Common stock acquired and retired	**—**	(142)	(3,715)
Cash dividends paid	**(350)**	(287)	(303)
Employee stock options exercised, including income tax benefits	**12**	12	182
Noncontrolling interests, net	**(23)**	2,296	—
Other, net	**(56)**	(25)	—
Cash provided by (used in) financing activities - continuing operations	**1,311**	2,497	(3,828)
Cash provided by (used in) financing activities - discontinued operations	**—**	—	(7)
Net cash provided by (used in) financing activities	**1,311**	2,497	(3,835)
Net Increase (Decrease) in Cash and Cash Equivalents	**16**	272	630
Cash and Cash Equivalents at Beginning of Year	**2,716**	2,444	1,814
Cash and Cash Equivalents at End of Year	**$ 2,732**	$ 2,716	$ 2,444

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	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Hess Stockholders' Equity	Noncontrolling Interests	Total Equity
					(In millions)			
Balance at January 1, 2014	$ —	$ 325	$ 3,498	$ 21,235	$ (338)	$ 24,720	$ 64	$ 24,784
Net income (loss)	—	—	—	2,317	—	2,317	57	2,374
Other comprehensive income (loss)	—	—	—	—	(1,072)	(1,072)	—	(1,072)
Share-based compensation, including income taxes	—	4	261	—	—	265	—	265
Dividends on common stock	—	—	—	(303)	—	(303)	—	(303)
Common stock acquired and retired	—	(43)	(482)	(3,197)	—	(3,722)	—	(3,722)
Noncontrolling interests, net	—	—	—	—	—	—	(6)	(6)
Balance at December 31, 2014	$ —	$ 286	$ 3,277	$ 20,052	$ (1,410)	$ 22,205	$ 115	$ 22,320
Net income (loss)	—	—	—	(3,056)	—	(3,056)	49	(3,007)
Other comprehensive income (loss)	—	—	—	—	(254)	(254)	—	(254)
Share-based compensation, including income taxes	—	1	105	—	—	106	—	106
Dividends on common stock	—	—	—	(287)	—	(287)	—	(287)
Common stock acquired and retired	—	(1)	(18)	(72)	—	(91)	—	(91)
Formation of Bakken Midstream joint venture	—	—	763	—	—	763	1,298	2,061
Noncontrolling interests, net	—	—	—	—	—	—	(447)	(447)
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, 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**

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 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, Equatorial Guinea, the Malaysia/Thailand Joint Development Area (JDA), Malaysia, and Norway. The Bakken Midstream operating segment, which was established in the second quarter of 2015, provides fee-based services, including gathering, compressing and processing natural gas and fractionating natural gas liquids, or NGLs; gathering, terminaling, loading and transporting crude oil and NGLs; and storing and terminaling propane, 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 exploration and production 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 2016, we adopted Accounting Standard Update (ASU) 2015-03, *Simplifying the Presentation of Debt Issuance Costs*, which requires debt issuance costs to be presented in the balance sheet as a direct reduction to the associated debt liability. The *Consolidated Balance Sheet* at December 31, 2015 has been recast to reduce Other assets and Long-term debt by $38 million.

In 2014, the FASB issued ASU 2014-15, *Presentation of Financial Statements – Going Concern*. This ASU requires that management evaluate whether there are conditions or events, considered in the aggregate, that raise substantial doubt about the entity's ability to continue as a going concern within one year after the date the financial statements are issued. This ASU is effective for us beginning in the fourth quarter of 2016. The adoption of ASU 2014-15 did not have an 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 the *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: The E&P segment recognizes revenue from the sale of crude oil, natural gas liquids, and natural gas, when title passes to the customer. Differences between E&P natural gas volumes sold and our entitlement share of natural gas production are not material.

In our E&P activities, we engage in crude oil purchase and sale transactions with the same counterparty that are entered into in contemplation of one another for the primary purpose of changing location or quality. These arrangements are reported net in Sales and other operating revenues in the *Statement of Consolidated Income*.

Our Bakken Midstream segment recognizes revenue from fee-based services including crude oil and natural gas gathering, processing of natural gas and the fractionation of natural gas liquids, terminaling and loading crude oil and natural gas liquids, transportation of crude oil by rail car and the storage and terminaling of propane when pervasive evidence of an arrangement exists, delivery has occurred or services rendered, price is fixed or determinable, and collectability is reasonably assured.

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. In production operations, costs of injected CO_2 for tertiary recovery are expensed as incurred.

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 impairments 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. As a result of the prevailing low crude oil price environment, we tested our oil and gas properties for impairment. See *Note 6, Impairment*.

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 based on a two-step process. In step one of the impairment test, 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, we perform step two to determine possible impairment by comparing the implied fair value of goodwill with the carrying amount. If the implied fair value of goodwill is less than its carrying amount, an impairment loss would be recorded. In addition to our annual test, we also performed separate goodwill impairment tests at December 31, 2015 and June 30, 2015. See *Note 6, Impairment.*

Cash and Cash Equivalents: Cash equivalents consist of highly liquid investments, which are readily convertible into cash and have maturities of three months or less when acquired.

Inventories: Inventories are valued at the lower of cost or market. Cost is generally determined using average actual costs.

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 do not provide for deferred U.S. income taxes for that portion of undistributed earnings of foreign subsidiaries that are indefinitely reinvested in foreign operations. We classify interest and penalties associated with uncertain tax positions as income tax expense.

Asset Retirement Obligations: We have material legal obligations to remove and dismantle long-lived assets and to restore land or the seabed at certain exploration and production 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.

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 firm commitments (fair value hedges). The effective portion of changes in fair value of derivatives that are designated as cash flow hedges is recorded as a component of other comprehensive income (loss) while the ineffective portion of the changes in fair value is recorded currently in earnings. 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 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 as expense on a straight-line basis over the full vesting period of the awards. We estimate the fair value of employee stock options at the date of grant using a Black-Scholes valuation model, performance share units using a Monte Carlo simulation model, and restricted stock 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 most 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 operations that do not use the U.S. Dollar as the functional currency, primarily those in Norway where the Norwegian Krone is used, adjustments resulting from translating foreign currency assets and liabilities into U.S. Dollars are recorded in the *Consolidated Balance Sheet* in a separate component of equity titled Accumulated other comprehensive income (loss).

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 2016, 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 May 2014, the Financial Accounting Standards Board (FASB) issued ASU 2014-09, *Revenue from Contracts with Customers*, as a new Accounting Standards Codification (ASC) Topic, ASC 606. This ASU is effective for us beginning in the first quarter of 2018, with early adoption permitted from the first quarter of 2017. We have developed a project plan for the implementation of ASC 606 in the first quarter of 2018, and conducted an evaluation of a sample of revenue contracts with customers against the requirements of the standard. Further analysis is planned in 2017 to complete the implementation plan. Based on our assessment to date, we have not identified any changes to the timing of revenue recognition based on the requirements of ASC 606 that would have a material impact on our consolidated financial statements. We plan to adopt ASC 606 using the modified retrospective method that requires application of the new standard prospectively from the date of adoption with a cumulative effect adjustment recorded to retained earnings as of January 1, 2018.

In February 2016, the FASB issued ASU 2016-02, *Leases*, as a new ASC Topic, ASC 842. The new standard will require assets and liabilities to be reported on the balance sheet for all leases with lease terms greater than one year, including leases currently treated as operating leases under the existing standard. This ASU is effective for us beginning in the first quarter of 2019, with early adoption permitted. We are currently assessing the impact of the ASU on our consolidated financial statements.

In March 2016, the FASB issued Accounting Standards Update (ASU) 2016-09, *Improvements to Employee Share-Based Payment Accounting.* This ASU makes changes to various provisions associated with share-based accounting, including provisions affecting the accounting for income taxes, the accounting for forfeitures, and the consideration of net settlement provisions on the balance sheet classification of the share-based award. This ASU is effective for us beginning in the first quarter of 2017. The adoption of ASU 2016 – 09 is not expected to have a material impact on our consolidated financial statements.

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 from the first quarter of 2019. We are currently assessing the impact of the ASU on our consolidated financial statements.

In October 2016, the FASB issued ASU 2016-16, *Income Taxes – Intra-Entity Transfer of Assets Other than Inventory*. This ASU will require the recognition of income tax consequences from intra-entity transfer of assets other than inventory when the transfer occurs. This ASU is effective for us beginning in the first quarter of 2018, with early adoption permitted. We plan to adopt ASU 2016-16 in the first quarter of 2017, which is not expected to have a material impact on our consolidated financial statements.

In January 2017, the FASB issued ASU 2017-01, *Business Combinations – Clarifying the Definition of a Business*. This ASU provides a screen that excludes an integrated set of activities and assets from the definition of a business if the fair value of the gross assets acquired (or disposed of) is concentrated in a single identifiable asset or group of similar identifiable assets. This ASU also clarifies that an integrated set of activities and assets must include (at a minimum), an input and a substantive process that together significantly contribute to the ability to create output to be considered a business. This ASU is effective for us beginning in the first quarter of 2018, with early application permitted. We are currently assessing the impact of the ASU on our consolidated financial statements.

In January 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 the 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. The impairment charge would be limited by the amount of goodwill allocated to the reporting unit. This ASU removes the requirement to determine goodwill impairment by calculating the implied fair value of goodwill by assigning the fair value of a reporting unit to all of its assets and liabilities as if the reporting unit had been acquired in a business combination. This ASU is effective for us beginning in the first quarter of 2020, with early adoption permitted. We are currently assessing the impact of the ASU on our consolidated financial statements.

2. 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 will be 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 average share price over a period of twenty consecutive trading days ending prior to February 1, 2019 (the “Final Average Price”), subject to anti-dilution adjustments. See *Note 17, Outstanding and Weighted Average Common Shares.*

We also entered into capped call transactions that are expected generally to reduce the potential dilution to our common stock upon conversion of the Convertible Preferred Stock if the Final Average Price exceeds $45.83 per share, subject to anti-dilution adjustments. The number of common shares to be delivered by the counterparties to us will be the value of the capped call transactions at conversion divided by the Final Average Price. The value of the capped call transactions will be zero if the Final Average Price is $45.83 or less and can be up to the capped value of approximately $98 million if the Final Average Price is $53.625 or higher. For any Final Average Price between $45.83 and $53.625, the value of the capped call transactions will be 12.55 million covered shares multiplied by the difference between the Final Average Price and $45.83. 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*.

3. Inventories

Inventories at December 31 were as follows:

	2016	2015
	(In millions)	
Crude oil and natural gas liquids	**$ 77**	$ 144
Materials and supplies	**246**	255
Total Inventories	**$ 323**	$ 399

4. Property, Plant and Equipment

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

	2016	2015
	(In millions)	
Exploration and Production		
Unproved properties	**$ 710**	$ 958
Proved properties	**4,258**	4,202
Wells, equipment and related facilities	**38,821**	38,738
	43,789	43,898
Bakken Midstream	**3,018**	2,757
Corporate and Other	**100**	171
Total — at cost	**46,907**	46,826
Less: Reserves for depreciation, depletion, amortization and lease impairment	**23,312**	20,474
Property, Plant and Equipment — Net	**$ 23,595**	$ 26,352

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:

	2016	2015	2014
		(In millions)	
Balance at January 1	**$ 1,415**	$ 1,416	$ 2,045
Additions to capitalized exploratory well costs pending the determination of proved reserves	**79**	424	292
Reclassifications to wells, facilities and equipment based on the determination of proved reserves	**—**	(72)	(629)
Capitalized exploratory well costs charged to expense	**(897)**	(356)	(235)
Dispositions and other	**—**	3	(57)
Balance at December 31	**$ 597**	$ 1,415	$ 1,416
Number of Wells at December 31	**17**	35	37

Additions to capitalized exploratory well costs primarily related to drilling activity at the Stabroek license offshore Guyana and in the Gulf of Mexico in 2016 and 2015. In 2014, additions related to the Deepwater Tano/Cape Three Points license offshore Ghana and in Kurdistan. Reclassifications to wells, facilities and equipment based on the determination of proved reserves primarily related to Equatorial Guinea in 2015, and the Stampede development project in the Gulf of Mexico in 2014.

Capitalized exploratory well costs charged to expense include the following:

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. In the second quarter, 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 current 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.

2015: At the Dinarta Block in the Kurdistan Region of Iraq, we expensed an exploration well resulting from our and our partners' decision to cease further drilling and relinquish the block. At the Deepwater/Tano Cape Three Points block, offshore Ghana, we expensed well costs primarily related to natural gas discoveries where we were unable to sufficiently progress appraisal negotiations with the regulator, and we expensed three wells with discovered resources offshore Australia that we determined would not be included in the development concept for the Equus project.

2014: At Green Canyon Block 469 in the Gulf of Mexico, we expensed a previously capitalized exploration well where it was determined no further development activities were planned.

The preceding table excludes exploratory dry hole costs of $167 million (2015: $54 million; 2014: $66 million), which were incurred and subsequently expensed in the same year.

Exploratory well costs capitalized for greater than one year following completion of drilling were $511 million at December 31, 2016, separated by year of completion as follows (in millions):

2015	$	238
2014		80
2013		48
2012		145
	$	511

Ghana: Approximately 55% of the capitalized well costs in excess of one year relates to our Deepwater Tano/Cape Three Points license (Hess 50% license interest), offshore Ghana. In 2014 we drilled three successful appraisal wells. Well results continue to be evaluated and development planning is progressing. The government of Côte d'Ivoire has challenged the maritime border between it and the country of Ghana, which includes a portion of our Deepwater Tano/Cape Three Points license. We are unable to proceed with development of this license until there is a resolution of this matter, which may also impact our ability to develop the license. The International Tribunal for Law of the Sea is expected to render a final ruling on the maritime border dispute in 2017. Under terms of our license and subject to resolution of the border dispute, we declared commerciality for four discoveries, including the Pecan Field which would be the primary development hub for the block in March 2016. We are continuing to work with the government on how best to progress work on the block given the maritime border dispute.

Guyana: Approximately 20% of the capitalized well costs in excess of one year relates to the Stabroek Block, offshore Guyana (Hess 30% participating interest), where the operator, Esso Exploration and Production Guyana Limited, announced a significant oil discovery at the Liza-1 well in the second quarter of 2015. During 2016, the operator completed a 17,000 square kilometer 3D seismic acquisition on the Stabroek Block and drilled the Liza-2 and Liza-3 wells, both of which encountered hydrocarbons. Pre-development planning is underway and we expect to be in a position to sanction the first phase of the Liza development in 2017.

Gulf of Mexico: Approximately 20% of the capitalized well costs in excess of one year relates to an appraisal well in 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. The operator is evaluating plans for developing this area of the field.

JDA: Approximately 5% of the capitalized well costs in excess of one year relates to the JDA in the Gulf of Thailand where hydrocarbons were encountered in three successful exploration wells drilled in the western part of Block A-18. The operator is currently evaluating well results and formulating future drilling plans in the area.

5. Goodwill

The changes in the carrying amount of goodwill were as follows:

	Exploration and Production	Bakken Midstream	Total
		(In millions)	
Balance at January 1, 2015	$ 1,858	$ —	$ 1,858
Reclassification	(375)	375	—
Impairment	(1,483)	—	(1,483)
Balance at December 31, 2015	—	375	375
Reclassification	—	—	—
Impairment	—	—	—
Balance at December 31, 2016	**$ —**	**$ 375**	**$ 375**

In the second quarter of 2015, we established a new operating segment, the Bakken Midstream segment which had previously been reported as part of the Onshore reporting unit within the E&P operating segment. The E&P operating segment previously had two reporting units, Offshore which had allocated goodwill of $1,098 million and Onshore which had allocated goodwill of $760 million prior to forming the Bakken Midstream operating segment. Upon formation of the Bakken Midstream operating segment, we allocated $375 million of goodwill from the Onshore reporting unit to the Bakken Midstream operating segment based on the relative fair values of the Bakken Midstream business and the remainder of the Onshore reporting unit. There was no change to the composition of the Offshore reporting unit. See *Note 6, Impairment* for further information.

6. Impairment

In 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 approximate fair value and represent a Level 3 fair value measurement as defined under accounting standards.

In 2015, we recorded pre-tax goodwill impairment charges totaling $1,483 million ($1,483 million after income taxes). As a result of establishing the Bakken Midstream operating segment in the second quarter of 2015, (see *Note 5, Goodwill*), we performed impairment tests on the Offshore and Onshore reporting units prior to creation of the Bakken Midstream segment in accordance with accounting standards for goodwill. No impairment resulted from this assessment. In addition, we performed separate impairment tests at June 30, 2015, on the allocated goodwill to the Bakken Midstream segment and Onshore reporting unit of the E&P segment following the creation of the Bakken Midstream segment. No impairment existed for the Bakken Midstream segment, but goodwill allocated to the Onshore reporting unit of $385 million did not pass the impairment test, and as a result was reduced to its implied fair value of zero based on a hypothetical purchase price allocation as stipulated in the accounting standards. In addition, as part of the further deterioration in crude oil prices in the fourth quarter of 2015, we determined goodwill allocated to the Offshore reporting unit of $1,098 million did not pass the impairment test, and as a result was reduced to its implied fair value of zero based on a hypothetical purchase price allocation as stipulated in the accounting standards. Fair value of our Onshore and Offshore reporting units were determined using multiple valuation techniques, including projected discounted cash flows of producing assets and known development projects. 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. We also considered the relative market valuation of similar peer companies using market multiples, and other observable market data, in assessing fair value of each reporting unit. The valuation methodologies used represent Level 3 measurements.

As a result of the prevailing low crude oil price in 2015, we also recognized an impairment charge of $133 million pre-tax ($83 million after income taxes) relating to our legacy conventional North Dakota assets based on projected discounted cash flows, using similar Level 3 inputs to those discussed above.

7. Bakken Midstream Joint Venture

On July 1, 2015, we sold a 50% interest in HIP to Global Infrastructure Partners (GIP) for net cash consideration of approximately $2.6 billion. HIP and its affiliates primarily comprise our Bakken Midstream operating segment which provides fee-based services including crude oil and natural gas gathering, processing of natural gas and the fractionation of natural gas liquids, transportation of crude oil by rail car, terminaling and loading crude oil and natural gas liquids, and the storage and terminaling of propane, primarily in the Bakken shale play of North Dakota. The Bakken 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 Bakken 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 Bakken 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 Bakken Midstream segment has minimal direct commodity price exposure, and the E&P segment retains ownership of the crude oil, natural gas or natural gas liquids processed, terminaled, stored or transported by the Bakken Midstream segment.

We consolidate the activities of 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. 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.

As a result of the sale to GIP in 2015, we recorded an after-tax gain of $763 million in additional paid-in-capital and $1,298 million in noncontrolling interest representing GIP’s proportional share of our basis in the net assets of HIP. The results attributable to GIP’s 50% ownership are reported within Net income (loss) attributable to noncontrolling interests in the *Statement of Consolidated Income*, while the carrying amount of GIP’s equity is included as Noncontrolling interests in the *Consolidated Balance Sheet*.

Upon formation, the joint venture incurred $600 million of borrowings through a 5-year Term Loan A facility with the proceeds distributed equally to the partners. At December 31, 2016, HIP liabilities totaling $841 million (2015: $831 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 $2 million (2015: $3 million) and Property, plant and equipment totaling $2,528 million (2015: $2,358 million).

8. Dispositions

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).

2015: We sold approximately 13,000 acres of Utica dry gas acreage for a sale price of approximately $120 million. This transaction resulted in a pre-tax gain of $49 million ($31 million after income taxes). We also disposed of our interest in Algeria and recognized a pre-tax loss of $21 million ($21 million after income taxes) and sold land associated with our former joint venture interest in the Bayonne Energy Center for $20 million, resulting in a pre-tax gain of $20 million ($13 million after income taxes).

2014: We completed the sale of our interest in the Pangkah asset, offshore Indonesia for cash proceeds of approximately $650 million, which resulted in a pre-tax gain of $31 million ($10 million loss after income taxes). We also completed the sale of our interests in Thailand for cash proceeds of approximately $805 million, which resulted in a pre-tax gain of $706 million ($706 million after income taxes). In addition, we completed the sale of approximately 77,000 net acres in the dry gas area of the Utica shale play including related wells and facilities through multiple transactions, for cash proceeds of $1,075 million and recorded a pre-tax gain of $62 million ($35 million after income taxes). In June, we completed the sale of our joint venture interest in an electric generating facility in Newark, New Jersey for cash proceeds of $320 million, resulting in a pre-tax gain of approximately $13 million ($8 million after income taxes). In September, we sold our joint venture interest in Bayonne Energy Center for $79 million, which did not result in a gain or loss. Also in September, we completed the sale of our interest in an exploration asset in the United Kingdom North Sea for $53 million, which resulted in a pre-tax gain of $33 million ($33 million after income taxes).

9. Discontinued Operations

The results of operations for our divested Marketing and Refining businesses, which included ownership of the energy trading partnership through February 2015 and retail marketing through September 2014, have been reported as discontinued operations in the *Statement of Consolidated Income* and the *Statement of Consolidated Cash Flows* for all periods presented.

Sales and other operating revenues and income from discontinued operations were as follows:

	2016	2015	2014
		(In millions)	
Sales and other operating revenues	$ —	$ 14	$ 9,576
Income (Loss) from Discontinued Operations Before Income Taxes	$ —	$ (74)	$ 1,071
Current tax provision (benefit)	—	—	—
Deferred tax provision (benefit)	—	(26)	389
Provision (benefit) for income taxes	—	(26)	389
Income (loss) from Discontinued Operations, Net of Income Taxes	$ —	$ (48)	$ 682
Less: Net income (loss) attributable to noncontrolling interests	—	—	57
Income (Loss) from Discontinued Operations Attributable to Hess Corporation	$ —	$ (48)	$ 625

2015: In February, we sold our interest in HETCO, which was subsequently renamed Hartree Partners, LP (Hartree). Pursuant to the terms of the sale, Hartree was permitted to utilize our guarantees issued in favor of Hartree's existing counterparties until November 12, 2015, provided that new trades were for a period of one year or less, complied with certain credit requirements, and net exposures remained within value at risk limits previously applied by us. The guarantees remain in effect until the qualifying trades outstanding at November 12, 2015 mature. We have the right to seek reimbursement from Hartree and a separate Hartree credit support facility upon any counterparty draw on the applicable guarantee from us. No draws on the guaranteed trades have occurred through December 31, 2016.

2014: In September, we completed the sale of our retail business for cash proceeds of approximately $2.8 billion. This transaction resulted in a pre-tax gain of $954 million ($602 million after income taxes) after deducting the net book value of assets, including $115 million of goodwill. During the year, we recorded pre-tax gains of $275 million ($171 million after income taxes) relating to the liquidation of last-in, first-out (LIFO) inventories associated with the divested downstream operations. In addition, we recorded pre-tax charges totaling $308 million ($202 million after income taxes) for impairments, environmental matters, severance and exit related activities associated with the divestiture of downstream operations. We also recognized a pre-tax charge of $115 million ($72 million after income taxes) related to the termination of lease contracts and the purchase of 180 retail gasoline stations in preparation for the sale of the retail operations. In January, our retail business acquired our partners’ 56% interest in WilcoHess, a retail gasoline joint venture, for approximately $290 million and the settlement of liabilities. In connection with this business combination, we recorded a pre-tax gain of $39 million ($24 million after income taxes) to remeasure the carrying value of our original 44% equity interest in WilcoHess to fair value, including recognition of goodwill in the amount of $115 million. The assets and liabilities acquired from WilcoHess were included in the sale of the retail business in September 2014.

10. HOVENSA LLC

HOVENSA LLC (HOVENSA), a 50/50 joint venture between the Corporation's subsidiary, Hess Oil Virgin Islands Corp. (HOVIC), and Petroleos de Venezuela S.A. (PDVSA), had previously shut down its U.S. Virgin Islands refinery in 2012 and filed a voluntary petition for relief under Chapter 11 of the United States Bankruptcy Code in the United States District Court of the Virgin Islands in September 2015. To fund HOVENSA's sale process and orderly wind-down, HOVENSA entered into a $40 million debtor-in-possession credit facility with HOVENSA's owners, the terms of which were approved by the Bankruptcy Court. On December 1, 2015, the Bankruptcy Court entered an order approving the sale of HOVENSA's terminal and refinery assets to Limetree Bay Terminals, LLC (Limetree). The Senate of the U.S. Virgin Islands approved the sale on December 29, 2015, and the sale to Limetree was completed on January 4, 2016. On January 19, 2016, the Bankruptcy Court entered an order confirming HOVENSA's Chapter 11 plan of liquidation (the "Liquidation Plan"). Under the Liquidation Plan, HOVENSA established a liquidating trust to distribute certain assets and sale proceeds to its creditors, established an environmental response trust to administer to HOVENSA's remaining environmental obligations and to conduct an orderly wind-down of its remaining activities. The Liquidation Plan also provided for releases of any claims held by HOVENSA and its bankruptcy estate against us and HOVIC, which were effective on the effective date of the Liquidation Plan. In connection with the Liquidation Plan and HOVENSA's asset sale, we relinquished our claims against HOVENSA to recover the 2012 and 2015 promissory notes issued by HOVENSA. In addition, we assumed the HOVENSA pension plan upon the effective date of the Liquidation Plan. In 2015, we recorded a charge of $30 million primarily representing the estimated net difference between the HOVENSA pension plan obligation and fair value of the plan assets.

11. Asset Retirement Obligations

The following table describes changes to our asset retirement obligations:

	2016	2015
	(In millions)	
Balance at January 1	**$ 2,383**	$ 2,723
Liabilities incurred	**42**	57
Liabilities settled or disposed of	**(196)**	(360)
Accretion expense	**117**	126
Revisions of estimated liabilities	**(230)**	92
Foreign currency translation	**12**	(255)
Balance at December 31	**2,128**	2,383
Less: Current Obligations	**216**	225
Long-term Obligations at end of period	**$ 1,912**	$ 2,158

The liabilities settled or disposed of related primarily to abandonment activities conducted at the Valhall field offshore Norway in 2016 and 2015, the Gulf of Mexico in 2016, and the U.K. North Sea in 2015. The revisions in 2016 primarily relate to the South Arne Field, offshore Denmark, as a result of a 20-year extension to the license that extends expiry to 2047. Other revisions in 2016 and 2015 reflect changes in the expected scope of operations and updates to service and equipment costs. The fair value of sinking fund deposits that are legally restricted for purposes of settling asset retirement obligations, which are included in non-current Other assets in the *Consolidated Balance Sheet*, was $102 million at December 31, 2016 and $79 million at December 31, 2015.

12. Debt

Long-term debt at December 31 consisted of the following:

	2016	2015
	(In millions)	
Debt Excluding Bakken Midstream:		
Fixed-rate public notes:		
1.3% due 2017	$ —	$ 299
8.1% due 2019	**349**	996
3.5% due 2024	**297**	296
4.3% due 2027	**989**	—
7.9% due 2029	**499**	693
7.3% due 2031	**679**	744
7.1% due 2033	**596**	595
6.0% due 2040	**740**	739
5.6% due 2041	**1,232**	1,231
5.8% due 2047	**493**	—
Total fixed-rate public notes	**5,874**	5,593
Financing obligations associated with floating production system	**192**	264
Fair value adjustments - interest rate hedging	**7**	31
Total Debt Excluding Bakken Midstream	**$ 6,073**	$ 5,888
Debt Related to Bakken Midstream		
Bakken Midstream - term loan A facility	**$ 580**	$ 594
Bakken Midstream - revolving credit facility	**153**	110
Total Debt Related to Bakken Midstream	**$ 733**	$ 704
Total Long-Term Debt:		
Total debt (a) (b)	**$ 6,806**	$ 6,592
Less: Current maturities of long-term debt	**112**	86
Total Long-Term Debt	**$ 6,694**	$ 6,506

(a) *At December 31, 2016 the fair value of total debt amounted to $7,548 million (2015: $6,515 million).*
(b) *The aggregate total debt maturing during the next five years is as follows (in millions): 2017: $112; 2018: $123; 2019: $448; 2020: $598 and 2021: $-.*

Debt refinancing transaction: In September 2016, Hess Corporation issued $1 billion of 4.30% senior notes, due in April 2027, and $500 million of 5.80% senior notes, due in April 2047 primarily to fund the repurchase of tendered higher-coupon debt and redemption of near-term maturities. We used proceeds of $1.38 billion to purchase or redeem $650 million principal amount of 8.125% notes due 2019, $196 million principal amount of 7.875% notes due 2029, $66 million principal amount of 7.30% notes due 2031 and $300 million principal amount of 1.30% notes due 2017. As a result of this debt refinancing transaction, we incurred a charge of $148 million for the loss on extinguishment of the tendered and redeemed notes.

Debt excluding Bakken Midstream: At December 31, 2016, Hess Corporation's fixed-rate public notes had a gross principal amount of $5,938 million (2015: $5,650 million) and a weighted average interest rate of 6.0% (2015: 6.4%). 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 $4,585 million of secured debt at December 31, 2016. In 2016, we capitalized $61 million of interest (2015: $45 million; 2014: $76 million).

Hess Corporation has a $4 billion syndicated revolving credit facility that expires in January 2020. Borrowings on the facility will generally bear interest at 1.3% 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 total borrowings on the last day of each fiscal quarter to 65% of the Corporation's total capitalization, defined as total debt plus stockholders' equity. At December 31, 2016, Hess Corporation had no outstanding borrowings or letters of credit issued against the syndicated revolving credit facility and was in compliance with this financial covenant.

Letters of credit: Outstanding letters of credit at December 31 were as follows:

	2016	2015
	(In millions)	
Committed lines (a)	**$ 1**	$ 10
Uncommitted lines (a)	**187**	103
Total (b)	**$ 188**	$ 113

(a) At December 31, 2016, committed and uncommitted lines have expiration dates through 2018.
(b) At December 31, 2016, $27 million relates to contingent liabilities and $161 million relates to liabilities recorded in the Consolidated Balance Sheet (2015: $32 million and $81 million, respectively).

Debt related to Bakken Midstream: In July 2015, HIP, a 50/50 joint venture between us and GIP, incurred $600 million of debt through a 5-year Term Loan A facility. The proceeds from the debt were distributed equally to the partners. HIP also entered into a $400 million 5-year syndicated revolving credit facility, which can be used for borrowings and letters of credit, and is expected to fund the joint venture's operating activities and capital expenditures. Borrowings on both loan facilities are non-recourse to Hess Corporation and generally bear interest at LIBOR plus an applicable margin ranging from 1.10% to 2.00%. The interest rate is 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 the joint venture obtains credit ratings, pricing levels will be based on its credit ratings in effect from time to time. The joint venture is subject to customary covenants in the credit agreement, including 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 interest expense, of no less than 2.25 to 1.0 for the prior four fiscal quarters. HIP is in compliance with all debt covenants at December 31, 2016, and its financial covenants do not currently impact their ability to issue indebtedness to fund future capital expenditures.

13. Share-based Compensation

We have established and maintain a Long-term Incentive Plan (LTIP), as amended, for the granting of restricted common shares, performance share units (PSUs) and stock options to our employees. As of December 31, 2016, the total number of authorized common stock under LTIP, as amended, was 38.0 million shares, of which we have 10.6 million shares available for issuance. Outstanding restricted stock and PSUs generally vest three years from the date of grant. Restricted common shares are valued based on the prevailing market price of our common stock on the date of grant. Outstanding stock options vest over three years from the date of grant and have a 10-year term and an exercise price equal to the market price on the date of grant.

The number of shares of common stock to be issued under the 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.

Share-based compensation expense consisted of the following:

	2016	2015	2014
		(In millions)	
Restricted stock	**$ 45**	$ 67	$ 62
Stock options	**7**	5	2
Performance share units	**21**	25	19
Share-based compensation expense before income taxes (a)	**$ 73**	$ 97	$ 83
Income tax benefit on share-based compensation expense	**$ 28**	$ 36	$ 31

(a)Includes benefit related to discontinued operations of $4 million for 2014.

Based on share-based compensation awards outstanding at December 31, 2016, unearned compensation expense, before income taxes, will be recognized in future years as follows (in millions): 2017—$66, 2018—$35, and 2019—$6.

Share-based compensation activity consisted of the following:

	Performance Share Units		Stock Options		Restricted Stock	
	Performance Share Units	Weighted - Average Fair Value on Date of Grant	Options	Weighted - Average Exercise Price per Share	Shares of Restricted Common Stock	Weighted - Average Price on Date of Grant
	(In thousands, except per share amounts)					
Outstanding at January 1, 2016	820	$ 89.43	6,911	$ 67.77	2,820	$ 75.32
Granted	447	50.94	824	44.60	1,661	44.69
Exercised	—	—	(227)	53.43	—	—
Vested	(193)	111.49	—	—	(833)	69.57
Forfeited	(59)	65.11	(916)	55.00	(547)	66.98
Outstanding at December 31, 2016	1,015	$ 69.68	6,592	$ 67.15	3,101	$ 61.93

As of December 31, 2016, there were 6.6 million outstanding stock options (5.5 million exercisable) with a weighted average remaining contractual life of 3.6 years (2.6 years for exercisable options) and an aggregated intrinsic value of $27 million ($14 million for exercisable options). The weighted average exercise price for options exercisable at December 31, 2016 was $69.71 per share.

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

	2016	2015	2014
Risk free interest rate	**1.47%**	1.77%	1.86%
Stock price volatility	**0.326**	0.312	0.363
Dividend yield	**2.26%**	1.34%	1.24%
Expected life in years	**6.0**	6.0	6.0
Weighted average fair value per option granted	**$ 11.33**	$ 21.00	$ 26.46

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

	2016	2015	2014
Risk free interest rate	**0.96%**	1.02%	0.65%
Stock price volatility	**0.329**	0.270	0.359
Contractual term in years	**3.0**	3.0	3.0
Grant date price of Hess common stock	**$ 44.31**	$ 74.49	$ 80.35

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 peer group using the vesting period. The contractual term is equivalent to the vesting period.

14. 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	
	2016	**2015**	**2016**	**2015**	**2016**	**2015**
			(In millions)			
Change In Benefit Obligation						
Balance at January 1	**$ 2,321**	$ 2,450	**$ 259**	$ 278	**$ 98**	$ 94
Service cost	**44**	51	**16**	16	**4**	4
Interest cost	**98**	93	**9**	9	**3**	3
Actuarial loss (gain) (a)	**162**	(156)	**(5)**	(2)	**(13)**	5
Benefit payments (b)	**(132)**	(85)	**(23)**	(42)	**(8)**	(8)
Plan curtailments	**(2)**	(4)	**—**	—	**—**	—
Special termination benefits	**1**	1	**—**	—	**—**	—
Assumption of HOVENSA pension plan	**151**	—	**—**	—	**—**	—
Foreign currency exchange rate changes	**(83)**	(29)	**—**	—	**—**	—
Balance at December 31	**2,560**	2,321	**256**	259	**84**	98
Change In Fair Value of Plan Assets						
Balance at January 1	**$ 2,206**	$ 2,251	**$ —**	$ —	**$ —**	$ —
Actual return on plan assets	**153**	28	**—**	—	**—**	—
Employer contributions	**26**	44	**23**	42	**8**	8
Benefit payments (b)	**(132)**	(85)	**(23)**	(42)	**(8)**	(8)
Assumption of HOVENSA pension plan	**126**	—	**—**	—	**—**	—
Foreign currency exchange rate changes	**(95)**	(32)	**—**	—	**—**	—
Balance at December 31	**2,284**	2,206	**—**	—	**—**	—
Funded Status (Plan assets greater (less) than benefit obligations) at December 31	**$ (276)**	$ (115)	**$ (256)**	$ (259)	**$ (84)**	$ (98)
Unrecognized Net Actuarial (Gains) Losses	**$ 895**	$ 775	**$ 93**	$ 105	**$ (13)**	$ —

(a) The change in discount rate in 2016 resulted in total actuarial losses of approximately $175 million.
(b) Benefit payments include lump-sum settlement payments of $65 million in 2016 (2015: $41 million).

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

	Funded Pension Plans		Unfunded Pension Plan		Postretirement Medical Plan	
	2016	**2015**	**2016**	**2015**	**2016**	**2015**
			(In millions)			
Pension asset / (accrued benefit liability)	**$ (276)**	$ (115)	**$ (256)**	$ (259)	**$ (84)**	$ (98)
Accumulated other comprehensive loss, pre-tax (a)	**895**	775	**93**	105	**(13)**	**—**

(a) *The after-tax deficit reflected in Accumulated other comprehensive income (loss) was $660 million at December 31, 2016 (2015: $563 million deficit).*

At December 31, 2016, the accumulated benefit obligation for the funded and unfunded defined benefit pension plans was $2,471 million and $203 million, respectively (2015: $2,223 million and $196 million, respectively).

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

	Pension Plans			Postretirement Medical Plan		
	2016	2015	2014	**2016**	2015	2014
	(In millions)					
Service cost	**$ 60**	$ 67	$ 57	**$ 4**	$ 4	$ 4
Interest cost	**107**	102	100	**3**	3	3
Expected return on plan assets	**(166)**	(168)	(161)	**—**	—	—
Amortization of unrecognized net actuarial losses	**60**	75	32	**—**	—	—
Settlement loss	**—**	17	24	**—**	—	—
Special termination benefit recognized	**1**	1	1	**—**	—	—
Net Periodic Benefit Cost	**$ 62**	$ 94	$ 53	**$ 7**	$ 7	$ 7

For 2017, the pension and postretirement medical expense is estimated to be approximately $61 million, which includes approximately $67 million related to the amortization of unrecognized net actuarial losses.

The weighted average actuarial assumptions used for funded and unfunded pension plans were as follows:

	2016	2015	2014
Weighted Average Assumptions Used to Determine Benefit Obligations at December 31			
Discount rate	**3.7%**	4.1%	3.8%
Rate of compensation increase	**4.6%**	4.5%	5.0%
Weighted Average Assumptions Used to Determine Net Periodic Benefit Cost for the Years Ended December 31			
Discount rate	**4.1%**	3.8%	4.6%
Expected return on plan assets	**7.4%**	7.5%	7.5%
Rate of compensation increase	**4.5%**	5.0%	4.4%

The actuarial assumptions used for postretirement medical plan, as follows:

	2016	2015	2014
Assumptions Used to Determine Benefit Obligations at December 31			
Discount rate	**3.5%**	3.5%	3.1%
Initial health care trend rate	**7.7%**	6.7%	6.8%
Ultimate trend rate	**4.5%**	4.5%	4.5%
Year in which ultimate trend rate is reached	**2038**	2038	2029

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. 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.

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 the Corporation 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, 25% fixed income securities (including cash and short-term investment funds) and 25% 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.

The following tables provide the fair value of the financial assets of the funded pension plans as of December 31, 2016 and 2015 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	Total
	(In millions)			
December 31, 2016				
Cash and Short-Term Investment Funds	$ **9**	$ **79**	$ —	$ **88**
Equities:				
U.S. equities (domestic)	**550**	**—**	**—**	**550**
International equities (non-U.S.)	**160**	**275**	**—**	**435**
Global equities (domestic and non-U.S.)	**2**	**197**	**—**	**199**
Fixed Income:				
Treasury and government issued (a)	**—**	**202**	**—**	**202**
Government related (b)	**—**	**38**	**—**	**38**
Mortgage-backed securities (c)	**—**	**164**	**2**	**166**
Corporate	**1**	**186**	**—**	**187**
Other:				
Hedge funds	**—**	**—**	**209**	**209**
Private equity funds	**—**	**—**	**126**	**126**
Real estate funds	**10**	**—**	**52**	**62**
Diversified commodities funds	**—**	**22**	**—**	**22**
	$ 732	**$ 1,163**	**$ 389**	**$ 2,284**
December 31, 2015				
Cash and Short-Term Investment Funds	$ —	$ 34	$ —	$ 34
Equities:				
U.S. equities (domestic)	556	—	—	556
International equities (non-U.S.)	159	266	—	425
Global equities (domestic and non-U.S.)	2	217	—	219
Fixed Income:				
Treasury and government issued (a)	—	213	—	213
Government related (b)	—	6	1	7
Mortgage-backed securities (c)	—	174	2	176
Corporate	—	157	—	157
Other:				
Hedge funds	—	—	216	216
Private equity funds	—	—	122	122
Real estate funds	12	—	52	64
Diversified commodities funds	—	17	—	17
	$ 729	$ 1,084	$ 393	$ 2,206

(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.*

Cash and short-term investment funds consist of cash on hand and short-term investment funds that provide for daily investments and redemptions and are valued and carried at a $1 net asset value (NAV) per fund share. Cash on hand is classified as Level 1 and short-term investment funds are classified as Level 2.

Equities consist of equity securities issued by U.S. and non-U.S. corporations as well as commingled investment funds that invest in equity securities. Individually held equity securities, which are traded actively on exchanges and have readily available price quotes, are classified as Level 1. Commingled fund values, which are valued at the NAV per fund share derived from the quoted prices in active markets of the underlying securities, are classified as Level 2.

Fixed income investments consist 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 on the basis of 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 or 3. Fixed income commingled fund values, which reflect the NAV per fund share derived indirectly from observable inputs or from quoted prices in less liquid markets of the underlying securities, are classified as Level 2.

Other investments consist of exchange-traded real estate investment trust securities, as well as commingled fund and limited partnership investments in hedge funds, private equity, real estate and diversified commodities. Exchange-traded securities are classified as Level 1. Commingled fund values reflect the NAV per fund share and are classified as Level 2 or 3. Private equity and real estate limited partnership values reflect information reported by the fund managers, which include inputs such as cost, operating results, discounted future cash flows, market based comparable data and independent appraisals from third-party sources with professional qualifications. Hedge funds, private equity and non-exchange-traded real estate investments are classified as Level 3.

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	Hedge Funds	Private Equity Funds	Real Estate Funds	Total
			(In millions)		
Balance at January 1, 2015	$ 2	$ 302	$ 105	$ 48	$ 457
Actual return on plan assets	—	(5)	18	9	22
Purchases, sales or other settlements	1	(81)	(1)	(5)	(86)
Net transfers in (out) of Level 3	—	—	—	—	—
Balance at December 31, 2015	3	216	122	52	393
Actual return on plan assets	**—**	**(7)**	**5**	**7**	**5**
Purchases, sales or other settlements	**(1)**	**—**	**(1)**	**(7)**	**(9)**
Net transfers in (out) of Level 3	**—**	**—**	**—**	**—**	**—**
Balance at December 31, 2016	**$ 2**	**$ 209**	**$ 126**	**$ 52**	**$ 389**

We expect to contribute approximately $52 million to our funded pension plans in 2017.

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):

2017	$ 138
2018	123
2019	133
2020	135
2021	136
Years 2022 to 2026	725

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 $25 million in 2016 for contributions to these plans (2015: $28 million; 2014: $32 million).

15. Exit and Disposal Costs

In 2016, we incurred severance expense of $55 million (2015: $13 million; 2014: $76 million) and paid accrued severance costs of $52 million (2015: $57 million; 2014: $170 million). The severance charge in 2016 primarily resulted from a realignment of our organizational structure communicated in November 2016. Severance charges in 2015 and 2014 resulted from a divestiture program announced in 2013. Severance charges were based on amounts incurred under ongoing severance arrangements or other statutory requirements, plus amounts earned under enhanced benefit arrangements. The expense associated with the enhanced benefits was recognized ratably over the estimated service period required for the employee to earn the benefit upon termination. In 2015, we recorded other exit related costs of $15 million (2014: $65 million). In 2016, we paid $2 million (2015: $21 million; 2014: $158 million) for accrued facility and other exit costs. The facility and other exit costs related to charges associated with the cessation of use of certain leased office space, contract terminations, and costs associated with the shutdown of Port Reading refining operations.

At December 31, 2016, we had accrued liabilities for severance costs of $36 million (2015: $33 million) and accrued liabilities for exit costs of $17 million (2015: $19 million). Of the accrued liabilities at December 31, 2016, all severance costs are expected to be paid in 2017 and the exit costs of $14 million will be paid over the next several years.

16. Income Taxes

The provision (benefit) for income taxes from continuing operations consisted of:

	2016	2015	2014
		(In millions)	
United States			
Federal			
Current	**$ (27)**	$ (7)	$ (1)
Deferred taxes and other accruals	**1,948**	(995)	156
State	**23**	(61)	57
	1,944	(1,063)	212
Foreign			
Current	**36**	4	453
Deferred taxes and other accruals	**235**	(231)	79
	271	(227)	532
Total	**2,215**	(1,290)	744
Adjustment of deferred taxes for foreign income tax law changes	**7**	(9)	—
Total Provision (Benefit) For Income Taxes (a)	**$ 2,222**	$ (1,299)	$ 744

(a) Includes charges of $3,749 million in 2016 to establish valuation allowances on net deferred tax assets which is discussed further below.

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

	2016	2015	2014
		(In millions)	
United States (a)	**$ (2,431)**	$ (2,728)	$ 676
Foreign	**(1,423)**	(1,530)	1,760
Total Income (Loss) from Continuing Operations Before Income Taxes	**$ (3,854)**	$ (4,258)	$ 2,436

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

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

	2016	2015
	(In millions)	
Deferred Tax Liabilities		
Property, plant and equipment and investments	**$ (3,810)**	$ (3,743)
Other	**(255)**	(257)
Total Deferred Tax Liabilities	**(4,065)**	(4,000)
Deferred Tax Assets		
Net operating loss carryforwards	**5,767**	3,852
Tax credit carryforwards	**164**	188
Property, plant and equipment and investments	**834**	981
Accrued compensation, deferred credits and other liabilities	**526**	492
Asset retirement obligations	**1,077**	1,220
Other	**62**	165
Total Deferred Tax Assets	**8,430**	6,898
Valuation allowances	**(5,450)**	(1,579)
Total deferred tax assets, net of valuation allowances	**2,980**	5,319
Net Deferred Tax Assets (Liabilities)	**$ (1,085)**	$ 1,319

At December 31, 2016, we have recognized a gross deferred tax asset related to net operating loss carryforwards of $5,767 million before application of valuation allowances. The deferred tax asset is comprised of $2,610 million attributable to foreign net operating losses which begin to expire in 2024, $2,766 million attributable to U.S. federal operating losses which begin to expire in 2021 and $391 million attributable to losses in various U.S. states which began to expire in 2017. The deferred tax asset attributable to foreign net operating losses, net of valuation allowances, is $1,468 million, substantially all of which relates to loss carryforwards in Norway. The deferred tax asset attributable to U.S. federal net operating losses, net of valuation allowances, is $39 million. A full valuation allowance is established against the deferred tax asset attributable to U.S. state net operating losses. At December 31, 2016, we have U.S. federal, U.S. state and foreign alternative minimum tax credit carryforwards of $77 million which can be carried forward indefinitely, and approximately $6 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 $81 million, which begin to expire in 2017.

As of December 31, 2016, the Balance Sheet reflects a $5,450 million valuation allowance against the net deferred tax assets for multiple jurisdictions based on application of the relevant accounting standards, with $3,749 million recorded in the fourth quarter of 2016 related primarily to the U.S., Denmark (hydrocarbon tax only), and Malaysia. The charge in 2016 is comprised of net deferred tax assets as of the beginning of the year totaling $2,683 million and additional net deferred tax assets recognized during the year of $1,066 million. 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, 2016 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.

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

	2016	2015
	(In millions)	
Deferred income taxes (long-term asset)	$ **59**	$ 2,653
Deferred income taxes (long-term liability)	**(1,144)**	(1,334)
Net Deferred Tax Assets (Liabilities)	$ **(1,085)**	$ 1,319

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

	2016	2015	2014
U.S. statutory rate	**35.0 %**	35.0 %	35.0 %
Effect of foreign operations (a)	**4.6**	5.9	0.7
State income taxes, net of Federal income tax	**1.9**	0.9	1.5
Change in enacted tax laws	**(0.2)**	0.2	—
Gains on asset sales, net	—	(0.2)	(8.3)
Impairment	**(2.1)**	(12.2)	—
Valuation allowance against previously benefitted deferred tax assets	**(97.3)**	(3.1)	0.6
Benefit of legal entity restructuring	—	3.5	—
Other	**0.4**	0.5	1.0
Total	**(57.7) %**	30.5 %	30.5 %

(a) The variance in effective income tax rates attributable to the effect of foreign operations primarily resulted from the mix of income among high and low tax rate jurisdictions.

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

	2016	2015
	(In millions)	
Balance at January 1	$ **604**	$ 603
Additions based on tax positions taken in the current year	**19**	19
Additions based on tax positions of prior years	**113**	29
Reductions based on tax positions of prior years	**(274)**	(31)
Reductions due to settlements with taxing authorities	**(27)**	(12)
Reductions due to lapses in statutes of limitation	**(11)**	(4)
Balance at December 31	$ **424**	$ 604

The December 31, 2016 balance of unrecognized tax benefits includes $233 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 by approximately $85 million due to settlements with taxing authorities or other resolutions, as well as lapses in statutes of limitation. At December 31, 2016, our accrued interest and penalties related to unrecognized tax benefits is $29 million (2015: $74 million).

We have not recognized deferred income taxes on the portion of undistributed earnings of foreign subsidiaries expected to be indefinitely reinvested in foreign operations. At December 31, 2016, we have undistributed earnings from foreign subsidiaries, which we expect to be indefinitely reinvested in foreign operations, of approximately $7.6 billion. We have not measured the unrecognized deferred tax liability related to these earnings because this determination is not practicable.

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.

17. Outstanding and Weighted Average Common Shares

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

	2016	2015	2014
		(In millions)	
Balance at January 1	**286.0**	285.8	325.3
Shares issued	**28.8**	—	—
Activity related to restricted stock awards, net	**1.1**	0.8	0.6
Stock options exercised	**0.2**	0.2	3.3
PSU vested	**0.4**	0.6	—
Shares repurchased (a)	**—**	(1.4)	(43.4)
Balance at December 31	**316.5**	286.0	285.8

(a) See Note 18, Share Repurchase Plan.

The following table presents the calculation of basic and diluted earnings per share:

	2016	2015	2014
		(In millions, except per share amounts)	
Net Income (Loss) Attributable to Hess Corporation Common Stockholders:			
Income (loss) from continuing operations, net of income taxes	**$ (6,076)**	$ (2,959)	$ 1,692
Less: Net income (loss) attributable to noncontrolling interests	**56**	49	—
Net income (loss) from continuing operations attributable to Hess Corporation	**(6,132)**	(3,008)	1,692
Less: Preferred stock dividends	**41**	—	—
Net income (loss) from continuing operations attributable to Hess Corporation Common Stockholders	**(6,173)**	(3,008)	1,692
Income (loss) from discontinued operations, net of income taxes	**—**	(48)	682
Less: Net income (loss) attributable to noncontrolling interests	**—**	—	57
Net income (loss) from discontinued operations attributable to Hess Corporation	**—**	(48)	625
Net income (loss) attributable to Hess Corporation Common Stockholders	**$ (6,173)**	$ (3,056)	$ 2,317
Weighted Average Number of Common Shares Outstanding:			
Basic	**309.9**	283.6	303.7
Effect of dilutive securities			
Restricted common stock	**—**	—	1.5
Stock options	**—**	—	1.8
Performance share units	**—**	—	0.7
Mandatory Convertible Preferred stock	**—**	—	—
Diluted	**309.9**	283.6	307.7
Net Income (Loss) Attributable to Hess Corporation per Common Share:			
Basic:			
Continuing operations	**$ (19.92)**	$ (10.61)	$ 5.57
Discontinued operations	**—**	(0.17)	2.06
Net income (loss) per common share	**$ (19.92)**	$ (10.78)	$ 7.63
Diluted:			
Continuing operations	**$ (19.92)**	$ (10.61)	$ 5.50
Discontinued operations	**—**	(0.17)	2.03
Net income (loss) per common share	**$ (19.92)**	$ (10.78)	$ 7.53

The following table summarizes the number of antidilutive shares excluded from the computation of diluted shares:

	2016	2015	2014
		(In millions)	
Restricted common stock	**3.3**	2.9	—
Stock options	**6.9**	6.9	1.4
Performance share units	**0.9**	1.0	—
Common shares from conversion of preferred stock	**11.2**	—	—

In 2016, 2015 and 2014, cash dividends declared on common stock totaled $1.00 per share ($0.25 per quarter).

18. Share Repurchase Plan

In 2013, our Board of Directors authorized the repurchase of up to $4.0 billion in aggregate purchase price of our common stock. In May 2014, the Board of Directors approved an increase in the program to $6.5 billion. Repurchases under this program to date have been as follows:

	2016	2015	2014	To Date
		(In millions)		
Total cost of shares repurchased	**$ —**	$ 91	$ 3,722	$ 5,351
Total number of shares repurchased	**—**	1.45	43.35	64.11

As of December 31, 2016, we are authorized, but not required, to purchase additional common stock up to a value of $1.15 billion.

19. Supplementary Cash Flow Information

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

	2016	2015	2014
		(In millions)	
Cash Flows From Operating Activities			
Interest paid	**$ (338)**	$ (331)	$ (326)
Net income taxes (paid) refunded	**132**	(140)	(455)
Cash Flows From Investing Activities			
Capital expenditures incurred - E&P	**(1,645)**	(3,753)	(4,920)
Increase (decrease) in related liabilities	**(334)**	(203)	53
Additions to property, plant and equipment - E&P	**(1,979)**	(3,956)	(4,867)
Capital expenditures incurred - Bakken Midstream	**(276)**	(296)	(301)
Increase (decrease) in related liabilities	**4**	(69)	(46)
Additions to property, plant and equipment - Bakken Midstream	**(272)**	(365)	(347)
Cash Flows From Financing Activities			
Contribution from formation of Bakken Midstream joint venture	**—**	2,628	—
Distributions to partner in Bakken Midstream joint venture	**(23)**	(332)	—
Noncontrolling interests, net related to Continuing operations	**(23)**	2,296	—
Significant Non-Cash Transactions			
Increase in debt due to construction of a floating production system - Tubular Bells Field	**$ —**	$ —	$ 68

20. Leased Assets

We and certain of our subsidiaries lease drilling rigs, 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, 2016, future minimum rental payments applicable to non-cancelable operating leases with remaining terms of one year or more (other than oil and gas property leases) are as follows (in millions):

2017	$	376
2018		375
2019		351
2020		124
2021		67
Remaining years		338
Total Minimum Lease Payments		1,631
Less: Income from subleases		78
Net Minimum Lease Payments	$	1,553

Rental expense was as follows:

	2016		2015		2014	
			(In millions)			
Total rental expense	**$**	**106**	$	167	$	248
Less: Income from subleases		**5**		10		17
Net Rental Expense	**$**	**101**	$	157	$	231

21. Guarantees, Contingencies and Commitments

Guarantees and Contingencies

At December 31, 2016, we have $27 million in letters of credit for which we are contingently liable. In addition, 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 is a defective product and that these parties 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. In June 2014, the Commonwealth of Pennsylvania and the State of Vermont each filed independent lawsuits alleging that we and all major oil companies with operations in each respective state, have damaged the groundwater in those states by introducing thereto gasoline with MTBE. The Pennsylvania suit has been removed to Federal court and has been forwarded to the existing MTBE multidistrict litigation pending in the Southern District of New York. The suit filed in Vermont is proceeding there in a state court. In September 2016, the State of Rhode Island also filed a lawsuit in Federal court alleging that we and other major oil companies damaged the groundwater in Rhode Island by introducing thereto gasoline with MTBE.

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. In April 2014, the EPA issued a Focused Feasibility Study (FFS) proposing to conduct bank-to-bank dredging of the lower eight miles of the Lower Passaic River at an estimated cost of $1.7 billion. 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, 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, 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 there are numerous other parties who we expect will share in the cost of remediation and damages and our former terminal did not store or use contaminants which are of the greatest concern in the river sediments and could not have contributed contamination along most of the river's length.

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 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 neutral experts selected by the parties will determine the final shares of the Remedial Design costs to be paid by each of the participants. The parties have not yet addressed the allocation of costs associated with implementing the remedy that is currently being designed.

On January 18, 2017, we entered into a Consent Decree with the North Dakota Department of Health resolving alleged non-compliance with North Dakota's air pollution laws and provisions of the federal Clean Air Act. Pursuant to the Consent Decree, we are required to implement corrective actions, including implementation of a leak detection and repair program, at most of our existing facilities in North Dakota. We were assessed a base penalty of $922,000, which is subject to adjustment based on the date we complete corrective actions required under the terms of the Consent Decree. We made an initial penalty payment of $55,000 during the first quarter of 2017.

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 such 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, 2016 which are not included elsewhere within these *Consolidated Financial Statements*:

		Payments Due by Period			
	Total	2017	2018 and 2019	2020 and 2021	Thereafter
	(In millions)				
Capital expenditures	$ 708	$ 632	$ 76	$ —	$ —
Operating expenses	497	393	76	18	10
Transportation and related contracts	1,560	182	457	433	488

22. Segment Information

We currently have two operating segments, Exploration and Production and Bakken Midstream. The Exploration and Production operating segment explores for, develops, produces, purchases and sells crude oil, natural gas liquids and natural gas with production operations primarily in the United States (U.S.), Denmark, Equatorial Guinea, the JDA, Malaysia, and Norway. The Bakken Midstream operating segment provides fee-based services including crude oil and natural gas gathering, processing of natural gas and the fractionation of natural gas liquids, transportation of crude oil by rail car, terminaling and loading crude oil and natural gas liquids, and the storage and terminaling of propane, 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 for continuing operations (in millions):

2016	**Exploration and Production**	**Bakken Midstream**	**Corporate, Interest and Other**	**Eliminations**	**Total**
Operating Revenues - Third parties	**$ 4,762**	**$ —**	**$ —**	**$ —**	**$ 4,762**
Intersegment Revenues	**—**	**510**	**—**	**(510)**	**—**
Operating Revenues	**$ 4,762**	**$ 510**	**$ —**	**$ (510)**	**$ 4,762**
Net Income (Loss) from Continuing Operations Attributable to Hess Corporation	**$ (4,963)**	**$ 41**	**$ (1,210)**	**$ —**	**$ (6,132)**
Interest Expense	**—**	**19**	**319**	**—**	**338**
Depreciation, Depletion and Amortization	**3,132**	**102**	**10**	**—**	**3,244**
Impairment	**—**	**67**	**—**	**—**	**67**
Provision (Benefit) for Income Taxes	**1,588**	**25**	**609**	**—**	**2,222**
Investment in Affiliates	**146**	**—**	**—**	**—**	**146**
Identifiable Assets	**23,102**	**2,919**	**2,600**	**—**	**28,621**
Capital Expenditures	**1,645**	**276**	**—**	**—**	**1,921**

2015	**Exploration and Production**	**Bakken Midstream**	**Corporate, Interest and Other**	**Eliminations**	**Total**
Operating Revenues - Third parties	$ 6,636	$ —	$ —	$ —	$ 6,636
Intersegment Revenues	—	564	—	(564)	—
Operating Revenues	$ 6,636	$ 564	$ —	$ (564)	$ 6,636
Net Income (Loss) from Continuing Operations Attributable to Hess Corporation	$ (2,717)	$ 86	$ (377)	$ —	$ (3,008)
Interest Expense	—	10	331	—	341
Depreciation, Depletion and Amortization	3,852	88	15	—	3,955
Impairment	1,616	—	—	—	1,616
Provision (Benefit) for Income Taxes	(1,111)	52	(240)	—	(1,299)
Investment in Affiliates	154	—	—	—	154
Identifiable Assets	28,863	2,754	2,540	—	34,157
Capital Expenditures	3,753	296	—	—	4,049

2014	Exploration and Production	Bakken Midstream	Corporate, Interest and Other	Eliminations	Total
Operating Revenues - Third parties	$ 10,737	$ —	$ —	$ —	$ 10,737
Intersegment Revenues	—	319	—	(319)	—
Operating Revenues	$ 10,737	$ 319	$ —	$ (319)	$ 10,737
Net Income (Loss) from Continuing Operations Attributable to Hess Corporation	$ 2,086	$ 10	$ (404)	$ —	$ 1,692
Interest Expense	—	2	321	—	323
Depreciation, Depletion and Amortization	3,140	70	14	—	3,224
Provision (Benefit) for Income Taxes	989	7	(252)	—	744
Capital Expenditures	4,920	301	53	—	5,274

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)			
2016						
Operating revenues	**$ 3,085**	**$ 610**	**$ 601**	**$ 466**	$ —	**$ 4,762**
Net income (loss) from continuing operations 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**
Identifiable assets	**16,096**	**5,180**	**1,507**	**3,238**	**2,600**	**28,621**
Property, plant and equipment (net) (a)	**14,596**	**4,907**	**1,266**	**2,779**	**47**	**23,595**
Capital expenditures	**1,400**	**59**	**10**	**452**	—	**1,921**
2015						
Operating revenues	$ 4,150	$ 870	$ 945	$ 671	$ —	$ 6,636
Net income (loss) from continuing operations attributable to Hess Corporation	(1,834)	(408)	(274)	(115)	(377)	(3,008)
Depreciation, depletion and amortization	2,449	635	539	317	15	3,955
Impairment	986	279	100	251	—	1,616
Provision (benefit) for income taxes	(522)	(84)	(48)	(405)	(240)	(1,299)
Identifiable assets	18,365	6,207	2,178	4,867	2,540	34,157
Property, plant and equipment (net) (a)	15,729	5,300	1,682	3,520	121	26,352
Capital expenditures	2,727	297	160	865	—	4,049
2014						
Operating revenues	$ 6,270	$ 1,557	$ 2,002	$ 908	$ —	$ 10,737
Net income (loss) from continuing operations attributable to Hess Corporation	654	226	545	671	(404)	1,692
Depreciation, depletion and amortization	1,751	683	487	289	14	3,224
Provision (benefit) for income taxes	446	91	435	24	(252)	744
Capital expenditures	3,467	524	399	831	53	5,274

(a) Of the total Europe, Property, plant and equipment (net), Norway represented $3,893 million in 2016 (2015: $4,108 million).

23. Related Party Transactions

The following table presents our related party transactions:

	2016	2015	2014
	(In millions)		
Sales:			
WilcoHess (a)	**$ —**	$ —	$ 211
HOVENSA	**—**	—	31

(a) We acquired our partners' 56% interest in WilcoHess in January 2014 for approximately $290 million. See Note 9, Discontinued Operations.

24. 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 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 produced 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 the business with the intent of reducing exposure to foreign currency fluctuations. These forward contracts comprise various currencies, primarily the British Pound and Danish Krone. 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 financial risk management derivative contracts outstanding at December 31, were as follows:

	2016	2015
	(In millions of USD)	
Foreign exchange	**$ 785**	$ 967
Interest rate swaps	**350**	1,300

The table below reflects the gross and net fair values of the risk management derivative instruments, all of which are based on Level 2 inputs:

	Accounts Receivable	Accounts Payable
	(In millions)	
December 31, 2016		
Derivative Contracts Designated as Hedging Instruments		
Interest rate	$ —	$ —
Total derivative contracts designated as hedging instruments	—	—
Derivative Contracts Not Designated as Hedging Instruments		
Foreign exchange	9	(1)
Total derivative contracts not designated as hedging instruments	9	(1)
Gross fair value of derivative contracts	9	(1)
Master netting arrangements	(1)	1
Net Fair Value of Derivative Contracts	$ 8	$ —
December 31, 2015		
Derivative Contracts Designated as Hedging Instruments		
Interest rate	$ 3	$ —
Total derivative contracts designated as hedging instruments	3	—
Derivative Contracts Not Designated as Hedging Instruments		
Foreign exchange	19	(3)
Total derivative contracts not designated as hedging instruments	19	(3)
Gross fair value of derivative contracts	22	(3)
Master netting arrangements	(3)	3
Net Fair Value of Derivative Contracts	$ 19	$ —

Derivative contracts designated as hedging instruments:

Commodity: In 2015, crude oil price hedging contracts increased E&P Sales and other operating revenues by $126 million, including losses of $48 million associated with changes in the time value of crude oil collars. In 2014, crude oil price hedging contracts increased E&P Sales and other operating revenues by $193 million. There were no crude oil hedge contracts in 2016.

Interest rate swaps: At December 31, 2016, we had interest rate swaps with gross notional amounts of $350 million (2015: $1,300 million), which were designated as fair value hedges. During 2016, we settled existing interest rate swaps and received cash proceeds of $5 million (2015: $41 million). 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 2016, we recorded an increase of $6 million, excluding accrued interest, in the fair value of interest rate swaps and a corresponding adjustment in the carrying value of the hedged fixed-rate debt (2015: $4 million increase; 2014: $1 million increase).

Derivative contracts not designated as hedging instruments:

Foreign exchange: Total foreign exchange gains and losses were a gain of $26 million in 2016 (2015: loss of $21 million; 2014: loss of $43 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 gain of $62 million in 2016 (2015: gain of $98 million; 2014: gain of $117 million).

The after-tax foreign currency translation adjustments included in the *Statement of Consolidated Comprehensive Income* amounted to a gain of $56 million for the year-ended December 31, 2016 (2015: loss of $344 million; 2014: loss of $756 million). Cumulative currency translation adjustments reduced stockholders' equity by $1,045 million at December 31, 2016 and $1,101 million at December 31, 2015.

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. As of December 31, 2016, our Accounts receivable —Trade were concentrated with the following counterparty industry segments: Integrated companies — 37%, Independent E&P companies — 19%, National oil companies — 16%, Storage and transportation companies — 10%, Refining and marketing companies — 7% and Others — 11%. 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, 2016, we had outstanding letters of credit totaling $188 million (2015: $113 million).

Fair Value Measurement: We have other short-term financial instruments, primarily cash equivalents, accounts receivable and accounts payable, for which the carrying value approximated fair value at December 31, 2016 and December 31, 2015. In addition, the disclosure for fair value of long-term debt in *Note 12*, *Debt* was based on Level 2 inputs.

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, 2016, we produced crude oil, natural gas liquids and natural gas principally in the United States (U.S.), Europe (Norway and Denmark), Africa (Equatorial Guinea, Libya and Algeria) and Asia and Other (the Malaysia/Thailand Joint Development Area (JDA), Malaysia, Thailand, and Indonesia). Exploration activities were also conducted, or are planned, in certain of these areas as well as additional countries. See *Note 8, 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 (c)	Africa	Asia and Other
			(In millions)		
2016					
Property acquisitions					
Unproved	**$ 11**	**$ 11**	**$ —**	**$ —**	**$ —**
Proved	**—**	**—**	**—**	**—**	**—**
Exploration (a)	**491**	**211**	**6**	**(2)**	**276**
Production and development capital expenditures (b)	**1,188**	**1,006**	**(64)**	**(58)**	**304**
2015					
Property acquisitions					
Unproved	$ 22	$ 22	$ —	$ —	$ —
Proved	—	—	—	—	—
Exploration (a)	622	255	1	3	363
Production and development capital expenditures (b)	3,549	2,414	310	155	670
2014					
Property acquisitions					
Unproved	$ 88	$ 21	$ —	$ —	$ 67
Proved	—	—	—	—	—
Exploration (a)	763	354	16	113	280
Production and development capital expenditures (b)	4,727	2,991	778	319	639

(a) Includes $13 million of exploration costs incurred for unconventional assets in 2016 (2015: $45 million; 2014: $283 million).
(b) Includes a reduction of $188 million for asset retirement obligations related to net accruals and revisions in 2016 (2015: $151 million increase; 2014: $326 million increase).
(c) Costs incurred in oil and gas producing activities in Norway, were as follows for the years ended December 31:

	2016	*2015*	*2014*
		(In millions)	
Property Acquisitions	***$ —***	*$ —*	*$ —*
Exploration	***—***	*—*	*—*
*Production and development capital expenditures**	***(19)***	*92*	*525*

* *Includes net accruals and revisions for asset retirement obligations.*

Capitalized Costs Relating to Oil and Gas Producing Activities

	At December 31, 2016	At December 31, 2015
	(In millions)	
Unproved properties	**$ 710**	$ 958
Proved properties	**4,258**	4,202
Wells, equipment and related facilities	**38,821**	38,738
Total costs	**43,789**	43,898
Less: Reserve for depreciation, depletion, amortization and lease impairment	**22,768**	20,025
Net Capitalized Costs	**$ 21,021**	$ 23,873

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, natural gas liquids and natural gas, interest expense and other 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 22, 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)		
2016					
Sales and Other Operating Revenues	**$ 3,668**	**$ 2,096**	**$ 597**	**$ 519**	**$ 456**
Costs and Expenses					
Operating costs and expenses	**1,697**	**955**	**321**	**249**	**172**
Production and severance taxes	**101**	**94**	**1**	**—**	**6**
Bakken Midstream tariffs	**478**	**478**	**—**	**—**	**—**
Exploration expenses, including dry holes and lease impairment	**1,442**	**342**	**6**	**—**	**1,094**
General and administrative expenses	**235**	**218**	**1**	**7**	**9**
Depreciation, depletion and amortization	**3,132**	**2,031**	**502**	**375**	**224**
Total Costs and Expenses	**7,085**	**4,118**	**831**	**631**	**1,505**
Results of Operations Before Income Taxes	**(3,417)**	**(2,022)**	**(234)**	**(112)**	**(1,049)**
Provision (benefit) for income taxes (a)	**1,550**	**380**	**208**	**244**	**718**
Results of Operations	**$ (4,967)**	**$ (2,402)**	**$ (442)**	**$ (356)**	**$ (1,767)**
2015					
Sales and Other Operating Revenues	$ 5,201	$ 2,706	$ 870	$ 956	$ 669
Costs and Expenses					
Operating costs and expenses	1,764	786	402	426	150
Production and severance taxes	146	138	2	4	2
Bakken Midstream tariffs	449	449	—	—	—
Exploration expenses, including dry holes and lease impairment	881	255	1	183	442
General and administrative expenses	317	262	31	4	20
Depreciation, depletion and amortization	3,852	2,361	635	539	317
Impairment	1,616	986	279	100	251
Total Costs and Expenses	9,025	5,237	1,350	1,256	1,182
Results of Operations Before Income Taxes	(3,824)	(2,531)	(480)	(300)	(513)
Provision (benefit) for income taxes	(1,117)	(588)	(76)	(48)	(405)
Results of Operations	$ (2,707)	$ (1,943)	$ (404)	$ (252)	$ (108)
2014					
Sales and Other Operating Revenues	$ 8,839	$ 4,461	$ 1,540	$ 1,962	$ 876
Costs and Expenses					
Operating costs and expenses	1,815	731	461	441	182
Production and severance taxes	275	240	3	—	32
Bakken Midstream tariffs	212	212	—	—	—
Exploration expenses, including dry holes and lease impairment	840	359	90	36	355
General and administrative expenses	325	270	—	16	39
Depreciation, depletion and amortization	3,140	1,681	683	487	289
Total Costs and Expenses	6,607	3,493	1,237	980	897
Results of Operations Before Income Taxes	2,232	968	303	982	(21)
Provision (benefit) for income taxes	919	392	101	435	(9)
Results of Operations	$ 1,313	$ 576	$ 202	$ 547	$ (12)

(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 were as follows for the years ended December 31.

	2016	2015	2014
		(In millions)	
Sales and Other Operating Revenues	$ 419	$ 635	$ 1,102
Costs and Expenses			
Operating costs and expenses	252	314	376
Production and severance taxes	—	2	3
Exploration expenses, including dry holes and lease impairment	—	—	—
General and administrative expenses	6	3	4
Depreciation, depletion and amortization	362	501	513
Total Costs and Expenses	620	820	896
Results of Operations Before Income Taxes	(201)	(185)	206
Provision (benefit) for income taxes	(157)	(171)	103
Results of Operations	$ (44)	$ (14)	$ 103

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 the Corporation’s Director, Global Reserves and its Chief Financial Officer. Estimates of reserves are prepared by technical staff who work directly with the oil and gas properties using standard reserve estimation guidelines, definitions and methodologies. Each year, reserve estimates for a selection 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 87 through 92). 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 2016 was Mr. David DuBois, Director Global Reserves. Mr. DuBois is a member of the Society of Petroleum Engineers and has over 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. DuBois 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 78% of 2016 year-end reported reserve quantities on a barrel of oil equivalent basis (2015: 83%). 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 1, 2017, 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, 2016 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 3% 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, 2016 were $42.68 per barrel for WTI (2015: $50.13; 2014: $94.42) and $44.45 per barrel for Brent (2015: $55.10; 2014: $101.35). New York Mercantile Exchange (NYMEX) natural gas prices used were $2.54 per mcf in 2016 (2015: $2.63; 2014: $4.30). Revisions primarily associated with lower crude oil prices reduced proved reserves by 29 million boe at December 31, 2016 and 234 million boe at December 31, 2015.

At December 31, 2016, spot prices for WTI oil closed at $53.75 per barrel. If crude oil prices in 2017 average below those used in determining 2016 proved reserves, we may recognize further negative revisions of our December 31, 2016 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 2017 above those used in determining 2016 proved reserves could result in positive revisions to proved reserves at December 31, 2017. It is difficult to estimate the magnitude of any potential negative or positive change in proved reserves as of December 31, 2017, due to a number of factors that are currently unknown, including 2017 crude oil prices, any revisions based on 2017 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	Total	United States	Europe (b)	Asia	Total
Net Proved Reserves									
At January 1, 2014	469	271	210	22	972	113	20	3	136
Revisions of previous estimates (a)	(26)	(23)	(8)	1	(56)	(8)	3	—	(5)
Extensions, discoveries and other additions	115	30	6	1	152	22	4	—	26
Sales of minerals in place	—	—	—	(16)	(16)	—	—	(3)	(3)
Production	(46)	(13)	(20)	(1)	(80)	(8)	(1)	—	(9)
At December 31, 2014	512	265	188	7	972	119	26	—	145
Revisions of previous estimates (a)	(157)	(54)	9	(1)	(203)	(42)	—	—	(42)
Extensions, discoveries and other additions	45	6	1	—	52	11	1	—	12
Sales of minerals in place	—	—	(8)	—	(8)	—	—	—	—
Production	(54)	(14)	(18)	(1)	(87)	(14)	—	—	(14)
At December 31, 2015	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**
Net Proved Developed Reserves									
At January 1, 2014	227	118	185	15	545	51	8	2	61
At December 31, 2014	264	114	163	3	544	56	9	—	65
At December 31, 2015	253	114	148	5	520	51	12	—	63
At December 31, 2016	**245**	**116**	**138**	**5**	**504**	**59**	**3**	**—**	**62**
Net Proved Undeveloped Reserves									
At January 1, 2014	242	153	25	7	427	62	12	1	75
At December 31, 2014	248	151	25	4	428	63	17	—	80
At December 31, 2015	93	89	24	—	206	23	15	—	38
At December 31, 2016	**110**	**94**	**24**	**—**	**228**	**27**	**5**	**—**	**32**

(a) The impact of changes in selling prices on the reserve estimates for production sharing contracts with cost recovery provisions in 2016 was an increase to Crude oil and condensate reserves of 1 million barrels (2015: 5 million barrels increase; 2014: 1 million barrels increase).

(b) Crude oil and condensate and Natural gas liquids proved reserves in Norway were as follows:

	Crude Oil & Condensate (Millions of bbls)			*Natural Gas Liquids (Millions of bbls)*		
	2016	*2015*	*2014*	***2016***	*2015*	*2014*
At January 1	***171***	*231*	*237*	***27***	*25*	*19*
Revisions of previous estimates	***(2)***	*(55)*	*(25)*	***(19)***	*2*	*3*
Extensions, discoveries and other additions	***4***	*5*	*28*	***—***	*—*	*4*
Sales of minerals in place	***—***	*—*	*—*	***—***	*—*	*—*
Production	***(8)***	*(10)*	*(9)*	***—***	*—*	*(1)*
At December 31	***165***	*171*	*231*	***8***	*27*	*25*
Net Proved Developed Reserves at December 31	***75***	*86*	*86*	***3***	*12*	*9*
Net Proved Undeveloped Reserves at December 31	***90***	*85*	*145*	***5***	*15*	*16*

	Natural Gas					Total				
	United States	Europe (d)	Africa	Asia	Total	United States	Europe (d)	Africa	Asia	Total
	(Millions of mcf)					(Millions of boe)				
Net Proved Reserves										
At January 1, 2014	464	238	160	1,113	1,975	660	331	236	210	1,437
Revisions of previous estimates (a)	58	(31)	(3)	26	50	(24)	(25)	(8)	5	(52)
Extensions, discoveries and other additions	184	26	—	192	402	168	38	6	33	245
Sales of minerals in place	(20)	—	—	(329)	(349)	(4)	—	—	(73)	(77)
Production (b)	(66)	(13)	(2)	(116)	(197)	(66)	(16)	(20)	(20)	(122)
At December 31, 2014	620	220	155	886	1,881	734	328	214	155	1,431
Revisions of previous estimates (a)	(113)	25	(5)	(116)	(209)	(218)	(50)	8	(20)	(280)
Extensions, discoveries and other additions	102	5	—	3	110	73	8	1	—	82
Sales of minerals in place	—	—	—	—	—	—	—	(8)	—	(8)
Production (b)	(104)	(16)	(2)	(106)	(228)	(85)	(17)	(18)	(19)	(139)
At December 31, 2015	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 (c)	**590**	**220**	**143**	**744**	**1,697**	**539**	**255**	**186**	**129**	**1,109**
Net Proved Developed Reserves										
At January 1, 2014	279	104	149	578	1,110	325	143	210	113	791
At December 31, 2014	350	96	144	329	919	378	139	187	58	762
At December 31, 2015	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**
Net Proved Undeveloped Reserves										
At January 1, 2014	185	134	11	535	865	335	188	26	97	646
At December 31, 2014	270	124	11	557	962	356	189	27	97	669
At December 31, 2015	137	111	11	24	283	139	122	26	4	291
At December 31, 2016	**186**	**95**	**11**	**5**	**297**	**168**	**115**	**26**	**1**	**310**

(a) The impact of changes in selling prices on the reserve estimates for production sharing contracts with cost recovery provisions in 2016 was an increase to natural gas reserves of 12 million mcf (2015: 42 million mcf increase; 2014: 7 million mcf increase).

(b) Natural gas production in 2016 includes 15 million mcf used for fuel (2015: 14 million mcf; 2014: 10 million mcf).

(c) Excludes approximately 165 million mcf of carbon dioxide gas for sale or use in company operations.

(d) Natural gas and Total proved reserves in Norway were as follows:

	Natural Gas			*Total*		
	2016	***2015***	***2014***	***2016***	***2015***	***2014***
	(Millions of mcf)			*(Millions of boe)*		
At January 1	***191***	*180*	*198*	***230***	*286*	*289*
Revisions of previous estimates	***(26)***	*18*	*(33)*	***(25)***	*(50)*	*(28)*
Extensions, discoveries and other additions	***4***	*3*	*24*	***5***	*6*	*36*
Sales of minerals in place	***—***	*—*	*—*	***—***	*—*	*—*
Production	***(9)***	*(10)*	*(9)*	***(10)***	*(12)*	*(11)*
At December 31	***160***	*191*	*180*	***200***	*230*	*286*
Net Proved Developed Reserves at December 31	***72***	*84*	*67*	***90***	*112*	*106*
Net Proved Undeveloped Reserves at December 31	***88***	*107*	*113*	***110***	*118*	*180*

Extensions, discoveries and other additions ('Additions')

2016: Total Additions were 69 million boe, of which 45 million boe (34 million barrels of crude oil, 2 million barrels of natural gas liquids 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 shale play in North Dakota 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 natural gas liquids and 59 million mcf of natural gas) and are discussed in further detail below.

2015: Total Additions were 82 million boe, of which 33 million boe (19 million barrels of crude oil, 5 million barrels of natural gas liquids and 54 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 and the Utica shale play in Ohio. Additions to proved undeveloped reserves were 49 million boe (33 million barrels of crude oil, 7 million barrels of natural gas liquids and 56 million mcf of natural gas) and are discussed in further detail below.

2014: Total Additions were 245 million boe, of which 32 million boe (17 million barrels of crude oil, 5 million barrels of natural gas liquids and 62 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 and the Utica shale play in Ohio. Additions to proved undeveloped reserves were 213 million boe (135 million barrels of crude oil, 21 million barrels of natural gas liquids and 340 million mcf of natural gas) and are discussed in further detail below.

Revisions of previous estimates

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 natural gas liquids 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 natural gas liquids 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 natural gas liquids and 235 million mcf increase of natural gas) reflecting improved expected recoveries in the Bakken shale play in North Dakota, 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 natural gas liquids and natural gas, and negative price revisions mostly related to crude oil reserves. Revisions associated with proved undeveloped reserves are discussed in further detail below.

2015: Total revisions of previous estimates were a net decrease of 280 million boe. Negative revisions associated with lower crude oil prices reduced proved reserves at December 31, 2015 by 234 million boe (158 million barrels of crude oil; 26 million barrels of natural gas liquids and 299 million mcf of natural gas), including 220 million boe (147 million barrels of crude oil, 22 million barrels of natural gas liquids and 303 million mcf of natural gas) associated with proved undeveloped reserves. Other net negative revisions were 46 million boe, which also primarily related to proved undeveloped reserves that are discussed below.

2014: Total negative revisions to proved reserves were 52 million boe (56 million barrels of crude oil and 4 million barrels of natural gas liquids, partially offset by an increase of 50 million mcf in natural gas), that primarily reflect changes in proved undeveloped reserves which are discussed in further detail below.

Proved Undeveloped Reserves

Following are the Corporation’s proved undeveloped reserves:

	United States	Europe	Africa	Asia	Total
			(Millions of boe)		
Net Proved Undeveloped Reserves					
At January 1, 2014	335	188	26	97	646
Revisions of previous estimates	(44)	(11)	1	(2)	(56)
Extensions, discoveries and other additions	138	38	4	33	213
Transfers to proved developed reserves	(73)	(26)	(4)	(8)	(111)
Sales of minerals in place (a)	—	—	—	(23)	(23)
At December 31, 2014	356	189	27	97	669
Revisions of previous estimates	(203)	(57)	(1)	(31)	(292)
Extensions, discoveries and other additions	42	7	—	—	49
Transfers to proved developed reserves	(56)	(17)	—	(62)	(135)
Sales of minerals in place	—	—	—	—	—
At December 31, 2015	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**

(a) In 2014, the Corporation divested of its remaining operations in Indonesia and Thailand.

Extensions, discoveries and other additions (‘Additions’)

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 shale play in North Dakota 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.

2015: In the United States, we recognized additions of 29 million boe in the Bakken shale play and 13 million boe related to the Tubular Bells and Penn State fields in the Gulf of Mexico based on drilling plans for new wells.

2014: In the United States, we recognized additions of 97 million boe in the Bakken shale play and 18 million boe in the Utica shale play based on drilling plans for new wells. We also recognized 21 million boe related to the sanction of the Stampede development project in the Gulf of Mexico. At the Valhall Field offshore Norway, additions resulting from planned drilling activity were 37 million boe. At the North Malay Basin offshore Malaysia, we recognized additions of 31 million boe upon signing a gas sales agreement for the full field development phase of the project.

Revisions of previous estimates

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 shale play in North Dakota, which was partially offset by negative revisions at the Valhall Field offshore Norway due to changes in expected recoveries of natural gas liquids and natural gas. Negative revisions resulting from lower commodity prices totaled 11 million boe and were primarily in the Bakken shale play.

2015: Total negative reserve revisions were 292 million boe. Negative revisions resulting from lower commodity prices totaled 220 million boe, and were primarily in the Bakken shale play (127 million boe), the North Malay Basin offshore Malaysia (34 million boe), the Valhall Field offshore Norway (30 million boe) and the Stampede project in the Gulf of Mexico (21 million boe). Other negative revisions included 48 million boe related to planned drilling dates of certain Bakken wells moving beyond 2020 due to reprioritization of the drilling schedule, and 26 million boe at the Valhall Field offshore Norway primarily related to drilling schedule changes.

2014: In the United States, Bakken negative revisions of 47 million boe were as a result of well performance and reprioritization of well locations in the drilling schedule resulting in certain wells moving beyond 2019. At the Valhall Field offshore Norway, downward technical revisions amounted to 9 million boe.

Transfers to proved developed reserves ('Transfers')

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

2015: Transfers from proved undeveloped reserves to proved developed reserves included 43 million boe in the Bakken shale play and 11 million boe at the Valhall Field offshore Norway associated with drilling activity. Transfers of 61 million boe related to the JDA gas field in the Gulf of Thailand primarily resulted from additional development and drilling activity.

2014: Transfers from proved undeveloped reserves into proved developed reserves included 38 million boe in the Bakken shale play and 15 million boe at the Valhall Field offshore Norway associated with drilling activity. Transfers of 30 million boe were the result of achieving first production from the Tubular Bells Field in the Gulf of Mexico.

In 2016, capital expenditures of $589 million were incurred to convert proved undeveloped reserves to proved developed reserves (2015: $1,931 million; 2014: $3,110 million). Capital expenditures in 2014 include production facilities and subsea infrastructure for the Tubular Bells field in the Gulf of Mexico which achieved first production in late 2014.

We are also involved in multiple long-term projects that have staged developments. Certain of these projects have proved reserves, which have been classified as undeveloped for a period in excess of five years, totaling 80 million boe or 7% of total proved reserves at December 31, 2016. Most of the proved undeveloped reserves in excess of five years relate to the Valhall Field offshore Norway.

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, 2016 are presented separately below, as well as volumes produced and received during 2016, 2015 and 2014 from these production sharing contracts.

	Crude Oil					Natural Gas				
	United States	Europe	Africa	Asia	Total	United States	Europe	Africa	Asia	Total
	(Millions of bbls)					(Millions of mcf)				
Production Sharing Contracts										
Proved Reserves										
At December 31, 2014	—	—	52	7	59	—	—	27	886	913
At December 31, 2015	—	—	34	5	39	—	—	20	667	687
At December 31, 2016	**—**	**—**	**24**	**5**	**29**	**—**	**—**	**15**	**744**	**759**
Production										
2014	—	—	18	1	19	—	—	2	105	107
2015	—	—	18	1	19	—	—	2	106	108
2016	**—**	**—**	**12**	**1**	**13**	**—**	**—**	**2**	**83**	**85**

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 2016 were $42.68 per barrel for WTI (2015: $50.13; 2014: $94.42) and $44.45 per barrel for Brent (2015: $55.10; 2014: $101.35). New York Mercantile Exchange (NYMEX) natural gas prices used were $2.54 per mcf in 2016 (2015: $2.63; 2014: $4.30) and do not include the effects of commodity hedges. 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
			(In millions)		
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**
2015					
Future revenues	$ 41,010	$ 15,257	$ 13,456	$ 9,419	$ 2,878
Less:					
Future production costs	14,275	6,775	5,000	1,628	872
Future development costs	8,486	2,901	4,088	1,150	347
Future income tax expenses	7,237	—	1,022	6,089	126
	29,998	9,676	10,110	8,867	1,345
Future net cash flows	11,012	5,581	3,346	552	1,533
Less: Discount at 10% annual rate	3,822	1,826	1,469	114	413
Standardized Measure of Discounted Future Net Cash Flows	$ 7,190	$ 3,755	$ 1,877	$ 438	$ 1,120
2014					
Future revenues	$ 107,949	$ 51,054	$ 31,150	$ 19,448	$ 6,297
Less:					
Future production costs	27,790	14,553	9,116	2,743	1,378
Future development costs	21,393	10,150	7,930	1,244	2,069
Future income tax expenses	27,060	6,798	7,143	12,876	243
	76,243	31,501	24,189	16,863	3,690
Future net cash flows	31,706	19,553	6,961	2,585	2,607
Less: Discount at 10% annual rate	14,704	9,988	3,251	393	1,072
Standardized Measure of Discounted Future Net Cash Flows	$ 17,002	$ 9,565	$ 3,710	$ 2,192	$ 1,535

(a) At December 31, the standardized measure of discounted future net cash flows relating to proved reserves in Norway were as follows:

	2016	*2015*	*2014*
		(In millions)	
Future revenues	***$ 8,188***	*$ 11,639*	*$ 27,502*
Less:			
Future production costs	***4,004***	*4,404*	*8,159*
Future development costs	***3,931***	*3,653*	*7,318*
Future income tax expenses (b)	***(2,112)***	*903*	*6,683*
	5,823	*8,960*	*22,160*
Future net cash flows	***2,365***	*2,679*	*5,342*
Less: Discount at 10% annual rate	***1,969***	*1,332*	*2,792*
Standardized Measure of Discounted Future Net Cash Flows	***$ 396***	*$ 1,347*	*$ 2,550*

(b) The Petroleum Tax Act provides for compensation by the Norwegian government to a company upon cessation of its exploration and production 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	2016	2015	2014
		(In millions)	
Standardized Measure of Discounted Future Net Cash Flows at January 1	**$ 7,190**	$ 17,002	$ 20,460
Changes during the year			
Sales and transfers of oil and gas produced during the year, net of production costs	**(1,392)**	(2,842)	(6,537)
Development costs incurred during the year	**1,376**	3,398	4,401
Net changes in prices and production costs applicable to future production	**(4,284)**	(20,236)	(4,657)
Net change in estimated future development costs	**(76)**	5,116	(485)
Extensions and discoveries (including improved recovery) of oil and gas reserves, less related costs	**338**	530	2,249
Revisions of previous oil and gas reserve estimates	**376**	(1,274)	(161)
Net purchases (sales) of minerals in place, before income taxes	**—**	(18)	(2,157)
Accretion of discount	**779**	2,799	3,243
Net change in income taxes	**1,331**	7,601	3,180
Revision in rate or timing of future production and other changes	**(1,613)**	(4,886)	(2,534)
Total	**(3,165)**	(9,812)	(3,458)
Standardized Measure of Discounted Future Net Cash Flows at December 31	**$ 4,025**	$ 7,190	$ 17,002

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES
QUARTERLY FINANCIAL DATA (UNAUDITED)

Following are quarterly results of operations:

	2016			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In millions, except per share amounts)			
Sales and other operating revenues	**$ 973**	**$ 1,224**	**$ 1,177**	**$ 1,388**
Gross profit (loss) from continuing operations (a)	**$ (539)**	**$ (333)**	**$ (304)**	**$ (417)**
Net income (loss)	**(488)**	**(373)**	**(317)**	**(4,898)**
Less: Net income (loss) attributable to noncontrolling interests	**21**	**19**	**22**	**(6)**
Net income (loss) attributable to Hess Corporation	**(509)**	**(392)**	**(339)**	**(4,892)**
Less: Preferred stock dividends	**6**	**12**	**12**	**11**
Net income (loss) applicable to Hess Corporation common stockholders	**$ (515)**	**$ (404)(b)**	**$ (351)**	**$ (4,903)(c)**
Net income (loss) attributable to Hess Corporation per common share:				
Basic:				
Continuing operations	**$ (1.72)**	**$ (1.29)**	**$ (1.12)**	**$ (15.65)**
Discontinued operations	**—**	**—**	**—**	**—**
Net income (loss) per common share	**$ (1.72)**	**$ (1.29)**	**$ (1.12)**	**$ (15.65)**
Diluted:				
Continuing operations	**$ (1.72)**	**$ (1.29)**	**$ (1.12)**	**$ (15.65)**
Discontinued operations	**—**	**—**	**—**	**—**
Net income (loss) per common share	**$ (1.72)**	**$ (1.29)**	**$ (1.12)**	**$ (15.65)**

	2015			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In millions, except per share amounts)			
Sales and other operating revenues	$ 1,538	$ 1,953	$ 1,671	$ 1,474
Gross profit (loss) from continuing operations (a)	$ (238)	$ (364)	$ (210)	$ (1,592)
Income (loss) from continuing operations	$ (376)	$ (553)	$ (239)	$ (1,791)
Income (loss) from discontinued operations	(13)	(14)	(13)	(8)
Net income (loss)	(389)	(567)	(252)	(1,799)
Less: Net income (loss) attributable to noncontrolling interests	—	—	27	22
Net income (loss) attributable to Hess Corporation	$ (389)(d)	$ (567)(e)	$ (279)(f)	$ (1,821)(g)
Net income (loss) attributable to Hess Corporation per common share:				
Basic:				
Continuing operations	$ (1.32)	$ (1.94)	$ (0.94)	$ (6.40)
Discontinued operations	(0.05)	(0.05)	(0.04)	(0.03)
Net income (loss) per common share	$ (1.37)	$ (1.99)	$ (0.98)	$ (6.43)
Diluted:				
Continuing operations	$ (1.32)	$ (1.94)	$ (0.94)	$ (6.40)
Discontinued operations	(0.05)	(0.05)	(0.04)	(0.03)
Net income (loss) per common share	$ (1.37)	$ (1.99)	$ (0.98)	$ (6.43)

(a) Gross profit represents Sales and other operating revenues, less Cost of products sold, Operating costs and expenses, Production and severance taxes, Depreciation, depletion and amortization and Impairments.

(b) Includes an after-tax charge of $52 million related to dry hole and related expenses, an after-tax charge of $22 million associated with the termination of a drilling rig contract and an after-tax gain of $17 million related to the sale of undeveloped acreage, onshore United States.

(c) Includes a noncash charge of $3,749 million to establish valuation allowances against net deferred tax assets at December 31, 2016, an after-tax charge of $693 million to fully impair the carrying value of our Equus natural gas project offshore the North West Shelf of Australia, and other after-tax charges of $145 million related to offshore rig costs, loss on debt extinguishment, impairment of rail cars, severance and other charges.

(d) Includes after-tax charges of $77 million related to dry hole and related expenses and an after-tax charge of $16 million for inventory write-offs.

(e) Includes a non-taxable charge of $385 million related to goodwill impairment associated with our onshore E&P business and an after-tax charge of $21 million related to terminated international office space.

(f) Includes an after-tax gain of $31 million from the sale of Utica dry gas acreage, $50 million tax benefit associated with an international investment incentive, and an after-tax charge of $43 million of dry hole, lease impairment and other exploration expenses.

(g) Includes a non-taxable charge of $1,098 million related to goodwill impairment, exploration charges of $178 million primarily related to previously capitalized well costs, and a net after-tax impairment charge of $83 million associated with our legacy conventional assets in North Dakota. We also recorded an after-tax charge of $41 million for our estimated liability resulting from HOVENSA LLC's bankruptcy settlement.

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, 2016, 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, 2016.

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, 2016 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 2017 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 2017 annual meeting of stockholders.

Executive Officers of the Corporation

The following table presents information as of February 23, 2017 regarding executive officers of the Corporation:

Name	Age	Office Held* and Business Experience	Year Individual Became an Executive Officer
John B. Hess	62	*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	55	*Chief Operating Officer, Executive Vice President and President, Exploration and Production* Mr. Hill has been Chief Operating Officer since 2014. Mr. Hill has been President of 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	59	*Senior Vice President and General Counsel* Mr. Goodell has been the Senior Vice President and General Counsel of the Corporation since 2009. 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	54	*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	55	*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
Brian D. Truelove	58	*Senior Vice President, Global Services* Mr. Truelove has been Senior Vice President, Offshore of the Corporation since 2013. He previously served as Senior Vice President, Services. Prior to joining the Corporation in 2011, Mr. Truelove spent 30 years with Royal Dutch Shell and its affiliates, where he served in a variety of managerial and operating roles around the world.	2014
Michael R. Turner	57	*Senior Vice President, Global Production* Mr. Turner has been Senior Vice President, Onshore of the Corporation since 2013. He previously served as Senior Vice President, Global Production. 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	60	*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 the Directors following 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 May 4, 2016.*

Except for 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, Ms.

Lowery-Yilmaz served in senior executive positions in exploration and production at BP plc and 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 2017 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 2017 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 2017 annual meeting of stockholders.

Item 14. Principal Accounting Fees and Services

Information relating to this item is incorporated by reference to “Ratification of Selection of Independent Auditors” from the Corporation’s definitive proxy statement for the 2017 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*.

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.

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 23rd day of February 2017.

HESS CORPORATION
(Registrant)

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

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 23, 2017
/s/ JAMES H. QUIGLEY **James H. Quigley**	Director and Chairman of the Board	February 23, 2017
/s/ RODNEY F. CHASE **Rodney F. Chase**	Director	February 23, 2017
/s/ TERRENCE J. CHECKI **Terrence J. Checki**	Director	February 23, 2017
/s/ LEONARD S. COLEMAN JR. **Leonard S. Coleman Jr.**	Director	February 23, 2017
/s/ EDITH E. HOLIDAY **Edith E. Holiday**	Director	February 23, 2017
/s/ DR. RISA LAVIZZO-MOUREY **Dr. Risa Lavizzo-Mourey**	Director	February 23, 2017
/s/ MARC S. LIPSCHULTZ **Marc S. Lipschultz**	Director	February 23, 2017
/s/ DAVID MCMANUS **David McManus**	Director	February 23, 2017
/s/ DR. KEVIN O. MEYERS **Dr. Kevin O. Meyers**	Director	February 23, 2017
/s/ JOHN H. MULLIN, III **John H. Mullin, III**	Director	February 23, 2017
/s/ FREDRIC G. REYNOLDS **Fredric G. Reynolds**	Director	February 23, 2017
/s/ JOHN P. RIELLY **John P. Rielly**	Senior Vice President and Chief Financial Officer (Principal Financial and Accounting Officer)	February 23, 2017
/s/ WILLIAM G. SCHRADER **William G. Schrader**	Director	February 23, 2017

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES

VALUATION AND QUALIFYING ACCOUNTS

For the Years Ended December 31, 2016, 2015 and 2014

		Additions			
Description	**Balance January 1**	**Charged to Costs and Expenses**	**Charged to Other Accounts**	**Deductions from Reserves**	**Balance December 31**
			(In millions)		
2016					
Losses on receivables	**$ 43**	**$ 5**	**$ —**	**$ 40**	**$ 8**
Deferred income tax valuation	**$ 1,578**	**$ 3,962**	**$ —**	**$ 90**	**$ 5,450**
2015					
Losses on receivables	$ 13	$ 32	$ —	$ 2	$ 43
Deferred income tax valuation	$ 1,416	$ 280	$ —	$ 118	$ 1,578
2014					
Losses on receivables	$ 27	$ —	$ —	$ 14	$ 13
Deferred income tax valuation	$ 1,519	$ 142	$ (1)	$ 244	$ 1,416

EXHIBIT INDEX

3(1)	Restated Certificate of Incorporation of Registrant, including amendment thereto dated May 3, 2006 incorporated by reference to Exhibit 3 of Registrant's Form 10-Q for the three months ended June 30, 2006.
3(2)	Certificate of Amendment to the 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 the 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)	Certificate of Designations of the 8.00% Series A Mandatory Convertible Preferred Stock of Hess Corporation, including Form of Certificate for the 8.00% Series A Mandatory Convertible Preferred Stock incorporated by reference to Exhibit 3(1) of Form 8-K of Registrant filed on February 10, 2016.
3(5)	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, among Registrant, certain subsidiaries of Registrant, J.P. Morgan Chase Bank, N.A. as lender and administrative agent, and the other lenders party thereto, incorporated by reference to Exhibit 10(1) of Form 8-K of Registrant filed on January 27, 2015.
4(2)	Amendment No. 1 to the Five-Year Credit Agreement, dated as of July 10, 2015 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(2) of Form 10-Q of Registrant for the three months ended June 30, 2015.
4(3)	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(4)	First Supplemental Indenture, dated as of October 1, 1999, between Registrant and The Chase Manhattan Bank, as Trustee, relating to Registrant's $7^3/_8$% Notes due 2009 and $7^7/_8$% 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(5)	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(6)	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(7)	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(8)	Form of 8.125% Note due 2019, incorporated by reference to Exhibit 4(2) to Form 8-K of the Registrant, filed on February 4, 2009.
4(9)	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(10)	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(11)	Form of 1.30% Note due 2017, incorporated by reference to Exhibit 4(2) to Form 8-K of Registrant filed on June 25, 2014.
4(12)	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(13)	Deposit Agreement, dated as of February 10, 2016, among Hess Corporation and Computershare Inc. and Computershare Trust Company, N.A., as depositary, on behalf of all holders from time to time of the receipts issued thereunder, including Form of Depositary Receipt for the Depositary Shares incorporated by reference to Exhibit 4(2) of Form 8-K of Registrant filed on February 10, 2016.
4(14)	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(15)	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 percent 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 4, 2016.
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)*	2016 Performance Incentive Plan for Senior Officers, as approved by stockholders on May 4, 2016, incorporated by reference to Exhibit 10(1) to Form 8-K of Registrant filed on May 10, 2016.
10(5)*	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.
10(6)*	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(7)*	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(8)*	Second Amended and Restated 1995 Long-term Incentive Plan, including forms of awards thereunder, incorporated by reference to Exhibit 10(11) of Form 10-K of Registrant for the fiscal year ended December 31, 2004.
10(9)*	Amended and Restated 2008 Long-term Incentive Plan, incorporated by reference to Form 8-K of the Registrant filed on May 12, 2015.
10(10)*	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(11)*	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(12)*	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(13)*	Form of Performance Award Agreement for the three-year period ending December 31, 2016 under Registrant's 2008 Long-term Incentive Plan, incorporated by reference to Exhibit 10(1) of Form 10-Q of Registrant for the three months ended March 31, 2014.
10(14)*	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(15)*	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(16)*	Form of Amended and Restated Change of 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(17)*	Amended and Restated Change of 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(18)	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(19)*	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(20)*	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(21)*	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(22)	Agreement, dated as of May 16, 2013, among Registrant, Elliott Associates, L.P. and Elliott International, L.P., incorporated by reference to Exhibit 99(1) of Form 8-K of Registrant filed on May 22, 2013.
21	Subsidiaries of Registrant.
23(1)	Consent of Ernst & Young LLP, Independent Registered Public Accounting Firm, dated February 23, 2017.
23(2)	Consent of DeGolyer and MacNaughton dated February 23, 2017.
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 1, 2017, on proved reserves audit as of December 31, 2016 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.*

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 Canada Oil and Gas ULC	100	Canada
Hess Capital Corporaton S.a.r.l.	100	Luxembourg
Hess Capital Holdings Limited	100	Cayman Islands
Hess Capital Limited	100	Cayman Islands
Hess Capital Services Corporation	100	Delaware
Hess Capital Services L.L.C.	100	Delaware
Hess Conger LLC	100	Delaware
Hess CO2 Resources L.L.C.	100	Delaware
Hess Denmark Aps	100	Denmark
Hess Exploration and Production Malaysia B.V.	100	The Netherlands
Hess Exploration Australia PTY Limited	100	Australia
Hess Energy Exploration Limited	100	Delaware
Hess Equatorial Guinea Inc.	100	Cayman Islands
Hess Exploration & Production Holdings Limited	100	Delaware
Hess Finance	100	England & Wales
Hess Ghana Exploration Limited	100	Ghana
Hess (Ghana) Limited	100	Cayman Islands
Hess Ghana Investments II Limited	100	Cayman Islands
Hess Ghana (Paradise) Limited	100	Cayman Islands
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 West Africa Limited	100	Cayman Islands
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 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 (Netherlands) Oil & Gas Holdings C.V.	100	The Netherlands
Hess New Ventures Exploration Limited	100	Cayman Islands
Hess Norge AS	100	Norway
Hess North Dakota Export Logistics L.L.C.	50	Delaware
Hess North Dakota Export Logistics Holdings L.L.C.	50	Delaware
Hess North Dakota Export Logistics Operations LP	50	Delaware
Hess North Dakota Pipelines L.L.C.	50	Delaware
Hess North Dakota Pipelines Holdings L.L.C.	50	Delaware

Name of Company	Registrant ownership %	Jurisdiction
Hess Norway LP	100	Cayman Islands
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 Canada Oil and Gas ULC	100	Canada
Hess Oil Company Of Thailand (JDA) Limited	100	Cayman Islands
Hess Shenzi L.L.C.	100	Delaware
Hess Stampede L.L.C.	100	Delaware
Hess Tank Cars L.L.C.	50	Delaware
Hess TGP Finance Company L.L.C.	100	Delaware
Hess TGP Holdings L.L.C.	50	Delaware
Hess TGP Operations LP	50	Delaware
Hess Tioga Gas Plant L.L.C.	50	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 44 subsidiary holding companies (15 domestic and 29 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 and discontinued activities.

Other subsidiaries (names omitted because such unnamed subsidiaries, 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 and Stock Bonus Plan,

(2) Registration Statement (Form S-8 No. 333-94851) pertaining to the Hess Corporation Amended and Restated 1995 Long-Term Incentive Plan,

(3) Registration Statement (Form S-8 No. 333-115844) pertaining to the Hess Corporation Second Amended and Restated 1995 Long-Term Incentive Plan,

(4) Registration Statement (Form S-8 No. 333-150992) pertaining to the Hess Corporation 2008 Long-Term Incentive Plan,

(5) Registration Statement (Form S-8 No. 333-167076) pertaining to the Hess Corporation 2008 Long-Term Incentive Plan,

(6) Registration Statement (Form S-8 No. 333-181704) pertaining to the Hess Corporation 2008 Long-Term Incentive Plan,

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

(8) Registration Statement (Form S-3 No. 333-202379) of Hess Corporation;

of our reports dated February 23, 2017, with respect to the consolidated financial statements and schedule 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, 2016.

/s/ Ernst & Young LLP
New York, New York
February 23, 2017

Exhibit 23(2)

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

February 23, 2017

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 1, 2017, containing our opinion on the proved reserves attributable to certain properties owned by Hess Corporation, as of December 31, 2016, (our “Report”), under the heading “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, 2016. 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. 333-202-379) and Form S-8 (No. 333-43569, No. 333-94851, No. 333-115844, No. 333-150992, No. 333-167076, No. 333-181704, and No. 333-204929).

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 23, 2017

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 23, 2017

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, 2016 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 23, 2017

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, 2016 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 23, 2017

Exhibit 99.1

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

February 1, 2017

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

Ladies and Gentlemen:

Pursuant to your request, we have conducted a reserves audit of the net proved oil, condensate, natural gas liquids (NGL), and gas reserves, as of December 31, 2016, of certain selected properties in which Hess Corporation (Hess) has represented that it owns an interest to determine the reasonableness of Hess' estimates. This evaluation was completed on February 1, 2017. Hess has represented to us that these properties account for approximately 78.3 percent on a net equivalent barrel basis of Hess' net proved reserves, as of December 31, 2016, 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, 2016, 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 to be produced from these properties after December 31, 2016. Net reserves are defined as that portion of the gross reserves attributable to the interests owned by Hess after deducting all interests owned by others.

Certain properties in which Hess has an interest are subject to the terms of various profit sharing agreements. The terms of these agreements 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 cubic foot of gas equivalent by dividing by product prices to determine the "entitlement reserves." These entitlement reserves 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 certain properties subject to these agreements is the entitlement based on Hess' working interest.

Estimates of oil, condensate, NGL, and gas reserves should be regarded only as estimates. Such estimates are based upon information that is currently available and may change as further production history and additional information become available. Such estimates are also subject to the uncertainties inherent in the application of judgmental factors in interpreting such information.

Data used in this audit were obtained from reviews with Hess personnel, from Hess files, from records on file with the appropriate regulatory agencies, and from public sources. Additionally, this information includes data supplied by IHS Global Inc.; Copyright 2016 IHS Global Inc. In the preparation of this report we have relied, without independent verification, upon such information furnished by Hess with respect to property interests, production from such properties, costs of operation and development, 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. In our opinion, the adequacy and quality of the data provided to us were sufficient for us to conduct this reserves audit.

Hess has represented that its estimated net proved reserves attributable to the reviewed properties are based on the definition of proved reserves of the SEC. The Hess net proved reserves attributable to these properties, as of December 31, 2016, and which represent approximately 78.3 percent of total Hess net reserves on a net equivalent barrel basis, are summarized as follows, expressed in millions of barrels (MMbbl), billions of cubic feet (Bcf), and millions of barrels of oil equivalent (MMboe):

	Estimated by Hess Net Proved Reserves as of December 31, 2016			
	Oil and Condensate (MMbbl)	**Natural Gas Liquids (MMbbl)**	**Gas (Bcf)**	**Oil Equivalent (MMboe)**
United States	321	80	499	484
Norway	165	8	160	200
Denmark	45	0	60	55
Asia	5	0	744	129
Total	**536**	**88**	**1,464**	**869**

Notes:

1. Gas is converted to oil equivalent using an energy equivalent factor of 6,000 cubic feet of gas per 1 barrel of oil equivalent.
2. Total may vary due to rounding.

Opinion

The assumptions, data, methods, and procedures used by DeGolyer and MacNaughton to conduct the reserves audit are appropriate for the purposes of this report.

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.

In comparing the detailed net proved reserves estimates by field prepared by us and by Hess, we have found differences, both positive and negative, resulting in an aggregate difference of less than 3 percent when compared on the basis of net equivalent barrels. It is our opinion that the total net proved reserves estimates prepared by Hess, as of December 31, 2016, on the properties reviewed by us and referred to in the table above, when compared on the basis of net equivalent barrels, do not differ materially from those prepared by us.

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 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 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 the analyses of areas offsetting existing wells with test or production data, reserves were classified as proved.

When applicable, the volumetric method was used to estimate the original oil in place (OOIP) and the original gas in place (OGIP). Structure 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 and other engineering methods were used to estimate OOIP or OGIP.

Estimates of ultimate recovery were obtained after applying recovery factors to OOIP or OGIP. These recovery factors were based on consideration of the type of energy inherent in the reservoirs, analyses of the fluid properties, the structural positions of the properties, and the production histories. When applicable, material balance and other engineering methods were used to estimate recovery factors. An analysis of reservoir performance, including production rate, reservoir pressure, and gas-oil ratio behavior, was used in the estimation of reserves.

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 or to the limit of the production licenses, whichever occurred earlier.

Petroleum reserves estimated by Hess and by us are classified as proved and 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. Reserves were estimated only to the limit of economic production rates 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.

Gas quantities herein are expressed as marketable gas at the pressure and temperature base of the state or area in which the property is located. Marketable gas is defined as the total gas produced from the reservoir after reduction for shrinkage resulting from field separation; processing, including removal of nonhydrocarbon gas to meet pipeline specifications; and flare and other losses but not from fuel usage. Fuel gas is included as reserves. Oil and condensate reserves estimated herein are those to be recovered by conventional lease separation. Oil, NGL, and condensate reserves estimates included in this report are expressed in terms of barrels representing 42 United States gallons per barrel. NGL reserves are those attributed to the leasehold interests according to processing agreements and involve low-temperature separation. For reporting purposes, oil and condensate reserves have been estimated separately and are presented herein as a summed quantity.

<u>Definition of Reserves</u>

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.

Primary Economic Assumptions

The following economic assumptions were used for estimating existing and future prices and costs:

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 $42.68 per barrel for West Texas Intermediate and $44.45 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 price for the fields evaluated was $39.10 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 $4.12 per barrel.

Gas Prices

Hess has represented that the non-contracted 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 $2.54 per thousand cubic feet and the UK International Petroleum Exchange reference price was $4.79 per million British thermal units. The gas prices were adjusted for each property using differentials to NYMEX or the UK International Petroleum Exchange furnished by Hess and held constant thereafter. A portion of the gas reserves evaluated are in international properties where the gas is sold based on contracted prices. The contract was used to determine the gas price but inflation was not taken into account in the calculation of the average price. The volume-weighted average gas price for the fields evaluated was $2.41 per thousand cubic feet.

Operating Expenses and Capital Costs

Operating expenses and capital costs, based on information provided by Hess, were used in estimating future costs required to operate the properties. Future costs are typically based on existing costs and, where appropriate, adjusted to reflect planned changes in operating conditions. These costs were not escalated for inflation.

Possible Effects of Regulations

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 impact 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 oil and gas reserves, neither we nor Hess are aware of any such governmental actions which restrict the recovery of the December 31, 2016, estimated oil and gas 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 company did prepare the letter report dated February 1, 2017, on the proved reserves audit of certain properties attributable to Hess Corporation, and that I, as Senior Vice President, was responsible for the preparation of this letter report.

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 International Society of Petroleum Engineers and that I have in excess of 33 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