UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-K

☑ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2013

or

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

Commission File Number 1-1204

Hess Corporation

(Exact name of Registrant as specified in its charter)

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

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

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

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

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

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

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act. Yes ☐ No ☑

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☑ No ☐

Indicate by check mark whether the registrant submitted electronically and posted on its Corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☑ No ☐

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

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

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☑

The aggregate market value of voting stock held by non-affiliates of the Registrant amounted to $20,200,000,000 computed using the outstanding common shares and closing market price on June 28, 2013, the last business day of the Registrant's most recently completed second fiscal quarter.

At December 31, 2013, there were 325,314,177 shares of Common Stock outstanding.

Part III is incorporated by reference from the Proxy Statement for the 2014 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 and natural gas. Prior to 2013, the Corporation also operated a Marketing and Refining (M&R) segment, which it began to divest during the year. The M&R businesses manufacture refined petroleum products and purchase, market, store and trade refined products, natural gas and electricity, as well as operate retail gasoline stations, most of which have convenience stores.

In the first quarter of 2013, the Corporation announced several initiatives to continue its transformation into a more focused pure play E&P company that is expected to deliver compound average annual production growth of 5% to 8% through 2017, from its 2012 pro forma production of 289,000 barrels of oil equivalent per day (boepd). The transformation plan included fully exiting the Corporation's 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, thus completing its exit from all refining operations. 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. HOVIC and its partner have also commenced a sales process for HOVENSA. The transformation plan also committed to the sale of mature E&P assets in Indonesia and Thailand, and the pursuit of monetizing Bakken midstream assets by 2015.

As part of its transformation during 2012 and 2013, the Corporation sold mature or lower margin assets in Azerbaijan, Indonesia, Norway, Russia, the United Kingdom (UK) North Sea, and certain interests onshore in the U.S. In the fourth quarter of 2013, the Corporation sold its energy marketing business and its terminal network. In 2014, the Corporation plans to divest its remaining downstream businesses, including its retail marketing business and energy trading joint venture, plus its E&P assets in Thailand. The Corporation has also reached an agreement to sell dry gas acreage in the Utica shale play in the U.S.

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)	
	2013	2012	2013	2012	2013	2012
	(Millions of barrels)		(Millions of mcf)		(Millions of barrels)	
Developed						
United States	**278**	280	**279**	232	**325**	318
Europe (c)	**126**	181	**104**	190	**143**	213
Africa	**185**	188	**149**	122	**210**	208
Asia	**17**	27	**578**	676	**113**	140
	606	676	**1,110**	1,220	**791**	879
Undeveloped						
United States	**304**	193	**185**	168	**335**	222
Europe (c)	**165**	235	**134**	167	**188**	263
Africa	**25**	46	**11**	20	**26**	49
Asia	**8**	21	**535**	720	**97**	140
	502	495	**865**	1,075	**646**	674
Total						
United States	**582**	473	**464**	400	**660**	540
Europe (c)	**291**	416	**238**	357	**331**	476
Africa	**210**	234	**160**	142	**236**	257
Asia	**25**	48	**1,113**	1,396	**210**	280
	1,108	1,171	**1,975**	2,295	**1,437**	1,553

(a) *Total natural gas liquids reserves were 136 million barrels (61 million barrels developed and 75 million barrels undeveloped) at December 31, 2013 and 136 million barrels (76 million barrels developed and 60 million barrels undeveloped) at December 31, 2012. Of the total natural gas liquids reserves, 83% and 78% were in the U.S. and 15% and 17% were in Norway at December 31, 2013 and 2012, respectively. 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 8.*

(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 8.*

(c) *Proved reserves in Norway, which represented 20% and 21% of the Corporation's total reserves at December 31, 2013 and 2012, respectively, were as follows:*

	Crude Oil, Condensate & Natural Gas Liquids		Natural Gas		Total Barrels of Oil Equivalent (BOE) (b)	
	2013	2012	2013	2012	2013	2012
	(Millions of barrels)		(Millions of mcf)		(Millions of barrels)	
Developed	**107**	102	**87**	73	**121**	114
Undeveloped	**149**	182	**111**	146	**168**	207
Total	**256**	284	**198**	219	**289**	321

On a barrel of oil equivalent basis, 45% of the Corporation's worldwide proved reserves were undeveloped at December 31, 2013 compared with 43% at December 31, 2012. Proved reserves held under production sharing contracts at December 31, 2013 totaled 7% of crude oil and natural gas liquids reserves and 46% of natural gas reserves, compared with 10% of crude oil and natural gas liquids reserves and 52% of natural gas reserves at December 31, 2012. Pro forma year-end reserves, which exclude assets in Indonesia and Thailand classified as held for sale at December 31, 2013, were 1,362 million boe. See the Supplementary Oil and Gas Data on pages 87 through 94 in the accompanying financial statements for additional information on the Corporation's oil and gas reserves.

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

	2013	2012	2011
Crude oil (thousands of barrels per day)			
United States			
Bakken	**55**	47	26
Other Onshore	**10**	13	11
Total Onshore	**65**	60	37
Offshore	**43**	48	44
Total United States	**108**	108	81
Europe			
Russia	**16**	49	45
United Kingdom	—	15	14
Norway (a)	**20**	11	20
Denmark	**8**	9	10
	44	84	89
Africa			
Equatorial Guinea	**44**	48	54
Libya	**13**	20	4
Algeria	**5**	7	8
	62	75	66
Asia			
Azerbaijan	**2**	7	6
Indonesia	**5**	6	3
Other	**4**	4	4
	11	17	13
Total	**225**	284	249

	2013	2012	2011
Natural gas liquids (thousands of barrels per day)			
United States			
Bakken	**6**	5	2
Other Onshore	**4**	5	5
Total Onshore	**10**	10	7
Offshore	**5**	6	6
Total United States	**15**	16	13
Europe (a)	**1**	2	3
Asia	**1**	1	1
Total	**17**	19	17
Natural gas (thousands of mcf per day)			
United States			
Bakken	**38**	27	13
Other Onshore	**25**	27	26
Total Onshore	**63**	54	39
Offshore	**61**	65	61
Total United States	**124**	119	100
Europe			
United Kingdom	**1**	25	41
Norway (a)	**15**	10	29
Denmark	**7**	8	11
	23	43	81
Asia and Other			
Joint Development Area of Malaysia/Thailand (JDA)	**235**	252	267
Thailand	**87**	90	84
Indonesia	**52**	66	56
Malaysia	**33**	39	35
Other	**11**	7	—
	418	454	442
Total	**565**	616	623
Barrels of oil equivalent (per day) (b)	**336**	406	370

(a) *Norway production for 2013 included 20 thousand barrels per day of crude oil, 1 thousand barrels per day of natural gas liquids and 15 thousand mcf per day of natural gas from the Valhall Field. Norway production for 2012 included 11 thousand barrels per day of crude oil, 0.5 thousand barrels per day of natural gas liquids and 8 thousand mcf per day of natural gas from the Valhall Field. Norway production for 2011 included 18 thousand barrels per day of crude oil, 1 thousand barrels per day of natural gas liquids and 15 thousand mcf per day of natural gas from the Valhall Field.*

(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 8.*

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

United States

At December 31, 2013, 46% of the Corporation's total proved reserves were located in the U.S. During 2013, 51% of the Corporation's crude oil and natural gas liquids production and 22% 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 as well as in the Permian Basin of Texas and the Utica Basin of Ohio.

***Onshore*:** In North Dakota, the Corporation holds approximately 645,000 net acres in the Bakken at December 31, 2013. During 2013, the Corporation operated 14 rigs, drilled 195 wells, completed 181 wells, and brought on production 168 wells, bringing the total operated production wells to 722. During 2014, the Corporation plans to operate 17 rigs, to bring on production a further 225 wells with full year 2014 production from Bakken expected to average between 80,000 boepd and 90,000 boepd.

The Corporation owns the Tioga Gas Plant in North Dakota which had a processing capacity of approximately 110,000 mcf per day of natural gas during 2013. The Corporation is completing an expansion of the plant which will increase total processing capacity to approximately 250,000 mcf per day, with capability for ethane recovery, full fractionation and sales of natural gas liquids. Residual gas sales and ethane extraction are expected to commence in the first quarter of 2014. Other North Dakota infrastructure includes the Tioga rail terminal, nine unit trains each with 104 cars, the Ramberg truck terminal, gas compression stations and related gathering lines.

In the Utica shale play, the Corporation owns a 100% interest in approximately 92,000 acres in the dry gas area. In January 2014, the Corporation reached an agreement to sell approximately 74,000 acres of this dry gas position for $924 million. The Corporation also owns a 50% undivided interest in CONSOL Energy Inc.'s (CONSOL) acreage in the Utica Basin. During the second quarter of 2013, the Corporation reached an agreement with CONSOL relating to title verification. This agreement reduced the gross joint venture acreage by approximately 64,000 acres to approximately 146,000 acres and also reduced the Corporation's total carry obligation from $534 million to $335 million. At December 31, 2013, the Corporation's remaining carry obligation was approximately $200 million. During 2013, a total of 29 wells were drilled, 24 wells were completed and 17 wells were tested across both the Corporation's 100% owned and joint venture acreage with CONSOL. In 2014, the Corporation plans to drill three wells on its 100% owned acreage and 32 wells with CONSOL on its joint venture acreage.

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%), Hack Wilson (Hess 25%) and Penn State (Hess 50%) fields.

At the outside operated Shenzi Field, development drilling continued during 2013 with the completion of two production wells and two water injection wells. Further field development drilling at Shenzi is planned for 2014. At the outside operated Llano Field, the Llano #4 production well was completed and first oil commenced in the fourth quarter of 2013. Llano production during 2013 was impacted by multiple shut-ins for planned and unplanned maintenance activities at outside operated processing and export facilities. At the operated Conger Field, seismic data was acquired during 2013 for future field development planning.

At the Hess operated Tubular Bells Field (Hess 57%), the Corporation completed drilling of the second and third production wells, and commenced a batch completion program in the fourth quarter of 2013. Facilities construction is ongoing with offshore installation expected to commence in the first quarter and first oil anticipated in the third quarter of 2014. A fourth production well is planned to be drilled during 2014.

The Corporation is operator and holds a 20% interest in the Stampede offshore development project, which consists of the Corporation's Pony discovery and the third-party Knotty Head discovery. An application to unitize Blocks 468, 512, the western half of 469 and the eastern half of 511 is expected to be filed with the Bureau of Safety and Environmental Enforcement in the first quarter of 2014. Field development is progressing and the project is targeted for sanction in 2014.

At December 31, 2013, the Corporation had interests in 207 blocks in the Gulf of Mexico, of which 178 were exploration blocks comprising approximately 700,000 net undeveloped acres, with an additional 66,000 net acres held for production and development operations. During 2013, the Corporation's interests in 47 leases, comprising approximately 165,000 net undeveloped acres, either expired or were relinquished. In the next three years, an additional 114 exploration leases, comprising approximately 430,000 net undeveloped acres, are due to expire.

Europe

At December 31, 2013, 23% of the Corporation's total proved reserves were located in Europe (Norway 20% and Denmark 3%). During 2013, 18% of the Corporation's crude oil and natural gas liquids production and 4% 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.

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

The Valhall Field was shut down from July 2012 through January 2013 to install a new production, utilities and accommodation platform, that extends the field life by approximately 40 years. Production resumed at reduced rates until the Valhall Field was shut down during June 2013 for planned maintenance at a third party processing facility. Net production from the Valhall Field for 2013 averaged 23,000 boepd with full year 2014 production expected to be in the range of 30,000 boepd to 35,000 boepd. In addition, the Corporation has a well abandonment program and is decommissioning the old infrastructure that is no longer being used.

United Kingdom: In January 2013, the Corporation completed the sale of its interests in the Beryl fields (Hess 22%) and the Scottish Area Gas Evacuation (SAGE) pipeline in the UK North Sea. The Corporation has commenced decommissioning activities in its non-producing fields comprising Atlantic (Hess 25%), Cromarty (Hess 90%), Fife, Flora and Angus (Hess 85%), Fergus (Hess 65%), Ivanhoe and Rob Roy (Hess 77%).

Denmark: Production comes from the Corporation's operated interest in the South Arne Field (Hess 62%), offshore Denmark. During 2013, the Corporation completed its phase three development program in which two new wellhead platforms were successfully installed in the Field. Development drilling commenced in the first half of 2013 and first oil from the development was achieved in the fourth quarter of 2013. Net production from the South Arne Field for 2013 averaged 9,000 boepd with full year 2014 production expected to be in the range of 10,000 boepd to 15,000 boepd.

Russia: The Corporation's activities in Russia were conducted through its interest in Samara-Nafta, a subsidiary operating in the Volga-Urals region. In April 2013, the Corporation completed the sale of its subsidiary.

France: The Corporation has interests in more than 300,000 net acres in the Paris Basin. In 2013, the Corporation drilled three vertical wells, which were logged and cored. Technical evaluation of the well results is expected to be completed in 2014. A law prohibiting the use of hydraulic fracturing was implemented by the French government in July 2011 and remains in place.

Africa

At December 31, 2013, 16% of the Corporation's total proved reserves were located in Africa (Equatorial Guinea 3.5%, Libya 12% and Algeria 0.5%). During 2013, 26% 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. During 2013, the Corporation completed three additional production wells at the Ceiba Field, which concluded the Ceiba Phase II drilling campaign. At the Okume Complex, an infill drilling campaign commenced in the fourth quarter of 2013 based on 4D seismic and will continue throughout 2014. Net production from Equatorial Guinea averaged 44,000 boepd in 2013 and is expected to be in the range of 40,000 boepd to 45,000 boepd in 2014.

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 continuing civil unrest in Libya, production has been shut-in from the beginning of the third quarter of 2013. Net production at the Waha fields averaged 15,000 boepd during 2013 and 21,000 boepd in 2012. The Corporation also owns a 100% interest in offshore exploration Area 54 in the Mediterranean Sea. As a result of the ongoing civil and political unrest, the Corporation expensed the two previously capitalized exploration wells on the block in the fourth quarter of 2013.

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 100% paying interest and is operator of the Deepwater Tano Cape Three Points license. The Ghana National Petroleum Corporation holds a 10% carried interest in the block. The Corporation has drilled seven successful exploration wells on the block. In June 2013, the Corporation submitted appraisal plans for each of the seven discoveries to the Ghanaian government for approval. Four of these appraisal plans, including the appraisal plan for the largest discovery, Pecan, were approved by year-end. The Corporation plans to commence a three well appraisal drilling campaign in the second half of 2014. Discussions continue with the Ghanaian government on the outstanding three appraisal plans.

Asia and Other

At December 31, 2013, 15% of the Corporation's total proved reserves were located in the Asia region (JDA 9%, Indonesia 2%, Thailand 3% and Malaysia 1%). During 2013, 5% of the Corporation's crude oil and natural gas liquids production and 74% of its natural gas production were from its Asian and Other operations. In December 2013, the Corporation completed the sale of its Natuna A Field, located off the coast of Indonesia and in January 2014, its Pangkah asset, also located off the coast of Indonesia. In the first quarter of 2013, the Corporation sold its interests in Azerbaijan in the Caspian Sea and announced its intent to divest its interests in Thailand.

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 2013, the operator continued development drilling, successfully installed two new wellhead platforms, sanctioned a further wellhead platform and continued with a major booster compression project. In 2014, the operator intends to progress the compression project, continue development drilling and commence production at the platforms installed in 2013. Net production for 2013 averaged 41,000 boepd with full year 2014 production expected to be approximately 250,000 mcf 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 where the natural gas is processed. The Corporation also owns a 50% interest and is the operator of Blocks PM302, PM325 and PM326B located in the North Malay Basin (NMB), offshore Peninsular Malaysia, where a multi-phase natural gas development project is underway. The project achieved first production on the Early Production System in October 2013 where net production averaged approximately 30 million cubic feet per day in the fourth quarter. The Corporation expects net production to average approximately 40 million cubic feet per day through 2016 until full field development is completed in late 2016. Net production is expected to increase to approximately 165 million cubic feet per day in 2017.

Indonesia: The Corporation's production in Indonesia came from its interests offshore in the operated Ujung Pangkah asset (Hess 75%) and the outside operated Natuna A Field. In December 2013, the Corporation completed the sale of its Natuna A Field and, in January 2014, the Pangkah asset was sold.

Thailand: The Corporation's production in Thailand comes from the outside operated offshore Pailin Field (Hess 15%) and the operated onshore Sinphuhorm Block (Hess 35%). The Corporation has a sales process underway for its assets in Thailand.

Azerbaijan: The Corporation completed the sale of its interests in the Azeri-Chirag-Guneshli (ACG) fields, in the Caspian Sea, and in the Baku-Tbilisi-Ceyhan (BTC) oil transportation pipeline company, in March 2013.

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, including negotiations with potential liquefaction partners continued in 2013. Successful negotiation with a third party liquefaction partner is necessary before the Corporation can negotiate a gas sales agreement and sanction development of the project. In addition, the Corporation has approximately 1.7 million net acres in the Canning Basin, onshore Western Australia, where seismic re-processing and aero-magnetic surveys and interpretation were ongoing during 2013.

Brunei: The Corporation has an interest in Block CA-1 (Hess 14%). In 2012, the operator drilled two wells, Jagus East and Julong East, which both encountered hydrocarbons. These wells are being evaluated and seismic processing is ongoing.

Kurdistan Region of Iraq: The Corporation is operator and has an 80% paying interest (64% working interest) in the Dinarta and Shakrok exploration blocks, which have a combined area of more than 670 square miles. The Corporation spud its first exploration well on the Shakrok block during 2013. A second exploration well in Kurdistan, which will be on the Dinarta block, is planned for the first half of 2014.

China: In July 2013, the Corporation signed a Production Sharing Agreement with China National Petroleum Corporation (CNPC) to evaluate unconventional oil and gas resource opportunities covering approximately 200,000 gross acres in the Santanghu Basin. Under the agreement, Hess owns a 49% working interest share. The exploration phase commenced in August 2013 and one vertical well has been drilled to date. Further drilling is planned for 2014.

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Sales Commitments

In the E&P segment, 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 99 billion cubic feet per year based on current entitlements under a sales contract expiring in 2027. The estimated total volume of production subject to sales commitments under all of these contracts is approximately 1.7 trillion cubic feet of natural gas.

The Corporation has NGL contracts relating to its Bakken production with delivery commitments which begin in January 2014. The minimum contract quantity under these contracts, which expire in 2023, is approximately 8 million barrels per year, or approximately 98 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.

Average selling prices and average production costs

	2013	2012	2011
Average selling prices (a)			
Crude oil — per barrel (including hedging)			
United States			
Onshore	**$ 90.00**	$ 84.78	$ 91.11
Offshore	**103.83**	101.80	104.83
Total United States	**95.50**	92.32	98.56
Europe (b)	**88.03**	74.14	80.18
Africa	**108.70**	89.02	88.46
Asia	**107.40**	107.45	111.71
Worldwide	**98.48**	86.94	89.99
Crude oil — per barrel (excluding hedging)			
United States			
Onshore	**$ 89.81**	$ 85.66	$ 91.11
Offshore	**103.15**	104.39	104.83
Total United States	**95.11**	93.96	98.56
Europe (b)	**87.45**	75.06	80.18
Africa	**108.07**	110.92	110.28
Asia	**107.40**	109.35	111.71
Worldwide	**98.01**	93.70	95.60
Natural gas liquids — per barrel			
United States			
Onshore	**$ 43.14**	$ 44.22	$ 79.75
Offshore	**29.18**	35.24	50.88
Total United States	**38.07**	40.75	58.59
Europe (b)	**58.31**	78.43	75.49
Asia	**74.94**	77.92	72.29
Worldwide	**40.68**	47.81	62.72

Average selling prices and average production costs

	2013	2012	2011
Natural gas — per mcf			
United States			
Onshore	**$ 3.08**	$ 2.02	$ 3.16
Offshore	**2.83**	2.15	3.54
Total United States	**2.96**	2.09	3.39
Europe (b)	**11.06**	9.50	8.79
Asia and other	**7.50**	6.90	6.02
Worldwide	**6.64**	6.16	5.96
Average production (lifting) costs per barrel of oil equivalent produced (c)			
United States			
Onshore	**$ 29.42**	$ 28.97	$ 29.14
Offshore	**4.98**	5.21	5.08
Total United States	**19.45**	18.25	16.30
Europe (b)	**36.02**	29.56	25.13
Africa	**19.26**	14.45	15.95
Asia and other	**12.89**	11.13	10.62
Worldwide	**20.26**	18.52	17.40

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

(b) *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 selling prices in Norway for 2011 were $112.38 per barrel for crude oil, $62.07 per barrel for natural gas liquids and $9.77 per mcf for natural gas. The average production (lifting) costs in Norway were $44.69 per barrel of oil equivalent produced in 2013, $62.38 per barrel of oil equivalent produced in 2012, reflecting a shutdown of production from July 2012 through the end of 2012, and $31.09 per barrel of oil equivalent produced in 2011.*

(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, 2013

	Undeveloped Acreage (a)	
	Gross	Net
	(In thousands)	
United States	1,692	1,197
Europe (b)	807	639
Africa	6,453	3,380
Asia and other	11,845	7,874
Total (c)	20,797	13,090

(a) *Includes acreage held under production sharing contracts.*

(b) *Gross and net undeveloped acreage in Norway was 61 thousand and 9 thousand, respectively.*

(c) *Licenses covering approximately 69% of the Corporation's net undeveloped acreage held at December 31, 2013 are scheduled to expire during the next three years pending the results of exploration activities. These scheduled expirations are largely in Africa, Asia and the U.S.*

Gross and net developed acreage and productive wells at December 31, 2013

	Developed Acreage Applicable to Productive Wells		Productive Wells (a)			
			Oil		Gas	
	Gross	Net	Gross	Net	Gross	Net
	(In thousands)					
United States	1,212	813	2,029	885	59	47
Europe (b)	102	59	64	41	—	—
Africa	9,832	933	826	121	—	—
Asia and other	914	355	17	13	499	113
Total	12,060	2,160	2,936	1,060	558	160

(a) Includes multiple completion wells (wells producing from different formations in the same bore hole) totaling 48 gross wells and 35 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 50 and 32, respectively.

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

	Net Exploratory Wells			Net Development Wells		
	2013	2012	2011	2013	2012	2011
Productive wells						
United States	**10**	3	20	**146**	184	98
Europe	**—**	3	6	**1**	23	25
Africa	**2**	3	1	**2**	1	1
Asia and other	**4**	3	4	**18**	20	18
	16	12	31	**167**	228	142
Dry holes						
United States	**—**	1	—	**—**	—	—
Europe	**3**	3	2	**—**	—	—
Africa	**—**	—	1	**—**	—	—
Asia and other	**1**	2	1	**—**	—	—
	4	6	4	**—**	—	—
Total	**20**	18	35	**167**	228	142

Number of wells in process of drilling at December 31, 2013

	Gross Wells	Net Wells
United States	184	81
Europe*	5	3
Africa	16	2
Asia and other	23	6
Total	228	92

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

Marketing and Refining

The Corporation is in the process of exiting all downstream businesses to become a pure play E&P company.

At December 31, 2013, the Corporation had 1,350 HESS ® retail gasoline stations, including stations owned by its WilcoHess joint venture (Hess 44%). Approximately 93% of the gasoline stations are operated by the Corporation or WilcoHess. Of the operated stations, 96% have convenience stores on the sites. Most of the Corporation's gasoline stations are in New York, New Jersey, Pennsylvania, Florida, Massachusetts, North Carolina and South Carolina. In January 2014, the Corporation acquired the remaining interest in WilcoHess. The Corporation is pursuing a dual track to divest its retail marketing business either through a third-party sale or a tax free spin-off into a new public company.

The table below summarizes marketing sales volumes:

	2013	2012	2011
Retail Marketing			
Number of retail stations*	**1,350**	1,361	1,360
Convenience store revenue (in millions)	**$ 1,069**	$ 1,123	$ 1,189
Average gasoline volume per station (thousands of gallons per month)	**187**	192	195

* *Includes operated, WilcoHess, dealer and branded retailer stations.*

In addition, the Corporation plans to divest its interests in an energy trading partnership, a joint venture (Hess 50%) to build a 655-megawatt natural gas fueled electric generating facility in Newark, New Jersey, and the Bayonne Energy Center, LLC (Hess 50%), a joint venture that operates a 512-megawatt natural gas fueled electric generating station in Bayonne, New Jersey, which provides power to New York City.

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. to wholesale distributors, industrial and commercial users, other petroleum companies, governmental agencies 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. HOVENSA, a 50/50 joint venture between the Corporation's subsidiary, HOVIC, and a subsidiary of PDVSA, had previously shut down its refinery in St. Croix, U.S. Virgin Islands in January 2012 and continued operating solely as an oil storage terminal. During 2012 and continuing into 2013, HOVENSA and the Government of the Virgin Islands negotiated a plan to pursue the sale of HOVENSA and the sales process commenced in the fourth quarter. If an agreement to sell the refinery cannot be reached, HOVENSA will likely not be able to continue operating as an oil storage terminal. For further discussion of the refinery shutdown, see Note 10, HOVENSA L.L.C. Joint Venture, in the notes to the Consolidated Financial Statements.

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 Well Containment Company (MWCC), Wild Well Control (WWC), Subsea Well Intervention Service (SWIS), National Response Corporation (NRC) and Oil Spill Response (OSR). CGA is a regional spill response organization 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 OSR 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 300,000 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, Hess 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 Committee of CGA and the Board of Directors of OSR.

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 $2.38 billion in total, depending on the asset coverage level, as described above. Additionally, the Corporation carries insurance which provides third party coverage for general liability, and sudden and accidental pollution, up to $1.05 billion.

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 fault, 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 blowouts, cratering and loss of hole, regardless of cause, although exceptions for losses attributable to gross negligence and/or willful misconduct do exist. Lastly, many 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, not covered by or in excess of insurance carried by 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 a party, in which case such party is solely liable. However, under some production sharing contracts between a governmental entity and commercial parties, liability of the commercial parties to the governmental 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. The Corporation spent approximately $16 million in 2013 for environmental remediation, principally relating to the downstream businesses. The Corporation anticipates capital expenditures for E&P facilities, primarily to comply with federal, state and local environmental standards of approximately $65 million in 2014 and approximately $50 million in 2015. The Corporation anticipates capital expenditures for the downstream businesses of approximately $8 million in 2014. 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 at year-end was approximately 12,225 in 2013 and 14,775 in 2012. The reduction in the number of employees between 2013 and 2012 was largely a result of the Corporation's asset sales program. Of the employees remaining at year-end, approximately 8,800 in 2013 (approximately 9,500 in 2012) were employed in the Corporation's downstream businesses that are due to be divested.

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. 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 utilizes 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.

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.

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, as well as other political developments may affect our operations. As a result of the accident in April 2010 at the BP p.l.c. (BP) operated Macondo prospect in the Gulf of Mexico (in which the Corporation was not a participant) and the ensuing significant oil spill, a temporary drilling moratorium was imposed in the Gulf of Mexico. While this moratorium has since been lifted, significant new regulations have been imposed and further legislation and regulations may be proposed. The new regulatory environment has resulted in a longer permitting process and higher costs. We also 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 may result in heightened regulatory scrutiny that may lead to an increase in the costs of transporting crude oil and other hydrocarbons by rail and otherwise adversely impact 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. 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. For example, production at the Waha fields in Libya, which has a net production capacity of approximately 25,000 boepd, has been shut-in since August 2013 and was also shut-in for eight months in 2011 due to civil unrest. 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.

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. For example, a moratorium prohibiting hydraulic fracturing is currently impacting the Corporation’s exploration activities in France.

Concerns about climate change 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. Finally, to the extent that climate change may result in more extreme weather related events, we could experience increased costs related to prevention, maintenance and remediation of affected operations in addition to higher costs and lost revenues related to delays and shutdowns.

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.

Cyber-attacks targeting our computer and 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, the loss or corruption of our data and proprietary information and communications interruptions. In addition, computers control oil and gas distribution systems globally and are necessary to deliver our production to market. A cyber-attack impacting these distribution 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. Our systems and procedures for protecting against such attacks and mitigating such risks may prove to be insufficient and such attacks could have an adverse impact on our business and operations.

Item 3. Legal Proceedings

The Corporation, along with many other 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. In 2008, the majority of the cases against the Corporation were settled. In 2010 and 2011, additional cases were settled including an action brought in state court by the State of New Hampshire. Cases brought by the State of New Jersey and the Commonwealth of Puerto Rico remain unresolved. The Corporation has reserves recorded which it believes are adequate to cover its expected liability in these cases.

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. The CERCLA claims have been dismissed and a trial is scheduled in June 2014 on the remaining claims. HOVIC and HOVENSA are continuing to vigorously defend this matter and do not believe that this matter will result in a material liability as they believe that they have strong defenses against this complaint.

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.

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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:

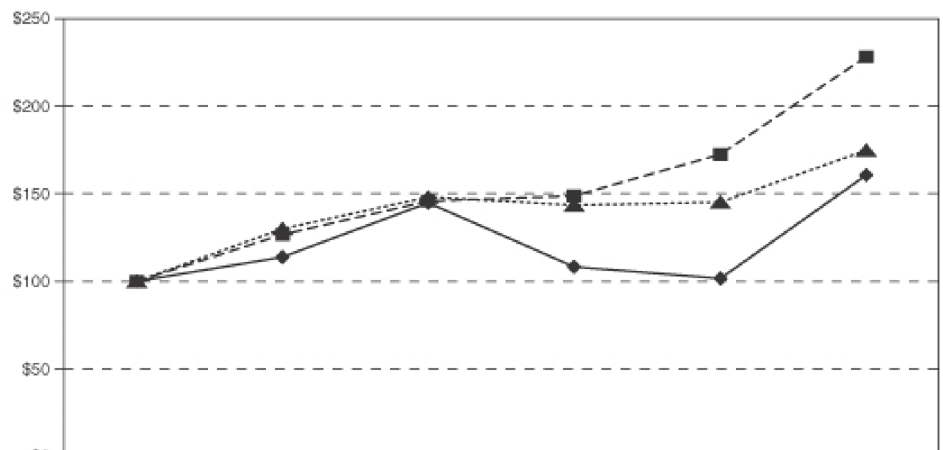
	2013		2012	
Quarter Ended	High	Low	High	Low
March 31	**$ 72.63**	**$ 53.06**	$ 67.86	$ 54.10
June 30	**74.48**	**61.32**	60.20	39.67
September 30	**80.41**	**66.23**	57.34	41.94
December 31	**85.15**	**76.83**	55.96	48.20

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 16 oil and gas peer companies, including the Corporation (as disclosed in the Corporation's 2013 Proxy Statement).

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



	2008	2009	2010	2011	2012	2013
Hess Corporation	$100.00	$113.61	$144.67	$108.03	$101.51	$160.54
S&P 500	$100.00	$126.45	$145.52	$148.55	$172.29	$228.04
Proxy Peer Group	$100.00	$129.90	$148.04	$143.24	$145.11	$174.77

Holders

At December 31, 2013, there were 3,961 stockholders (based on the number of holders of record) who owned a total of 325,314,177 shares of common stock.

Dividends

In 2013, cash dividends 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) for both 2012 and 2011.

Share Repurchase Activities

Hess's share repurchase activities for the year ended December 31, 2013, were as follows:

2013	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)
July	—	$ —	—	$ 4,000
August	3,033,073	75.05	3,033,073	3,772
September	3,495,977	77.95	3,495,977	3,500
October	5,159,765	81.31	5,159,765	3,080
November	3,910,569	81.43	3,910,569	2,762
December	3,710,300	80.85	3,710,300	2,462
Total for 2013	19,309,684	$ 79.65	19,309,684	

(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.

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Equity Compensation Plans

Following is information on the Registrant's equity compensation plans at December 31, 2013:

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	10,141,000	$ 63.08	10,244,000(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 13, Share-based Compensation in the notes to the Consolidated Financial Statements for further discussion of the Corporation's equity compensation plans.

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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:

	2013	2012	2011	2010	2009
	(In millions, except per share amounts)				
Sales and other operating revenues					
Crude oil and natural gas liquids	**$ 9,824**	$ 10,332	$ 8,921	$ 7,235	$ 5,665
Natural gas (including sales of purchased gas)	**1,394**	1,394	1,362	1,373	1,215
Refined petroleum products	**9,684**	10,190	9,712	5,409	4,382
Convenience store sales and other operating revenues	**1,382**	1,465	1,456	1,636	1,716
Total	**$ 22,284**	$ 23,381	$ 21,451	$ 15,653	$ 12,978
Income from continuing operations	**$ 3,968**	$ 1,867	$ 1,531	$ 1,955	$ 571
Income from discontinued operations	**1,254**	196	145	183	236
Net income	**$ 5,222**	$ 2,063	$ 1,676	$ 2,138	$ 807
Less: Net income (loss) attributable to noncontrolling interests	**170**	38	(27)	13	67
Net income attributable to Hess Corporation	**$ 5,052(a)**	$ 2,025(b)	$ 1,703(c)	$ 2,125(d)	$ 740(e)
Net income attributable to Hess Corporation per share:					
Basic:					
Continuing operations	**$ 11.28**	$ 5.40	$ 4.62	$ 5.96	$ 1.56
Discontinued operations	**3.73**	0.58	0.43	0.56	0.72
Net income per share	**$ 15.01**	$ 5.98	$ 5.05	$ 6.52	$ 2.28
Diluted:					
Continuing operations	**$ 11.14**	$ 5.37	$ 4.58	$ 5.92	$ 1.55
Discontinued operations	**3.68**	0.58	0.43	0.55	0.72
Net income per share	**$ 14.82**	$ 5.95	$ 5.01	$ 6.47	$ 2.27
Total assets	**$ 42,754**	$ 43,441	$ 39,136	$ 35,396	$ 29,465
Total debt	**$ 5,798**	$ 8,111	$ 6,057	$ 5,583	$ 4,467
Total equity	**$ 24,784**	$ 21,203	$ 18,592	$ 16,809	$ 13,528
Dividends per share of common stock	**$ 0.70**	$ 0.40	$ 0.40	$ 0.40	$ 0.40

(a) 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 last-in, first-out (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.

(b) 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.

(c) 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.

(d) 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.

(e) Includes after-tax expenses totaling $104 million relating to repurchases of fixed-rate public notes, retirement benefits, employee severance costs and asset impairments, partially offset by after-tax income totaling $101 million principally relating to the resolution of a U.S. royalty dispute.

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

Overview

Hess Corporation (the Corporation or Hess) is a global Exploration and Production (E&P) company that develops, produces, purchases, transports and sells crude oil and natural gas. Prior to 2013, the Corporation also operated a Marketing and Refining (M&R) segment, which it began to divest during the year. The M&R businesses manufacture refined petroleum products and purchase, market, store and trade refined products, natural gas and electricity, as well as operate retail gas stations, most of which have convenience stores.

In the first quarter of 2013, the Corporation announced several initiatives to continue its transformation into a more focused pure play E&P company that is expected to deliver compound average production growth of 5% to 8% through 2017, from its 2012 pro forma production of 289,000 barrels of oil equivalent per day (boepd). The transformation plan included fully exiting the Corporation's 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, thus completing its exit from all refining operations. 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. HOVIC and its partner have also commenced a sales process for HOVENSA. The transformation plan also committed to the sale of mature E&P assets in Indonesia and Thailand and the pursuit of monetizing Bakken midstream assets by 2015.

As part of its transformation during 2012 and 2013, the Corporation sold mature or lower margin assets in Azerbaijan, Indonesia, Norway, Russia, the United Kingdom (UK) North Sea, and certain interests onshore in the U.S. In the fourth quarter of 2013, the Corporation sold its energy marketing business and its terminal network. In 2014, the Corporation plans to divest its remaining downstream businesses, including its retail marketing business and energy trading joint venture, plus its E&P assets in Thailand. The Corporation has also reached an agreement to sell dry gas acreage in the Utica shale play in the U.S.

Other actions announced by the Corporation in March 2013 included repaying debt, establishing a cash cushion and returning capital to shareholders. By year-end 2013, approximately $2.4 billion of short-term debt had been repaid. In addition, commencing in the third quarter of 2013, the Corporation increased its quarterly dividend 150% to $0.25 per common share and commenced share repurchases under its authorized $4 billion share repurchase program. Through December 31, 2013, Hess had purchased approximately 19.3 million common shares at a cost of approximately $1.54 billion.

Net income was $5,052 million in 2013 compared with $2,025 million in 2012 and $1,703 million in 2011. Diluted earnings per share were $14.82 in 2013 compared with $5.95 in 2012 and $5.01 in 2011. Excluding items affecting comparability, net income was $1,892 million in 2013, $1,998 million in 2012, and $1,984 million in 2011. See the table of items affecting comparability of earnings between periods on page 24.

Exploration and Production

The Corporation's total proved reserves were 1,437 million barrels of oil equivalent (boe) at December 31, 2013 compared with 1,553 million boe at December 31, 2012 and 1,573 million boe at December 31, 2011. Proved reserves related to assets sold in 2013 totaled 139 million boe. Pro forma year-end reserves, which exclude assets in Indonesia and Thailand classified as held for sale at December 31, 2013, were 1,362 million boe.

E&P earnings were $4,303 million in 2013, $2,212 million in 2012 and $2,675 million in 2011. Excluding items affecting comparability of earnings between periods on page 28, E&P net income was $2,192 million, $2,256 million and $2,431 million for 2013, 2012 and 2011, respectively. Average realized crude oil selling prices including the impact of hedging were $98.48 per barrel in 2013, $86.94 in 2012 and $89.99 in 2011. Average realized natural gas selling prices were $6.64 per mcf in 2013, $6.16 in 2012 and $5.96 in 2011. Production averaged 336,000 boepd in 2013, 406,000 boepd in 2012 and 370,000 boepd in 2011.

Excluding production from assets sold and classified as held for sale, pro forma production was 285,000 boepd in 2013 and 289,000 boepd in 2012. The Corporation expects compound average annual production growth of 5% to 8% through 2017, from 2012 pro forma production. The Corporation currently expects total worldwide production to average between 305,000 boepd and 315,000 boepd in 2014, excluding asset sales and any contribution from Libya, which has a net production capacity of approximately 25,000 boepd and is shut-in due to civil unrest in the country. Pro forma production excluding Libya was 270,000 boepd in 2013 and 268,000 boepd in 2012.

The following is an update of significant E&P activities during 2013:

- In North Dakota, net production from the Bakken oil shale play averaged 67,000 boepd during 2013, an increase of 20% from 56,000 boepd in 2012 despite the transition to pad drilling in the first half of the year and the required shut-ins late in the fourth quarter of 2013 for the expansion of the Tioga Gas Plant which is expected to be operational in the first quarter of 2014. Production is expected to average between 80,000 boepd and 90,000 boepd in 2014, an increase of 19% to 34% from 2013. The Corporation also increased its peak net production guidance for the Bakken to 150,000 boepd in 2018 from prior guidance of 120,000 boepd in 2016, based upon performance to date and current development spacing based on five Middle Bakken wells and four Three Forks wells per 1,280 acre Drilling Spacing Unit (DSU). During 2014, the Corporation plans to pilot test tighter well spacing to determine whether there is additional upside in the estimates for future production and resources. During the year, 168 wells were brought on production bringing the total operated production wells to 722 . In 2014, the Corporation plans to increase the rig count in the Bakken to 17 from 14 but expects to maintain capital spending at approximately $2.2 billion, which is consistent with 2013 levels.
- At the Valhall Field in Norway (Hess 64%), net production averaged 23,000 boepd during 2013, compared with 13,000 boepd during 2012. The Field was shut-in during the second half of 2012 and January 2013 to complete a multiyear redevelopment project. Full year 2014 net production for Valhall is expected to be in the range of 30,000 boepd to 35,000 boepd.
- In the North Malay Basin, the project achieved first production from the Early Production System in October 2013 and net production averaged approximately 30 million cubic feet per day in the fourth quarter. The Corporation expects net production to average approximately 40 million cubic feet per day through 2016 until full field development is completed in late 2016. Net production is expected to increase to approximately 165 million cubic feet per day in 2017.
- In December 2013, the Corporation commenced production from its phase three development program at the South Arne Field (Hess 62%) offshore Denmark, following the installation of two new wellhead platforms and modifications to existing production facilities. Development drilling will continue in 2014.
- At Block A-18 of the Joint Development Area of Malaysia/Thailand (JDA), the Corporation successfully installed two new wellhead platforms and progressed a major booster compression project that is expected to be completed in 2015.
- In the Utica shale, 29 wells were drilled, 24 wells were completed and 17 wells were tested across both the Corporation’s 100% owned and joint venture acreage. Production test rates in the wet gas area averaged over 2,200 boepd with 47% liquids.
- In Libya, production from the Waha fields was shut-in late August of 2013 and remains shut-in due to civil unrest in the country. For the full year 2013, Libya production averaged 15,000 boepd. In addition, the Corporation wrote-off in the fourth quarter two previously capitalized exploration wells in offshore Area 54 which resulted in a pre-tax charge of $260 million ($163 million after income taxes).
- During the year, the Corporation completed drilling its second and third production wells at the Tubular Bells Field, offshore U.S., and commenced a batch completion program during the fourth quarter of 2013 for the three wells drilled to date. Facilities construction is ongoing with offshore installation expected to commence in the first quarter and first oil in the third quarter of 2014 at a net rate of 25,000 boepd.
- The Corporation completed its exploration drilling phase on the Deepwater Tano Cape Three Points Block, offshore Ghana that resulted in a total of seven successful exploration wells. The Corporation submitted appraisal plans to the Ghanaian government and four appraisal areas have been approved to date. A three well appraisal drilling program has been scheduled in the second half of 2014.
- In the third quarter, the Corporation spud its first exploration well on the Shakrok block in the Kurdistan Region of Iraq (Hess 80%) and plans to begin drilling an exploration well on the Dinarta block in the first half of 2014.
- During 2013, the E&P segment sold its assets in Azerbaijan and Russia as well as its interests in the Natuna A Field, offshore Indonesia, the Beryl fields in the UK North Sea and certain interests onshore in the U.S., for total proceeds of approximately $4.5 billion. Asset sales reduced production by approximately 60,000 boepd in 2013 compared to 2012. In January 2014, the Corporation announced it had reached agreement to sell approximately 74,000 acres of its 100% interest in the Utica Shale for $924 million. Approximately two-thirds of these proceeds are expected at the end of the first quarter of 2014, with the balance to be received in the third quarter of 2014.

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Downstream Businesses

The downstream businesses reported income of $1,189 million in 2013 and $231 million in 2012 and a loss of $584 million in 2011. Excluding items affecting comparability of earnings between periods on page 31, the downstream businesses generated income of $116 million in 2013 and $160 million in 2012 and a loss of $59 million in 2011. The downstream businesses comprise the Corporation's retail, energy marketing, terminal, energy trading and refining operations, together with its interests in two power plant joint ventures. By year-end all of these businesses were either divested by the Corporation or the divestiture processes remained on-going.

Liquidity and Capital and Exploratory Expenditures

Net cash provided by operating activities was $4,870 million in 2013, $5,660 million in 2012 and $4,984 million in 2011. At December 31, 2013, cash and cash equivalents totaled $1,814 million, up from $642 million at December 31, 2012. Total debt was $5,798 million at December 31, 2013 and $8,111 million at December 31, 2012. The Corporation's debt to capitalization ratio at December 31, 2013 was 19.0% compared with 27.7% at the end of 2012.

Capital and exploratory expenditures were as follows:

	2013	2012	2011
		(In millions)	
Exploration and Production			
United States			
Bakken	**$ 2,231**	$ 3,164	$ 2,361
Other Onshore	**708**	729	1,532
Total Onshore	**2,939**	3,893	3,893
Offshore	**865**	870	412
Total United States	**3,804**	4,763	4,305
Europe	**724**	1,381	1,274
Africa	**630**	771	414
Asia and other	**993**	1,231	1,351
Total Exploration and Production	**6,151**	8,146	7,344
Other*	**164**	119	118
Total Capital and Exploratory Expenditures	**$ 6,315**	$ 8,265	$ 7,462
Exploration expenses charged to income included above:			
United States	**$ 192**	$ 142	$ 197
International	**250**	328	259
Total exploration expenses charged to income included above	**$ 442**	$ 470	$ 456

** Includes capital expenditures related to discontinued operations of $33 million, $52 million and $65 million in 2013, 2012 and 2011, respectively.*

The Corporation anticipates investing approximately $5.8 billion in E&P capital and exploratory expenditures in 2014 and approximately $350 million for retail marketing, primarily for the acquisition of its partner's share of the WilcoHess joint venture which closed in January 2014.

Consolidated Results of Operations

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

	2013	2012	2011
		(In millions, except per share amounts)	
Exploration and Production	**$ 4,303**	$ 2,212	$ 2,675
Corporate and Interest	**(440)**	(418)	(388)
Downstream businesses	**1,189**	231	(584)
Net income attributable to Hess Corporation	**$ 5,052**	$ 2,025	$ 1,703
Net income per share (diluted)	**$ 14.82**	$ 5.95	$ 5.01

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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 28 through 31.

	2013	2012	2011
		(In millions)	
Exploration and Production	**$ 2,111**	$ (44)	$ 244
Corporate and Interest	**(24)**	—	—
Downstream businesses	**1,073**	71	(525)
Total items affecting comparability of earnings between periods	**$ 3,160**	$ 27	$ (281)

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:

	2013	2012	2011
		(In millions)	
Sales and other operating revenues	**$11,905**	$ 12,245	$ 10,646
Gains on asset sales, net	**2,171**	584	446
Other, net	**(57)**	99	18
Total revenues and non-operating income	**14,019**	12,928	11,110
Costs and expenses			
Cost of products sold (excluding items shown separately below)	**1,853**	1,334	580
Operating costs and expenses	**2,116**	2,202	1,876
Production and severance taxes	**372**	550	476
Exploration expenses, including dry holes and lease impairment	**1,031**	1,070	1,195
General and administrative expenses	**377**	314	313
Depreciation, depletion and amortization	**2,671**	2,853	2,305
Asset impairments	**289**	582	358
Total costs and expenses	**8,709**	8,905	7,103
Results of operations before income taxes	**5,310**	4,023	4,007
Provision for income taxes	**831**	1,793	1,313
Net income	**4,479**	2,230	2,694
Less: Net income attributable to noncontrolling interests	**176**	18	19
Net income attributable to Hess Corporation	**$ 4,303**	$ 2,212	$ 2,675

Excluding the E&P items affecting comparability of earnings between periods in the table on page 28, 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 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 had significantly lower crude oil prices, and slightly higher average West Texas Intermediary (WTI) benchmark prices in 2013. Average crude oil realized selling prices were 3% lower in 2012 compared with 2011, primarily due to lower average WTI benchmark prices.

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The Corporation's average selling prices were as follows:

	2013	2012	2011
Crude oil — per barrel (including hedging)			
United States			
Onshore	**$ 90.00**	$ 84.78	$ 91.11
Offshore	**103.83**	101.80	104.83
Total United States	**95.50**	92.32	98.56
Europe	**88.03**	74.14	80.18
Africa	**108.70**	89.02	88.46
Asia	**107.40**	107.45	111.71
Worldwide	**98.48**	86.94	89.99
Crude oil — per barrel (excluding hedging)			
United States			
Onshore	**$ 89.81**	$ 85.66	$ 91.11
Offshore	**103.15**	104.39	104.83
Total United States	**95.11**	93.96	98.56
Europe	**87.45**	75.06	80.18
Africa	**108.07**	110.92	110.28
Asia	**107.40**	109.35	111.71
Worldwide	**98.01**	93.70	95.60
Natural gas liquids — per barrel			
United States			
Onshore	**$ 43.14**	$ 44.22	$ 79.75
Offshore	**29.18**	35.24	50.88
Total United States	**38.07**	40.75	58.59
Europe	**58.31**	78.43	75.49
Asia	**74.94**	77.92	72.29
Worldwide	**40.68**	47.81	62.72
Natural gas — per mcf			
United States			
Onshore	**$ 3.08**	$ 2.02	$ 3.16
Offshore	**2.83**	2.15	3.54
Total United States	**2.96**	2.09	3.39
Europe	**11.06**	9.50	8.79
Asia and other	**7.50**	6.90	6.02
Worldwide	**6.64**	6.16	5.96

Crude oil price hedging contracts increased E&P Sales and other operating revenues by $39 million ($25 million after income taxes) in 2013, and reduced E&P Sales and other operating revenues by $688 million ($431 million after income taxes) in 2012 and $517 million ($327 million after income taxes) in 2011. During 2013, the Corporation had Brent crude oil fixed-price swap contracts to hedge 90,000 barrels of oil per day (bopd) of crude oil sales volumes at an average price of $109.70 per barrel. In 2012, the Corporation had Brent crude oil fixed-price swap contracts to hedge 120,000 bopd of crude oil sales volumes for the full year at an average price of $107.70 per barrel. In 2011 and 2012, the Corporation also realized hedge losses from previously closed Brent crude oil hedges that covered 24,000 bopd during the year. The Corporation has entered into Brent crude oil fixed-price swap contracts to hedge 25,000 bopd for calendar year 2014 at an average price of $109.12 per barrel.

Production Volumes: The Corporation's crude oil and natural gas production was 336,000 boepd in 2013, 406,000 boepd in 2012 and 370,000 boepd in 2011. Approximately 72% in 2013, 75% in 2012 and 72% in 2011 of the Corporation's production was from crude oil and natural gas liquids. The Corporation currently expects total worldwide production to average between 305,000 boepd and 315,000 boepd in 2014, excluding asset sales and any contribution from Libya, which has a net production capacity of approximately 25,000 boepd and is shut-in due to civil unrest in the country.

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

	2013	2012	2011
		(In thousands)	
Crude oil — barrels per day			
United States			
Bakken	**55**	47	26
Other Onshore	**10**	13	11
Total Onshore	**65**	60	37
Offshore	**43**	48	44
Total United States	**108**	108	81
Europe	**44**	84	89
Africa	**62**	75	66
Asia	**11**	17	13
Total	**225**	284	249
Natural gas liquids — barrels per day			
United States			
Bakken	**6**	5	2
Other Onshore	**4**	5	5
Total Onshore	**10**	10	7
Offshore	**5**	6	6
Total United States	**15**	16	13
Europe	**1**	2	3
Asia	**1**	1	1
Total	**17**	19	17
Natural gas — mcf per day			
United States			
Bakken	**38**	27	13
Other Onshore	**25**	27	26
Total Onshore	**63**	54	39
Offshore	**61**	65	61
Total United States	**124**	119	100
Europe	**23**	43	81
Asia and other	**418**	454	442
Total	**565**	616	623
Barrels of oil equivalent — per day*	**336**	406	370

* *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 25.*

United States: 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. Crude oil, natural gas liquids and natural gas production was higher in 2012 compared with 2011, primarily due to new wells in the Bakken oil shale play. In the second quarter of 2012, production restarted following the successful workover of a well in the Llano Field, which had been shut-in for mechanical reasons since the first quarter of 2011.

Europe: 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. Crude oil production in 2012 was lower than 2011, primarily due to the downtime at the Valhall Field in

Norway, during the second half of 2012. Natural gas production was lower in 2012 compared with 2011, primarily due to the sale of the Snohvit Field, offshore Norway, in January 2012, downtime at the Valhall Field and natural decline at the Beryl fields in the UK North Sea.

Africa: Crude oil production in Africa was lower in 2013 compared 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 addition, offshore Equatorial Guinea production was lower due to decline at the Okume Complex, partially offset by new production from the Ceiba Field. Crude oil production increased in 2012 compared with 2011 mainly due to the resumption of production in Libya, partly offset by lower production in Equatorial Guinea due to downtime and natural field decline.

Asia and Other: 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 Azeri-Chirag-Guneshli (ACG) fields in Azerbaijan. The assets were producing at a net rate of approximately 6,000 boepd at the time of sale. Natural gas production was lower in 2013 compared to 2012, mainly due to lower production entitlement at the Joint Development Area of Malaysia/Thailand (JDA) together with lower production at the Pangkah Field in Indonesia following the facility's shutdown for planned maintenance in the second quarter of 2013. Natural gas production in 2012 was higher than 2011, primarily due to new wells at the Pangkah Field in Indonesia and a full year's contribution from the Gajah Baru Complex at the Natuna A Field in Indonesia, which commenced production in the fourth quarter of 2011.

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

	2013	2012	2011
		(In thousands)	
Crude oil — barrels	**82,402**	101,770	92,235
Natural gas liquids — barrels	**6,244**	7,138	6,346
Natural gas — mcf	**206,122**	225,607	227,331
Barrels of oil equivalent*	**123,000**	146,510	136,470
Crude oil — barrels per day	**226**	278	253
Natural gas liquids — barrels per day	**17**	19	17
Natural gas — mcf per day	**565**	616	623
Barrels of oil equivalent per day*	**337**	400	374

** 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 25.*

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. The increase in Cost of products sold in the 2013 compared with 2012 and 2011 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 $201 million in 2013 compared with 2012 and increased by $401 million in 2012 compared with 2011. The decrease in 2013 was due to lower production taxes mainly due to the sale of the Corporation's Russian operations, lower transportation costs, lower lease operating expenses and employee costs, partly offset by severance charges and other exit costs incurred as part of the Corporation's transformation to a pure play E&P company. The increase in costs in 2012 reflects higher production taxes as a result of increased production volumes at the Bakken oil shale play and in Russia, together with higher operating and maintenance costs at the Valhall Field in Norway, the Llano Field, offshore U.S. in the Gulf of Mexico and the Bakken, onshore in the U.S.

Depreciation, Depletion and Amortization: Depreciation, depletion and amortization charges decreased by $182 million in 2013 and increased by $548 million in 2012, compared with the corresponding amounts in prior years. The decrease in 2013 primarily reflects asset sales and the mix of production volumes. The increase in 2012 was primarily due to higher volumes and per barrel costs associated with the assets that contributed the production growth.

Excluding items affecting comparability of earnings between periods in the table below, cash operating costs per barrel of oil equivalent were $22.63 in 2013, $20.63 in 2012 and $19.71 in 2011 and depreciation, depletion and amortization costs per barrel of oil equivalent were $21.61 in 2013, $19.20 in 2012 and $17.06 in 2011. Total production unit costs were $44.24 per boe in 2013, $39.83 per boe in 2012 and $36.77 per boe in 2011. Excluding assets sold, classified as held for sale, and any contribution from Libyan operations, pro forma total production unit costs for 2013 were $49.80 per boe.

For 2014, cash operating costs are estimated to be in the range of $20.50 to $21.50 per barrel and depreciation, depletion and amortization costs are estimated to be in the range of $29.00 to $30.00 per barrel, resulting in total production unit costs of $49.50 to $51.50 per barrel of oil equivalent assuming no contribution from Libya.

Exploration 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 amortization expenses. Dry hole expenses in 2013 included an amount to write-off previously capitalized wells in Area 54, offshore Libya. Leasehold amortization expenses in 2013 included a charge to write-off the Corporation's leasehold acreage in the Marcellus, onshore U.S. Exploration expenses decreased in 2012 compared to 2011, primarily due to lower dry hole expenses and lease amortization. Dry hole expenses in 2012 included amounts associated with two exploration wells, Ness Deep in the Gulf of Mexico and Ajek-1, offshore Indonesia.

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 43% in 2013, 45% in 2012 and 38% in 2011. The decrease in the effective income tax rate in 2013 compared with 2012 was primarily due to the impact of shut-in production in Libya from the third quarter of 2013. The increase in the effective income tax rate in 2012 compared with 2011 was predominantly due to the resumption of Libyan operations, which were shut-in for substantially all of 2011. The effective income tax rate for E&P operations in 2014, excluding items affecting comparability of earnings, is estimated to be in the range of 37% to 41% assuming no contribution from Libya.

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		
	2013	2012	2011	**2013**	2012	2011
	(In millions)					
Gains on asset sales, net	**$2,195**	$ 584	$ 446	**$2,145**	$557	$ 413
Noncontrolling interest share of gain on asset sale	**(168)**	—	—	**(168)**	—	—
Asset impairments	**(289)**	(582)	(358)	**(187)**	(344)	(140)
Dry hole and other expenses	**(260)**	(86)	—	**(163)**	(56)	—
Leasehold amortization	**(38)**	—	—	**(23)**	—	—
Employee severance*	**(67)**	—	—	**(55)**	—	—
Facility and other exit costs	**(62)**	—	—	**(62)**	—	—
Income tax adjustments	**—**	—	—	**624**	(201)	(29)
	$1,311	$ (84)	$ 88	**$2,111**	$ (44)	$ 244

** Amounts are net of the reversal of share-based compensation expense of $8 million ($7 million after income taxes) for expected stock grant forfeitures.*

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. The Corporation recorded a pre-tax asset impairment charge of $289 million ($187 million after income taxes) related to Pangkah to adjust its carrying value to its fair value at December 31, 2013. 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 nontaxable gain on sale of $1,119 million, of which $168 million related to the noncontrolling interest holder's share, 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. See also Note 2, Dispositions in the notes to the Consolidated Financial Statements.

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. The Corporation also recorded a pre-tax charge of $38 million ($23 million after income taxes) to write-off the Corporation's leasehold acreage in the Marcellus, onshore U.S.

During 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. See also Note 4, Exit and Disposal Costs in the notes to the Consolidated Financial Statements.

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. See also Note 2, Dispositions in the notes to the Consolidated Financial Statements.

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.

During 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.

2011: The Corporation completed the sale of its interests in certain natural gas producing assets in the UK North Sea, the Snorre Field (Hess 1%), offshore Norway, and the Cook Field (Hess 28%) in the UK North Sea for total cash proceeds of $490 million. These disposals resulted in pre-tax gains totaling $446 million ($413 million after income taxes). These assets had an aggregate net productive capacity of approximately 17,500 boepd at the time of sale.

In the third quarter of 2011, the Corporation recorded asset impairment charges of $358 million ($140 million after income taxes) related to increases in the Corporation's estimated abandonment liabilities for non-producing properties.

In July 2011, the UK increased the supplementary tax rate on petroleum operations to 32% from 20%. As a result, the Corporation recorded a charge of $29 million to increase deferred tax liabilities in the UK.

Corporate and Interest

The following table summarizes corporate and interest expenses:

	2013	2012	2011
		(In millions)	
Corporate expenses (excluding items affecting comparability)	**$ 263**	$ 262	$ 260
Interest expense	**466**	447	396
Less: Capitalized interest	**(60)**	(28)	(13)
Interest expense, net	**406**	419	383
Corporate and Interest expenses before income taxes	**669**	681	643
Income taxes (benefits)	**(253)**	(263)	(255)
Net Corporate and Interest expenses after income taxes	**416**	418	388
Items affecting comparability of earnings between periods, after-tax	**24**	—	—
Total Corporate and Interest expenses after income taxes	**$ 440**	$ 418	$ 388

Corporate expenses were comparable in 2013, 2012 and 2011. After-tax corporate expenses in 2014 are estimated to be in the range of $125 million to $135 million, down from adjusted expenses excluding items affecting comparability provided below of $161 million in 2013.

The decrease in 2013 interest expense, net primarily reflects higher capitalized interest related to the Tubular Bells and North Malay Basin projects. The increase in 2012 interest expense, net principally reflects higher average debt and bank facility fees, partially offset by higher capitalized interest due to the sanctioning of the Tubular Bells project in September 2011. After-tax interest expense in 2014 is expected to be in the range of $225 million to $235 million, down from $255 million in 2013.

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

	Before Income Taxes			After Income Taxes		
	2013	2012	2011	2013	2012	2011
			(In millions)			
Employee severance*	**$(21)**	$—	$—	**$(13)**	$—	$—
Facility and other exit costs	**(17)**	—	—	**(11)**	—	—
	$(38)	$—	$—	**$(24)**	$—	$—

* *Amounts are net of the reversal of share-based compensation expense of $8 million ($5 million after income taxes) for expected stock grant forfeitures.*

During 2013, the Corporation recorded net pre-tax severance charges of $21 million ($13 million after income taxes) related to the Corporation’s transformation into a pure play E&P company. In addition, the Corporation incurred a pre-tax charge of $17 million ($11 million after income taxes) associated with the cessation of certain leased office space in 2013.

Downstream Businesses

Downstream businesses reported income of $1,189 million in 2013, income of $231 million in 2012 and a loss of $584 million in 2011. The downstream businesses comprise the Corporation’s retail, energy marketing, terminal, energy trading and refining operations. Excluding items affecting comparability of earnings between periods provided below, the downstream businesses generated earnings of $116 million in 2013, earnings of $160 million in 2012 and a loss of $59 million in 2011. These results reflect earnings from marketing operations and Port Reading refining activities which were permanently shut down in February 2013. In 2011, the Corporation’s share of HOVENSA’s results was a loss of $198 million.

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

	Before Income Taxes			After Income Taxes		
	2013	2012	2011	2013	2012	2011
	(In millions)					
Gains on asset sales, net	**$1,500**	$ —	$ —	**$ 995**	$ —	$ —
LIFO inventory liquidations	**678**	165	—	**414**	104	—
Facility and other exit costs	**(59)**	—	—	**(36)**	—	—
Employee severance*	**(131)**	—	—	**(80)**	—	—
Asset impairments	**(80)**	(43)	—	**(51)**	(33)	—
Port Reading refinery shutdown costs	**(82)**	—	—	**(49)**	—	—
Other charges	**(173)**	—	—	**(106)**	—	—
Income tax adjustments	**—**	—	—	**(14)**	—	—
Charges related to equity investment in HOVENSA	**—**	—	(875)	**—**	—	(525)
	$1,653	$ 122	$(875)	**$1,073**	$ 71	$(525)

** Amounts are net of the reversal of share-based compensation expense of $17 million ($10 million after income taxes) for expected stock grant forfeitures.*

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 last-in, first-out (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 $59 million ($36 million after income taxes) of other exit costs, including legal and professional fees. The Corporation also incurred charges of $173 million ($106 million after taxes) for legal, environmental, non-cash mark-to-market adjustments in energy marketing and other charges and $14 million for an income tax adjustment. 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 to certain marketing properties and other charges.

2011: The Corporation recorded a charge of $875 million ($525 million after income taxes) due to the impairment recorded by HOVENSA and other charges associated with its decision to shut down the refinery. The Corporation's share of the impairment related losses recorded by HOVENSA represented an amount equivalent to the Corporation's financial support to HOVENSA at December 31, 2011, its planned future funding commitments for costs related to the refinery shutdown, and a charge of $135 million for the write-off of related assets held by the subsidiary which owns the Corporation's investment in HOVENSA. A deferred income tax benefit of $350 million, consisting primarily of U.S. income taxes, was recorded on the Corporation's share of HOVENSA's impairment and refinery shutdown related charges.

Liquidity and Capital Resources

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

	2013	2012
	(In millions)	
Cash and cash equivalents	**$ 1,814**	$ 642
Short-term debt and current maturities of long-term debt	**$ 378**	$ 787
Total debt	**$ 5,798**	$ 8,111
Total equity	**$24,784**	$21,203
Debt to capitalization ratio*	**19.0%**	27.7%

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

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Cash Flows

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

	2013	2012	2011
		(In millions)	
Cash flows from operating activities			
Cash provided by operating activities — continuing operations	**$ 3,589**	$ 5,573	$ 4,910
Cash provided by operating activities — discontinued operations	**1,281**	87	74
Net cash provided by operating activities	**4,870**	5,660	4,984
Cash flows from investing activities			
Capital expenditures	**(5,840)**	(7,743)	(6,941)
Proceeds from asset sales	**4,458**	843	490
Other, net	**(224)**	(60)	(50)
Cash provided by (used in) investing activities — continuing operations	**(1,606)**	(6,960)	(6,501)
Cash provided by (used in) investing activities — discontinued operations	**2,184**	(91)	(65)
Net cash provided by (used in) investing activities	**578**	(7,051)	(6,566)
Cash flows from financing activities			
Cash provided by (used in) financing activities — continuing operations	**(4,274)**	1,684	327
Cash provided by (used in) financing activities — discontinued operations	**(2)**	(2)	(2)
Net cash provided by (used in) financing activities	**(4,276)**	1,682	325
Net increase (decrease) in cash and cash equivalents	**$ 1,172**	$ 291	$ (1,257)

***Operating Activities*:** Net cash provided by operating activities amounted to $4,870 million in 2013 compared with $5,660 million in 2012, reflecting decreases in cash flows from changes in working capital. Operating cash flow increased to $5,660 million in 2012 from $4,984 million in 2011 principally reflecting higher operating earnings and increases in cash flows from changes in working capital.

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

	2013	2012	2011
		(In millions)	
Exploration and Production			
Exploration	**$ 602**	$ 619	$ 869
Production and development	**5,051**	6,790	4,673
Acquisitions (including leaseholds)	**56**	267	1,346
Total Exploration and Production	**5,709**	7,676	6,888
Retail Marketing and Other	**73**	61	50
Corporate	**58**	6	3
Total capital expenditures — continuing operations	**5,840**	7,743	6,941
Downstream businesses — discontinued operations	**33**	52	65
Total capital expenditures	**$ 5,873**	$ 7,795	$ 7,006

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, and at the Valhall Field following the completion of the redevelopment project in January 2013 as well as asset sales. The increased spend on capital expenditures in 2012 compared to 2011 primarily reflected additional spending at the Bakken oil shale play as a result of more drilling rigs operated in the field, higher working interest wells and increased spending on field infrastructure projects. Capital expenditures in 2011 included acquisitions of approximately $800 million for 195,000 net acres in the Utica Shale play in Ohio, $214 million for interests in two blocks in the Kurdistan Region of Iraq and $116 million for an additional 4% interest in the South Arne Field in Denmark.

Total proceeds from the sale of E&P assets was approximately $4.5 billion in 2013, $843 million in 2012 and $490 million in 2011. Completed sales in 2013 included the Corporation's interests in the Beryl, ACG, Eagle Ford and Natuna A fields, its Russian subsidiary, Samara-Nafta, and proceeds of approximately $2.2 billion from the sale of the Corporation's energy marketing operations and its U.S. East Coast terminal network, St. Lucia terminal and related businesses.

Financing Activities: During 2013, the Corporation repaid a net amount of $2,348 million 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. During 2011, net borrowings on available credit facilities were $422 million.

In 2013, the Corporation used approximately $1.5 billion of cash from the proceeds of its asset divestiture program, for the repurchase of common shares under a board authorized $4 billion repurchase plan. Total common stock dividends paid were $235 million in 2013, $171 million in 2012 and $136 million in 2011. In the third quarter of 2013, the Corporation increased its quarterly dividend to $0.25 per common share, from $0.10 per share. In 2012, the Corporation made five quarterly common stock dividend payments as a result of accelerating payment of the fourth quarter 2012 dividend, which historically would have been paid in the first quarter of 2013. The Corporation received net proceeds from the exercise of stock options, including related income tax benefits of $128 million, $11 million and $88 million in 2013, 2012 and 2011, respectively.

Future Capital Requirements and Resources

The Corporation anticipates investing a total of approximately $5.8 billion in capital and exploratory expenditures during 2014 for E&P operations and approximately $350 million for retail marketing primarily for the acquisition of its partner's interest in the WilcoHess joint venture. The Corporation expects to fund its 2014 projected cash flow deficit, including capital expenditures, dismantlement obligations, dividends, pension contributions, debt repayments and share repurchases under its Board authorized plan, with existing cash on-hand, cash flows from operations and proceeds from asset sales. Looking forward, the Corporation expects its continued production growth, driven largely by the Bakken, Valhall and Tubular Bells, to generate free cash flow post 2014 at $100 Brent prices.

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. If conditions were to change, such as a significant decrease in commodity prices or an unexpected increase in capital expenditures, the Corporation would take steps to protect its financial flexibility and may pursue other sources of liquidity, including discontinuing stock repurchases, reducing its planned capital program, utilizing existing credit facilities, issuing debt and equity securities, and/or further asset sales.

The table below summarizes the capacity, usage, and available capacity of the Corporation's borrowing and letter of credit facilities at December 31, 2013:

	Expiration Date	Capacity	Borrowings	Letters of Credit Issued	Total Used	Available Capacity
				(In millions)		
Revolving credit facility	April 2016	$ 4,000	$ —	$ —	$ —	$ 4,000
Committed lines	Various*	1,640	—	274	274	1,366
Uncommitted lines	Various*	136	—	136	136	—
Total		$5,776	$ —	$ 410	$ 410	$5,366

** Committed and uncommitted lines have expiration dates through 2015.*

The Corporation's $410 million in letters of credit outstanding at December 31, 2013 were primarily issued to satisfy margin requirements. See also Note 23, Risk Management and Trading Activities in the notes to the Consolidated Financial Statements.

The Corporation has a $4 billion syndicated revolving credit facility that matures in 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. The Corporation also had a 364 day asset-backed-credit facility, which was terminated in September 2013.

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. At December 31, 2013, the Corporation is permitted to borrow up to an additional $35.5 billion for the construction or acquisition of assets. The Corporation has the ability to borrow up to an additional $5.9 billion of secured debt at December 31, 2013.

The Corporation also has a shelf registration under which it may issue 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 risk management and trading 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, 2013:

		Payments Due by Period			
	Total	2014	2015 and 2016	2017 and 2018	Thereafter
			(In millions)		
Total debt*	$5,798	$ 378	$ 152	$ 147	$5,121
Operating leases	2,532	805	656	228	843
Purchase obligations					
Supply commitments	4,081	3,635	112	104	230
Capital expenditures and other investments	3,558	1,911	1,178	389	80
Operating expenses	1,157	787	304	60	6
Other liabilities	3,736	615	582	366	2,173

** At December 31, 2013, the Corporation's debt bears interest at a weighted average rate of 6.1%.*

Supply commitments include term purchase agreements at market prices for a portion of the gasoline necessary to supply the Corporation's retail marketing system. In addition, the Corporation has commitments to purchase refined petroleum products, natural gas and electricity on behalf of Direct Energy to supply contracted customers from its divested energy marketing business until the customer contracts transfer to Direct Energy, which is expected to be substantially complete in the first half of 2014. See Item 7A. Quantitative and Qualitative Disclosures About Market Risk and Note 23, Risk Management and Trading Activities. These commitments were computed based predominately on year-end market prices.

The table also reflects future capital expenditures, including the portion of the Corporation's planned capital expenditure program for 2014 that was contractually committed at December 31, 2013. Obligations for operating expenses include commitments for transportation, seismic purchases, oil and gas production expenses and other normal business expenses. Other long-term liabilities reflect contractually committed obligations in the Consolidated Balance Sheet at December 31, 2013, including asset retirement obligations, pension plan liabilities and estimates for uncertain income tax positions.

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

The Corporation is contingently liable under $117 million of letters of credit of other entities directly related to its business at December 31, 2013.

Off-balance Sheet Arrangements

The Corporation has leveraged leases not included in its Consolidated Balance Sheet, primarily related to retail gasoline stations that the Corporation operates. The net present value of these leases is $238 million at December 31, 2013 compared with $342 million at December 31, 2012. In connection with the planned divestiture of its retail operations, the Corporation plans to either buyout these leveraged leases or sublet the retail gas stations to the divested operations. The Corporation estimates that it will incur an after-tax charge of approximately $100 million in connection with a buyout or sublet of the leases. If these leases were included as debt, the Corporation's December 31, 2013 debt to capitalization ratio would increase to 19.6% from 19.0%.

See also Note 20, 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, Denmark and France), Africa (Equatorial Guinea, Libya, Algeria and Ghana) and Asia and Other (Malaysia, Thailand, Australia, Brunei, the Kurdistan region of Iraq and China). Therefore, the Corporation is subject to the risks associated with foreign operations, including political risk, 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.

Impairment of Long-lived Assets and Goodwill: As explained below, there are significant differences in the way long-lived assets and goodwill are evaluated and measured for impairment testing. 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 undiscounted future net cash flow estimates, the assets are impaired and an impairment loss is recorded. The amount of impairment is 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.

The Corporation's goodwill is tested for impairment annually in the fourth quarter or when events or circumstances indicate that the carrying amount of the goodwill may not be recoverable. 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 has 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 segment manager. Accordingly, the Corporation expects that the benefits of goodwill will be recovered through the operations of each of its reporting units.

The Corporation's fair value estimate of each reporting unit is the sum of the discounted anticipated cash flows of producing assets and known developments 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 Corporation also considers the relative market valuation of similar onshore and offshore peer companies. 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. 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 an impairment of goodwill.

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.

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 several jurisdictions, including the United States, 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 realizability of deferred tax assets, the Corporation refers to the reversal periods for available carryforward periods for net operating losses and credit carryforwards, temporary differences, 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. Additionally, the Corporation has income taxes which have been deferred on intercompany transactions eliminated in consolidation related to transfers of property, plant and equipment remaining within the consolidated group. The amortization of these income taxes deferred on intercompany transactions will occur ratably with the recovery through depletion and depreciation of the carrying value of these assets. 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 and an unfunded supplemental pension 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; and rate of future increases in compensation levels. 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 risk management and trading activities. In 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, natural gas, refined petroleum products and electricity, 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.

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's derivative instruments are recorded at fair value, with changes in fair value recognized in earnings or other comprehensive income each period as appropriate. The Corporation uses various valuation approaches in determining fair value, 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. The fair value of certain of the Corporation's exchange traded futures and options are considered Level 1.

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. The Corporation utilizes fair value measurements based on Level 2 inputs for certain forwards, swaps and options.

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. For example, the Corporation sold natural gas and electricity to customers and offsets the price exposure by purchasing forward contracts. The fair value of these sales and purchases may be based on specific prices at less liquid delivered locations, which are classified as Level 3. Fair values determined using discounted cash flows and other unobservable data are also classified as Level 3.

Impairment of Equity Investees: The Corporation reviews equity method investments for impairment whenever events or changes in circumstances indicate that an other than temporary decline in value may have occurred. The fair value measurement used in the impairment assessment is based on quoted market prices, where available, or other valuation techniques, including discounted cash flows.

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, 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 2013, the Corporation's reserve for estimated remediation liabilities was approximately $65 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 $16 million in 2013 and $19 million in both 2012 and 2011. Capital expenditures for facilities, primarily to comply with federal, state and local environmental standards were approximately $100 million in 2013, $70 million in 2012 and $95 million in 2011.

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, indicating that 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

In the normal course of its business, the Corporation is exposed to commodity risks related to changes in the prices of crude oil, natural gas, refined petroleum products and electricity, as well as to changes in interest rates and foreign currency values. In the disclosures that follow, risk management activities are referred to as corporate risk management activities. The Corporation also has trading operations, through a 50% voting interest in a consolidated partnership, that trades energy-related commodities, securities and derivatives. These activities are also exposed to commodity risks primarily related to the prices of crude oil, natural gas, refined petroleum products and electricity. The following describes how these risks are controlled and managed.

In November 2013, the Corporation completed the sale of its energy marketing business to Direct Energy, a North American subsidiary of Centrica plc (Centrica). Certain derivative contracts, including new transactions following the closing date, (the "delayed transfer derivative contracts") have not been transferred to Direct Energy, as required customer or regulatory consents have not been obtained. However, the agreement entered into between Hess and Direct Energy on the closing date transfers all economic risks and rewards of the energy marketing business, including the ownership of the delayed transfer derivative contracts, to Direct Energy. As a result, the assets and liabilities related to the delayed transfer derivative contracts remain on the Corporation's Consolidated Balance Sheet at December 31, 2013 but changes in their fair value are offset based on the terms of the agreement between Hess and Direct Energy. The Corporation therefore has no market risk related to these delayed transfer derivative contracts and only retains credit risk exposure, which has been guaranteed by Centrica. It is expected that the transfer of these contracts will be substantially complete in the first half 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 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 risk management and trading activities, including the consolidated trading partnership. 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.

The Corporation uses value at risk to monitor and control commodity risk within its 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 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 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 the Thai Baht, 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 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.

Corporate Risk Management Activities

Corporate 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 entered into Brent crude oil fixed price swap contracts to hedge 25,000 boepd for calendar year 2014 at an average price of $109.12 per barrel. 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% strengthening of the U.S. Dollar exchange rate is estimated to be a gain of approximately $4 million at December 31, 2013.

The Corporation's outstanding long-term debt of $5,798 million, including current maturities, had a fair value of $6,641 million at December 31, 2013. A 15% decrease in the rate of interest would increase the fair value of debt by approximately $160 million at December 31, 2013. A 15% increase in the rate of interest would decrease the fair value of debt by approximately $150 million at December 31, 2013.

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

	2013	2012
	(In millions)	
At December 31	**$ 13**	$ —
Average	**27**	47
High	**44**	95
Low	**13**	—

The increase in the value at risk for the Corporation's risk management commodity derivatives activities at December 31, 2013 is primarily due to the new Brent crude oil cash flow hedge positions entered in December 2013 as described in Note 23, Risk Management and Trading Activities in the notes to the Consolidated Financial Statements.

Trading Activities

Trading activities are conducted through a trading partnership in which the Corporation has a 50% voting interest that is currently for sale. The partnership intends to generate earnings through various strategies primarily using energy related commodities, securities and derivatives.

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

	2013	2012
	(In millions)	
At December 31	**$ 4**	$ 4
Average	**4**	6
High	**5**	7
Low	**3**	4

The information that follows represents 100% of the trading partnership. 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 $191 million in 2013 and $60 million in 2012. The following table provides an assessment of the factors affecting the changes in fair value of net assets (liabilities) relating to financial instruments and derivative commodity contracts used in trading activities:

	2013	2012
	(In millions)	
Fair value of contracts outstanding at January 1	**$ (96)**	$ (86)
Change in fair value of contracts outstanding at the beginning of the year and still outstanding at the end of the year	**10**	17
Reversal of fair value for contracts closed during the year	**10**	70
Fair value of contracts entered into during the year and still outstanding	**(85)**	(97)
Fair value of contracts outstanding at December 31	**$ (161)**	$ (96)

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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, 2013:

	Total	2014	2015	2016	2017 and Beyond
			(In millions)		
Sources of fair value					
Level 1	$ 130	$ 153	$ (8)	$ (15)	$ —
Level 2	(307)	(267)	(42)	2	—
Level 3	16	2	17	(2)	(1)
Total	$ (161)	$ (112)	$ (33)	$ (15)	$ (1)

The following table summarizes the fair values of receivables net of cash margin and letters of credit relating to the Corporation's trading activities and the credit ratings of counterparties at December 31:

	2013	2012
	(In millions)	
Investment grade determined by outside sources	**$ 187**	$ 294
Investment grade determined internally*	**58**	59
Less than investment grade	**47**	39
Fair value of net receivables outstanding at December 31	**$ 292**	$ 392

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

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Item 8. Financial Statements and Supplementary Data

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES
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** 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.*

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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 (1992 framework). Based on our evaluation, management concluded that our internal control over financial reporting was effective as of December 31, 2013.

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, 2013, as stated in their report, which is included herein.

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

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

February 28, 2014

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, 2013, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (1992 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, 2013 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, 2013 and 2012, 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, 2013 of Hess Corporation and consolidated subsidiaries, and our report dated February 28, 2014 expressed an unqualified opinion thereon.

/S/ ERNST & YOUNG LLP
February 28, 2014
New York, New York

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, 2013 and 2012, 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, 2013. 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, 2013 and 2012, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2013, 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, 2013, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (1992 framework) and our report dated February 28, 2014 expressed an unqualified opinion thereon.

/S/ ERNST & YOUNG LLP
February 28, 2014
New York, New York

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HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES

CONSOLIDATED BALANCE SHEET

	December 31, 2013	December 31, 2012
	(In millions, except share amounts)	
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 1,814	$ 642
Accounts receivable		
Trade	3,093	4,057
Other	432	281
Inventories	954	1,259
Assets held for sale	1,097	1,092
Other current assets	1,209	1,056
Total current assets	8,599	8,387
INVESTMENTS IN AFFILIATES	687	443
PROPERTY, PLANT AND EQUIPMENT		
Total — at cost	45,950	45,553
Less: Reserves for depreciation, depletion, amortization and lease impairment	17,179	16,746
Property, plant and equipment — net	28,771	28,807
GOODWILL	1,869	2,208
DEFERRED INCOME TAXES	2,319	3,126
OTHER ASSETS	509	470
TOTAL ASSETS	$ 42,754	$ 43,441
LIABILITIES AND EQUITY		
CURRENT LIABILITIES		
Accounts payable	$ 2,109	$ 2,809
Accrued liabilities	3,265	3,287
Taxes payable	520	960
Liabilities associated with assets held for sale	286	539
Short-term debt and current maturities of long-term debt	378	787
Total current liabilities	6,558	8,382
LONG-TERM DEBT	5,420	7,324
DEFERRED INCOME TAXES	2,292	2,662
ASSET RETIREMENT OBLIGATIONS	2,249	2,212
OTHER LIABILITIES AND DEFERRED CREDITS	1,451	1,658
Total liabilities	17,970	22,238
EQUITY		
Hess Corporation stockholders' equity		
Common stock, par value $1.00		
Authorized — 600,000,000 shares		
Issued: 2013 — 325,314,177 shares; 2012 — 341,527,617 shares	325	342
Capital in excess of par value	3,498	3,524
Retained earnings	21,235	17,717
Accumulated other comprehensive income (loss)	(338)	(493)
Total Hess Corporation stockholders' equity	24,720	21,090
Noncontrolling interests	64	113
Total equity	24,784	21,203
TOTAL LIABILITIES AND EQUITY	$ 42,754	$ 43,441

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, 2013	2012	2011
	(In millions, except per share amounts)		
REVENUES AND NON-OPERATING INCOME			
Sales (excluding excise taxes) and other operating revenues	**$ 22,284**	$ 23,381	$ 21,451
Loss from equity investment in HOVENSA L.L.C.	**—**	—	(1,073)
Gains on asset sales, net	**2,174**	584	446
Other, net	**(37)**	121	32
Total revenues and non-operating income	**24,421**	24,086	20,856
COSTS AND EXPENSES			
Cost of products sold (excluding items shown separately below)	**11,368**	11,500	10,528
Operating costs and expenses	**2,116**	2,202	1,876
Production and severance taxes	**372**	550	476
Marketing expenses	**867**	802	814
Exploration expenses, including dry holes and lease impairment	**1,031**	1,070	1,195
General and administrative expenses	**709**	613	613
Interest expense	**406**	419	383
Depreciation, depletion and amortization	**2,770**	2,922	2,373
Asset impairments	**289**	582	358
Total costs and expenses	**19,928**	20,660	18,616
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	**4,493**	3,426	2,240
Provision for income taxes	**525**	1,559	709
INCOME FROM CONTINUING OPERATIONS	**3,968**	1,867	1,531
INCOME FROM DISCONTINUED OPERATIONS, NET OF INCOME TAXES	**1,254**	196	145
NET INCOME	**5,222**	2,063	1,676
Less: Net income (loss) attributable to noncontrolling interests	**170**	38	(27)
NET INCOME ATTRIBUTABLE TO HESS CORPORATION	**$ 5,052**	$ 2,025	$ 1,703
NET INCOME ATTRIBUTABLE TO HESS CORPORATION PER SHARE			
BASIC:			
Continuing operations	**$ 11.28**	$ 5.40	$ 4.62
Discontinued operations	**3.73**	0.58	0.43
NET INCOME PER SHARE	**$ 15.01**	$ 5.98	$ 5.05
DILUTED:			
Continuing operations	**$ 11.14**	$ 5.37	$ 4.58
Discontinued operations	**3.68**	0.58	0.43
NET INCOME PER SHARE	**$ 14.82**	$ 5.95	$ 5.01
WEIGHTED AVERAGE NUMBER OF COMMON SHARES OUTSTANDING (DILUTED)	**340.9**	340.3	339.9

See accompanying notes to the consolidated financial statements.

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HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES

STATEMENT OF CONSOLIDATED COMPREHENSIVE INCOME

	Years Ended December 31,		
	2013	2012	2011
		(In millions)	
NET INCOME	**$ 5,222**	$ 2,063	$ 1,676
OTHER COMPREHENSIVE INCOME (LOSS):			
Derivatives designated as cash flow hedges			
Effect of hedge (gains) losses reclassified to income	**(33)**	676	690
Income taxes on effect of hedge (gains) losses reclassified to income	**18**	(252)	(258)
Net effect of hedge (gains) losses reclassified to income	**(15)**	424	432
Change in fair value of cash flow hedges	**68**	(156)	4
Income taxes on change in fair value of cash flow hedges	**(25)**	60	(2)
Net change in fair value of cash flow hedges	**43**	(96)	2
Change in derivatives designated as cash flow hedges, after-tax	**28**	328	434
Pension and other postretirement plans			
Reduction (increase) of unrecognized actuarial losses	**414**	(100)	(439)
Income taxes on actuarial changes in plan liabilities	**(157)**	39	164
Reduction of unrecognized actuarial losses, net	**257**	(61)	(275)
Amortization of net actuarial losses	**63**	85	48
Income taxes on amortization of net actuarial losses	**(23)**	(32)	(19)
Net effect of amortization of net actuarial losses	**40**	53	29
Change in pension and other postretirement plans, after-tax	**297**	(8)	(246)
Foreign currency translation adjustment			
Foreign currency translation adjustment	**(283)**	256	(94)
Reclassified to Gains on asset sales, net	**119**	—	—
Change in foreign currency translation adjustment	**(164)**	256	(94)
TOTAL OTHER COMPREHENSIVE INCOME (LOSS)	**161**	576	94
COMPREHENSIVE INCOME	**5,383**	2,639	1,770
Less: Comprehensive income (loss) attributable to noncontrolling interests	**176**	40	(25)
COMPREHENSIVE INCOME ATTRIBUTABLE TO HESS CORPORATION	**$ 5,207**	$ 2,599	$ 1,795

See accompanying notes to the consolidated financial statements.

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES

STATEMENT OF CONSOLIDATED CASH FLOWS

	2013	2012	2011
	Years Ended December 31, (In millions)		
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	**$ 5,222**	$ 2,063	$ 1,676
Adjustments to reconcile net income to net cash provided by operating activities			
Gains on asset sales, net	**(2,174)**	(584)	(446)
Depreciation, depletion and amortization	**2,770**	2,922	2,373
Loss from equity investment in HOVENSA L.L.C.	**—**	—	1,073
Asset impairments	**289**	582	358
Exploratory dry hole costs	**344**	377	438
Lease impairment	**245**	223	301
Stock compensation expense	**60**	83	86
Provision (benefit) for deferred income taxes	**(460)**	(575)	(699)
Income from discontinued operations	**(1,254)**	(196)	(145)
Changes in operating assets and liabilities:			
(Increase) decrease in accounts receivable	**(185)**	540	(280)
(Increase) decrease in inventories	**116**	66	(51)
Increase (decrease) in accounts payable and accrued liabilities	**(675)**	188	323
Increase (decrease) in taxes payable	**(435)**	28	46
Changes in other assets and liabilities	**(274)**	(144)	(143)
Cash provided by operating activities — continuing operations	**3,589**	5,573	4,910
Cash provided by operating activities — discontinued operations	**1,281**	87	74
Net cash provided by operating activities	**4,870**	5,660	4,984
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures	**(5,840)**	(7,743)	(6,941)
Proceeds from asset sales	**4,458**	843	490
Other, net	**(224)**	(60)	(50)
Cash provided by (used in) investing activities — continuing operations	**(1,606)**	(6,960)	(6,501)
Cash provided by (used in) investing activities — discontinued operations	**2,184**	(91)	(65)
Net cash provided by (used in) investing activities	**578**	(7,051)	(6,566)
CASH FLOWS FROM FINANCING ACTIVITIES			
Net borrowings (repayments) of debt with maturities of 90 days or less	**(1,748)**	1,648	100
Debt with maturities of greater than 90 days			
Borrowings	**535**	630	422
Repayments	**(1,271)**	(433)	(100)
Cash dividends paid	**(235)**	(171)	(136)
Common stock acquired and retired	**(1,493)**	—	—
Noncontrolling interests, net	**(190)**	(1)	(47)
Employee stock options exercised, including income tax benefits	**128**	11	88
Cash provided by (used in) financing activities — continuing operations	**(4,274)**	1,684	327
Cash provided by (used in) financing activities — discontinued operations	**(2)**	(2)	(2)
Net cash provided by (used in) financing activities	**(4,276)**	1,682	325
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	**1,172**	291	(1,257)
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR	**642**	351	1,608
CASH AND CASH EQUIVALENTS AT END OF YEAR	**$ 1,814**	$ 642	$ 351

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, 2011	$ 338	$3,256	$ 14,254	$ (1,159)	$16,689	$ 120	$16,809
Net income			1,703		1,703	(27)	1,676
Other comprehensive income (loss)				92	92	2	94
Comprehensive income (loss)					1,795	(25)	1,770
Activity related to restricted common stock awards, net	1	52	—	—	53	—	53
Employee stock options, including income tax benefits	1	138	—	—	139	—	139
Cash dividends declared	—	—	(136)	—	(136)	—	(136)
Noncontrolling interests, net	—	(29)	5	—	(24)	(19)	(43)
Balance at December 31, 2011	340	3,417	15,826	(1,067)	18,516	76	18,592
Net income			2,025		2,025	38	2,063
Other comprehensive income (loss)				574	574	2	576
Comprehensive income (loss)					2,599	40	2,639
Activity related to restricted common stock awards, net	2	55	—	—	57	—	57
Employee stock options, including income tax benefits	—	44	—	—	44	—	44
Performance share units	—	8	—	—	8	—	8
Cash dividends declared	—	—	(136)	—	(136)	—	(136)
Noncontrolling interests, net	—	—	2	—	2	(3)	(1)
Balance at December 31, 2012	342	3,524	17,717	(493)	21,090	113	21,203
Net income			**5,052**		**5,052**	**170**	**5,222**
Other comprehensive income (loss)				**155**	**155**	**6**	**161**
Comprehensive income (loss)					**5,207**	**176**	**5,383**
Activity related to restricted common stock awards, net	**1**	**32**	**—**	**—**	**33**	**—**	**33**
Employee stock options, including income tax benefits	**2**	**137**	**—**	**—**	**139**	**—**	**139**
Performance share units	**—**	**10**	**—**	**—**	**10**	**—**	**10**
Cash dividends declared	**—**	**—**	**(235)**	**—**	**(235)**	**—**	**(235)**
Common stock acquired and retired	**(20)**	**(205)**	**(1,313)**	**—**	**(1,538)**	**—**	**(1,538)**
Noncontrolling interests, net	**—**	**—**	**14**	**—**	**14**	**(225)**	**(211)**
Balance at December 31, 2013	**$ 325**	**$ 3,498**	**$ 21,235**	**$ (338)**	**$ 24,720**	**$ 64**	**$ 24,784**

See accompanying notes to consolidated financial statements.

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HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Summary of Significant Accounting Policies

Nature of Business: Hess Corporation 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 and natural gas. Prior to 2013, the Corporation also operated a Marketing and Refining (M&R) segment, which it began to divest during the year. The M&R businesses manufacture refined petroleum products and purchase, market, store and trade refined products, natural gas and electricity, as well as operate retail gas stations, most of which have convenience stores. See also Note 21, Segment Information in the notes to the Consolidated Financial Statements for a description of the Corporation's reportable segments at December 31, 2013.

In the first quarter of 2013, the Corporation announced several initiatives to continue its transformation into a more focused pure play E&P company. The transformation plan included fully exiting the Corporation's 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, thus completing its exit from all refining operations. 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. HOVIC and its partner have also commenced a sales process for HOVENSA. The transformation plan also committed to the sale of mature E&P assets in Indonesia and Thailand and the pursuit of monetizing Bakken midstream assets by 2015. See also Note 2, Dispositions and Note 24, Subsequent Events in the notes to the Consolidated Financial Statements for a description of the divestitures completed to date under this transformation plan.

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 trading partnership 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 2012 and 2011 financial information has been recast so that the basis of presentation is consistent with that of the 2013 financial information which reflects the results of operations and cash flows of the Corporation's divested downstream businesses as discontinued operations for all periods presented (See Note 3, 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. In the preparation of these financial statements, the Corporation has evaluated subsequent events through the date of issuance.

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, refined petroleum products and other merchandise when title passes to the customer. Sales are reported net of excise and similar taxes in the Statement of Consolidated Income. 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 share of natural gas production are not material.

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. Similarly, in its marketing activities, the Corporation enters into refined petroleum product purchase and sale transactions with the same counterparty. 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. Retail gas stations and equipment related to leased properties, are depreciated over the estimated useful lives not to exceed the remaining lease period.

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 for impairment whenever events or changes in circumstances indicate that the carrying amounts may not be recovered. If the carrying amounts are not expected to be recovered by undiscounted future cash flows, the assets are impaired and an impairment loss is recorded. The amount of impairment is 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 net present value of future 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 the average prices used in the standardized measure of discounted future net cash flows.

Impairment of Equity Investees: The Corporation reviews equity method investments for impairment whenever events or changes in circumstances indicate that an other than temporary decline in value may have occurred. The fair value measurement used in the impairment assessment is based on quoted market prices, where available, or other valuation techniques, including discounted cash flows.

Impairment of Goodwill: The Corporation's goodwill is assigned to the E&P operating segment. Goodwill is tested for impairment annually in the fourth quarter or when events or changes in circumstances indicate that the carrying amount of the goodwill may not be recoverable. This impairment test is performed at the reporting unit level, which accounting standards define as an operating segment or one level below an operating segment. Following a reorganization of its management structure in 2013, the Corporation determined its reporting units are its onshore and offshore businesses and tests for impairment by comparing the fair value of each reporting unit to its book value, including goodwill. If the fair value of a reporting unit exceeds the carrying amount, goodwill is not impaired. If the carrying value exceeds the fair value, the Corporation calculates the possible impairment loss by comparing the implied fair value of goodwill with the carrying amount. If the implied fair value of goodwill is less than the carrying amount, an impairment would be recorded.

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.

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

Inventories: Inventories are valued at the lower of cost or market. For refined petroleum product inventories valued at cost, the Corporation uses principally the last-in, first-out (LIFO) inventory method. For the remaining inventories, cost is generally determined using average actual costs.

Income Taxes: Deferred income taxes are determined using the liability method. The Corporation regularly assesses the realizability of deferred tax assets, based on estimates of future taxable income, the availability of tax planning strategies, the existence of appreciated assets, the available carryforward periods for net operating losses and other factors. 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 expected to be realized. 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. Additionally, the Corporation has income taxes which have been deferred on intercompany transactions eliminated in consolidation related to transfers of property, plant and equipment remaining within the consolidated group. The amortization of these income taxes deferred on intercompany transactions will occur ratably with the recovery through depletion and depreciation of the carrying value of these assets. 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 risk management and trading activities. In risk management activities, the Corporation uses futures, forwards, options and swaps, individually or in combination, to mitigate its exposure to fluctuations in prices of crude oil, natural gas, refined petroleum products and electricity, as well as changes in interest and foreign currency exchange rates. The Corporation, through a consolidated partnership, 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, 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. The fair value of certain of the Corporation's exchange traded futures and options are considered Level 1.

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. The Corporation utilizes fair value measurements based on Level 2 inputs for certain forwards, swaps and options.

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. For example, the Corporation entered into contracts to sell natural gas and electricity to customers and offsets the price exposure by purchasing forward contracts. The fair value of these sales and purchases may be based on specific prices at less liquid delivered locations, which are classified as Level 3. There may be offsets to these positions that are priced based on more liquid markets, which are, therefore, classified as Level 1 or Level 2. 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 non-functional currency into 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, adjustments resulting from translating foreign currency assets and liabilities into U.S. Dollars are recorded 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 environmental costs on an undiscounted basis to remediate existing conditions related to past operations when the future costs are probable and reasonably estimable. The Corporation capitalizes environmental expenditures that increase the life or efficiency of property or reduce or prevent future adverse impacts to the environment.

Changes in Accounting Policies: Effective January 1, 2013, the Corporation adopted ASU 2013-02, Comprehensive Income (Topic 220): Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income (AOCI) which requires aggregated disclosures of amounts reclassified out of AOCI as well as a presentation of changes in AOCI balances by component. The changes in AOCI by component, including amounts reclassified out of AOCI in their entirety are presented in the Statement of Consolidated Comprehensive Income.

Effective January 1, 2013, the Corporation adopted ASU 2011-11, Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities which requires disclosure of information needed to evaluate the effects or potential effects of the contractual right of setoff for assets and liabilities. This accounting standard update applies to assets and liabilities related to financial instruments and derivatives subject to an enforceable master netting arrangement or similar agreement. The required disclosures are presented in Note 23, Risk Management and Trading Activities.

2. Dispositions

Exploration and Production

2013: 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.

In April, the Corporation completed the sale of 100% of its Russian subsidiary, Samara-Nafta for cash proceeds of approximately $2.1 billion. Based on its 90% interest in Samara-Nafta, total after-tax proceeds to the Corporation were approximately $1.9 billion after working capital and other adjustments. The transaction resulted in a nontaxable gain of $1,119 million after deducting the net book value of assets, including allocated goodwill of $148 million. After reduction of the noncontrolling interest holder's share of $168 million, which is reflected in Net income (loss) attributable to noncontrolling interests, the net gain attributable to the Corporation was $951 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 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.

2012: 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 an after-tax gain of $172 million, after deducting the net book value of assets including allocated goodwill of $12 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 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 an after-tax gain of $36 million, after deducting the net book value of assets including allocated goodwill of $14 million.

2011: In February, the Corporation completed the sale of its interests in certain natural gas producing assets in the UK North Sea for cash proceeds of $359 million. These disposals resulted in pre-tax gains totaling $343 million ($310 million after income taxes). In August, the Corporation completed the sale of its interests in the Snorre Field (Hess 1%), offshore Norway and the Cook Field (Hess 28%) in the UK North Sea for cash proceeds of $131 million. These disposals resulted in after-tax gains totaling $103 million.

Discontinued Operations

2013: In December, the Corporation completed the sale of its U.S. East Coast terminal network, St. Lucia terminal and related businesses for cash proceeds of approximately $1.0 billion, which generated a pre-tax gain of $739 million ($531 million after income taxes), after deducting the net book value of assets. In November, the Corporation completed the sale of its energy marketing business for cash proceeds of approximately $1.2 billion, which generated a pre-tax gain of $761 million ($464 million after income taxes).

3. Discontinued Operations

As a result of the Corporation's divestiture of its energy marketing business and terminals network and its cessation of refining at the Port Reading facility, the results of operations for these businesses 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:

	2013	2012	2011
		(In millions)	
Sales and other operating revenues	**$ 12,273**	$ 14,386	$ 17,132
Income from discontinued operations before income taxes	**$ 1,943**	$ 312	$ 222
Current tax provision (benefit)	**—**	—	—
Deferred tax provision (benefit)	**689**	116	77
Provision for income taxes	**689**	116	77
Income from discontinued operations, net of income taxes*	**$ 1,254**	$ 196	$ 145

** In 2013, Income from discontinued operations included pre-tax gains on asset sales of $1,500 million ($995 million after income taxes).*

The Corporation's retail marketing business and energy trading joint venture have been classified as continuing operations for all periods presented as the Corporation is contemplating different methods of disposal and is experiencing lengthy marketing processes. There was no material impact to the results of operations as a result of these re-classifications for any period presented. The retail marketing business and energy trading joint venture will be classified as discontinued operations when these businesses are divested.

4. Exit and Disposal Costs

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

	Exploration and Production	Retail Marketing and Other	Corporate	Discontinued Operations	Total
			(In millions)		
Employee Severance					
Balance at January 1, 2013	$ —	$ —	$ —	$ —	$ —
Provision (a)	75	40	29	108	252(b)
Payments	(43)	—	(3)	(35)	(81)
Balance at December 31, 2013	32	40	26	73	171
Facility and Other Exit Costs					
Balance at January 1, 2013	—	—	—	—	—
Provision	62(c)	28(d)	17(e)	113(f)	220
Payments	(9)	(24)	—	(69)	(102)
Balance at December 31, 2013	53	4	17	44	118
Total restructuring accruals at December 31, 2013	$ 85	$ 44	$ 43	$ 117	$ 289

(a) Amounts are before the reversal of approximately $33 million of share-based compensation expense related to grants that are expected to be forfeited.

(b) Of the total employee severance charges for 2013, $22 million was included in Operating costs and expenses, $19 million in Exploration expenses, $40 million in Marketing expenses, $63 million in General and administrative expenses and $108 million in Income from discontinued operations.

(c) Included $37 million in General and administrative expenses, $16 million in Depreciation, depletion and amortization, $1 million in Operating costs and expenses and $8 million in Other, net.

(d) Included in Marketing expenses.

(e) Included in General and administrative expenses.

(f) Included in Income from discontinued operations.

The employee severance charges primarily resulted from the Corporation's divestiture program announced in March 2013, which was initiated to continue its transformation to a more focused pure play E&P company. The severance charges were based on probable amounts incurred under ongoing severance arrangements or other statutory requirements, plus amounts earned through December 31, 2013 under enhanced benefit arrangements. The expense associated with the enhanced benefits is recognized ratably over the estimated service period required for the employee to earn the benefit upon termination.

The Corporation expects to incur additional enhanced benefit charges of approximately $30 million beyond the amounts accrued at December 31, 2013, of which $5 million relates to E&P, $10 million to Retail Marketing and Other, $10 million to Corporate and $5 million to discontinued operations. The Corporation's estimate of employee severance costs could change due to a number of factors, including the number of employees that work through the requisite service date and the timing of when each remaining divestiture occurs.

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

5. Acquisitions

In 2011, the Corporation entered into agreements to acquire approximately 85,000 net acres in the dry gas area of the Utica Shale play in Ohio for approximately $750 million, principally through the acquisition of Marquette Exploration, LLC (Marquette). The acquisition of Marquette was accounted for as a business combination and the assets acquired and the liabilities assumed were recorded at fair value. The fair value measurements of the oil and gas assets were based, in part, on significant inputs not observable in the market and thus represent a Level 3 measurement. The majority of the purchase price was assigned to unproved properties and the remainder to producing wells and working capital. See Note 24, Subsequent Events in the notes to the Consolidated Financial Statements for the divestiture of dry gas acreage.

Also in 2011, the Corporation completed the acquisition of a 50% undivided interest in CONSOL Energy Inc.'s (CONSOL) approximately 200,000 acres, in the Utica Shale play in Ohio, for $59 million in cash at closing and the agreement to fund 50% of CONSOL's share of the drilling costs up to $534 million within a 5-year period. This transaction was accounted for as an asset acquisition. During the second quarter of 2013, the Corporation reached an agreement with CONSOL relating to its ongoing title verification efforts, which reduced the gross joint venture acreage by approximately 64,000 acres, to approximately 146,000 acres, and the total carry obligation to $335 million, from $534 million. At December 31, 2013, the Corporation's remaining carry obligation was approximately $200 million.

6. Inventories

Inventories at December 31 were as follows:

	2013	2012
	(In millions)	
Crude oil and other charge stocks	**$ 291**	$ 493
Refined petroleum products and natural gas	**618**	1,362
Less: LIFO adjustment	**(339)**	(1,123)
	570	732
Merchandise, materials and supplies	**384**	527
Total inventories	**$ 954**	$1,259

The percentage of last-in, first-out (LIFO) inventories to total crude oil, refined petroleum products and natural gas inventories was 43% and 71% at December 31, 2013 and 2012, respectively. During 2013 and 2012, the Corporation reduced LIFO inventories, which are carried at lower costs than current inventory costs, resulting in gains of $678 million ($414 million after income taxes) and $165 million ($104 million after income taxes), respectively, that were all classified in Income from discontinued operations. Inventories related to the E&P segment were $599 million at December 31, 2013 and $738 million at December 31, 2012.

7. Property, Plant and Equipment

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

	2013	2012
	(In millions)	
Exploration and Production		
Unproved properties	**$ 2,460**	$ 3,558
Proved properties	**4,121**	4,072
Wells, equipment and related facilities	**37,274**	35,385
	43,855	43,015
Retail Marketing, Corporate and Other	**2,095**	2,538
Total — at cost	**45,950**	45,553
Less: Reserves for depreciation, depletion, amortization and lease impairment	**17,179**	16,746
Property, plant and equipment — net	**$28,771**	$ 28,807

Assets Held for Sale: In March 2013, the Corporation approved a plan to divest its E&P assets in Thailand (comprising the Pailin (Hess 15%) and Sinphuhorm (Hess 35%) fields) and the Pangkah Field, offshore Indonesia (Hess 75%). At December 31, 2013, the book value of assets associated with these properties totaling $1,097 million, primarily consisting of the net property, plant and equipment balances as well as allocated goodwill of $76 million, were reported as assets held for sale. In addition, liabilities related to these properties totaling $286 million, primarily consisting of asset retirement obligations and deferred income taxes, were reported in liabilities associated with assets held for sale. At December 31,

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

2012, assets totaling $1,092 million, including allocated goodwill of $100 million, and liabilities totaling $539 million that were related to the ACG and Beryl fields, which were divested in the first quarter of 2013, were reported as held for sale. Properties classified as held for sale are not depreciated but are subject to impairment testing.

Capitalized Exploratory Wells 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:

	2013	2012	2011
		(In millions)	
Beginning balance at January 1	**$2,259**	$ 2,022	$1,783
Additions to capitalized exploratory well costs pending the determination of proved reserves	**237**	407	512
Reclassifications to wells, facilities and equipment based on the determination of proved reserves	**(106)**	(41)	(171)
Capitalized exploratory well costs charged to expense	**(267)**	(129)	(90)
Dispositions and other	**(78)**	—	(12)
Ending balance at December 31	**$2,045**	$2,259	$2,022
Number of wells at end of year	**50**	68	59

In 2013, capitalized well costs reclassified 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 in the preceding table include $260 million to write-off previously capitalized exploration wells in Area 54, offshore Libya, due to civil unrest. The preceding table excludes exploratory dry hole costs of $77 million, $248 million and $348 million in 2013, 2012 and 2011, respectively, which were incurred and subsequently expensed in the same year.

At December 31, 2013, exploratory drilling costs capitalized in excess of one year past completion of drilling were incurred as follows (in millions):

2012	$ 372
2011	385
2010	358
2009	159
2008 and prior	610
	$1,884

The capitalized well costs in excess of one year relate to 8 projects. Approximately 45% relates to Block WA-390-P, offshore Western Australia, where development planning and commercial activities, including negotiations with potential liquefaction partners, are ongoing. Successful negotiation with a third party liquefaction partner is necessary before the Corporation can negotiate a gas sales agreement and sanction development of the project. Approximately 27% relates to the Corporation's Pony discovery on Block 468 in the deepwater Gulf of Mexico, and 8% relates to the Pony #3 well on Block 469. The Corporation has signed an exchange agreement with the partners of the adjacent Green Canyon Blocks 512 and 511, which contain the Knotty Head discovery. Under this agreement, Hess was appointed operator and has a 20% working interest in the blocks, which are now collectively referred to as the Stampede project. An application to unitize Blocks 468, 512, the western half of 469 and the eastern half of 511 is due to be filed with the Bureau of Safety and Environmental Enforcement in the first quarter of 2014. Field development planning is progressing and the project is targeted for sanction in 2014. Approximately 16% 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 for approval in June 2013 and by year-end four had been approved. The Corporation plans to commence a three well appraisal drilling program in the second half of 2014. The remainder 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.

8. Goodwill

The changes in the carrying amount of goodwill, all of which relate to the E&P segment, are as follows:

	2013	2012
	(In millions)	
Beginning balance at January 1	**$2,208**	$2,305
Dispositions*	**(339)**	(97)
Ending balance at December 31	**$1,869**	$2,208

** Includes $76 million and $52 million reclassified to Assets held for sale in 2013 and 2012, respectively.*

9. Asset Impairments

During the fourth quarter of 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, fourth quarter 2013 results included a pre-tax gain on asset 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. During 2011, the Corporation recorded E&P asset impairment charges of $358 million ($140 million after income taxes) related to non-producing properties.

10. HOVENSA L.L.C. Joint Venture

Hess Oil Virgin Islands Corp., 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. In 2013, 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. If an agreement to sell the refinery cannot be reached, HOVENSA will likely not be able to continue operating as an oil storage terminal.

In 2011 the Corporation recorded a total of $1,073 million of losses from its equity investment in HOVENSA, which included $875 million ($525 million after income taxes) related to an impairment recorded by HOVENSA and other charges associated with its decision to shut down the refinery. The Corporation's share of the impairment related losses recorded by HOVENSA represented an amount equivalent to the Corporation's financial support to HOVENSA at December 31, 2011, its planned future funding commitments for costs related to the refinery shutdown, and a charge of $135 million for the write-off of related assets held by the subsidiary which owns the Corporation's investment in HOVENSA.

The Corporation's investment in HOVENSA is accounted for using the equity method. In accordance with Rule 3-09 of Regulation S-X, the Corporation has filed financial statements for HOVENSA in this report on Form 10-K.

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11. Asset Retirement Obligations

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

	2013	2012
	(In millions)	
Asset retirement obligations at January 1	**$ 2,661**	$ 2,071
Liabilities incurred	**42**	186
Liabilities settled or disposed of	**(576)**	(324)
Accretion expense	**129**	135
Revisions of estimated liabilities	**573**	529
Foreign currency translation	**(57)**	64
Asset retirement obligations at December 31	**2,772**	2,661
Less: Current obligations	**523**	449
Long-term obligations at December 31	**$ 2,249**	$ 2,212

The revisions in 2013 and 2012 reflect overall increases in estimated abandonment obligations resulting from changes in the expected scope of operations, increases in the time expected to complete dismantlement activities and updates to service rates.

12. Debt and Interest Expense

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

	2013	2012
	(In millions)	
Revolving credit facility, weighted average rate 1.6% in 2012	**$ —**	$ 758
Asset-backed credit facility, weighted average rate 0.8% in 2012	**—**	600
Short-term credit facilities, weighted average rate 1.5% in 2012	**—**	990
Fixed-rate public notes:		
7.0% due 2014	**250**	250
8.1% due 2019	**998**	998
7.9% due 2029	**695**	695
7.3% due 2031	**747**	746
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	**5,275**	5,274
Leased floating production system	**296**	180
Other fixed-rate notes, weighted average rate 12.9%, due through 2023	**135**	111
Project lease financing, weighted average rate 5.1%, due through 2014	**60**	78
Fair value adjustments — interest rate hedging	**30**	65
Pollution control revenue bonds, weighted average rate 5.9% in 2012	**—**	53
Other debt	**2**	2
Total debt	**5,798**	8,111
Less: Short-term debt and current maturities of long-term debt	**378**	787
Total long-term debt	**$ 5,420**	$ 7,324

The Corporation has a $4 billion syndicated revolving credit facility that is unused at December 31, 2013 and matures in 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. The Corporation also had a 364-day asset-backed credit facility which was terminated in September 2013.

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.

At December 31, 2013, the Corporation's fixed-rate public notes have a principal amount of $5,300 million ($5,275 million net of unamortized discount). Interest rates on the outstanding fixed-rate public notes have a weighted average rate of 6.9%.

During 2013, the Corporation recorded a net increase of $116 million in debt related to progress on construction of a leased floating production system to be used at the Tubular Bells project.

The aggregate long-term debt maturing during the next five years is as follows (in millions): 2014 — $378; 2015 — $74; 2016 — $78; 2017 — $89 and 2018 — $58.

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. At December 31, 2013, the Corporation is permitted to borrow up to an additional $35.5 billion for the construction or acquisition of assets. The Corporation has the ability to borrow up to an additional $5.9 billion of secured debt at December 31, 2013.

Outstanding letters of credit at December 31 were as follows:

	2013	2012
	(In millions)	
Committed lines*	**$ 274**	$ 463
Uncommitted lines*	**136**	283
Total	**$ 410**	$ 746

** Committed and uncommitted lines have expiration dates through 2015.*

Of the $410 million of letters of credit outstanding at December 31, 2013, $117 million relates to contingent liabilities and the remaining $293 million relates to liabilities recorded in the Consolidated Balance Sheet.

The total amount of interest paid (net of amounts capitalized) was $408 million, $419 million and $383 million in 2013, 2012 and 2011, respectively. The Corporation capitalized interest of $60 million, $28 million and $13 million in 2013, 2012 and 2011, respectively.

13. Share-based Compensation

The Corporation granted restricted common shares and performance share units (PSUs) in 2013 and 2012 under its 2008 Long-term Incentive Plan (LTIP), as amended. The Corporation began awarding PSUs under this plan in March 2012. Prior to 2012, the Corporation awarded restricted common stock and stock options. 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 fifteen peer companies over a three-year performance period ending December 31 of the year prior to grant issuance. 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.

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Share-based compensation expense consisted of the following:

	Before Income Taxes			After Income Taxes		
	2013	2012	2011	2013	2012	2011
	(In millions)					
Restricted stock	**$ 31**	$ 57	$ 53	**$ 19**	$ 35	$ 32
Stock options	**13**	34	51	**8**	21	31
Performance share units	**10**	8	—	**6**	5	—
Total*	**$ 54**	$ 99	$104	**$ 33**	$ 61	$ 63

** Includes pre-tax share-based compensation expense (benefit) included in Income from discontinued operations of approximately $(6) million, $16 million and $18 million for 2013, 2012 and 2011, respectively.*

During 2013, 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) for grants that are 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, 2013, unearned compensation expense, before income taxes, will be recognized in future years as follows (in millions): 2014 — $45, 2015 — $27 and 2016 — $4.

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

	Performance Share Units		Stock Options		Restricted Stock	
	Performance Share Units	Weighted-Average Fair Value on Date of Grant	Options	Weighted-Average Exercise Price per Share	Shares of Restricted Common Stock	Weighted-Average Price on Date of Grant
	(In thousands)		(In thousands)		(In thousands)	
Outstanding at January 1, 2013	414	$ 73.26	12,903	$ 61.45	2,904	$ 66.89
Granted	279	111.49	—	—	1,207	69.49
Exercised	—	—	(2,323)	51.17	—	—
Vested	—	—	—	—	(812)	60.52
Forfeited	(58)	79.99	(439)	78.41	(434)	69.78
Outstanding at December 31, 2013*	635	$ 89.45	10,141	$ 63.08	2,865	$ 69.36

** Includes 9,570 thousand exercisable options at a weighted average price of $61.99 at December 31, 2013.*

The table below summarizes information regarding the outstanding and exercisable stock options as of December 31, 2013:

	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	629	1	$ 28.16	629	$ 28.16
$40.01 – $50.00	1,223	2	49.34	1,217	49.36
$50.01 – $60.00	3,064	4	54.98	3,031	54.98
$60.01 – $80.00	1,818	6	60.64	1,797	60.55
$80.01 – $120.00	3,407	5	83.04	2,896	82.89
	10,141	4	$ 63.08	9,570	$ 61.99

The intrinsic value (or the amount by which the market price of the Corporation's common stock exceeds the exercise price of an option) at December 31, 2013 totaled $204 million and $203 million for outstanding options and exercisable options, respectively. At December 31, 2013, the weighted average remaining contractual term of exercisable options was four years.

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

	2013	2012
Risk free interest rate	**0.36%**	0.40%
Stock price volatility	**.359**	.394
Contractual term in years	**3.0**	3.0
Grant date price of Hess common stock	**$ 69.49**	$ 64.14

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.

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, 2013, the Corporation had 10.2 million shares that remain available for issuance under the 2008 LTIP, as amended, out of the total of 29 million shares of common stock authorized for issuance under the 2008 LTIP, as amended.

14. Foreign Currency

Foreign currency gains (losses) before income taxes recorded in Other, net in the Statement of Consolidated Income amounted to a loss of $54 million in 2013, a gain of $37 million in 2012 and a loss of $29 million in 2011, 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 $(1) million at December 31, 2013 and $169 million at December 31, 2012.

15. 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	
	2013	2012	2013	2012	2013	2012
			(In millions)			
Change in benefit obligation						
Balance at January 1	**$2,110**	$1,866	**$ 234**	$ 227	**$134**	$ 125
Service cost	**61**	64	**12**	10	**4**	7
Interest cost	**82**	81	**7**	7	**3**	5
Actuarial (gain) loss	**(139)**	134	**28**	13	**(4)**	2
Benefit payments	**(69)**	(54)	**(20)**	(2)	**(5)**	(5)
Plan curtailments (a)	**(103)**	—	**(8)**	—	**(35)**	—
Plan settlements (b)	**—**	—	**—**	(21)	**—**	—
Special termination benefits	**5**	—	**—**	—	**—**	—
Foreign currency exchange rate changes	**10**	19	**—**	—	**—**	—
Balance at December 31	**1,957**	2,110	**253**	234	**97**	134

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

	Funded Pension Plans 2013	Funded Pension Plans 2012	Unfunded Pension Plan 2013	Unfunded Pension Plan 2012	Postretirement Medical Plan 2013	Postretirement Medical Plan 2012
	(In millions)					
Change in fair value of plan assets						
Balance at January 1	**$1,763**	$ 1,493	**$ —**	$ —	**$ —**	$ —
Actual return on plan assets	**292**	155	**—**	—	**—**	—
Employer contributions	**146**	150	**20**	23	**5**	5
Benefit payments	**(69)**	(54)	**(20)**	(2)	**(5)**	(5)
Plan settlements (b)	**—**	—	**—**	(21)	**—**	—
Foreign currency exchange rate changes	**13**	19	**—**	—	**—**	—
Balance at December 31	**2,145**	1,763	**—**	—	**—**	—
Funded status (plan assets greater (less) than benefit obligations) at December 31	**188**	(347)	**(253)**	(234)	**(97)**	(134)
Unrecognized net actuarial (gains) losses	**405**	850	**108**	97	**(2)**	39
Net amount recognized	**$ 593**	$ 503	**$ (145)**	$ (137)	**$ (99)**	$ (95)

(a) 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.

(b) Plan settlements amounts reported include a charge of $9 million ($5 million after income taxes) due to employee retirements in 2012.

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

	Funded Pension Plans 2013	Funded Pension Plans 2012	Unfunded Pension Plan 2013	Unfunded Pension Plan 2012	Postretirement Medical Plan 2013	Postretirement Medical Plan 2012
	(In millions)					
Pension asset / (accrued benefit liability)	**$ 188**	$ (347)	**$ (253)**	$ (234)	**$ (97)**	$ (134)
Accumulated other comprehensive loss, pre-tax*	**405**	850	**108**	97	**(2)**	39
Net amount recognized	**$ 593**	$ 503	**$ (145)**	$ (137)	**$ (99)**	$ (95)

** The after-tax deficit reflected in Accumulated other comprehensive income (loss) for these retirement plans was $342 million at December 31, 2013 and $639 million at December 31, 2012.*

The accumulated benefit obligation for the funded defined benefit pension plans decreased to $1,873 million at December 31, 2013 from $1,937 million at December 31, 2012. The accumulated benefit obligation for the unfunded defined benefit pension plan was $222 million at December 31, 2013 and $216 million at December 31, 2012.

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

	Pension Plans 2013	Pension Plans 2012	Pension Plans 2011	Postretirement Medical Plan 2013	Postretirement Medical Plan 2012	Postretirement Medical Plan 2011
	(In millions)					
Service cost	**$ 73**	$ 74	$ 58	**$ 4**	$ 7	$ 6
Interest cost	**89**	88	89	**3**	5	5
Expected return on plan assets	**(141)**	(116)	(109)	**—**	—	—
Amortization of unrecognized net actuarial losses	**61**	83	47	**1**	2	2
Settlement loss	**—**	9	—	**—**	—	—
Curtailment loss	**1**	—	—	**—**	—	—
Special termination benefit recognized	**5**	—	—	**—**	—	—
Net periodic benefit cost	**$ 88**	$ 138	$ 85	**$ 8**	$ 14	$ 13

The Corporation's 2014 pension and postretirement medical expense is estimated to be approximately $20 million, which includes approximately $28 million related to the amortization of unrecognized net actuarial losses, offset by improved returns on plan assets.

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

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

	2013	2012	2011
Weighted average assumptions used to determine benefit obligations at December 31			
Discount rate	**4.6%**	3.8%	4.3%
Rate of compensation increase	**4.4**	4.3	4.3
Weighted average assumptions used to determine net benefit cost for the years ended December 31			
Discount rate	**4.0**	4.3	5.3
Expected return on plan assets	**7.5**	7.5	7.5
Rate of compensation increase	**4.3**	4.3	4.4

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

	2013	2012	2011
Assumptions used to determine benefit obligations at December 31			
Discount rate	**3.6%**	3.1%	3.9%
Initial health care trend rate	**7.1%**	7.3%	8.0%
Ultimate trend rate	**4.6%**	4.8%	5.0%
Year in which ultimate trend rate is reached	**2027**	2022	2018

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.

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

The following tables provide the fair value of the financial assets of the funded pension plans as of December 31, 2013 and 2012 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, 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**
December 31, 2012				
Cash and short-term investment funds	$ 2	$ 37	$ —	$ 39
Equities:				
U.S. equities (domestic)	534	—	—	534
International equities (non-U.S.)	61	148	—	209
Global equities (domestic and non-U.S.)	5	174	—	179
Fixed income:				
Treasury and government issued (a)	—	184	2	186
Government related (b)	—	8	—	8
Mortgage-backed securities (c)	—	96	—	96
Corporate	1	110	—	111
Other:				
Hedge funds	—	—	255	255
Private equity funds	—	—	75	75
Real estate funds	9	—	45	54
Diversified commodities funds	—	17	—	17
	$ 612	$ 774	$ 377	$1,763

(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, 2012	$ 4	$ 211	$ 58	$ 44	$ 317
Actual return on plan assets held at December 31, 2012	—	13	5	1	19
Purchases, sales or other settlements	(1)	31	12	—	42
Net transfers in (out) of Level 3	(1)	—	—	—	(1)
Balance at December 31, 2012	2	255	75	45	377
Actual return on plan assets held at December 31, 2013	**—**	**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**

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

The Corporation has budgeted contributions of approximately $80 million to its funded pension plans in 2014.

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):

2014	$ 162
2015	106
2016	119
2017	110
2018	117
Years 2019 to 2023	649

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 $41 million in 2013, $40 million in 2012 and $28 million in 2011 for contributions to these plans.

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16. Income Taxes

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

	2013	2012	2011
		(In millions)	
United States			
Federal			
Current	**$ 8**	$ 30	$ 202
Deferred	**67**	(419)	(653)
State	**4**	34	6
	79	(355)	(445)
Foreign			
Current	**941**	2,019	1,185
Deferred	**187**	(220)	(60)
	1,128	1,799	1,125
Total	**1,207**	1,444	680
Adjustment of deferred taxes for foreign income tax law changes*	**(682)**	115	29
Total provision for income taxes	**$ 525**	$ 1,559	$ 709

** In 2013, amount 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, amount reflects the effect of the UK supplementary income tax rate change in July 2012. In 2011, amount reflects the July 2011 increase in the supplementary tax on petroleum operations in the UK.*

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

	2013	2012	2011
		(In millions)	
United States (a)	**$ 473**	$ (520)	$ 14
Foreign (b)	**4,020**	3,946	2,226
Total income from continuing operations before income taxes	**$ 4,493**	$ 3,426	$ 2,240

(a)Includes substantially all of the Corporation's interest expense and the results of hedging activities.
(b)Foreign income includes the Corporation's Virgin Islands and other operations located outside of the U.S.

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

	2013	2012
	(In millions)	
Deferred tax liabilities		
Property, plant and equipment	**$(5,581)**	$(5,345)
Other	**(155)**	(105)
Total deferred tax liabilities	**(5,736)**	(5,450)
Deferred tax assets		
Net operating loss carryforwards	**2,726**	1,985
Tax credit carryforwards	**161**	373
Property, plant and equipment and investments	**2,643**	2,796
Accrued compensation, deferred credits and other liabilities	**982**	976
Asset retirement obligations	**1,516**	1,340
Other	**216**	313
Total deferred tax assets	**8,244**	7,783
Valuation allowances	**(1,519)**	(1,282)
Total deferred tax assets, net of valuation allowances	**6,725**	6,501
Net deferred tax assets	**$ 989**	$ 1,051

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

At December 31, 2013, the Corporation has recognized a gross deferred tax asset related to net operating loss carryforwards of $2,726 million before application of the valuation allowances. The deferred tax asset is comprised of $2,390 million attributable to foreign net operating losses which begin to expire in 2020, $71 million attributable to U.S. federal operating losses which begin to expire in 2020 and $265 million attributable to losses in various U.S. states which begin to expire in 2014. The deferred tax asset attributable to foreign net operating losses, net of valuation allowances, is $1,704 million, substantially all of which relates to loss carryforwards in Denmark, Norway and Malaysia. At December 31, 2013, the Corporation has federal, state and foreign alternative minimum tax credit carryforwards of $110 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 $50 million.

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

	2013	2012
	(In millions)	
Other current assets	**$ 963**	$ 596
Deferred income taxes (long-term asset)	**2,319**	3,126
Accrued liabilities	**(1)**	(9)
Deferred income taxes (long-term liability)	**(2,292)**	(2,662)
Net deferred tax assets	**$ 989**	$ 1,051

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:

	2013	2012	2011
U.S. statutory rate	**35.0%**	35.0%	35.0%
Effect of foreign operations*	**7.2**	12.5	(4.1)
State income taxes, net of Federal income tax	**0.1**	0.6	0.1
Change in enacted tax laws	**(15.2)**	3.3	1.3
Gains on asset sales, net	**(16.0)**	(5.3)	(5.5)
Effect of equity loss and operations related to HOVENSA L.L.C.	**—**	—	3.1
Other	**0.6**	(0.6)	1.8
Total	**11.7%**	45.5%	31.7%

** The variance in effective income tax rates attributable to the effect of foreign operations primarily resulted from the suspension of operations in Libya for most of 2011 and part of 2013.*

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

	2013	2012
	(In millions)	
Balance at January 1	**$ 523**	$ 415
Additions based on tax positions taken in the current year	**161**	132
Additions based on tax positions of prior years	**2**	45
Reductions based on tax positions of prior years	**(96)**	(33)
Reductions due to settlements with taxing authorities	**(19)**	(30)
Reductions due to lapses in statutes of limitation	**(1)**	(6)
Balance at December 31	**$ 570**	$ 523

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

The December 31, 2013 balance of unrecognized tax benefits includes $503 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 $15 million to $25 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 $52 million and $60 million as of December 31, 2013 and 2012, 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 $7.5 billion as of December 31, 2013. If these earnings were not indefinitely reinvested, a deferred tax liability of approximately $2.6 billion would be recognized, not accounting for the utilization of foreign tax credits in the U.S.

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 2013, 2012 and 2011 amounted to $1,353 million, $1,822 million and $1,384 million, respectively.

17. Outstanding and Weighted Average Common Shares

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

	2013	2012	2011
		(In millions)	
Balance at January 1	**341.5**	340.0	337.7
Activity related to restricted common stock awards, net	**0.8**	1.3	0.6
Stock options exercised	**2.3**	0.2	1.7
Shares repurchased*	**(19.3)**	—	—
Balance at December 31	**325.3**	341.5	340.0

** See Note 18, Share Repurchase Plan in the notes to the Consolidated Financial Statements.*

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

	2013	2012	2011
		(In millions)	
Income from continuing operations, net of income taxes	**$ 3,968**	$ 1,867	$ 1,531
Less: Net income (loss) attributable to noncontrolling interests	**170**	38	(27)
Net income from continuing operations attributable to Hess Corporation	**3,798**	1,829	1,558
Income from discontinued operations, net of income taxes	**1,254**	196	145
Net income attributable to Hess Corporation	**$ 5,052**	$ 2,025	$ 1,703
Weighted average common shares outstanding:			
Basic	**336.6**	338.4	336.9
Effect of dilutive securities			
Restricted common stock	**1.4**	1.1	1.4
Stock options	**1.7**	0.8	1.6
Performance share units	**1.2**	—	—
Diluted	**340.9**	340.3	339.9

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

	2013	2012	2011
Net income attributable to Hess Corporation per share:			
Basic:			
Continuing operations	**$11.28**	$ 5.40	$ 4.62
Discontinued operations	**3.73**	0.58	0.43
Net income per share	**$15.01**	$ 5.98	$ 5.05
Diluted:			
Continuing operations	**$11.14**	$ 5.37	$ 4.58
Discontinued operations	**3.68**	0.58	0.43
Net income per share	**$14.82**	$ 5.95	$ 5.01

The weighted average common shares used in the diluted earnings per share calculations exclude the effect of approximately 4.4 million, 9.2 million and 3.5 million out-of-the-money stock options for 2013, 2012 and 2011, respectively. Based on the Corporation's TSR, the diluted earnings per share calculations also exclude the effects of 414,175 PSUs for 2012. 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) during 2013. Cash dividends were $0.40 per share ($0.10 per quarter) for both 2012 and 2011.

18. Share Repurchase Plan

In March 2013, the Corporation announced a board authorized plan to repurchase up to $4 billion of outstanding common stock using proceeds from its announced asset divestiture program. From August through December 31, 2013, the Corporation purchased approximately 19.3 million shares for a total cost of approximately $1.54 billion, which is an average cost of $79.65 per share including transaction fees. As of December 31, 2013, the Corporation may purchase up to approximately $2.46 billion of additional common stock under its board authorized plan. The weighted average of common shares outstanding used in the earnings per share calculations for 2013 do not reflect the full amount of the stock repurchases, due to the timing of the purchases.

19. Leased Assets

The Corporation and certain of its subsidiaries lease gasoline stations, drilling rigs, tankers, office space and other assets for varying periods under contractual obligations accounted for as operating leases. Certain operating leases provide an option to purchase the related property at fixed prices. At December 31, 2013, 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):

2014	$ 805
2015	530
2016	126
2017	122
2018	106
Remaining years	843
Total minimum lease payments	2,532
Less: Income from subleases	54
Net minimum lease payments	$ 2,478

Operating lease expenses for drilling rigs used to drill development wells and successful exploration wells are capitalized.

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

Rental expense was as follows:

	2013	2012	2011
		(In millions)	
Total rental expense	**$ 355**	$ 375	$ 348
Less: Income from subleases	**15**	15	12
Net rental expense	**$ 340**	$ 360	$ 336

20. Guarantees and Contingencies

At December 31, 2013, the Corporation has $117 million in letters of credit for which it is contingently liable. 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 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.

The Corporation, along with many other 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 United States 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. In 2008, the majority of the cases against the Corporation were settled. In 2010 and 2011, additional cases were settled including an action brought in state court by the State of New Hampshire. Cases brought by the State of New Jersey and the Commonwealth of Puerto Rico remain unresolved. The Corporation has reserves recorded which it believes are adequate to cover its expected liability in these cases.

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.

21. Segment Information

The Corporation is transitioning to a pure play E&P company. In the first quarter of 2013, the Corporation announced plans to divest its downstream businesses, which were previously included in the M&R operating segment. Accordingly, the results of operations for the downstream businesses that were sold or ceased operations during 2013 have been classified as discontinued operations and are excluded from these segment disclosures for all periods presented. As a result, the Corporation currently has two operating segments, E&P and Retail Marketing and Other, which consists of the remaining downstream businesses that it plans to divest. This structure is used by the chief operating decision maker to allocate resources and assess operating performance.

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

The following table presents financial data by operating segment:

	Exploration and Production	Retail Marketing and Other	Corporate	Total
	(In millions)			
2013				
Operating revenues (a)	**$ 11,905**	**$ 10,379**	**$ —**	**$ 22,284**
Net income (loss) from continuing operations attributable to Hess Corporation	**$ 4,303**	**$ (65)**	**$ (440)**	**$ 3,798**
Interest expense	**$ —**	**$ —**	**$ 406**	**$ 406**
Depreciation, depletion and amortization	**2,671**	**84**	**15**	**2,770**
Asset impairments	**289**	**—**	**—**	**289**
Provision (benefit) for income taxes	**831**	**(39)**	**(267)**	**525**
Investments in affiliates	**109**	**578**	**—**	**687**
Identifiable assets (b)	**37,863**	**2,644**	**939**	**41,446**
Capital employed (c)	**27,850**	**1,597**	**1,939**	**31,386**
Capital expenditures	**5,709**	**73**	**58**	**5,840**
2012				
Operating revenues (a)	$ 12,245	$ 11,136	$ —	$ 23,381
Net Income (loss) from continuing operations attributable to Hess Corporation	$ 2,212	$ 35	$ (418)	$ 1,829
Interest expense	$ —	$ —	$ 419	$ 419
Depreciation, depletion and amortization	2,853	56	13	2,922
Asset impairments	582	—	—	582
Provision (benefit) for income taxes	1,793	29	(263)	1,559
Investments in affiliates	75	368	—	443
Identifiable assets (b)	37,687	2,066	615	40,368
Capital employed (c)	26,339	1,212	405	27,956
Capital expenditures	7,676	61	6	7,743
2011				
Operating revenues (a)	$ 10,646	$ 10,805	$ —	$ 21,451
Net income (loss) from continuing operations attributable to Hess Corporation	$ 2,675	$ (729)	$ (388)	$ 1,558
Loss from equity investment in HOVENSA L.L.C.	$ —	$ (1,073)	$ —	$ (1,073)
Interest expense	—	—	383	383
Depreciation, depletion and amortization	2,305	55	13	2,373
Asset impairments	358	—	—	358
Provision (benefit) for income taxes	1,313	(349)	(255)	709
Investments in affiliates	97	287	—	384
Identifiable assets (b)	32,323	2,960	511	35,794
Capital employed (c)	22,699	1,453	(387)	23,765
Capital expenditures	6,888	50	3	6,941

(a) Consists of Sales and other operating revenues that are reported net of excise and similar taxes in the Statement of Consolidated Income, which amounted to approximately $1,230 million, $1,530 million and $1,450 million in 2013, 2012 and 2011, respectively.

(b) Excludes identifiable assets related to the discontinued operations.

(c) E&P, Retail Marketing and Other and Corporate only. Calculated as equity plus debt.

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

The following table presents financial information by major geographic area:

	United States	Europe	Africa	Asia and Other	Total
			(In millions)		
2013					
Operating revenues	**$ 16,589**	**$ 1,336**	**$ 2,736**	**$ 1,623**	**$ 22,284**
Property, plant and equipment (net) (b)	**16,082**	**7,475 (a)**	**2,310**	**2,899**	**28,766**
2012					
Operating revenues	$16,588	$ 2,530	$ 2,484	$ 1,779	$ 23,381
Property, plant and equipment (net) (b)	13,914	8,172 (a)	2,517	3,875	28,478
2011					
Operating revenues	$14,916	$ 3,137	$ 1,782	$ 1,616	$21,451
Property, plant and equipment (net) (b)	11,172	6,826 (a)	2,355	4,033	24,386

(a) *Of the total Europe, Property, plant and equipment (net), Norway represented $6,348 million, $6,426 million and $5,031 million in 2013, 2012 and 2011, respectively.*

(b) *Excludes Property, plant and equipment (net) related to the discontinued operations.*

22. Related Party Transactions

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

	2013	2012	2011
		(In millions)	
Purchases:			
HOVENSA (a)	**$ —**	$ 145	$ 3,806
Bayonne Energy Center LLC (b)	**38**	20	—
Sales:			
WilcoHess	**2,828**	3,058	2,898
HOVENSA	**90**	191	710

(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.*

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

	2013	2012
	(In millions)	
WilcoHess	**$ 114**	$ 119
Bayonne Energy Center LLC	**(4)**	(3)

23. 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, natural gas, refined petroleum products and electricity, as well as changes in interest rates and foreign currency values. In the disclosures that follow, risk management activities are referred to as corporate and energy marketing risk management activities. The Corporation also has trading operations, through a 50% voting interest in a consolidated partnership, that trades energy-related commodities, securities and derivatives. These activities are also exposed to commodity price risks primarily related to the prices of crude oil, natural gas, refined petroleum products and electricity as well as foreign currency values. In March 2013, the Corporation announced plans to divest its downstream businesses, which included its energy marketing risk management and trading activities. In November, the Corporation completed the sale of its energy marketing business.

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The Corporation maintains a control environment for all of its 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 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 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.

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 Risk Management Activities: Corporate 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 including the British Pound and Thai Baht. 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 Corporate risk management derivative contracts outstanding at December 31, were as follows:

	2013	2012
Commodity, primarily crude oil (millions of barrels)	**9**	1
Foreign exchange (millions of U.S. Dollars)	**$ 220**	$1,285
Interest rate swaps (millions of U.S. Dollars)	**$ 865**	$ 880

Crude oil price hedging contracts increased E&P Sales and other operating revenues by $39 million ($25 million after income taxes) in 2013, and reduced E&P Sales and other operating revenues by $688 million ($431 million after income taxes) in 2012 and $517 million ($327 million after income taxes) in 2011. At December 31, 2013, the after-tax deferred gains in Accumulated other comprehensive income (loss) related to Brent crude oil hedges were $5 million, which will be reclassified into earnings during 2014 as the hedged crude oil sales are recognized in earnings. The amount of ineffectiveness from Brent crude oil hedges that was recognized immediately in Sales and other operating revenues was immaterial in 2013, a loss of $9 million in 2012 and a gain of $9 million in 2011.

During 2013, the Corporation had Brent crude oil fixed-price swap contracts to hedge 90,000 barrels of oil per day (bopd) of crude oil sales volumes at an average price of approximately $109.70 per barrel. In October 2008, the Corporation closed Brent crude oil hedges covering 24,000 bopd through 2012 by entering into offsetting contracts with the same counterparty. The deferred after-tax losses, as of the date the hedge positions were closed, were recorded in earnings as the contracts matured. The Corporation also had Brent crude oil fixed-price swap contracts to hedge 120,000 bopd of crude oil sales volumes for the full year of 2012 at an average price of $107.70 per barrel. The Corporation has entered into Brent crude oil fixed price swap contracts to hedge 25,000 bopd for calendar year 2014 at an average price of $109.12 per barrel.

At December 31, 2013 and 2012, the Corporation had interest rate swaps with gross notional amounts of $865 million and $880 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, 2013 and 2012, the Corporation recorded a decrease of $35 million and an increase of $12 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:

	2013	2012	2011
		(In millions)	
Commodity	**$ —**	$ 1	$ 1
Foreign exchange	**(39)**	43	(15)
Total	**$ (39)**	$ 44	$ (14)

Energy Marketing Risk Management Activities: In November 2013, the Corporation completed the sale of its energy marketing business to Direct Energy, a North American subsidiary of Centrica plc (Centrica). Certain derivative contracts, including new transactions following the closing date, (the "delayed transfer derivative contracts") have not been transferred to Direct Energy, as required customer or regulatory consents have not been obtained. However, the agreement entered into between Hess and Direct Energy on the closing date transfers all economic risks and rewards of the energy marketing business, including the ownership of the delayed transfer derivative contracts, to Direct Energy. As a result, the assets and liabilities related to the delayed transfer derivative contracts remain on the Corporation's Consolidated Balance Sheet at December 31, 2013 but changes in their fair value are offset based on the terms of the agreement between Hess and Direct Energy. The Corporation therefore has no market risk related to these delayed transfer derivative contracts and only retains credit risk exposure, which has been guaranteed by Centrica. It is expected that the transfer of these contracts will be substantially complete in the first half of 2014.

The gross volumes of the Corporation's energy marketing derivative contracts outstanding at December 31, including the delayed derivative transfer contracts were as follows:

	2013	2012
Crude oil and refined petroleum products (millions of barrels)	**19**	26
Natural gas (millions of mcf*)	**3,325**	2,938
Electricity (millions of megawatt hours)	**258**	278

** One mcf represents one thousand cubic feet.*

The changes in fair value of certain energy marketing commodity contracts that are not designated as hedges, as well as revenues from the sales contracts, supply contract purchases and net settlements from financial derivatives related to these energy marketing activities, are presented in Income from discontinued operations in the Statement of Consolidated Income. For contracts that were designated as hedges, the effective portion of changes in the fair value of cash flow hedges was recorded as a component of Accumulated other comprehensive income (loss) in the Consolidated Balance Sheet. Net realized and unrealized pre-tax gains on derivative contracts not designated as hedges amounted to $22 million in 2013, $127 million in 2012 and $65 million in 2011. After-tax deferred losses relating to energy marketing activities recorded in Accumulated other comprehensive income (loss) were $22 million at December 31, 2012, all of which were re-classified into Income from discontinued operations during the year. There were no after-tax deferred gains or losses relating to energy marketing activities recorded in Accumulated other comprehensive income (loss) at December 31, 2013.

Trading Activities: Trading activities are conducted through a trading partnership in which the Corporation has a 50% voting interest that is currently for sale. This partnership intends to generate earnings through various strategies primarily using energy-related commodities, securities and derivatives. The information that follows represents 100% of the trading partnership and, for 2012, the Corporation's proprietary trading accounts.

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

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

	2013	2012
Commodity		
Crude oil and refined petroleum products (millions of barrels)	**1,815**	1,179
Natural gas (millions of mcf)	**2,735**	3,377
Electricity (millions of megawatt hours)	**1**	19
Foreign exchange (millions of U.S. Dollars)	**$ 52**	$ 412
Other		
Interest rate (millions of U.S. Dollars)	**$ —**	$ 167
Equity securities (millions of shares)	**11**	14

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

	2013	2012	2011
		(In millions)	
Commodity	**$78**	$ 104	$ 44
Foreign exchange	**—**	3	—
Other	**1**	10	(28)
Total*	**$79**	$117	$ 16

** The unrealized pre-tax gains and losses included in earnings were reflected in Sales and other operating revenues and 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.

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

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* (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, 2013						
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)**
Interest rate and other	**(12)**	**10**	**—**	**(2)**	**3**	**1**
Counterparty netting	**—**	**206**	**—**	**206**	**—**	**206**
Total derivative contracts	**$ (3,224)**	**$ 2,083**	**$ 168**	**$ (973)**	**$ 44**	**$ (929)**
December 31, 2012						
Assets						
Derivative contracts						
Commodity	$ 3,253	$ (2,661)	$ (34)	$ 558	$ (45)	$ 513
Interest rate and other	100	(8)	—	92	(6)	86
Counterparty netting	—	(81)	—	(81)	—	(81)
Total derivative contracts	$ 3,353	$ (2,750)	$ (34)	$ 569	$ (51)	$ 518
Liabilities						
Derivative contracts						
Commodity	$ (3,312)	$ 2,661	$ 5	$ (646)	$ 45	$ (601)
Other	(10)	8	—	(2)	6	4
Counterparty netting	—	81	—	81	—	81
Total derivative contracts	$ (3,322)	$ 2,750	$ 5	$ (567)	$ 51	$ (516)

** There is no cash collateral that was not offset in the Consolidated Balance Sheet.*

The net assets and liabilities that were offset in the Consolidated Balance Sheet as reflected in column (iv) of the table above were included in Accounts receivable — Trade and Accounts payable, respectively. Included in those amounts were the assets and liabilities related to the Corporation's discontinued operations of $612 million and $620 million as of December 31, 2013, respectively ($378 million and $376 million as of December 31, 2012).

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

The table below reflects the gross and net fair values of the corporate and energy marketing risk management and trading derivative instruments:

	Accounts Receivable	Accounts Payable
	(In millions)	
December 31, 2013		
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*		
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)**
December 31, 2012		
Derivative contracts designated as hedging instruments		
Commodity	$ 65	$ (124)
Interest rate and other	72	(2)
Total derivative contracts designated as hedging instruments	137	(126)
Derivative contracts not designated as hedging instruments*		
Commodity	3,188	(3,188)
Foreign exchange	14	—
Other	14	(8)
Total derivative contracts not designated as hedging instruments	3,216	(3,196)
Gross fair value of derivative contracts	3,353	(3,322)
Master netting arrangements	(2,750)	2,750
Cash collateral (received) posted	(34)	5
Net fair value of derivative contracts	$ 569	$ (567)

* *Includes trading derivatives and derivatives used for risk management.*

The Corporation determines fair value in accordance with the fair value measurements accounting standard (Accounting Standards Codification 820 – Fair Value Measurements and Disclosures), which established a hierarchy that categorizes the sources of 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 presented below is based on the lowest significant input level within this fair value hierarchy.

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HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

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, 2013						
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 (a)**
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)**
Other liabilities measured at fair value on a recurring basis	**(31)**	**—**	**—**	**—**	**—**	**(31)**
Total liabilities measured at fair value on a recurring basis	**$ (113)**	**$ (883)**	**$ (285)**	**$ 109**	**$ 168**	**$ (1,004) (b)**
Other fair value measurement disclosures						
Long-term debt (c)	**$ —**	**$ (6,641)**	**$ —**	**$ —**	**$ —**	**$ (6,641)**
December 31, 2012						
Assets						
Derivative contracts						
Commodity	$ 94	$ 445	$ 243	$ (190)	$ (34)	$ 558
Interest rate and other	6	86	1	(1)	—	92
Collateral and counterparty netting	(23)	(54)	(4)	—	—	(81)
Total derivative contracts	77	477	240	(191)	(34)	569
Other assets measured at fair value on a recurring basis	5	49	—	(2)	—	52
Total assets measured at fair value on a recurring basis	$ 82	$ 526	$ 240	$ (193)	$ (34)	$ 621
Liabilities						
Derivative contracts						
Commodity	$ (83)	$ (657)	$ (101)	$ 190	$ 5	$ (646)
Other	(1)	(2)	—	1	—	(2)
Collateral and counterparty netting	23	54	4	—	—	81
Total derivative contracts	(61)	(605)	(97)	191	5	(567)
Other liabilities measured at fair value on a recurring basis	(40)	(2)	(2)	2	—	(42)
Total liabilities measured at fair value on a recurring basis	$ (101)	$ (607)	$ (99)	$ 193	$ 5	$ (609)
Other fair value measurement disclosures						
Long-term debt (c)	$ —	$ (8,887)	$ —	$ —	$ —	$ (8,887)

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HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

(a) *Includes a total of $239 million of Level 1, $180 million of Level 2 and $51 million of Level 3 assets that relate to the Corporation's continuing operations.*

(b) *Includes a total of $79 million of Level 1, $447 million of Level 2 and $32 million of Level 3 liabilities that relate to the Corporation's continuing operations.*

(c) *Long-term debt, including current maturities, had a carrying value of $5,798 million and $7,361 million at December 31, 2013 and 2012, respectively.*

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, 2013 and 2012.

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

	2013	2012
	(In millions)	
Transfers into Level 1	**$ 3**	$ 251
Transfers out of Level 1	**76**	210
	$ 79	$ 461
Transfers into Level 2	**$ (113)**	$ (234)
Transfers out of Level 2	**88**	(293)
	$ (25)	$ (527)
Transfers into Level 3	**$ (85)**	$ 99
Transfers out of Level 3	**31**	(33)
	$ (54)	$ 66

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) that are measured at fair value based on Level 3 inputs:

	2013	2012
	(In millions)	
Balance at January 1	**$ 141**	$ (143)
Unrealized pre-tax gains (losses)		
Included in earnings (a)	**175**	(78)
Included in other comprehensive income (b)	**—**	44
Purchases (c)	**45**	247
Sales (c)	**(34)**	(266)
Settlements (d)	**(61)**	271
Transfers into Level 3	**(85)**	99
Transfers out of Level 3	**31**	(33)
Balance at December 31	**$ 212**	$ 141

(a) *The unrealized pre-tax gains and losses included in earnings were reflected in Sales and other operating revenues and Income from discontinued operations in the Statement of Consolidated Income.*

(b) *The unrealized pre-tax gains (losses) included in the other comprehensive income (loss) are reflected in the Change in fair value of cash flow hedges in the Statement of Consolidated Comprehensive Income.*

(c) *Purchases and sales primarily represent option premiums paid or received, respectively, during the reporting period and were reflected in Sales and other operating revenues and Income from discontinued operations in the Statement of Consolidated Income.*

(d) *Settlements represent realized gains (losses) on derivatives settled during the reporting period and were reflected in Sales and other operating revenues and 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 beginning 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, 2013		
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**

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

	Unit of Measurement	Range / Weighted Average
December 31, 2012		
Assets		
Commodity contracts with a fair value of $243 million		
Contract prices		
Crude oil and refined petroleum products	$ / bbl (a)	$79.35 - 144.27 / 113.06
Electricity	$ / MWH (b)	$23.37 - 79.27 / 40.81
Basis prices		
Natural gas	$ / MMBTU (c)	$(0.47) - 6.66 / 0.39
Contract volatilities		
Crude oil and refined petroleum products	%	23.00 - 27.00 / 26.00
Natural gas	%	21.00 - 36.00 / 25.00
Electricity	%	18.00 - 40.00 / 28.00
Liabilities		
Commodity contracts with a fair value of $101 million		
Contract prices		
Crude oil and refined petroleum products	$ / bbl (a)	$83.49 - 133.38 / 109.94
Electricity	$ / MWH (b)	$25.01 - 72.60 / 40.38
Basis prices		
Natural gas	$ / MMBTU (c)	$(0.72) - 6.66 / 1.26
Contract volatilities		
Crude oil and refined petroleum products	%	24.00 - 27.00 / 26.00
Natural gas	%	21.00 - 28.00 / 22.00

(a) Price per barrel.
(b) Price per megawatt hour.
(c) Price per million British thermal unit.
Note: Fair value measurement for all recurring inputs was performed using a combination of income and market approach techniques.

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, 2013, the Corporation's net Accounts receivable — Trade related to continuing operations were concentrated with the following counterparty industry segments: Integrated Oil Companies — 45%, Refiners — 18%, Financial Institutions — 14%, Government Entities — 8% and Trading Companies — 7%. As of December 31, 2012, the Corporation's net Accounts receivable — Trade, which included the receivables for the downstream businesses, were concentrated as follows: Integrated Oil Companies — 23%, Refiners — 15%, Government Entities — 11%, Real Estate — 8%, Services — 8% and Manufacturing — 6%. 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, 2013 and December 31, 2012, the Corporation held cash from counterparties of $79 million and $34 million, respectively. The Corporation posted cash to counterparties at December 31, 2013 and December 31, 2012, of $168 million and $5 million, respectively.

The Corporation had outstanding letters of credit totaling $410 million and $746 million at December 31, 2013 and December 31, 2012, respectively, primarily issued to satisfy margin requirements (approximately $196 million and $357 million related to discontinued operations at December 31, 2013 and December 31, 2012, 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, 2013 and 2012, the net liability related to both realized and unrealized derivative contracts with contingent collateral provisions was $281 million and approximately $435 million, respectively. As of December 31, 2013, the cash collateral posted on those derivatives was $31 million and there was no cash collateral posted as of December 31, 2012. At December 31, 2013 and 2012, 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 $134 million at December 31, 2013 and approximately $275 million at December 31, 2012.

24. Subsequent Events

In January 2014, the Corporation completed the sale of its interest in the Pangkah asset, offshore Indonesia for cash proceeds of approximately $650 million. In January, the Corporation also announced that it had reached agreement to sell approximately 74,000 acres of its dry gas position in the Utica Shale for $924 million. Approximately two-thirds of these proceeds are expected at the end of the first quarter of 2014, with the balance to be received in the third quarter of 2014.

In January 2014, the Corporation's retail marketing business acquired its partner's 56% interest in WilcoHess, a retail gasoline joint venture, for approximately $290 million and the settlement of liabilities.

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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, 2013, 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 (Malaysia, Thailand, Azerbaijan and Indonesia). Exploration activities were also conducted, or are planned, in certain of these areas as well as additional countries.

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)		
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
2011					
Property acquisitions					
Unproved	$ 1,224	$ 992	$ —	$ —	$ 232
Proved	122	6	116	—	—
Exploration (a)	1,325	525	98	292	410
Production and development capital expenditures (b)	5,645	2,951	1,734	189	771

(a) Includes $560 million, $319 million and $432 million of exploration costs incurred for unconventional assets in 2013, 2012 and 2011, respectively.

(b) Includes $615 million, $715 million and $972 million in 2013, 2012 and 2011, 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:

	2013	*2012*	*2011*
		(In millions)	
Property Acquisitions	***$ —***	*$ —*	*$ —*
Exploration	***6***	*—*	*10*
*Production and development capital expenditures**	***781***	*1,081*	*741*

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

Capitalized Costs Relating to Oil and Gas Producing Activities

	At December 31, 2013	At December 31, 2012
	(In millions)	
Unproved properties	**$ 2,460**	$ 3,558
Proved properties	**4,121**	4,072
Wells, equipment and related facilities	**37,274**	35,385
Total costs	**43,855**	43,015
Less: Reserve for depreciation, depletion, amortization and lease impairment	**16,298**	15,558
Net capitalized costs	**$27,557**	$ 27,457

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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 21, 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)		
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 (b)	**1,479**	**483**	**60**	**767**	**169**
Results of operations	**$ 1,660**	**$ 776**	**$ 108**	**$ 595**	**$ 181**
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 (c)	1,664	269	334	905	156
Results of operations	$ 1,658	$ 418	$ 411	$ 605	$ 224
2011					
Sales and other operating revenues	$ 10,047	$ 3,371	$ 3,019	$ 2,081	$ 1,576
Costs and expenses					
Operating costs and expenses	1,876	531	656	376	313
Production and severance taxes	476	129	312	7	28
Exploration expenses, including dry holes and lease impairment	1,195	475	76	231	413
General and administrative expenses	313	190	56	17	50
Depreciation, depletion and amortization	2,305	800	588	502	415
Asset impairments	358	16	342	—	—
Total costs and expenses	6,523	2,141	2,030	1,133	1,219
Results of operations before income taxes	3,524	1,230	989	948	357
Provision for income taxes	1,300	473	522	230	75
Results of operations	$ 2,224	$ 757	$ 467	$ 718	$ 282

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

	2013	2012	2011
		(In millions)	
Sales and other operating revenues	$860	$518	$996
Costs and expenses			
Operating costs and expenses	376	297	271
Production and severance taxes	6	5	19
Exploration expenses, including dry holes and lease impairment	6	—	10
General, administrative and other expenses	8	10	9
Depreciation, depletion and amortization	364	139	232
Total costs and expenses	760	451	541
Results of operations before income taxes	100	67	455
Provision(benefit) for income taxes	36	(82)	295
Results of operations	$ 64	$149	$160

(b) *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.*

(c) *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 process which are administered by the Corporation's Vice President of E&P Technology 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 2013 was Mr. Randy Johnson, Vice President of E&P Technology. 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

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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 82% of 2013 year-end reported reserve quantities on a barrel of oil equivalent basis (76% in 2012). 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 7, 2014, 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, 2013 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 approximately 2% 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, 2011	304	466	270	64	1,104 (b)	280	719	1,599	2,598
Revisions of previous estimates (a)	33	59	(1)	(7)	84	36	7	69	112
Extensions, discoveries and other additions	70	7	5	—	82	85	—	—	85
Improved recovery	—	—	—	—	—	—	—	—	—
Purchases of minerals in place	—	3	—	—	3	1	6	—	7
Sales of minerals in place	—	(7)	—	—	(7)	—	(135)	—	(135)
Production (f)	(34)	(34)	(24)	(5)	(97)	(42)	(34)	(168)	(244)
At December 31, 2011	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
Purchases of minerals in place	—	—	—	—	—	—	—	—	—
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**
Improved recovery	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Purchases of minerals in place	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
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 (b)**	**464 (c)**	**238**	**1,273**	**1,975**
Net Proved Developed Reserves (d)									
At January 1, 2011	180	210	215	22	627	199	424	692	1,315
At December 31, 2011	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**

	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 Undeveloped Reserves (e)									
At January 1, 2011	124	256	55	42	477	81	295	907	1,283
At December 31, 2011	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**

(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 of 0.1 million barrels to crude oil, condensate and natural gas liquids reserves in 2013. Reductions to crude oil, condensate and natural gas liquids reserves were 2 million barrels and 11 million barrels in 2012 and 2011, respectively, due to higher selling prices. Revisions also included reductions to natural gas reserves of 9 million mcf, 2 million mcf and 83 million mcf in 2013, 2012 and 2011, respectively, due to higher selling prices.*

(b) *Includes 8 million barrels in 2012 and 10 million barrels in 2011 of crude oil reserves relating to a noncontrolling interest owner of a corporate joint venture. The corporate joint venture was sold in April 2013.*

(c) *Excludes approximately 270 million mcf of carbon dioxide gas for sale or use in company operations.*

(d) *Natural gas liquids net proved developed reserves were 61 million barrels, 76 million barrels and 56 million barrels at December 31, 2013, 2012 and 2011, respectively, and 54 million barrels at January 1, 2011. Natural gas liquids net proved developed reserves in the United States were 83%, 82% and 74% at December 31, 2013, 2012 and 2011, respectively. Natural gas liquids net proved developed reserves in Norway were 15%, 10% and 16% at December 31, 2013, 2012 and 2011, respectively.*

(e) *Natural gas liquids net proved undeveloped reserves were 75 million barrels, 60 million barrels and 57 million barrels at December 31, 2013, 2012 and 2011, respectively, and 48 million barrels at January 1, 2011. Natural gas liquids net proved undeveloped reserves in the United States were 83%, 72% and 67% at December 31, 2013, 2012 and 2011, respectively. Natural gas liquids net proved undeveloped reserves in Norway were 15%, 25% and 28% at December 31, 2013, 2012 and 2011, 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*		
	2013	*2012*	*2011*	*2013*	*2012*	*2011*
	(Millions of barrels)			*(Millions of mcf)*		
At January 1	***284***	*293*	*264*	***219***	*388*	*404*
Revisions of previous estimates	***(21)***	*—*	*40*	***(16)***	*1*	*(4)*
Sales of minerals in place	*—*	*(5)*	*(3)*	*—*	*(165)*	*—*
Production	***(7)***	*(4)*	*(8)*	***(5)***	*(5)*	*(12)*
At December 31	***256***	*284*	*293*	***198***	*219*	*388*
Net Proved Developed Reserves at December 31 (d)	***107***	*102*	*108*	***87***	*73*	*137*
Net Proved Undeveloped Reserves at December 31 (e)	***149***	*182*	*185*	***111***	*146*	*251*

(h) *Natural gas reserves in Africa were 160 million mcf in 2013, 142 million mcf in 2012 and 71 million mcf in 2011.*

Proved Undeveloped Reserves

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 barrels of oil equivalent (boe), classified as proved undeveloped reserves. Overall volumes of proved undeveloped reserves decreased by 28 million boe compared with year-end 2012. Additions and revisions in proved undeveloped reserves from existing fields amounted to 123 million boe, primarily in the United States. These increases resulted from ongoing technical assessments, performance evaluations and additional planned development activities. In 2013, 88 million boe were converted from proved undeveloped reserves to proved developed reserves resulting from continuing development activity and new wells principally in North Dakota and the Gulf of Mexico in the U.S., Norway, Libya, Malaysia and Equatorial Guinea. The Corporation estimates that capital expenditures of $1,765 million were incurred to convert proved undeveloped reserves to proved developed reserves during 2013. Dispositions of assets in 2013 further reduced proved undeveloped reserves by 63 million boe.

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 90 million boe or 6% of total 2013 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 nine wellhead platforms. In 2013, the operator continued development drilling, successfully installed two new wellhead platforms, sanctioned a further wellhead platform and continued a major booster compression project. In 2014, the operator intends to progress the compression project, continue development drilling and commence production at the platforms installed in 2013.
- Valhall — The multi-year Valhall redevelopment project was completed in early 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 plans 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, 2013 are presented separately below, as well as volumes produced and received during 2013, 2012 and 2011 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, 2011	—	—	89	46	135	—	—	1,230	1,230
At December 31, 2012	—	—	76	40	116	—	—	1,183	1,183
At December 31, 2013	**—**	**—**	**57**	**18**	**75**	**—**	**—**	**914**	**914**
Production									
2011	—	—	23	4	27	—	—	136	136
2012	—	—	20	6	26	—	—	137	137
2013	**—**	**—**	**18**	**3**	**21**	**—**	**—**	**122**	**122**

** Includes natural gas liquids of 3 million barrels in 2013, 5 million barrels in 2012 and 5 million barrels in 2011.*

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 relating to the Corporation's proved oil and gas reserves. Future net cash flows are discounted at the prescribed rate of 10%. The discounted future net cash flow estimates do not include exploration expenses, interest expense or corporate general and administrative expenses. The selling prices of crude oil and natural gas are highly volatile. The prices which are required to be used for the discounted future net cash flows do not include the effects of hedges and may not be representative of future selling prices. The future net cash flow estimates could be materially different if other assumptions were used.

At December 31	Total	United States	Europe*	Africa	Asia
			(In millions)		
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	**31,521**	**7,281**	**7,182**	**15,491**	**1,567**
	83,618	**30,984**	**27,768**	**19,991**	**4,875**
Future net cash flows	**32,208**	**18,386**	**5,937**	**3,413**	**4,472**
Less: Discount at 10% annual rate	**11,778**	**7,708**	**2,070**	**704**	**1,296**
Standardized measure of discounted future net cash flows	**$ 20,430**	**$ 10,678**	**$ 3,867**	**$ 2,709**	**$ 3,176**
2012					
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
2011					
Future revenues	$126,874	$ 33,225	$50,876	$27,299	$ 15,474
Less:					
Future production costs	31,517	9,220	16,020	3,455	2,822
Future development costs	17,858	5,854	7,751	1,761	2,492
Future income tax expenses	43,008	7,022	16,368	16,933	2,685
	92,383	22,096	40,139	22,149	7,999
Future net cash flows	34,491	11,129	10,737	5,150	7,475
Less: Discount at 10% annual rate	14,753	6,190	4,599	1,488	2,476
Standardized measure of discounted future net cash flows	$ 19,738	$ 4,939	$ 6,138	$ 3,662	$ 4,999

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

	2013	*2012*	*2011*
		(In millions)	
Future revenues	***$29,668***	*$33,974*	*$34,495*
Less:			
Future production costs	***11,538***	*9,734*	*10,596*
Future development costs	***7,226***	*4,507*	*4,270*
Future income tax expenses	***6,661***	*14,976*	*13,247*
	25,425	*29,217*	*28,113*
Future net cash flows	***4,243***	*4,757*	*6,382*
Less: Discount at 10% annual rate	***1,419***	*1,587*	*2,755*
Standardized measure of discounted future net cash flows	***$ 2,824***	*$ 3,170*	*$ 3,627*

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

For the Years Ended December 31	2013	2012	2011
		(In millions)	
Standardized measure of discounted future net cash flows at January 1	**$20,559**	$ 19,738	$15,702
Changes during the year			
Sales and transfers of oil and gas produced during the year, net of production costs	**(7,507)**	(8,141)	(7,695)
Development costs incurred during year	**5,051**	6,790	4,673
Net changes in prices and production costs applicable to future production	**(2,847)**	1,678	9,233
Net change in estimated future development costs	**(2,798)**	(2,181)	(1,963)
Extensions and discoveries (including improved recovery) of oil and gas reserves, less related costs	**3,836**	3,612	1,040
Revisions of previous oil and gas reserve estimates	**(1,189)**	1,890	2,587
Net purchases (sales) of minerals in place, before income taxes	**(3,905)**	(1,856)	(398)
Accretion of discount	**4,038**	4,032	3,096
Net change in income taxes	**8,834**	(1,906)	(5,234)
Revision in rate or timing of future production and other changes	**(3,642)**	(3,097)	(1,303)
Total	**(129)**	821	4,036
Standardized measure of discounted future net cash flows at December 31	**$20,430**	$20,559	$19,738

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES

QUARTERLY FINANCIAL DATA (UNAUDITED)

Following are quarterly results of operations:

	2013			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In millions, except per share amounts)			
Sales and other operating revenues	$ 6,104	$ 5,657	$ 5,340	$ 5,183
Gross profit from continuing operations (a)	$ 1,423	$ 1,410	$ 1,098	$ 571
Income from continuing operations	$ 1,143	$ 1,604	$ 368	$ 853
Income from discontinued operations	130	12	50	1,062
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 (b)	$ 1,431 (c)	$ 420 (d)	$ 1,925 (e)
Net income attributable to Hess Corporation per share:				
Basic:				
Continuing operations	$ 3.38	$ 4.17	$ 1.09	$ 2.62
Discontinued operations	0.38	0.04	0.15	3.22
Net income per share	$ 3.76	$ 4.21	$ 1.24	$ 5.84
Diluted:				
Continuing operations	$ 3.34	$ 4.12	$ 1.08	$ 2.58
Discontinued operations	0.38	0.04	0.15	3.18
Net income per share	$ 3.72	$ 4.16	$ 1.23	$ 5.76

	2012			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In millions, except per share amounts)			
Sales and other operating revenues	$5,597	$6,085	$5,981	$5,718
Gross profit from continuing operations (a)	$ 1,280	$ 1,530	$ 1,096	$ 917
Income from continuing operations	$ 528	$ 548	$ 535	$ 256
Income (loss) from discontinued operations	32	(13)	57	120
Net income	560	535	592	376
Less: Net income (loss) attributable to noncontrolling interests	15	(14)	35	2
Net income attributable to Hess Corporation	$ 545 (f)	$ 549 (g)	$ 557 (h)	$ 374 (i)
Net income (loss) attributable to Hess Corporation per share:				
Basic:				
Continuing operations	$ 1.52	$ 1.66	$ 1.48	$ 0.75
Discontinued operations	0.09	(0.04)	0.17	0.35
Net income per share	$ 1.61	$ 1.62	$ 1.65	$ 1.10
Diluted:				
Continuing operations	$ 1.51	$ 1.65	$ 1.47	$ 0.75
Discontinued operations	0.09	(0.04)	0.17	0.35
Net income per share	$ 1.60	$ 1.61	$ 1.64	$ 1.10

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

(b) 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.

(c) 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.

(d) 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.

(e) Includes after-tax gains of $1,472 million related to asset sales and the liquidation of LIFO inventories, as well as a 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.

(f) Includes an after-tax gain of $36 million related to an asset sale.

(g) Includes an after-tax charge of $36 million related to an asset impairment.

(h) Includes an after-tax gain of $349 million related to an asset sale, partially offset by after-tax charges of $116 million for asset impairments and $56 million to write-off the Corporation's exploration assets in Peru and an income tax charge of $115 million to reflect a change in the United Kingdom supplementary income tax rate applicable to deductions for dismantlement expenditures.

(i) Includes an after-tax charge of $192 million for an asset impairment, an income tax charge of $86 million and after-tax charge of $33 million for asset impairments and other charges, partially offset by an after-tax gain of $172 million related to an asset sale and after-tax income of $104 million from the partial liquidation of LIFO inventories.

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, 2013, 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, 2013.

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, 2013 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 2014 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 2014 annual meeting of stockholders.

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Executive Officers of the Registrant

The following table presents information as of February 1, 2014 regarding executive officers of the Registrant:

Name	Age	Office Held*	Year Individual Became an Executive Officer
John B. Hess	59	Chief Executive Officer and Director	1983
Gregory P. Hill	52	Executive Vice President and President of Worldwide Exploration and Production	2009
Timothy B. Goodell	56	Senior Vice President and General Counsel	2009
John P. Rielly	51	Senior Vice President and Chief Financial Officer	2002
Mykel J. Ziolo	61	Senior Vice President	2009
Eric S. Fishman	44	Vice President and Treasurer	2013

** 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 16, 2013, except for Mr. Fishman who was elected to the office September 1, 2013.*

Each of the above officers has been employed by the Registrant or its subsidiaries in various managerial and executive capacities for more than five years.

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 2014 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 2014 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 2014 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 2014 annual meeting of stockholders.

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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 the Registrant, dated May 22, 2013, incorporated by reference to Exhibit 3(1) of Form 8-K of the Registrant filed on May 22, 2013.
3(3)	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 April 14, 2011, 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 April 18, 2011.
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) to 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 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)(2) under the Securities Act of 1933 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, as Trustee, including form of Note. Incorporated by reference to Exhibit 4 to Registrant's Form S-3ASR filed with the Securities and Exchange Commission on March 1, 2006.
4(7)	Form of 2014 Note issued pursuant to Indenture, dated as of March 1, 2006, among Registrant and The Bank of New York Mellon, as successor to JP Morgan Chase as Trustee. Incorporated by reference to Exhibit 4(1) to Registrant's Form 8-K filed with the Securities and Exchange Commission on February 4, 2009.
4(8)	Form of 2019 Note issued pursuant to Indenture, dated as of March 1, 2006, among Registrant and The Bank of New York Mellon, as successor to JP Morgan Chase, as Trustee. Incorporated by reference to Exhibit 4(2) to Registrant's Form 8-K filed with the Securities and Exchange Commission on February 4, 2009.
4(9)	Form of 6.00% Note, incorporated by reference to Exhibit 4(1) to the Form 8-K of Registrant filed on December 15, 2009.
4(10)	Form of 5.60% Note incorporated by reference to Exhibit 4(1) to the Form 8-K of Registrant filed on August 12, 2010. 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 Commission a copy of any instruments defining the rights of holders of long-term debt of Registrant and its subsidiaries upon request.
10(1)*	Incentive Cash Bonus Plan description incorporated by reference to Item 5.02 of Form 8-K of Registrant filed on March 8, 2013.
10(2)*	Financial Counseling Program description incorporated by reference to Exhibit 10(6) of Form 10-K of Registrant for 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 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 the 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 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 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 Registrant's Form 10-K 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)*	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(15)*	Compensation program description for non-employee directors, incorporated by reference to Item 1.01 of Form 8-K of Registrant filed on January 4, 2007.
10(16)*	Amended and Restated Change of Control Termination Benefits Agreement dated as of May 29, 2009 between Registrant and F. Borden Walker, incorporated by reference to Exhibit 10(1) of Form 10-Q of Registrant for the three months ended June 30, 2009. A substantially identical agreement (differing only in the signatories thereto) was entered into between Registrant and John B. Hess.
10(17)*	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 Registrant's Form 10-K 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 those referred to in Exhibit 10(17)).
10(18)*	Letter Agreement dated March 18, 2002 between Registrant and F. Borden Walker relating to Mr. Walker's participation in the Hess Corporation Pension Restoration Plan incorporated by reference to Exhibit 10(16) of Form 10-K of Registrant for the fiscal year ended December 31, 2001.
10(19)*	Agreement between Registrant and Gregory P. Hill relating to his 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 his 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 by and among Hess Corporation, Elliott Associates, L.P. and Elliott International, L.P. dated as of May 16, 2013, incorporated by reference to Exhibit 99(1) of Form 8-K of the Registrant filed on May 22, 2013.

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21	Subsidiaries of Registrant.
23(1)	Consent of Ernst & Young LLP, Independent Registered Public Accounting Firm, dated February 28, 2014.
23(2)	Consent of DeGolyer and MacNaughton dated February 28, 2014.
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 7, 2014, on proved reserves audit as of December 31, 2013 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.*

(b) Reports on Form 8-K

During the three months ended December 31, 2013, Registrant filed or furnished the following report on Form 8-K:

1. Filing dated October 30, 2013 reporting under Items 2.02 and 9.01, and a news release dated October 30, 2013 reporting results for the third quarter of 2013.

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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 28th day of February 2014.

HESS CORPORATION
(Registrant)

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

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

Signature	Title	Date
/s/ JOHN B. HESS John B. Hess	Director and Chief Executive Officer (Principal Executive Officer)	February 28, 2014
/s/ DR. MARK R. WILLIAMS Dr. Mark R. Williams	Director and Chairman of the Board	February 28, 2014
/s/ RODNEY F. CHASE Rodney F. Chase	Director	February 28, 2014
/s/ HARVEY GOLUB Harvey Golub	Director	February 28, 2014
/s/ EDITH E. HOLIDAY Edith E. Holiday	Director	February 28, 2014
/s/ JOHN KRENICKI, JR. John Krenicki, Jr.	Director	February 28, 2014
/s/ DR. RISA LAVIZZO-MOUREY Dr. Risa Lavizzo-Mourey	Director	February 28, 2014
/s/ DAVID MCMANUS David McManus	Director	February 28, 2014
/s/ DR. KEVIN O. MEYERS Dr. Kevin O. Meyers	Director	February 28, 2014
/s/ JOHN H. MULLIN, III John H. Mullin, III	Director	February 28, 2014
/s/ JAMES H. QUIGLEY James H. Quigley	Director	February 28, 2014
/s/ FREDRIC G. REYNOLDS Fredric G. Reynolds	Director	February 28, 2014
/s/ JOHN P. RIELLY John P. Rielly	Senior Vice President and Chief Financial Officer (Principal Financial and Accounting Officer)	February 28, 2014
/s/ WILLIAM G. SCHRADER William G. Schrader	Director	February 28, 2014
/s/ ROBERT N. WILSON Robert N. Wilson	Director	February 28, 2014

Schedule II

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES

VALUATION AND QUALIFYING ACCOUNTS

For the Years Ended December 31, 2013, 2012 and 2011

		Additions			
Description	Balance January 1	Charged to Costs and Expenses	Charged to Other Accounts	Deductions from Reserves	Balance December 31
			(In millions)		
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
2011					
Losses on receivables	$ 58	$ 4	$ 1	$ 8	$ 55
Deferred income tax valuation	$ 444	$ 648	$ —	$ 21	$ 1,071

Report of Independent Auditors

The Members
HOVENSA L.L.C.

We have audited the accompanying statements of operations, comprehensive loss and (accumulated deficit) retained earnings, and cash flows of HOVENSA L.L.C. ("the Company") for the year ended December 31, 2011. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the 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. We were not engaged to perform an audit of the Company's internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and 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 results of the Company's operations and its cash flows for the year ended December 31, 2011 in conformity with U.S. generally accepted accounting principles.

/s/ ERNST & YOUNG LLP
February 27, 2012
New York, New York

HOVENSA L.L.C.

BALANCE SHEETS
(Dollars in thousands)

	December 31, 2013 (Unaudited)	December 31, 2012 (Unaudited)
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	**$ 158,089**	$ 336,570
Accounts receivable:		
Members and affiliates	**102**	268
Trade (less allowance in 2013 of $0 and 2012 of $6,859)	**802**	8,783
Other	**28**	851
Inventories	**47,583**	68,230
Deposits and prepaid expenses	**721**	1,485
Total current assets	**207,325**	416,187
OTHER ASSETS	**38,323**	119
TOTAL ASSETS	**$ 245,648**	$ 416,306
LIABILITIES AND MEMBERS' EQUITY		
CURRENT LIABILITIES		
Accounts payable	**$ 12,910**	$ 19,117
Accrued liabilities	**102,737**	190,158
Interest and taxes payable	**150,961**	64,843
Payable to members for financial support	**1,622,000**	1,622,000
Total current liabilities	**1,888,608**	1,896,118
OTHER LIABILITIES	**85,219**	102,222
Total liabilities	**1,973,827**	1,998,340
MEMBERS' EQUITY		
Members' initial investment	**1,343,429**	1,343,429
Accumulated deficit	**(3,054,573)**	(2,885,218)
Accumulated other comprehensive loss	**(17,035)**	(40,245)
Total members' equity	**(1,728,179)**	(1,582,034)
TOTAL LIABILITIES AND MEMBERS' EQUITY	**$ 245,648**	$ 416,306

See accompanying notes to financial statements.

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HOVENSA L.L.C.

STATEMENTS OF OPERATIONS, COMPREHENSIVE INCOME (LOSS) AND (ACCUMULATED DEFICIT) RETAINED EARNINGS (Dollars in thousands)

	Years Ended December 31,		
	2013 (Unaudited)	2012 (Unaudited)	2011 (Audited)
SALES	**$ 129,306**	$ 1,633,357	$ 13,126,326
OPERATING EXPENSES			
Product costs	**111,172**	1,073,019	12,803,408
Operating expenses	**117,502**	324,794	554,516
Depreciation and amortization	**—**	—	128,403
Asset impairments and shutdown related charges	**—**	152,759	2,072,600
Total operating expenses	**228,674**	1,550,572	15,558,927
OPERATING INCOME (LOSS)	**(99,368)**	82,785	(2,432,601)
OTHER NON-OPERATING INCOME (EXPENSE)			
Interest expense, net	**(84,744)**	(82,419)	(38,689)
Other income (expense), net	**14,757**	12,648	(15,962)
NET INCOME (LOSS)	**$ (169,355)**	$ 13,014	$ (2,487,252)
COMPONENTS OF COMPREHENSIVE INCOME (LOSS)			
Net income (loss)	**$ (169,355)**	$ 13,014	$ (2,487,252)
Other comprehensive income (loss):			
Change in retirement plan liabilities	**23,210**	(2,589)	9,898
COMPREHENSIVE INCOME (LOSS)	**$ (146,145)**	$ 10,425	$ (2,477,354)
(ACCUMULATED DEFICIT) RETAINED EARNINGS			
Opening balance	**$(2,885,218)**	$ (2,898,232)	$ (410,980)
Net income (loss)	**(169,355)**	13,014	(2,487,252)
CLOSING BALANCE	**$(3,054,573)**	$(2,885,218)	$ (2,898,232)

See accompanying notes to financial statements.

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HOVENSA L.L.C.

STATEMENTS OF CASH FLOWS
(Dollars in thousands)

	Years Ended December 31, 2013 (Unaudited)	2012 (Unaudited)	2011 (Audited)
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income (loss)	**$(169,355)**	$ 13,014	$(2,487,252)
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:			
Depreciation and amortization	**—**	—	128,403
Asset impairments and shutdown related charges	**—**	152,759	2,072,600
Decrease in accounts receivable	**8,970**	177,445	181,227
Decrease in inventories	**20,647**	80,724	65,698
Decrease (increase) in deposits and prepaid expenses	**764**	12,353	(510)
(Increase) decrease in other assets	**(38,204)**	10,255	16,419
Decrease in accounts payable and accrued liabilities	**(93,628)**	(812,828)	(218,068)
Increase (decrease) in interest and taxes payable	**86,118**	63,384	(509)
Increase (decrease) in other liabilities	**6,207**	(26,489)	(25,473)
Net cash used in operating activities	**(178,481)**	(329,383)	(267,465)
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures	**—**	—	(39,373)
Net cash used in investing activities	**—**	—	(39,373)
CASH FLOWS FROM FINANCING ACTIVITIES			
Decrease (increase) in debt service fund	**—**	11,361	(11)
Decrease in long-term debt, net	**—**	(355,683)	(350,000)
Increase in payable to members for financial support	**—**	968,000	654,000
Net cash provided by financing activities	**—**	623,678	303,989
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	**(178,481)**	294,295	(2,849)
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR	**336,570**	42,275	45,124
CASH AND CASH EQUIVALENTS AT END OF YEAR	**$ 158,089**	$ 336,570	$ 42,275

See accompanying notes to financial statements.

HOVENSA L.L.C.

NOTES TO FINANCIAL STATEMENTS
(Dollars in thousands)

1. Basis of Financial Statements and Significant Accounting Policies

Nature of Business

Background: HOVENSA L.L.C. (the "Company" or "HOVENSA") was formed as a 50/50 joint venture between subsidiaries of Petroleos de Venezuela, SA. ("PDVSA") and Hess Corporation ("Hess"), to own and operate the Company's refinery located in St. Croix, United States (U.S.) Virgin Islands. The Company's members are PDVSA V.I., Inc., a subsidiary of PDVSA, and Hess Oil Virgin Islands Corp. ("HOVIC"), a subsidiary of Hess. Through January 2012, the Company purchased crude oil from PDVSA, Hess and third parties, and manufactured and sold petroleum products primarily to PDVSA and Hess. Since January 2012, the Company has operated the facility as an oil storage terminal.

HOVENSA operates under a Concession Agreement with the Government of the U.S. Virgin Islands. The original Concession Agreement was entered into on September 1, 1965. On November 5, 2013, HOVENSA entered into the Fourth Amendment to the Concession Agreement that provides for a process to sell the oil refinery and related facilities, which has commenced. The Company has opened a data room and has retained an investment advisor. The Concession Agreement can be extended with Virgin Islands government approval, which has occurred on four previous occasions.

Shutdown of Refinery: In December 2011, the Company's members agreed to shut down refining operations effective January 18, 2012. As a result of this decision, the Company recorded noncash charges totaling $2,072,600 in December 2011 to fully impair its property, plant and equipment and recognize certain other expenses related to the shutdown decision. Following the refinery shutdown, the Company redeemed its outstanding debt, liquidated a majority of its inventory and settled a portion of its liabilities. In 2012, additional shutdown related charges totaling $152,759 were recorded, primarily for the estimated legal obligations for hydrocarbon removal and tank cleaning costs.

Basis of Presentation

The accompanying financial statements of HOVENSA have been prepared in conformity with United States generally accepted accounting principles ("U.S. GAAP"). As further explained in Notes 2 and 3 below, the Company fully impaired its property, plant and equipment and recorded certain refinery shutdown costs at December 31, 2011. Refinery shutdown activities occurred in 2012 and 2013. The Company received financial support from the members in 2012 to fund a portion of the expenditures for the refinery shutdown and conversion to an oil storage terminal.

The members' primary objective is to sell the refinery and related facilities. The Company believes that it has cash reserves that are only sufficient to fund its operations through the first three quarters of 2014 and the members currently do not anticipate providing any additional funding to the Company. If an agreement to sell the refinery cannot be reached, the Company will likely not be able to continue operating the facility as an oil storage terminal.

Use of Estimates

In preparing financial statements in conformity with U.S. GAAP, management makes estimates and assumptions that affect the reported amounts of assets and liabilities in the balance sheet and revenues and expenses in the statement of operations. Actual results could differ from those estimates. Among the estimates made by management are asset impairments, refinery shutdown costs, inventory and other asset valuations, legal and environmental obligations and pension liabilities.

Revenue Recognition

The Company recognizes revenues from the sale of petroleum products when title passes to the customer, which generally occurs when products are shipped or delivered in accordance with the terms of the respective sales agreements.

In addition, the Company provides storage and other related services for third-party customers. Tank storage and related revenue is recognized in the period the service is provided. Product stored remains the property of these third-party customers.

HOVENSA L.L.C.

NOTES TO FINANCIAL STATEMENTS – (Continued)
(Dollars in thousands)

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 of crude oil and refined products used in refining operations were valued at the lower of last-in, first-out (“LIFO”) cost or market. Other inventories, including refined products purchased for resale or used in operations, as well as materials and supplies are valued at the lower of average cost or market.

Depreciation

Depreciation of refinery facilities through December 31, 2011 was determined principally on the units-of-production method based on estimated production volumes. Depreciation of all other equipment was determined on the straight-line method based on estimated useful lives.

Maintenance and Repairs

Maintenance and repairs are expensed as incurred.

Impairment of Long-Lived Assets

Long-lived assets are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of the assets may not be recoverable. The impairment recognized is the amount by which the carrying amount exceeds the estimated fair market value of the assets.

Asset Retirement Obligations

Asset retirement obligations must be recorded at fair value in the period in which it is determined that a legal obligation exists and a reasonable estimate of the fair value of the liability can be made.

Environmental Expenditures

Liabilities for future remediation costs are recorded when environmental assessments or remedial efforts are probable and the costs can be reasonably estimated. Other than for assessments, the timing and magnitude of these accruals generally are based on the completion of investigations or other studies or a commitment to a formal plan of action. Environmental liabilities are based on best estimates of probable undiscounted future costs using currently available technology and applying current regulations. Such accruals are adjusted as further information develops or circumstances change.

Income Taxes

The Company is a limited liability company and, as a result, income taxes are the responsibility of the members. Accordingly, no effect of income tax has been recognized in the accompanying financial statements.

Retirement Plans

The Company recognizes on its balance sheet the underfunded status of its defined benefit retirement plans measured as the difference between the fair value of plan assets and the benefit obligations. The benefit obligation is the projected benefit obligation in the case of the non-contributory defined benefit pension plan and the projected post-retirement benefit obligation for the post-retirement medical plan. The Company recognizes the net changes in the plan assets and benefit obligations of its defined benefit retirement plans in the year in which such changes occur.

(Dollars in thousands)

Prior service costs and 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.

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 and rate of future increases in compensation levels. These assumptions represent estimates made by the Company, some of which can be affected by external factors.

2. Asset Impairment and Refinery Shutdown Related Charges

On January 18, 2012, HOVENSA announced the decision to shut down its refinery operations after experiencing substantial operating losses due to global economic conditions and competitive disadvantages versus other refiners. Such losses were incurred despite efforts to improve operating performance by reducing refining capacity to 350,000 barrels per day from 500,000 barrels per day in the first half of 2011. Operating losses were also projected to continue. The Company prepared an impairment analysis as of December 31, 2011, which indicated that undiscounted future cash flows would not recover the carrying value of its assets. As a result, the Company recorded an impairment charge of $1,900,349 representing the difference between the carrying value and the estimated fair market value of property, plant and equipment at December 31, 2011. Estimated fair value was determined based on discounted future cash flows (a Level 3 fair value measure). In addition, the Company recorded other charges totaling $172,251 for obligations incurred in 2011 related to the decision to shut down the refinery, including recognition of legally required employee and contractor severance costs of $66,200 and reductions in carrying value of warehouse inventory and other assets totaling $106,051.

During 2012, the Company recorded a charge $175,000 for estimated obligations incurred due to hydrocarbon removal and tank cleaning costs, that became legal obligations upon shutdown of the refinery. In addition, the Company recorded a charge of $23,408 in 2012 to write down warehouse inventory and other assets and reduced its allowance for doubtful accounts by $45,649 upon collection of a previously written-off receivable.

3. Future Refinery Shutdown Expenditures

The Company is expected to incur additional refinery shutdown costs in excess of amounts that can be accrued under US GAAP, including costs related to the preservation of refinery process equipment, enhanced employee and contractor severance and benefits, estimated losses on long-term contracts and other costs. Of the amounts that were accrued, the following is the movement in the shutdown reserve:

	2013 (Unaudited)	2012 (Unaudited)	2011 (Audited)
Shutdown reserve			
Opening balance	**$187,528**	$ 66,200	$ —
Provisions	**—**	175,000	66,200
Payments	**(87,046)**	(53,672)	—
Ending balance	**$100,482**	$187,528	$66,200

The shutdown reserve is reflected in accrued liabilities on the balance sheet.

HOVENSA L.L.C.

NOTES TO FINANCIAL STATEMENTS – (Continued)
(Dollars in thousands)

4. Related Party Transactions

During 2012 and 2011, HOVENSA received financial support from its members primarily by delaying the normal timing of payments to PDVSA for crude oil purchases, as well as accelerating payments from Hess for refined product sales. At December 31, 2012 and 2011, interest bearing financial support provided by both members in the aggregate of $1,622,000 and $654,000, respectively, is recorded as a current liability in the balance sheet. The Company incurred interest expense of $85,155 in 2013, and $80,148 in 2012, and $14,278 in 2011 on payables to its members for their financial support.

The Company had long-term crude oil supply agreements with Petroleum Marketing International ("Petromar") a subsidiary of PDVSA, under which Petromar agreed to sell to HOVENSA a monthly average of 155,000 barrels per day of Mesa crude oil and 115,000 barrels per day of Merey crude oil. The Company also had a product sales agreement with Hess and Petromar that requires Hess and Petromar each to purchase after any sales of refined products by HOVENSA to third parties, 50% of HOVENSA's gasoline, distillate, residual fuel and other products at market prices. Purchases and sales under these agreements ceased on April 1, 2012 following the shutdown of refining operations.

A summary of all material transactions between the Company, its members and affiliates follows:

	2013 (Unaudited)	2012 (Unaudited)	2011 (Audited)
Sales of petroleum products:			
Hess	**$ —**	$ 144,797	$ 3,805,821
PDVSA	**—**	147,232	3,937,571
Purchases of crude oil and products:			
Hess	**90,235**	191,425	709,570
PDVSA	**—**	524,517	6,412,491
Administrative service agreement fee paid to Hess	**2,756**	4,286	4,018
Bareboat charter of tugs and barges paid to HOVIC	**2,873**	2,880	2,873
Marine revenues received from PDVSA and Hess	**—**	—	567

5. Inventories

Inventories as of December 31 were as follows:

	2013 (Unaudited)	2012 (Unaudited)
Crude oil	**$ 52,878**	$ 52,878
Refined and other finished products	**63,308**	92,154
Less: LIFO adjustment	**(82,195)**	(103,318)
	33,991	41,714
Materials and supplies	**13,592**	26,516
Total	**$ 47,583**	$ 68,230

During 2013 and 2012, the Company liquidated LIFO inventories that are carried at below market costs, which improved operating results by approximately $10,000 and $745,000, respectively. During 2014, the Company intends to liquidate its remaining crude oil, refined and other finished products inventories.

HOVENSA L.L.C.

NOTES TO FINANCIAL STATEMENTS – (Continued)
(Dollars in thousands)

6. Tax Exempt Revenue Bonds and Other Long-Term Debt

During 2012, the Company redeemed $355,683 of tax-exempt revenue bonds. The terms of the tender offer included a purchase price at par value, plus accrued but unpaid interest up to the purchase date, subject to the terms of the offering document. In conjunction with the redemption of the tax-exempt revenue bonds, the Company's debt service fund was liquidated.

7. Environmental Matters

In 2011, the Company signed a Consent Decree with the U.S. Environmental Protection Agency (EPA) and the United States Virgin Islands, which among other things requires the Company to install equipment and implement additional operating procedures to reduce emissions over the next 10 years. The cost of installing this equipment would have been approximately $700,000. Since the refining facilities were shut down in 2012 and the Company reached an agreement in 2013 with the United States Virgin Islands to engage in a sale process, the Company believes it will not be required to make the material capital expenditures outlined in the Consent Decree. Under the terms of the Consent Decree, the Company paid a penalty of $5,375 in 2011.

In the normal course of its business, the Company records liabilities for future environmental remediation expenditures when such environmental obligations are probable and reasonably estimable.

The Company is required to provide financial assurance to the EPA in connection with various forms of environmental compliance. The required financial assurance totaled approximately $47,000 at December 31, 2013 and $41,000 at December 31, 2012. This requirement was met in 2013 by establishing a trust for $38,000, which is reflected in other assets on the balance sheet, and posting a letter of credit for $9,000. In 2012, the Company met the requirement by posting a letter of credit.

8. Contingencies

The Company is subject to loss contingencies with respect to various lawsuits, claims and other proceedings, including environmental matters. A liability is recognized in the Company's financial statements when it is probable 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 Company discloses the nature of those contingencies. In management's opinion, based upon currently known facts and circumstances, the outcome of such loss contingencies will not have a material adverse effect on the Company's financial condition, results of operations and cash flows.

9. Retirement Plans

The Company has a funded non-contributory, defined benefit pension plan for substantially all of its employees. The plan provides defined benefits based on years of service and final average salary. At December 31, 2013 and 2012, the actuarial assumptions for the determination of the projected benefit obligation reflect the transition of the refinery to an oil storage terminal. The non-contributory defined benefit pension plan will remain in place and meet future obligations in accordance with terms of the plan, but terminated employees will no longer earn service toward future benefits.

HOVENSA L.L.C.

NOTES TO FINANCIAL STATEMENTS – (Continued)
(Dollars in thousands)

The following table reconciles the projected benefit obligation and fair value of plan assets and shows the funded status of the pension plan:

	2013 (Unaudited)	2012 (Unaudited)
Reconciliation of projected benefit obligation:		
Benefit obligation at January 1	**$ 143,158**	$128,567
Service costs	**1,977**	5,707
Interest costs	**5,639**	5,413
Actuarial (gain) loss	**(20,313)**	6,560
Benefit payments	**(4,427)**	(3,089)
Projected benefit obligation at December 31	**126,034**	143,158
Reconciliation of fair value of plan assets:		
Fair value of plan assets at January 1	**104,242**	84,751
Actual return on plan assets	**5,785**	9,480
Employer contributions	**10,000**	13,100
Benefit payments	**(4,427)**	(3,089)
Fair value of plan assets at December 31	**115,600**	104,242
Funded status (plan assets less than benefit obligation)	**(10,434)**	(38,916)
Unrecognized net actuarial losses	**13,399**	37,941
Net amount recognized	**$ 2,965**	$ (975)

The accumulated benefit obligation was $120,287 at December 31, 2013 and $137,831 at December 31, 2012.

Components of funded pension expense consisted of the following:

	2013 (Unaudited)	2012 (Unaudited)	2011 (Audited)
Service cost	**$ 1,977**	$ 5,707	$ 9,243
Interest cost	**5,639**	5,413	6,373
Expected return on plan assets	**(3,721)**	(6,221)	(5,427)
Amortization of unrecognized net actuarial losses	**2,166**	1,727	1,896
Net periodic benefit cost	**$ 6,061**	$ 6,626	$ 12,085

The actuarial assumptions used in the Company's pension plan were as follows:

	2013 (Unaudited	2012 (Unaudited)	2011 (Audited)
Assumptions used to determine benefit obligations at December 31:			
Discount rate	**4.9%**	4.0%	4.4%
Rate of compensation increase	**4.1%**	4.2%	4.2%
Assumptions used to determine net costs for years ended December 31:			
Discount rate	**4.0%**	4.4%	5.6%
Expected return on plan assets	**3.5%**	7.0%	7.0%
Rate of compensation increase	**4.1%**	4.2%	4.2%

HOVENSA L.L.C.

NOTES TO FINANCIAL STATEMENTS – (Continued)
(Dollars in thousands)

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 investments that matches the maturity of the plan obligations. The overall expected return on plan assets is developed from the expected future returns for each asset category, weighted by the expected allocation of pension assets to that asset category. The Company engages an independent investment consultant to assist in the development of expected returns.

The Company's pension plan assets by category are as follows:

	2013 (Unaudited)	2012 (Unaudited)
Asset category		
Equity securities	**28%**	27%
Debt securities	**72**	73
Total	**100%**	100%

Target investment allocations are 73% debt securities and 27% equity securities. Asset allocations are rebalanced on a regular basis throughout the year to bring assets to within a 2-3% range of target levels. Target allocations take into account analyses performed by the Company's pension consultant to optimize long-term risk/return relationships. All assets are highly liquid and may be readily adjusted to provide liquidity for current benefit payment requirements.

For purposes of valuing pension investments, a hierarchy for the inputs is used to measure fair value based on the source of the input, 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).

The following tables provide the fair value hierarchy of the financial assets of the qualified pension plan as of December 31, 2013 and 2012:

	Level 1	Level 2	Level 3
December 31, 2013 (Unaudited)			
Cash and short-term investment funds	**$ —**	**$ 1,396**	**$ —**
U.S. equities (domestic)	**26,674**	**—**	**—**
International equities (non-U.S.)	**5,813**	**—**	**—**
Fixed income	**81,720**	**—**	**—**
Total	**$ 114,207**	**$ 1,396**	**$ —**
December 31, 2012 (Unaudited)			
Cash and short-term investment funds	$ —	$ 144	$ —
U.S. equities (domestic)	22,934	—	—
International equities (non-U.S.)	5,537	—	—
Fixed income	75,627	—	—
Total	$ 104,098	$ 144	$ —

Cash and short-term investment funds consist of cash on hand, which is invested in a short-term investment fund that provides for daily investments and redemptions and is valued and carried at a $1 net asset value (NAV) per fund share.

Equities consist of registered mutual fund investments whose diversified holdings primarily include common stock securities issued by U.S. and non-U.S. corporations, respectively. Mutual fund shares are valued daily, with the NAV per fund share published at the close of each business day. These investments are classified as Level 1.

Fixed income securities consist of registered mutual fund investments whose diversified holdings primarily include U.S. Treasury securities, corporate bonds and mortgage backed securities.

HOVENSA L.L.C.

NOTES TO FINANCIAL STATEMENTS – (Continued)
(Dollars in thousands)

HOVENSA has budgeted contributions to its funded pension plan of approximately $13,000 in 2014.

Estimated future pension benefit payments are as follows:

2014	$ 4,329
2015	4,492
2016	4,675
2017	4,860
2018	5,120
Years 2019 to 2023	30,233

The Company also maintains an unfunded post-retirement medical plan that provides health benefits to certain qualified retirees from ages 55 through 65. The projected benefit obligation for this plan was approximately $11,160 as of December 31, 2013 and $11,325 as of December 31, 2012. The decrease in the projected benefit obligation includes a change in actuarial assumptions to reflect the transition of the refinery to an oil storage terminal. This plan remains in place, but terminated employees will no longer earn service toward future benefits.

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EXHIBIT INDEX

3(1)	Restated Certificate of Incorporation of Registrant, including amendment thereto dated May 3, 2006 incorporated by reference to Exhibit 3 of Registrant's Form 10-Q for the three months ended June 30, 2006.
3(2)	Certificate of Amendment to the Restated Certificate of Incorporation of the Registrant, dated May 22, 2013, incorporated by reference to Exhibit 3(1) of Form 8-K of the Registrant filed on May 22, 2013.
3(3)	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 April 14, 2011, 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 April 18, 2011.
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) to 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 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)(2) under the Securities Act of 1933 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, as Trustee, including form of Note. Incorporated by reference to Exhibit 4 to Registrant's Form S-3ASR filed with the Securities and Exchange Commission on March 1, 2006.
4(7)	Form of 2014 Note issued pursuant to Indenture, dated as of March 1, 2006, among Registrant and The Bank of New York Mellon, as successor to JP Morgan Chase as Trustee. Incorporated by reference to Exhibit 4(1) to Registrant's Form 8-K filed with the Securities and Exchange Commission on February 4, 2009.
4(8)	Form of 2019 Note issued pursuant to Indenture, dated as of March 1, 2006, among Registrant and The Bank of New York Mellon, as successor to JP Morgan Chase, as Trustee. Incorporated by reference to Exhibit 4(2) to Registrant's Form 8-K filed with the Securities and Exchange Commission on February 4, 2009.
4(9)	Form of 6.00% Note, incorporated by reference to Exhibit 4(1) to the Form 8-K of Registrant filed on December 15, 2009.
4(10)	Form of 5.60% Note incorporated by reference to Exhibit 4(1) to the Form 8-K of Registrant filed on August 12, 2010. 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 Commission a copy of any instruments defining the rights of holders of long-term debt of Registrant and its subsidiaries upon request.
10(1)*	Incentive Cash Bonus Plan description incorporated by reference to Item 5.02 of Form 8-K of Registrant filed on March 8, 2013.
10(2)*	Financial Counseling Program description incorporated by reference to Exhibit 10(6) of Form 10-K of Registrant for 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 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 the 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 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 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 Registrant's Form 10-K 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)*	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(15)*	Compensation program description for non-employee directors, incorporated by reference to Item 1.01 of Form 8-K of Registrant filed on January 4, 2007.
10(16)*	Amended and Restated Change of Control Termination Benefits Agreement dated as of May 29, 2009 between Registrant and F. Borden Walker, incorporated by reference to Exhibit 10(1) of Form 10-Q of Registrant for the three months ended June 30, 2009. A substantially identical agreement (differing only in the signatories thereto) was entered into between Registrant and John B. Hess.
10(17)*	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 Registrant's Form 10-K 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 those referred to in Exhibit 10(17)).
10(18)*	Letter Agreement dated March 18, 2002 between Registrant and F. Borden Walker relating to Mr. Walker's participation in the Hess Corporation Pension Restoration Plan incorporated by reference to Exhibit 10(16) of Form 10-K of Registrant for the fiscal year ended December 31, 2001.
10(19)*	Agreement between Registrant and Gregory P. Hill relating to his 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 his 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 by and among Hess Corporation, Elliott Associates, L.P. and Elliott International, L.P. dated as of May 16, 2013, incorporated by reference to Exhibit 99(1) of Form 8-K of the Registrant filed on May 22, 2013.
21	Subsidiaries of Registrant.
23(1)	Consent of Ernst & Young LLP, Independent Registered Public Accounting Firm, dated February 28, 2014.
23(2)	Consent of DeGolyer and MacNaughton dated February 28, 2014.
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 7, 2014, on proved reserves audit as of December 31, 2013 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.*

Exhibit 21

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES
SUBSIDIARIES OF THE REGISTRANT

Name of Company	Jurisdiction
Hess Bakken Investments III L.L.C.	Delaware
Hess Bakken Investments IV L.L.C.	Delaware
Hess Capital Services Corporation	Delaware
Hess Capital Services L.L.C.	Delaware
Hess Energy Exploration Limited	Delaware
Hess Equatorial Guinea Inc.	Cayman Islands
Hess Exploration & Production Holdings Limited	Delaware
Hess (Ghana) Limited	Cayman Islands
Hess Gulf of Mexico Ventures L.L.C.	Delaware
Hess International Holdings Corporation	Delaware
Hess International Holdings Limited	Cayman Islands
Hess (Netherlands) Oil & Gas Holdings C.V.	The Netherlands
Hess Norge AS	Norway
Hess Oil and Gas Holdings Inc.	Cayman Islands
Hess Upstream North Dakota Inc.	Delaware
Hess West Africa Holdings Limited	Cayman Islands
Samara Holdings Limited	Cayman Islands

Other subsidiaries (names omitted because such unnamed subsidiaries, considered in the aggregate as a single subsidiary, would not constitute a significant subsidiary).

Each of the foregoing subsidiaries conducts business under the name listed, and is 100% owned by the Registrant.

Exhibit 23(1)

Consent of Independent Registered Public Accounting Firm

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

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

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

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

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

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

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

(7) Registration Statement (Form S-3 No. 333-179744) of Hess Corporation;

of our reports dated February 28, 2014, with respect to the consolidated financial statements and schedule of Hess Corporation and consolidated subsidiaries and the effectiveness of internal control over financial reporting of Hess Corporation and our report dated February 27, 2012 with respect to the statements of operations, comprehensive income (loss) and (accumulated deficit) retained earnings, and cash flows of HOVENSA L.L.C., for the year ended December 31, 2011, included in this Annual Report (Form 10-K) for the year ended December 31, 2013.

/s/ Ernst & Young LLP
New York, New York
February 28, 2014

Exhibit 23(2)

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

February 28, 2014

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

Ladies and Gentlemen:

We hereby consent to the use of the name DeGolyer and MacNaughton, to references to DeGolyer and MacNaughton as an independent petroleum engineering consulting firm, to references to our third party letter report dated February 7, 2014, containing our opinion on the proved reserves attributable to certain properties owned by Hess Corporation, as of December 31, 2013, (our "Report"), under the heading "Oil and Gas Reserves-Reserves Audit," and to the inclusion of our Report as an exhibit in Hess Corporation's Annual Report on Form 10-K for the year ended December 31, 2013. We also consent to all such references, including under the heading "Experts," and to the incorporation by reference of our Report in the Registration Statements filed by Hess Corporation on Form S-3 (No. 333-179744) and Form S-8 (No. 333-43569, No. 333-94851, No. 333-115844, No. 333-150992, No. 333-167076, and No. 333-181704).

Very truly yours,

/s/ DeGolyer and MacNaughton

DEGOLYER AND MACNAUGHTON
Texas Registered Engineering Firm F-716

Exhibit 31(1)

I, John B. Hess, certify that:

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

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

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

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

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

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

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

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

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

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

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

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

Date: February 28, 2014

Exhibit 31(2)

I, John P. Rielly, certify that:

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

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

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

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

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

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

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

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

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

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

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

By /s/ John P. Rielly

John P. Rielly
Senior Vice President and
Chief Financial Officer

Date: February 28, 2014

Exhibit 32(1)

CERTIFICATION PURSUANT TO

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

In connection with the Annual Report of Hess Corporation (the Corporation) on Form 10-K for the period ending December 31, 2013 as filed with the Securities and Exchange Commission on the date hereof (the Report), I, John B. Hess, Chief Executive Officer of the Corporation, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

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

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

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

Date: February 28, 2014

Exhibit 32(2)

CERTIFICATION PURSUANT TO

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

In connection with the Annual Report of Hess Corporation (the Corporation) on Form 10-K for the period ending December 31, 2013 as filed with the Securities and Exchange Commission on the date hereof (the Report), I, John P. Rielly, Senior Vice President and Chief Financial Officer of the Corporation, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

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

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

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

Date: February 28, 2014

Exhibit 99(1)

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

February 7, 2014

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

Ladies and Gentlemen:

Pursuant to your request, we have conducted a reserves audit of the net proved crude oil, condensate, natural gas liquids (NGL), and natural gas reserves, as of December 31, 2013, of certain selected properties of Hess Corporation (Hess) to determine the reasonableness of Hess' estimates. The audit was completed on February 7, 2014. Hess has represented to us that these properties account for approximately 82 percent on a net equivalent barrel basis of Hess' net proved reserves, as of December 31, 2013. We have reviewed information provided to us by Hess that it represents to be Hess' estimates of the net reserves, as of December 31, 2013, for the same properties as those which we evaluated. This report was prepared in accordance with guidelines specified in Item 1202 (a)(8) of Regulation S-K of the United States Securities and Exchange Commission (SEC) and is to be used for inclusion in certain SEC filings by Hess.

Reserves included herein are expressed as net reserves as represented by Hess. Gross reserves are defined as the total estimated petroleum to be produced from these properties after December 31, 2013. Net reserves are defined as that portion of the gross reserves attributable to the interests owned by Hess after deducting all interests owned by others.

Certain properties in which Hess has an interest are subject to the terms of various profit sharing agreements. The terms of these agreements generally allow for working interest participants to be reimbursed for portions of capital costs and operating expenses and to share in the profits. The reimbursements and profit proceeds are converted to a barrel of oil equivalent or standard cubic foot of gas equivalent by dividing by product prices to determine the "entitlement reserves." These entitlement reserves are equivalent in principle to net reserves and are used to calculate an equivalent net share, termed an “entitlement interest.” In this report, Hess net reserves or interest for certain properties subject to these agreements is the entitlement based on Hess’ working interest.

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

Data used in this audit were obtained from reviews with Hess personnel, Hess files, from records on file with the appropriate regulatory agencies, and from public sources. Additionally, this information includes data supplied by IHS Global Inc.; Copyright 2013 IHS Global Inc. In the preparation of this report we have relied, without independent verification, upon such information furnished by Hess with respect to property interests, production from such properties, costs of operation and development, prices for production, agreements relating to current and future operations and sale of production, and various other information and data that were accepted as represented. A field examination of the properties was not considered necessary for the purposes of this report. In our opinion, the adequacy and quality of the data provided to us was sufficient for us to conduct this reserves audit.

The Hess net proved reserves attributable to these properties as of December 31, 2013, and which represent approximately 82 percent of total Hess net reserves on a net equivalent barrel basis, are as follows, expressed in millions of barrels (MMbbl), billions of cubic feet (Bcf), and millions of barrels of oil equivalent (MMboe):

	Estimated by Hess Net Proved Reserves as of December 31, 2013			
	Oil and Condensate (MMbbl)	Natural Gas Liquids (MMbbl)	Natural Gas (Bcf)	Oil Equivalent (MMboe)
United States	390	58	260	491
Norway	235	20	197	288
Denmark	35	0	40	42
Africa	202	0	160	228
Asia	6	0	778	136
Total	**868**	**78**	**1,435**	**1,185**

Note: Gas is converted to oil equivalent using a factor of 6,000 cubic feet of gas per 1 barrel of oil equivalent.

Opinion

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

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

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

In comparing the detailed net proved reserves estimates by field prepared by us and by Hess, we have found differences, both positive and negative, resulting in an aggregate difference of approximately 2 percent when compared on the basis of net equivalent barrels. It is our opinion that the total net proved reserves estimates prepared by Hess as of December 31, 2013, on the properties reviewed by us and referred to in the table above, when compared on the basis of net equivalent barrels, do not differ materially from those prepared by us.

Methodology and Procedures

Estimates of reserves were prepared by the use of appropriate geologic, petroleum engineering, and evaluation 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 was tempered by experience with similar reservoirs, stage of development, quality and completeness of basic data, and production history.

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

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

For depletion-type reservoirs or those whose performance disclosed a reliable decline in producing-rate trends or other diagnostic characteristics, reserves were estimated by the application of appropriate decline curves or other performance relationships. In the analyses of production-decline curves, reserves were estimated only to the limits of economic production or to the limit of the production licenses as appropriate.

Petroleum reserves estimated by Hess and by us are classified as proved and are judged to be economically producible in future years from known reservoirs under existing economic and operating conditions and assuming continuation of current regulatory practices using conventional production methods and equipment. Reserves were estimated only to the limit of economic production rates under existing economic and operating conditions using prices and costs consistent with the effective date of this report, including consideration of changes in existing prices provided only by contractual arrangements but not including escalations based upon future conditions.

Gas volumes herein are expressed as marketable gas at the legal pressure and temperature base of the state or area in which the property is located.

Marketable gas is defined as the total gas produced from the reservoir after reduction for shrinkage resulting from field separation; processing, including removal of nonhydrocarbon gas to meet pipeline specifications; and flare and other losses but not from fuel usage. Fuel gas is included as reserves. Condensate reserves estimated herein are those to be recovered by conventional lease separation. NGL reserves are those attributed to the leasehold interests according to processing agreements.

Definition of Reserves

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

Proved oil and gas reserves – Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

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

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

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

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:
(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and, (B) The project has been approved for development by all necessary parties and entities, including governmental entities.

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

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

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

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

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

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

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

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

S-X, or by other evidence using reliable technology establishing reasonable certainty.

Primary Economic Assumptions

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

Oil and Condensate Prices

Hess has represented that the oil and condensate prices were based on a 12-month average price (reference price), calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, unless prices are defined by contractual arrangements. The 12-month average reference prices used were $97.33 per barrel for West Texas Intermediate and $108.85 per barrel for Brent. Hess supplied appropriate differentials by field to the relevant reference prices and the prices were held constant thereafter. The volume weighted average price for the fields evaluated was $102.22 per barrel.

NGL Prices

Hess has represented that the NGL prices were based on a 12-month average price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, unless prices are defined by contractual arrangements. These prices were held constant over the lives of the properties. The volume weighted average NGL price for the fields evaluated was $36.36 per barrel.

Natural Gas Prices

Hess has represented that the non-contracted natural gas prices were based on reference prices, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, unless prices are defined by contractual arrangements. The 12-month average reference price for NYMEX was $3.672 per thousand cubic feet and the UK International Petroleum Exchange reference price was $10.410 per thousand cubic feet. The gas prices were adjusted for each property using differentials to NYMEX or the UK International Petroleum Exchange furnished by Hess and held constant thereafter. A portion of the gas reserves evaluated are in international properties where the gas is sold based on contracted prices. The contract was used to determine the gas price but inflation was not taken into account in the calculation of the average price. The volume weighted average gas price for the fields evaluated was $6.65 per thousand cubic feet.

Operating Expenses and Capital Costs

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

Possible Effects of Regulations

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

Changes in the regulatory environment by host governments may impact the operating environment and oil and gas reserves estimates of industry participants. Such regulatory changes could include increased mandatory government participation in producing contracts, changes in royalty terms, cancellation or amendment of contract rights, or expropriation or nationalization of property. While the oil and gas industry is subject to regulatory changes that could affect an industry participant's ability to recover its oil and gas reserves, neither we nor Hess are aware of any such governmental actions which restrict the recovery of the December 31, 2013, estimated oil and gas volumes.

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

Submitted,

/s/ DeGolyer and MacNaughton

DeGOLYER and MacNAUGHTON
Texas Registered Engineering Firm F-716

/s/ James W. Hail, Jr., P.E.
James W. Hail, Jr., P.E.
Chairman of the Board and Chief
Executive Officer
DeGolyer and MacNaughton

[SEAL]

CERTIFICATE of QUALIFICATION

I, James W. Hail, Jr., Petroleum Engineer with DeGolyer and MacNaughton, 5001 Spring Valley Road, Suite 800 East, Dallas, Texas, 75244 U.S.A., hereby certify:

1. That I am the Chairman of the Board and Chief Executive Officer of DeGolyer and MacNaughton, which company did prepare the letter report dated February 7, 2014, on the proved reserves audit of certain properties attributable to Hess Corporation, and that I, as Chairman of the Board and Chief Executive Officer, was responsible for the preparation of this report.

2. That I attended Texas A&M University, and that I graduated with a Bachelor of Science degree in Chemical Engineering in 1972; that I am a Registered Professional Engineer in the State of Texas; that I am a member of the International Society of Petroleum Engineers; the American Association of Petroleum Geologists; and the Society of Petroleum Evaluation Engineers and that I have in excess of 40 years of experience in oil and gas reservoir studies and reserves evaluations.

[SEAL]

/s/ James W. Hail, Jr., P.E.

James W. Hail, Jr., P.E.
Chairman of the Board and Chief
Executive Officer
DeGolyer and MacNaughton