HESS CORP
Form 10-K
February 27, 2015

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

þ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2014

or

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

Commission File Number 1-1204

Hess Corporation

(Exact name of Registrant as specified in its charter)

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

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

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

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

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

None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes þ 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 þ

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 þ 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 þ 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	þ	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 þ

The aggregate market value of voting stock held by non-affiliates of the Registrant amounted to $26,590,000,000 computed using the outstanding common shares and closing market price on June 30, 2014, the last business day of the Registrant's most recently completed second fiscal quarter.

At December 31, 2014, there were 285,834,964 shares of Common Stock outstanding.

Part III is incorporated by reference from the Proxy Statement for the 2015 annual meeting of stockholders.

HESS CORPORATION

Form 10-K

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PART I

Items 1 and 2. Business and Properties

Hess Corporation (the Registrant) is a Delaware corporation, incorporated in 1920. The Registrant with its subsidiaries (collectively referred to as the Corporation or Hess) is a global Exploration and Production (E&P) company that develops, produces, purchases, transports and sells crude oil, natural gas liquids, and natural gas with its production operations located primarily in the United States (U.S.), Denmark, Equatorial Guinea, the Joint Development Area of Malaysia/Thailand (JDA), Malaysia, and Norway.

In the first quarter of 2013, the Corporation announced several initiatives to continue its transformation into a more focused pure play E&P company. These initiatives represented the culmination of a multi-year strategic transformation designed to deliver long-term, cash generative growth and increase returns to stockholders by focusing on lower risk, higher growth unconventional assets, exploiting existing discoveries by leveraging offshore drilling and project development capabilities, and executing a smaller, more targeted exploratory program.

As part of its transformation, the Corporation sold over the reporting period of 2012 through 2014 mature or lower margin E&P assets in Azerbaijan, Indonesia, Norway, Russia, Thailand, the United Kingdom (UK) North Sea, and certain interests onshore in the U.S. In addition, 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 facility. HOVENSA L.L.C. (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 January 2012 and continued operating solely as an oil storage terminal through the first quarter of 2015. See Item 3. Legal Proceedings. As of December 31, 2014, all downstream businesses were sold or shut down except for the energy trading joint venture, HETCO, which was sold in February 2015, and HOVENSA, which will be shut down in the first quarter of 2015.

See also the Overview in Management's Discussion and Analysis of Financial Condition and Results of Operations.

Exploration and Production

The Corporation's total proved developed and undeveloped reserves at December 31 were as follows:

	Crude Oil, Condensate & Natural Gas Liquids (a)		Natural Gas		Total Barrels of Oil Equivalent (BOE) (b)	
	2014	2013	2014	2013	2014	2013
	(Millions of barrels)		(Millions of mcf)		(Millions of barrels)	
Developed						
United States	320	278	350	279	378	325
Europe (c)	123	126	96	104	139	143
Africa	163	185	144	149	187	210
Asia	3	17	329	578	58	113
	609	606	919	1,110	762	791
Undeveloped						
United States	311	304	270	185	356	335
Europe (c)	168	165	124	134	189	188
Africa	25	25	11	11	27	26
Asia	4	8	557	535	97	97
	508	502	962	865	669	646
Total						
United States	631	582	620	464	734	660
Europe (c)	291	291	220	238	328	331
Africa	188	210	155	160	214	236
Asia	7	25	886	1,113	155	210
	1,117	1,108	1,881	1,975	1,431	1,437

(a) Total natural gas liquids reserves were 145 million barrels (65 million barrels developed and 80 million barrels undeveloped) at December 31, 2014 and 136 million barrels (61 million barrels developed and 75 million barrels undeveloped) at December 31, 2013. Of the total natural gas liquids reserves, 82% and 83% were in the U.S. and 18% and 15% were in Norway at December 31, 2014 and 2013, respectively. Natural gas liquids do not sell at prices equivalent to crude oil. See the average selling prices in the table beginning on page 9.

(b) 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 beginning on page 9.

(c)

Proved reserves in Norway, which represented 20% of the Corporation's total reserves at both December 31, 2014 and 2013, were as follows:

	Crude Oil, Condensate & Natural Gas Liquids		Natural Gas		Total Barrels of Oil Equivalent (BOE) (b)	
	2014	2013	2014	2013	2014	2013
	(Millions of barrels)		(Millions of mcf)		(Millions of barrels)	
Developed	95	107	67	87	106	121
Undeveloped	161	149	113	111	180	168
Total	256	256	180	198	286	289

On a barrel of oil equivalent basis, 47% of the Corporation's worldwide proved reserves were undeveloped at December 31, 2014 compared with 45% at December 31, 2013. Proved reserves held under production sharing contracts at 2014 totaled 5% of crude oil and natural gas liquids reserves and 49% of natural gas reserves, compared with 7% of crude oil and natural gas liquids reserves and 46% of natural gas reserves at December 31, 2013. Asset sales reduced proved reserves by 77 million boe in 2014, 140 million boe in 2013, and 83 million boe in 2012.

See the Supplementary Oil and Gas Data on pages 87 through 95 in the accompanying financial statements for additional information on the Corporation's oil and gas reserves, including a discussion of the implications that potential sustained lower crude oil prices may have on proved reserves at December 31, 2015.

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

	2014	2013	2012
Crude oil (thousands of barrels per day)			
United States			
Bakken	66	55	47
Other Onshore	10	10	13
Total Onshore	76	65	60
Offshore	51	43	48
Total United States	127	108	108
Europe			
Norway	25	20	11
Denmark	11	8	9
Russia	—	16	49
United Kingdom	—	—	15
	36	44	84
Africa			
Equatorial Guinea	43	44	48
Libya	4	13	20
Algeria	7	5	7
	54	62	75
Asia			
Azerbaijan	—	2	7
Indonesia	—	5	6
Joint Development Area of Malaysia/Thailand (JDA) and Other	3	4	4
	3	11	17
Total	220	225	284

	2014	2013	2012
Natural gas liquids (thousands of barrels per day)			
United States			
Bakken	10	6	5
Other Onshore	7	4	5
Total Onshore	17	10	10
Offshore	6	5	6
Total United States	23	15	16
Europe	1	1	2

Asia	—	1	1
Total	24	17	19

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	2014	2013	2012
Natural gas (thousands of mcf per day)			
United States			
Bakken	40	38	27
Other Onshore	47	25	27
Total Onshore	87	63	54
Offshore	78	61	65
Total United States	165	124	119
Europe			
Norway	25	15	10
Denmark	11	7	8
United Kingdom	—	1	25
	36	23	43
Asia and Other			
Joint Development Area of Malaysia/Thailand (JDA)	222	235	252
Thailand	29	87	90
Indonesia	1	52	66
Malaysia (a)	60	33	39
Other	—	11	7
	312	418	454
Total	513	565	616
Barrels of oil equivalent (per day) (b)	329	336	406

(a) Includes 20 mmcf, 12 mmcf, and 39 mmcf per day of production for 2014, 2013, and 2012, respectively from Block PM301 which is unitized into the JDA.

(b) Reflects natural gas production converted on the basis of relative energy content (six mcf equals one barrel). 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. In addition, natural gas liquids do not sell at prices equivalent to crude oil. See the average selling prices in the table beginning on page 9.

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

United States

At December 31, 2014, 51% of the Corporation's total proved reserves were located in the U.S. During 2014, 61% of the Corporation's crude oil and natural gas liquids production and 32% of its natural gas production were from U.S.

operations. The Corporation's production in the U.S. was from offshore properties in the Gulf of Mexico and onshore properties principally in the Bakken oil shale play in the Williston Basin of North Dakota, the Permian Basin of Texas, and the Utica Basin of Ohio.

Onshore: The Corporation held approximately 613,000 net acres in the Bakken at December 31, 2014. During 2014, the Corporation operated an average of 17 rigs, drilled 261 wells, completed 230 wells, and brought on production 238 wells, bringing the total operated production wells to 982. In addition, the Corporation announced in 2014 it plans to develop future 1280-acre drilling space units (DSUs) primarily using a 7/6 spacing design whereby seven wells will be drilled into the Middle Bakken reservoir and six wells will be drilled into the Three Forks reservoir per DSU. In 2015, the Corporation plans to operate an average of 9.5 rigs to drill 170 wells and bring 210 wells on production while reducing capital expenditures to $1.8 billion in 2015 from $2.2 billion in 2014. Bakken production is forecast to average between 95,000 boepd and 105,000 boepd in 2015.

In North Dakota, the Corporation owns and operates the Tioga Gas Plant. In the first quarter of 2014, the Corporation completed an expansion of the plant that increased total processing capacity to approximately 250,000 mcf per day and 60,000 barrels per day of full NGL fractionation capabilities. The Corporation's Tioga Rail Terminal has loading capacity of approximately 140,000 barrels per day of crude oil and approximately 30,000 barrels per day of natural gas liquids with on-site crude oil storage of 287,000 barrels. The Corporation also owns nine crude oil unit trains, each consisting of 104 crude oil rail cars, all of which were constructed to American Association of Railroads Petition 1577 (CPC-1232) safety standards. Other infrastructure includes the Ramberg Truck Facility, that is capable of delivering up to an aggregate of 130,000 barrels per day of crude oil into an interconnecting pipeline for transportation to the Tioga Rail Terminal and to multiple third-party pipelines and storage facilities.

In 2014, the Corporation formed Hess Midstream Partners LP to own, operate, develop and acquire a diverse set of midstream assets to provide fee-based services to both Hess and third party crude oil and natural gas producers. Hess Midstream Partners LP filed a registration statement on Form S-1 in September 2014 and expects to complete an initial public offering of its securities in 2015. The assets to be held by Hess Midstream Partners LP at the time of its initial public offering are expected to include a 30% economic interest in Hess TGP Operations LP (owner of the Tioga Gas Plant), a 50% economic interest in Hess North Dakota Export Logistics Operations LP (owner of the Tioga rail terminal, Ramberg truck facility and crude oil rail cars), and a 100% interest in Hess Mentor Storage Holdings LLC (owner of a 328,000 barrel propane storage cavern with a rail and truck transloading facility).

The Corporation also owned a 50% undivided working interest in approximately 45,000 net acres in the wet gas area of the Utica Basin of Ohio. During 2014, a total of 38 wells were drilled, 36 wells were completed and 39 wells were brought on production as the Corporation transitioned from appraisal to early development activities. In 2015, the Corporation and its joint venture partner plan to execute a two rig drilling program that will allow for 20 to 25 wells to be drilled and for 25 to 30 wells to be brought online. Net production is forecast to be in the range of 15,000 boepd to 20,000 boepd in 2015. During 2014, the Corporation sold approximately 77,000 net acres of its 100% owned acreage in the dry gas area of the Utica shale play for cash proceeds of approximately $1,075 million.

In the Permian Basin, the Corporation operates and holds a 34% interest in the Seminole San Andres Unit. In 2013, the Corporation sold its interests in the Eagle Ford shale play in Texas.

Offshore: The Corporation’s production offshore in the Gulf of Mexico was principally from the Shenzi (Hess 28%), Llano (Hess 50%), Conger (Hess 38%), Baldpate (Hess 50%), Tubular Bells (Hess 57%), Hack Wilson (Hess 25%) and Penn State (Hess 50%) fields.

At the Hess operated Tubular Bells Field, the Corporation achieved first production in November 2014 following completion of construction, installation and commissioning of offshore production facilities and subsea equipment. Three wells are currently producing with a fourth production well expected to be completed in 2015.

At the BHP Billiton Petroleum operated Shenzi Field, development drilling continued during 2014 with the completion of one production well. A continuous drilling program is planned through 2016.

The Corporation is operator and holds a 25% interest in the Stampede offshore development project on Green Canyon Blocks 468, 511 and 512 in the Gulf of Mexico. In 2014, the co-owners of the project sanctioned the field development and committed to two deepwater drilling rigs that are expected to commence drilling operations in the fourth quarter of 2015 and the first quarter of 2016. Construction of production facilities and subsea equipment is underway with first production from the field targeted for 2018.

The Corporation holds a 25% interest in the Sicily prospect in the deepwater Gulf of Mexico. The operator, Chevron, has commenced drilling of an exploration well with the objective of reaching target depth in the third quarter of 2015.

At December 31, 2014, the Corporation had interests in 177 deepwater blocks in the Gulf of Mexico, of which 148 were exploration blocks comprising approximately 550,000 net undeveloped acres, with an additional 66,000 net acres held for production and development operations. During 2014, the Corporation's interests in 45 leases, comprising approximately 175,000 net undeveloped acres, either expired or were relinquished. In the next three years, an additional 81 exploration leases, comprising approximately 280,000 net undeveloped acres, are due to expire.

Europe

At December 31, 2014, 23% of the Corporation's total proved reserves were located in Europe (Norway 20% and Denmark 3%). During 2014, 16% of the Corporation's crude oil and natural gas liquids production and 7% of its natural gas production were from European operations. In 2013, the Corporation completed the sale of its Russian subsidiary, Samara Nafta, and sold its interests in the Beryl fields, completing its exit from producing operations in the UK North Sea. In 2012, the Corporation sold its interests in the Bittern and Schiehallion fields in the UK North Sea.

Norway: The Corporation's Norwegian production was from its non-operated interests in the Valhall (Hess 64%) and Hod fields (Hess 63%).

In the first quarter of 2013, BP, the operator of the Valhall Field completed the installation of a new production, utilities and accommodation platform that extends the field life by approximately 40 years. A multi-year drilling program is continuing and net production is forecast to be in the range of 30,000 boepd to 35,000 boepd in 2015. In addition, the operator is executing a multi-year well abandonment program.

Denmark: Production comes from the Corporation's operated interest in the South Arne Field (Hess 62%), offshore Denmark. Development drilling commenced in 2013 and is planned to continue through 2015. During 2013, the Corporation completed its phase three development program in which two new wellhead platforms were successfully installed in the field.

Africa

At December 31, 2014, 15% of the Corporation's total proved reserves were located in Africa (Equatorial Guinea 3.5%, Libya 11% and Algeria 0.5%). During 2014, 22% of the Corporation's crude oil and natural gas liquids production were from its African operations.

Equatorial Guinea: The Corporation is operator and owns an interest in Block G (Hess 85% paying interest) which contains the Ceiba Field and the Okume Complex. The national oil company of Equatorial Guinea holds a 5% carried interest in Block G. At the Okume Complex, an infill drilling campaign commenced in the fourth quarter of 2013 based on 4D seismic and will continue into the first half of 2015.

Libya: The Corporation, in conjunction with its Oasis Group partners, has production operations in the Waha concessions in Libya (Hess 8%) which contain the Defa, Faregh, Gialo, North Gialo, Belhedan and other fields. Due to the civil unrest in Libya, production was shut in beginning in the third quarter of 2013 and restarted, on a significantly reduced rate, in the third quarter of 2014. Net production at the Waha fields averaged 4,000 boepd in 2014, 15,000 boepd during 2013 and 21,000 boepd in 2012. In December 2014 the Libyan National Oil Company declared force majeure with respect to the Waha fields and production is currently shut-in. In addition, the Corporation expensed two previously capitalized exploration wells on offshore exploration Area 54 in the Mediterranean Sea in the fourth quarter of 2013 due to the ongoing civil and political unrest. The Libyan operations have assets with a book value of $365 million at December 31, 2014.

Algeria: The Corporation has a 49% interest in a venture with the Algerian national oil company that redeveloped three oil fields. In 2013, the Corporation sold its interest in the development project, Bir El Msana (Hess 45%).

Ghana: The Corporation holds a 44% paying interest and is operator of the Deepwater Tano Cape Three Points license while the Ghana National Petroleum Corporation holds an 11% paying interest and a 10% carried interest in the block. These ownership percentages are based on terms of a farmout agreement with a third party that is subject to approval by the Ghanaian government. The Corporation has drilled seven successful exploration wells on the block since 2011. In June 2013, the Corporation submitted appraisal plans for each of the seven discoveries, which comprise both oil and natural gas condensates, to the Ghanaian government for approval. Approval has been received on four appraisal plans and discussions continue with the Ghanaian government to receive approval on the remaining three appraisal plans. In 2014, the Corporation drilled three successful appraisal wells. In 2015 the Corporation and its partners will continue to analyze data from both appraisal drilling and 3D seismic with an expected project sanction decision in 2016. See Capitalized Exploratory Well Costs in Note 6 – Property, Plant and Equipment in Notes to Consolidated Financial Statements.

Asia and Other

At December 31, 2014, 11% of the Corporation's total proved reserves were located in the Asia region (JDA 7% and Malaysia 4%). During 2014, 1% of the Corporation's crude oil and natural gas liquids production and 61% of its natural gas production were from its Asian and Other operations. The Corporation completed the sale of its interests in Thailand in April 2014. In addition, the Corporation sold its Pangkah asset and its interest in the Natuna A Field, both offshore Indonesia, in January 2014 and December 2013, respectively. In the first quarter of 2013, the Corporation sold its interests in Azerbaijan in the Caspian Sea.

Joint Development Area of Malaysia/Thailand (JDA): The Corporation owns an interest in Block A 18 of the JDA (Hess 50%) in the Gulf of Thailand. In 2014, the operator continued development drilling and successfully installed a new wellhead platform. Further development drilling is planned for 2015 and the completion of a booster compression project is planned for early 2016. Net production in 2015 is expected to be approximately 250,000 million cubic feet per day.

Malaysia: The Corporation's production in Malaysia comes from its interest in Block PM301 (Hess 50%), which is adjacent to and is unitized with Block A 18 of the JDA and its 50% interest in Blocks PM302, PM325 and PM326B located in the North Malay Basin (NMB), offshore Peninsular Malaysia, where the Corporation is operator of a multi phase natural gas development project. NMB achieved first production in October 2013 from an Early Production System. The Corporation expects net production to average approximately 40 million cubic feet per day through 2016 until full field development is completed. Net production is expected to increase to approximately 165 million cubic feet per day in 2017.

Australia: The Corporation holds an interest in an exploration license covering approximately 780,000 acres in the Carnarvon Basin offshore Western Australia (WA 390 P Block, also known as Equus) (Hess 100%). The Corporation has drilled 13 natural gas discoveries. Development planning and commercial activities continued in 2014, which included the execution of a non-binding letter of intent with a potential liquefaction partner. Successful negotiation of a binding agreement with the third party liquefaction partner is necessary before the Corporation can execute a gas sales agreement and sanction development of the project. See Capitalized Exploratory Well Costs in Note 6 – Property, Plant and Equipment in Notes to Consolidated Financial Statements.

Kurdistan Region of Iraq: The Corporation is operator and holds an 80% paying interest (64% working interest) in the Dinarta exploration block. Drilling activities have been suspended on the Shireen exploration well in the Dinarta Block and the Corporation is currently assessing its completion options.

China: In July 2013, the Corporation signed a Production Sharing Agreement (PSA) with China National Petroleum Corporation to evaluate unconventional oil and gas resource opportunities covering approximately 200,000 gross acres in the Santanghu Basin. The exploration phase commenced in August 2013 and two wells were drilled and expensed. In December, 2014 the Corporation provided formal notice of its intent to end its participation in the PSA.

Guyana: The Corporation holds a 30% participating interest in the offshore Stabroek license. The Corporation anticipates the operator, Esso Exploration and Production Guyana Limited, to commence drilling of the Liza-1 well in March 2015.

Canada: The Corporation received regulatory approval to hold a 40% participating interest in four exploration licenses offshore Nova Scotia. The Corporation expects the operator, BP, to commence exploration drilling in 2017.

Sales Commitments

The Corporation has contracts to sell fixed quantities of its natural gas and natural gas liquids (NGL) production. The natural gas contracts principally relate to producing fields in Asia. The most significant of these commitments relates to the JDA where the minimum contract quantity of natural gas is estimated at 96 billion cubic feet per year based on current entitlements under a sales contract with the national oil companies of Malaysia and Thailand expiring in 2027. At the North Malay Basin development project, the Corporation has a commitment to deliver a minimum of 24 billion cubic feet of natural gas per year from full field development start-up, which is expected in 2017, through 2033. The estimated total volume of production subject to sales commitments is approximately 1.7 trillion cubic feet of natural gas.

The Corporation has NGL delivery commitments in the Bakken and Permian Basin of Texas through 2023 of approximately 9 million barrels per year, or approximately 99 million barrels over the life of the contracts.

The Corporation has not experienced any significant constraints in satisfying the committed quantities required by its sales commitments, and it anticipates being able to meet future requirements from available proved and probable reserves and projected third party supply.

Average selling prices and average production costs

	2014	2013	2012
Average selling prices (a)			
Crude oil - per barrel (including hedging)			
United States			
Onshore	$80.67	$90.00	$84.78
Offshore	95.05	103.83	101.80
Total United States	86.48	95.50	92.32
Europe (b)	104.21	88.03	74.14
Africa	97.31	108.70	89.02
Asia	89.71	107.40	107.45
Worldwide	92.17	98.48	86.94
Crude oil - per barrel (excluding hedging)			
United States			
Onshore	$80.67	$89.81	$85.66
Offshore	92.22	103.15	104.39
Total United States	85.34	95.11	93.96
Europe (b)	99.20	87.45	75.06
Africa	93.70	108.07	110.92
Asia	89.71	107.40	109.35
Worldwide	89.78	98.01	93.70
Natural gas liquids - per barrel			
United States			
Onshore	$28.92	$43.14	$44.22
Offshore	30.40	29.18	35.24
Total United States	29.32	38.07	40.75
Europe (b)	52.66	58.31	78.43
Asia	—	74.94	77.92
Worldwide	30.59	40.68	47.81
Natural gas - per mcf			
United States			
Onshore	$3.18	$3.08	$2.02
Offshore	3.79	2.83	2.15
Total United States	3.47	2.96	2.09
Europe (b)	10.00	11.06	9.50
Asia and other	6.94	7.50	6.90
Worldwide	6.04	6.64	6.16
Average production (lifting) costs per barrel of oil equivalent produced (c)			

United States			
Onshore	$24.51	$29.42	$28.97
Offshore	5.06	4.98	5.21
Total United States	16.77	19.45	18.25
Europe (b)	29.14	36.02	29.56
Africa	22.39	19.26	14.45
Asia and other	10.67	12.89	11.13
Worldwide	18.31	20.26	18.52

(a) Includes inter company transfers valued at approximate market prices.

(b) The average selling prices in Norway for 2014 were $105.35 per barrel for crude oil (including hedging), $100.34 per barrel for crude oil (excluding hedging), $52.13 per barrel for natural gas liquids and $12.22 per mcf for natural gas. The average selling prices in Norway for 2013 were $110.25 per barrel for crude oil (including hedging), $109.41 per barrel for crude oil (excluding hedging), $57.87 per barrel for natural gas liquids and $13.50 per mcf for natural gas. The average selling prices in Norway for 2012 were $109.23 per barrel for crude oil (including hedging), $113.08 per barrel for crude oil (excluding hedging), $58.48 per barrel for natural gas liquids and $12.21 per mcf for natural gas. The average production (lifting) costs in Norway were $33.76 per barrel of oil equivalent produced in 2014, $44.69 per barrel of oil equivalent produced in 2013 and $62.38 per barrel of oil equivalent produced in 2012, reflecting a shutdown of production from July 2012 through the end of 2012.

(c) Production (lifting) costs consist of amounts incurred to operate and maintain the Corporation’s producing oil and gas wells, related equipment and facilities, transportation costs and production and severance taxes. The average production costs per barrel of oil equivalent reflect the crude oil equivalent of natural gas production converted on the basis of relative energy content (six mcf equals one barrel).

The table above does not include costs of finding and developing proved oil and gas reserves, or the costs of related general and administrative expenses, interest expense and income taxes.

Gross and net undeveloped acreage at December 31, 2014

	Undeveloped Acreage (a)	
	Gross	Net
	(In thousands)	
United States	1,217	828
Europe	528	424
Africa	6,433	3,321
Asia and other	16,655	7,378
Total (b)	24,833	11,951

(a) Includes acreage held under production sharing contracts.

(b) Licenses covering approximately 67% of the Corporation’s net undeveloped acreage held at December 31, 2014 are scheduled to expire during the next three years pending the results of exploration activities. These scheduled expirations are largely in Australia and Africa.

Gross and net developed acreage and productive wells at December 31, 2014

Developed Acreage

	Applicable to Productive Wells		Productive Wells (a)			
			Oil		Gas	
	Gross	Net	Gross	Net	Gross	Net
	(In thousands)					
United States	1,265	816	2,454	1,088	123	59
Europe (b)	102	59	71	44	—	—
Africa	9,832	933	836	130	—	—
Asia and other	258	129	—	—	90	45
Total	11,457	1,937	3,361	1,262	213	104

(a) Includes multiple completion wells (wells producing from different formations in the same bore hole) totaling 129 gross wells and 81 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 53 and 33, respectively.

Number of net exploratory and development wells drilled during the years ended December 31

	Net Exploratory Wells			Net Development Wells		
	2014	2013	2012	2014	2013	2012
Productive wells						
United States	8	10	3	202	146	184
Europe	—	—	3	4	1	23
Africa	2	2	3	4	2	1
Asia and other	—	4	3	4	18	20
	10	16	12	214	167	228
Dry holes						
United States	1	—	1	—	—	—
Europe	—	3	3	—	—	—
Asia and other	3	1	2	—	—	—
	4	4	6	—	—	—
Total	14	20	18	214	167	228

Number of wells in process of drilling at December 31, 2014

	Gross Wells	Net Wells
United States	175	81
Europe*	5	3
Africa	1	1
Asia and other	2	1
Total	183	86

*Gross and net wells in process of drilling in Norway were 4 and 3, respectively.

Marketing and Refining- Discontinued Operations

All downstream businesses were sold or shutdown as of December 31, 2014, except for the energy trading joint venture, HETCO, which was sold in February 2015, and HOVENSA, which will be shut down in the first quarter of 2015.

In the third quarter of 2014, the Corporation sold its retail marketing business consisting of approximately 1,350 retail gasoline stations, most of which had convenience stores. In addition, the Corporation sold in 2014 two joint venture investments in natural gas fueled electric generating projects in Newark and Bayonne, New Jersey.

In the fourth quarter of 2013, the Corporation sold its energy marketing and terminal network businesses which marketed refined petroleum products, natural gas and electricity on the East Coast of the U.S. primarily to wholesale distributors, industrial and commercial users, and public utilities. In the first quarter of 2013, the Corporation permanently shut down refining operations at its Port Reading, New Jersey facility, thus completing its exit from all refining operations.

Hess Oil Virgin Islands Corp. (HOVIC), a subsidiary of the Corporation, has a 50% interest in HOVENSA, a joint venture with a subsidiary of PDVSA, which owns a refinery in St. Croix, U.S. Virgin Islands. In January 2012, HOVENSA shut down its refinery and continued operating solely as an oil storage terminal through the first quarter of 2015. HOVENSA and the Government of the Virgin Islands agreed to a plan to pursue a sale of HOVENSA and the sales process commenced in the fourth quarter of 2013. In the fourth quarter of 2014, the Government of the Virgin Islands did not approve a proposed operating agreement required to complete a proposed sale of HOVENSA. See Item 3. Legal Proceedings.

Competition and Market Conditions

See Item 1A. Risk Factors Related to Our Business and Operations, for a discussion of competition and market conditions.

Other Items

Emergency Preparedness and Response Plans and Procedures

The Corporation has 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 ensure 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 the Corporation's plans. The Corporation's contractors, service providers, representatives from government agencies and, where applicable, joint venture partners participate in the drills to ensure that emergency procedures are comprehensive and can be effectively implemented.

To complement internal capabilities and to ensure coverage for its global operations, the Corporation maintains 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), National Response Corporation (NRC) 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. NRC and OSRL are global response organizations and are available to assist the Corporation when needed anywhere in the world. In addition to owning response assets in their own right, these organizations maintain business relationships that provide immediate access to additional critical response support services if required. These owned response assets included nearly 300 recovery and storage vessels and barges, more than 250 skimmers, over 600,000 feet of boom, and significant quantities of dispersants and other ancillary equipment, including aircraft. In addition to external well control and oil spill response support, the Corporation has contracts with wildlife, environmental, meteorology, incident management, medical and security resources. If the Corporation were to engage these organizations to obtain additional critical response support services, it would fund such services and seek reimbursement under its insurance coverage described below. In certain circumstances, the Corporation pursues and enters into mutual aid agreements with other companies and government cooperatives to receive and provide oil spill response equipment and personnel support. The Corporation maintains close associations with emergency response organizations through its representation on the Executive Committees of CGA and MSRC, as well as the Board of Directors of OSRL.

The Corporation continues 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

The Corporation maintains insurance coverage that includes coverage for physical damage to its 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 the Corporation against liability from all potential consequences and damages.

The amount of insurance covering physical damage to the Corporation’s property and liability related to negative environmental effects resulting from a sudden and accidental pollution event, excluding Atlantic Named Windstorm coverage for which it is 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 $300 million of coverage is provided through an industry mutual insurance group. Above this $300 million threshold, insurance is carried which ranges in value up to $2.53 billion in total, depending on the asset coverage level, as described above. Additionally, the Corporation carries 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 the Corporation’s participating interest.

The Corporation's 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, the Corporation's drilling contracts (and most of its 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.

The Corporation is customarily responsible for, and indemnifies the Contractor against all claims, including those from third parties, to the extent attributable to pollution or contamination by substances originating from its reservoirs or other property (regardless of cause, including gross negligence and willful misconduct) and the Contractor is responsible for and indemnifies the Corporation for all claims attributable to pollution emanating from the Contractor's property. Additionally, the Corporation is generally liable for all of its 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 severably 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 the Corporation's 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. The Corporation spent approximately $12 million in 2014 for environmental remediation, principally relating to the downstream businesses. 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 the Corporation's capital expenditures and operating expenses. For further discussion of environmental matters see the Environment, Health and Safety section of Item 7. Management's Discussion and Analysis of Financial Condition and

Results of Operations.

Number of Employees

The number of persons employed by the Corporation was approximately 3,045 at December 31, 2014 and approximately 12,225 at December 31, 2013, of which approximately 8,700 related to the retail business which was sold in 2014.

Other

The Corporation's internet address is www.hess.com. On its website, the Corporation makes available free of charge its 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 the Corporation electronically files with or furnishes such material to the Securities and Exchange Commission. The contents of the Corporation's website are not incorporated by reference in this report. Copies of the Corporation's Code of Business Conduct and Ethics, its Corporate Governance Guidelines and the charters of the Audit Committee, the Compensation and Management Development Committee and the Corporate Governance and Nominating Committee of the Board of Directors are available on the Corporation's website and are also available free of charge upon request to the Secretary of the Corporation at its principal executive offices. The Corporation has also filed with the New York Stock Exchange (NYSE) its annual certification that the Corporation's Chief Executive Officer is unaware of any violation of the NYSE's corporate governance standards.

Item 1A. Risk Factors Related to Our Business and Operations

Our business activities and the value of our securities are subject to significant risk factors, including those described below. The risk factors described below 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, and future earnings are highly dependent on the prices of crude oil, natural gas liquids and natural gas, which are volatile and influenced by numerous factors beyond our control. The major foreign oil producing countries, including members of the Organization of Petroleum Exporting Countries (OPEC), 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 has a significant impact on the oil markets. In the fourth quarter of 2014, prices for Brent crude oil and West Texas Intermediate crude oil declined by approximately 40% to end the year at $57 per barrel and $53 per barrel, respectively. If crude oil prices remain at these levels for the remainder of 2015, there will be a significant decrease in 2015 revenues, and earnings from 2014 levels. We cannot predict how long these lower price levels will continue to prevail. The 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. To the extent that we engage in hedging activities to mitigate commodity price volatility, we may not realize the benefit of price increases above the hedged price. Changes in commodity prices can also have a material impact on collateral and margin requirements under our derivative contracts. In order to manage the potential volatility of cash flows and credit requirements, the Corporation maintains significant bank credit facilities. An inability to renew or replace such credit facilities or access other sources of funding as they mature would negatively impact our liquidity. 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.

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. The costs of drilling and development activities have increased in recent years which could negatively affect expected economic returns. 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. 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.

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 the fourth quarter of 2014. 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 partners under such agreements may fail to meet their obligations. We conduct many of our exploration and production 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 transport some of our crude oil production, particularly from the Bakken shale oil play, by rail. Recent rail accidents have raised public awareness of rail safety and resulted in heightened regulatory scrutiny. We own our own fleet of tank cars that exceed the current federal standards for construction and safety. We expect that in 2015, the Department of Transportation will issue new standards for tank car design which may require us to retrofit our existing tank cars. Depending on the requirements of the regulation, changes in tank car design and limitations on the availability of shop capacity to undertake retrofits, as well as other possible regulations aimed at increasing rail safety, may lead to a significant increase in the costs of transporting crude oil and other hydrocarbons by rail and otherwise adversely affect our operations.

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, 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, the Corporation has 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 our sales of crude oil and other hydrocarbons. 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 has significantly increased 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 the Corporation 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. The Corporation is 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 and unfavorable weather conditions. This may lead to delays and differences between estimated and actual timing of critical events. These delays could impact information detailed in forward-looking statements, and may have material negative economic consequences.

Departures of key members from the Corporation’s senior management team, and/or difficulty in recruiting and retaining adequate numbers of experienced technical personnel, could negatively impact the Corporation’s ability to deliver its 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 the Corporation from executing its strategy in full or, in part, with a commensurate impact on shareholder value.

The Corporation is 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 Exploration and Production industry. As a result, the Corporation may encounter difficulties in obtaining required services or could face an increase in cost. These consequences may impact the ability of the Corporation to run its operations and to deliver projects on time with the potential for material negative economic consequences.

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.

Item 3. Legal Proceedings

The Corporation, along with many companies engaged in refining and marketing of gasoline, has 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 the Corporation. 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 the Corporation have been settled. In 2014, the Corporation settled and paid claims against it arising out of an action brought by the State of New Jersey for approximately $35 million. The settlement was approved by the trial judge and the Corporation paid the settlement amount in December 2014. In June 2014, the Commonwealth of Pennsylvania and the State of Vermont each filed independent lawsuits alleging that the Corporation 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. An action brought by the Commonwealth of Puerto Rico also remained unresolved at December 31, 2014. The Corporation has recorded reserves for its estimated liabilities for its unresolved MTBE lawsuits.

The Corporation received a directive from the New Jersey Department of Environmental Protection (NJDEP) to remediate contamination in the sediments of the lower Passaic River and the NJDEP is also seeking natural resource damages. The directive, insofar as it affects the Corporation, relates to alleged releases from a petroleum bulk storage terminal in Newark, New Jersey previously owned by the Corporation. The Corporation and over 70 companies entered into an Administrative Order on Consent with the Environmental Protection Agency (EPA) to study the same contamination. The Corporation and other parties recently settled a cost recovery claim by the State of New Jersey and also agreed to fund remediation of a portion of the site. The EPA is continuing to study contamination and remedial designs for other portions of the River. In addition, the federal trustees for natural resources have begun a separate assessment of damages to natural resources in the Passaic River. Given the ongoing studies, remedial costs cannot be reliably estimated at this time. Based on currently known facts and circumstances, the Corporation does not believe that this matter will result in a material liability because its terminal could not have contributed contamination along most of the river’s length and did not store or use contaminants which are of the greatest concern in the river sediments, and because there are numerous other parties who will likely share in the cost of remediation and damages.

On July 25, 2011, the Virgin Islands Department of Planning and Natural Resources commenced an enforcement action against HOVENSA by issuance of documents titled “Notice Of Violation, Order For Corrective Action, Notice Of Assessment of Civil Penalty, Notice Of Opportunity For Hearing” (the “NOVs”). The NOVs assert violations of Virgin Islands Air Pollution Control laws and regulations arising out of odor incidents on St. Croix in May 2011 and proposed total penalties of $210,000. HOVENSA believes that it has good defenses against the asserted violations.

In July 2004, HOVIC and HOVENSA, each received a letter from the Commissioner of the Virgin Islands Department of Planning and Natural Resources and Natural Resources Trustees, advising of the Trustee's intention to bring suit against HOVIC and HOVENSA under the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA). The letter alleges that HOVIC and HOVENSA are potentially responsible for damages to natural resources arising from releases of hazardous substances from the HOVENSA refinery, which had been operated by HOVIC until October 1998. An action was filed on May 5, 2005 in the District Court of the Virgin Islands against HOVENSA, HOVIC and other companies that operated industrial facilities on the south shore of St. Croix asserting that the defendants are liable under CERCLA and territorial statutory and common law for damages to natural resources. In 2014 HOVIC, HOVENSA and the government of the U.S. Virgin Islands entered into a settlement agreement pursuant to which HOVENSA paid $3.5 million and agreed to pay the government of the U.S. Virgin Islands an additional $40 million no later than December 31, 2014. HOVENSA was unable to make this additional payment because the U.S.Virgin Islands legislature did not approve a proposed operating agreement required to complete a proposed sale of HOVENSA, which would have provided funds to make the settlement payment. Under the terms of the settlement agreement, the U.S. Virgin Islands government was granted a first lien on HOVENSA's assets to secure the settlement payment, and in January 2015 the government commenced a foreclosure action to enforce this lien. HOVENSA intends to defend this action and may take other steps in response to the action, including the sale of assets and/or the commencement of bankruptcy proceedings. The Registrant does not believe that the resolution of this matter will have a material adverse effect on its financial condition.

In February 2015, the Pension Benefit Guaranty Corporation (PBGC) issued a notice of determination to terminate the HOVENSA pension plan. HOVENSA had been in negotiations with the PBGC to make additional contributions to the plan with proceeds from a proposed sale of HOVENSA, which was not completed for the reasons described above. The Registrant does not believe that the resolution of this matter will have a material adverse effect on its financial condition.

The Corporation periodically receives notices from the EPA that it is a “potential responsible party” under the Superfund legislation with respect to various waste disposal sites. Under this legislation, all potentially responsible parties are jointly and severally liable. For certain sites, the EPA’s claims or assertions of liability against the Corporation 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 the business or accounts of the Corporation 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.

The Corporation is from time to time involved in other judicial and administrative proceedings, including proceedings relating to other environmental matters. The Corporation 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 the financial condition, results of operations or cash flows of the Corporation.

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

The common stock of Hess Corporation is traded principally on the New York Stock Exchange (ticker symbol: HES). High and low sales prices were as follows:

	2014		2013	
Quarter Ended	High	Low	High	Low
March 31	$83.56	$73.36	$72.63	$53.06
June 30	99.10	82.52	74.48	61.32
September 30	104.50	93.57	80.41	66.23
December 31	94.58	63.80	85.15	76.83

Performance Graph

Set forth below is a line graph comparing the five year shareholder return on a $100 investment in the Corporation’s 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 12 oil and gas peer companies, including the Corporation (as disclosed in the Corporation’s 2014 Proxy Statement).

Comparison of Five Year Shareholder Returns

Years Ended December 31,

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Holders

At December 31, 2014, there were 3,752 stockholders (based on the number of holders of record) who owned a total of 285,834,964 shares of common stock.

Dividends

In 2014, cash dividends on common stock totaled $1.00 per share ($0.25 per quarter). In 2013, cash dividends declared on common stock totaled $0.70 per share ($0.10 per share for the first two quarters and $0.25 per share commencing in the third quarter of 2013). Cash dividends were $0.40 per share ($0.10 per quarter) in 2012.

Share Repurchase Activities

Hess's share repurchase activities for the year ended December 31, 2014, were as follows:

2014	Total Number of Shares Purchased (a)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Approximate Dollar Value of Shares that May Yet be Purchased Under the Plans or Programs (b) (In millions)
January	4,433,061	$ 78.95	4,433,061	$ 2,112
February	4,468,163	78.33	4,468,163	1,762
March	3,675,267	81.01	3,675,267	1,464
April	1,690,824	85.76	1,690,824	1,319
May	2,285,984	89.35	2,285,984	3,615
June	4,380,305	95.50	4,380,305	3,197
July	2,499,830	99.23	2,499,830	2,949
August	3,106,967	99.28	3,106,967	2,640
September	3,548,637	97.55	3,548,637	2,294
October	5,179,300	83.75	5,179,300	1,860
November	3,312,000	82.44	3,312,000	1,587
December	4,770,901	72.58	4,770,901	1,241
Total for 2014 (c)	43,351,239	$ 85.83	43,351,239	

(a) Repurchased in open market transactions. The average price paid per share was inclusive of transaction fees.
(b) In March 2013, the Corporation announced a board authorized plan to repurchase up to $4 billion of outstanding common shares. In May 2014, the Corporation increased the repurchase program to $6.5 billion.
(c) Since initiation of the buyback program in August 2013, total shares repurchased through December 31, 2014 amounted to 62.7 million at a total cost of $5.26 billion for an average cost per share of $83.93.

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Equity Compensation Plans

Following is information on the Registrant’s equity compensation plans at December 31, 2014.

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	6,766,000	$ 66.79	8,541,000(a)
Equity compensation plans not approved by security holders (b)	—	—	—

(a) These securities may be awarded as stock options, restricted stock, performance share units or other awards permitted under the Registrant’s equity compensation plan.
(b) The Corporation has a Stock Award Program pursuant to which each non-employee director annually receives approximately $175,000 in value of the Corporation’s common stock. These awards are made from shares purchased by the Corporation in the open market.

See Note 11, Share based Compensation in the Notes to the Consolidated Financial Statements for further discussion of the Corporation’s 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 the Corporation's consolidated financial statements and the accompanying notes and Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations included elsewhere in this Annual Report:

	2014		2013		2012		2011		2010	
	(In millions, except per share amounts)									
Sales and other operating revenues										
Crude oil and natural gas liquids	$9,455		$10,455		$10,802		$9,224		$7,660	
Natural gas	1,247		1,394		1,394		1,362		1,373	
Other operating revenues	35		56		49		61		90	
Total	$10,737		$11,905		$12,245		$10,647		$9,123	
Income from continuing operations	$1,692		$4,036		$1,808		$1,570		$1,946	
Income from discontinued operations	682		1,186		255		106		192	
Net income	$2,374		$5,222		$2,063		$1,676		$2,138	
Less: Net income (loss) attributable to noncontrolling interests*	57		170		38		(27)		13	
Net income attributable to Hess Corporation	$2,317	(a)	$5,052	(b)	$2,025	(c)	$1,703	(d)	$2,125	(e)
Net income attributable to Hess Corporation per share:										
Basic:										
Continuing operations	$5.57		$11.47		$5.29		$4.60		$5.92	
Discontinued operations	2.06		3.54		0.69		0.45		0.60	
Net income per share	$7.63		$15.01		$5.98		$5.05		$6.52	
Diluted:										
Continuing operations	$5.50		$11.33		$5.26		$4.56		$5.88	
Discontinued operations	2.03		3.49		0.69		0.45		0.59	
Net income per share	$7.53		$14.82		$5.95		$5.01		$6.47	
Total assets	$38,578		$42,754		$43,441		$39,136		$35,396	
Total debt	$5,987		$5,798		$8,111		$6,057		$5,583	
Total equity	$22,320		$24,784		$21,203		$18,592		$16,809	
Dividends per share of common stock	$1.00		$0.70		$0.40		$0.40		$0.40	

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

(a) 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.

(b) 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.

(c) 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.

(d) Includes after tax charges totaling $694 million relating to the shutdown of the HOVENSA L.L.C. (HOVENSA) refinery, asset impairments and an increase in the United Kingdom supplementary tax rate, partially offset by after tax income of $413 million relating to gains on asset sales.

(e) Includes after tax income of $1,130 million relating to gains on asset sales, partially offset by after tax charges totaling $694 million for an asset impairment, an impairment of the Corporation's equity investment in HOVENSA, dry hole expenses and premiums on repurchases of fixed rate public notes.

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 that develops, produces, purchases, transports and sells crude oil, natural gas liquids, and natural gas with production operations primarily in the United States (U.S.), Denmark, Equatorial Guinea, the joint development area of Malaysia/Thailand (JDA), Malaysia, and Norway.

Transformation to a Pure Play Exploration and Production Company

In the first quarter of 2013, the Corporation announced several initiatives to continue its transformation into a more focused pure play E&P company. These initiatives represented the culmination of a multi-year strategic transformation designed to deliver long-term, cash generative growth and increase returns to stockholders by focusing on lower risk, higher growth unconventional assets, exploiting existing discoveries by leveraging offshore drilling and project development capabilities, and executing a smaller, more targeted exploratory program.

As part of its transformation, the Corporation sold during the period of 2012 through 2014 mature or lower margin E&P assets in Azerbaijan, Indonesia, Norway, Russia, Thailand, the United Kingdom North Sea (UK), and certain interests onshore in the U.S. In addition, 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 facility. HOVENSA L.L.C. (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 January 2012 and continued operating solely as an oil storage terminal through the first quarter of 2015. See Item 3. Legal Proceedings. As of December 31, 2014, all downstream businesses were sold or shutdown except for the energy trading joint venture, HETCO, which was sold in February 2015, and HOVENSA, which will be shut down in the first quarter of 2015.

Proceeds from sales of assets in E&P and M&R during the period of 2012 through 2014 totaling $13.4 billion were used primarily to reinvest in the E&P business, repay debt, repurchase the Corporation’s common stock, and increase cash balances. In 2013, the Corporation’s board of directors authorized a plan to repurchase up to $4 billion of the Corporation’s outstanding common stock, and subsequently in 2014 increased the authorized repurchase plan to $6.5 billion. Through December 31, 2014, the Corporation has repurchased a total of approximately $5.26 billion of outstanding common stock.

Response to the Fourth Quarter 2014 Decline in Crude Oil Prices

Brent crude oil and West Texas Intermediate crude oil prices declined approximately 40 percent in the fourth quarter of 2014 to end the year at $57 per barrel and $53 per barrel, respectively. The Corporation has responded by reducing its planned 2015 capital and exploratory program to $4.7 billion, down 16 percent from $5.6 billion in 2014. As part of the 2015 capital program, the Corporation expects to spend $1.8 billion in the Bakken shale play compared with $2.2 billion in 2014, and reflects reducing the rig count from seventeen rigs in 2014 to an average of 9.5 rigs in 2015. The Corporation plans to actively pursue other cost savings, including cost reductions from service providers, and significantly moderate the pace of share repurchases in 2015 to preserve liquidity in the current oil price environment.

Consolidated Net Income

Net income was $2,317 million in 2014 compared with $5,052 million in 2013 and $2,025 million in 2012. Diluted earnings per share were $7.53 in 2014 compared with $14.82 in 2013 and $5.95 in 2012. Excluding items affecting comparability, net income was $1,308 million in 2014, $1,892 million in 2013, and $1,998 million in 2012. See the table of items affecting comparability of earnings between periods on page 26.

Exploration and Production

The Corporation's total proved reserves were 1,431 million barrels of oil equivalent (boe) at December 31, 2014 compared with 1,437 million boe at December 31, 2013 and 1,553 million boe at December 31, 2012. Proved reserves related to assets sold were 77 million boe in 2014, 140 million boe in 2013 and 83 million boe in 2012.

E&P earnings were $2,098 million in 2014, $4,303 million in 2013 and $2,212 million in 2012. Excluding items affecting comparability of earnings between periods on page 31, E&P net income was $1,556 million, $2,192 million and $2,256 million for 2014, 2013 and 2012, respectively. Average realized crude oil selling prices including the impact of hedging were $92.17 per barrel in 2014, $98.48 in 2013 and $86.94 in 2012. Average realized natural gas selling prices were $6.04 per mcf in 2014, $6.64 in 2013 and $6.16 in 2012. Production averaged 329,000 barrels of oil equivalent per day (boepd) in 2014, 336,000 boepd in 2013 and 406,000 boepd in 2012.

Excluding production from assets sold and Libya, pro forma production was 318,000 boepd in 2014, 269,000 boepd in 2013 and 268,000 boepd in 2012. The Corporation currently expects total worldwide production to average between 350,000 boepd and 360,000 boepd in 2015, excluding any contribution from Libya.

The following is an update of significant E&P activities during 2014:

- In North Dakota, net production from the Bakken oil shale play averaged 83,000 boepd, an increase of 24% from 67,000 boepd in 2013, primarily due to ongoing field development and operations commencing at the expanded Tioga Gas Plant in late March 2014. During 2014, the Corporation operated an average of 17 rigs to drill 261 wells and complete 230 wells bringing the total operated production wells to 982 at December 31, 2014. Drilling and completion costs per operated well averaged $7.3 million in 2014, down from $8.1 million in 2013. In 2015, the Corporation plans to operate an average of 9.5 rigs to drill 170 wells and bring 210 wells on production while reducing capital expenditures to $1.8 billion from $2.2 billion in 2014. Bakken production is forecast to average between 95,000 boepd and 105,000 boepd in 2015.
- At the Valhall Field in Norway (Hess 64%), net production averaged 31,000 boepd during 2014 compared with 23,000 boepd in 2013. This increase reflected the impact of start-up operations following completion of a redevelopment project in 2013, ongoing drilling of production wells and higher facilities uptime.
- At Block A 18 of the Joint Development Area of Malaysia/Thailand (JDA), the operator, Carigali Hess Operating Company, continued drilling production wells and successfully installed a new wellhead platform in 2014. Production averaged 42,000 boepd in 2014 compared to 45,000 boepd in 2013, including contribution from unitized acreage in Malaysia. Further development drilling is planned for 2015 and the completion of a booster compression project is planned for early 2016.
- At the Hess operated Tubular Bells Field in the Gulf of Mexico, the Corporation achieved first production in November 2014 following completion of construction, installation and commissioning of offshore production facilities and subsea equipment. Three wells are currently producing with a fourth production well expected to be completed in 2015. Full year 2015 net production for Tubular Bells is expected to be in the range of 30,000 boepd to 35,000 boepd.
- In the North Malay Basin (NMB), net production from the Early Production System averaged 40 million cubic feet per day during 2014 compared with 30 million cubic feet per day in the fourth quarter of 2013. First production from the Field commenced in October 2013 with the first condensate offtake occurring in November 2014. Full field development is scheduled to be completed in 2017 when net production is expected to increase to approximately 165 million cubic feet per day.
- At the South Arne Field (Hess 62%) offshore Denmark, the Corporation continued drilling operations in 2014 following the December 2013 start-up of its phrase three development project which comprised the installation of two new wellhead platforms and modifications to existing production facilities. Development drilling is planned to continue into 2015.
- In the Utica shale, 38 wells were drilled, 36 wells were completed and 39 wells were brought into operation. Net production increased to approximately 13,000 boepd in the fourth quarter of 2014. The Corporation and its joint venture partner plan to operate two drilling rigs in 2015 to drill 20 – 25 wells and bring on production 25 – 30 wells.

- In Libya, civil and political unrest has largely interrupted production and crude oil export capability since August 2013. At the WAHA fields (Hess 8%), the operator recommenced production in the third quarter of 2014 at a reduced rate and the Corporation was able to sell four tank cargos of crude oil by year-end. The Corporation's net production from Libya averaged 4,000 boepd in 2014, 15,000 boepd in 2013 and 21,000 boepd in 2012. In December 2014 the Libyan National Oil Company declared force majeure with respect to the Waha fields and production is currently shut in.
- In Ghana, the Corporation completed its three well appraisal program on the Deepwater Tano Cape Three Points Block, offshore Ghana. In 2015 the Corporation and its partners will continue to analyze data from both appraisal drilling and 3D seismic with an expected project sanction decision in 2016.
- In the fourth quarter of 2014, the Corporation announced that together with its project co-owners it will proceed with the development of the Stampede project in the Gulf of Mexico. A two-rig drilling program is planned with

the first rig commencing operations in the fourth quarter of 2015 and the second in 2016. First production is expected in 2018.

- At the Equus project in the offshore Carnarvon Basin of Australia, the Corporation executed a non-binding letter of intent with a third-party liquefaction partner. Successful execution of a binding agreement with the third party liquefaction partner is necessary before the Corporation can execute a gas sales agreement and sanction development.
- In the second quarter, the Corporation completed its first exploration well on the Shakrok block in the Kurdistan Region of Iraq (Hess 64%). The well encountered sub-commercial amounts of hydrocarbons and was expensed. Drilling activities have been suspended on the Shireen exploration well in the Dinarta Block and the Corporation is currently assessing its completion options.

Liquidity, and Capital and Exploratory Expenditures

Net cash provided by operating activities was $4,464 million in 2014, $4,870 million in 2013 and $5,660 million in 2012. At December 31, 2014, cash and cash equivalents totaled $2,444 million, up from $1,814 million at December 31, 2013. Total debt was $5,987 million at December 31, 2014 and $5,798 million at December 31, 2013. The Corporation's debt to capitalization ratio at December 31, 2014 was 21.2% compared with 19.0% at December 31, 2013.

Capital and exploratory expenditures from continuing operations were as follows:

	2014	2013	2012
	(In millions)		
United States			
Bakken	$2,149	$2,231	$3,164
Other Onshore	731	766	735
Total Onshore	2,880	2,997	3,899
Offshore	765	865	870
Total United States	3,645	3,862	4,769
Europe	540	724	1,381
Africa	435	630	771
Asia and other	986	993	1,231
Total*	5,606	6,209	8,152
Exploration expenses charged to income included above:			
United States	$125	$192	$142
International	207	250	328
Total exploration expenses charged to	$332	$442	$470

income included above

*Excludes capital expenditures related to discontinued operations of $431 million, $106 million and $113 million in 2014, 2013 and 2012, respectively.

The Corporation anticipates investing approximately $4.7 billion in capital and exploratory expenditures in 2015 down from $5.6 billion in 2014. The decline reflects a planned reduction in the Corporation's work program in response to the lower commodity price environment.

Consolidated Results of Operations

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

	2014	2013	2012
	(In millions, except per share amounts)		
Exploration and Production	$2,098	$4,303	$2,212
Corporate, Interest and Other	(406)	(443)	(422)
Net income from continuing operations attributable to Hess Corporation	1,692	3,860	1,790
Net income from discontinued operations attributable to Hess Corporation	625	1,192	235
Net income attributable to Hess Corporation	$2,317	$5,052	$2,025
Net income attributable to Hess Corporation per share - Diluted	$7.53	$14.82	$5.95

The following table summarizes, on an after tax basis, items of income (expense) that are included in net income and affect comparability between periods. The items in the table below are explained on pages 31 through 34.

	2014	2013	2012
	(In millions)		
Exploration and Production	$542	$2,111	$(44)
Corporate, Interest and Other	(74)	(26)	—
Discontinued operations	541	1,075	71
Total items affecting comparability of earnings between periods	$1,009	$3,160	$27

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.

Comparison of Results

Exploration and Production

Following is a summarized income statement of the Corporation's E&P operations:

	2014	2013	2012
	(In millions)		
Revenues and Non-operating Income			
Sales and other operating revenues	$10,737	$11,905	$12,245
Gains on asset sales, net	817	2,171	584
Other, net	(46)	(57)	99
Total revenues and non-operating income	11,508	14,019	12,928
Costs and Expenses			
Cost of products sold (excluding items shown separately below)	1,826	1,853	1,334
Operating costs and expenses	1,927	2,116	2,202
Production and severance taxes	275	372	550
Exploration expenses, including dry holes and lease impairment	840	1,031	1,070
General and administrative expenses	336	377	314
Depreciation, depletion and amortization	3,210	2,671	2,853
Asset impairments	—	289	582
Total costs and expenses	8,414	8,709	8,905
Results of operations before income taxes	3,094	5,310	4,023
Provision for income taxes	996	831	1,793
Net income	2,098	4,479	2,230
Less: Net income attributable to noncontrolling interests	—	176	18
Net income attributable to Hess Corporation	$2,098	$4,303	$2,212

Excluding the E&P items affecting comparability of earnings between periods in the table on page 31, 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, exploration expenses and income taxes, as discussed below.

Selling Prices: Average crude oil realized selling prices were $92.17 per boe in 2014, or 6% lower compared to 2013 primarily due to declines in the benchmark prices for Brent and West Texas Intermediary (WTI) crude oil. Average crude oil selling prices were 13% higher in 2013 compared to 2012 due to a combination of hedging losses realized in 2012, the second quarter 2013 sale of the Corporation's subsidiary in Russia which realized significantly lower crude oil prices, and slightly higher average WTI benchmark prices in 2013.

The Corporation's average selling prices were as follows:

	2014	2013	2012
Crude oil - per barrel (including hedging)			
United States			
Onshore	$80.67	$90.00	$84.78
Offshore	95.05	103.83	101.80
Total United States	86.48	95.50	92.32
Europe	104.21	88.03	74.14
Africa	97.31	108.70	89.02
Asia	89.71	107.40	107.45
Worldwide	92.17	98.48	86.94
Crude oil - per barrel (excluding hedging)			
United States			
Onshore	$80.67	$89.81	$85.66
Offshore	92.22	103.15	104.39
Total United States	85.34	95.11	93.96
Europe	99.20	87.45	75.06
Africa	93.70	108.07	110.92
Asia	89.71	107.40	109.35
Worldwide	89.78	98.01	93.70
Natural gas liquids - per barrel			
United States			
Onshore	$28.92	$43.14	$44.22
Offshore	30.40	29.18	35.24
Total United States	29.32	38.07	40.75
Europe	52.66	58.31	78.43
Asia	—	74.94	77.92
Worldwide	30.59	40.68	47.81

Natural gas - per mcf			
United States			
Onshore	$3.18	$3.08	$2.02
Offshore	3.79	2.83	2.15
Total United States	3.47	2.96	2.09
Europe	10.00	11.06	9.50
Asia and other	6.94	7.50	6.90
Worldwide	6.04	6.64	6.16

Crude oil price hedging contracts increased E&P Sales and other operating revenues by $193 million ($121 million after income taxes) and $39 million ($25 million after income taxes) in 2014 and 2013, respectively, and reduced E&P Sales and other operating revenues by $688 million ($431 million after income taxes) in 2012.

Production Volumes: The Corporation's crude oil, natural gas liquids and natural gas production was 329,000 boepd in 2014, 336,000 boepd in 2013 and 406,000 boepd in 2012. Production volumes associated with assets sold were 8,000 boepd in 2014, 52,000 boepd in 2013, and 117,000 boepd in 2012. Crude oil and natural gas liquids comprised 74%, 72% and 75% of the Corporation's total production in 2014, 2013 and 2012, respectively. The Corporation currently expects total worldwide production to average between 350,000 boepd and 360,000 boepd in 2015, excluding any contribution from Libya.

The Corporation's net daily worldwide production was as follows:

	2014	2013	2012
	(In thousands)		
Crude oil - barrels per day			
United States			
Bakken	66	55	47
Other Onshore	10	10	13
Total Onshore	76	65	60
Offshore	51	43	48
Total United States	127	108	108
Europe	36	44	84
Africa	54	62	75
Asia	3	11	17
Total	220	225	284
Natural gas liquids - barrels per day			
United States			
Bakken	10	6	5
Other Onshore	7	4	5
Total Onshore	17	10	10
Offshore	6	5	6
Total United States	23	15	16
Europe	1	1	2
Asia	—	1	1
Total	24	17	19
Natural gas - mcf per day			
United States			
Bakken	40	38	27
Other Onshore	47	25	27
Total Onshore	87	63	54
Offshore	78	61	65
Total United States	165	124	119
Europe	36	23	43
Asia and other	312	418	454
Total	513	565	616
Barrels of oil equivalent - per day*	329	336	406

* Reflects natural gas production converted on the basis of relative energy content (six mcf equals one barrel). 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. In addition, natural gas liquids do not sell at prices equivalent to crude oil. See the average selling prices on page 28.

United States: Crude oil, natural gas liquids and natural gas production was higher in 2014 compared with 2013, a result of continued development of the Bakken oil shale play, higher production resulting from an active drilling program in the Utica Shale and a new production well combined with lower downtime at the Llano Field in the Gulf of Mexico. Crude oil, natural gas liquids and natural gas production was comparable in 2013 and 2012, as higher production from the Bakken oil shale play was partly offset by natural decline and maintenance in the other U.S. assets.

Europe: Crude oil production was lower in 2014 compared to 2013, primarily due to the April 2013 sale of the Corporation's Russian subsidiary, partially offset by higher production during 2014 at the Vahall Field in Norway following completion of the redevelopment project in 2013. Higher natural gas production in 2014 compared to 2013 was a result of higher uptime from the Valhall Field. Crude oil and natural gas production was lower in 2013 compared to 2012, primarily due to asset sales. The Bittern and Schiehallion fields in the UK North Sea, which were sold in the second half of 2012, were producing at an aggregate net rate of approximately 12,000 boepd at the time of sale. The Beryl fields, also in the UK North Sea, which were producing at an aggregate net rate of approximately 10,000 boepd at the time of sale, were sold in the first quarter of 2013, and the Corporation's Russian subsidiary, which was producing approximately 50,000 boepd at the time of sale, was sold in April 2013.

Africa: Crude oil production in Africa was lower in 2014 compared to 2013, and from 2013 to 2012, primarily due to the shutdown of the Es Sider terminal in Libya in the third quarter of 2013, following civil unrest in the country. In December 2014 the Libyan National Oil Company declared force majeure with respect to the Waha fields and production is currently shut-in. The decline from 2013 compared to 2012 was also due to lower production from the Okume Complex in offshore Equatorial Guinea, which was partially offset by new production from the Ceiba Field.

Asia and Other: Crude oil production was lower in 2014 compared to 2013, largely as a result of the divestiture of the Corporation's interests in the Pangkah Field in Indonesia in January 2014 and the Corporation's interest in the Azeri-Chirag-Guneshli (ACG) fields, Azerbaijan in March 2013. Natural gas production was lower in 2014 compared to 2013 following the Corporation's divestiture of its interests in Indonesia and Thailand in 2014 and lower production from the Joint Development Area of Malaysia/Thailand (JDA), which was partially offset by a full year of production from the North Malay Basin. Crude oil production was lower in 2013 compared to 2012 mainly due to the sale in March 2013 of the Corporation's interest in the ACG fields. Natural gas production was lower in 2013 compared to 2012, mainly due to lower production entitlement at the JDA together with lower production at the Pangkah Field in Indonesia.

Sales Volumes: The Corporation's worldwide sales volumes were as follows:

	2014	2013	2012
	(In thousands)		
Crude oil - barrels	80,869	82,402	101,770
Natural gas liquids - barrels	8,793	6,244	7,138
Natural gas - mcf	187,381	206,122	225,607
Barrels of oil equivalent*	120,892	123,000	146,510
Crude oil - barrels per day	222	226	278
Natural gas liquids - barrels per day	24	17	19
Natural gas - mcf per day	513	565	616
Barrels of oil equivalent per day*	331	337	400

* Reflects natural gas production converted on the basis of relative energy content (six mcf equals one barrel). 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. In addition, natural gas liquids do not sell at prices equivalent to crude oil. See the average selling prices on page 28.

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 the Corporation's partners in Hess operated wells or other third parties. Cost of products sold in 2014 was comparable to 2013 as a result of increased volumes purchased from partners in wells operated by the Corporation being offset by lower purchases from third parties. The increase in Cost of products sold in 2013 compared with 2012 principally reflected higher volumes of crude oil purchases from third parties.

Cash Operating Costs: Cash operating costs, consisting of Operating costs and expenses, Production and severance taxes and General and administrative expenses, decreased by approximately $330 million in 2014 compared with 2013 and decreased by approximately $200 million in 2013 compared with 2012. The decrease in 2014 compared to 2013 primarily reflects lower production taxes and operating costs following the divestitures of Indonesia and Thailand assets in early 2014 and the Corporation's interests in Russia in April 2013, as well as lower employee costs. The decrease in 2013 was due to lower production taxes following the sale of the Corporation's Russian operations, and reductions in transportation costs, lease operating expenses and employee costs, which were partially offset by severance charges and other exit costs incurred as part of the Corporation's transformation to a more focused E&P company.

Depreciation, Depletion and Amortization: Depreciation, depletion and amortization charges increased by approximately $540 million in 2014 and decreased by $182 million in 2013, compared with the corresponding amounts in prior years. The increase in 2014 was primarily associated with higher production volumes from the Bakken, Utica, Valhall, and North Malay Basin, each of which had a DD&A rate higher than the portfolio average in 2014. The decrease in 2013 largely reflects asset sales and the mix of production volumes.

Excluding items affecting comparability of earnings between periods in the table below, cash operating costs per barrel of oil equivalent (boe) were $21.03 in 2014, $22.63 in 2013 and $20.63 in 2012 and depreciation, depletion and amortization costs per boe were $26.68 in 2014, $21.61 in 2013 and $19.20 in 2012. Total production unit costs were $47.71 per boe in 2014, $44.24 per boe in 2013 and $39.83 per boe in 2012.

For 2015, cash operating costs are estimated to be in the range of $19.50 to $20.50 per boe and depreciation, depletion and amortization costs are estimated to be in the range of $28.50 to $29.50 per boe, resulting in total production unit costs of $48.00 to $50.00 per boe assuming no contribution from Libya.

Exploration Expenses: Exploration expenses, excluding items affecting comparability of earnings, were lower in 2014 compared to 2013, primarily due to lower leasehold impairment expense, geologic and seismic costs, and employee expenses. Exploration expenses decreased in 2013 compared to 2012, primarily due to lower dry hole expenses and geological and seismic expenses partly offset by higher leasehold impairment expenses.

Income Taxes: Excluding the impact of items affecting comparability of earnings between periods provided below, the effective income tax rates for E&P operations were 41% in 2014, 43% in 2013 and 45% in 2012. The decline in the effective income tax rate in 2014 compared with 2013 and in 2013 compared with 2012 was primarily due to the impact of shut in production in Libya from the third quarter of 2013. Based on current strip crude oil prices, we are forecasting a pre-tax loss for 2015 and, as a result, the E&P effective tax rate, excluding items affecting comparability, is expected to be a benefit in the range of 38% to 42% excluding Libyan operations.

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		
	2014	2013	2012	2014	2013	2012
	(In millions)					
Gains on asset sales, net	$801	$2,195	$584	$774	$2,145	$557
Noncontrolling interest share of gain on asset sale	—	(168)	—	—	(168)	—
Dry hole and related expenses	(169)	(260)	(86)	(105)	(163)	(56)
Leasehold impairment expenses	(135)	(327)	(582)	(68)	(210)	(344)
Employee severance and exit costs	(28)	(129)	—	(11)	(117)	—
Income taxes	—	—	—	(48)	624	(201)
	$469	$1,311	$(84)	$542	$2,111	$(44)

2014: In April 2014, the Corporation completed the sale of its Thailand assets for cash proceeds of approximately $805 million. This transaction resulted in a pre-tax gain of $706 million ($706 million after income taxes). The assets in Thailand were producing at an aggregate net rate of approximately 19,000 boepd at the time of sale and had a total of 45 million boe of proved reserves at December 31, 2013. During 2014, the Corporation sold approximately 77,000 net acres, including related wells and facilities, in the dry gas area of the Utica shale play, for total cash proceeds of approximately $1,075 million, which resulted in a pre-tax gain of $62 million ($35 million after income taxes). Production and proved reserves from the disposed Utica acreage were not material. In the third quarter, the Corporation completed the sale of an exploration asset in the United Kingdom North Sea, for cash proceeds of

$53 million, which resulted in a pre-tax gain of $33 million ($33 million after income taxes). In 2014, the Corporation 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 the Corporation's interest in a natural gas exploration project, offshore Sabah, Malaysia. In 2014, the Corporation recorded pre-tax severance and other exit costs of $28 million ($11 million after income taxes) resulting from its transformation to a more focused pure play E&P company. In addition, the Corporation recorded an income tax charge of $48 million for remeasurement of deferred taxes resulting from legal entity restructurings.

2013: In the fourth quarter, the Corporation announced the sale of its Indonesian assets for after tax proceeds of approximately $1.3 billion. The sale was executed in two separate transactions with the sale of Natuna A completing in December 2013 and the sale of Pangkah closing in January 2014, as a result of a partner exercising their preemptive rights. The sale of Natuna A, which had sales proceeds of approximately $656 million, resulted in a pre tax gain of $388 million ($343 million after income taxes). The Natuna Field was producing at an aggregate net rate of approximately 5,500 boepd at the time of sale and had a total of 21 million boe of proved reserves at December 31, 2012. In April, the Corporation completed the sale of its Russian subsidiary, Samara Nafta, for cash proceeds of $2.1 billion after working capital and other adjustments. Based on the Corporation's 90% interest in Samara Nafta, after tax proceeds to Hess were approximately $1.9 billion. This transaction resulted in a pre-tax gain of $1,119 million ($1,119 million after income taxes), which was reduced by $168 million for the noncontrolling interest holder's share of the gain, resulting in a net gain attributable to the

Corporation of $951 million. Samara Nafta was producing at an aggregate net rate of approximately 50,000 boepd at the time of sale and had a total of 82 million boe of proved reserves at December 31, 2012. In the first quarter of 2013, the Corporation completed the sale of its interests in the Beryl fields in the UK North Sea for cash proceeds of $442 million, resulting in a pre tax gain of $328 million ($323 million after income taxes) and the sale of its interests in the Azeri Chirag Guneshli (ACG) fields, offshore Azerbaijan in the Caspian Sea, for cash proceeds of $884 million, resulting in a pre tax gain of $360 million ($360 million after income taxes). These assets were producing at an aggregate net rate of approximately 16,000 boepd at the time of sale and had a total of 38 million boe of proved reserves at December 31, 2012. In December 2013, the Corporation recorded dry hole costs of $260 million ($163 million after income taxes) associated with Area 54, offshore Libya due to continued civil unrest in the country. In addition, during 2013, the Corporation recorded pre-tax impairment charges totaling $327 million ($210 million after income taxes). These impairment charges consisted of $289 million ($187 million after income taxes) related to Pangkah to adjust its carrying value to its fair value at December 31, 2013 and $38 million ($23 million after income taxes) to write off the Corporation's leasehold acreage in the Marcellus, onshore U.S. In 2013, the Corporation recorded net pre tax charges of $129 million ($117 million after income taxes) for severance, non cash charges associated with the cessation of use of certain leased office space and other exit costs, resulting from its planned divestitures and transformation into a more focused pure play E&P company. In December 2013, Denmark enacted a new hydrocarbon income tax law that resulted in a combination of changes to tax rates, revisions to the amount of uplift allowed on capital expenditures and special transition rules. As a consequence of the tax law change, the Corporation recorded a deferred tax asset of $674 million. In addition, during 2013, the Corporation recorded a non cash income tax charge of $28 million as a result of a planned asset divestiture and a charge of $22 million relating to the repatriation of foreign earnings.

2012: The Corporation completed the sale of its interests in the Schiehallion Field (Hess 16%) and the Bittern Field (Hess 28%), which are both located in the UK North Sea, as well as the Snohvit Field (Hess 3%), offshore Norway, for total cash proceeds of $843 million. These transactions resulted in pre tax gains totaling $584 million ($557 million after income taxes). These assets were producing at an aggregate net rate of approximately 15,000 boepd at the time of sale and had a total of 83 million boe of proved reserves at December 31, 2011. The Corporation recorded asset impairment charges totaling $582 million ($344 million after income taxes). These impairment charges consisted of $374 million ($228 million after income taxes) associated with the divestiture of assets in the Eagle Ford Shale in Texas and $208 million ($116 million after income taxes) related to non producing properties in the UK North Sea. In 2012, the Corporation decided to cease further development and appraisal activities in Peru. As a result, the Corporation recorded exploration expenses totaling $86 million ($56 million after income taxes) to write off its exploration assets in the country. In July 2012, the government of the UK changed the supplementary income tax rate applicable to deductions for dismantlement expenditures to 20% from 32%. As a result, the Corporation recorded a one time charge in the third quarter of 2012 of $115 million for deferred taxes related to asset retirement obligations in the UK. In the fourth quarter of 2012, the Corporation recorded an income tax charge of $86 million for a disputed application of an international tax treaty.

Corporate, Interest and Other

The following table summarizes corporate, interest and other expenses:

	2014	2013	2012
	(In millions)		
Corporate and Other expenses (excluding items affecting comparability)	$217	$263	$267
Interest expense	399	466	447
Less: Capitalized interest	(76)	(60)	(28)
Interest expense, net	323	406	419
Corporate, Interest and Other expenses before income taxes	540	669	686
Income taxes (benefits)	(208)	(252)	(264)
Net Corporate, Interest and Other expenses after income taxes	332	417	422
Items affecting comparability of earnings between periods, after-tax	74	26	—
Total Corporate, Interest and Other expenses after income taxes	$406	$443	$422

Corporate expenses were lower in 2014 compared to 2013, reflecting lower employee related costs, contract labor and professional fees. Corporate expenses were comparable in 2013 and 2012. After tax corporate expenses in 2015 are estimated to be in the range of $120 million to $130 million, compared with after-tax corporate expenses of $134 million, excluding items affecting comparability of earnings between periods in 2014.

Interest expense, net was lower in 2014 compared to 2013, reflecting lower average outstanding debt, lower letter of credit fees and higher capitalized interest. The decrease in 2013 interest expense, net compared with 2012 primarily reflects higher capitalized interest related to the Tubular Bells and North Malay Basin projects. After tax interest expense in 2015 is expected to be in the range of $205 million to $215 million, compared with after-tax interest expenses of $202 million in 2014.

Items Affecting Comparability of Earnings Between Periods: Reported Corporate, interest and other expenses included the following items affecting comparability of income (expense) before and after income taxes:

	Before Income Taxes			After Income Taxes		
	2014	2013	2012	2014	2013	2012
	(In millions)					
Write down of equity investment	$(84)	$—	$ —	$(52)	$—	$ —
Employee severance	(19)	(21)	—	(12)	(13)	—
Facility and other exit costs	(15)	(19)	—	(10)	(13)	—
	$(118)	$(40)	$ —	$(74)	$(26)	$ —

The Corporation recorded a charge of $84 million ($52 million after income taxes) to reduce the carrying value of its investment in the Bayonne Energy Center to fair value. The Corporation recorded net pre tax severance charges related to the Corporation's transformation into a pure play E&P company of $19 million ($12 million after income taxes) in 2014 and $21 million ($13 million after income taxes) in 2013. In addition, the Corporation recorded pre-tax charges of $15 million ($10 million after income taxes) in 2014 and pre tax charges of $19 million ($13 million after income taxes) in 2013 for exit related costs, including costs for cessation of leased office space in 2013.

Discontinued Operations

Discontinued operations attributable to Hess Corporation had income of $625 million in 2014, $1,192 million in 2013, and $235 million in 2012 which comprised the Corporation's retail, energy marketing, terminal, energy trading and refining operations. Excluding items affecting comparability of earnings between periods provided below, discontinued operations generated adjusted net income of $84 million in 2014, $117 million in 2013, and $164 million in 2012. Discontinued operations results reflect ownership of its energy trading partnership through December 2014, retail marketing through September 2014, terminals through December 2013, energy marketing through November 2013 and Port Reading refining activities through the date it was permanently shut down in February 2013.

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

	Before Income Taxes			After Income Taxes		
	2014	2013	2012	2014	2013	2012
	(In millions)					
Gains on asset sales	$982	$1,500	$—	$620	$995	$—
LIFO inventory liquidations	275	678	165	171	414	104
Gain recognized on acquisition of controlling interest in equity investee	39	—	—	24	—	—
Environmental, exit and other charges	(211)	(230)	—	(141)	(154)	—
Asset impairments	(50)	(80)	(43)	(31)	(51)	(33)
Charge for termination of lease contracts for retail gasoline stations	(115)	—	—	(72)	—	—
Employee severance	(41)	(131)	—	(26)	(80)	—
Port Reading refinery shutdown costs	(6)	(82)	—	(4)	(49)	—
	$873	$1,655	$122	$541	$1,075	$71

2014: In September, the Corporation completed the sale of its 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 the year, the Corporation 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, the Corporation 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. The Corporation 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, the Corporation's retail business acquired its 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, the Corporation recorded a pre-tax gain of $39 million ($24 million after income taxes) to remeasure the carrying value of the Corporation's original 44% equity interest in WilcoHess to fair value. The assets and liabilities acquired from WilcoHess were included in the sale of the retail business in September 2014.

2013: In December 2013, the Corporation sold its U.S. East Coast terminal network, St. Lucia terminal and related businesses for cash proceeds of approximately $1.0 billion. The transaction resulted in a pre-tax gain of $739 million ($531 million after income taxes). In November 2013, the Corporation sold its energy marketing business for cash proceeds of approximately $1.2 billion which resulted in a pre-tax gain of $761 million ($464 million after income taxes). In addition, the Corporation recognized pre-tax gains of $678 million ($414 million after income taxes) relating to the liquidation of LIFO inventories as a result of ceasing refining operations and the sales of its energy marketing and terminals businesses. During the year, the Corporation incurred $131 million ($80 million after income taxes) of net employee severance charges and $230 million ($154 million after income taxes) of other exit costs, including environmental, legal and professional fees. As a result of the permanent shutdown of the Port Reading refining facility, the Corporation recorded charges of $82 million ($49 million after income taxes) for shutdown related costs and $80 million ($51 million after income taxes) for asset impairments.

2012: In 2012, the Corporation recorded pre-tax income of $165 million ($104 million after income taxes) from the partial liquidation of LIFO inventories. The Corporation also recorded pre-tax charges of $43 million ($33 million after income taxes) for asset impairments and other charges.

Liquidity and Capital Resources

The following table sets forth certain relevant measures of the Corporation's liquidity and capital resources at December 31:

	2014	2013
	(In millions)	
Cash and cash equivalents	$2,444	$1,814
Short-term debt and current maturities of long-term debt	$68	$378
Total debt	$5,987	$5,798
Total equity	$22,320	$24,784
Debt to capitalization ratio*	21.2 %	19.0 %

*Total debt as a percentage of the sum of total debt plus equity.

Cash Flows

The following table sets forth a summary of the Corporation's cash flows:

	2014	2013	2012
	(In millions)		
Cash flows from operating activities			
Cash provided by operating activities - continuing operations	$4,511	$3,708	$5,521
Cash provided by (used in) operating activities - discontinued operations	(47)	1,162	139
Net cash provided by operating activities	4,464	4,870	5,660
Cash flows from investing activities			
Capital expenditures	(5,274)	(5,767)	(7,682)
Proceeds from asset sales	2,978	4,458	843
Other, net	(139)	(227)	(64)
Cash provided by (used in) investing activities - continuing operations	(2,435)	(1,536)	(6,903)
Cash provided by (used in) investing activities - discontinued operations	2,436	2,114	(148)
Net cash provided by (used in) investing activities	1	578	(7,051)
Cash flows from financing activities			
Cash provided by (used in) financing activities - continuing operations	(3,828)	(4,266)	1,685

Cash provided by (used in) financing activities - discontinued operations	(7)	(10)	(3)
Net cash provided by (used in) financing activities	(3,835)	(4,276)	1,682
Net increase in cash and cash equivalents	$630	$1,172	$291

Operating Activities: Net cash provided by operating activities amounted to $4,464 million in 2014 compared with $4,870 million in 2013, reflecting the impact of changes in working capital, lower operating earnings primarily as a result of asset sales and the decline in benchmark crude oil prices. Operating cash flow decreased to $4,870 million in 2013 from $5,660 million in 2012 principally reflecting decreases in cash flows from asset sales and changes in working capital.

Investing Activities: The following table summarizes the Corporation's capital expenditures:

	2014	2013	2012
	(In millions)		
Exploration and Production			
Exploration	$431	$602	$619
Production and development	4,702	5,051	6,790
Acquisitions (including leaseholds)	88	56	267
Total Exploration and Production	5,221	5,709	7,676
Corporate	53	58	6
Total capital expenditures - continuing operations	5,274	5,767	7,682
Downstream businesses - discontinued operations	431	106	113
Total capital expenditures	$5,705	$5,873	$7,795

The decrease in capital expenditures in 2014, as compared with 2013, is largely due to the ongoing reduction in capital expenditures in the Bakken, reflecting lower well costs and completion of the Tioga gas plant expansion project. The decrease in capital expenditures in 2013 as compared to 2012 was mainly due to reduced capital expenditures in the Bakken, resulting from fewer drilling rigs being operated in the field as well as lower costs per well. In addition, completion of the redevelopment project at the Valhall Field in January 2013 as well as asset sales reduced 2013 capital expenditures.

Total proceeds from the sale of assets related to continuing operations amounted to approximately $3.0 billion in 2014, $4.5 billion in 2013 and $0.8 billion in 2012. In 2014, the Corporation completed asset sales of its dry gas acreage in the Utica shale play, its assets in Thailand, the Pangkah Field, offshore Indonesia, and its interests in two power plant joint ventures. Completed sales in 2013 included the Corporation's interests in the Beryl, ACG, Eagle Ford and Natuna A fields, and its Russian subsidiary, Samara Nafta.

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, the Corporation acquired in January 2014, its partners' 56% interest in WilcoHess, a retail gasoline joint venture, for approximately $290 million. In June 2014, the Corporation incurred capital expenditures of $105 million related to the acquisition of previously leased retail gasoline stations. Both of these transactions were undertaken in connection with the Corporation's divestiture of its retail business. Net cash provided by investing activities related to discontinued operations for 2013 includes proceeds of approximately $2.2 billion from the sales of the Corporation's energy marketing operations and its U.S. East Coast terminal network, St. Lucia terminal and related businesses.

Financing Activities: During 2014, the Corporation issued $600 million ($598 million net of discount) of unsecured, fixed rate notes and repaid $590 million of debt, including $250 million of unsecured, fixed rate notes, $74 million assumed in the acquisition of WilcoHess, and $249 million for the payment of various lease obligations primarily related to the retirement of the Corporation’s retail gasoline station leases. In 2013, the Corporation repaid $2,348 million, net under available credit facilities and repaid $136 million of other debt. The net repayments under the credit facilities consisted of $990 million on the Corporation’s short term credit facilities, $758 million on its syndicated revolving credit facility and $600 million on its asset backed credit facility. During 2012, the Corporation borrowed a net of $1,845 million from available credit facilities, which consisted of borrowings of $758 million from its syndicated revolving credit facility, $890 million from its short term credit facilities and $250 million from its asset backed credit facility, partially offset by net repayments of other debt of $53 million.

The Corporation repurchased Hess common stock of approximately $3.7 billion in 2014 and approximately $1.5 billion in 2013 under its $6.5 billion board authorized stock repurchase plan. Total common stock dividends paid were $303 million in 2014, $235 million in 2013 and $171 million in 2012. The Corporation received net proceeds from the exercise of stock options, including related income tax benefits of $182 million, $128 million and $11 million in 2014, 2013 and 2012, respectively.

Future Capital Requirements and Resources

The Corporation anticipates investing approximately $4.7 billion in capital and exploratory expenditures in 2015 compared to $5.6 billion in 2014. Based on current strip crude oil prices, the Corporation forecasts in 2015 a significant net loss and net cash flow deficit after funding planned capital expenditures, dismantlement obligations, pension contributions, dividends and any share repurchases under its Board authorized plan. The Corporation expects to fund its 2015 net cash flow deficit with existing cash on hand of $2.4 billion at December 31, 2014 and, if necessary, borrowings under its long-term credit facility.

Crude oil and natural gas prices are volatile and difficult to predict. In addition, unplanned increases in the Corporation's capital expenditure program could occur. The Corporation plans to preserve its financial flexibility and to improve its cash flow by pursuing cost reductions from vendors, significantly moderating stock repurchases compared with 2014, and depending on where crude oil prices trend, potentially further reducing its planned capital program. In addition, should needs dictate, the Corporation may also access other sources of liquidity by utilizing other existing uncommitted credit facilities, issuing debt and equity securities, and/or pursuing further asset sales.

The Corporation held $1.1 billion of its year-end 2014 total cash and cash equivalents of $2.4 billion outside of the U.S. and has the ability to bring its December 31, 2014 international cash balance back to the U.S. without triggering a U.S. cash tax liability.

The table below summarizes the capacity, usage, and available capacity of the Corporation's borrowing and letter of credit facilities at December 31, 2014:

	Expiration Date	Capacity	Borrowings	Letters of Credit Issued	Total Used	Available Capacity
	(In millions)					
Revolving credit facility	January 2020	$ 4,000	$ —	$ —	$ —	$ 4,000
Committed lines	Various*	1,175	—	25	25	1,150
Uncommitted lines	Various*	372	—	372	372	—
Total		$ 5,547	$ —	$ 397	$ 397	$ 5,150

*Committed and uncommitted lines have expiration dates through 2020.

The Corporation's $397 million in letters of credit outstanding at December 31, 2014 were primarily issued to satisfy margin requirements. See also Note 21, Financial Risk Management and Trading Activities in the Notes to the Consolidated Financial Statements.

At December 31, 2014, the Corporation had a $4 billion syndicated revolving credit facility with a maturity date of April 2016. In January 2015, the Corporation entered into a new $4 billion five year credit agreement with a maturity date of January 2020. This facility can be used for borrowings and letters of credit. Borrowings on the new facility bear interest at 1.075% above the London Interbank Offered Rate. A fee of 0.175% per annum is also payable on the amount of the facility. The interest rate and facility fee are subject to adjustment if the Corporation's credit rating changes.

The Corporation's 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 the Corporation to borrow up to an additional $5.6 billion of secured debt at December 31, 2014.

The Corporation also has a shelf registration under which it may issue additional debt securities, warrants, common stock or preferred stock. Promptly after filing this Annual Report on Form 10-K, as a result of the Corporation's existing shelf registration statement expiring on February 27, 2015, the Corporation anticipates filing a new shelf registration statement under the Securities Act of 1933, as amended, under which it may issue, among other things, additional debt securities, warrants, common stock or preferred stock.

Credit Ratings

There are three major credit rating agencies that rate the Corporation's debt. All three agencies have currently assigned an investment grade rating with a stable outlook to the Corporation's debt. The interest rates and facility fees charged on some of the Corporation's credit facilities, as well as margin requirements from financial risk management counterparties, are subject to adjustment if the Corporation's credit rating changes.

Contractual Obligations and Contingencies

The following table shows aggregate information about certain contractual obligations at December 31, 2014:

	Payments Due by Period				
	Total	2015	2016 and 2017	2018 and 2019	Thereafter
	(In millions)				
Total debt (excludes interest)*	$5,987	$68	$444	$1,148	$ 4,327
Operating leases	2,818	773	1,049	651	345
Purchase obligations:					
Capital expenditures	3,500	2,246	1,019	194	41
Operating expenses	1,306	451	436	278	141
Asset retirement obligations	2,723	442	419	222	1,640
Transportation and related contracts	1,738	124	355	451	808
Other liabilities	1,177	138	115	116	808

* The Corporation anticipates cash payments for interest of $355 million for 2015, $722 million for 2016-2017, $680 million for 2018-2019, and $4,265 million thereafter for a total of $6,022 million.

Capital expenditures represent amounts that were contractually committed at December 31, 2014, including the portion of the Corporation’s planned capital expenditure program for 2015. Obligations for operating expenses include commitments for oil and gas production expenses, seismic purchases and other normal business expenses. Other long term liabilities reflect contractually committed obligations in the Consolidated Balance Sheet at December 31, 2014, including pension plan liabilities and estimates for uncertain income tax positions.

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

The Corporation is contingently liable under $54 million of letters of credit at December 31, 2014.

Off-Balance Sheet Arrangements

The Corporation had leveraged leases associated with certain retail gasoline stations which were not included in its Consolidated Balance Sheet and had a fair value of approximately $238 million at December 31, 2013. If these leases were included as debt, the Corporation’s December 31, 2013 debt to capitalization ratio would have increased to 19.6% from 19.0%. The leases were terminated in 2014 in conjunction with the anticipated divestiture of retail marketing that closed in September 2014.

See also Note 18, Guarantees and Contingencies in the Notes to the Consolidated Financial Statements.

Foreign Operations

The Corporation conducts exploration and production activities outside the U.S., principally in Europe (Norway and Denmark), Africa (Equatorial Guinea, Libya, Algeria and Ghana) and Asia and Other (Joint Development Area of Malaysia/Thailand, Malaysia, Australia, the Kurdistan region of Iraq, China, Guyana and Canada). Therefore, the Corporation is subject to the risks associated with foreign operations, including political risk, corruption, acts of terrorism, tax law changes and currency risk.

See also Item 1A. Risk Factors Related to Our Business and Operations.

Accounting Policies

Critical Accounting Policies and Estimates

Accounting policies and estimates affect the recognition of assets and liabilities in the Corporation's 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, the Corporation's 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. The Corporation maintains its own internal reserve estimates that are calculated by technical staff that work directly with the oil and gas properties. The Corporation's 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. The

Corporation also engages an independent third party consulting firm to audit approximately 80% of the Corporation's total proved reserves each year.

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 remained at significantly higher levels during the first ten months of 2014 and declined during the last two months of the year. As a result, the average crude oil price used to calculate proved reserves at December 31, 2014 is significantly higher than the year-end 2014 crude oil price. The year-end 2015 reserve estimates will be based on the same unweighted arithmetic average formula using first-day-of-the-month prices for 2015 and will reflect the current low crude oil price environment from the beginning of the year. If current strip crude oil prices hold through 2015, proved reserves at December 31, 2015 could be significantly lower than proved reserves at December 31, 2014. It is difficult to estimate the magnitude of any net negative change in proved reserves that may result from lower crude oil prices due to a number of factors that are currently unknown, including 2015 crude oil prices, any revisions in proved reserves that may occur based on 2015 reservoir performance, the levels to which industry costs will decline in response to lower prices, and management's plans as of December 31, 2015 for developing proved undeveloped reserves through the year 2020 which will be the five-year window for recognizing proved undeveloped reserves as of December 31, 2015. Despite the uncertainties cited, based on facts and assumptions existing at December 31, 2014 if Brent crude oil prices were to average $60 per barrel in 2015, the Corporation estimates that 2015 depreciation, depletion, and amortization expenses would increase by not more than $75 million, after-tax as a result of changes in proved reserves compared with December 31, 2014. See the Supplementary Oil and Gas Data on pages 87 through 95 in the accompanying financial statements for additional information on the Corporation's oil and gas reserves.

Impairment of Long-lived Assets: The Corporation reviews 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.

The Corporation's impairment tests of long lived E&P producing assets are based on its 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. The Corporation 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 significant decline in crude oil prices in the fourth quarter of 2014, the Corporation tested its oil and gas properties for impairment and determined no impairment existed at December 31, 2014.

Impairment of Goodwill: The Corporation's 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. Following a reorganization of its management structure in 2013, the Corporation concluded that within its E&P segment it has two reporting units, offshore and onshore, consistent with the manner in which performance is assessed by the Operating segment manager.

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, the Corporation performs 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.

The Corporation's 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. The Corporation also considers 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 the Corporation's 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, or one or more assets of the reporting unit having taxable temporary differences that result in recognition of goodwill for the reporting unit under purchase accounting requirements in a business combination.

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.

Crude oil prices declined significantly following the date of the Corporation's annual goodwill impairment test on October 1, 2014. In addition, the Corporation's stock price decreased to a level at December 31, 2014 that resulted in the Corporation's book value exceeding its market capitalization by 6%. As a result of these potential indicators of impairment, the Corporation performed a separate goodwill impairment test at December 31, 2014. The offshore and onshore reporting units, which have allocated goodwill of $1,098 million and $760 million, respectively at December 31, 2014, each passed step one of the impairment test. However, the onshore reporting unit's fair value exceeded its carrying value by 5%. While not required, the Corporation performed a hypothetical step two test for the onshore reporting unit and estimated that the implied fair value of goodwill exceeded its carrying value. Accordingly, the Corporation expects that the benefits of its goodwill totaling $1,858 million will be recovered through the operations of each of its reporting units based on market conditions at December 31, 2014.

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.

The Corporation has net operating loss carryforwards or credit carryforwards in multiple jurisdictions and has recorded deferred tax assets for those losses and credits. Additionally, the Corporation has 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 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. In evaluating the realizability of deferred tax assets, the Corporation considers the reversal of temporary differences, the expected utilization of net operating losses and credit carryforwards during available carryforward periods, the availability of tax planning strategies, the existence of appreciated assets and estimates of future taxable income and other factors. Estimates of future taxable income are based on assumptions of oil and gas reserves and selling prices that are consistent with the Corporation's internal business forecasts. The Corporation does 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: The Corporation has 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, the Corporation recognizes a liability for the fair value of required asset retirement obligations. In addition, the fair value of any legally required conditional asset retirement obligations is recorded if the liability can be reasonably estimated. The Corporation capitalizes such costs as a component of the carrying amount of the underlying assets in the period in which the liability is incurred. In order to measure these obligations, the Corporation estimates the fair value of the obligations by discounting the future payments that will be required to satisfy the obligations. In determining these estimates, the Corporation is 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, the Corporation's 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: The Corporation has funded non-contributory defined benefit pension plans, an unfunded supplemental pension plan and an unfunded post-retirement medical plan. The Corporation recognizes in the Consolidated Balance Sheet the net change in the funded status of the projected benefit obligation for these plans.

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 the Corporation, some of which can be affected by external factors. For example, the discount rate used to estimate the Corporation's 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 the Corporation's financial statements.

Derivatives: The Corporation utilizes derivative instruments for both financial risk management and trading activities. In financial risk management activities, the Corporation uses futures, forwards, options and swaps, individually or in combination to mitigate its exposure to fluctuations in the prices of crude oil and natural gas, as well as changes in interest and foreign currency exchange rates. In trading activities, the Corporation, principally through a consolidated partnership, trades energy related commodities and derivatives, including futures, forwards, options and swaps, based on expectations of future market conditions. The energy trading joint venture, HETCO, was sold in the first quarter of 2015.

All derivative instruments are recorded at fair value in the Corporation's Consolidated Balance Sheet. The Corporation's 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.

Derivatives that are designated as either cash flow or fair value hedges are tested for effectiveness prospectively before they are executed and both prospectively and retrospectively on an on-going basis to determine whether they continue to qualify for hedge accounting. The prospective and retrospective effectiveness calculations are performed using either historical simulation or other statistical models, which utilize historical observable market data consisting of futures curves and spot prices.

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

The Corporation also records 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.

The Corporation determines 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). 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. To value derivatives that are characterized as Level 2 and 3, the Corporation uses observable inputs for similar instruments that are available from exchanges, pricing services or broker quotes. These observable inputs may be supplemented with other methods, including internal extrapolation or interpolation, that result in the most representative prices for instruments with similar characteristics. 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.

Environment, Health and Safety

The Corporation's long term vision and values provide a foundation for how we do business and define our commitment to meeting the highest standards of corporate citizenship and creating a long lasting positive impact on the communities where we do business. The Corporation's strategy is reflected in its environment, health, safety and social responsibility (EHS & SR) policies and by a management system framework that helps protect the Corporation's workforce, customers and local communities. The Corporation's 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 the Corporation's 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. The Corporation has 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.

The Corporation recognizes that climate change is a global environmental concern. The Corporation assesses, monitors and takes measures to reduce our carbon footprint at existing and planned operations. The Corporation is committed to complying with all Greenhouse Gas (GHG) emissions mandates and the responsible management of GHG emissions at its facilities.

The Corporation 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 the Corporation retained liability and, although not currently significant, "Superfund" sites where the Corporation has been named a potentially responsible party.

The Corporation accrues for environmental assessment and remediation expenses when the future costs are probable and reasonably estimable. At year end 2014, the Corporation's reserve for estimated remediation liabilities was approximately $80 million. The Corporation expects that existing reserves for environmental liabilities will adequately cover costs to assess and remediate known sites. The Corporation's remediation spending was approximately $12 million in 2014, $16 million in 2013 and $19 million in 2012. 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 the Corporation’s capital expenditures and operating expenses.

Forward-looking Information

Certain sections of this Annual Report on Form 10 K, including Business and Properties, Management’s Discussion and Analysis of Financial Condition and Results of Operations and Quantitative and Qualitative Disclosures about Market Risk, include references to the Corporation’s future results of operations and financial position, liquidity and capital resources, capital expenditures, asset sales, oil and gas production, tax rates, debt repayment, hedging, derivative, market risk and environmental disclosures, off balance sheet arrangements and contractual obligations and contingencies, which include forward looking information. These sections typically include statements with words such as “anticipate”, “estimate”, “expect”, “forecast”, “guidance”, “could”, “may”, “should”, “would” or similar words, indicat future outcomes are uncertain. Forward looking disclosures are based on the Corporation’s current understanding and assessment of these activities and reasonable assumptions about the future. Actual results may differ from these disclosures because of changes in market conditions, government actions and other factors. For more information regarding the factors that may cause the Corporation’s results to differ from these statements, see Item 1A. Risk Factors Related to Our Business and Operations.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

As discussed in Note 21, Financial Risk Management and Trading Activities, in the Notes to the Consolidated Financial Statements, the Corporation is exposed in the normal course of its business 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. The Corporation is also exposed to commodity price risks primarily related to crude oil, natural gas, refined petroleum products and electricity, as well as foreign currency values, from its 50% voting interest in a consolidated energy trading joint venture, HETCO, which was sold in the first quarter of 2015.

In conjunction with the Corporation's sale of its energy marketing business in the fourth quarter of 2013, certain derivative contracts, including new transactions following the closing date, (the "delayed transfer derivative contracts") were not transferred to the acquirer, Direct Energy, a North American subsidiary of Centrica plc (Centrica), as required customer or regulatory consents had not been obtained. However, the agreement entered into between Hess and Direct Energy on the closing date transferred all economic risks and rewards of the energy marketing business, including the ownership of the delayed transfer derivative contracts, to Direct Energy. The transfer of these remaining contracts was completed during the third quarter of 2014.

Controls: The Corporation maintains a control environment under the direction of its chief risk officer and through its corporate risk policy, which the Corporation's senior management has approved. Controls include volumetric, term and value at risk limits. The chief risk officer must approve the trading of new instruments or commodities. Risk limits are monitored and are reported on a daily basis to business units and senior management. The Corporation's financial risk management department also performs independent price verifications (IPV's) of sources of fair values and validations of valuation models. These controls apply to all of the Corporation's financial risk management and trading activities, including the consolidated trading joint venture. The Corporation's treasury department is responsible for administering and monitoring foreign exchange rate and interest rate hedging programs using similar controls and processes, where applicable.

Value at Risk: The Corporation uses value at risk to monitor and control commodity risk within its financial risk management and trading activities. The value at risk model uses historical simulation and the results represent the potential loss in fair value over one day at a 95% confidence level. The model captures both first and second order sensitivities for options. Results may vary from time to time as strategies change in trading activities or hedging levels change in financial risk management activities.

Instruments: The Corporation primarily uses forward commodity contracts, foreign exchange forward contracts, futures, swaps, options and energy commodity based securities in its financial risk management and trading activities. These contracts are generally widely traded instruments with standardized terms. The following describes these instruments and how the Corporation uses them:

Forward Commodity Contracts: The Corporation enters into contracts for the forward purchase and sale of commodities. At settlement date, the notional value of the contract is exchanged for physical delivery of the commodity. Forward contracts that are deemed normal purchase and sale contracts are excluded from the quantitative market risk disclosures.

Forward Foreign Exchange Contracts: The Corporation enters into forward contracts, primarily for the British Pound and Danish Krone which commit the Corporation to buy or sell a fixed amount of these currencies at a predetermined exchange rate on a future date.

Exchange Traded Contracts: The Corporation uses 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.

Swaps: The Corporation uses financially settled swap contracts with third parties as part of its financial risk management and trading 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.

Options: Options on various underlying energy commodities include exchange traded and third party contracts and have various exercise periods. As a seller of options, the Corporation receives a premium at the outset and bears the risk of unfavorable changes in the price of the commodity underlying the option. As a purchaser of options, the Corporation pays a premium at the outset and has the right to participate in the favorable price movements in the underlying commodities.

Energy Securities: Energy securities include energy related equity or debt securities issued by a company or government or related derivatives on these securities.

Financial Risk Management Activities

Financial risk management activities include transactions designed to reduce risk in the selling prices of crude oil or natural gas produced by the Corporation or to reduce exposure to foreign currency or interest rate movements. Generally, futures, swaps or option strategies may be used to reduce risk in the selling price of a portion of the Corporation's crude oil or natural gas production. Forward contracts may also be used to purchase certain currencies in which the Corporation does business with the intent of reducing exposure to foreign currency fluctuations. Interest rate swaps may also be used, generally to convert fixed rate interest payments to floating.

The Corporation has outstanding foreign exchange contracts used to reduce its 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 $120 million at December 31, 2014.

The Corporation's outstanding long term debt of $5,987 million, including current maturities, had a fair value of $7,003 million at December 31, 2014. A 15% decrease in the rate of interest would increase the fair value of debt by approximately $485 million at December 31, 2014. A 15% increase in the rate of interest would decrease the fair value of debt by approximately $430 million at December 31, 2014.

Following is the value at risk for the Corporation's financial risk management commodity derivatives activities associated with continuing operations, excluding foreign exchange and interest rate derivatives described above:

	2014	2013
	(In millions)	
At December 31	$ —	$ 13
Average	8	27
High	15	44
Low	—	13

Trading Activities

Trading activities were conducted through the energy trading joint venture HETCO, which generated earnings through various strategies primarily using energy related commodities, securities and derivatives.

Following is the value at risk for the Corporation's trading activities:

	2014	2013
	(In millions)	
At December 31	$ 3	$ 4
Average	5	4
High	6	5
Low	3	3

The information that follows represents 100% of the trading joint venture. Derivative trading transactions are marked to market and unrealized gains or losses are recognized currently in earnings. Gains or losses from sales of physical products are recorded at the time of sale. Net realized gains on trading activities amounted to $551 million in 2014 and $191 million in 2013. The following table summarizes the related unrealized net gains and losses for financial instruments and derivative commodity contracts, and includes an assessment of the factors affecting the changes in fair value of net assets (liabilities):

	2014	2013
	(In millions)	
Fair value of contracts outstanding at January 1	$(161)	$(96)
Change in fair value of contracts outstanding at the beginning of the year and still outstanding at the end of the year	(79)	10
Reversal of fair value for contracts closed during the year	130	10
Fair value of contracts entered into during the year and still outstanding	(312)	(85)
Fair value of contracts outstanding at December 31	$(422)	$(161)

The following table summarizes the sources of net asset (liability) fair values of financial instruments and derivative commodity contracts by year of maturity used in the Corporation’s trading activities at December 31, 2014:

	Total	2015	2016	2017	2018 and Beyond
	(In millions)				
Sources of fair value					
Level 1	$400	$404	$ (6)	$ 2	$ —
Level 2	(875)	(915)	38	2	—
Level 3	53	52	(1)	—	2
Total	$(422)	$(459)	$ 31	$ 4	$ 2

The following table summarizes the fair values of receivables, net of cash margin and letters of credit, by counterparty credit rating at December 31 for the energy trading joint venture, HETCO, and which have been included under Other current assets in the consolidated balance sheet:

	2014	2013
	(In millions)	
Investment grade determined by outside sources	$169	$187
Investment grade determined internally*	125	58
Less than investment grade	299	47
Fair value of net receivables outstanding at December 31	$593	$292

*Based on information provided by counterparties and other available sources.

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, 2014.

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, 2014, as stated in their report, which is included herein.

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

February 26, 2015

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, 2014, 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, 2014, 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, 2014 and 2013, 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, 2014 of Hess Corporation and consolidated subsidiaries, and our report dated February 26, 2015 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

New York, New York

February 26, 2015

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders

Hess Corporation

We have audited the accompanying consolidated balance sheet of Hess Corporation and consolidated subsidiaries (the "Corporation") as of December 31, 2014 and 2013, 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, 2014. 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, 2014 and 2013, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2014, 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, 2014, 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 26, 2015 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

New York, New York

February 26, 2015

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES

CONSOLIDATED BALANCE SHEET

	December 31, 2014	2013
	(In millions, except share amounts)	
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$2,444	$1,814
Accounts receivable		
Trade	1,642	3,093
Other	431	432
Inventories	527	954
Other current assets	1,643	2,306
Total current assets	6,687	8,599
PROPERTY, PLANT AND EQUIPMENT		
Total — at cost	46,522	45,950
Less: Reserves for depreciation, depletion, amortization and lease impairment	19,005	17,179
Property, plant and equipment — net	27,517	28,771
GOODWILL	1,858	1,869
DEFERRED INCOME TAXES	2,169	2,319
OTHER ASSETS	347	1,196
TOTAL ASSETS	$38,578	$42,754
LIABILITIES AND EQUITY		
CURRENT LIABILITIES		
Accounts payable	$708	$2,109
Accrued liabilities	3,781	3,551
Taxes payable	294	520
Short-term debt and current maturities of long-term debt	68	378
Total current liabilities	4,851	6,558
LONG-TERM DEBT	5,919	5,420
DEFERRED INCOME TAXES	2,009	2,292
ASSET RETIREMENT OBLIGATIONS	2,281	2,249
OTHER LIABILITIES AND DEFERRED CREDITS	1,198	1,451
Total liabilities	16,258	17,970
EQUITY		
Hess Corporation stockholders’ equity		
Common stock, par value $1.00		
Authorized — 600,000,000 shares		
Issued: 2014 — 285,834,964 shares; 2013 — 325,314,177 shares	286	325
Capital in excess of par value	3,277	3,498
Retained earnings	20,052	21,235
Accumulated other comprehensive income (loss)	(1,410)	(338)
Total Hess Corporation stockholders’ equity	22,205	24,720

Noncontrolling interests	115	64
Total equity	22,320	24,784
TOTAL LIABILITIES AND EQUITY	$38,578	$42,754

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,		
	2014	2013	2012
	(In millions, except per share amounts)		
REVENUES AND NON-OPERATING INCOME			
Sales (excluding excise taxes) and other operating revenues	$10,737	$11,905	$12,245
Gains on asset sales, net	823	2,174	584
Other, net	(121)	(51)	106
Total revenues and non-operating income	11,439	14,028	12,935
COSTS AND EXPENSES			
Cost of products sold (excluding items shown separately below)	1,826	1,853	1,333
Operating costs and expenses	1,927	2,116	2,202
Production and severance taxes	275	372	550
Exploration expenses, including dry holes and lease impairment	840	1,031	1,070
General and administrative expenses	588	673	576
Interest expense	323	406	419
Depreciation, depletion and amortization	3,224	2,687	2,866
Asset impairments	—	289	582
Total costs and expenses	9,003	9,427	9,598
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	2,436	4,601	3,337
Provision for income taxes	744	565	1,529
INCOME FROM CONTINUING OPERATIONS	1,692	4,036	1,808
INCOME FROM DISCONTINUED OPERATIONS, NET OF INCOME TAXES	682	1,186	255
NET INCOME	2,374	5,222	2,063
Less: Net income attributable to noncontrolling interests	57	170	38
NET INCOME ATTRIBUTABLE TO HESS CORPORATION	$2,317	$5,052	$2,025
NET INCOME ATTRIBUTABLE TO HESS CORPORATION PER SHARE			
BASIC:			
Continuing operations	$5.57	$11.47	$5.29
Discontinued operations	2.06	3.54	0.69
NET INCOME PER SHARE	$7.63	$15.01	$5.98
DILUTED:			
Continuing operations	$5.50	$11.33	$5.26
Discontinued operations	2.03	3.49	0.69
NET INCOME PER SHARE	$7.53	$14.82	$5.95
WEIGHTED AVERAGE NUMBER OF COMMON SHARES OUTSTANDING (DILUTED)	307.7	340.9	340.3

See accompanying Notes to Consolidated Financial Statements.

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HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES

STATEMENT OF CONSOLIDATED COMPREHENSIVE INCOME

	Years Ended December 31,		
	2014	2013	2012
	(In millions)		
NET INCOME	$2,374	$5,222	$2,063
OTHER COMPREHENSIVE INCOME (LOSS):			
Derivatives designated as cash flow hedges			
Effect of hedge (gains) losses reclassified to income	(137)	(33)	676
Income taxes on effect of hedge (gains) losses reclassified to income	51	18	(252)
Net effect of hedge (gains) losses reclassified to income	(86)	(15)	424
Change in fair value of cash flow hedges	128	68	(156)
Income taxes on change in fair value of cash flow hedges	(48)	(25)	60
Net change in fair value of cash flow hedges	80	43	(96)
Change in derivatives designated as cash flow hedges, after-tax	(6)	28	328
Pension and other postretirement plans			
Reduction (increase) of unrecognized actuarial losses	(534)	414	(100)
Income taxes on actuarial changes in plan liabilities	186	(157)	39
Reduction (increase) in unrecognized actuarial losses, net	(348)	257	(61)
Amortization of net actuarial losses	56	63	85
Income taxes on amortization of net actuarial losses	(18)	(23)	(32)
Net effect of amortization of net actuarial losses	38	40	53
Change in pension and other postretirement plans, after-tax	(310)	297	(8)
Foreign currency translation adjustment			
Foreign currency translation adjustment	(756)	(283)	256
Reclassified to Gains on asset sales, net	—	119	—
Change in foreign currency translation adjustment	(756)	(164)	256
TOTAL OTHER COMPREHENSIVE INCOME (LOSS)	(1,072)	161	576
COMPREHENSIVE INCOME	1,302	5,383	2,639
Less: Comprehensive income (loss) attributable to noncontrolling interests	57	176	40
COMPREHENSIVE INCOME ATTRIBUTABLE TO HESS CORPORATION	$1,245	$5,207	$2,599

See accompanying Notes to the Consolidated Financial Statements.

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES

STATEMENT OF CONSOLIDATED CASH FLOWS

	Years Ended December 31,		
	2014	2013	2012
	(In millions)		
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$2,374	$5,222	$2,063
Adjustments to reconcile net income to net cash provided by operating activities			
(Gains) losses on asset sales	(823)	(2,174)	(584)
Depreciation, depletion and amortization	3,224	2,687	2,866
Loss from equity affiliates	84	—	—
Asset impairments	—	289	582
Exploratory dry hole costs	301	344	377
Exploration lease impairment	207	245	223
Stock compensation expense	87	60	83
Provision (benefit) for deferred income taxes	270	(427)	(584)
Income from discontinued operations	(682)	(1,186)	(255)
Changes in operating assets and liabilities:			
(Increase) decrease in accounts receivable	(199)	(239)	125
(Increase) decrease in inventories	62	134	(124)
Increase (decrease) in accounts payable and accrued liabilities	86	(603)	884
Increase (decrease) in taxes payable	(108)	(435)	28
Changes in other assets and liabilities	(372)	(209)	(163)
Cash provided by operating activities - continuing operations	4,511	3,708	5,521
Cash provided by (used in) operating activities - discontinued operations	(47)	1,162	139
Net cash provided by operating activities	4,464	4,870	5,660
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures	(5,274)	(5,767)	(7,682)
Proceeds from asset sales	2,978	4,458	843
Other, net	(139)	(227)	(64)
Cash provided by (used in) investing activities - continuing operations	(2,435)	(1,536)	(6,903)
Cash provided by (used in) investing activities - discontinued operations	2,436	2,114	(148)
Net cash provided by (used in) investing activities	1	578	(7,051)
CASH FLOWS FROM FINANCING ACTIVITIES			
Net borrowings (repayments) of debt with maturities of 90 days or less	—	(1,748)	1,648
Debt with maturities of greater than 90 days			
Borrowings	598	535	630
Repayments	(590)	(1,271)	(433)
Common stock acquired and retired	(3,715)	(1,493)	—
Cash dividends paid	(303)	(235)	(171)
Noncontrolling interests, net	—	(182)	—
Employee stock options exercised, including income tax benefits	182	128	11
Cash provided by (used in) financing activities - continuing operations	(3,828)	(4,266)	1,685

Cash provided by (used in) financing activities - discontinued operations	(7)	(10)	(3)
Net cash provided by (used in) financing activities	(3,835)	(4,276)	1,682
NET INCREASE IN CASH AND CASH EQUIVALENTS	630	1,172	291
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR	1,814	642	351
CASH AND CASH EQUIVALENTS AT END OF YEAR	$2,444	$1,814	$642

See accompanying Notes to Consolidated Financial Statements.

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES

STATEMENT OF CONSOLIDATED EQUITY

	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, 2012	$340	$ 3,417	$15,826	$ (1,067)	$ 18,516	$ 76	$18,592
Net income			2,025		2,025	38	2,063
Other comprehensive income (loss)				574	574	2	576
Comprehensive income (loss)					2,599	40	2,639
Activity related to restricted common stock awards, net	2	55	—	—	57	—	57
Employee stock options, including income tax benefits	—	44	—	—	44	—	44
Performance share units	—	8	—	—	8	—	8
Cash dividends declared	—	—	(136)	—	(136)	—	(136)
Noncontrolling interests, net	—	—	2	—	2	(3)	(1)
Balance at December 31, 2012	342	3,524	17,717	(493)	21,090	113	21,203
Net income			5,052		5,052	170	5,222
Other comprehensive income (loss)				155	155	6	161
Comprehensive income (loss)					5,207	176	5,383
Activity related to restricted common stock awards, net	1	32	—	—	33	—	33
Employee stock options, including income tax benefits	2	137	—	—	139	—	139
Performance share units	—	10	—	—	10	—	10
Common stock acquired and retired	(20)	(205)	(1,313)	—	(1,538)	—	(1,538)
Cash dividends declared	—	—	(235)	—	(235)	—	(235)
Noncontrolling interests, net	—	—	14	—	14	(225)	(211)
Balance at December 31, 2013	325	3,498	21,235	(338)	24,720	64	24,784
Net income			2,317		2,317	57	2,374
Other comprehensive income (loss)				(1,072)	(1,072)	—	(1,072)
Comprehensive income (loss)					1,245	57	1,302
Activity related to restricted common stock awards, net	1	60	—	—	61	—	61
Employee stock options, including income tax benefits	3	182	—	—	185	—	185
Performance share units	—	19	—	—	19	—	19
	(43)	(482)	(3,197)	—	(3,722)	—	(3,722)

Common stock acquired and retired							
Cash dividends declared	—	—	(303)	—	(303)	—	(303)
Noncontrolling interests, net	—	—	—	—	—	(6)	(6)
Balance at December 31, 2014	$286	$3,277	$20,052	$(1,410)	$22,205	$115	$22,320

See accompanying Notes to Consolidated Financial Statements.

1. Summary of Significant Accounting Policies

Nature of Business: Hess Corporation (the Registrant) with its subsidiaries (collectively referred to as the Corporation or Hess) is a global Exploration and Production (E&P) company that develops, produces, purchases, transports and sells crude oil, natural gas liquids and natural gas with production operations primarily in the United States (U.S.), Denmark, Equatorial Guinea, the Joint Development Area of Malaysia/Thailand (JDA), Malaysia, and Norway.

In the first quarter of 2013, the Corporation announced several initiatives to continue its transformation into a focused pure play E&P company. As part of its transformation, the Corporation sold mature or lower margin E&P assets in Azerbaijan, Indonesia, Norway, Russia, Thailand, the United Kingdom (UK) North Sea, and certain interests onshore in the U.S. over the period of 2012 through 2014. In addition, the transformation plan included fully exiting the Corporation's Marketing and Refining (M&R) businesses including its terminal, retail, energy marketing, and energy trading operations, as well as the permanent shutdown of refining operations at its Port Reading facility. HOVENSA L.L.C. (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 United States (U.S.) Virgin Islands refinery in January 2012 and continued operating solely as an oil storage terminal. All downstream businesses were sold or shutdown as of December 31, 2014, except for the energy trading joint venture, Hess Energy Trading Corporation (HETCO), which was sold in February 2015, and Hovensa. See Note 2, Discontinued Operations, Note 3, Dispositions, and Note 22, Subsequent Events for additional disclosures related to the divestitures and Note 18, Guarantees and Contingencies for additional information related to HOVENSA in the Notes to the Consolidated Financial Statements.

Principles of Consolidation and Basis of Presentation: The consolidated financial statements include the accounts of Hess Corporation and entities in which the Corporation owns more than a 50% voting interest or entities that the Corporation controls. The Corporation consolidates the energy trading joint venture in which it owns a 50% voting interest and over which it exercises control. The Corporation's undivided interests in unincorporated oil and gas exploration and production ventures are proportionately consolidated. Investments in affiliated companies, 20% to 50% owned and where the Corporation has the ability to influence the operating or financial decisions of the affiliate, are accounted for using the equity method.

The prior years' financial information has been recast to reflect consolidated results of operations, cash flows and other information of the Corporation's divested consolidated downstream businesses, the Port Reading refining facility, and HETCO as discontinued operations. See also Note 2, Discontinued Operations in the Notes to the Consolidated Financial Statements. Certain other information in the financial statements and notes has been reclassified to conform to the current period presentation.

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 Corporation recognizes revenues from the sale of crude oil, natural gas liquids, and natural gas, when title passes to the customer. The Corporation recognizes revenues from the production of natural gas properties based on sales to customers. Differences between E&P natural gas volumes sold and the Corporation's entitlement share of natural gas production are not material. Sales of refined petroleum products and other merchandise from divested downstream operations were also recognized when title passed to customers.

In its E&P activities, the Corporation engages 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.

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: The Corporation records 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 equipment 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: The Corporation reviews 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 significant decline in crude oil prices in the fourth quarter of 2014, the Corporation tested its oil and gas properties for impairment and determined no impairment existed at December 31, 2014.

Impairment of Goodwill: The Corporation's 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. Following a reorganization of its management structure in 2013, the Corporation concluded that within its E&P segment it has two reporting units, offshore and onshore. 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, the Corporation performs 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. The Corporation performed a separate goodwill impairment test at December 31, 2014, and determined no impairment existed.

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. At December 31, 2013, refined petroleum product inventories associated with the now divested downstream businesses were valued at cost, using principally the last in, first out (LIFO) inventory method.

Income Taxes: Deferred income taxes are determined using the liability method. The Corporation has net operating loss carryforwards or credit carryforwards in multiple jurisdictions and has recorded deferred tax assets for those losses and credits. Additionally, the Corporation has 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 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. In evaluating the realizability of deferred tax assets, the Corporation considers the reversal of temporary differences, the expected utilization of net operating losses and credit carryforwards during available carryforward periods, the availability of tax planning strategies, the existence of appreciated assets and estimates of future taxable income and other factors. In addition, the Corporation recognizes 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. The Corporation does not provide for deferred U.S. income taxes for that portion of undistributed earnings of foreign subsidiaries that are indefinitely reinvested in foreign operations. The Corporation classifies interest and penalties associated with uncertain tax positions as income tax expense.

Asset Retirement Obligations: The Corporation has material legal obligations to remove and dismantle long lived assets and to restore land or seabed at certain exploration and production locations. The Corporation recognizes a liability for the fair value of legally required asset retirement obligations associated with long lived assets in the period in which the retirement obligations are incurred. In addition, the fair value of any legally required conditional asset retirement obligations is recorded if the liability can be reasonably estimated. The Corporation capitalizes the associated asset retirement costs as part of the carrying amount of the long lived assets.

Retirement Plans: The Corporation recognizes 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. The Corporation recognizes the net changes in the funded status of these plans in the year in which such changes occur. Prior service costs and 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.

Derivatives: The Corporation utilizes derivative instruments for both financial risk management and trading activities. In risk management activities, the Corporation may use futures, forwards, options and swaps, individually or in combination, to mitigate its exposure to fluctuations in prices of crude oil, natural gas, as well as changes in interest and foreign currency exchange rates. The Corporation, through a consolidated joint venture which is classified as held-for-sale at December 31, 2014, trades energy related commodities and derivatives including futures, forwards, options and swaps based on expectations of future market conditions.

All derivative instruments are recorded at fair value in the Corporation’s Consolidated Balance Sheet. The Corporation’s 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: The Corporation uses various valuation approaches in determining fair value for financial instruments, including the market and income approaches. The Corporation’s fair value measurements also include non-performance risk and time value of money considerations. Counterparty credit is considered for receivable balances, and the Corporation’s credit is considered for accrued liabilities. The Corporation also records 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. The Corporation determines 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). 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. To value derivatives that are characterized as Level 2 and 3, the Corporation uses observable inputs for similar instruments that are available from exchanges, pricing services or broker quotes. These observable inputs may be supplemented with other methods, including internal extrapolation or interpolation, that result in the most representative prices for instruments with similar characteristics. 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.

Share-based Compensation: 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. The Corporation estimates 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 translating 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: The Corporation accrues and expenses 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 2014, the Corporation’s reserve for estimated remediation liabilities was approximately $80 million and was included within accrued liabilities. 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 April 2014, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2014-08, Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity. The ASU amends the criteria for reporting discontinued operations to include only disposals representing a strategic shift in operations. The ASU also requires expanded disclosures regarding the assets, liabilities, income, and expenses of discontinued operations. This ASU is effective for the Corporation in the first quarter of 2015 and early adoption is permitted. The Corporation did not elect early adoption of this ASU and does not expect adoption to have a significant impact on its consolidated financial statements.

In May 2014, the 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 the Corporation beginning in the first quarter of 2017 and early adoption is not permitted. The Corporation is currently assessing the impact of the ASU on its consolidated financial statements.

2. Discontinued Operations

The results of operations for the Corporation's divested retail, energy marketing and terminal operations, the Port Reading refining facility which ceased operations in 2013, and the energy trading joint venture, HETCO, which was classified as held for sale at December 31, 2014, have been reported as discontinued operations in the Statement of Consolidated Income for all periods presented. These businesses were previously included in the M&R segment.

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

	2014	2013	2012
	(In millions)		
Sales and other operating revenues	$9,576	$22,652	$25,517
Income from discontinued operations before income taxes	$1,071	$1,835	$400
Current tax provision (benefit)*	—	—	7
Deferred tax provision (benefit)	389	649	138
Provision for income taxes	389	649	145
Income (loss) from discontinued operations, net of income taxes	$682	$1,186	$255
Less: Net income (loss) attributable to noncontrolling interests	57	(6)	20
Income from discontinued operations attributable to Hess Corporation	$625	$1,192	$235

* Substantially all current tax expense relates to foreign taxes on energy trading operations.

2014: In September, the Corporation completed the sale of its 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, the Corporation 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, the Corporation 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. The Corporation 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, the Corporation's retail business acquired its 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, the Corporation recorded a pre-tax gain of $39 million ($24 million after income taxes) to remeasure the carrying value of the Corporation's original 44% equity interest in WilcoHess to fair value, including recognition of goodwill in the amount of $115 million. Effective from the acquisition date, the Corporation consolidated the results of WilcoHess' operations, which have been included in the results of discontinued operations reported above. The assets and liabilities acquired from WilcoHess were included in the sale of the retail business in September 2014.

2013: In December, the Corporation sold its U.S. East Coast terminal network, St. Lucia terminal and related businesses for cash proceeds of approximately $1.0 billion. The transaction resulted in a pre-tax gain of $739 million ($531 million after income taxes). In November, the Corporation sold its energy marketing business for cash proceeds of approximately $1.2 billion, which resulted in a pre-tax gain of $761 million ($464 million after income taxes). During the year the Corporation recognized pre-tax gains of $678 million ($414 million after income taxes) relating to the liquidation of LIFO inventories. In addition, the Corporation recorded pre-tax charges totaling $523 million ($334 million after income taxes) for impairments, severance, Port Reading refinery shutdown costs, environmental matters, and exit related activities associated with the divestiture of downstream operations.

2012: In 2012, the Corporation recorded pre-tax income of $165 million ($104 million after income taxes) from the partial liquidation of LIFO inventories. The Corporation also recorded pre-tax charges totaling $43 million ($33 million after income taxes) for asset impairments to certain marketing properties and other charges.

3. Dispositions

2014: In January, the Corporation completed the sale of its interest in the Pangkah asset, offshore Indonesia for cash proceeds of approximately $650 million. This transaction resulted in a pre-tax gain of $31 million ($10 million loss after income taxes) after deducting the net book value of assets, including allocated goodwill of $56 million. In April, the Corporation completed the sale of its interests in Thailand for cash proceeds of approximately $805 million. This transaction resulted in a pre-tax gain of $706 million ($706 million after income taxes) after deducting the net book value of assets, including allocated goodwill of $76 million. In the first six months of 2014, the Corporation completed, through multiple transactions, the sale of approximately 77,000 net acres in the dry gas area of the Utica shale play including related wells and facilities, for total cash proceeds of approximately $1,075 million and recorded a pre-tax gain of $62 million ($35 million gain after income taxes) after deducting the net book value of assets, including allocated goodwill of $11 million. In June, the Corporation completed the sale of its 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, the Corporation sold its joint venture interest in the Bayonne Energy Center (BEC) for $79 million. In the first quarter of 2014, the Corporation recorded a charge of $84 million ($52 million after income taxes) to reduce to fair value its investment in BEC. In September, the Corporation completed the sale of its 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).

2013: In January, the Corporation completed the sale of its interests in the Beryl fields and the Scottish Area Gas Evacuation System (SAGE) in the UK North Sea for cash proceeds of $442 million. The transaction resulted in a pre tax gain of $328 million ($323 million after income taxes), after deducting the net book value of assets including allocated goodwill of $48 million. In March, the Corporation sold its interests in the Azeri Chirag Guneshli (ACG) fields (Hess 3%), offshore Azerbaijan in the Caspian Sea, and the associated Baku Tbilisi Ceyhan (BTC) oil transportation pipeline company (Hess 2%) for cash proceeds of $884 million. The transaction resulted in a pre tax gain of $360 million ($360 million after income taxes), after deducting the net book value of assets including allocated goodwill of $52 million. In April, the Corporation completed the sale of its Russian subsidiary, Samara-Nafta, for cash proceeds of $2.1 billion after working capital and other adjustments, including allocated goodwill of $148 million. Based on the Corporation's 90% interest in Samara-Nafta, after-tax proceeds to Hess were approximately $1.9 billion. This transaction resulted in a pre-tax gain of $1,119 million ($1,119 million after income taxes), which was reduced by $168 million for the noncontrolling interest holder's share of the gain, resulting in a net gain attributable to the Corporation of $951 million. In December, the Corporation completed the sale of its interest in the Natuna A Field, offshore Indonesia for total cash proceeds of approximately $656 million. The transaction resulted in a pre tax gain of $388 million ($343 million after income taxes), after deducting the net book value of assets including allocated goodwill of $39 million.

2012: In January, the Corporation completed the sale of its interest in the Snohvit Field (Hess 3%), a liquefied natural gas project, offshore Norway, for cash proceeds of $132 million. The transaction resulted in a pre-tax gain of $36 million ($36 million after income taxes), after deducting the net book value of assets including allocated goodwill of $14 million. In September, the Corporation completed the sale of its interests in the Schiehallion Field (Hess 16%) in the UK North Sea, its share of the associated floating production, storage and offloading vessel, and the West of Shetland pipeline system for cash proceeds of $524 million. The transaction resulted in a pre tax gain of $376 million ($349 million after income taxes), after deducting the net book value of assets including allocated goodwill of $27 million. In October, the Corporation completed the sale of its interests in the Bittern Field (Hess 28%) in the UK North Sea and the associated Triton floating production, storage and offloading vessel for cash proceeds of $187 million. The transaction resulted in a pre-tax gain of $172 million ($172 million after income taxes) after deducting the net book value of assets including allocated goodwill of $12 million.

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4. Exit and Disposal Costs

The following table provides the components of and changes in the Corporation’s restructuring accruals:

	Exploration and Production	Corporate, Interest and Other	Discontinued Operations	Total
	(In millions)			
Employee Severance				
Balance at January 1, 2014	$32	$ 26	$ 113	$171
Provision	19	16	41	76
Payments	(35)	(26)	(109)	(170)
Balance at December 31, 2014	16	16	45	77
Facility and Other Exit Costs				
Balance at January 1, 2014	53	17	48	118
Provision	(15)	10	70	65
Payments, settlements and other	(38)	(12)	(108)	(158)
Balance at December 31, 2014	—	15	10	25
Total restructuring accruals at December 31, 2014	$16	$ 31	$ 55	$102

The following table provides the financial statement classification of costs and expenses associated with the Corporation’s restructuring program:

	2014	2013
	(In millions)	
Employee Severance		
Operating costs and expenses	$ 5	$ 22
Exploration expenses, including dry holes and lease impairment	3	19
General and administrative expenses	27	63
Income from discontinued operations	41	148
Total employee severance	$ 76	$ 252
Facility and Other Exit Costs		
Other, net	$ —	$8
Operating costs and expenses	—	1
General and administrative expenses	(2)	54
Depreciation, depletion and amortization	(3)	16
Income from discontinued operations	70	141
Total facility and other exit costs	$ 65	$ 220

The employee severance charges primarily resulted from the Corporation’s divestiture program announced in March 2013. The severance charges were based on probable 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.

The facility and other exit costs relate to charges associated with the cessation of use of certain leased office space, contract terminations and professional fees associated with the divestitures as well as costs associated with the shutdown of Port Reading refining operations.

For the accrued employee severance at December 31, 2014 totaling $77 million, the Corporation expects to pay approximately 95% in 2015 and the remainder in 2016. For the accrued facility and other exit costs totaling $25 million, the Corporation expects to pay approximately 45% in 2015 and the remainder in 2016 and beyond.

5. Inventories

Inventories at December 31 were as follows:

	2014	2013
	(In millions)	
Crude oil	$246	$291
Natural gas and refined petroleum products	—	618
Less: LIFO adjustment	—	(339)
	246	570
Materials , supplies and merchandise	281	384
Total inventories	$527	$954

Inventories related to the downstream businesses, consisting primarily of refined petroleum products and merchandise, were $355 million at December 31, 2013. The percentage of LIFO inventories to total crude oil, refined petroleum products and natural gas inventories was 43% at December 31, 2013. See also Note 2, Discontinued Operations.

6. Property, Plant and Equipment

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

	2014	2013
	(In millions)	
Exploration and Production		
Unproved properties	$1,468	$2,460
Proved properties	4,211	4,121
Wells, equipment and related facilities	40,649	37,274
	46,328	43,855
Corporate, Interest and Other	194	2,095
Total — at cost	46,522	45,950
Less: Reserves for depreciation, depletion, amortization and lease impairment	19,005	17,179
Property, plant and equipment — net*	$27,517	$28,771

* At December 31, 2013, Corporate, Interest and Other included $1,021 million of property, plant and equipment, net related to the divested Retail Marketing operations.

Assets Held for Sale: At December 31, 2014, assets totaling $1,035 million, which consisted of accounts receivable and other long-lived assets, related to the Corporation's interest in HETCO, are reported in Other current assets in the Consolidated Balance Sheet. In addition, liabilities totaling $797 million, which consisted primarily of accounts payable, were reported in Accrued Liabilities. See Note 22, Subsequent Events.

At December 31, 2013, E&P assets totaling $1,097 million, primarily consisting of the net property, plant and equipment balances as well as allocated goodwill of $76 million, for the Corporation's assets in Thailand and the Pangkah Field, offshore Indonesia (Hess 75%) were classified as held for sale and are reported within Other current assets in the Consolidated Balance Sheet. In addition, liabilities related to these properties totaling $286 million, primarily consisting of asset retirement obligations and deferred income taxes, are reported within Accrued liabilities. In 2014, the Corporation completed the sale of its interests in Thailand and Pangkah.

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:

	2014	2013	2012
	(In millions)		
Beginning balance at January 1	$2,045	$2,259	$2,022
Additions to capitalized exploratory well costs pending the determination of proved reserves	292	237	407
Reclassifications to wells, facilities and equipment based on the determination of proved reserves	(629)	(106)	(41)
Capitalized exploratory well costs charged to expense	(235)	(267)	(129)
Dispositions and other	(57)	(78)	—
Ending balance at December 31	$1,416	$2,045	$2,259
Number of wells at end of year	37	50	68

In 2014, reclassifications to wells, facilities and equipment based on the determination of proved reserves primarily related to the Stampede project in the Gulf of Mexico, which the co-owners sanctioned for development. Capitalized exploratory well costs charged to expense in 2014 included $169 million to write-off a previously capitalized exploration well in Green Canyon Block 469 in the

Gulf of Mexico. In 2013, reclassifications to wells, facilities and equipment based on the determination of proved reserves primarily related to the Shenzi project in the Gulf of Mexico. Capitalized exploratory well costs charged to expense in 2013 included $260 million to write-off two previously capitalized exploration wells in Area 54, offshore Libya, due to civil unrest in the country. The preceding table excludes exploratory dry hole costs of $66 million, $77 million and $248 million in 2014, 2013 and 2012, respectively, which were incurred and subsequently expensed in the same year.

At December 31, 2014, exploratory drilling costs capitalized in excess of one year past the indicated year of completion of drilling were as follows (in millions):

2013	$74
2012	373
2011	338
2010	211
2009 and prior	236
	$1,232

Capitalized exploratory well costs greater than one year old after completion of drilling were $1,232 million at December 31, 2014. Approximately 68% of the capitalized well costs in excess of one year relates to Block WA-390-P, offshore Western Australia, where development planning and commercial activities for the Corporation's natural gas discoveries are ongoing. In December 2014, the Corporation executed a non-binding letter of intent with the North West Shelf (NWS), a third party joint venture with existing natural gas processing and liquefaction facilities. Successful execution of binding agreements with NWS is necessary before the Corporation can execute a gas sales agreement and sanction development of the project. Approximately 30% relates to offshore Ghana where the Corporation has drilled seven successful exploration wells. Appraisal plans for the seven wells on the block were submitted to the Ghanaian government in June 2013 for approval. Four of the plans were approved and discussions continue with the government on the three remaining appraisal plans. In the third quarter of 2014, the Corporation completed a three well appraisal program in Ghana. Well results are being evaluated and development planning is progressing. The remaining 2% of the capitalized well costs in excess of one year relates to projects where further drilling is planned or development planning and other assessment activities are ongoing to determine the economic and operating viability of the projects.

7. Goodwill

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

	2014	2013
	(In millions)	
Beginning balance at January 1	$1,869	$2,208
Acquisitions	115	—
Dispositions*	(126)	(339)
Ending balance at December 31	$1,858	$1,869

* In 2013, the dispositions include $21 million allocated to other assets sold and $76 million that was classified as held for sale and reported within Other current assets.

The increase in goodwill in 2014 resulted from the Corporation's acquisition of WilcoHess, which was subsequently disposed of as part of the sale of the Corporation's retail marketing operations. See Note 2, Discontinued Operations, in the Notes to the Consolidated Financial Statements.

8. Asset Impairments

In 2013, the Corporation announced the sale of its E&P assets in Indonesia for approximately $1.3 billion. The sale was executed in two separate transactions, with Natuna A completing in December 2013 and Pangkah in January 2014, as a result of a partner exercising their preemptive rights. Based on the sales proceeds for each transaction, results of operations for 2013 included a pre tax gain on sale related to Natuna A of $388 million ($343 million after income taxes), and a pre tax asset impairment charge of $289 million ($187 million after income taxes) to adjust the carrying value of the Pangkah assets to their fair value at December 31, 2013.

During 2012, the Corporation recorded E&P asset impairment charges totaling $582 million ($344 million after income taxes). These impairment charges consisted of $374 million ($228 million after income taxes) associated with the divestiture of assets in the Eagle Ford Shale in Texas and $208 million ($116 million after income taxes) related to non producing properties in the UK North Sea.

9. Asset Retirement Obligations

The following table describes changes to the Corporation's asset retirement obligations:

	2014	2013
	(In millions)	
Asset retirement obligations at January 1	$2,772	$2,661
Liabilities incurred	63	42
Liabilities settled or disposed of	(420)	(576)
Accretion expense	136	129
Revisions of estimated liabilities	263	573
Foreign currency translation	(91)	(57)
Asset retirement obligations at December 31	2,723	2,772
Less: Current obligations	442	523
Long-term obligations at December 31	$2,281	$2,249

The revisions in 2014 and 2013 primarily reflect changes in the expected scope of operations and updates to service and equipment costs. The 2013 revision also reflects increases in the time expected to complete dismantlement activities.

10. Debt and Interest Expense

Long term debt at December 31 consisted of the following:

	2014	2013
	(In millions)	
Fixed-rate public notes:		
7.0% due 2014	$ —	$250
1.3% due 2017	300	—
8.1% due 2019	999	998
3.5% due 2024	298	—
7.9% due 2029	696	695
7.3% due 2031	747	747
7.1% due 2033	598	598
6.0% due 2040	745	745
5.6% due 2041	1,242	1,242
Total fixed-rate public notes	5,625	5,275
Financing obligations associated with floating production system	331	296
Other fixed-rate notes, weighted average rate 12.9%	—	135
Project lease financing, weighted average rate 5.1%	—	60
Fair value adjustments - interest rate hedging	31	30
Other debt	—	2
Total debt	5,987	5,798
Less: Short-term debt and current maturities of long-term debt	68	378
Total long-term debt	$ 5,919	$ 5,420

At December 31, 2014, the Corporation had a $4 billion syndicated revolving credit facility that is unused and has a maturity date of April 2016. This facility can be used for borrowings and letters of credit. Borrowings on the facility bear interest at 1.25% above the London Interbank Offered Rate. A fee of 0.25% per annum is also payable on the amount of the facility. The interest rate and facility fee are subject to adjustment if the Corporation's credit rating changes. In January 2015, the Corporation entered into a new five-year credit agreement that replaces the previous agreement. See Note 22, Subsequent Events.

In June 2014, the Corporation issued $600 million of unsecured, fixed-rate notes ($598 million net of discount) comprising $300 million with a coupon of 1.3% and scheduled to mature in June 2017 as well as $300 million with a coupon of 3.5% and scheduled to mature in July 2024. In 2014, the Corporation repaid $590 million of debt, including $250 million of unsecured, fixed-rate notes, $249 million for the payment of various lease obligations primarily to retire retail gasoline station leases and $74 million assumed in the acquisition of WilcoHess.

During 2013, the Corporation repaid a net amount of $2,348 million under available credit facilities, which consisted of $758 million from its syndicated revolving credit facility, $990 million from the Corporation's short-term credit facilities and $600 million from its asset-backed credit facility. The Corporation recorded capital lease obligations totaling $98 million in conjunction with its commitment to acquire 50 existing Hess retail gasoline stations that were previously held under operating leases. The Corporation repaid $136 million of other debt in 2013.

The Corporation recorded a non-cash net increase in debt of $68 million in 2014 and $116 million in 2013 related to progress on construction of a floating production system for the Tubular Bells Field, which commenced production in the fourth quarter of 2014.

At December 31, 2014, the Corporation's fixed rate public notes have a principal amount of $5,650 million ($5,625 million net of unamortized discount). Interest rates on the outstanding fixed rate public notes have a weighted average rate of 6.4%.

The aggregate long term debt maturing during the next five years is as follows (in millions): 2015—$68; 2016—$71; 2017—$373; 2018—$78 and 2019—$1,070.

The Corporation's 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 the Corporation to borrow up to an additional $5.6 billion of secured debt at December 31, 2014.

Outstanding letters of credit at December 31 were as follows:

	2014	2013
	(In millions)	
Committed lines*	$25	$274
Uncommitted lines*	372	136
Total	$397	$410

*Committed and uncommitted lines have expiration dates through 2016.

Of the $397 million of letters of credit outstanding at December 31, 2014, $54 million relates to contingent liabilities and the remaining $343 million relates to liabilities recorded in the Consolidated Balance Sheet.

The total amount of interest paid (net of amounts capitalized) was $326 million, $408 million and $419 million in 2014, 2013 and 2012, respectively. The Corporation capitalized interest of $76 million, $60 million and $28 million in 2014, 2013 and 2012, respectively.

11. Share-based Compensation

The Corporation granted restricted common shares, performance share units (PSUs) and stock options to employees under its 2008 Long term Incentive Plan (LTIP), as amended. Outstanding restricted stock and PSUs generally vest three years from 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:

	Before Income Taxes			After Income Taxes		
	2014	2013	2012	2014	2013	2012
	(In millions)					
Restricted stock	$62	$ 31	$ 57	$39	$ 19	$ 35

Stock options	2	13	34	1	8	21
Performance share units	19	10	8	12	6	5
Total*	$ 83	$ 54	$ 99	$ 52	$ 33	$ 61

* Includes pre tax share based compensation expense included in Income from continuing operations of approximately $87 million, $60 million and $83 million for 2014, 2013 and 2012, respectively.

The Corporation reversed share based compensation expenses totaling $33 million ($25 million for restricted stock, $7 million for PSUs and $1 million for stock options) in 2013 for grants that were not expected to vest as a result of the Corporation's transformation to a pure play E&P company.

Based on share based compensation awards outstanding at December 31, 2014, unearned compensation expense, before income taxes, will be recognized in future years as follows (in millions): 2015—$66, 2016—$39 and 2017—$7.

The Corporation’s share based compensation activity consisted of the following:

	Performance Share Units		Stock Options		Restricted Stock Shares	
	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)		(In thousands)		(In thousands)	
Outstanding at January 1, 2014	635	$ 89.45	10,141	$ 63.08	2,865	$ 69.36
Granted	298	90.32	163	80.35	1081	81.20
Exercised	—	—	(3,327)	54.99	—	—
Vested	—	—	—	—	(510)	82.42
Forfeited	(133)	88.60	(211)	85.07	(535)	68.74
Outstanding at December 31, 2014	800	$ 89.91	6,766	$ 66.79	2,901	$ 71.58

The table below summarizes information regarding the outstanding and exercisable stock options as of December 31, 2014:

	Outstanding Options			Exercisable Options	
Range of Exercise Prices	Options	Weighted-Average Remaining Contractual Life	Weighted-Average Exercise Price per Share	Options	Weighted-Average Exercise Price per Share
	(In thousands)	(Years)		(In thousands)	
$20.00 – $40.00	65	1	$ 29.96	65	$ 29.96
$40.01 – $50.00	684	2	49.42	681	49.44
$50.01 – $60.00	1,927	4	55.08	1,921	55.08
$60.01 – $80.00	1,302	4	60.68	1,302	60.68
$80.01 – $120.00	2,788	5	82.85	2,625	83.00
	6,766	4	$ 66.79	6,594	$ 66.47

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

	2014	2013
Risk free interest rate	0.65 %	0.36 %
Stock price volatility	.359	.359

Contractual term in years	3.0	3.0
Grant date price of Hess common stock	$80.35	$69.49

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.

Restricted common shares are valued based on the prevailing market price of the Corporation's common stock on the date of grant.

In May 2008, shareholders approved the 2008 LTIP, which was amended in May 2010 and May 2012 to increase the number of new shares of common stock available for awards. At December 31, 2014, the Corporation had 8.5 million shares that remain available for issuance under the 2008 LTIP, as amended, out of the total of 29.0 million shares of common stock authorized for issuance under the 2008 LTIP, as amended.

12. Foreign Currency

Foreign currency gains (losses) before income taxes recorded in Other, net in the Statement of Consolidated Income amounted to a loss of $43 million in 2014, a loss of $54 million in 2013 and a gain of $36 million in 2012, all of which related to the Corporation's continuing operations. The after tax foreign currency translation adjustments included in Accumulated other comprehensive income (loss) totaled $(757) million at December 31, 2014 and $(1) million at December 31, 2013. The change in 2014 related to the Corporation's Norwegian operations and reflects translation impacts of the strengthening U.S. dollar versus the Norwegian Krone.

13. Retirement Plans

The Corporation has funded noncontributory defined benefit pension plans for a significant portion of its employees. In addition, the Corporation has an unfunded supplemental pension plan covering certain employees, which provides incremental payments that would have been payable from the Corporation's 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, the Corporation maintains 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 Corporation's benefit obligations and the fair value of plan assets and shows the funded status of the pension and postretirement medical plans:

	Funded Pension Plans		Unfunded Pension Plan		Postretirement Medical Plan	
	2014	2013	2014	2013	2014	2013
	(In millions)					
Change in benefit obligation						
Balance at January 1	$1,957	$2,110	$253	$234	$97	$134
Service cost	45	61	12	12	4	4
Interest cost	91	82	9	7	3	3
Actuarial (gain) loss (a)	470	(139)	61	28	(4)	(4)
Benefit payments (b)	(77)	(69)	(57)	(20)	(6)	(5)
Plan curtailments (c)	(3)	(103)	—	(8)	—	(35)
Special termination benefits	2	5	—	—	—	—
Foreign currency exchange rate changes	(35)	10	—	—	—	—
Balance at December 31	2,450	1,957	278	253	94	97
Change in fair value of plan assets						
Balance at January 1	2,145	1,763	—	—	—	—
Actual return on plan assets	151	292	—	—	—	—
Employer contributions	68	146	56	20	6	5
Benefit payments (b)	(77)	(69)	(56)	(20)	(6)	(5)
Foreign currency exchange rate changes	(36)	13	—	—	—	—
Balance at December 31	2,251	2,145	—	—	—	—
Funded status (plan assets greater (less) than benefit obligations) at December 31	(199)	188	(278)	(253)	(94)	(97)
Unrecognized net actuarial (gains) losses	859	405	135	108	(5)	(2)

(a) The change in discount rate and mortality assumptions in 2014 resulted in total actuarial losses of approximately $330 million and $125 million, respectively.

(b) Benefit payments include lump-sum settlement payments of $55 million in 2014.

(c) During the first quarter of 2013, the Corporation's pension and other postretirement plans were impacted by a significant reduction in the expected future service from active participants due to the Corporation's announced asset sales program.

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

	Funded Pension Plans		Unfunded Pension Plan		Postretirement Medical Plan	
	2014	2013	2014	2013	2014	2013
	(In millions)					
Pension asset / (accrued benefit liability)	$(199)	$188	$(278)	$(253)	$(94)	$(97)
Accumulated other comprehensive loss, pre-tax*	859	405	135	108	(5)	(2)

*

The after tax deficit reflected in Accumulated other comprehensive income (loss) for these retirement plans was $652 million at December 31, 2014 and $342 million at December 31, 2013.

The accumulated benefit obligation for the funded defined benefit pension plans was $2,325 million at December 31, 2014 and $1,873 million at December 31, 2013. The accumulated benefit obligation for the unfunded defined benefit pension plan was $214 million at December 31, 2014 and $222 million at December 31, 2013.

Components of net periodic benefit cost for funded and unfunded pension plans and the postretirement medical plan consisted of the following:

	Pension Plans			Postretirement Medical Plan		
	2014	2013	2012	2014	2013	2012
	(In millions)					
Service cost	$57	$73	$74	$ 4	$ 4	$ 7
Interest cost	100	89	88	3	3	5
Expected return on plan assets	(161)	(141)	(116)	—	—	—
Amortization of unrecognized net actuarial losses	31	61	83	—	1	2
Settlement loss	24	—	9	—	—	—
Curtailment loss	—	1	—	—	—	—
Special termination benefit recognized	1	5	—	—	—	—
Net periodic benefit cost	$52	$88	$138	$ 7	$ 8	$ 14

The Corporation's 2015 pension and postretirement medical expense is estimated to be approximately $80 million, which includes approximately $75 million related to the amortization of unrecognized net actuarial losses.

The weighted average actuarial assumptions used by the Corporation's funded and unfunded pension plans were as follows:

	2014	2013	2012
Weighted average assumptions used to determine benefit obligations at December 31			
Discount rate	3.8 %	4.6 %	3.8 %
Rate of compensation increase	5.0	4.4	4.3
Weighted average assumptions used to determine net periodic benefit cost for the years ended December 31			
Discount rate	4.6	4.0	4.3
Expected return on plan assets	7.5	7.5	7.5
Rate of compensation increase	4.4	4.3	4.3

The actuarial assumptions used by the Corporation's postretirement medical plan were as follows:

	2014	2013	2012
Assumptions used to determine benefit obligations at December 31			
Discount rate	3.1 %	3.6 %	3.1 %
Initial health care trend rate	6.8 %	7.1 %	7.3 %
Ultimate trend rate	4.5 %	4.6 %	4.8 %
Year in which ultimate trend rate is reached	2029	2027	2022

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.

The Corporation's 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 the Corporation's 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, 2014 and 2013 in accordance with the fair value measurement hierarchy described in Note 1, Summary of Significant Accounting Policies in the Notes to the Consolidated Financial Statements:

	Level 1	Level 2	Level 3	Total
	(In millions)			
December 31, 2014				
Cash and short-term investment funds	$6	$ 47	$ —	$53
Equities:				
U.S. equities (domestic)	719	—	—	719
International equities (non-U.S.)	72	177	—	249
Global equities (domestic and non-U.S.)	10	218	—	228
Fixed income:				
Treasury and government issued (a)	—	222		222
Government related (b)	—	7	1	8
Mortgage-backed securities (c)	—	147	1	148
Corporate	3	137		140
Other:				
Hedge funds	—	—	302	302
Private equity funds	—	—	105	105
Real estate funds	12	—	48	60
Diversified commodities funds	—	17	—	17
	$822	$ 972	$ 457	$2,251
December 31, 2013				
Cash and short-term investment funds	$3	$ 72	$ —	$75
Equities:				
U.S. equities (domestic)	729	—	—	729
International equities (non-U.S.)	81	171	—	252
Global equities (domestic and non-U.S.)	8	208	—	216
Fixed income:				
Treasury and government issued (a)	—	169	1	170
Government related (b)	—	9	—	9
Mortgage-backed securities (c)	—	109	1	110
Corporate	2	124	1	127
Other:				
Hedge funds	—	—	291	291
Private equity funds	—	—	89	89
Real estate funds	10	—	47	57
Diversified commodities funds	—	20	—	20
	$833	$ 882	$ 430	$2,145

(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, 2013	$2	$ 255	$ 75	$ 45	$377
Actual return on plan assets	—	26	11	2	39
Purchases, sales or other settlements	1	10	3	—	14
Net transfers in (out) of Level 3	—	—	—	—	—
Balance at December 31, 2013	3	291	89	47	430
Actual return on plan assets	—	9	15	—	24
Purchases, sales or other settlements	(1)	2	1	1	3
Net transfers in (out) of Level 3	—	—	—	—	—
Balance at December 31, 2014	$2	$ 302	$ 105	$ 48	$457

* Fixed Income includes treasury and government issued, government related, mortgage backed and corporate securities.

The Corporation has budgeted contributions of approximately $55 million to its funded pension plans in 2015.

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):

2015	$157
2016	112
2017	118
2018	121
2019	129
Years 2020 to 2024	694

The Corporation also contributes to several defined contribution plans for eligible employees. Employees may contribute a portion of their compensation to the plans and the Corporation matches a portion of the employee contributions. The Corporation recorded expense of $32 million in 2014, $41 million in 2013 and $40 million in 2012 for contributions to these plans.

14. Income Taxes

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

	2014	2013	2012
	(In millions)		
United States			
Federal			
Current	$(1)	$8	$30
Deferred	156	103	(435)
State	57	9	31
	212	120	(374)
Foreign			
Current	453	941	2,012
Deferred	79	186	(224)
	532	1,127	1,788
Total	744	1,247	1,414
Adjustment of deferred taxes for foreign income tax law changes*	—	(682)	115
Total provision for income taxes	$744	$565	$1,529

*The reported amount for 2013 reflects $674 million for the effect of the Denmark hydrocarbon income tax law change to the Chapter 3A regime from the Chapter 3 regime in December 2013 and $8 million for the effect of a change in Norway's hydrocarbon and base corporate income tax rates in December 2013. In 2012, the reported amount reflects the effect of the UK supplementary income tax rate change in July 2012.

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

	2014	2013	2012
	(In millions)		
United States (a)	$676	$580	$(608)
Foreign	1,760	4,021	3,945
Total income from continuing operations before income taxes	$2,436	$4,601	$3,337

(a) Includes substantially all of the Corporation's 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:

	2014	2013
	(In millions)	
Deferred tax liabilities		
Property, plant and equipment and investments	$(5,361)	$(5,581)
Other	(269)	(155)
Total deferred tax liabilities	(5,630)	(5,736)
Deferred tax assets		
Net operating loss carryforwards	3,010	2,726
Tax credit carryforwards	193	161
Property, plant and equipment and investments	2,245	2,643
Accrued compensation, deferred credits and other liabilities	449	982
Asset retirement obligations	1,421	1,516
Other	261	216
Total deferred tax assets	7,579	8,244
Valuation allowances	(1,416)	(1,519)

Total deferred tax assets, net of valuation allowances	6,163	6,725
Net deferred tax assets	$533	$989

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At December 31, 2014, the Corporation has recognized a gross deferred tax asset related to net operating loss carryforwards of $3,010 million before application of valuation allowances. The deferred tax asset is comprised of $2,131 million attributable to foreign net operating losses which begin to expire in 2029, $712 million attributable to U.S. federal operating losses which begin to expire in 2020 and $167 million attributable to losses in various U.S. states which begin to expire in 2015. The deferred tax asset attributable to foreign net operating losses, net of valuation allowances, is $1,504 million, substantially all of which relates to loss carryforwards in Denmark, Norway and Malaysia. At December 31, 2014, the Corporation has federal, state and foreign alternative minimum tax credit carryforwards of $109 million which can be carried forward indefinitely, and approximately $1 million of other business credit carryforwards. Foreign tax credit carryforwards, which begin to expire in 2016, total $83 million.

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

	2014	2013
	(In millions)	
Other current assets	$373	$963
Deferred income taxes (long-term asset)	2,169	2,319
Accrued liabilities	—	(1)
Deferred income taxes (long-term liability)	(2,009)	(2,292)
Net deferred tax assets	$533	$989

A net deferred tax asset of $5 million relating to the energy trading joint venture, HETCO, is included in current assets associated with assets held for sale in the consolidated balance sheet at December 31, 2014. A net deferred tax liability of $157 million, primarily relating to fixed asset basis differences and net operating losses of the Corporation's subsidiaries in Thailand and Indonesia, is included in current liabilities associated with assets held for sale in the Consolidated Balance Sheet at December 31, 2013.

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

	2014	2013	2012
U.S. statutory rate	35.0%	35.0 %	35.0%
Effect of foreign operations*	1.0	6.9	12.5
State income taxes, net of Federal income tax	1.5	0.1	0.6
Change in enacted tax laws	—	(14.8)	3.4
Gains on asset sales, net	(8.3)	(15.6)	(5.4)
Other	1.3	0.7	(0.3)
Total	30.5%	12.3 %	45.8%

* The variance in effective income tax rates attributable to the effect of foreign operations primarily resulted from the suspension of operations in Libya for a portion of 2013 and most of 2014.

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

	2014	2013
	(In millions)	
Balance at January 1	$570	$523
Additions based on tax positions taken in the current year	42	161
Additions based on tax positions of prior years	70	2
Reductions based on tax positions of prior years	(76)	(96)
Reductions due to settlements with taxing authorities	(3)	(19)
Reductions due to lapses in statutes of limitation	—	(1)

Balance at December 31	$603	$570

The December 31, 2014 balance of unrecognized tax benefits includes $528 million that, if recognized, would impact the Corporation's effective income tax rate. Over the next 12 months, it is reasonably possible that the total amount of unrecognized tax benefits could decrease by up to $94 million due to settlements with taxing authorities or other resolutions, as well as lapses in statutes of limitation. The Corporation had accrued interest and penalties related to unrecognized tax benefits of $62 million and $52 million as of December 31, 2014 and 2013, respectively.

The Corporation has not recognized deferred income taxes on the portion of undistributed earnings of foreign subsidiaries expected to be indefinitely reinvested in foreign operations. The Corporation had undistributed earnings from foreign subsidiaries that it expects to be indefinitely reinvested in foreign operations of approximately $8.3 billion as of December 31, 2014. The Corporation has not measured the unrecognized deferred tax liability related to these earnings because this determination is not practicable.

The Corporation and its subsidiaries file income tax returns in the U.S. and various foreign jurisdictions. The Corporation is no longer subject to examinations by income tax authorities in most jurisdictions for years prior to 2005.

Income taxes paid (net of refunds) in 2014, 2013 and 2012 amounted to $455 million, $1,353 million and $1,822 million, respectively.

15. Outstanding and Weighted Average Common Shares

The following table provides the changes in the Corporation's outstanding common shares:

	2014	2013	2012
	(In millions)		
Balance at January 1	325.3	341.5	340.0
Activity related to restricted common stock awards, net	0.6	0.8	1.3
Stock options exercised	3.3	2.3	0.2
Shares repurchased*	(43.4)	(19.3)	—
Balance at December 31	285.8	325.3	341.5

* See Note 16, Share Repurchase Plan in the Notes to the Consolidated Financial Statements.

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

	2014	2013	2012
	(In millions)		
Income from continuing operations, net of income taxes	$1,692	$4,036	$1,808
Less: Net income attributable to noncontrolling interests	—	176	18
Net income from continuing operations attributable to Hess Corporation	1,692	3,860	1,790
Income from discontinued operations, net of income taxes	682	1,186	255
Less: Net income (loss) attributable to noncontrolling interests	57	(6)	20
Net income from discontinued operations attributable Hess Corporation	625	1,192	235
Net income attributable to Hess Corporation	$2,317	$5,052	$2,025
Weighted average common shares outstanding:			
Basic	303.7	336.6	338.4
Effect of dilutive securities			
Restricted common stock	1.5	1.4	1.1
Stock options	1.8	1.7	0.8
Performance share units	0.7	1.2	—
Diluted	307.7	340.9	340.3
Net income attributable to Hess Corporation per share:			
Basic:			
Continuing operations	$5.57	$11.47	$5.29
Discontinued operations	2.06	3.54	0.69
Net income per share	$7.63	$15.01	$5.98
Diluted:			
Continuing operations	$5.50	$11.33	$5.26
Discontinued operations	2.03	3.49	0.69
Net income per share	$7.53	$14.82	$5.95

The weighted average common shares used in the diluted earnings per share calculations exclude the effect of approximately 1.4 million, 4.4 million and 9.2 million out of the money stock options for 2014, 2013 and 2012, respectively. Based on the Corporation's TSR, the diluted earnings per share calculations also exclude the effects of

414,175 PSUs for 2012.

In 2014, cash dividends on common stock totaled $1.00 per share ($0.25 per quarter). In 2013, cash dividends declared on common stock totaled $0.70 per share ($0.10 per share for the first two quarters and $0.25 per share commencing in the third quarter of 2013). Cash dividends were $0.40 per share ($0.10 per quarter) in 2012.

16. Share Repurchase Plan

In March 2013, the Corporation announced a board authorized plan to repurchase up to $4.0 billion of outstanding common shares. In May 2014, the Corporation increased the repurchase program to $6.5 billion. For the year ended December 31, 2014, the Corporation purchased approximately 43.4 million shares for a total cost of approximately $3.7 billion, or an average cost of $85.83 per share including transaction fees. From August through December 31, 2013, the Corporation purchased approximately 19.3 million shares for a total cost of approximately $1.5 billion, or an average cost of $79.65 per share including transaction fees. As of

December 31, 2014, the Corporation is authorized to purchase up to approximately $1.24 billion of additional common stock under its board approved plan. Due to the current oil price environment, the Corporation plans to significantly moderate stock repurchases in 2015 compared with 2014.

17. Leased Assets

The Corporation and certain of its subsidiaries lease drilling rigs, tankers, 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, 2014, 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):

2015	$773
2016	627
2017	422
2018	348
2019	303
Remaining years	345
Total minimum lease payments	2,818
Less: Income from subleases	36
Net minimum lease payments	$2,782

Rental expense was as follows:

	2014	2013	2012
	(In millions)		
Total rental expense	$248	$355	$375
Less: Income from subleases	17	15	15
Net rental expense	$231	$340	$360

18. Guarantees and Contingencies

At December 31, 2014, the Corporation has $54 million in letters of credit for which it is contingently liable. In addition, the Corporation is subject to loss contingencies with respect to various lawsuits, claims and other proceedings, including environmental matters. A liability is recognized in the Corporation's 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, the Corporation discloses the nature of those contingencies.

In July 2004, HOVIC and HOVENSA, each received a letter from the Commissioner of the Virgin Islands Department of Planning and Natural Resources and Natural Resources Trustees, advising of the Trustee's intention to bring suit against HOVIC and HOVENSA under the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA). The letter alleges that HOVIC and HOVENSA are potentially responsible for damages to natural resources arising from releases of hazardous substances from the HOVENSA refinery, which had been operated by HOVIC until October 1998. An action was filed on May 5, 2005 in the District Court of the Virgin

Islands against HOVENSA, HOVIC and other companies that operated industrial facilities on the south shore of St. Croix asserting that the defendants are liable under CERCLA and territorial statutory and common law for damages to natural resources. In 2014 HOVIC, HOVENSA and the government of the U.S. Virgin Islands entered into a settlement agreement pursuant to which HOVENSA paid $3.5 million and agreed to pay the government of the U.S. Virgin Islands an additional $40 million no later than December 31, 2014. HOVENSA was unable to make this additional payment because the U.S.Virgin Islands legislature did not approve a proposed operating agreement required to complete a proposed sale of HOVENSA, which would have provided funds to make the settlement payment. Under the terms of the settlement agreement, the U.S. Virgin Islands government was granted a first lien on HOVENSA’s assets to secure the settlement payment, and in January 2015 the government commenced a foreclosure action to enforce this lien. HOVENSA intends to defend this action and may take other steps in response to the action, including the sale of assets and/or the commencement of bankruptcy proceedings. The Registrant does not believe that the resolution of this matter will have a material adverse effect on its financial condition.

In February 2015, the Pension Benefit Guaranty Corporation (PBGC) issued a notice of determination to terminate the HOVENSA pension plan. HOVENSA had been in negotiations with the PBGC to make additional contributions to the plan with proceeds from a proposed sale of HOVENSA, which was not completed for the reasons described above. The Registrant does not believe that the resolution of this matter will have a material adverse effect on its financial condition.

The Corporation, along with many companies engaged in refining and marketing of gasoline, has 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 the Corporation. 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 the Corporation have been settled. In March 2014, the Corporation agreed to settle claims against it arising out of an action brought by the State of New Jersey for approximately $35 million. The settlement was approved by the trial judge and the Corporation paid the settlement amount in December 2014. In June 2014, the Commonwealth of Pennsylvania and the State of Vermont each filed independent lawsuits alleging that the Corporation 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. An action brought by the Commonwealth of Puerto Rico also remained unresolved at December 31, 2014. The Corporation has recorded reserves for its estimated liabilities for its unresolved MTBE lawsuits.

The Corporation is subject to loss contingencies with respect to various claims, lawsuits and other proceedings. The Corporation cannot predict with certainty if, how or when such claims, lawsuits and proceedings will be resolved or what the eventual relief, if any, may be. 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 is not expected to have a material adverse effect on the financial condition of the Corporation. However, the Corporation could incur judgments, enter into settlements or revise its opinion regarding the outcome of certain matters, and such developments could have a material adverse effect on its results of operations in the period in which the amounts are accrued and its cash flows in the period in which the amounts are paid.

19. Segment Information

The Corporation has substantially completed its transition to a pure play E&P company. The results of operations for its retail, energy marketing, terminal and refining businesses as well as the energy trading joint venture, HETCO, have been classified as discontinued operations. The Corporation currently has one operating segment, Exploration and Production, and other unallocated costs reflected under Corporate, Interest and Other. The following table presents operating segment financial data for continuing operations:

	Exploration and Production	Corporate, Interest and Other	Total
	(In millions)		
2014			
Operating revenues	$10,737	$ —	$10,737
Net income (loss) from continuing operations attributable to Hess Corporation	$2,098	$ (406)	$1,692
Interest expense	$—	$ 323	$323
Depreciation, depletion and amortization	3,210	14	3,224
Provision (benefit) for income taxes	996	(252)	744
Investments in affiliates	151	—	151
Identifiable assets	36,512	908	37,420
Capital expenditures	5,221	53	5,274
2013			
Operating revenues	$11,905	$ —	$11,905
Net Income (loss) from continuing operations attributable to Hess Corporation	$4,303	$ (443)	$3,860
Interest expense	$—	$ 406	$406
Depreciation, depletion and amortization	2,671	16	2,687
Asset impairments	289	—	289
Provision (benefit) for income taxes	831	(266)	565
Investments in affiliates	109	397	506
Identifiable assets	37,863	1,352	39,215
Capital expenditures	5,709	58	5,767
2012			
Operating revenues	$12,245	$ —	$12,245
Net income (loss) from continuing operations attributable to Hess Corporation	$2,212	$ (422)	$1,790
Interest expense	$—	$ 419	$419
Depreciation, depletion and amortization	2,853	13	2,866
Asset impairments	582	—	582
Provision (benefit) for income taxes	1,793	(264)	1,529
Investments in affiliates	75	198	273
Identifiable assets	37,687	813	38,500
Capital expenditures	7,676	6	7,682

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)					
2014						
Operating revenues	$6,270	$1,557	$2,002	$ 908	$ —	$10,737
Net income (loss) from continuing operations attributable to Hess Corporation	656	226	545	671	(406)	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
Identifiable assets	18,472	7,800	3,049	7,191	908	37,420
Property, plant and equipment (net) (a)	15,595	6,339	2,235	3,232	116	27,517
Capital expenditures	3,467	524	399	831	53	5,274
2013						
Operating revenues	$6,076	$1,337	$2,736	$ 1,756	$ —	$11,905
Net income (loss) from continuing operations attributable to Hess Corporation	777	2,051	594	881	(443)	3,860
Depreciation, depletion and amortization	1,393	484	518	276	16	2,687
Asset impairments	—	—	—	289	—	289
Provision (benefit) for income taxes	495	(646)	767	215	(266)	565
Identifiable assets	18,617	9,032	3,198	7,016	1,352	39,215
Property, plant and equipment (net) (a)	14,873	7,475	2,310	2,899	193	27,750
Capital expenditures	3,613	689	578	829	58	5,767
2012						
Operating revenues	$5,294	$2,530	$2,484	$ 1,937	$ —	$12,245
Net income (loss) from continuing operations attributable to Hess Corporation	438	1,010	602	162	(422)	1,790
Depreciation, depletion and amortization	1,406	466	529	452	13	2,866
Asset impairments	432	119	—	31	—	582
Provision (benefit) for income taxes	267	376	905	245	(264)	1,529
Identifiable assets	16,403	8,957	3,811	8,516	813	38,500
Property, plant and equipment (net) (a)	12,893	8,172	2,516	3,875	86	27,542
Capital expenditures	4,620	1,330	733	993	6	7,682

(a) Of the total Europe, Property, plant and equipment (net), Norway represented $5,246 million, $6,348 million and $6,426 million in 2014, 2013, and 2012, respectively.

20. Related Party Transactions

The following table presents the Corporation's related party transactions:

	2014	2013	2012
	(In millions)		
Purchases:			

HOVENSA (a)	$—	$—	$145
Bayonne Energy Center LLC (b)	—	38	20
Sales:			
WilcoHess (c)	211	2,828	3,058
HOVENSA	31	90	191

(a) The Corporation ceased purchasing refined products from HOVENSA following the closure of HOVENSA's refinery in January 2012.

(b) Represents purchases of electricity from this 50% owned joint venture under a tolling agreement.

(c) The Corporation acquired its partners' 56% interest in WilcoHess in January 2014.

The following table presents the Corporation's related party accounts receivable (payable) at December 31:

	2014	2013
	(In millions)	
WilcoHess	$—	$114
Bayonne Energy Center LLC	—	(4)

21. Financial Risk Management and Trading Activities

In the normal course of its business, the Corporation is 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 risk management activities refer to the mitigation of these risks through hedging activities. The Corporation is also exposed to commodity price risks primarily related to crude oil, natural gas, refined petroleum products and electricity, as well as foreign currency values from a 50% voting interest in a consolidated energy trading joint venture. The energy trading joint venture was sold in February 2015.

In conjunction with the sale of the energy marketing business in the fourth quarter of 2013, certain derivative contracts, including new transactions following the closing date, (the “delayed transfer derivative contracts”) were not transferred to the acquirer, Direct Energy, a North American subsidiary of Centrica plc (Centrica), as required customer or regulatory consents had not been obtained. However, the agreement entered into between Hess and Direct Energy on the closing date transferred all economic risks and rewards of the energy marketing business, including the ownership of the delayed transfer derivative contracts, to Direct Energy. The transfer of these remaining contracts was completed during 2014.

The Corporation maintains a control environment for all of its financial risk management and trading activities under the direction of its chief risk officer and through its corporate risk policy, which the Corporation’s senior management has approved. Controls include volumetric, term and value at risk limits. The chief risk officer must approve the trading of new instruments and commodities. Risk limits are monitored and reported on a daily basis to business units and senior management. The Corporation’s financial risk management department also performs independent price verifications (IPV’s) of sources of fair values and validations of valuation models. The Corporation’s treasury department is responsible for administering foreign exchange rate and interest rate hedging programs using similar controls and processes, where applicable.

The Corporation’s financial risk management department, in performing the IPV procedures, utilizes independent sources and valuation models that are specific to the individual contracts and pricing locations to identify positions that require adjustments to better reflect the market. This review is performed quarterly and the results are presented to the chief risk officer and senior management. The IPV process considers the reliability of the pricing services through assessing the number of available quotes, the frequency at which data is available and, where appropriate, the comparability between pricing sources.

The following is a description of the Corporation’s activities that use derivatives as part of their operations and strategies. Derivatives include both financial instruments and forward purchase and sale contracts. 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.

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 produced by the Corporation or to reduce 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 the Corporation’s crude oil or natural gas production. Forward contracts may also be used to purchase certain currencies in which the Corporation does 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.

The gross volumes of the financial risk management derivative contracts outstanding at December 31, were as follows:

	2014	2013
Commodity, primarily crude oil (millions of barrels)	—	9
Foreign exchange (millions of USD*)	$1,189	$220
Interest rate swaps (millions of USD)	$1,300	$865

*Denominated in U.S. dollars (USD).

Crude oil price hedging contracts increased E&P Sales and other operating revenues by $193 million ($121 million after income taxes) and $39 million ($25 million after income taxes) in 2014 and 2013, respectively, and reduced E&P Sales and other operating revenues by $688 million ($431 million after income taxes) in 2012. The amount of ineffectiveness from crude oil hedges that was recognized immediately in Sales and other operating revenues was immaterial in 2014 and 2013, and a loss of $9 million in 2012. At December 31, 2014, the Corporation has no after tax deferred gains in Accumulated other comprehensive income (loss) related to Brent crude oil and West Texas Intermediate (WTI) crude oil hedges.

At December 31, 2014 and 2013, the Corporation had interest rate swaps with gross notional amounts of $1,300 million and $865 million, respectively, which were designated as fair value hedges. 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. For the years ended December 31, 2014 and 2013, the Corporation recorded an increase of $1 million and a decrease of $35 million (excluding accrued interest) respectively, in the fair value of interest rate swaps and a corresponding adjustment in the carrying value of the hedged fixed rate debt.

Gains or losses on foreign exchange contracts that are not designated as hedges are recognized immediately in Other, net in Revenues and non operating income in the Statement of Consolidated Income.

Net realized and unrealized pre tax gains (losses) on derivative contracts used in Corporate Risk Management activities and not designated as hedges amounted to the following:

	2014	2013	2012
	(In millions)		
Commodity	$—	$—	$ 1
Foreign exchange	117	(39)	43
Total	$ 117	$ (39)	$ 44

Trading Activities: The energy trading joint venture generated earnings through various strategies primarily using energy-related commodities, securities and derivatives. The information that follows represents 100% of the energy trading joint venture as well as the Corporation's proprietary trading activities, which ceased in 2013.

The gross volumes of derivative contracts outstanding related to trading activities at December 31, were as follows:

	2014	2013
Commodity		
Crude oil and refined petroleum products (millions of barrels)	1,396	1,815
Natural gas (millions of mcf)	2,224	2,735
Electricity (millions of megawatt hours)	1	1
Foreign exchange (millions of USD)	$ 77	$ 52
Interest rate (millions of USD)	$ 29	$—
Equity securities (millions of shares)	5	11

Pre tax unrealized and realized gains (losses) recorded in the Statement of Consolidated Income from trading activities amounted to the following:

	2014	2013	2012
	(In millions)		
Commodity	$ 168	$ 78	$ 104
Foreign exchange	2	—	3
Other	32	1	10
Total *	$ 202	$ 79	$ 117

* The unrealized pre tax gains and losses included in earnings were reflected in Income from discontinued operations in the Statement of Consolidated Income.

Fair Value Measurements: The Corporation generally enters 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 the Corporation's intent and practice is to offset amounts in the case of such a termination, the Corporation's policy is to record the fair value of derivative assets and liabilities on a net basis.

In the normal course of business the Corporation relies 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 the Corporation, "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. The Corporation is 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.

The following table provides information about the effect of netting arrangements on the presentation of the Corporation's physical and financial derivative assets and (liabilities) that are measured at fair value, with the effect of single counterparty multilateral netting being included in column (v):

	Gross Amounts (i)	Gross Amounts Offset in the Consolidated Balance Sheet: Physical Derivative and Financial Instruments (ii)	Gross Amounts Offset in the Consolidated Balance Sheet: Cash Collateral (a) (iii)	Net Amounts Presented in the Consolidated Balance Sheet (iv)=(i)+(ii)+(iii)	Gross Amounts Not Offset in the Consolidated Balance Sheet (v)	Net Amounts (vi)=(iv)+(v)
	(In millions)					
December 31, 2014						
Assets						
Derivative contracts						
Commodity	$7,465	$(6,664)	$ (36)	$ 765	$ (3)	$ 762
Interest rate and other	76	(7)	(1)	68	(1)	67
Counterparty netting	—	(63)	—	(63)	—	(63)
Total derivative contracts	$7,541	$(6,734)	$ (37)	$ 770	$ (4)	$ 766
Liabilities						
Derivative contracts						
Commodity	$(7,871)	$6,664	$ 299	$ (908)	$ 3	$ (905)
Interest rate and other	(13)	7	3	(3)	1	(2)
Counterparty netting	—	63	—	63	—	63
Total derivative contracts	$(7,884)	$6,734	$ 302	$ (848)	$ 4	$ (844)
December 31, 2013 (b)						
Assets						
Derivative contracts						
Commodity	$3,086	$(1,867)	$ (79)	$ 1,140	$ (41)	$ 1,099
Interest rate and other	51	(10)	—	41	(3)	38
Counterparty netting	—	(206)	—	(206)	—	(206)
Total derivative contracts	$3,137	$(2,083)	$ (79)	$ 975	$ (44)	$ 931
Liabilities						
Derivative contracts						
Commodity	$(3,212)	$1,867	$ 168	$ (1,177)	$ 41	$ (1,136)
Other	(12)	10	—	(2)	3	1
Counterparty netting	—	206	—	206	—	206
Total derivative contracts	$(3,224)	$2,083	$ 168	$ (973)	$ 44	$ (929)

(a) All cash collateral was offset in the Consolidated Balance Sheet.
(b) Assets and liabilities in 2013 include amounts relating to the divested energy marketing business.

The net assets and liabilities that were offset in the Consolidated Balance Sheet as reflected in column (iv) of the table above were primarily included in Accounts receivable—Trade and Accounts payable, respectively. Included in these net amounts were the assets and liabilities related to the Corporation's discontinued operations of approximately $701 million and $845 million, respectively, as of December 31, 2014, and $612 million and $620 million, respectively, as of December 31, 2013.

The table below reflects the gross and net fair values of the risk management and trading derivative instruments and, at December 31, 2013 also includes energy marketing risk management derivative instruments:

	Accounts Receivable	Accounts Payable
	(In millions)	
December 31, 2014		
Derivative contracts designated as hedging instruments		
Commodity	$—	$—
Interest rate and other	39	(2)
Total derivative contracts designated as hedging instruments	39	(2)
Derivative contracts not designated as hedging instruments (a)		
Commodity	7,465	(7,871)
Foreign exchange	31	—
Other	6	(11)
Total derivative contracts not designated as hedging instruments	7,502	(7,882)
Gross fair value of derivative contracts	7,541	(7,884)
Master netting arrangements	(6,734)	6,734
Cash collateral (received) posted	(37)	302
Net fair value of derivative contracts	$770	$(848)
December 31, 2013 (b)		
Derivative contracts designated as hedging instruments		
Commodity	$11	$(3)
Interest rate and other	36	(1)
Total derivative contracts designated as hedging instruments	47	(4)
Derivative contracts not designated as hedging instruments (a)		
Commodity	3,075	(3,209)
Foreign exchange	2	(3)
Other	13	(8)
Total derivative contracts not designated as hedging instruments	3,090	(3,220)
Gross fair value of derivative contracts	3,137	(3,224)
Master netting arrangements	(2,083)	2,083
Cash collateral (received) posted	(79)	168
Net fair value of derivative contracts	$975	$(973)

(a) Includes trading derivatives and derivatives used for risk management

(b) Assets and liabilities in 2013 include amounts relating to the divested energy marketing business

Fair Value Measurements:

The following table provides the Corporation's net physical derivative and financial assets and (liabilities) that are measured at fair value based on this hierarchy:

	Level 1	Level 2	Level 3	Counterparty netting	Collateral	Balance
	(In millions)					
December 31, 2014						
Assets						
Derivative contracts						
Commodity	$755	$390	$114	$ (458)	$ (36)	$765
Interest rate and other	(1)	70	—	—	(1)	68
Collateral and counterparty netting	(43)	(20)	—	—	—	(63)
Total derivative contracts	711	440	114	(458)	(37)	770
Other assets measured at fair value on a recurring basis	27	—	—	—	—	27
Total assets measured at fair value on a recurring basis	$738	$440	$114	$ (458)	$ (37)	$797
Liabilities						
Derivative contracts						
Commodity	$(338)	$(1,265)	$(62)	$ 458	$ 299	$(908)
Other	(3)	(1)	(2)	—	3	(3)
Collateral and counterparty netting	43	20	—	—	—	63
Total derivative contracts	(298)	(1,246)	(64)	458	302	(848)
Other liabilities measured at fair value on a recurring basis	(40)	—	—	—	—	(40)
Total liabilities measured at fair value on a recurring basis	$(338)	$(1,246)	$(64)	$ 458	$ 302	$(888)
Other fair value measurement disclosures						
Long-term debt (a)	$—	$(7,003)	$—	$ —	$ —	$(7,003)
December 31, 2013 (b)						
Assets						
Derivative contracts						
Commodity	$254	$579	$494	$ (108)	$ (79)	$1,140
Interest rate and other	2	37	3	(1)	—	41
Collateral and counterparty netting	(15)	(191)	—	—	—	(206)
Total derivative contracts	241	425	497	(109)	(79)	975
Other assets measured at fair value on a recurring basis	—	—	—	—	—	—
Total assets measured at fair value on a recurring basis	$241	$425	$497	$ (109)	$ (79)	$975
Liabilities						
Derivative contracts						
Commodity	$(97)	$(1,071)	$(285)	$ 108	$ 168	$(1,177)
Other	—	(3)	—	1	—	(2)
Collateral and counterparty netting	15	191	—	—	—	206
Total derivative contracts	(82)	(883)	(285)	109	168	(973)
	(31)	—	—	—	—	(31)

Other liabilities measured at fair value on a recurring basis						
Total liabilities measured at fair value on a recurring basis	$(113)	$(883)	$(285)	$ 109	$ 168	$(1,004)
Other fair value measurement disclosures						
Long-term debt (a)	$—	$(6,641)	$—	$ —	$ —	$(6,641)

(a) Long-term debt, including current maturities, had a carrying value of $5,987 million and $5,798 million at December 31, 2014 and 2013, respectively.

(b) Assets and liabilities in 2013 include amounts relating to the divested energy marketing business.

In addition to the financial assets and (liabilities) disclosed in the tables above, the Corporation had other short term financial instruments, primarily cash equivalents and accounts receivable and payable, for which the carrying value approximated their fair value at December 31, 2014 and 2013.

The following table provides total net transfers into and out of each level of the fair value hierarchy:

	2014	2013
	(In millions)	
Transfers into Level 1	$25	$3
Transfers out of Level 1	(47)	76
	$(22)	$79
Transfers into Level 2	$25	$(113)
Transfers out of Level 2	(128)	88
	$(103)	$(25)
Transfers into Level 3	$105	$(85)
Transfers out of Level 3	20	31
	$125	$(54)

The Corporation's policy is to recognize transfers in and transfers out as of the end of the reporting period. Transfers between levels result from the passage of time as contracts move closer to their maturities, fluctuations in the market liquidity for certain contracts and/or changes in the level of significance of fair value measurement inputs.

The following table provides changes in physical derivatives and financial assets and (liabilities) primarily related to commodities that are measured at fair value based on Level 3 inputs:

	2014	2013
	(In millions)	
Balance at January 1	$212	$141
Unrealized pre-tax gains (losses)		
Included in earnings (a)	(298)	175
Purchases (b)	31	45
Sales (b)	(24)	(34)
Settlements (c)	4	(61)
Transfers into Level 3	105	(85)
Transfers out of Level 3	20	31
Balance at December 31	$50	$212

(a) The unrealized pre tax gains and losses included in earnings were reflected in Income from discontinued operations in the Statement of Consolidated Income.
(b) Purchases and sales primarily represent option premiums paid or received, respectively, during the reporting period and were reflected in Income from discontinued operations in the Statement of Consolidated Income.
(c) Settlements represent realized gains (losses) on derivatives settled during the reporting period and were reflected in Income from discontinued operations in the Statement of Consolidated Income.

The significant unobservable inputs used in Level 3 fair value measurements for the Corporation's physical commodity contracts and derivative instruments primarily include less liquid delivered locations for physical commodity contracts or volatility assumptions for out of the money options. The following table provides information about the Corporation's significant recurring unobservable inputs used in the Level 3 fair value measurements. Natural gas contracts are usually quoted and transacted using basis pricing relative to an active pricing location (e.g. Henry Hub), for which price inputs represent the approximate value of differences in geography and local market conditions. All other price inputs in the table below represent full contract prices. Significant changes in any of the inputs, independently or correlated, may result in a different fair value.

	Unit of Measurement	Range / Weighted Average
December 31, 2014		
Assets		
Commodity contracts with a fair value of $114 million		
Contract prices		
Crude oil and refined petroleum products	$ / bbl (a)	$36.27 - 122.66 / 65.63
Electricity	$ / MWH (b)	$38.80 - 71.69 / 57.22
Basis prices		
Natural gas	$ / MMBTU (c)	$(0.61) - 13.50 / 6.19
Contract volatilities		
Crude oil and refined petroleum products	%	32.00 - 45.00 / 43.00
Natural gas	%	19.00 - 53.00 / 40.00
Liabilities		
Commodity contracts with a fair value of $62 million		
Contract prices		
Crude oil and refined petroleum products	$ / bbl (a)	$36.27 - 85.40 / 69.54
Basis prices		
Natural gas	$ / MMBTU (c)	$2.84 - 4.45 / 2.94
Contract volatilities		
Crude oil and refined petroleum products	%	32.00 - 45.00 / 41.00
Natural gas	%	23.00 - 53.00 / 41.00

	Unit of Measurement	Range / Weighted Average
December 31, 2013 (b)		
Assets		
Commodity contracts with a fair value of $494 million		
Contract prices		
Crude oil and refined petroleum products	$ / bbl (a)	$78.45 - 228.86 / 118.68
Electricity	$ / MWH (b)	$19.52 -165.75 / 45.76
Basis prices		
Natural gas	$ / MMBTU (c)	$(4.99) - 18.10 / 0.23
Contract volatilities		
Crude oil and refined petroleum products	%	16.00 - 18.00 / 17.00
Natural gas	%	17.00 - 35.00 / 22.00
Electricity	%	16.00 - 36.00 / 23.00
Liabilities		
Commodity contracts with a fair value of $285 million		
Contract prices		
Crude oil and refined petroleum products	$ / bbl (a)	$57.45 - 183.89 / 122.54
Electricity	$ / MWH (b)	$26.48 - 155.33 / 43.12
Basis prices		
Natural gas	$ / MMBTU (c)	$(1.90) - 18.00 / (0.62)
Contract volatilities		
Crude oil and refined petroleum products	%	16.00 - 17.00 / 17.00
Natural gas	%	34.00 - 35.00 / 35.00
Electricity	%	16.00 – 36.00 / 22.00

(a) Price per barrel.
(b) Price per megawatt hour.
(c) Price per million British thermal unit
(d Assets and liabilities in 2013 include amounts relating to the divested energy marketing business.

Credit Risk: The Corporation is 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, 2014, the Corporation's net Accounts receivable—Trade related to continuing operations were concentrated with the following counterparty industry segments: Integrated Oil Companies — 23%, Financial Institutions — 22%, Government Entities —18%, Refiners — 14%, and Trading Companies — 13%. As of December 31, 2013, the Corporation's net Accounts receivable —

Trade, which included the receivables for the downstream businesses, were concentrated as follows: Integrated Oil Companies — 45%, Refiners — 18%, Financial Institutions — 14% Government Entities — 8%, and Trading Companies — 7 The Corporation reduces its risk related to certain counterparties by using master netting arrangements and requiring collateral, generally cash or letters of credit. The Corporation records the cash collateral received or posted as an offset to the fair value of derivatives executed with the same counterparty. At December 31, 2014 and December 31, 2013, the Corporation held cash from counterparties of $37 million and $79 million, respectively. The Corporation posted cash to counterparties at December 31, 2014 and December 31, 2013, of $302 million and $168 million, respectively.

The Corporation had outstanding letters of credit totaling $397 million and $410 million at December 31, 2014 and December 31, 2013, respectively, primarily issued to satisfy margin requirements (approximately $240 million and $302 million related to discontinued operations at December 31, 2014 and December 31, 2013, respectively). Certain of the Corporation's agreements also contain contingent collateral provisions that could require the Corporation to post additional collateral if the Corporation's credit rating declines. As of December 31, 2014 and 2013, the net liability related to both realized and unrealized derivative contracts with contingent collateral provisions was $130 million and approximately $281 million, respectively. As of December 31, 2014, the cash collateral posted on those derivatives was $17 million compared to $31 million at December 31, 2013. At December 31, 2014 and 2013, all three major credit rating agencies that rate the Corporation's debt had assigned an investment grade rating. If one of the three agencies were to downgrade the Corporation's rating below investment grade, the Corporation would be required to post additional collateral of approximately $55 million at December 31, 2014 and approximately $134 million at December 31, 2013.

22. Subsequent Events

In January 2015, the Corporation entered into a new $4 billion syndicated revolving credit facility that matures in January 2020. The new facility, which replaced the $4 billion facility that was scheduled to mature in April 2016, can be used for borrowings and letters of credit. Borrowings on the facility bear interest at 1.075% above the London Interbank Offered Rate. A facility fee of 0.175% per annum is also payable on the amount of the facility. The interest rate and facility fee are subject to adjustment if the Corporation's credit rating changes. The restrictions on the amount of total borrowings and secured debt are substantially similar to the previous facility.

In February 2015, the Corporation sold its interest in the energy trading joint venture, HETCO, which was renamed Hartree Partners, LP. Pursuant to the terms of the sale, Hartree is permitted to continue to utilize the Corporation's guarantees issued in favor of Hartree's existing counterparties until November 12, 2015, provided that new trades are for a period of one year or less, comply with certain credit requirements, and net exposures remain within VAR limits previously applied by the Corporation. The Corporation has the right to seek reimbursement from Hartree and a separate Hartree credit support facility upon any counterparty draw on the applicable guarantee from the Corporation.

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES

SUPPLEMENTARY OIL AND GAS DATA (UNAUDITED)

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

During the three year period which ended December 31, 2014, the Corporation produced crude oil, natural gas liquids and/or natural gas principally in the United States (U.S.), Europe (Norway, Denmark, Russia and the United Kingdom), Africa (Equatorial Guinea, Libya and Algeria) and Asia and Other (the Joint Development Area of Malaysia/Thailand, Malaysia, Thailand, Azerbaijan and Indonesia). Exploration activities were also conducted, or are planned, in certain of these areas as well as additional countries. See Note 3, Dispositions in 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)				
2014					
Property acquisitions					
Unproved	$88	$21	$—	$ —	$ 67
Proved	—	—	—	—	—
Exploration (a)	763	354	16	113	280
Production and development capital expenditures (b)	5,028	3,292	778	319	639
2013					
Property acquisitions					
Unproved	$56	$55	$—	$ —	$ 1
Proved	—	—	—	—	—
Exploration (a)	1,044	592	98	119	235
Production and development capital expenditures (b)	5,666	3,259	1,008	586	813
2012					
Property acquisitions					
Unproved	$267	$179	$78	$ —	$ 10
Proved	—	—	—	—	—
Exploration (a)	1,089	405	89	260	335
Production and development capital expenditures (b)	7,505	4,236	1,792	506	971

(a) Includes $283 million, $560 million and $319 million of exploration costs incurred for unconventional assets in 2014, 2013 and 2012, respectively.
(b) Includes $326 million, $615 million and $715 million in 2014, 2013 and 2012, respectively, related to the accruals and revisions for asset retirement obligations.
(c) Costs incurred in oil and gas producing activities in Norway, were as follows for the years ended December 31:

	2014	2013	2012
	(In millions)		
Property Acquisitions	$—	$—	$—
Exploration	—	6	—
Production and development capital expenditures*	525	781	1,081

*Includes accruals and revisions for asset retirement obligations.

Capitalized Costs Relating to Oil and Gas Producing Activities

	At December 31,	
	2014	2013
	(In millions)	
Unproved properties	$1,468	$2,460
Proved properties	4,211	4,121
Wells, equipment and related facilities	40,649	37,274
Total costs	46,328	43,855
Less: Reserve for depreciation, depletion, amortization and lease impairment	18,927	16,298
Net capitalized costs	$27,401	$27,557

Results of Operations for Oil and Gas Producing Activities

The results of operations shown below exclude non oil and gas producing activities, primarily gains on sales of oil and gas properties, sales of purchased crude oil and natural gas, interest expense, gains and losses resulting from foreign exchange transactions and other non-operating income. Therefore, these results are on a different basis than the net income from E&P operations reported in Management's Discussion and Analysis of Financial Condition and Results of Operations and in Note 19, Segment Information in the Notes to the Consolidated Financial Statements.

For the Years Ended December 31	Total	United States	Europe (a)	Africa	Asia and Other	
	(In millions)					
2014						
Sales and other operating revenues	$8,839	$4,461	$1,540	$1,962	$ 876	
Costs and expenses						
Operating costs and expenses	1,927	843	461	441	182	
Production and severance taxes	275	240	3	—	32	
Exploration expenses, including dry holes and lease impairment	840	359	90	36	355	
General and administrative expenses	336	281	—	16	39	
Depreciation, depletion and amortization	3,210	1,751	683	487	289	
Total costs and expenses	6,588	3,474	1,237	980	897	
Results of operations before income taxes	2,251	987	303	982	(21)	
Provision (benefit) for income taxes	926	399	101	435	(9)	
Results of operations	$1,325	$588	$202	$547	$ (12)	(b)
2013						
Sales and other operating revenues	$9,995	$4,268	$1,482	$2,671	$ 1,574	
Costs and expenses						
Operating costs and expenses	2,116	795	539	448	334	
Production and severance taxes	372	232	98	3	39	
Exploration expenses, including dry holes and lease impairment	1,031	371	114	323	223	
General and administrative expenses	377	218	79	17	63	
Depreciation, depletion and amortization	2,671	1,393	484	518	276	
Asset impairments	289	—	—	—	289	
Total costs and expenses	6,856	3,009	1,314	1,309	1,224	
Results of operations before income taxes	3,139	1,259	168	1,362	350	
Provision for income taxes (c)	1,479	483	60	767	169	
Results of operations	$1,660	$776	$108	$595	$ 181	(b)
2012						
Sales and other operating revenues	$10,893	$4,104	$2,460	$2,545	$ 1,784	
Costs and expenses						
Operating costs and expenses	2,202	758	678	404	362	
Production and severance taxes	550	199	335	2	14	
Exploration expenses, including dry holes and lease impairment	1,070	426	71	84	489	
General and administrative expenses	314	196	46	17	55	
Depreciation, depletion and amortization	2,853	1,406	466	528	453	
Asset impairments	582	432	119	—	31	
Total costs and expenses	7,571	3,417	1,715	1,035	1,404	
Results of operations before income taxes	3,322	687	745	1,510	380	

Provision for income taxes (d)	1,664	269	334	905	156	
Results of operations	$1,658	$418	$411	$605	$ 224	(b)

(a) Results of operations for oil and gas producing activities in Norway were as follows for the years ended December 31.

	2014	2013	2012
	(In millions)		
Sales and other operating revenues	$1,102	$860	$518
Costs and expenses			
Operating costs and expenses	376	376	297
Production and severance taxes	3	6	5
Exploration expenses, including dry holes and lease impairment	—	6	—
General, administrative and other expenses	4	8	10
Depreciation, depletion and amortization	513	364	139
Total costs and expenses	896	760	451
Results of operations before income taxes	206	100	67
Provision(benefit) for income taxes	103	36	(82)
Results of operations	$103	$64	$149

(b) Includes other countries where exploration activities are ongoing. Net losses for other countries were $266 million, $223 million and $373 million in 2014, 2013 and 2012, respectively.

(c) Excludes a deferred tax benefit of $674 million which represents the effect of the Denmark hydrocarbon income tax law change to the Chapter 3A regime from the Chapter 3 regime in December 2013.

(d) Asia and Other excludes an income tax charge of $86 million for a disputed application of an international tax treaty.

Oil and Gas Reserves

The Corporation's 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. The Corporation's estimation of net recoverable quantities of liquid hydrocarbons and natural gas is a highly technical process performed by internal teams of geoscience professionals and reservoir engineers. Estimates of reserves were prepared by the use of appropriate geologic, petroleum engineering, and evaluation principals 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. The Corporation's proved reserves are subject to certain risks and uncertainties, which are discussed in Item 1A, Risk Factors Related to Our Business and Operations 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 Vice President of E&P Technology & Excellence and its Chief Financial Officer. Estimates of reserves are prepared by technical staff that 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 90 through 91). 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 2014 was Mr. Randy Johnson, Vice President of E&P Technology & Excellence. Mr. Johnson 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 Engineering and a MS degree in Petroleum Engineering. He is a licensed professional engineer in Texas. His experience includes over 20 years primarily focused on oil and gas subsurface understanding and reserves estimation in both domestic and international areas. The Corporation's upstream technology organization, which Mr. Johnson manages, focuses on oil and gas industry subsurface and reservoir engineering technologies and evaluation techniques. Mr. Johnson is also 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

The Corporation engaged the consulting firm of DeGolyer and MacNaughton (D&M) to perform an audit of the internally prepared reserve estimates on certain fields aggregating 80% of 2014 year end reported reserve quantities on a barrel of oil equivalent basis (82% in 2013). 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 4, 2015, 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, 2014 oil and gas reserves is included as an exhibit to this Form 10 K. While the D&M report should be read in its entirety, the report concludes that for the properties reviewed by D&M, the total net proved reserve estimates prepared by Hess and audited by D&M, in the aggregate, differed by less than 1% 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.

Following are the Corporation's proved reserves:

	Crude Oil, Condensate & Natural Gas Liquids					Natural Gas			
	United States	Europe (g)	Africa	Asia	Total	United States	Europe (g)	Asia and Africa (h)	Total
	(Millions of barrels)					(Millions of mcf)			
Net Proved Developed and Undeveloped Reserves									
At January 1, 2012	373	494	250	52	1,169 (b)	360	563	1,500	2,423
Revisions of previous estimates (a)	32	(16)	(5)	1	12	10	4	42	56
Extensions, discoveries and other additions	108	18	17	1	144	76	1	171	248
Improved recovery	7	—	—	—	7	4	—	—	4
Sales of minerals in place	(2)	(49)	—	—	(51)	—	(192)	—	(192)
Production (f)	(45)	(31)	(28)	(6)	(110)	(50)	(19)	(175)	(244)
At December 31, 2012	473	416	234	48	1,171 (b)	400	357	1,538	2,295
Revisions of previous estimates (a)	(55)	(24)	—	—	(79)	(12)	(66)	(5)	(83)
Extensions, discoveries and other additions	211	4	2	—	217	131	4	7	142
Sales of minerals in place	(2)	(89)	(4)	(18)	(113)	(4)	(47)	(108)	(159)
Production (f)	(45)	(16)	(22)	(5)	(88)	(51)	(10)	(159)	(220)
At December 31, 2013	582	291	210	25	1,108	464	238	1,273	1,975
Revisions of previous estimates (a)	(34)	(20)	(8)	1	(61)	58	(31)	23	50
Extensions, discoveries and other additions	137	34	6	1	178	184	26	192	402
Sales of minerals in place	—	—	—	(19)	(19)	(20)	—	(329)	(349)
Production (f)	(54)	(14)	(20)	(1)	(89)	(66)	(13)	(118)	(197)
At December 31, 2014	631	291	188	7	1,117	620 (c)	220	1,041	1,881
Net Proved Developed Reserves (d)									
At January 1, 2012	190	212	194	25	621	199	273	740	1,212
At December 31, 2012	280	181	188	27	676	232	190	798	1,220
At December 31, 2013	278	126	185	17	606	279	104	727	1,110
At December 31, 2014	320	123	163	3	609	350	96	473	919

Net Proved Undeveloped Reserves (e)									
At January 1, 2012	183	282	56	27	548	161	290	760	1,211
At December 31, 2012	193	235	46	21	495	168	167	740	1,075
At December 31, 2013	304	165	25	8	502	185	134	546	865
At December 31, 2014	311	168	25	4	508	270	124	568	962

(a) Includes the impact of changes in selling prices on the reserve estimates for production sharing contracts with cost recovery provisions. Revisions included an increase to crude oil, condensate and natural gas liquids reserves of 1 million barrels and 0.1 million barrels in 2014 and 2013, respectively and a decrease of 2 million barrels in 2012. Revisions also included an increase to natural gas reserves of 7 million mcf in 2014 and reductions to natural gas reserves of 9 million mcf and 2 million mcf in 2013 and 2012, respectively, due to changes in selling prices.

(b) Includes 8 million barrels as of December 31, 2012 and 10 million barrels as of January 1, 2012 of crude oil reserves related to a noncontrolling interest. The joint venture including the noncontrolling interest was sold in April 2013.

(c) Excludes approximately 235 million mcf of carbon dioxide gas for sale or use in company operations.

(d) Natural gas liquids net proved developed reserves were 65 million barrels, 61 million barrels and 76 million barrels at December 31, 2014, 2013 and 2012, respectively, and 56 million barrels at January 1, 2012. Natural gas liquids net proved developed reserves in the United States were 85%, 83% and 82% at December 31, 2014, 2013 and 2012, respectively. Natural gas liquids net proved developed reserves in Norway were 15%, 15% and 10% at December 31, 2014, 2013 and 2012, respectively.

(e) Natural gas liquids net proved undeveloped reserves were 80 million barrels, 75 million barrels and 60 million barrels at December 31, 2014, 2013 and 2012, respectively, and 57 million barrels at January 1, 2012. Natural gas liquids net proved undeveloped reserves in the United States were 79%, 83% and 72% at December 31, 2014, 2013 and 2012, respectively. Natural gas liquids net proved undeveloped reserves in Norway were 21%, 15% and 25% at December 31, 2014, 2013 and 2012, respectively.

(f) Natural gas production includes volumes used for fuel.

(g) Proved reserves in Norway were as follows:

	Crude Oil, Condensate & Natural Gas Liquids			Natural Gas		
	2014	2013	2012	2014	2013	2012
	(Millions of barrels)			(Millions of mcf)		
At January 1	256	284	293	198	219	388
Revisions of previous estimates	(22)	(21)	—	(33)	(16)	1
Extensions, discoveries and other additions	32	—	—	24	—	—
Sales of minerals in place	—	—	(5)	—	—	(165)
Production	(10)	(7)	(4)	(9)	(5)	(5)
At December 31	256	256	284	180	198	219
Net Proved Developed Reserves at December 31 (d)	95	107	102	67	87	73
Net Proved Undeveloped Reserves at December 31 (e)	161	149	182	113	111	146

(h) Natural gas reserves in Africa were 155 million mcf in 2014, 160 million mcf in 2013 and 142 million mcf in 2012.

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 remained at significantly higher levels during the first ten months of 2014 and declined during the last two months of the year. As a result, the average crude oil price used to calculate proved reserves at December 31, 2014 is significantly higher than the year-end 2014 crude oil price. The year-end 2015 reserve estimates will be based on the same unweighted arithmetic average formula using first-day-of-the-month prices for 2015 and will reflect the current low crude oil price environment from the beginning of the year. If current strip crude oil prices hold through 2015, proved reserves at December 31, 2015 could be significantly lower than proved reserves at December 31, 2014. It is difficult to estimate the magnitude of any potential net negative change in proved reserves that may result from lower crude oil prices as of December 31, 2015, due to a number of factors that are currently unknown, including 2015 crude oil prices, any revisions in proved reserves based on 2015 reservoir performance, the levels to which industry costs will decline in response to lower prices, and management’s plans as of December 31, 2015 for developing proved undeveloped reserves through the year 2020 which will be the five-year window for recognizing proved undeveloped reserves as of December 31, 2015.

In 2014, proved reserve additions in the United States were 115 million barrels of crude oil, 22 million barrels of natural gas liquids and 184 million mcf of natural gas primarily from the Bakken oil shale play in North Dakota, Utica shale in Ohio and the Gulf of Mexico. New wells completed in 2014 added proved reserves of 16 million barrels of crude oil, 5 million barrels of natural gas liquids and 58 million mcf of natural gas. Other additions and revisions to proved reserves primarily relate to proved undeveloped reserves which are discussed in further detail below.

In 2013, proved reserve additions in the United States were 179 million barrels of crude oil, 32 million barrels of natural gas liquids and 131 million mcf of natural gas primarily from the Bakken oil shale play in North Dakota. New wells completed in 2013 added proved reserves of 19 million barrels of crude oil, 3 million barrels of natural gas liquids and 40 million mcf of natural gas. The remaining proved reserve additions are due to new well locations, primarily relating to new wells to be drilled in the Bakken oil shale play through 2018.

Proved Undeveloped Reserves

The December 31, 2014 oil and gas reserve estimates disclosed above include 508 million barrels of liquid hydrocarbons and 962 million mcf of natural gas, or an aggregate of 669 million barrels of oil equivalent (boe), classified as proved undeveloped reserves. Total proved undeveloped reserves increased by 23 million boe compared with year end 2013. Extensions, discoveries and other additions (additions) and Revisions of previous estimates (revisions) to proved undeveloped reserves amounted to a net increase of 157 million boe. Transfers to proved developed reserves were 110 million boe and dispositions of assets in Thailand and Indonesia reduced proved undeveloped reserves by 24 million boe.

The 2014 additions, revisions and transfers primarily consisted of the following:

- In the Bakken shale play in North Dakota, additions, revisions, and transfers in proved undeveloped reserves amounted to a net increase of 12 million boe. Additions of 97 million boe (consisting of 77 million barrels of crude oil, 14 million barrels of natural gas liquids and 39 million mcf of natural gas) relate to planned drilling of additional new wells through 2019. Additions were partially offset by downward revisions of 47 million boe (consisting of 40 million barrels of crude oil and 7 million barrels of natural gas liquids) as a result of well performance and reprioritization of well locations in the drilling schedule resulting in certain wells moving beyond 2019. Transfers from proved undeveloped reserves into proved developed reserves amounted to 38 million boe (consisting of 31 million barrels of crude oil, 5 million barrels of natural gas liquids and 15 million mcf of natural gas).
- In the Utica wet gas play, in Ohio, the Corporation added 18 million boe of proved undeveloped reserves (consisting of 1 million barrels of crude oil, 3 million barrels of natural gas liquids and 79 million mcf of natural gas) as a result of additional planned drilling.
- In the Gulf of Mexico, additions, revisions, and transfers in proved undeveloped reserves amounted to a net decrease of 3 million boe. Additions of 21 million boe (consisting of 20 million barrels of crude oil and 9 million mcf of natural gas) relate to the sanction of the Stampede project. In addition, reserve revisions of 6 million boe from the Conger Field increased year-end proved undeveloped reserves. Primarily as a result of first production at the Tubular Bells Field, 30 million boe (consisting of 21 million barrels of crude oil, 3 million barrels of natural gas liquids and 35 million mcf of natural gas) were transferred from proved undeveloped to proved developed reserves.
- At the Valhall Field, offshore Norway, additions, revisions, and transfers from proved undeveloped reserves amounted to a net increase of 13 million boe. Additions resulting from planned drilling activity were 37 million boe (consisting of 29 million barrels of crude oil, 4 million barrels of natural gas liquids and 24 million mcf of natural gas). Revisions reduced proved undeveloped reserves by 9 million boe and transfers into proved developed reserves were 15 million boe.
- In the North Malay Basin, offshore Peninsular Malaysia, where the Corporation is operator of a multi phase natural gas development project, additions were 31 million boe (186 million mcf) of natural gas following the signing of a gas sales agreement for the full field development phase of the project.
- Total other transfers of proved undeveloped reserves to proved developed reserves of 26 million boe were from Denmark, the JDA and other assets.

The Corporation estimates that capital expenditures totaling $3,110 million were incurred to convert 110 million boe of proved undeveloped reserves to proved developed reserves during 2014. The capital expenditures include production facilities and subsea infrastructure for the Tubular Bells field in the Gulf of Mexico which achieved first production in late 2014.

The December 31, 2013 oil and gas reserve estimates disclosed above include 502 million barrels of liquid hydrocarbons and 865 million mcf of natural gas, or an aggregate of 646 million boe, classified as proved undeveloped reserves. Overall volumes of proved undeveloped reserves decreased by 28 million boe compared with year-end 2012. In 2013, additions and revisions to proved undeveloped reserves amounted to 123 million boe, primarily in the United States. The additions and revisions primarily resulted from ongoing technical assessments, performance evaluations, and additional planned development activities. In 2013, transfers to proved developed reserves amounted to 88 million boe resulting from continued development activity and new wells principally in North Dakota and the Gulf of Mexico in the U.S., Norway, Malaysia and Equatorial Guinea. Asset sales reduced proved undeveloped reserves by 63 million boe.

In the United States, 2013 proved undeveloped reserve additions of 160 million barrels of crude oil, 29 million barrels of natural gas liquids and 90 million mcf of natural gas relate primarily to new well locations to be drilled in the Bakken oil shale play through 2018. Negative revisions of proved undeveloped reserves in the United States of 37 million barrels of crude oil, 5 million barrels of natural gas liquids and 46 million mcf of natural gas were primarily due to the reprioritization of well locations in the drilling schedule for the Bakken oil shale play resulting in certain wells moving beyond 2018. Transfers to proved developed reserves in the United States of 32 million barrels of crude oil, 5 million barrels of natural gas liquids and 27 million mcf of natural gas resulted from drilling activity.

The Corporation estimates that 2013 capital expenditures of $1,765 million were incurred to convert 88 million boe of proved undeveloped reserves to proved developed reserves during 2013 resulting from continuing development activity and new wells principally in North Dakota and the Gulf of Mexico in the U.S., Norway, Malaysia and Equatorial Guinea.

The Corporation is 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 6% of total 2014 proved reserves. Most of the proved undeveloped reserves in excess of five years relate to two offshore producing assets. As discussed below, a natural gas project at the JDA is being developed in phases to meet long term natural gas sales contracts and an oil and gas project at the Valhall Field in Norway is also being developed in phases. A summary of the development status of each of the projects follows:

- JDA – This natural gas project in the Gulf of Thailand currently has a central processing platform and twelve wellhead platforms. In 2014, the operator continued development drilling and successfully installed one new wellhead platform. Further development drilling is planned for 2015 and completion of a major booster compression project is scheduled for early 2016.
- Valhall – The multi year Valhall redevelopment project was completed in 2013. The project included the installation of a new production, utilities and accommodation platform, and expansion of gross production capacity to 120,000 barrels of liquids per day and 143,000 mcf of natural gas per day. The operator is currently executing a multi year development drilling program.

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, 2014 are presented separately below, as well as volumes produced and received during 2014, 2013 and 2012 from these production sharing contracts.

	Crude Oil, Condensate & Natural Gas Liquids					Natural Gas			
	United States	Europe	Africa	Asia	Total	United States	Europe	Asia and Africa	Total
	(Millions of barrels)					(Millions of mcf)			
Production Sharing Contracts									
Proved Reserves*									
At December 31, 2012	—	—	76	40	116	—	—	1,183	1,183
At December 31, 2013	—	—	57	18	75	—	—	914	914
At December 31, 2014	—	—	52	7	59	—	—	913	913
Production									
2012	—	—	20	6	26	—	—	137	137
2013	—	—	18	3	21	—	—	122	122
2014	—	—	18	1	19	—	—	107	107

* Includes natural gas liquids of - million barrels in 2014, 3 million barrels in 2013 and 5 million barrels in 2012.

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 selling prices of crude oil and natural gas are highly volatile. The prices required to be used for the discounted future net cash flows are on the same basis for determining proved oil and gas reserves and do not include the effects of commodity hedges. 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.

The standardized measure of discounted future net cash flows relating to proved oil and gas reserves at December 31, 2012 and January 1, 2012 have been restated to include excess carryforward deductions relating to proved oil and gas reserves in the computation of future income tax expenses at each date to be consistent with the computation of future income taxes at December 31, 2014 and 2013. In prior Form 10-K filings, excess carryforward deductions relating to proved oil and gas reserves were not included in the computation of future income tax expenses for December 31, 2012 and prior years as such attributes were available to be utilized against future taxable income of the Corporation's business activities other than those associated with proved oil and gas reserves. Commencing with 2013, the Corporation changed its computation of future income tax expenses to include excess tax carryforward deductions relating to proved oil and gas reserves in conjunction with the Corporation's transition to a pure play Exploration and Production company, based on the expectation such excess carryforward deductions would be utilized against future taxable income relating to proved oil and gas reserves. In the presentation below, amounts are shown on a restated basis and as originally presented in the 2013 Form 10-K.

At December 31	Total	United States	Europe *	Africa	Asia
	(In millions)				
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
2013					
Future revenues	$115,826	$49,370	$33,705	$23,404	$9,347
Less:					
Future production costs	32,112	14,877	12,506	3,034	1,695
Future development costs	19,985	8,826	8,080	1,466	1,613
Future income tax expenses	30,427	7,281	6,088	15,491	1,567
	82,524	30,984	26,674	19,991	4,875
Future net cash flows	33,302	18,386	7,031	3,413	4,472
Less: Discount at 10% annual rate	12,842	7,708	3,134	704	1,296
Standardized measure of discounted future net cash flows	$20,460	$10,678	$3,897	$2,709	$3,176
2012 – Revised					
Future revenues	$126,603	$39,900	$44,387	$27,162	$15,154
Less:					
Future production costs	32,529	12,603	13,277	3,547	3,102
Future development costs	17,363	6,465	6,648	1,623	2,627
Future income tax expenses	40,319	5,844	14,233	17,510	2,732
	90,211	24,912	34,158	22,680	8,461
Future net cash flows	36,392	14,988	10,229	4,482	6,693
Less: Discount at 10% annual rate	13,160	6,139	3,659	1,109	2,253
Standardized measure of discounted future net cash flows	$23,232	$8,849	$6,570	$3,373	$4,440
2012 – As Reported in 2013 Form 10-K					
Future revenues	$126,603	$39,900	$44,387	$27,162	$15,154
Less:					
Future production costs	32,529	12,603	13,277	3,547	3,102

Future development costs	17,363	6,465	6,648	1,623	2,627
Future income tax expenses	44,201	7,686	16,273	17,510	2,732
	94,093	26,754	36,198	22,680	8,461
Future net cash flows	32,510	13,146	8,189	4,482	6,693
Less: Discount at 10% annual rate	11,951	5,906	2,683	1,109	2,253
Standardized measure of discounted future net cash flows	$20,559	$7,240	$5,506	$3,373	$4,440

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

	2014	2013	2012
	(In millions)		
Future revenues	$27,502	$29,668	$33,974
Less:			
Future production costs (a)	8,159	11,538	9,734
Future development costs	7,318	7,226	4,507
Future income tax expenses (b)	6,683	5,567	12,936
	22,160	24,331	27,177
Future net cash flows (b)	5,342	5,337	6,797
Less: Discount at 10% annual rate (b)	2,792	2,483	2,563
Standardized measure of discounted future net cash flows (b)	$2,550	$2,854	$4,234

(a) Future production costs for 2014 decreased primarily due to the reduction of projected well workover and related costs by the operator of the Valhall Field based on the operator's well life study completed in 2014 and the impact of changes in foreign exchange rates associated with the strengthening of the U.S. dollar versus the Norwegian Krone.

(b) Future income taxes for 2012 have been restated as described above. Future income taxes for 2013 have been restated to include the impact of deductions for abandonment costs at the end of field life to be consistent with 2012. Previous amounts reported in the 2013 Form 10-K were as follows: future income tax expenses - $6,661 for 2013 and $14,976 for 2012; future net cash flows -$4,243 for 2013 and $4,757 for 2012; discount at 10% annual rate – $1,419 for 2013 and $1,587 for 2012; and standardized measure of discounted future net cash flows - $2,824 for 2013 and $3,170 for 2012.

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

For the Years Ended December 31	2014	2013	2012
	(In millions)		
Standardized measure of discounted future net cash flows at January 1*	$20,460	$23,232	$20,841
Changes during the year			
Sales and transfers of oil and gas produced during the year, net of production costs	(6,637)	(7,507)	(8,141)
Development costs incurred during year	4,702	5,051	6,790
Net changes in prices and production costs applicable to future production	(4,657)	(2,847)	1,678
Net change in estimated future development costs	(485)	(2,798)	(2,181)
Extensions and discoveries (including improved recovery) of oil and gas reserves, less related costs	2,249	3,836	3,612
Revisions of previous oil and gas reserve estimates	(161)	(1,189)	1,890
Net purchases (sales) of minerals in place, before income taxes	(2,157)	(3,905)	(1,856)
Accretion of discount	3,243	4,038	4,032
Net change in income taxes*	3,180	6,191	(336)
Revision in rate or timing of future production and other changes	(2,735)	(3,642)	(3,097)
Total*	(3,458)	(2,772)	2,391
Standardized measure of discounted future net cash flows at December 31*	$17,002	$20,460	$23,232

* Previous amounts reported in the 2013 Form 10-K were as follows: net change in income taxes - $8,834 for 2013 and ($1,906) for 2012; total changes during the year – ($129) for 2013 and $821 for 2012; and standardized measure of discounted future net cash flows at January 1, 2012 – $19,738, at December 31, 2012 – $20,599, and at December

31, 2014 – $20,430.

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES

QUARTERLY FINANCIAL DATA (UNAUDITED)

Following are quarterly results of operations:

	2014 First Quarter		Second Quarter		Third Quarter		Fourth Quarter	
	(In millions, except per share amounts)							
Sales and other operating revenues	$2,673		$2,829		$2,678		$2,557	
Gross profit from continuing operations (a)	$1,026		$1,000		$837		$622	
Income from continuing operations	$364		$974		$359		$(5	)
Income (loss) from discontinued operations	57		(44	)	671		(2	)
Net income	421		930		1,030		(7	)
Less: Net income (loss) attributable to noncontrolling interests	35		(1	)	22		1	
Net income (loss) attributable to Hess Corporation	$386	(b)	$931	(c)	$1,008	(d)	$(8	)(e)
Net income (loss) attributable to Hess Corporation per share:								
Basic:								
Continuing operations	$1.14		$3.15		$1.19		$(0.02	)
Discontinued operations	0.07		(0.14	)	2.16		(0.01	)
Net income (loss) per share	$1.21		$3.01		$3.35		$(0.03	)
Diluted:								
Continuing operations	$1.13		$3.10		$1.18		$(0.02	)
Discontinued operations	0.07		(0.14	)	2.13		(0.01	)
Net income (loss) per share	$1.20		$2.96		$3.31		$(0.03	)

	2013 First Quarter		Second Quarter		Third Quarter		Fourth Quarter	
	(In millions, except per share amounts)							
Sales and other operating revenues	$3,466		$3,011		$2,706		$2,722	
Gross profit from continuing operations (a)	$1,476		$1,370		$1,091		$651	
Income from continuing operations	$1,183		$1,577		$365		$911	
Income from discontinued operations	90		39		53		1,004	
Net income	1,273		1,616		418		1,915	
Less: Net income (loss) attributable to noncontrolling interests	(3	)	185		(2	)	(10	)
Net income attributable to Hess Corporation	$1,276	(f)	$1,431	(g)	$420	(h)	$1,925	(i)
Net income (loss) attributable to Hess Corporation per share:								
Basic:								
Continuing operations	$3.47		$4.14		$1.08		$2.76	
Discontinued operations	0.29		0.07		0.16		3.08	
Net income per share	$3.76		$4.21		$1.24		$5.84	
Diluted:								
Continuing operations	$3.43		$4.09		$1.07		$2.73	
Discontinued operations	0.29		0.07		0.16		3.03	
Net income per share	$3.72		$4.16		$1.23		$5.76	

(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 Asset impairments.
(b) Includes after tax charge of $52 million to reduce carrying value of its investments in Bayonne Energy Center asset sales to fair value and $48 million after-tax charge relating to severance and other exits costs partially offset by $40 million after-tax gain on sale of assets and liquidation of LIFO inventories.
(c) Includes after-tax gain of $765 million related to an asset sale and liquidation of LIFO inventories, partially offset by after tax charges totaling $266 million for dry hole expenses, asset impairment, employee severance and other exit costs.
(d) Includes an after tax gain of $749 million relating to asset sales and liquidation of LIFO inventories, partially offset by after tax charges totaling $118 million related to environmental, impairment, severance and exit related costs.
(e) Includes after-tax charge of $48 million for remeasurement of deferred taxes resulting from legal entity restructurings and $13 million after-tax charges related to severance, exit costs and other charges.
(f) Includes after tax gains of $820 million related to asset sales and the liquidation of LIFO inventories, partially offset by after tax charges of $213 million for an asset impairment, employee severance costs, refinery shutdown costs and an income tax charge related to a planned divestiture.
(g) Includes a non taxable gain of $951 million related to an asset sale, partially offset by after tax charges totaling $40 million for employee severance, refinery shutdown costs and other exit costs.

(h) Includes an after tax gain of $143 million resulting from the liquidation of LIFO inventories, largely offset by after tax charges totaling $128 million related to a non cash mark to market adjustment, employee severance costs, refinery shutdown costs, and other charges.
(i) Includes after tax gains of $1,472 million related to asset sales and liquidation of LIFO inventories, as well as deferred tax benefit of $674 million which represents the effect of Denmark's enacted changes to the hydrocarbon income tax law, partially offset by after tax charges of $540 million related to asset impairments, dry hole expenses, severance and other exit costs, income tax charges, refinery shutdown costs, and other charges.

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, 2014, 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, 2014.

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, 2014 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 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 Registrant's definitive proxy statement for the 2015 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 registrant's definitive proxy statement for the 2015 annual meeting of stockholders.

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Executive Officers of the Registrant

The following table presents information as of February 1, 2015 regarding executive officers of the Registrant:

Name	Age	Office Held* and Business Experience	Year Individual Became an Executive Officer
John B. Hess	60	Chief Executive Officer and Director Mr. Hess has been Chief Executive Officer of the Registrant since 1995 and employed by the Registrant since 1977. He has over 37 years of experience in the oil and gas industry.	1983
Gregory P. Hill	53	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 Registrant's worldwide exploration and production business since joining the Registrant in January 2009. Prior to joining the Registrant, Mr. Hill spend 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	57	Senior Vice President and General Counsel Mr. Goodell has been the Senior Vice President and General Counsel of the Registrant since 2009. Prior to joining the Registrant in 2009, he was a partner at the law firm of White & Case, LLP where he spent 25 years.	2009
John P. Rielly	52	Senior Vice President and Chief Financial Officer Mr. Rielly has been the Senior Vice President and Chief Financial Officer of the Registrant since 2004. Mr. Rielly previously served as Vice President and Controller of the Registrant from 2001 to 2004. Prior to joining the Registrant in 2001, he was a Partner at Ernst & Young, LLP where he was employed for 16 years.	2002
Brian D. Truelove	56	Senior Vice President, Offshore Mr. Truelove has been Senior Vice President, Offshore of the Registrant since 2013. He previously served as Senior Vice President, Services. Prior to joining the Registrant 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	55	Senior Vice President, Onshore Mr. Turner has been Senior Vice President, Onshore of the Registrant since 2013. He previously served as Senior Vice President, Global Production. Prior to joining the Registrant 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
	58	Senior Vice President, Exploration	2014

Barbara Lowery-Yilmaz		Ms. Lowery-Yilmaz has been the Senior Vice President, Exploration of the Registrant 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.	
Mykel J. Ziolo	62	Senior Vice President, Human Resources Mr. Ziolo has been Senior Vice President, Human Resources of the Registrant since 2009. He has a 38-year career in human resources working in the United States and internationally. Mr. Ziolo previously served as Global Head and Vice President, Human Resources – worldwide exploration and production of the Registrant. Prior to joining the Registrant in 2002, Mr. Ziolo served in served in several human resource positions in the energy industry, including 15 years with BHP Billiton.	2009

* 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 his name on May 7, 2014.

Except for Mr. Truelove and Ms. Lowery-Yilmaz, each of the above officers has been employed by the Registrant or its affiliates in various managerial and executive capacities for more than five years. Prior to joining the Registrant, Mr. Truelove and Ms. Lowery-Yilmaz served in senior executive positions in exploration and production at Royal Dutch Shell and its affiliates and BP plc and its affiliates, respectively.

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 Registrant’s definitive proxy statement for the 2015 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 Registrant’s definitive proxy statement for the 2015 annual meeting of stockholders.

See Equity Compensation Plans in Item 5 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 Registrant’s definitive proxy statement for the 2015 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 Registrant’s definitive proxy statement for the 2015 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

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)	By laws of Registrant incorporated by reference to Exhibit 3(1) of Form 8 K of Registrant filed on August 13, 2013.
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)	Indenture dated as of October 1, 1999, between Registrant and The Chase Manhattan Bank, as Trustee, incorporated by reference to Exhibit 4(1) of Form 10 Q of Registrant for the three months ended September 30, 1999.
4(3)	First Supplemental Indenture, dated as of October 1, 1999 between Registrant and The Chase Manhattan Bank, as Trustee, relating to Registrant's $7^3/_8$% 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(4)	Prospectus Supplement, dated August 8, 2001, to Prospectus dated July 27, 2001 relating to Registrant's 5.30% Notes due 2004, 5.90% Notes due 2006, 6.65% Notes due 2011 and 7.30% Notes due 2031, incorporated

by reference to Registrant's prospectus filed pursuant to Rule 424(b)(2) under the Securities Act of 1933, as amended, on August 9, 2001.

4(5) Prospectus Supplement, dated February 28, 2002, to Prospectus dated July 27, 2001 relating to Registrant's 7.125% Notes due 2033, incorporated by reference to Registrant's prospectus filed pursuant to Rule 424(b)(4) under the Securities Act of 1933, as amended, on March 1, 2002.

4(6) Indenture dated as of March 1, 2006, between Registrant and The Bank of New York Mellon, as successor to JP Morgan Chase Bank, N.A., as Trustee, including form of Note. incorporated by reference to Exhibit 4 to Registrant's Form S 3ASR filed on March 1, 2006.

4(7) Form of 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(8) 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(9) 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(10) 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(11) 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.

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 10, 2014.

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)* Performance Incentive Plan for Senior Officers, as amended, as approved by stockholders on May 4, 2011, incorporated by reference to Annex A to the definitive proxy statement of Registrant filed on March 25, 2011.

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)* 2008 Long term Incentive Plan, incorporated by reference to Annex B to Registrant's definitive proxy statement filed on March 27, 2008.

10(10)* First Amendment, dated March 3, 2010 and approved May 5, 2010 to Registrant's 2008 Long term Incentive Plan, incorporated by reference to Annex B of Registrant's definitive proxy statement filed on March 25, 2010.

10(11)* 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(12)* 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(13)* Modified Form of Restricted Stock Award Agreement under Registrant's 2008 Long term Incentive Plan incorporated by reference to Exhibit 10(3) of Form 8 K of Registrant filed on March 13, 2012.

10(14)* 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 filed on May 8, 2014.

10(15)* Second Amendment, dated March 23, 2012 and approved May 2, 2012, to Registrant's 2008 Long-term Incentive Plan, incorporated by reference to Annex A of Registrant's definitive proxy statement filed on March 23, 2012.

10(16)* 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(17)* 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(18)* 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 other than Michael Turner and John B. Hess).

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 26, 2015.
23(2)	Consent of DeGolyer and MacNaughton dated February 26, 2015.
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 4, 2015, on proved reserves audit as of December 31, 2014 of certain properties attributable to Registrant.

101(INS)	XBRL Instance Document
101(SCH)	XBRL Schema Document
101(CAL)	XBRL Calculation Linkbase Document
101(LAB)	XBRL Labels Linkbase Document
101(PRE)	XBRL Presentation Linkbase Document
101(DEF)	XBRL Definition Linkbase Document

* These exhibits relate to executive compensation plans and arrangements.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on the 26th day of February 2015.

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	Director and	February 26, 2015
	Chief Executive Officer	
John B. Hess	(Principal Executive Officer)	
/s/ dr. mark r. williams	Director and	February 26, 2015
	Chairman of the Board	
Dr. Mark R. Williams		
/s/ rodney F. Chase	Director	February 26, 2015
Rodney F. Chase		
/s/ Terrence J. Checki	Director	February 26, 2015
Terrence J. Checki		

/s/ Harvey Golub	Director	February 26, 2015
Harvey Golub		
/s/ Edith E. Holiday	Director	February 26, 2015
Edith E. Holiday		
/s/ dr. Risa Lavizzo-Mourey	Director	February 26, 2015
Dr. Risa Lavizzo-Mourey		
/s/ david mcmanus	Director	February 26, 2015
David McManus		
/s/ dr. kevin o. meyers	Director	February 26, 2015
Dr. Kevin O. Meyers		
/s/ john h. mullin, iii	Director	February 26, 2015
John H. Mullin, III		
/s/ james h. quigley	Director	February 26, 2015
James H. Quigley		
/s/ fredric g. reynolds	Director	February 26, 2015
Fredric G. Reynolds		
/s/ John P. Rielly	Senior Vice President and Chief	February 26, 2015

John P. Rielly	Financial Officer (Principal Financial and Accounting Officer)	
/s/ William g. schrader	Director	February 26, 2015
William G. Schrader		
/s/ Robert N. Wilson	Director	February 26, 2015
Robert N. Wilson		

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Schedule II

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES

VALUATION AND QUALIFYING ACCOUNTS

For the Years Ended December 31, 2014, 2013 and 2012

Description	Balance January 1	Additions: Charged to Costs and Expenses	Additions: Charged to Other Accounts	Deductions from Reserves	Balance December 31
	(In millions)				
2014					
Losses on receivables	$27	$ —	$ —	$ 14	$ 13
Deferred income tax valuation	$1,519	$ 142	$ (1)	$ 244	$ 1,416
2013					
Losses on receivables	$34	$ 10	$ —	$ 17	$ 27
Deferred income tax valuation	$1,282	$ 383	$ (17)	$ 129	$ 1,519
2012					
Losses on receivables	$55	$ —	$ —	$ 21	$ 34
Deferred income tax valuation	$1,071	$ 248	$ —	$ 37	$ 1,282

EXHIBIT INDEX

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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.

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4(4) Prospectus Supplement, dated August 8, 2001, to Prospectus dated July 27, 2001 relating to Registrant's 5.30% Notes due 2004, 5.90% Notes due 2006, 6.65% Notes due 2011 and 7.30% Notes due 2031, incorporated by reference to Registrant's prospectus filed pursuant to Rule 424(b)(2) under the Securities Act of 1933, as amended, on August 9, 2001.

4(5) Prospectus Supplement, dated February 28, 2002, to Prospectus dated July 27, 2001 relating to Registrant's 7.125% Notes due 2033, incorporated by reference to Registrant's prospectus filed pursuant to Rule 424(b)(4) under the Securities Act of 1933, as amended, on March 1, 2002.

4(6)

Indenture dated as of March 1, 2006, between Registrant and The Bank of New York Mellon, as successor to JP Morgan Chase Bank, N.A., as Trustee, including form of Note. incorporated by reference to Exhibit 4 to Registrant's Form S 3ASR filed on March 1, 2006.

4(7) Form of 8.125% Note due 2019, incorporated by reference to Exhibit 4(2) to Form 8 K of the Registrant, filed on February 4, 2009.

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10(4)* Performance Incentive Plan for Senior Officers, as amended, as approved by stockholders on May 4, 2011, incorporated by reference to Annex A to the definitive proxy statement of Registrant filed on March 25, 2011.

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10(13)* Modified Form of Restricted Stock Award Agreement under Registrant's 2008 Long term Incentive Plan, incorporated by reference to Exhibit 10(3) of Form 8 K of Registrant filed on March 13, 2012.

10(14)* 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 filed on May 8, 2014.

10(15)* Second Amendment, dated March 23, 2012 and approved May 2, 2012, to Registrant's 2008 Long term Incentive Plan, incorporated by reference to Annex A of Registrant's definitive proxy statement filed on March 23, 2012.

10(16)* 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(17)* 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.

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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 26, 2015.
23(2)	Consent of DeGolyer and MacNaughton dated February 26, 2015.
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 4, 2015, on proved reserves audit as of December 31, 2014 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.

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