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, 2010

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 $14,497,000,000 computed using the outstanding common shares and closing market price on June 30, 2010.

At December 31, 2010, there were 337,680,780 shares of Common Stock outstanding.

Part III is incorporated by reference from the Proxy Statement for the annual meeting of stockholders to be held on May 4, 2011.

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 and its subsidiaries (collectively referred to as the Corporation or Hess) is a global integrated energy company that operates in two segments, Exploration and Production (E&P) and Marketing and Refining (M&R). The E&P segment explores for, develops, produces, purchases, transports and sells crude oil and natural gas. These exploration and production activities take place principally in Algeria, Australia, Azerbaijan, Brazil, Brunei, China, Colombia, Denmark, Egypt, Equatorial Guinea, France, Ghana, Indonesia, Libya, Malaysia, Norway, Peru, Russia, Thailand, the United Kingdom and the United States. The M&R segment manufactures refined petroleum products and purchases, markets and trades refined petroleum products, natural gas and electricity. The Corporation owns 50% of a refinery joint venture in the United States Virgin Islands. An additional refining facility, terminals and retail gasoline stations, most of which include convenience stores, are located on the East Coast of the United States.

Exploration and Production

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

	Crude Oil, Condensate & Natural Gas Liquids (c)		Natural Gas		Total Barrels of Oil Equivalent (BOE)(a)	
	2010	2009	2010	2009	2010	2009
	(Millions of barrels)		(Millions of mcf)		(Millions of barrels)	
Developed						
United States	**180**	154	**199**	205	**213**	188
Europe(b)	**210**	171	**424**	417	**281**	241
Africa	**215**	241	**54**	59	**224**	251
Asia	**22**	27	**638**	864	**128**	170
	627	593	**1,315**	1,545	**846**	850
Undeveloped						
United States	**124**	95	**81**	101	**138**	112
Europe(b)	**256**	159	**295**	225	**305**	197
Africa	**55**	73	**9**	12	**56**	75
Asia	**42**	47	**898**	938	**192**	203
	477	374	**1,283**	1,276	**691**	587
Total						
United States	**304**	249	**280**	306	**351**	300
Europe(b)	**466**	330	**719**	642	**586**	438
Africa	**270**	314	**63**	71	**280**	326
Asia	**64**	74	**1,536**	1,802	**320**	373
	1,104	967	**2,598**	2,821	**1,537**	1,437

(a) Reflects natural gas reserves 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. See the average selling prices in the table on page 8.

(b) As a result of acquisitions in 2010, proved reserves in Norway represent 22% of the Corporation's total reserves. Proved reserves in Norway at December 31, 2010 were as follows:

	Crude Oil and Natural Gas Liquids (Millions of barrels)	Natural Gas (Millions of mcf)	Total Barrels of Oil Equivalent (BOE) (Millions of barrels)
Developed	*97*	*157*	*123*
Undeveloped	*167*	*247*	*208*
Total	*264*	*404*	*331*

(c) Total natural gas liquids reserves at December 31, 2010, were 102 million barrels (54 million barrels developed and 48 million barrels undeveloped). Total natural gas liquids reserves at December 31, 2009, were 71 million barrels (41 million barrels developed and 30 million barrels undeveloped).

On a barrel of oil equivalent (boe) basis, 45% of the Corporation's worldwide proved reserves are undeveloped at December 31, 2010 (41% at December 31, 2009). Proved reserves held under production sharing contracts at December 31, 2010 totaled 15% of crude oil and natural gas liquids and 51% of natural gas reserves (24% and 57%, respectively, at December 31, 2009).

The Securities and Exchange Commission (SEC) revised its oil and gas reserve estimation and disclosure standards effective December 31, 2009. See the Supplementary Oil and Gas Data on pages 88 through 97 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:

	2010	**2009**	**2008**
Crude oil (thousands of barrels per day)			
United States			
Offshore	**52**	39	15
Onshore	**23**	21	17
	75	60	32
Europe			
United Kingdom	**19**	21	29
Norway*	**16**	13	16
Denmark	**11**	12	11
Russia	**42**	37	27
	88	83	83
Africa			
Equatorial Guinea	**69**	70	72
Algeria	**11**	14	15
Gabon	**10**	14	14
Libya	**23**	22	23
	113	120	124
Asia			
Azerbaijan	**7**	8	7
Other	**6**	8	6
	13	16	13
Total	**289**	279	252
Natural gas liquids (thousands of barrels per day)			
United States			
Offshore	**7**	4	3
Onshore	**7**	7	7
	14	11	10
Europe*	**3**	3	4
Asia	**1**	—	—
Total	**18**	14	14

	2010	2009	2008
Natural gas (thousands of mcf per day)			
United States			
Offshore	**70**	55	37
Onshore	**38**	38	41
	108	93	78
Europe			
United Kingdom	**93**	118	223
Norway*	**29**	21	22
Denmark	**12**	12	10
	134	151	255
Asia and Other			
Joint Development Area of Malaysia/Thailand (JDA)	**282**	294	185
Thailand	**85**	85	87
Indonesia	**50**	65	82
Other	**10**	2	2
	427	446	356
Total	**669**	690	689
Barrels of oil equivalent (per day)**	**418**	408	381

* *Norway production for 2010 included 14 thousand barrels per day of crude oil, 1 thousand barrels per day of natural gas liquids and 13 thousand mcf per day of natural gas from the Valhall Field.*

** *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. See the average selling prices in the table on page 8.*

A description of our significant E&P operations follows:

United States

At December 31, 2010, 23% of the Corporation’s total proved reserves were located in the United States. During 2010, 29% of the Corporation’s crude oil and natural gas liquids production and 16% of its natural gas production were from United States operations. The Corporation’s production in the United States was from properties offshore in the Gulf of Mexico, as well as onshore properties in the Williston Basin of North Dakota and in the Permian Basin of Texas.

Offshore: The Corporation’s production offshore the United States 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 Shenzi Field, the operator is pursuing water injection and additional development drilling opportunities. However, development and exploration activities are currently being affected by the uncertain regulatory environment in the Gulf of Mexico. See Gulf of Mexico Update on page 12.

At the Pony project on Green Canyon Block 468 (Hess 100%), the Corporation has signed a non-binding agreement in principle with the owners on adjacent Green Canyon Block 512 that outlines a proposal to jointly develop the Pony and Knotty Head fields. Negotiation of a joint operating agreement and planning for field development are underway. The agreement in principle provides that Hess will be operator of the joint development. The Corporation also commenced and subsequently suspended drilling the Pony 3 appraisal well on Green Canyon Block 469 in 2010. The Corporation is planning to resume drilling in 2011 contingent upon receipt of necessary permits.

In the third quarter of 2010, the Corporation acquired an additional 20% interest in the Tubular Bells oil and gas field in the Gulf of Mexico. The Corporation now has a 40% working interest in the field and is operator. Engineering and design work for the field development progressed during 2010 and will continue in 2011.

At December 31, 2010, the Corporation had interests in 306 blocks in the Gulf of Mexico, of which 272 were exploration blocks comprising 1,069,000 net undeveloped acres, with an additional 78,000 net acres held for production and development operations.

Onshore: In North Dakota, the Corporation holds more than 900,000 net acres in the Bakken oil shale play (Bakken). In December 2010, the Corporation acquired approximately 85,000 net acres in the Bakken through the purchase of American Oil & Gas Inc. (American Oil & Gas) through the issuance of approximately 8.6 million shares of the Corporation's stock. Further, in December 2010, the Corporation acquired an additional 167,000 net acres in the Bakken from TRZ Energy, LLC for $1,075 million in cash. The Corporation is currently operating 18 drilling rigs in the Bakken and is expanding production and export facilities to accommodate future production growth. In 2011, the Corporation plans to invest $1.8 billion for drilling and infrastructure in the Bakken.

In Texas, the Corporation holds a 34% interest in the Seminole-San Andres Unit and is operator. The Corporation is developing a part of this producing field using tertiary CO_2 flooding operations.

During 2010, the Corporation acquired approximately 90,000 net acres in the Eagle Ford shale formation in Texas. The Corporation plans to drill an initial six exploration wells, which will be followed by 12 appraisal wells. Exploration drilling commenced in the fourth quarter of 2010.

In the Marcellus gas shale formation in Pennsylvania, the Corporation is operator and holds a 100% interest on approximately 53,000 net acres and holds a 50% non-operated interest in approximately 38,000 net acres. There is currently a drilling moratorium in the Delaware River Basin area, where the majority of the Corporation's acreage is located. The moratorium is expected to remain in place until the Delaware River Basin Commission establishes new drilling regulations.

Europe

At December 31, 2010, 38% of the Corporation's total proved reserves were located in Europe (United Kingdom 6%, Norway 22%, Denmark 3% and Russia 7%). During 2010, 30% of the Corporation's crude oil and natural gas liquids production and 20% of its natural gas production were from European operations.

United Kingdom: Production of crude oil and natural gas liquids from the United Kingdom North Sea was principally from the Corporation's non-operated interests in the Nevis (Hess 27%), Bittern (Hess 28%), Schiehallion (Hess 16%) and Beryl (Hess 22%) fields. Natural gas production from the United Kingdom was primarily from the Bacton Area (Hess 23%), Easington Catchment Area (Hess 30%), Everest (Hess 19%), Beryl (Hess 22%), Nevis (Hess 27%) and Lomond (Hess 17%) fields. The Corporation also has an 18% interest in the Central Area Transmission System (CATS) pipeline and interests in the Atlantic (Hess 25%) and Cromarty (Hess 90%) fields.

In September 2010, the Corporation disposed of all of its interests in the Clair Field as part of an exchange for additional interests in the Valhall and Hod fields in Norway as further described below.

In February 2011, the Corporation completed the previously announced sale of a package of natural gas producing assets in the United Kingdom North Sea including its interests in the Easington Catchment Area, the Bacton Area, the Everest Field and the Lomond Field for approximately $350 million, after closing adjustments. The sale of the Corporation's interest in the CATS pipeline is expected to close in the second quarter of 2011.

Norway: Substantially all of the 2010 Norwegian production was from the Corporation's interest in the Valhall Field (Hess 64%). The Corporation also holds an interest in the Hod (Hess 63%), Snohvit (Hess 3%) and Snorre (Hess 1%) fields. All four of the Corporation's Norwegian field interests are located offshore.

In September 2010, the Corporation exchanged its interests in Gabon and the Clair Field in the United Kingdom for additional interests of 28% and 25%, respectively, in the Valhall and Hod fields in Norway. Also in September 2010, the Corporation completed the acquisition of an additional 8% interest in the Valhall Field and 13% interest in the Hod Field for $507 million. After these transactions, the Corporation's interests in the Valhall and Hod fields are now 64% and 63%, respectively.

A field redevelopment for Valhall commenced in 2007 and the Valhall Flank Gas Lift project was sanctioned in 2009. In 2010, the operator continued work on these projects, which are expected to be completed and commissioned in 2011. In 2011, further drilling is planned for Valhall, which will include the addition of a jack-up rig during the second half of the year.

Denmark: Crude oil and natural gas production comes from the Corporation's operated interest in the South Arne Field (Hess 58%). In 2010, the Corporation drilled two new production wells and sanctioned an additional development phase at South Arne, which will include design, construction and installation of two new platforms and related infrastructure.

Russia: The Corporation's activities in Russia are conducted through its interest in a subsidiary operating in the Volga-Urals region. In the third quarter of 2010, the Corporation acquired an additional 5% interest in its subsidiary, increasing its ownership to 85%. As of December 31, 2010, this subsidiary had exploration and production rights in 18 license areas in the Samara and Ulyanovsk territories.

France: In 2010, the Corporation entered into an agreement with Toreador Resources Corporation (Toreador) under which it can invest in an initial exploration phase and earn up to a 50% working interest in, and become operator of, Toreador's Paris Basin acreage. An initial six exploration well program is scheduled to begin in 2011, with the first well expected to spud in the first half of 2011.

Africa

At December 31, 2010, 18% of the Corporation's total proved reserves were located in Africa (Equatorial Guinea 6%, Algeria 1% and Libya 11%). During 2010, 37% of the Corporation's crude oil and natural gas liquids production was from African operations. In September 2010, the Corporation disposed of all of its interests in Gabon as part of the exchange for additional interests in the Valhall and Hod fields in Norway.

Equatorial Guinea: The Corporation is the operator and owns an interest in Block G (Hess 85%) which contains the Ceiba Field and Okume Complex. In 2010, a 4D seismic survey was acquired covering the Okume Complex and the Ceiba Field. This seismic data will be processed and evaluated in 2011 in preparation for potential further development drilling.

Algeria: The Corporation has a 49% interest in a venture with the Algerian national oil company that redeveloped three oil fields. The Corporation also has an interest in Bir El Msana (BMS) Block 401C.

Libya: The Corporation, in conjunction with its Oasis Group partners, has oil and gas production operations in the Waha concessions in Libya (Hess 8%). The Corporation also owns a 100% interest in offshore exploration Area 54 in the Mediterranean Sea, where a successful exploration well was drilled in 2008. In 2009, the Corporation successfully drilled a down-dip appraisal well. In 2010, the Corporation received a five year extension to the Area 54 license.

Egypt: The Corporation has an interest in the West Mediterranean Block 1 concession (West Med Block) (Hess 55%). In September 2010, the Corporation recorded an after-tax charge of $347 million to fully impair the carrying value of its interest in the West Med Block and to expense a previously capitalized well. See further discussion in Management's Discussion and Analysis of Financial Condition and Results of Operations on page 29. The Corporation also owns a 100% interest in Block 1 offshore Egypt in the North Red Sea. The Corporation spud an exploration well on the North Red Sea block in late December 2010, the completion of which may be delayed by the current political unrest in Egypt. In December 2010, the Corporation entered a farm-out agreement that will, subject to government approval, reduce its interest in the block from 100% to 80%.

Ghana: The Corporation holds a 100% interest in the Deepwater Tano Cape Three Points License. In 2010, the Corporation acquired additional 3D seismic data and plans to drill a second exploration well on this block in 2011.

Asia

At December 31, 2010, 21% of the Corporation's total proved reserves were located in the Asia region (JDA 9%, Indonesia 6%, Thailand 3%, Azerbaijan 2% and Malaysia 1%). During 2010, 4% of the Corporation's crude oil and natural gas liquids production and 64% of its natural gas production were from its Asian operations.

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 2011, the operator will continue development of the block with further drilling and construction of additional platform facilities.

Malaysia: The Corporation's production in Malaysia comes from its interest in Block PM301 (Hess 50%), which is adjacent to Block A-18 of the JDA where the natural gas is processed. The Corporation also owns an interest in Block PM302 (Hess 50%) and Belud — Block SB302 (Hess 40%). Through December 31, 2010 the Corporation has drilled two wells on Block SB302 which were natural gas discoveries. Technical and commercial evaluations are underway to assess the development alternatives for this block.

Indonesia: The Corporation's natural gas production in Indonesia primarily comes from its interests offshore in the Ujung Pangkah project (Hess 75%), and the Natuna A Field (Hess 23%). In 2010, the Corporation installed a new wellhead platform at Ujung Pangkah and will install a new central processing platform in 2011 to expand oil and water handling capacity. At the Natuna A Field the operator is constructing a second wellhead platform and a central processing platform, which is expected to be placed in service in 2011. The Corporation also holds a 100% working interest in the offshore Semai V Block, where it plans to drill three exploration wells beginning in 2011. The Corporation owns a 100% working interest in the offshore South Sesulu Block and a 49% interest in the West Timor Block. In 2010, the Corporation sold its interest in the Jambi Merang onshore natural gas development project.

Thailand: The Corporation's natural gas production in Thailand primarily comes from the offshore Pailin Field (Hess 15%) and the onshore Sinphuhorm Block (Hess 35%).

Azerbaijan: The Corporation has an interest in the Azeri-Chirag-Guneshli (ACG) fields (Hess 3%) in the Caspian Sea and also owns an interest in the Baku-Tiblisi-Ceyhan oil transportation pipeline (Hess 2%). In 2010, the Corporation sanctioned the Chirag Oil Development project at ACG. This project includes construction and installation of a production, drilling and living-quarters platform and further development drilling.

Brunei: The Corporation has a 14% interest in Block CA-1 (previously known as Block J). The Corporation expects the operator to begin exploration drilling in the second half of 2011.

China: The Corporation has signed a joint study agreement with China National Petroleum Corporation and two joint study agreements with Sinopec to evaluate unconventional oil and gas resource opportunities in China.

Other Exploration Areas

Australia: The Corporation holds a 100% interest in an exploration license covering 780,000 acres in the Carnarvon basin offshore Western Australia (WA-390-P Block). The Corporation has drilled all of the 16 commitment wells on the block, 13 of which were natural gas discoveries. In the fourth quarter of 2010, the Corporation commenced an appraisal program that includes further drilling and flow testing certain wells. In November 2010, the Corporation sold its 50% interest in the WA-404-P Block located offshore Western Australia.

Brazil: The Corporation has a 40% interest in block BM-S-22 located offshore Brazil. In early 2011, the operator completed drilling of a third exploration well on this block, which did not encounter commercial quantities of hydrocarbons. See further discussion in Management's Discussion and Analysis of Financial Condition and Results of Operations on page 23. The Corporation also had an interest in Block BM-ES-30 but reassigned its 30% interest in 2010, pending government approval.

Peru: The Corporation has an interest in Block 64 in Peru (Hess 50%). In 2010, the Corporation successfully drilled a sidetrack to an exploration well on this block. Further evaluation work is planned for 2011.

Colombia: The Corporation has interests in offshore Blocks RC 6 and RC 7 (Hess 30%).

Sales Commitments

In the E&P segment, the Corporation has no contracts or agreements to sell fixed quantities of its crude oil production. The Corporation has contracts to supply fixed quantities of natural gas, principally relating 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 107 million mcf per year based on current entitlements under a natural gas sales contract expiring in 2027. There are additional natural gas supply commitments on producing fields in Thailand and Indonesia which currently total approximately 42 million mcf per year under contracts expiring in years 2021 through 2029. The Corporation is also currently committed to supply 7 million mcf per year of natural gas from its share of production to a liquefied natural gas (LNG) processing facility in Norway under a contract expiring in 2026. The estimated total volume of natural gas subject to sales commitments under these contracts is approximately 2,700 million mcf. The Corporation has not experienced any significant constraints in satisfying the committed quantities under these natural gas sales contracts and it anticipates being able to meet future requirements from available proved and probable reserves. In the United States there are no long-term sales contracts for natural gas production from the E&P segment.

Natural gas is marketed by the M&R segment on a spot basis and under contracts for varying periods of time to local distribution companies, and commercial, industrial and other purchasers. These natural gas marketing activities are primarily conducted in the eastern portion of the United States, where the principal source of supply is purchased natural gas, not the Corporation's production from the E&P segment. The Corporation has not experienced any significant constraints in obtaining the required supply of purchased natural gas.

Average selling prices and average production costs

	2010	2009	2008
Average selling prices(a)			
Crude oil (per barrel)			
United States	**$75.02**	$ 60.67	$96.82
Europe(b)	**58.11**	47.02	78.75
Africa	**65.02**	48.91	78.72
Asia	**79.23**	63.01	97.07
Worldwide	**66.20**	51.62	82.04
Natural gas liquids (per barrel)			
United States	**$47.92**	$ 36.57	$ 64.98
Europe(b)	**59.23**	43.23	74.63
Asia	**63.50**	46.48	—
Worldwide	**50.49**	38.47	67.61
Natural gas (per mcf)			
United States	**$ 3.70**	$ 3.36	$ 8.61
Europe(b)	**6.23**	5.15	9.44
Asia and other	**5.93**	5.06	5.24
Worldwide	**5.63**	4.85	7.17
Average production (lifting) costs per barrel of oil equivalent produced(c)			
United States	**$12.61**	$ 13.72	$ 18.46
Europe(b)	**17.55**	15.77	17.12
Africa	**11.00**	10.93	10.22
Asia	**8.16**	7.65	8.48
Worldwide	**12.61**	12.12	13.43

(a) Includes inter-company transfers valued at approximate market prices and the effect of the Corporation's hedging activities.

(b) The average selling prices in Norway for 2010 were $79.47 per barrel for crude oil, $52.26 per barrel for natural gas liquids and $7.32 per mcf for natural gas. The average production (lifting) cost in Norway was $18.33 per barrel of oil equivalent produced.

(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.

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Gross and net undeveloped acreage at December 31, 2010

	Undeveloped Acreage(a)	
	Gross	Net
	(In thousands)	
United States	3,650	2,478
Europe(c)	2,922	1,260
Africa	9,619	6,282
Asia and other	9,958	5,247
Total(b)	26,149	15,267

(a) Includes acreage held under production sharing contracts.

(b) Licenses covering approximately 19% of the Corporation's net undeveloped acreage held at December 31, 2010 are scheduled to expire during the next three years pending the results of exploration activities. These scheduled expirations are largely in South America, Africa and the United States.

(c) Gross and net undeveloped acreage in Norway was 1,143 thousand and 259 thousand, respectively.

Gross and net developed acreage and productive wells at December 31, 2010

	Developed Acreage Applicable to Productive Wells		Productive Wells*			
			Oil		Gas	
	Gross	Net	Gross	Net	Gross	Net
	(In thousands)					
United States	628	538	1,114	573	61	46
Europe**	1,381	847	289	158	151	31
Africa	9,831	933	905	132	—	—
Asia and other	2,200	630	74	7	468	98
Total	14,040	2,948	2,382	870	680	175

* *Includes multiple completion wells (wells producing from different formations in the same bore hole) totaling 20 gross wells and 15 net wells.*

** *Gross and net developed acreage in Norway was 161 thousand and 45 thousand, respectively. Gross and net productive oil wells in Norway were 74 and 29, respectively. Gross and net productive gas wells in Norway were 9 and 1, respectively.*

Number of net exploratory and development wells drilled

	Net Exploratory Wells			Net Development Wells		
	2010	2009	2008	**2010**	2009	2008
Productive wells						
United States	—	—	2	**83**	44	50
Europe*	**1**	7	11	**18**	12	11
Africa	**1**	1	1	**11**	23	23
Asia and other	**6**	8	5	**7**	12	25
	8	16	19	**119**	91	109
Dry holes						
United States	**5**	4	—	—	—	1
Europe*	—	—	3	—	—	—
Africa	**2**	—	2	**1**	—	—
Asia and other	**2**	2	1	—	—	—
	9	6	6	**1**	—	1
Total	**17**	22	25	**120**	91	110

* *Includes one net productive development well drilled in Norway in 2010.*

Number of wells in process of drilling at December 31, 2010:

	Gross Wells	Net Wells
United States	41	17
Europe	11	10
Africa	16	2
Asia and other	12	3
Total	80	32

Number of net waterfloods and pressure maintenance projects in process of installation at December 31, 2010 — 1

Marketing and Refining

Refining

The Corporation owns a 50% interest in HOVENSA L.L.C. (HOVENSA), a refining joint venture in the United States Virgin Islands with a subsidiary of Petroleos de Venezuela S.A. (PDVSA). In addition, it owns and operates a refining facility in Port Reading, New Jersey.

HOVENSA: Refining operations at HOVENSA consist of crude units, a fluid catalytic cracking unit (FCC) and a delayed coker unit.

The following table summarizes capacity and utilization rates for HOVENSA:

	Refinery Capacity (Thousands of barrels per day)	Refinery Utilization 2010	2009	2008
Crude	500	**78.0%**	80.3%	88.2%
Fluid catalytic cracker	150	**66.5%**	70.2%	72.7%
Coker	58	**78.3%**	81.6%	92.4%

In January 2011, HOVENSA announced plans to shut down certain older and smaller processing units on the west side of its refinery, which will reduce the refinery's crude oil distillation capacity from 500,000 to 350,000 barrels per day, with no impact on the capacity of its coker or FCC unit. This reconfiguration, which is expected to be completed in the first quarter of 2011, is being undertaken to improve efficiency, reliability and competitiveness. In 2010, the Corporation recorded an impairment charge related to its investment in HOVENSA. For discussion of the impairment charge, see Note 4, Refining Joint Venture in the notes to the financial statements on page 59.

The delayed coker unit permits HOVENSA to run lower-cost heavy crude oil. HOVENSA has long-term supply contracts with PDVSA to purchase 115,000 barrels per day of Venezuelan Merey heavy crude oil and 155,000 barrels per day of Venezuelan Mesa medium gravity crude oil. The remaining crude oil requirements are purchased mainly under contracts of one year or less from third parties and through spot purchases on the open market. After sales of refined products by HOVENSA to third parties, the Corporation purchases 50% of HOVENSA's remaining production at market prices.

Gross crude runs at HOVENSA averaged 390,000 barrels per day in 2010 compared with 402,000 barrels per day in 2009 and 441,000 barrels per day in 2008. The 2010 and 2009 utilization rates for HOVENSA reflect weaker refining margins, higher fuel costs and planned and unplanned maintenance. During the first quarter of 2010, the fluid catalytic cracking unit at HOVENSA was shut down for a scheduled turnaround. The 2008 utilization rates reflect a refinery wide shut down for Hurricane Omar.

Port Reading Facility: The Corporation owns and operates a fluid catalytic cracking facility in Port Reading, New Jersey, with a capacity of 70,000 barrels per day. This facility, which processes residual fuel oil and vacuum gas oil, operated at a rate of approximately 55,000 barrels per day in 2010 compared with 63,000 barrels per day in 2009 and 64,000 barrels per day in 2008. Substantially all of Port Reading's production is gasoline and heating oil. During 2010, the Port Reading refining facility was shutdown for 41 days for a scheduled turnaround.

Marketing

The Corporation markets refined petroleum products, natural gas and electricity on the East Coast of the United States to the motoring public, wholesale distributors, industrial and commercial users, other petroleum companies, governmental agencies and public utilities.

The Corporation had 1,362 HESS® gasoline stations at December 31, 2010, including stations owned by its WilcoHess joint venture (Hess 44%). Approximately 92% of the gasoline stations are operated by the Corporation or WilcoHess. Of the operated stations, 94% 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.

The table below summarizes marketing sales volumes:

	2010*	2009*	2008*
Refined Product sales (thousands of barrels per day)			
Gasoline	**242**	236	234
Distillates	**120**	134	143
Residuals	**69**	67	56
Other	**40**	36	39
Total refined product sales	**471**	473	472
Natural gas (thousands of mcf per day)	**2,016**	2,010	1,955
Electricity (megawatts round the clock)	**4,140**	4,306	3,152

* *Of total refined products sold, approximately 41%, 45% and 50% was obtained from HOVENSA and Port Reading in 2010, 2009 and 2008, respectively. The Corporation purchased the balance from third parties under short-term supply contracts and spot purchases.*

The Corporation owns 20 terminals with an aggregate storage capacity of 22 million barrels in its East Coast marketing areas. The Corporation also owns a terminal in St. Lucia with a storage capacity of 9 million barrels, which is operated for third party storage.

The Corporation has a 50% interest in Bayonne Energy Center, LLC, a joint venture established to build and operate a 512-megawatt natural gas fueled electric generating station in Bayonne, New Jersey. The joint venture plans to sell electricity into the New York City market by a direct connection with the Con Edison Gowanus substation. Construction of the facility began in mid-2010 and operations are expected to commence in 2012.

The Corporation has a 50% voting interest in a consolidated partnership that trades energy commodities and derivatives. The Corporation also takes energy commodity and derivative trading positions for its own account.

The Corporation is pursuing opportunities for LNG import terminals in Shannon, Ireland and on the East Coast of the United States. In addition, a subsidiary of the Corporation is exploring the development of fuel cell and hydrogen reforming technologies.

For additional financial information by segment see Note 18, Segment Information in the notes to the 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

Gulf of Mexico Update: In April 2010, an accident occurred on the Transocean Deepwater Horizon drilling rig at the BP p.l.c. (BP) operated Macondo prospect in the Gulf of Mexico, resulting in loss of life, the sinking of the rig and a significant crude oil spill. The Corporation was not a participant in the well. As a result of the accident, a temporary drilling moratorium was imposed in the Gulf of Mexico. In October 2010, the drilling moratorium was lifted by the United States Department of the Interior's Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE) provided operators complied with all rules and requirements, including a series of new drilling and safety rules issued by BOEMRE. The Corporation is currently evaluating the impact of these new requirements on its activities in the Gulf of Mexico, as well as seeking approvals for plans and permits submitted in connection with planned activities. However, the new regulatory environment is expected to result in a longer permitting process and higher costs.

The moratorium impacted development drilling at the Shenzi Field, in which the Corporation has a 28% interest. A production well that was being drilled was suspended and the drilling of a second production well that was planned for 2010 was postponed. The Corporation estimates that these delays reduced 2010 production by approximately 2,000 barrels of oil equivalent per day (boepd) and will likely reduce 2011 production by approximately 4,000 boepd. In 2010, the Corporation's only operated drilling rig in the Gulf of Mexico, the Stena Forth, left the Pony project on Green Canyon 469 as part of a preexisting agreement for a one well farm-out of the rig to another operator.

In January 2011, the BOEMRE announced that supplementary environmental reviews will not be required of 13 companies to resume work on the 16 wells that were in progress when the moratorium took effect, including the aforementioned suspended Shenzi and Pony wells. However, these projects must comply with the new safety rules and regulations before work can resume. As a result, the Corporation does not anticipate that it will be able to re-commence these operations before the second half of 2011.

Additionally, the Corporation has filed Suspension of Operations (SOO) applications with the BOEMRE for several exploration block licenses in the Gulf of Mexico that are due to expire in 2011 and may file additional applications as deemed necessary. These SOO applications seek approval for extension of the lease expiration terms due to circumstances outside the control of the Corporation that have delayed activities required to hold the licenses.

Remediation Plans and Procedures: The Corporation has in place a series of asset-specific emergency response and continuity plans which detail procedures for rapid and effective emergency response and environmental mitigation activities for its global offshore operations. These plans are maintained, reviewed and updated annually to ensure their accuracy and suitability.

Where appropriate, plans are reviewed and approved by the relevant host government authorities on a periodic basis. The Corporation has a current oil spill response plan for its Gulf of Mexico operations that has been approved by the BOEMRE. This plan sets forth expectations for response training, drills and capabilities and the strategies, procedures and methods that will be employed in the event of a spill covering the following topics: spill response organization, incident command post, communications and notifications, spill detection and assessment (including worst case discharge scenarios), identification and protection of environmental resources, strategic response planning, mobilization and deployment of spill response equipment and personnel, oil and debris removal and disposal, the use of dispersants and chemical and biological agents, in-situ burning of oil, wildlife rehabilitation and documentation requirements.

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, the Corporation maintains membership contracts with oil spill response organizations to provide coverage for its global drilling and production operations. These organizations are Clean Gulf Associates, National Response Corporation (NRC) and Oil Spill Response (OSR). Clean Gulf Associates is a regional spill response organization for the Gulf of Mexico; NRC and OSR are global response corporations 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 include 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. If the Corporation were to request these organizations to obtain additional critical response support services, it would provide the funding for such services and seek reimbursement under its insurance coverages 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. It also has representation on the Executive Committee of Clean Gulf Associates and the Board of Directors of OSR, maintaining close associations with these organizations.

In light of the recent events in the Gulf of Mexico, the Corporation is participating in a number of industry-wide task forces that are studying better ways to assess the risk of and prevent 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 windstorm coverage in the Gulf of Mexico where 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 $250 million of coverage is provided through an industry mutual insurance group. Above this $250 million threshold, insurance is carried which ranges in value to over $1.9 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 $995 million.

Other insurance policies provide coverage for, among other things: charterer's legal liability, in the amount of $500 million per occurrence and aircraft liability, in the amount of $300 million per occurrence.

The Corporation's insurance policies renew at various dates each year. Future insurance coverage for the industry 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 regardless of fault. Variations 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, whichever is greater.

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 where the claim is based upon the gross negligence and/or willful misconduct of a party in which case such party is solely liable.

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 $13 million in 2010 for environmental remediation. 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 13,800 in 2010 and 13,300 in 2009.

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 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, refined petroleum products and electricity, which can be very volatile. Our estimated proved reserves, revenue, operating cash flows, operating margins, future earnings and trading operations are highly dependent on the prices of crude oil, natural gas, refined petroleum products and electricity, which are influenced by numerous factors beyond our control. Historically these prices have been very volatile. 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, refined petroleum products and electricity. 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 addition, we utilize significant bank credit facilities to support these collateral and margin requirements. An inability to renew or replace such credit facilities as they mature would negatively impact our liquidity.

If we fail to successfully increase our reserves, our future crude oil and natural gas production will be adversely impacted. We own or have access to a finite amount of oil and gas reserves which will be depleted over time. Replacement of oil and gas production and reserves, including proved undeveloped reserves, is subject to successful exploration drilling, development activities, and enhanced recovery programs. Therefore, future oil and gas production is dependent on technical success in finding and developing additional hydrocarbon reserves. Exploration activity involves the interpretation of seismic and other geological and geophysical data, which does not always successfully predict the presence of commercial quantities of hydrocarbons. Drilling risks include unexpected adverse conditions, irregularities in pressure or formations, equipment failure, blowouts and weather interruptions. Future developments may be affected by unforeseen reservoir conditions which negatively affect recovery factors or flow rates. 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. Although due diligence is used in evaluating acquired oil and gas properties, similar risks 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 flow, 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 revisions 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 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, expropriation or nationalization of property, mandatory government participation, cancellation or amendment of contract rights, and changes in import and export regulations, limitations on access to exploration and development opportunities, as well as other political developments may affect our operations. We also market motor fuels through lessee-dealers and wholesalers in certain states where legislation prohibits producers or refiners of crude oil from directly engaging in retail marketing of motor fuels. Similar legislation has been periodically proposed in various other states. As a result of the accident in April 2010 at the 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, including an increase in the potential liability in the event of an oil spill. Uncertainty continues to exist as to the conditions under which future drilling in the Gulf of Mexico will occur. However, the new regulatory environment is expected to result in a longer permitting process and higher costs.

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. Current political unrest in North Africa and the Middle East may affect our operations in these areas as well as oil and gas markets generally. The threat of terrorism around the world also poses additional risks to the operations of the oil and gas industry.

Our oil and gas operations are subject to environmental risks and environmental laws and regulations that can result in significant costs and liabilities. Our oil and gas operations, like those of the industry, are subject to environmental risk 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. For example, the accident at the BP-operated Macondo prospect in April 2010 resulted in a significant release of crude oil which caused extensive environmental and economic damage. Our operations are also subject to numerous United States 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, particularly relating to the production of motor and other fuels, 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 unconventional oil and gas resources, particularly using the process of hydraulic fracturing. 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 temporary moratoriums and new regulations on such drilling operations that would likely have the effect of delaying and increasing the cost of such operations.

Concerns about climate change may result in significant operational changes and expenditures and reduced demand for our products. 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, we manufacture petroleum fuels, which through normal customer use result in the emission of greenhouse gases. Regulatory initiatives to reduce the use of these fuels may reduce our sales of, and revenues from, these products. 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 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 us. 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, and in purchasing and marketing of refined products, natural gas and electricity. Many competitors, including national oil companies, are larger and have substantially greater resources. We are also in competition with producers and marketers of other forms of energy. Increased competition for worldwide oil and gas assets has significantly increased the cost of acquisitions. In addition, competition for drilling services, technical expertise and equipment has, in the recent past, affected 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 and blowouts, such as the accident at the Macondo prospect operated by BP in the Gulf of Mexico. Although we maintain a level of insurance coverage consistent with industry practices 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.

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 United States against producers of MTBE and petroleum refiners who produced gasoline containing MTBE, including the Corporation. The principal allegation in all cases is 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, additional cases were settled, and three new cases were filed. The six unresolved cases consist of five cases that have been consolidated for pre-trial purposes in the Southern District of New York as part of a multi-district litigation proceeding and an action brought in state court by the State of New Hampshire. In 2007, a pre-tax charge of $40 million was recorded to cover all of the known MTBE cases against the Corporation.

Over the last several years, many refiners have entered into consent agreements to resolve the United States Environmental Protection Agency's (EPA) assertions that refining facilities were modified or expanded without complying with New Source Review regulations that require permits and new emission controls in certain circumstances and other regulations that impose emissions control requirements. These consent agreements, which arise out of an EPA enforcement initiative focusing on petroleum refiners and utilities, have typically imposed substantial civil fines and penalties and required (i) significant capital expenditures to install emissions control equipment over a three to eight year time period and (ii) changes to operations which resulted in increased operating costs. The capital expenditures, penalties and supplemental environmental projects for individual refineries covered by the settlements can vary significantly, depending on the size and configuration of the refinery, the circumstances of the alleged modifications and whether the refinery has previously installed more advanced pollution controls. In January 2011, HOVENSA signed a Consent Decree with EPA to resolve its claims. Under the terms of the Consent Decree, HOVENSA will pay a penalty of approximately $5 million and spend approximately $700 million over the next 10 years to install equipment and implement additional operating procedures at the HOVENSA refinery to reduce emissions. In addition, the Consent Decree requires HOVENSA to spend approximately $5 million to fund an environmental project to be determined at a later date by the Virgin Islands and $500,000 to assist the Virgin Islands Water and Power Authority with monitoring. The Consent Decree has been lodged with the United States District Court for the Virgin Islands and approval is pending. In addition, substantial progress has been made towards resolving this matter for the Port Reading refining facility, which is not expected to have a material adverse impact on the Corporation's financial position or results of operations.

On September 13, 2007, HOVENSA received a Notice Of Violation (NOV) pursuant to section 113(a)(i) of the Clean Air Act (Act) from the EPA finding that HOVENSA failed to obtain proper permitting for the construction and operation of its delayed coking unit in accordance with applicable law and regulations. HOVENSA believes it properly obtained all necessary permits for this project. The NOV states that the EPA has authority to issue an administrative order assessing penalties for violation of the Act. This matter is resolved by the Consent Decree discussed above, provided that the Consent Decree is entered by the court.

In December 2006, HOVENSA received a NOV from the EPA alleging non-compliance with emissions limits in a permit issued by the Virgin Islands Department of Planning and Natural Resources (DPNR) for the two process heaters in the delayed coking unit. The NOV was issued in response to a voluntary investigation and submission by HOVENSA regarding potential non-compliance with the permit emissions limits for two pollutants. Any exceedances were minor from the perspective of the amount of pollutants emitted in excess of the limits. This matter is resolved by the Consent Decree discussed above, provided that the Consent Decree is entered by the court.

On December 16, 2010, the Virgin Islands Department of Planning and Natural Resources commenced four separate enforcement actions 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 air release incidents at the HOVENSA refinery in 2009 and 2010 and propose total penalties of $1,355,000. HOVENSA intends to vigorously defend this matter.

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 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 now owned by the Corporation. The Corporation and over 70 companies entered into an Administrative Order on Consent with the EPA to study the same contamination. NJDEP has also sued several other companies linked to a facility considered by the State to be the largest contributor to river contamination. In January 2009, these companies added third party defendants, including the Corporation, to that case. In June 2007, the EPA issued a draft study which evaluated six alternatives for early action, with costs ranging from $900 million to $2.3 billion. Based on adverse comments from the Corporation and others, the EPA is reevaluating its alternatives. 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.

In July 2004, Hess Oil Virgin Islands Corp. (HOVIC), a wholly owned subsidiary of the Corporation, 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. HOVIC and HOVENSA do not believe that this matter will result in a material liability as they believe that they have strong defenses to this complaint, and they intend to vigorously defend this matter.

The Corporation periodically receives notices from 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, EPA’sclaims or assertions of liability against the Corporation relating to these sites have not been fully developed. With respect to the remaining sites, 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 will not have a material adverse effect on the financial condition of the Corporation, although the outcome of such proceedings could be material to the Corporation’s results of operations and cash flows for a particular period depending on, among other things, the level of the Corporation’s net income for such period.

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:

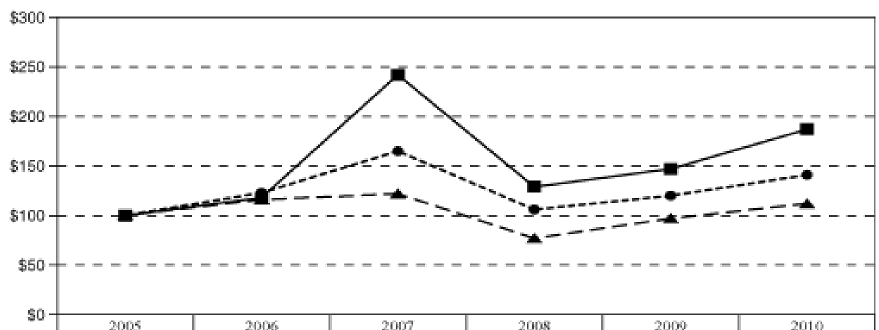
	2010		2009	
Quarter Ended	**High**	**Low**	**High**	**Low**
March 31	**$ 66.49**	**$ 55.89**	$66.84	$49.28
June 30	**66.22**	**48.70**	69.74	49.72
September 30	**59.79**	**48.71**	57.83	46.33
December 31	**76.98**	**59.23**	62.18	51.41

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 indexes:

- Standard & Poor's 500 Stock Index, which includes the Corporation, and
- AMEX Oil Index, which is comprised of companies involved in various phases of the oil industry including the Corporation.

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



	2005	2006	2007	2008	2009	2010
Hess Corporation	100.00	118.00	242.00	129.00	147.00	187.00
S & P 500	100.00	116.00	122.00	77.00	97.00	112.00
Amex Oil Index	100.00	123.00	165.00	106.00	120.00	141.00

Holders

At December 31, 2010, there were 5,791 stockholders (based on number of holders of record) who owned a total of 337,680,780 shares of common stock.

Dividends

Cash dividends on common stock totaled $0.40 per share ($0.10 per quarter) during 2010, 2009 and 2008.

Equity Compensation Plans

Following is information on the Registrant's equity compensation plans at December 31, 2010:

Plan Category	Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights (a)	Weighted Average Exercise Price of Outstanding Options, Warrants and Rights (b)	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column (a)) (c)
Equity compensation plans approved by security holders	13,420,000	$ 55.73	11,507,000*
Equity compensation plans not approved by security holders**	—	—	—

* *These securities may be awarded as stock options, restricted stock or other awards permitted under the Registrant's equity compensation plan.*

** *The Corporation has a Stock Award Program pursuant to which each non-employee director receives approximately $150,000 in value of the Corporation's common stock each year. These awards are made from shares purchased by the Corporation in the open market.*

See Note 10, Share-Based Compensation, in the notes to the financial statements for further discussion of the Corporation's equity compensation plans.

Item 6. *Selected Financial Data*

A five-year summary of selected financial data follows*:

	2010	2009	2008	2007	2006
		(Millions of dollars, except per share amounts)			
Sales and other operating revenues					
Crude oil and natural gas liquids	**$ 7,235**	$ 5,665	$ 7,764	$ 6,303	$ 5,307
Natural gas (including sales of purchased gas)	**5,723**	5,894	8,800	6,877	6,826
Refined petroleum products	**16,103**	12,931	19,765	14,741	13,339
Electricity	**3,165**	3,408	3,451	2,322	1,072
Convenience store sales and other operating revenues	**1,636**	1,716	1,354	1,484	1,632
Total	**$33,862**	$29,614	$ 41,134	$31,727	$28,176
Net income attributable to Hess Corporation	**$ 2,125(a)**	$ 740(b)	$ 2,360(c)	$ 1,832(d)	$ 1,920(e)
Less: preferred stock dividends	**—**	—	—	—	44
Net income applicable to Hess Corporation common shareholders	**$ 2,125**	$ 740	$ 2,360	$ 1,832	$ 1,876
Earnings per share					
Basic	**$ 6.52**	$ 2.28	$ 7.35	$ 5.86	$ 6.75
Diluted	**$ 6.47**	$ 2.27	$ 7.24	$ 5.74	$ 6.08
Total assets	**$35,396**	$29,465	$28,589	$26,131	$ 22,442
Total debt	**5,583**	4,467	3,955	3,980	3,772
Total equity	**16,809**	13,528	12,391	10,000	8,376
Dividends per share of common stock	**$ .40**	$ .40	$ .40	$ .40	$ .40

* *Reflects the retrospective adoption of a new accounting standard for noncontrolling interests in consolidated subsidiaries.*

(a) *Includes after-tax income of $1,130 million relating to gains on asset dispositions, partially offset by charges totaling $694 million for an asset impairment, an impairment of the Corporation's equity investment in HOVENSA L.L.C., dry hole expense and premiums on repurchases of fixed-rate notes.*

(b) *Includes after-tax expenses totaling $104 million relating to repurchases of fixed-rate 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 United States royalty dispute.*

(c) *Includes after-tax expenses totaling $26 million primarily relating to asset impairments and hurricanes in the Gulf of Mexico.*

(d) *Includes net after-tax expenses of $75 million primarily relating to asset impairments, estimated production imbalance settlements and a charge for MTBE litigation, partially offset by income from LIFO inventory liquidations and gains from asset sales.*

(e) *Includes net after-tax income of $173 million primarily from sales of assets, partially offset by income tax adjustments and accrued leased office closing costs.*

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

Overview

The Corporation is a global integrated energy company that operates in two segments, Exploration and Production (E&P) and Marketing and Refining (M&R). The E&P segment explores for, develops, produces, purchases, transports and sells crude oil and natural gas. The M&R segment manufactures refined petroleum products and purchases, markets and trades refined petroleum products, natural gas and electricity.

Net income in 2010 was $2,125 million compared with $740 million in 2009 and $2,360 million in 2008. Diluted earnings per share were $6.47 in 2010 compared with $2.27 in 2009 and $7.24 in 2008. A table of items affecting comparability between periods is shown on page 25.

Exploration and Production

The Corporation's strategy for the E&P segment is to profitably grow reserves and production in a sustainable and financially disciplined manner. The Corporation's total proved reserves were 1,537 million barrels of oil equivalent (boe) at December 31, 2010 compared with 1,437 million boe at December 31, 2009 and 1,432 million boe at December 31, 2008.

E&P earnings were $2,736 million in 2010, $1,042 million in 2009 and $2,423 million in 2008. Average realized crude oil selling prices were $66.20 per barrel in 2010, $51.62 in 2009, and $82.04 in 2008, including the impact of hedging. Production averaged 418,000 barrels of oil equivalent per day (boepd) in 2010, an increase of 10,000 boepd or 2.5% from 2009. Production averaged 408,000 boepd in 2009, an increase of 27,000 boepd or 7% from 381,000 boepd in 2008. The Corporation estimates that total worldwide production will average between 415,000 and 425,000 boepd in 2011.

The following is an update of significant E&P activities during 2010:

- In December, the Corporation acquired approximately 167,000 net acres in the Bakken oil shale play (Bakken) in North Dakota for $1,075 million in cash from TRZ Energy, LLC. The Corporation also completed the acquisition of American Oil & Gas Inc. (American Oil & Gas) through the issuance of approximately 8.6 million shares of the Corporation's stock, which further increased its acreage position in the Bakken by approximately 85,000 net acres. After these acquisitions, the Corporation holds more than 900,000 net acres in the Bakken. The properties acquired are located near the Corporation's existing acreage.
- In September, the Corporation completed the exchange of its interests in Gabon and the Clair Field in the United Kingdom for additional interests in the Valhall and Hod fields of 28% and 25%, respectively. This non-monetary exchange, which was recorded at fair value, resulted in a pre-tax gain of $1,150 million ($1,072 million after income taxes). The Corporation also completed the acquisition of an additional 8% interest in the Valhall Field and 13% interest in the Hod Field for $507 million in cash. As a result of these transactions, the Corporation's interests in the Valhall and Hod fields increased to 64% and 63%, respectively.
- In the fourth quarter, the Corporation completed the acquisition of an additional 20% interest in the Tubular Bells oil and gas field in the Gulf of Mexico for approximately $40 million. The Corporation now has a 40% working interest and is operator of the field.
- In January, the Corporation completed the sale of its interest in the Jambi Merang natural gas development project in Indonesia (Hess 25%) for cash proceeds of $183 million. The transaction resulted in a gain of $58 million.
- In March, the Corporation agreed to the sale of its interests in a package of natural gas production and transportation assets in the United Kingdom North Sea. The package includes the Corporation's interests in the Easington Catchment Area (Hess 30%), the Bacton Area (Hess 23%), the Everest Field (Hess 19%), the Lomond Field (Hess 17%) and the Central Area Transmission System (CATS) pipeline (Hess 18%). In February 2011, the Corporation completed the sale of the producing assets for approximately $350 million,

after closing adjustments. The sale of the Corporation's interest in the CATS pipeline is expected to close in the second quarter of 2011.

- In September, the Corporation recorded an impairment charge and dry hole expense totaling $554 million before income taxes ($347 million after income taxes) to reduce the carrying value of unproved property and suspended well costs relating to its 55% interest in the West Mediterranean Block 1 Concession (West Med Block), located offshore Egypt.
- In the Carnarvon basin offshore Western Australia, the Corporation drilled 4 exploration wells in 2010 on WA-390-P Block (Hess 100%). The Corporation has drilled all 16 commitment wells on the block, 13 of which were natural gas discoveries. In the fourth quarter of 2010, the Corporation commenced an appraisal program that includes further drilling and flow testing certain wells.
- On the Pony project in Green Canyon Block 468 (Hess 100%) in the deepwater Gulf of Mexico, the Corporation has signed a non-binding agreement in principle with the owners on the adjacent Green Canyon Block 512 that outlines a proposal to jointly develop the Pony and Knotty Head fields. The Corporation also spud and subsequently suspended an appraisal well on the Pony prospect in 2010. The Corporation is planning to resume drilling of the Pony appraisal well in 2011 contingent upon receipt of necessary drilling permits.
- In November, the third exploration well was spud on Block BM-S-22 (Hess 40%) offshore Brazil which encountered noncommercial quantities of hydrocarbons. As a result, dry hole expenses totaling $111 million ($72 million after-tax) were recorded relating to this well and the previously suspended Azulão well, which was drilled in 2009.

Gulf of Mexico Update: In April 2010, an accident occurred on the Transocean Deepwater Horizon drilling rig at the BP p.l.c. (BP) operated Macondo prospect in the Gulf of Mexico, resulting in loss of life, the sinking of the rig and a significant crude oil spill. The Corporation was not a participant in the well. As a result of the accident, a temporary drilling moratorium was imposed in the Gulf of Mexico. In October 2010, the drilling moratorium was lifted by the United States Department of the Interior's Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE) provided operators complied with all rules and requirements, including a series of new drilling and safety rules issued by BOEMRE. The Corporation is currently evaluating the impact of these new requirements on its activities in the Gulf of Mexico, as well as seeking approvals for plans and permits submitted in connection with planned activities. However, the new regulatory environment is expected to result in a longer permitting process and higher costs.

The moratorium impacted development drilling at the Shenzi Field, in which the Corporation has a 28% interest. A production well that was being drilled was suspended and the drilling of a second production well that was planned for 2010 was postponed. The Corporation estimates that these delays reduced 2010 production by approximately 2,000 boepd and will likely reduce 2011 production by approximately 4,000 boepd. In 2010, the Corporation's only operated drilling rig in the Gulf of Mexico, the Stena Forth, left the Pony project on Green Canyon 469 as part of a preexisting agreement for a one well farm-out of the rig to another operator.

In January 2011, the BOEMRE announced that supplementary environmental reviews will not be required of 13 companies to resume work on the 16 wells that were in progress when the moratorium took effect, including the aforementioned suspended Shenzi and Pony wells. However, these projects must comply with the new safety rules and regulations before work can resume. As a result, the Corporation does not anticipate that it will be able to re-commence these operations before the second half of 2011.

Additionally, the Corporation has filed Suspension of Operations (SOO) applications with the BOEMRE for several exploration block licenses in the Gulf of Mexico that are due to expire in 2011 and may file additional applications as deemed necessary. These SOO applications seek approval for extension of the lease expiration terms due to circumstances outside the control of the Corporation that have delayed activities required to hold the licenses.

Marketing and Refining

The Corporation's strategy for the M&R segment is to deliver consistent operating performance and generate free cash flow. M&R earnings (losses) were $(231) million in 2010, $127 million in 2009 and $277 million in 2008. Refining operations generated losses of $445 million in 2010 and $87 million in 2009 and income of $73 million in 2008. Refining results for 2010 include an after-tax impairment charge of $289 million ($300 million pre-tax) to reduce the carrying value of the Corporation's investment in HOVENSA L.L.C. to the estimated fair value. The refining results in 2010 and 2009 also reflect weak refining margins and lower volumes. Marketing earnings were $215 million in 2010, $168 million in 2009 and $240 million in 2008.

Liquidity and Capital and Exploratory Expenditures

Net cash provided by operating activities was $4,530 million in 2010, $3,046 million in 2009 and $4,688 million in 2008, principally reflecting fluctuations in earnings. At December 31, 2010, cash and cash equivalents totaled $1,608 million compared with $1,362 million at December 31, 2009. Total debt was $5,583 million at December 31, 2010 compared with $4,467 million at December 31, 2009. In August 2010, the Corporation issued $1,250 million of 30 year fixed-rate notes with a coupon of 5.6% that are scheduled to mature in 2041. The proceeds were used for the acquisition of additional acreage in the Bakken and additional interests in the Valhall and Hod fields. In January 2010, the Corporation completed the repurchase of the remaining $116 million of notes that were scheduled to mature in 2011. The Corporation's debt to capitalization ratio at December 31, 2010 was 24.9% compared with 24.8% at the end of 2009.

Capital and exploratory expenditures were as follows for the years ended December 31:

	2010	2009
	(Millions of dollars)	
Exploration and Production		
United States	**$2,935**	$ 1,200
International	**2,822**	1,927
Total Exploration and Production	**5,757**	3,127
Marketing, Refining and Corporate	**98**	118
Total capital and exploratory expenditures	**$ 5,855**	$ 3,245
Exploration expenses charged to income included above:		
United States	**$ 154**	$ 144
International	**209**	183
Total exploration expenses charged to income included above	**$ 363**	$ 327

The Corporation anticipates investing $5.6 billion in capital and exploratory expenditures in 2011, substantially all of which relates to E&P operations.

Consolidated Results of Operations

The after-tax results by major operating activity are summarized below:

	2010	2009	2008
		(Millions of dollars, except per share data)	
Exploration and Production	**$2,736**	$1,042	$ 2,423
Marketing and Refining	**(231)**	127	277
Corporate	**(159)**	(205)	(173)
Interest expense	**(221)**	(224)	(167)
Net income attributable to Hess Corporation	**$2,125**	$ 740	$2,360
Net income per share — diluted	**$ 6.47**	$ 2.27	$ 7.24

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.

	2010	2009	2008
		(Millions of dollars)	
Exploration and Production	**$ 732**	$ 45	$ (26)
Marketing and Refining	**(289)**	12	—
Corporate	**(7)**	(60)	—
	$ 436	$ (3)	$ (26)

In the discussion that follows, 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:

	2010	2009	2008
		(Millions of dollars)	
Sales and other operating revenues*	**$ 8,744**	$ 6,835	$ 9,806
Other, net	**1,233**	207	(167)
Total revenues and non operating income	**9,977**	7,042	9,639
Costs and expenses			
Production expenses, including related taxes	**1,924**	1,805	1,872
Exploration expenses, including dry holes and lease impairment	**865**	829	725
General, administrative and other expenses	**281**	255	302
Depreciation, depletion and amortization	**2,222**	2,113	1,922
Asset impairments	**532**	54	30
Total costs and expenses	**5,824**	5,056	4,851
Results of operations before income taxes	**4,153**	1,986	4,788
Provision for income taxes	**1,417**	944	2,365
Results of operations attributable to Hess Corporation	**$2,736**	$ 1,042	$ 2,423

* *Amounts differ from E&P operating revenues in Note 18, Segment Information, primarily due to the exclusion of sales of hydrocarbons purchased from third parties.*

After considering the E&P items in the table on page 28, the remaining changes in E&P earnings are primarily attributable to changes in selling prices, production and sales volumes, operating costs, exploration expenses, foreign exchange, and income taxes, as discussed below.

Selling prices: Higher average selling prices increased E&P revenues by approximately $1,775 million in 2010 compared with 2009. Lower average selling prices reduced E&P revenues by approximately $4,000 million in 2009 compared with 2008.

The Corporation's average selling prices were as follows:

	2010	2009	2008
Crude oil-per barrel (including hedging)			
United States	**$75.02**	$ 60.67	$96.82
Europe	**58.11**	47.02	78.75
Africa	**65.02**	48.91	78.72
Asia	**79.23**	63.01	97.07
Worldwide	**66.20**	51.62	82.04
Crude oil-per barrel (excluding hedging)			
United States	**$75.02**	$ 60.67	$96.82
Europe	**58.11**	47.02	78.75
Africa	**78.31**	60.79	93.57
Asia	**79.23**	63.01	97.07
Worldwide	**71.40**	56.74	89.23
Natural gas liquids-per barrel			
United States	**$47.92**	$ 36.57	$ 64.98
Europe	**59.23**	43.23	74.63
Asia	**63.50**	46.48	—
Worldwide	**50.49**	38.47	67.61
Natural gas-per mcf (including hedging)			
United States	**$ 3.70**	$ 3.36	$ 8.61
Europe	**6.23**	5.15	9.44
Asia and other	**5.93**	5.06	5.24
Worldwide	**5.63**	4.85	7.17
Natural gas-per mcf (excluding hedging)			
United States	**$ 3.70**	$ 3.36	$ 8.61
Europe	**6.23**	5.15	9.79
Asia and other	**5.93**	5.06	5.24
Worldwide	**5.63**	4.85	7.30

In October 2008, the Corporation closed its Brent crude oil hedges, covering 24,000 barrels per day from 2009 though 2012, by entering into offsetting contracts with the same counterparty. The deferred after-tax loss as of the date the hedge positions were closed will be recorded in earnings as the contracts mature. The estimated annual after-tax loss from the closed positions will be approximately $330 million in 2011 and 2012. Crude oil hedges reduced E&P earnings by $338 million ($533 million before income taxes) in 2010 and $337 million ($533 million before income taxes) in 2009. Crude oil and natural gas hedges reduced E&P earnings by $423 million ($685 million before income taxes) in 2008.

Production and sales volumes: The Corporation's crude oil and natural gas production was 418,000 boepd in 2010 compared with 408,000 boepd in 2009 and 381,000 boepd in 2008. Approximately 73% in 2010, 72% in 2009 and 70% in 2008 of the Corporation's production was from crude oil and natural gas liquids. The Corporation currently estimates that its 2011 production will average between 415,000 and 425,000 boepd, after a reduction of approximately 4,000 boepd due to drilling delays at the Shenzi Field in the Gulf of Mexico as well as the effect of the sale in February 2011 of natural gas producing assets in the United Kingdom North Sea.

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

	2010	2009	2008
		(In thousands)	
Crude oil (barrels per day)			
United States	**75**	60	32
Europe	**88**	83	83
Africa	**113**	120	124
Asia	**13**	16	13
Total	**289**	279	252
Natural gas liquids (barrels per day)			
United States	**14**	11	10
Europe	**3**	3	4
Asia	**1**	—	—
Total	**18**	14	14
Natural gas (mcf per day)			
United States	**108**	93	78
Europe	**134**	151	255
Asia and other	**427**	446	356
Total	**669**	690	689
Barrels of oil equivalent* (barrels per day)	**418**	408	381

* *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. See the average selling prices in the table above.*

United States: Crude oil and natural gas production in the United States was higher in 2010 compared with 2009, primarily due to production from the Shenzi, Llano, Conger and Bakken fields. Crude oil and natural gas production was higher in 2009 compared with 2008, primarily due to new production from the Shenzi Field and production resuming after the 2008 hurricanes. Hurricane impacts reduced full year 2008 production by an estimated 7,000 boepd.

Europe: Crude oil production was higher in 2010 compared with 2009, due to higher production in Russia and an increase in Norway following the acquisition of additional interests in the Valhall and Hod fields, partially offset by lower production in the United Kingdom North Sea following the exchange of Clair for additional Norway interests. Crude oil production was comparable in 2009 and 2008, as higher production in Russia offset lower production in the United Kingdom North Sea. Natural gas production was lower in 2010 compared with 2009, primarily due to downtime at certain United Kingdom gas fields. Natural gas production was lower in 2009 compared with 2008, primarily due to decline and subsequent cessation of production at the Atlantic and Cromarty fields.

Africa: Crude oil production decreased in 2010 compared with 2009 following the exchange of Gabon for additional interests in the Valhall and Hod fields in Norway in the third quarter and lower entitlement to Algerian production. Crude oil production decreased in 2009 compared with 2008, primarily due to lower production from the Ceiba Field.

Asia and other: Natural gas production in 2010 was lower than in 2009, primarily due to downtime at the Pangkah Field and a temporary shut-in at the Bumi Field in the Joint Development Area of Malaysia/Thailand (JDA). Natural gas production in 2009 was higher than in 2008, primarily due to a full year of Phase 2 sales from JDA. The decrease in crude oil production in 2010 from 2009 principally reflects changes to the Corporation's entitlement to production in Azerbaijan.

Sales volumes: Higher sales volumes and other operating revenues increased revenue by approximately $135 million in 2010 compared with 2009 and $1,030 million in 2009 compared with 2008.

Operating costs and depreciation, depletion and amortization: Cash operating costs, consisting of production expenses and general and administrative expenses, increased by $145 million in 2010 compared with 2009 and decreased by $114 million in 2009 compared with 2008. The increase in 2010 compared with 2009 was primarily due to higher production taxes as a result of higher selling prices. The decrease in 2009 compared with 2008 was primarily due to lower production taxes (due to lower realized selling prices), the cessation of production at several United Kingdom North Sea fields, the favorable impact of foreign exchange rates and cost savings initiatives, partially offset by the impact of higher production volumes.

Depreciation, depletion and amortization charges increased by $109 million in 2010 and $191 million in 2009, compared with the corresponding amounts in prior years. The increases in both 2010 and 2009 were primarily due to higher production volumes and per barrel costs, reflecting higher finding and development costs.

Excluding items affecting comparability between periods, cash operating costs per barrel of oil equivalent were $14.45 in 2010, $13.70 in 2009 and $15.49 in 2008. Cash operating costs in 2011 are estimated to be in the range of $15.00 to $16.00 per barrel of oil equivalent. Depreciation, depletion and amortization costs per barrel of oil equivalent were $14.56 in 2010, $14.19 in 2009 and $13.79 in 2008. Depreciation, depletion and amortization costs for 2011 are estimated to be in the range of $14.50 to $15.50 per barrel of oil equivalent.

Effective December 31, 2009, the Securities and Exchange Commission (SEC) issued updated standards for oil and gas reserve estimation and disclosure. The new rules allow, among other changes, the use of permitted technology in determining oil and gas reserve estimates. Since it was not practical to calculate reserve estimates under both the old and the new reserve estimation standards, it was not possible to precisely measure the effect of adopting the new SEC requirements on total proved reserves at December 31, 2009. However, the Corporation estimates that applying the new rules increased income during 2010 by approximately $80 million, after income taxes, due to lower depreciation, depletion and amortization expense.

Exploration expenses: Exploration expenses increased in 2010 from 2009, primarily due to higher lease amortization. Exploration expenses increased in 2009 compared to 2008, mainly due to higher dry hole costs and lease amortization.

Income taxes: Excluding the impact of items affecting comparability, the effective income tax rates for E&P operations were 44% in 2010, 48% in 2009 and 49% in 2008. The effective income tax rate for E&P operations in 2011 is estimated to be in the range of 45% to 49%.

Foreign Exchange: The after-tax foreign currency losses were $9 million in 2010, $10 million in 2009 and $80 million in 2008. The foreign currency loss in 2008 reflects the net effect of significant exchange rate movements in the fourth quarter of 2008 on the remeasurement of assets, liabilities and foreign currency forward contracts by certain foreign businesses.

Reported E&P earnings include the following items affecting comparability of income (expense) before and after income taxes:

	Before Income Taxes			After Income Taxes		
	2010	2009	2008	2010	2009	2008
	(Millions of dollars)					
Gains on asset sales	**$ 1,208**	$ —	$ —	**$ 1,130**	$ —	$ —
Royalty dispute resolution	**—**	143	—	**—**	89	—
Asset impairments	**(532)**	(54)	(30)	**(334)**	(26)	(17)
Dry hole expense	**(101)**	—	—	**(64)**	—	—
Reductions in carrying values of assets	**—**	(23)	—	**—**	(18)	—
Hurricane related costs	**—**	—	(15)	**—**	—	(9)
	$ 575	$ 66	$ (45)	**$ 732**	$ 45	$ (26)

2010: The Corporation completed the exchange of its interests in Gabon and the Clair Field in the United Kingdom for additional interests of 28% and 25%, respectively, in the Valhall and Hod fields in Norway. This non-monetary transaction, which was recorded at fair value, resulted in a pre-tax gain of $1,150 million ($1,072 million after income taxes). The Corporation also completed the sale of its interest in the Jambi Merang natural gas development project in Indonesia for a gain of $58 million.

The Corporation recorded a charge of $532 million ($334 million after income taxes) to fully impair the carrying value of its 55% interest in the West Med Block, located offshore Egypt. This interest was acquired in 2006 and included four natural gas discoveries and additional exploration prospects. The Corporation and its partners subsequently explored and further evaluated the area, made a fifth discovery, conducted development planning, and held negotiations with the Egyptian authorities to amend the existing gas sales agreement. In September 2010, the Corporation and its partners notified the Egyptian authorities of their decision to cease exploration activities and to relinquish a significant portion of the block. As a result, the Corporation fully impaired the carrying value of its interests in the West Med Block.

The Corporation recorded $101 million ($64 million after income taxes) of dry hole expenses related to previously suspended well costs on the West Med Block offshore Egypt and Block BM-S-22 offshore Brazil, both of which were drilled prior to 2010.

2009: The U.S. Supreme Court decided it would not review the decision of the 5th Circuit Court of Appeals against the U.S. Minerals Management Service (predecessor to the Bureau of Ocean Energy Management, Regulation and Enforcement) relating to royalty relief under the Deep Water Royalty Relief Act of 1995. As a result, the Corporation recognized after-tax income of $89 million to reverse all previously recorded royalties covering the periods from 2003 to 2009. The pre-tax amount of $143 million was reported in Other, net in the Statement of Consolidated Income.

The Corporation recorded total asset impairment charges of $54 million ($26 million after income taxes) to reduce the carrying value of two-short lived fields in the United Kingdom North Sea.

Pre-tax charges of approximately $25 million ($18 million after income taxes) were recorded to impair the carrying values of production equipment and to write down materials inventories in Equatorial Guinea and the United States. The pre-tax amount of most of the inventory write downs was reported in Production expenses in the Statement of Consolidated Income.

2008: Pre-tax charges of $30 million ($17 million after income taxes) were recorded to impair the carrying values of mature fields in the United States and the United Kingdom North Sea.

Pre-tax charges of $15 million ($9 million after income taxes) were recorded to expense costs associated with Hurricanes Gustav and Ike in the Gulf of Mexico. The pre-tax amount of the charges totaling $15 million were reported in Production expenses in the Statement of Consolidated Income.

The Corporation's future E&P earnings may be impacted by external factors, such as volatility in the selling prices of crude oil and natural gas, reserve and production changes, exploration expenses, industry cost inflation, changes in foreign exchange rates and income tax rates, the effects of weather, political risk, environmental risk and catastrophic risk. In addition, as a result of the oil spill in 2010 at the BP operated Macondo prospect in the Gulf of Mexico, there have been and there may be further changes in laws and regulations that could impact the Corporation's future drilling operations and increase its potential liability in the event of an oil spill. For a more comprehensive description of the risks that may affect the Corporation's E&P business, see Item 1A. Risk Factors Related to Our Business and Operations.

Marketing and Refining

Earnings (losses) from M&R activities amounted to $(231) million in 2010, $127 million in 2009 and $277 million in 2008. Excluding the items affecting comparability reflected in the table on page 25 and discussed below, the earnings were $58 million, $115 million and $277 million, respectively.

Refining: Refining earnings (losses), which consist of the Corporation's share of HOVENSA's results, Port Reading earnings and results of other miscellaneous operating activities, were $(445) million in 2010 (including the $289 million after-tax impairment charge discussed below), $(87) million in 2009 (including a benefit of $12 million due to an income tax adjustment) and $73 million in 2008.

In December 2010, the Corporation recorded an impairment charge of $300 million before income taxes ($289 million after income taxes) to reduce the carrying value of its equity investment in HOVENSA, which was recorded in Income (loss) from equity investment in HOVENSA L.L.C. The investment had been adversely affected by consecutive annual operating losses resulting from continued weak refining margins and refinery utilization, and a fourth quarter 2010 debt rating downgrade. As a result of a strategic assessment in 2010, HOVENSA decided to lower crude oil refining capacity from 500,000 to 350,000 barrels per day. The Corporation performed an impairment analysis and concluded that its investment had experienced an other than temporary decline in value. For discussion of the impairment charge, see Note 4, Refining Joint Venture in the notes to the financial statements on page 59. As a result of cumulative net operating losses in the last two years, the Corporation is not recognizing a full income tax benefit on the impairment charge.

The Corporation's share of HOVENSA's results was a loss of $138 million in 2010 ($222 million before income taxes) excluding the impairment charge, a loss of $142 million ($229 million before income taxes) in 2009, and income of $27 million ($44 million before income taxes) in 2008. These results reflect lower refining margins and lower sales volumes. The 2010 and 2009 utilization rates for HOVENSA reflect weaker refining margins and planned and unplanned maintenance. The 2008 utilization rates also reflect a refinery wide shut down for Hurricane Omar. During 2010, the fluid catalytic cracking unit at HOVENSA was shut down for a scheduled turnaround. The Corporation's share of HOVENSA's turnaround expenses was approximately $20 million after income taxes.

Other after-tax refining results, principally from Port Reading operations, were a loss of $18 million in 2010 and income of $43 million in both 2009 and 2008. During 2010, the Port Reading refining facility was shutdown for 41 days for a scheduled turnaround. The after-tax expenses for the Port Reading turnaround were approximately $30 million. The turnaround expenses are included in Other operating expenses, in the Statement of Consolidated Income.

The following table summarizes refinery utilization rates:

	Refinery Capacity (Thousands of barrels per day)	Refinery Utilization 2010	2009	2008
HOVENSA				
Crude	500	**78.0%**	80.3%	88.2%
Fluid catalytic cracker	150	**66.5%**	70.2%	72.7%
Coker	58	**78.3%**	81.6%	92.4%
Port Reading	70	**78.1%**	90.2%	90.7%

In January 2011, HOVENSA announced plans to shut down certain older and smaller processing units on the west side of its refinery, which will reduce the refinery's crude oil distillation capacity from 500,000 to 350,000 barrels per day, with no impact on the capacity of its coker or FCC unit. This reconfiguration, which is expected to be completed in the first quarter of 2011, is being undertaken to improve efficiency, reliability and competitiveness.

Marketing: Marketing operations, which consist principally of retail gasoline and energy marketing activities, generated income of $215 million in 2010, $168 million in 2009 and $240 million in 2008. The increase in earnings in 2010 compared with 2009 reflects improved margins from the weak economic environment in 2009.

The table below summarizes marketing sales volumes:

	2010	2009	2008
Refined product sales (thousands of barrels per day)	**471**	473	472
Natural gas (thousands of mcf per day)	**2,016**	2,010	1,955
Electricity (megawatts round the clock)	**4,140**	4,306	3,152

The Corporation has a 50% voting interest in a consolidated partnership that trades energy commodities and energy derivatives. The Corporation also takes trading positions for its own account. The Corporation's after-tax results from trading activities, including its share of the results of the trading partnership, amounted to a loss of $1 million in 2010, earnings of $46 million in 2009 and a loss of $36 million in 2008.

Marketing expenses increased in 2010 compared with 2009 and decreased in 2009 as compared with 2008, principally reflecting changes in retail credit card fees.

The Corporation's future M&R earnings may be impacted by supply and demand factors, volatility in margins, credit risks, the effects of weather, competitive industry conditions, political risk, environmental risk and catastrophic risk. For a more comprehensive description of the risks that may affect the Corporation's M&R business, see Item 1A. Risk Factors Related to Our Business and Operations.

Corporate

The following table summarizes corporate expenses:

	2010	2009	2008
	(Millions of dollars)		
Corporate expenses (excluding items affecting comparability)	**$ 256**	$227	$260
Income taxes (benefits)	**(104)**	(82)	(87)
Net corporate expenses	**152**	145	173
Items affecting comparability between periods, after-tax	**7**	60	—
Total corporate expenses, after-tax	**$ 159**	$205	$173

Excluding items affecting comparability between periods, the increase in corporate expenses in 2010 compared with 2009 primarily reflects higher employee and insurance costs, and bank facility fees. The decrease in corporate expenses in 2009 compared with 2008 primarily reflects gains on supplemental pension related investments and lower employee and professional costs. After-tax corporate expenses in 2011 are estimated to be in the range of $165 to $175 million.

In 2009, the Corporation recorded pre-tax charges of $54 million ($34 million after income taxes) related to the repurchase of $546 million in fixed-rate notes that were scheduled to mature in 2011 and $42 million ($26 million after income taxes) relating to retirement benefits and employee severance costs. In 2010, the Corporation recorded a pre-tax charge of $11 million ($7 million after income taxes) related to the repurchase of the remaining $116 million of notes that were scheduled to mature in 2011. The pre-tax charges in connection with the debt repurchases were recorded in Other, net, and the pre-tax amounts of the retirement benefits and severance costs were recorded in General and administrative expenses within the Statement of Consolidated Income.

Interest

Interest expense was as follows:

	2010	2009	2008
		(Millions of dollars)	
Total interest incurred	**$ 366**	$ 366	$ 274
Less capitalized interest	**5**	6	7
Interest expense before income taxes	**361**	360	267
Less income taxes	**140**	136	100
After-tax interest expense	**$ 221**	$ 224	$ 167

Interest expense was comparable in 2010 and 2009. The increase in interest expense in 2009 compared to 2008 primarily reflects higher debt and fees for letters of credit. After-tax interest expense in 2011 is expected to be in the range of $240 to $250 million.

Sales and Other Operating Revenues

Sales and other operating revenues totaled $33,862 million in 2010, $29,614 million in 2009 and $41,134 million in 2008. In 2010, sales and other operating revenues increased by 14% compared with 2009. In 2009, sales and other operating revenues decreased by 28% compared with 2008. The fluctuations in each year primarily reflect changes in crude oil and refined product selling prices.

The change in cost of goods sold in each year principally reflects the change in sales volumes and purchase prices of refined products, natural gas and electricity.

Liquidity and Capital Resources

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

	2010	2009
	(Millions of dollars)	
Cash and cash equivalents	**$ 1,608**	$ 1,362
Short-term debt and current maturities of long-term debt	**$ 46**	$ 148
Total debt	**$ 5,583**	$ 4,467
Total equity	**$ 16,809**	$13,528
Debt to capitalization ratio*	**24.9%**	24.8%

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

Cash Flows

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

	2010	2009	2008
		(Millions of dollars)	
Net cash provided by (used in):			
Operating activities	**$ 4,530**	$ 3,046	$ 4,688
Investing activities	**(5,259)**	(2,924)	(4,444)
Financing activities	**975**	332	57
Net increase in cash and cash equivalents	**$ 246**	$ 454	$ 301

Operating Activities: Net cash provided by operating activities, including changes in operating assets and liabilities, was $4,530 million in 2010 compared with $3,046 million in 2009, reflecting higher earnings. Operating cash flow decreased to $3,046 million in 2009 from $4,688 million in 2008 reflecting lower earnings.

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

	2010	2009	2008
		(Millions of dollars)	
Exploration and Production			
Exploration	**$ 552**	$ 611	$ 744
Production and development	**2,592**	1,927	2,523
Acquisitions (including leaseholds)	**2,250**	262	984
	5,394	2,800	4,251
Marketing, Refining and Corporate	**98**	118	187
Total	**$5,492**	$2,918	$ 4,438

Capital expenditures in 2010 include acquisitions of 167,000 net acres in the Bakken oil shale play in North Dakota from TRZ Energy, LLC for $1,075 million in cash and additional interests of 8% and 13% in the Valhall and Hod fields, respectively, for $507 million in cash.

Capital expenditures in 2009 include acquisitions of $188 million for unproved leaseholds and $74 million for a 50% interest in blocks PM301 and PM302 in Malaysia, which are adjacent to Block A-18 of the JDA. Capital expenditures in 2008 include $600 million for leasehold acquisitions in the United States and $210 million for the acquisition of the remaining 22.5% interest in the Corporation's Gabonese subsidiary. In 2008, the Corporation also selectively expanded its energy marketing business by acquiring fuel oil, natural gas, and electricity customer accounts, and a terminal and related assets, for an aggregate of approximately $100 million.

Financing Activities: During 2010, net proceeds from borrowings were $1,098 million. In August 2010, the Corporation issued $1,250 million of 30 year fixed-rate notes with a coupon of 5.6% scheduled to mature in 2041. The proceeds were used to purchase additional acreage in the Bakken and additional interests in the Valhall and Hod fields. In January 2010, the Corporation completed the repurchase of the remaining $116 million of notes that were scheduled to mature in 2011. During 2009, net proceeds from borrowings were $447 million, compared with net repayments of debt of $32 million in 2008.

Total common stock dividends paid were $131 million in 2010 and 2009 and $130 million in 2008. The Corporation received net proceeds from the exercise of stock options, including related income tax benefits of $54 million, $18 million and $340 million in 2010, 2009 and 2008, respectively.

Future Capital Requirements and Resources

The Corporation anticipates investing a total of approximately $5.6 billion in capital and exploratory expenditures during 2011, substantially all of which is targeted for E&P operations. In the Corporation's M&R operations, refining margins continue to be weak, which have adversely affected HOVENSA's liquidity position. The Corporation intends to provide its share of financial support for HOVENSA. The Corporation expects to fund its 2011 operations, including capital expenditures, dividends, pension contributions, required debt repayments and financial support for HOVENSA, with existing cash on-hand, cash flow from operations, proceeds from the sale of United Kingdom natural gas assets and its available credit facilities. Crude oil prices, natural gas prices and refining margins 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 the issuance of debt securities, the issuance of equity securities, and/or 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, 2010:

	Expiration Date	Capacity	Borrowings	Letters of Credit Issued	Total Used	Available Capacity
			(Millions of dollars)			
Revolving credit facility	May 2012(a)	$ 3,000	$ —	$ —	$ —	$ 3,000
Asset-backed credit facility	July 2011(b)	530	—	400	400	130
Committed lines	Various(c)	2,925	—	1,161	1,161	1,764
Uncommitted lines	Various(c)	521	—	521	521	—
Total		$ 6,976	$ —	$ 2,082	$ 2,082	$ 4,894

(a) $75 million expires in May 2011.

(b) Total capacity of $1.0 billion subject to the amount of eligible receivables posted as collateral.

(c) Committed and uncommitted lines have expiration dates through 2013.

The Corporation has a $3 billion syndicated revolving credit facility (the facility), which can be used for borrowings and letters of credit, substantially all of which is committed through May 2012. At December 31, 2010, the Corporation has available capacity on the facility of $3 billion.

The Corporation has a 364-day asset-backed credit facility securitized by certain accounts receivable from its Marketing and Refining operations. Under the terms of this financing arrangement, the Corporation has the ability to borrow or issue letters of credit of up to $1 billion subject to the availability of sufficient levels of eligible receivables. At December 31, 2010, outstanding letters of credit under this facility were collateralized by a total of $1,194 million of accounts receivable, which are held by a wholly-owned subsidiary. These receivables are only available to pay the general obligations of the Corporation after satisfaction of the outstanding obligations under the asset-backed facility.

The Corporation also has a shelf registration under which it may issue additional debt securities, warrants, common stock or preferred stock.

The Corporation's long-term debt agreements contain a financial covenant that restricts the amount of total borrowings and secured debt. At December 31, 2010, the Corporation is permitted to borrow up to an additional $22.4 billion for the construction or acquisition of assets. The Corporation has the ability to borrow up to an additional $4.4 billion of secured debt at December 31, 2010.

The Corporation's $2,082 million in letters of credit outstanding at December 31, 2010 were primarily issued to satisfy margin requirements. See also Note 16, Risk Management and Trading Activities.

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

Following is a table showing aggregated information about certain contractual obligations at December 31, 2010:

	Total	Payments Due by Period			
		2011	2012 and 2013	2014 and 2015	Thereafter
			(Millions of dollars)		
Total debt*	$ 5,583	$ 46	$ 72	$ 345	$ 5,120
Operating leases	3,077	410	840	558	1,269
Purchase obligations					
Supply commitments**	32,376	12,233	10,264	9,862	17
Capital expenditures and other investments	2,382	1,798	494	89	1
Operating expenses	1,677	830	483	214	150
Other long-term liabilities	2,308	204	326	310	1,468

* *At December 31, 2010, the Corporation's debt bears interest at a weighted average rate of 6.8%.*

** *The Corporation intends to continue purchasing refined product supply from HOVENSA. Estimated future purchases amount to approximately $5 billion annually using year-end 2010 prices, which have been included in the table through 2015.*

In the preceding table, the Corporation's supply commitments include its estimated purchases of 50% of HOVENSA's production of refined products, after anticipated sales by HOVENSA to unaffiliated parties. The value of future supply commitments will fluctuate based on prevailing market prices, actual refinery output and the amount of product sold by HOVENSA to unaffiliated third parties. Under the product sales agreement between the Corporation and HOVENSA, HOVENSA is entitled to reserve refined products for sale to unaffiliated third parties each month up to a maximum amount set by the executive committee of HOVENSA annually. The Corporation is obligated to purchase 50% of the remaining refined products produced by HOVENSA, including amounts reserved for third party sales by HOVENSA that remain unsold. The prices at which the Corporation purchases refined products are determined by reference to published market prices prevailing at the time of purchase. The amount of the purchase commitment from HOVENSA is based on the forecasted refinery output that is expected to be sold to the Corporation calculated using year-end prices.

Also included above are term purchase agreements at market prices for additional gasoline necessary to supply the Corporation's retail marketing system and feedstocks for the Port Reading refining facility. In addition, the Corporation has commitments to purchase refined products, natural gas and electricity to supply contracted customers in its energy marketing business. 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 $5.6 billion capital investment program for 2011 that is contractually committed at December 31, 2010. 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 on the balance sheet at December 31, 2010, including asset retirement obligations, pension plan liabilities and anticipated obligations 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.

As of December 31, 2010, the Corporation has a contingent purchase obligation, expiring in April 2012, to acquire the remaining interest in WilcoHess, a retail gasoline station joint venture, for approximately $190 million.

The Corporation guarantees the payment of up to 50% of HOVENSA's crude oil purchases from certain suppliers other than PDVSA. The amount of the Corporation's guarantee fluctuates based on the volume of crude oil purchased and related prices and at December 31, 2010 it amounted to $150 million. In addition, the Corporation has agreed to provide funding up to a maximum of $15 million to the extent HOVENSA does not have funds to meet its senior debt obligations.

The Corporation is contingently liable under letters of credit and under guarantees of the debt of other entities directly related to its business at December 31, 2010 as shown below (in millions):

Letters of credit	$ 81
Guarantees	165
	$ 246

Off-Balance Sheet Arrangements

The Corporation has leveraged leases not included in its balance sheet, primarily related to retail gasoline stations that the Corporation operates. The net present value of these leases is $394 million at December 31, 2010 compared with $412 million at December 31, 2009. The Corporation's December 31, 2010 debt to capitalization ratio would increase from 24.9% to 26.2% if these leases were included as debt.

See also Note 4, Refining Joint Venture, and Note 17, Guarantees and Contingencies, in the notes to the financial statements.

Foreign Operations

The Corporation conducts exploration and production activities outside the United States, principally in Algeria, Australia, Azerbaijan, Brazil, Brunei, China, Colombia, Denmark, Egypt, Equatorial Guinea, France, Ghana, Indonesia, Libya, Malaysia, Norway, Peru, Russia, Thailand, and the United Kingdom. Therefore, the Corporation is subject to the risks associated with foreign operations, including political risk, 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 on the Corporation's balance sheet and revenues and expenses on the income statement. 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: Exploration and production 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 SEC revised its oil and gas reserve estimation and disclosure requirements effective for year-end 2009 reporting. In addition, the Financial Accounting Standards Board (FASB) revised its accounting standard on oil and gas reserve estimation and disclosures. 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.

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 at a reporting unit level, which is an operating segment or one level below an operating segment. The impairment test is conducted annually in the fourth quarter or when events or changes in circumstances indicate that the carrying amount of the goodwill may not be recoverable. The reporting unit or units used to evaluate and measure goodwill for impairment are determined primarily from the manner in which the business is managed. The Corporation's goodwill is assigned to the E&P operating segment and it expects that the benefits of goodwill will be recovered through the operation of that segment.

The Corporation's fair value estimate of the E&P segment is the sum of: (1) the discounted anticipated cash flows of producing assets and known developments, (2) the estimated risk adjusted present value of exploration assets, and (3) 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, improved processes and increased market share. The Corporation also considers the relative market valuation of similar Exploration and Production companies.

The determination of the fair value of the E&P segment 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 the E&P segment 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 to the E&P segment.

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. Differences between the carrying value of the Corporation's equity investments and its equity in the net assets of the affiliate that result from impairment charges are amortized over the remaining useful life of the affiliate's fixed assets.

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.

Fair Value Measurements: The Corporation's derivative instruments and supplemental pension plan investments 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, 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 FASB fair value measurements accounting standard which established a hierarchy for the inputs used to measure the fair value of financial asset and liabilities 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). Multiple inputs may be used to measure fair value, however, the level of fair value 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. The liability related to the Corporation's crude oil hedges is classified as Level 2.

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, in its energy marketing business, the Corporation sells 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.

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 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 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 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.

Retirement Plans: The Corporation has funded non-contributory defined benefit pension plans and an unfunded supplemental pension plan. The Corporation recognizes on the 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.

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.

Changes in Accounting Policies

Effective January 1, 2010, the Corporation adopted the amended accounting standards that eliminated the consolidation exception for a qualifying special-purpose entity and changed the analysis necessary to determine whether consolidation of a variable interest entity is required. The adoption of these standards resulted in an increase of approximately $10 million to Property, plant and equipment and a corresponding increase to Long-term debt. The debt was subsequently repaid during the first quarter of 2010.

Effective December 31, 2009, the FASB adopted Accounting Standards Update (ASU) Extractive Activities — Oil and Gas (ASC 932) Oil and Gas Reserve Estimation and Disclosures, which amended the requirements for oil and gas reserve estimation and disclosures. The main provisions of the ASU, which align accounting standards with the previously issued Securities and Exchange Commission (SEC) requirements, expand the definition of oil and gas producing activities to include the extraction of resources which are saleable as synthetic oil or gas, to change the price assumption used for reserve estimation and future cash flows to a twelve month average from the year-end price and to amend the geographic disclosure requirements for reporting reserves and other supplementary oil and gas data. See the Supplementary Oil and Gas Data for these disclosures.

Environment, Health and Safety

The Corporation has a values-based, socially-responsible strategy focused on improving environment, health and safety performance and making a positive impact on communities where it does business. The strategy is reflected in the Corporation's environment, health, safety and social responsibility (EHS & SR) policies and by environment and safety management systems that help protect the Corporation's workforce, customers and local communities. The Corporation's management systems are designed to uphold or exceed international standards and 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 as collateral benefits 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.

The Corporation and HOVENSA produce and the Corporation distributes fuel oils in the United States. Many states and localities are adopting requirements that mandate a lower sulfur content of fuel oils and restrict the types of fuel oil sold within their jurisdictions. These proposals could require capital expenditures by the Corporation and HOVENSA to meet the required sulfur content standards or other changes in the marketing of fuel oils.

Over the last several years, many refiners have entered into consent agreements to resolve the United States Environmental Protection Agency's (EPA) assertions that refining facilities were modified or expanded without complying with New Source Review regulations that require permits and new emission controls in certain circumstances and other regulations that impose emissions control requirements. These consent agreements, which arise out of an EPA enforcement initiative focusing on petroleum refiners and utilities, have typically imposed substantial civil fines and penalties and required (i) significant capital expenditures to install emissions control equipment over a three to eight year time period and (ii) changes to operations which resulted in increased operating costs. The capital expenditures, penalties and supplemental environmental projects for individual refineries covered by the settlements can vary significantly, depending on the size and configuration of the refinery, the circumstances of the alleged modifications and whether the refinery has previously installed more advanced pollution controls. In January 2011, HOVENSA signed a Consent Decree with EPA to resolve its claims. Under the terms of the Consent Decree, HOVENSA will pay a penalty of approximately $5 million and spend approximately $700 million over the next 10 years to install equipment and implement additional operating procedures at the HOVENSA refinery to reduce emissions. In addition, the Consent Decree requires HOVENSA to spend approximately $5 million to fund an environmental project to be determined at a later date by the Virgin Islands and $500,000 to assist the Virgin Islands Water and Power Authority with monitoring. The Consent Decree has been lodged with the United States District Court for the Virgin Islands and approval is pending. In addition, substantial progress has been made towards resolving this matter for the Port Reading refining facility, which is not expected to have a material adverse impact on the Corporation's financial position or results of operations.

The Corporation has undertaken a program to assess, monitor and reduce the emission of greenhouse gases, including carbon dioxide and methane. The Corporation recognizes that climate change is a global environmental concern. The Corporation is committed to the responsible management of greenhouse gas emissions from our existing assets and future developments and is implementing a strategy to control our carbon emissions.

The Corporation will have continuing expenditures for environmental assessment and remediation. Sites where corrective action may be necessary include gasoline stations, terminals, onshore exploration and production facilities, refineries (including solid waste management units under permits issued pursuant to the Resource Conservation and Recovery Act) 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 2010, the Corporation's reserve for estimated remediation liabilities was approximately $55 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 $13 million in 2010 and $11 million in both 2009 and 2008. Capital expenditures for facilities, primarily to comply with federal, state and local environmental standards, other than for the low sulfur requirements, were approximately $85 million in 2010, $50 million in 2009 and $15 million in 2008.

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

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 use of new instruments or commodities. Risk limits are monitored and reported on daily to business units and to senior management. The Corporation's risk management department also performs independent verifications 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 foreign exchange rate and interest rate hedging programs.

The Corporation uses value at risk to monitor and control commodity risk within its trading and risk management 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.

Risk Management Activities

Energy marketing activities: In its energy marketing activities, the Corporation sells refined petroleum products, natural gas and electricity principally to commercial and industrial businesses at fixed and floating prices for varying periods of time. Commodity contracts such as futures, forwards, swaps and options together with physical assets, such as storage, are used to obtain supply and reduce margin volatility or lower costs related to sales contracts with customers.

Corporate risk management: Corporate risk management activities include transactions designed to reduce risk in the selling prices of crude oil, refined products 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 uses foreign exchange contracts to reduce its exposure to fluctuating foreign exchange rates by entering into formal contracts for various currencies including the British Pound and the Thai Baht. At December 31, 2010, the Corporation had a payable for foreign exchange contracts maturing in 2011 with a fair value of $7 million. The change in fair value of the foreign exchange contracts from a 10% strengthening of the US Dollar exchange rate is estimated to be an approximately $88 million loss at December 31, 2010.

The Corporation's fixed-rate debt of $5,569 million has a fair value of $6,353 million at December 31, 2010. A 15% decrease in the rate of interest would increase the fair value of debt by approximately $147 million at December 31, 2010.

Following is the value at risk for the Corporation's energy marketing and risk management commodity derivatives activities, excluding foreign exchange and interest derivatives described above:

	2010	2009
	(Millions of dollars)	
At December 31	**$ 5**	$ 8
Average	**5**	10
High	**6**	13
Low	**4**	8

Trading Activities

Trading activities are conducted principally through a trading partnership in which the Corporation has a 50% voting interest. This consolidated entity intends to generate earnings through various strategies primarily using energy commodities, securities and derivatives. The Corporation also takes trading positions for its own account.

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

	2010	2009
	(Millions of dollars)	
At December 31	**$ 14**	$ 9
Average	**14**	12
High	**15**	15
Low	**12**	9

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. Total realized gains on trading activities amounted to $375 million in 2010 and $642 million in 2009. The following table provides an assessment of the factors affecting the changes in fair value of trading activities and represents 100% of the trading partnership and other trading activities:

	2010	2009
	(Millions of dollars)	
Fair value of contracts outstanding at the beginning of the year	**$ 110**	$ 864
Change in fair value of contracts outstanding at the beginning of the year and still outstanding at the end of the year	**10**	(6)
Reversal of fair value for contracts closed during the year	**(233)**	(534)
Fair value of contracts entered into during the year and still outstanding	**207**	(214)
Fair value of contracts outstanding at the end of the year	**$ 94**	$ 110

The following table summarizes the sources of fair values of derivatives used in the Corporation's trading activities at December 31, 2010:

	Total	2011	2012	2013	2014 and Beyond
			(Millions of dollars)		
Source of fair value					
Level 1	$ (252)	$ (305)	$ 46	$ 5	$ 2
Level 2	(34)	(89)	44	8	3
Level 3	380	352	(14)	(2)	44
Total	$ 94	$ (42)	$ 76	$ 11	$ 49

The following table summarizes the 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:

	2010	2009
	(Millions of dollars)	
Investment grade determined by outside sources	**$ 314**	$ 232
Investment grade determined internally*	**272**	120
Less than investment grade	**48**	61
Fair value of net receivables outstanding at the end of the year	**$ 634**	$ 413

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

Item 8. ***Financial Statements and Supplementary Data***

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES
INDEX TO FINANCIAL STATEMENTS AND SCHEDULE

* *Schedules other than Schedule II have been omitted because of the absence of the conditions under which they are required or because the required information is presented in the financial statements or the notes thereto.*

Management's Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f). Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting, as required by Section 404 of the Sarbanes-Oxley Act, based on the framework in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our evaluation, management concluded that our internal control over financial reporting was effective as of December 31, 2010.

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, 2010, as stated in their report, which is included herein.

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

By ______________________
John B. Hess
Chairman of the Board and
Chief Executive Officer

February 25, 2011

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
Hess Corporation

We have audited Hess Corporation's internal control over financial reporting as of December 31, 2010, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). Hess 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 maintained, in all material respects, effective internal control over financial reporting as of December 31, 2010 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, 2010 and 2009, and the related statements of consolidated income, cash flows, and equity and comprehensive income of Hess Corporation and consolidated subsidiaries for each of the three years in the period ended December 31, 2010, and our report dated February 25, 2011 expressed an unqualified opinion thereon.

Ernst & Young LLP

February 25, 2011
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, 2010 and 2009, and the related statements of consolidated income, cash flows, and equity and comprehensive income for each of the three years in the period ended December 31, 2010. 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, 2010 and 2009, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2010, 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.

As discussed in Note 1 to the consolidated financial statements, the Corporation adopted new oil and gas reserve estimation and disclosure requirements effective December 31, 2009.

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, 2010, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 25, 2011 expressed an unqualified opinion thereon.

Ernst + Young LLP

February 25, 2011
New York, New York

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES

CONSOLIDATED BALANCE SHEET

	December 31, 2010	December 31, 2009
	(Millions of dollars; thousands of shares)	
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	**$ 1,608**	$ 1,362
Accounts receivable		
Trade	**4,478**	3,650
Other	**240**	274
Inventories	**1,452**	1,438
Other current assets	**1,002**	1,263
Total current assets	**8,780**	7,987
INVESTMENTS IN AFFILIATES		
HOVENSA L.L.C.	**158**	681
Other	**285**	232
Total investments in affiliates	**443**	913
PROPERTY, PLANT AND EQUIPMENT		
Total — at cost	**35,703**	29,871
Less reserves for depreciation, depletion, amortization and lease impairment	**14,576**	13,244
Property, plant and equipment — net	**21,127**	16,627
GOODWILL	**2,408**	1,225
DEFERRED INCOME TAXES	**2,167**	2,409
OTHER ASSETS	**471**	304
TOTAL ASSETS	**$ 35,396**	$ 29,465
LIABILITIES AND EQUITY		
CURRENT LIABILITIES		
Accounts payable	**$ 4,274**	$ 4,223
Accrued liabilities	**2,567**	1,954
Taxes payable	**726**	525
Short-term debt and current maturities of long-term debt	**46**	148
Total current liabilities	**7,613**	6,850
LONG-TERM DEBT	**5,537**	4,319
DEFERRED INCOME TAXES	**2,995**	2,222
ASSET RETIREMENT OBLIGATIONS	**1,203**	1,234
OTHER LIABILITIES AND DEFERRED CREDITS	**1,239**	1,312
Total liabilities	**18,587**	15,937
EQUITY		
Common stock, par value $1.00		
Authorized: 600,000 shares		
Issued: 2010 — 337,681 shares; 2009 — 327,229 shares	**338**	327
Capital in excess of par value	**3,256**	2,481
Retained earnings	**14,254**	12,251
Accumulated other comprehensive income (loss)	**(1,159)**	(1,675)
Total Hess Corporation stockholders' equity	**16,689**	13,384
Noncontrolling interests	**120**	144
Total equity	**16,809**	13,528
TOTAL LIABILITIES AND EQUITY	**$ 35,396**	$ 29,465

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,		
	2010	**2009**	**2008**
	(Millions of dollars, except per share data)		
REVENUES AND NON-OPERATING INCOME			
Sales (excluding excise taxes) and other operating revenues	**$ 33,862**	$ 29,614	$ 41,134
Income (loss) from equity investment in HOVENSA L.L.C.	**(522)**	(229)	44
Gains on asset sales	**1,208**	—	—
Other, net	**65**	184	(115)
Total revenues and non-operating income	**34,613**	29,569	41,063
COSTS AND EXPENSES			
Cost of products sold (excluding items shown separately below)	**23,407**	20,961	29,567
Production expenses	**1,924**	1,805	1,872
Marketing expenses	**1,021**	1,008	1,025
Exploration expenses, including dry holes and lease impairment	**865**	829	725
Other operating expenses	**213**	183	209
General and administrative expenses	**662**	647	672
Interest expense	**361**	360	267
Depreciation, depletion and amortization	**2,317**	2,200	1,999
Asset impairments	**532**	54	30
Total costs and expenses	**31,302**	28,047	36,366
INCOME BEFORE INCOME TAXES	**3,311**	1,522	4,697
Provision for income taxes	**1,173**	715	2,340
NET INCOME	**$ 2,138**	$ 807	$ 2,357
Less: Net income (loss) attributable to noncontrolling interests	**13**	67	(3)
NET INCOME ATTRIBUTABLE TO HESS CORPORATION	**$ 2,125**	$ 740	$ 2,360
BASIC NET INCOME PER SHARE	**$ 6.52**	$ 2.28	$ 7.35
DILUTED NET INCOME PER SHARE	**$ 6.47**	$ 2.27	$ 7.24
WEIGHTED AVERAGE NUMBER OF COMMON SHARES OUTSTANDING (DILUTED)	**328.3**	326.0	325.8

See accompanying notes to consolidated financial statements.

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES

STATEMENT OF CONSOLIDATED CASH FLOWS

	Years Ended December 31,		
	2010	**2009**	**2008**
		(Millions of dollars)	
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	**$ 2,138**	$ 807	$ 2,357
Adjustments to reconcile net income to net cash provided by operating activities			
Depreciation, depletion and amortization	**2,317**	2,200	1,999
Asset impairments	**532**	54	30
Exploratory dry hole costs	**237**	267	210
Lease impairment	**266**	231	125
(Income) loss from equity investment in HOVENSA L.L.C.	**522**	229	(44)
Stock compensation expense	**112**	128	119
Gains on asset sales	**(1,208)**	—	—
Benefit for deferred income taxes	**(495)**	(438)	(57)
Changes in operating assets and liabilities:			
(Increase) decrease in accounts receivable	**(760)**	320	357
Increase in inventories	**(16)**	(137)	(56)
Increase (decrease) in accounts payable and accrued liabilities	**1,141**	(542)	(252)
Increase (decrease) in taxes payable	**95**	(81)	61
Changes in other assets and liabilities	**(351)**	8	(161)
Net cash provided by operating activities	**4,530**	3,046	4,688
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures	**(5,492)**	(2,918)	(4,438)
Proceeds from asset sales	**183**	—	—
Other, net	**50**	(6)	(6)
Net cash used in investing activities	**(5,259)**	(2,924)	(4,444)
CASH FLOWS FROM FINANCING ACTIVITIES			
Net (repayments) borrowings of debt with maturities of 90 days or less	—	(850)	30
Debt with maturities of greater than 90 days			
Borrowings	**1,278**	1,991	—
Repayments	**(180)**	(694)	(62)
Cash dividends paid	**(131)**	(131)	(130)
Noncontrolling interests, net	**(46)**	(2)	(121)
Employee stock options exercised, including income tax benefits	**54**	18	340
Net cash provided by financing activities	**975**	332	57
NET INCREASE IN CASH AND CASH EQUIVALENTS	**246**	454	301
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR	**1,362**	908	607
CASH AND CASH EQUIVALENTS AT END OF YEAR	**$ 1,608**	$ 1,362	$ 908

See accompanying notes to consolidated financial statements.

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES

STATEMENT OF CONSOLIDATED EQUITY AND COMPREHENSIVE INCOME

	Common Stock	Capital in Excess of Par	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Hess Stockholders' Equity	Noncontrolling Interests	Total Equity
				(Millions of dollars)			
Balance at January 1, 2008	$ 321	$ 1,882	$ 9,412	$ (1,841)	$ 9,774	$ 226	$ 10,000
Net income (loss)			2,360		2,360	(3)	2,357
Deferred gains (losses) on cash flow hedges, after-tax							
Effect of hedge losses recognized in income				311	311	—	311
Net change in fair value of cash flow hedges				(310)	(310)	—	(310)
Effect of adoption of fair value measurements accounting standards				193	193	—	193
Change in post retirement plan liabilities, after-tax				(241)	(241)	—	(241)
Change in foreign currency translation adjustment and other				(120)	(120)	(18)	(138)
Comprehensive income (loss)					2,193	(21)	2,172
Activity related to restricted common stock awards, net	1	145	—	—	146	—	146
Employee stock options, including income tax benefits	4	320	—	—	324	—	324
Cash dividends declared	—	—	(130)	—	(130)	—	(130)
Noncontrolling interests, net	—	—	—	—	—	(121)	(121)
Balance at December 31, 2008	326	2,347	11,642	(2,008)	12,307	84	12,391
Net income			740		740	67	807
Deferred gain (losses) on cash flow hedges, after-tax							
Effect of hedge losses recognized in income				963	963	—	963
Net change in fair value of cash flow hedges				(729)	(729)	—	(729)
Change in post retirement plan liabilities, after-tax				(6)	(6)	—	(6)
Change in foreign currency translation adjustment and other				105	105	(5)	100
Comprehensive income (loss)					1,073	62	1,135
Activity related to restricted common stock awards, net	1	61	—	—	62	—	62
Employee stock options, including income tax benefits	—	73	—	—	73	—	73
Cash dividends declared	—	—	(131)	—	(131)	—	(131)
Noncontrolling interests, net	—	—	—	—	—	(2)	(2)
Balance at December 31, 2009	327	2,481	12,251	(1,675)	13,384	144	13,528
Net income			**2,125**		**2,125**	**13**	**2,138**
Deferred gains (losses) on cash flow hedges, after-tax							
Effect of hedge losses recognized in income				**656**	**656**	**—**	**656**
Net change in fair value of cash flow hedges				**(198)**	**(198)**	**—**	**(198)**
Change in post retirement plan liabilities, after-tax				**28**	**28**	**—**	**28**
Change in foreign currency translation adjustment and other				**30**	**30**	**1**	**31**
Comprehensive income (loss)					**2,641**	**14**	**2,655**
Common stock issued for acquisition	**9**	**639**	**—**	**—**	**648**	**—**	**648**
Activity related to restricted common stock awards, net	**1**	**59**	**—**	**—**	**60**	**—**	**60**
Employee stock options, including income tax benefits	**1**	**105**	**—**	**—**	**106**	**—**	**106**
Cash dividends declared	**—**	**—**	**(132)**	**—**	**(132)**	**—**	**(132)**
Noncontrolling interests, net	**—**	**(28)**	**10**	**—**	**(18)**	**(38)**	**(56)**
Balance at December 31, 2010	**$ 338**	**$ 3,256**	**$ 14,254**	**$ (1,159)**	**$ 16,689**	**$ 120**	**$ 16,809**

See accompanying notes to consolidated financial statements.

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Summary of Significant Accounting Policies

Nature of Business: Hess Corporation and its subsidiaries (the Corporation) engage in the exploration for and the development, production, purchase, transportation and sale of crude oil and natural gas. These activities are conducted principally in Algeria, Australia, Azerbaijan, Brazil, Brunei, China, Colombia, Denmark, Egypt, Equatorial Guinea, France, Ghana, Indonesia, Libya, Malaysia, Norway, Peru, Russia, Thailand, the United Kingdom and the United States. In addition, the Corporation manufactures refined petroleum products and purchases, markets and trades refined petroleum products, natural gas and electricity. The Corporation owns 50% of HOVENSA L.L.C. (HOVENSA), a refinery joint venture in the United States Virgin Islands. An additional refining facility, terminals and retail gasoline stations, most of which include convenience stores, are located on the East Coast of the United States.

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 balance sheet and revenues and expenses in the income statement. Actual results could differ from those estimates. Among the estimates made by management are oil and gas reserves, asset valuations, depreciable lives, pension liabilities, legal and environmental obligations, asset retirement obligations and income taxes. Certain 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.

Principles of Consolidation: 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, including HOVENSA, are accounted for using the equity method.

Revenue Recognition: The Corporation recognizes revenues from the sale of crude oil, natural gas, 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 Exploration and Production (E&P) natural gas volumes sold and the Corporation’s share of natural gas production are not material. Revenues from natural gas and electricity sales by the Corporation’s marketing operations are recognized based on meter readings and estimated deliveries to customers since the last meter reading.

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 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.

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 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 commodities 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 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.

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

Inventories: Inventories are valued at the lower of cost or market. For refined 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.

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 a leased property, are depreciated over the estimated useful lives not to exceed the remaining lease period. The Corporation records the cost of acquired customers in its energy marketing activities as intangible assets and amortizes these costs on the straight-line method over the expected renewal period based on historical experience.

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.

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.

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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. 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. Differences between the carrying value of the Corporation's equity investments and its equity in the net assets of the affiliate that result from impairment charges are amortized over the remaining useful life of the affiliate's fixed assets.

Impairment of Goodwill: 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 calculated at the reporting unit level, which for the Corporation's goodwill is the Exploration and Production operating segment. The Corporation identifies potential impairments by comparing the fair value of the reporting unit to its book value, including goodwill. If the fair value of the 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.

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.

Fair Value Measurements: The Corporation's derivative instruments and supplemental pension plan investments 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 GAAP. These fair value measurements are recorded in connection with business combinations, 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 the fair value of financial assets and liabilities 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). Multiple inputs may be used to measure fair value, however, the level of fair value 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. The liability related to the Corporation's crude oil hedges is classified as Level 2.

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, in its energy marketing business, the Corporation enters 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.

Effective December 31, 2008, the Corporation applied the provisions of a new accounting standard for the accounting for liabilities measured at fair value with a third-party credit enhancement (ASC 820 — Fair Value Measurements and Disclosures, originally issued as Emerging Issues Task Force 08-5, Issuer's Accounting for Liabilities Measured at Fair Value with a Third-Party Credit Enhancement). Upon adoption, the Corporation revalued certain derivative liabilities collateralized by letters of credit to reflect the Corporation's credit rating rather than the credit rating of the issuing bank. The adoption resulted in an increase in Sales and other operating revenues of approximately $13 million and an increase in Accumulated other comprehensive income of approximately $78 million, with a corresponding decrease in derivative liabilities recorded within Accounts payable.

Retirement Plans: The Corporation recognizes the funded status of defined benefit postretirement plans on the 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.

Share-Based Compensation: The fair value of all share-based compensation is expensed and recognized on a straight-line basis over the vesting period of the awards.

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, including costs of refinery turnarounds. Capital improvements are recorded as additions in Property, plant and equipment.

Environmental Expenditures: The Corporation accrues and expenses environmental costs 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 that reduce or prevent future adverse impacts to the environment.

Changes in Accounting Policies: Effective January 1, 2010, the Corporation adopted the amended accounting standards that eliminated the consolidation exception for a qualifying special-purpose entity and changed the analysis necessary to determine whether consolidation of a variable interest entity is required. The adoption of these standards resulted in an increase of approximately $10 million to Property, plant and equipment and a corresponding increase to Long-term debt. The debt was subsequently repaid during the first quarter of 2010.

Effective December 31, 2009, the Financial Accounting Standards Board (FASB) adopted Accounting Standards Update (ASU) Extractive Activities — Oil and Gas (ASC 932) Oil and Gas Reserve Estimation and Disclosures, which amended the requirements for oil and gas reserve estimation and disclosures. The main provisions of the ASU, which align accounting standards with the previously issued Securities and Exchange Commission (SEC) requirements, expand the definition of oil and gas producing activities to include the extraction of resources which are saleable as synthetic oil or gas, to change the price assumption used for reserve estimation and future cash flows to a twelve month average from the year-end price and to amend the geographic disclosure requirements for reporting reserves and other supplementary oil and gas data. See the Supplementary Oil and Gas Data for these disclosures.

2. Acquisitions and Divestitures

2010: In December, the Corporation acquired approximately 167,000 net acres in the Bakken oil shale play (Bakken) in North Dakota from TRZ Energy, LLC for $1,075 million in cash. In December, the Corporation also completed the acquisition of American Oil & Gas Inc. (American Oil & Gas) for approximately $675 million through the issuance of approximately 8.6 million shares of the Corporation's common stock, which increased the Corporation's acreage position in the Bakken by approximately 85,000 net acres. The properties acquired are located near the Corporation's existing acreage. These acquisitions strengthen the Corporation's acreage position in the Bakken, leverage existing capabilities and infrastructure and are expected to contribute to future reserve and production growth. Both of these transactions were accounted for as business combinations and the majority of the fair value of the assets acquired was assigned to unproved properties. The total goodwill recorded on these transactions was $347 million. The preliminary purchase price allocations are subject to normal post-closing adjustments.

In September, the Corporation completed the exchange of its interests in Gabon and the Clair Field in the United Kingdom for additional interests of 28% and 25%, respectively, in the Valhall and Hod fields offshore Norway. This non-monetary exchange was accounted for as a business combination and was recorded at fair value. The transaction resulted in a pre-tax gain of $1,150 million ($1,072 million after income taxes). The total combined carrying amount of the disposed assets prior to the exchange was $702 million, including goodwill of $65 million. The Corporation also acquired, from a different third party, additional interests of 8% and 13% in the Valhall and Hod fields, respectively, for $507 million in cash. This acquisition was accounted for as a business combination. As a result of both of these transactions, the Corporation's total interests in the Valhall and Hod fields are 64% and 63%, respectively. The primary reason for these transactions was to acquire long-lived crude oil reserves and future production growth. The following table summarizes the fair value of the assets acquired and liabilities assumed in both of these transactions:

	Exchange	Acquisition	Total
		(Millions of dollars)	
Property, plant and equipment	$ 2,020	$ 570	$2,590
Goodwill	688	220	908
Current assets	155	23	178
Total assets acquired	2,863	813	3,676
Current liabilities	(135)	(32)	(167)
Deferred tax liabilities	(688)	(220)	(908)
Asset retirement obligations	(188)	(54)	(242)
Net assets acquired	$ 1,852	$ 507	$2,359

For all 2010 acquisitions and the exchange described above, the assets acquired and liabilities assumed are recorded at fair value. The estimated fair value of the property, plant and equipment acquired in the transactions described above was primarily based on an income approach. The significant inputs used in this Level 3 fair value measurement include assumed future production and capital based on anticipated development plans, commodity prices, costs and a risk-adjusted discount rate. The goodwill recorded equals the deferred tax liability recognized for the differences in book and tax bases of the assets acquired. The goodwill is not expected to be deductible for income tax purposes.

In January, the Corporation completed the sale of its interest in the Jambi Merang natural gas development project in Indonesia (Hess 25%) for cash proceeds of $183 million. The transaction resulted in a gain of $58 million, after deducting the net book value of assets including goodwill of $7 million.

2009: The Corporation acquired for $74 million a 50% interest in Blocks PM301 and PM302 in Malaysia, which are adjacent to Block A-18 of the Joint Development Area of Malaysia/Thailand (JDA) and contain an extension of the Bumi Field. The Corporation also acquired 37 previously leased retail gasoline stations, primarily through the assumption of $65 million of fixed-rate notes.

2008: The Corporation acquired the remaining 22% interest in its Gabonese subsidiary for $285 million. In addition, the Corporation expanded its energy marketing business by acquiring fuel oil, natural gas, and electricity customer accounts, and a terminal and related assets, for an aggregate of approximately $100 million.

3. Inventories

Inventories at December 31 are as follows:

	2010	2009
	(Millions of dollars)	
Crude oil and other charge stocks	**$ 496**	$ 424
Refined products and natural gas	**1,528**	1,429
Less: LIFO adjustment	**(995)**	(815)
	1,029	1,038
Merchandise, materials and supplies	**423**	400
Total	**$1,452**	$ 1,438

The percentage of LIFO inventory to total crude oil, refined products and natural gas inventories was 65% and 64% at December 31, 2010 and 2009, respectively. In 2009, the Corporation recorded a pre-tax charge of approximately $25 million ($18 million after income taxes) to write down materials inventories in Equatorial Guinea and the United States, the majority of which was recorded in Production expenses.

4. Refining Joint Venture

The Corporation has an investment in HOVENSA L.L.C., a 50% joint venture with Petroleos de Venezuela, S.A. (PDVSA), which is accounted for using the equity method. HOVENSA owns and operates a refinery in the U.S. Virgin Islands. Summarized financial information for HOVENSA as of December 31 and for the years then ended follows:

	2010	2009	2008
		(Millions of dollars)	
Summarized Balance Sheet, at December 31			
Cash and cash equivalents	**$ 45**	$ 78	$ 75
Other current assets	**668**	580	664
Net fixed assets	**1,987**	2,080	2,136
Other assets	**27**	33	58
Current liabilities	**(1,001)**	(953)	(679)
Long-term debt	**(706)**	(356)	(356)
Deferred liabilities and credits	**(135)**	(137)	(104)
Members' equity	**$ 885**	$ 1,325	$ 1,794
Summarized Income Statement, for the years ended December 31			
Total revenues	**$ 12,300**	$ 10,085	$ 17,518
Costs and expenses	**(12,738)**	(10,536)	(17,423)
Net income (loss)	**$ (438)**	$ (451)	$ 95
Hess Corporation's share*	**$ (222)**	$ (229)	$ 44
Summarized Cash Flow Statement, for the years ended December 31			
Net cash provided by (used in):			
Operating activities	**$ (335)**	$ 87	$ (20)
Investing activities	**(48)**	(84)	(85)
Financing activities	**350**	—	(99)
Net increase (decrease) in cash and cash equivalents	**$ (33)**	$ 3	$ (204)

* *Before Virgin Islands income taxes, which were recorded in the Corporation's income tax provision. Excludes the impairment charge to reduce the carrying value of the Corporation's equity investment in HOVENSA.*

In December 2010, the Corporation recorded an impairment charge of $300 million before income taxes ($289 million after income taxes) to reduce the carrying value of its equity investment in HOVENSA to its fair value, which was recorded in Income (loss) from equity investment in HOVENSA L.L.C. The investment had been adversely affected by consecutive annual operating losses resulting from continued weak refining margins and refinery utilization and a fourth quarter 2010 debt rating downgrade. As a result of a strategic assessment in 2010, HOVENSA decided to lower crude oil refining capacity from 500,000 to 350,000 barrels per day. The Corporation performed an impairment analysis and concluded that its investment had experienced an other than temporary decline in value. The fair value was determined based on an income approach using estimated refined product selling prices and volumes, related costs of product sold, capital and operating expenditures and a market based discount rate (Level 3 fair value measurement). As a result of cumulative net operating losses in the last two years, the Corporation is not recognizing a full income tax benefit on the impairment charge.

The Corporation guarantees the payment of up to 50% of the value of HOVENSA's crude oil purchases from certain suppliers other than PDVSA. The guarantee amounted to $150 million at December 31, 2010. This amount fluctuates based on the volume of crude oil purchased and the related crude oil prices. In addition, the Corporation has agreed to provide funding up to $15 million to the extent HOVENSA does not have funds to meet its senior debt obligations.

5. Property, Plant and Equipment

Property, plant and equipment at December 31 consists of the following:

	2010	2009
	(Millions of dollars)	
Exploration and Production		
Unproved properties	**$ 3,796**	$ 2,347
Proved properties	**3,496**	3,121
Wells, equipment and related facilities	**26,064**	22,118
	33,356	27,586
Marketing, Refining and Corporate	**2,347**	2,285
Total — at cost	**35,703**	29,871
Less: reserves for depreciation, depletion, amortization and lease impairment	**14,576**	13,244
Property, plant and equipment — net	**$21,127**	$16,627

In March 2010, the Corporation agreed to sell a package of natural gas producing assets in the United Kingdom North Sea including its interests in the Easington Catchment Area (Hess 30%), the Bacton Area (Hess 23%), the Everest Field (Hess 19%), the Lomond Field (Hess 17%) and its interest in the Central Area Transmission System (CATS) pipeline (Hess 18%). The Corporation has classified all of these properties as held for sale. At December 31, 2010, the carrying amount of these assets totaling $238 million was reported in Other current assets. In addition, related asset retirement obligations and deferred income taxes totaling $212 million were reported in Accrued liabilities. In accordance with GAAP, properties classified as held for sale are not depreciated but are subject to impairment testing.

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:

	2010	2009	2008
		(Millions of dollars)	
Beginning balance at January 1	**$1,437**	$1,094	$ 608
Additions to capitalized exploratory well costs pending the determination of proved reserves	**675**	433	560
Reclassifications to wells, facilities, and equipment based on the determination of proved reserves	**(87)**	(16)	(67)
Capitalized exploratory well costs charged to expense	**(110)**	(74)	(7)
Dispositions	**(132)**	—	—
Ending balance at December 31	**$1,783**	$1,437	$1,094
Number of wells at end of year	**82***	53	45

* *The number of wells at the end of 2010 reflects increased onshore exploration activities, principally in the United States.*

Capitalized exploratory well costs charged to expense in the preceding table include $22 million related to the impairment of the West Med Block and $79 million related to the Azulão well in Brazil. Dispositions consist of well costs relating to the Corporation's 50% interest in WA-404-P Block located offshore Western Australia and the Clair Field, in the United Kingdom North Sea. The preceding table excludes exploratory dry hole costs of $127 million, $193 million and $203 million in 2010, 2009 and 2008, respectively, which were incurred and subsequently expensed in the same year.

At December 31, 2010, exploratory drilling costs capitalized in excess of one year past completion of drilling were as follows (in millions):

2009	$ 500
2008	439
2007	95
2006	186
2003 to 2005	56
	$1,276

The capitalized well costs in excess of one year relate to 15 projects. Approximately 49% of the capitalized well costs in excess of one year relates to two separate projects in the deepwater Gulf of Mexico, Pony and Tubular Bells, where development planning is progressing. In addition, at the Pony prospect the Corporation has signed a non-binding agreement in principle with the owners on adjacent Green Canyon Block 512 that outlines a proposal to jointly develop the Pony and Knotty Head fields. Negotiation of a joint operating agreement is ongoing. Approximately 21% of the capitalized well costs in excess of one year relates to Area 54 offshore Libya where commercial analysis and development planning activities are ongoing. Approximately 18% relates to Block WA-390-P offshore Western Australia where further drilling, other appraisal activities and commercial analysis are ongoing. 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.

6. Goodwill

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

	2010	2009
	(Millions of dollars)	
Beginning balance at January 1	**$1,225**	$1,225
Acquisitions*	**1,255**	—
Dispositions*	**(72)**	—
Ending balance at December 31	**$ 2,408**	$1,225

* *For a description of the acquisitions and dispositions in 2010 refer to Note 2, Acquisitions and Divestitures.*

7. Asset Impairments

During 2010, the Corporation recorded a charge of $532 million ($334 million after income taxes) to fully impair the carrying value of its 55% interest in the West Mediterranean Block 1 concession (West Med Block), located offshore Egypt. This interest was acquired in 2006 and included four natural gas discoveries and additional exploration prospects. The Corporation and its partners subsequently explored and further evaluated the area, made a fifth discovery, conducted development planning, and held negotiations with the Egyptian authorities to amend the existing gas sales agreement. In September 2010, the Corporation and its partners notified the Egyptian authorities of their decision to cease exploration activities on the block and to relinquish a significant portion of the block. As a result, the Corporation fully impaired the carrying value of its interests in the West Med Block. The

Corporation's estimated fair value of the West Med Block was determined using a valuation approach based on market related data (Level 3 fair value measurement).

During 2009, the Corporation recorded total asset impairment charges of $54 million ($26 million after income taxes) to reduce the carrying value of two short-lived fields in the United Kingdom North Sea. During 2008, the Corporation recorded total asset impairment charges of $30 million ($17 million after income taxes) to reduce the carrying value of mature fields in the United States and the United Kingdom North Sea.

8. Asset Retirement Obligations

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

	2010	2009
	(Millions of dollars)	
Asset retirement obligations at January 1	**$1,297**	$ 1,214
Liabilities incurred	**255**	14
Liabilities settled or disposed of	**(282)**	(58)
Accretion expense	**78**	72
Revisions	**(6)**	(23)
Foreign currency translation	**16**	78
Asset retirement obligations at December 31	**1,358**	1,297
Less: current obligations	**155**	63
Long-term obligations at December 31	**$1,203**	$ 1,234

9. Long-Term Debt

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

	2010	2009
	(Millions of dollars)	
Fixed-rate notes:		
6.7% due 2011	**$ —**	$ 116
7.0% due 2014	**250**	250
8.1% due 2019	**997**	997
7.9% due 2029	**695**	694
7.3% due 2031	**746**	746
7.1% due 2033	**598**	598
6.0% due 2040	**744**	744
5.6% due 2041	**1,241**	—
Total fixed-rate notes	**5,271**	4,145
Other fixed-rate notes, weighted average rate 8.4%, due through 2023	**133**	154
Project lease financing, weighted average rate 5.1%, due through 2014	**102**	113
Pollution control revenue bonds, weighted average rate 5.9%, due through 2034	**53**	53
Other debt	**10**	2
	5,569	4,467
Less: amount included in current maturities	**32**	148
Total	**$5,537**	$4,319

In August 2010, the Corporation issued $1,250 million of 30 year fixed-rate notes with a coupon of 5.6% scheduled to mature in 2041. The proceeds were used to purchase additional acreage in the Bakken and additional interests in the Valhall and Hod fields.

In December 2009, the Corporation issued $750 million of 30 year fixed-rate notes with a coupon of 6% and tendered for the $662 million of notes due in August 2011. The Corporation completed the purchase of $546 million of the 2011 notes in 2009 and recorded a charge of $54 million ($34 million after income taxes). The remaining $116 million of the 2011 notes, classified as short-term debt and current maturities of long term debt at December 31, 2009, was redeemed in January 2010, resulting in a charge of $11 million ($7 million after income taxes). The charges resulting from the repurchase of the notes are reported in Other, net within the Statement of Consolidated Income.

In February 2009, the Corporation issued $250 million of 5 year fixed-rate notes with a coupon of 7% and $1 billion of 10 year fixed-rate notes with a coupon of 8.125%. The majority of the proceeds were used to repay debt under the revolving credit facility and outstanding borrowings on other credit facilities.

The aggregate long-term debt maturing during the next five years is as follows (in millions): 2011 — $32 (included in short-term debt and current maturities of long-term debt); 2012 — $35; 2013 — $37; 2014 — $341 and 2015 — $4.

At December 31, 2010, the Corporation's fixed-rate notes have a principal amount of $5,300 million ($5,271 million net of unamortized discount). Interest rates on the outstanding fixed rate notes have a weighted average rate of 6.9%.

The Corporation has a $3 billion syndicated revolving credit facility (the facility), which can be used for borrowings and letters of credit, substantially all of which is committed through May 2012. At December 31, 2010, the Corporation has available capacity on the facility of $3 billion. Borrowings under the facility bear interest at 0.4% above the London Interbank Offered Rate. A facility fee of 0.1% 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 has a 364-day asset-backed credit facility securitized by certain accounts receivable from its Marketing and Refining operations. Under the terms of this financing arrangement, the Corporation has the ability to borrow or issue letters of credit of up to $1 billion, subject to the availability of sufficient levels of eligible receivables. At December 31, 2010, outstanding letters of credit under this facility were collateralized by a total of $1,194 million of accounts receivable, which are held by a wholly-owned subsidiary. These receivables are only available to pay the general obligations of the Corporation after satisfaction of the outstanding obligations under the asset-backed facility.

The Corporation's long-term debt agreements contain a financial covenant that restricts the amount of total borrowings and secured debt. At December 31, 2010, the Corporation is permitted to borrow up to an additional $22.4 billion for the construction or acquisition of assets. The Corporation has the ability to borrow up to an additional $4.4 billion of secured debt at December 31, 2010.

Outstanding letters of credit at December 31 were as follows:

	2010	2009
	(Millions of dollars)	
Asset-backed credit facility	**$ 400**	$ 500
Committed lines*	**1,161**	1,155
Uncommitted lines*	**521**	1,192
Total	**$2,082**	$ 2,847

* *Committed and uncommitted lines have expiration dates through 2013.*

Of the total letters of credit outstanding at December 31, 2010, $81 million relates to contingent liabilities and the remaining $2,001 million relates to liabilities recorded on the balance sheet.

The total amount of interest paid (net of amounts capitalized) was $319 million, $335 million and $266 million in 2010, 2009 and 2008, respectively. The Corporation capitalized interest of $5 million, $6 million and $7 million in 2010, 2009, and 2008, respectively.

10. Share-Based Compensation

The Corporation awards restricted common stock and stock options under its 2008 Long-Term Incentive Plan. Generally, stock options vest in one to three years from the date of grant, have a 10-year option life, and the exercise price equals or exceeds the market price on the date of grant. Outstanding restricted common stock generally vests in three years from the date of grant.

Share-based compensation expense consists of the following:

	Before Income Taxes			After Income Taxes		
	2010	2009	2008	2010	2009	2008
			(Millions of dollars)			
Stock options	**$ 52**	$ 58	$ 51	**$ 32**	$ 36	$ 31
Restricted stock	**60**	70	68	**37**	44	43
Total	**$ 112**	$ 128	$ 119	**$ 69**	$ 80	$ 74

Based on restricted stock and stock option awards outstanding at December 31, 2010, unearned compensation expense, before income taxes, will be recognized in future years as follows (in millions): 2011 — $77, 2012 — $40 and 2013 — $4.

The Corporation's stock option and restricted stock activity consisted of the following:

	Stock Options		Restricted Stock	
	Options (Thousands)	Weighted-Average Exercise Price per Share	Shares of Restricted Common Stock (Thousands)	Weighted-Average Price on Date of Grant
Outstanding at January 1, 2008	11,292	$ 38.31	4,801	$ 33.93
Granted	2,473	82.55	1,289	85.22
Exercised	(3,852)	29.17	—	—
Vested	—	—	(2,787)	21.40
Forfeited	(213)	60.61	(142)	58.60
Outstanding at December 31, 2008	9,700	52.73	3,161	64.78
Granted	3,135	56.44	1,056	56.27
Exercised	(416)	38.85	—	—
Vested	—	—	(893)	50.13
Forfeited	(317)	65.68	(376)	66.11
Outstanding at December 31, 2009	12,102	53.83	2,948	66.00
Granted	**2,792**	**60.12**	**952**	**60.04**
Exercised	**(1,080)**	**42.37**	**—**	**—**
Vested	**—**	**—**	**(880)**	**55.42**
Forfeited	**(394)**	**65.04**	**(182)**	**65.56**
Outstanding at December 31, 2010	**13,420**	**55.73**	**2,838**	**67.32**
Exercisable at December 31, 2008	4,522	$ 36.95		
Exercisable at December 31, 2009	6,636	46.11		
Exercisable at December 31, 2010	**8,079**	**51.73**		

The table below summarizes information regarding the outstanding and exercisable stock options as of December 31, 2010:

	Outstanding Options			Exercisable Options	
Range of Exercise Prices	Options (Thousands)	Weighted-Average Remaining Contractual Life (Years)	Weighted-Average Exercise Price per Share	Options (Thousands)	Weighted-Average Exercise Price per Share
$10.00 – $40.00	1,935	3	$ 26.62	1,935	$ 26.62
$40.01 – $50.00	1,708	5	49.19	1,705	49.20
$50.01 – $60.00	4,867	7	55.09	2,914	54.21
$60.01 – $80.00	2,753	9	60.32	80	65.31
$80.01 – $120.00	2,157	7	82.58	1,445	82.58
	13,420	7	55.73	8,079	51.73

The intrinsic value (or the amount by which the market price of the Corporation's Common Stock exceeds the exercise price of an option) for outstanding options and exercisable options at December 31, 2010 was $292 million and $209 million, respectively. At December 31, 2010, assuming forfeitures of 2% per year, 13,200,000 outstanding options are expected to vest at a weighted average exercise price of $55.66 per share. At December 31, 2010, the weighted average remaining term of exercisable options was six years.

The Corporation uses the Black-Scholes model to estimate the fair value of employee stock options. The following weighted average assumptions were utilized for stock options awarded:

	2010	2009	2008
Risk free interest rate	**2.14%**	1.80%	2.70%
Stock price volatility	**.390**	.390	.294
Dividend yield	**.67%**	.70%	.50%
Expected term in years	**4.5**	4.5	5.0
Weighted average fair value per option granted	**$20.18**	$18.47	$24.09

The assumption above for the risk free interest rate is based on the expected terms of the options and is obtained from published sources. The stock price volatility is determined from historical experience using the same period as the expected terms of the options. The expected stock option term is based on historical exercise patterns and the expected future holding period.

In May 2008, shareholders approved the 2008 Long-Term Incentive Plan and in May 2010 approved an amendment to the 2008 Long-Term Incentive Plan. The Corporation also has stock options outstanding under a former plan. At December 31, 2010, the number of common shares reserved for issuance under the 2008 Long-Term Incentive Plan, as amended, is as follows (in thousands):

Total common shares reserved for issuance	17,178
Less: stock options outstanding	5,671
Available for future awards of restricted stock and stock options	11,507

11. Foreign Currency Translation

Foreign currency gains (losses) before income taxes amounted to $(5) million in 2010, $20 million in 2009 and $(212) million in 2008. The foreign currency loss in 2008 reflects the net effect of significant exchange rate movements in the fourth quarter of 2008 on the remeasurement of assets, liabilities and foreign currency forward contracts by certain foreign businesses. The balances in Accumulated other comprehensive income (loss) related to foreign currency translation were an increase to stockholders' equity of $12 million at December 31, 2010 and a reduction to stockholders' equity of $18 million at December 31, 2009.

12. 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	
	2010	2009	2010	2009	2010	2009
	(Millions of dollars)					
Change in benefit obligation						
Balance at January 1	**$1,359**	$1,125	**$ 188**	$165	**$ 84**	$ 77
Service cost	**41**	34	**8**	6	**5**	3
Interest cost	**78**	72	**8**	11	**4**	4
Actuarial (gain) loss	**75**	139	**7**	43	**18**	3
Benefit payments	**(46)**	(43)	**(2)**	(2)	**(4)**	(3)
Plan settlements*	**—**	—	**(17)**	(35)	**—**	—
Foreign currency exchange rate changes	**(10)**	32	**—**	—	**—**	—
Balance at December 31	**1,497**	1,359	**192**	188	**107**	84
Change in fair value of plan assets						
Balance at January 1	**1,072**	745	**—**	—	**—**	—
Actual return on plan assets	**155**	161	**—**	—	**—**	—
Employer contributions	**192**	183	**20**	37	**4**	3
Benefit payments	**(46)**	(43)	**(20)**	(37)	**(4)**	(3)
Foreign currency exchange rate changes	**(8)**	26	**—**	—	**—**	—
Balance at December 31	**1,365**	1,072	**—**	—	**—**	—
Funded status (plan assets less than benefit obligations) at December 31	**(132)**	(287)	**(192)****	(188)**	**(107)**	(84)
Unrecognized net actuarial losses	**460**	495	**83**	92	**32**	16
Net amount recognized	**$ 328**	$ 208	**$(109)**	$ (96)	**$ (75)**	$ (68)

* *The Corporation recorded charges related to plan settlements of $8 million ($5 million after income taxes) in 2010 and $17 million ($10 million after income taxes) in 2009 due to employee retirements.*

** *The trust established by the Corporation for the supplemental plan held assets valued at $21 million at December 31, 2010 and $40 million at December 31, 2009.*

Amounts recognized in the consolidated balance sheet at December 31 consist of the following:

	Funded Pension Plans		Unfunded Pension Plan		Postretirement Medical Plan	
	2010	2009	2010	2009	2010	2009
	(Millions of dollars)					
Accrued benefit liability	**$ (132)**	$ (287)	**$ (192)**	$ (188)	**$ (107)**	$ (84)
Accumulated other comprehensive loss, pre-tax*	**460**	495	**83**	92	**32**	16
Net amount recognized	**$ 328**	$ 208	**$ (109)**	$ (96)	**$ (75)**	$ (68)

* *The after-tax reduction to equity recorded in Accumulated other comprehensive income (loss) was $385 million at December 31, 2010 and $413 million at December 31, 2009.*

The accumulated benefit obligation for the funded defined benefit pension plans was $1,355 million at December 31, 2010 and $1,229 million at December 31, 2009. The accumulated benefit obligation for the unfunded defined benefit pension plan was $176 million at December 31, 2010 and $172 million at December 31, 2009.

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

	Pension Plans			Postretirement Medical Plan		
	2010	2009	2008	**2010**	2009	2008
	(Millions of dollars)					
Service cost	**$ 49**	$ 40	$ 42	**$ 5**	$ 3	$ 3
Interest cost	**86**	83	80	**4**	4	4
Expected return on plan assets	**(86)**	(59)	(80)	**—**	—	—
Amortization of unrecognized net actuarial loss	**48**	65	19	**1**	—	—
Settlement loss	**8**	17	—	**—**	—	—
Net periodic benefit cost	**$105**	$146	$61	**$10**	$ 7	$ 7

The Corporation's 2011 pension and postretirement medical expense is estimated to be approximately $90 million, of which approximately $45 million relates to the amortization of unrecognized net actuarial losses.

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

	2010	2009	2008
Weighted-average assumptions used to determine benefit obligations at December 31			
Discount rate	**5.3%**	5.8%	6.3%
Rate of compensation increase	**4.4**	4.3	4.4
Weighted-average assumptions used to determine net benefit cost for years ended December 31			
Discount rate	**5.8**	6.3	6.3
Expected return on plan assets	**7.5**	7.5	7.5
Rate of compensation increase	**4.3**	4.4	4.4

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

	2010	2009	2008
Assumptions used to determine benefit obligations at December 31			
Discount rate	**4.8%**	5.4%	6.3%
Initial health care trend rate	**8.0%**	8.0%	9.0%
Ultimate trend rate	**5.0%**	4.5%	4.5%
Year in which ultimate trend rate is reached	**2017**	2013	2013

The assumptions used to determine net periodic benefit cost for each year were established at the end of each previous year while the assumptions used to determine benefit obligations were established at each year-end. The net periodic benefit cost and the actuarial present value of benefit obligations are based on actuarial assumptions that are reviewed on an annual basis. The discount rate is developed based on a portfolio of high-quality, fixed income debt instruments with maturities that approximate the expected payment of plan obligations. The overall expected return on plan assets is developed from the expected future returns for each asset category, weighted by the target allocation of pension assets to that asset category.

The Corporation's investment strategy is to maximize long-term returns at an acceptable level of risk through broad diversification of plan assets in a variety of asset classes. Asset classes and target allocations are determined by the Corporation's investment committee and include domestic and foreign equities, fixed income, and other investments, including hedge funds, real estate and private equity. Investment managers are prohibited from investing in securities issued by the Corporation unless indirectly held as part of an index strategy. The majority of plan assets are highly liquid, providing ample liquidity for benefit payment requirements. The current target allocations for plan assets are 50% equity securities, 25% fixed income securities (including cash and short-term investment funds) and 25% to all other types of investments. Asset allocations are rebalanced on a periodic basis throughout the year to bring assets to within an acceptable range of target levels.

The following tables provide the fair value of the financial assets of the funded pension plans as of December 31, 2010 and 2009 in accordance with the fair value measurement hierarchy described in Note 1, Summary of Significant Accounting Policies:

	Level 1	Level 2	Level 3	Total
		(Millions of dollars)		
December 31, 2010				
Cash and short-term investment funds	$ 5	$ 31	$ —	$ 36
Equities:				
U.S. equities (domestic)	444	—	—	444
International equities (non-U.S.)	53	121	—	174
Global equities (domestic and non-U.S.)	18	140	—	158
Fixed income:				
Treasury and government issued(a)	—	98	3	101
Government related(b)	—	14	3	17
Mortgage-backed securities(c)	—	61	—	61
Corporate	—	93	1	94
Other:				
Hedge funds	—	—	187	187
Private equity funds	—	—	40	40
Real estate funds	7	—	32	39
Diversified commodities funds	—	14	—	14
	$ 527	$ 572	$ 266	$1,365

	Level 1	Level 2	Level 3	Total
		(Millions of dollars)		
December 31, 2009				
Cash and short-term investment funds	$ 5	$ 39	$ —	$ 44
Equities:				
U.S. equities (domestic)	318	—	—	318
International equities (non-U.S.)	34	93	—	127
Global equities (domestic and non-U.S.)	19	117	—	136
Fixed income:				
Treasury and government issued(a)	—	74	3	77
Government related(b)	—	24	2	26
Mortgage-backed securities(c)	—	60	1	61
Corporate	—	78	2	80
Other:				
Hedge funds	—	—	143	143
Private equity funds	—	—	29	29
Real estate funds	6	—	14	20
Diversified commodities funds	—	11	—	11
	$ 382	$ 496	$ 194	$1,072

(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. The short-term investment funds provide for daily investments and redemptions and are valued and carried at a $1 net asset value (NAV) per fund share.

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 are traded actively on exchanges and price quotes for these shares are readily available. Individual equity securities are classified as Level 1. Commingled fund values reflect the NAV per fund share, derived from the quoted prices in active markets of the underlying securities. Equity commingled funds 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. Such prices are monitored and provided by an independent, third-party custodial firm responsible for safekeeping plan assets. Individual fixed income securities are classified as Level 2 or 3. Commingled fund values reflect the NAV per fund share, derived indirectly from observable inputs or from quoted prices in less liquid markets of the underlying securities. Fixed income commingled funds 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.

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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 (Millions of dollars)	Real Estate Funds	Total
Balance at January 1, 2010	**$ 8**	**$ 143**	**$ 29**	**$ 14**	**$ 194**
Actual return on plan assets:					
Related to assets held at December 31, 2010	**—**	**6**	**1**	**1**	**8**
Related to assets sold during 2010	**—**	**—**	**—**	**—**	**—**
Purchases, sales or other settlements	**1**	**38**	**10**	**17**	**66**
Net transfers in (out) of Level 3	**(2)**	**—**	**—**	**—**	**(2)**
Balance at December 31, 2010	**$ 7**	**$ 187**	**$ 40**	**$ 32**	**$ 266**
Balance at January 1, 2009	$ 12	$ 127	$ 25	$ 20	$ 184
Actual return on plan assets:					
Related to assets held at December 31, 2009	4	15	(4)	(7)	8
Related to assets sold during 2009	(1)	1	—	—	—
Purchases, sales or other settlements	(2)	—	8	1	7
Net transfers in (out) of Level 3	(5)	—	—	—	(5)
Balance at December 31, 2009	$ 8	$ 143	$ 29	$ 14	$ 194

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

The Corporation has budgeted contributions of approximately $190 million to its funded pension plans in 2011.

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

2011	$ 81
2012	79
2013	88
2014	91
2015	98
Years 2016 to 2020	612

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 $24 million in 2010 and 2009, and $22 million in 2008 for contributions to these plans.

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

13. Income Taxes

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

	2010	2009	2008
		(Millions of dollars)	
United States Federal			
Current	**$ 151**	$ 39	$ 10
Deferred	**(309)**	(284)	(140)
State	**46**	(15)	10
	(112)	(260)	(120)
Foreign			
Current	**1,515**	1,143	2,377
Deferred	**(230)**	(168)	87
	1,285	975	2,464
Adjustment of deferred tax liability for foreign income tax rate change	**—**	—	(4)
Total provision for income taxes	**$1,173**	$ 715	$ 2,340

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

	2010	2009	2008
		(Millions of dollars)	
United States*	**$ (108)**	$ (711)	$ (349)
Foreign**	**3,419**	2,233	5,046
Total income before income taxes	**$3,311**	$1,522	$4,697

* *Includes substantially all of the Corporation's interest expense and the results of hedging activities.*

** *Foreign income includes the Corporation's Virgin Islands and other operations located outside of the United States.*

A summary of the components of deferred tax liabilities, deferred tax assets and taxes deferred at December 31 follows:

	2010	2009
	(Millions of dollars)	
Deferred tax liabilities		
Property, plant and equipment and investments	**$3,853**	$ 3,021
Deferred taxes on undistributed earnings of foreign subsidiaries	—	174
Other	**52**	13
Total deferred tax liabilities	**3,905**	3,208
Deferred tax assets		
Net operating loss carryforwards	**896**	529
Tax credit carryforwards	**244**	860
Property, plant and equipment	**1,679**	1,575
Accrued liabilities	**391**	459
Asset retirement obligations	**369**	484
Other	**302**	339
Total deferred tax assets	**3,881**	4,246
Valuation allowance	**(444)**	(500)
Total deferred tax assets, net	**3,437**	3,746
Net deferred tax assets (liabilities)	**$ (468)**	$ 538

Net deferred tax assets in the foregoing table include the deferral of the tax consequences, including the utilization of net operating loss carryforwards and tax credits in the United States during 2009 and 2010, resulting from intercompany transactions eliminated in consolidation related to transfers of property, plant and equipment remaining within the consolidated group. At December 31, 2010, the Corporation has recognized a gross deferred tax asset, before application of valuation allowance, of $896 million related to net operating loss carryforwards. This is comprised of approximately $101 million attributable to United States federal income tax which begin to expire in 2020, $165 million attributable to various states which begin to expire in 2011, and $630 million attributable to foreign jurisdictions which begin to expire in 2020. At December 31, 2010, the Corporation has federal, state and foreign alternative minimum tax credit carryforwards of approximately $126 million, which can be carried forward indefinitely and approximately $1 million of other business credit carryforwards. Foreign tax credit carryforwards, which expire in 2019, total $117 million.

In the consolidated balance sheet at December 31, deferred tax assets and liabilities from the preceding table are netted by taxing jurisdiction, combined with taxes deferred on intercompany transactions, and are recorded in the following captions:

	2010	2009
	(Millions of dollars)	
Other current assets	**$ 386**	$ 372
Deferred income taxes (long-term asset)	**2,167**	2,409
Accrued liabilities	**(26)**	(21)
Deferred income taxes (long-term liability)	**(2,995)**	(2,222)
Net deferred tax assets (liabilities)	**$ (468)**	$ 538

The difference between the Corporation's effective income tax rate and the United States statutory rate is reconciled below:

	2010	2009	2008
United States statutory rate	**35.0%**	35.0%	35.0%
Effect of foreign operations	**9.4**	15.2	12.7
State income taxes, net of Federal income tax	**0.9**	(1.2)	0.1
Gains on asset sales	**(10.4)**	—	—
Impairment of equity investment	**3.1**	—	—
Other	**(2.6)**	(2.0)	2.0
Total	**35.4%**	47.0%	49.8%

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

	2010	2009
	(Millions of dollars)	
Balance at January 1	**$ 271**	$ 175
Additions based on tax positions taken in the current year	**152**	106
Additions based on tax positions of prior years	**57**	25
Reductions based on tax positions of prior years	**(2)**	(3)
Reductions due to settlements with taxing authorities	**(77)**	(20)
Reductions due to lapse of statutes of limitation	**(1)**	(12)
Balance at December 31	**$ 400**	$ 271

At December 31, 2010, the unrecognized tax benefits include $294 million, which if recognized, would affect 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 $40 million to $50 million due to settlements with taxing authorities. The Corporation had accrued interest and penalties related to unrecognized tax benefits of approximately $16 million as of December 31, 2010 and approximately $17 million as of December 31, 2009.

The Corporation has not recognized deferred income taxes for that portion of undistributed earnings of foreign subsidiaries expected to be indefinitely reinvested in foreign operations. The Corporation had undistributed earnings from foreign subsidiaries expected to be indefinitely reinvested in foreign operations of approximately $4.5 billion at December 31, 2010. If these earnings were not indefinitely reinvested, a deferred tax liability of approximately $1.6 billion would be recognized, not accounting for the potential utilization of foreign tax credits in the United States.

The Corporation and its subsidiaries file income tax returns in the United States 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 2010, 2009 and 2008 amounted to $1,450 million, $1,177 million and $2,420 million, respectively.

14. Outstanding and Weighted Average Common Shares

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

	2010	2009	2008
		(Thousands of shares)	
Balance at January 1	**327,229**	326,133	320,600
Issued for an acquisition*	**8,602**	—	—
Activity related to restricted common stock awards, net	**770**	680	1,148
Employee stock options	**1,080**	416	3,852
Conversion of preferred stock	**—**	—	533
Balance at December 31	**337,681**	327,229	326,133

* *See Note 2, Acquisitions and Divestitures.*

During 2008, the Corporation's remaining 284,139 outstanding shares of 3% cumulative convertible preferred shares were converted into common stock at a conversion rate of 1.8783 shares of common stock for each preferred share. The Corporation issued approximately 533,000 shares of common stock for the conversion of these preferred shares and fractional shares were settled by cash payments.

The weighted average number of common shares used in the basic and diluted earnings per share computations for each year is summarized below:

	2010	2009	2008
		(Thousands of shares)	
Common shares — basic	**325,999**	323,890	320,803
Effect of dilutive securities			
Stock options	**829**	836	2,870
Restricted common stock	**1,449**	1,239	1,815
Convertible preferred stock	**—**	—	359
Common shares — diluted	**328,277**	325,965	325,847

The calculation of weighted average common shares excludes the effect of 5,157,000, 4,050,000 and 425,000 out-of-the-money options for 2010, 2009 and 2008, respectively. Cash dividends on common stock totaled $0.40 per share ($0.10 per quarter) during 2010, 2009 and 2008.

15. 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, 2010, 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):

2011	$ 410
2012	421
2013	419
2014	377
2015	181
Remaining years	1,269
Total minimum lease payments	3,077
Less: income from subleases	58
Net minimum lease payments	$ 3,019

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

Rental expense was as follows:

	2010	2009	2008
	(Millions of dollars)		
Total rental expense	**$273**	$266	$ 270
Less: income from subleases	**13**	11	12
Net rental expense	**$ 260**	$255	$258

16. 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 products and electricity, as well as to changes in interest rates and foreign currency values. In the disclosures that follow these activities are referred to as energy marketing and corporate risk management activities. The Corporation also has trading operations, principally through a 50% voting interest in a consolidated partnership, that are exposed to commodity price risks primarily related to the prices of crude oil, natural gas, electricity, refined products, and energy-related securities.

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 use of new instruments or commodities. Risk limits are monitored and reported on daily to business units and to senior management. The Corporation's risk management department also performs independent verifications 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 foreign exchange and interest rate hedging programs.

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 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.

Energy Marketing Activities: In its energy marketing activities the Corporation sells refined petroleum products, natural gas and electricity principally to commercial and industrial businesses at fixed and floating prices for varying periods of time. Commodity contracts such as futures, forwards, swaps and options, together with physical assets such as storage and pipeline capacity, are used to obtain supply and reduce margin volatility or lower costs related to sales contracts with customers.

The table below shows the gross volume of the Corporation's energy marketing commodity contracts outstanding:

	At December 31,	
	2010	**2009**
Commodity Contracts		
Crude oil and refined products (millions of barrels)	**30**	34
Natural gas (millions of mcf)	**2,210**	1,876
Electricity (millions of megawatt hours)	**301**	166

The changes in fair value of certain energy marketing commodity contracts that are not designated as hedges are recognized currently in earnings. Revenues from the sales contracts are recognized in Sales and other operating revenues, supply contract purchases are recognized in Cost of products sold and net settlements from financial derivatives related to these energy marketing activities are recognized in Cost of products sold. Net realized and unrealized pre-tax gains on derivative contracts not designated as hedges amounted to $247 million in 2010 and $102 million in 2009.

At December 31, 2010, a portion of energy marketing commodity contracts are designated as cash flow hedges to hedge variability of expected future cash flows of forecasted supply transactions. The length of time over which the Corporation hedges exposure to variability in future cash flows is predominantly one year or less. For contracts outstanding at December 31, 2010, the maximum duration was approximately three years. The Corporation records the effective portion of changes in the fair value of cash flow hedges as a component of other comprehensive income. Amounts recorded in Accumulated other comprehensive income are reclassified into Cost of products sold in the same period that the hedged item is recognized in earnings. The ineffective portion of changes in fair value of cash flow hedges is recognized immediately in Cost of products sold.

At December 31, 2010, the after-tax deferred losses relating to energy marketing activities recorded in Accumulated other comprehensive income were $147 million ($303 million at December 31, 2009). The Corporation estimates that approximately $104 million of this amount will be reclassified into earnings over the next twelve months. During 2010, 2009 and 2008, the Corporation reclassified after-tax income (losses) from Accumulated other comprehensive income of $(318) million, $(596) million and $112 million, respectively. The amount of gain (loss) from hedge ineffectiveness reflected in earnings in 2010, 2009 and 2008 was $2 million, $(2) million and $1 million. The fair value of energy marketing cash flow hedge positions decreased by $164 million in 2010, $564 million in 2009 and $255 million in 2008. The pre-tax amount of deferred hedge losses is reflected in Accounts payable and the related income tax benefits are recorded as Deferred income tax assets on the balance sheet.

Corporate Risk Management: Corporate risk management activities include transactions designed to reduce risk in the selling prices of crude oil, refined products 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, refined products 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 table below shows the gross volume of Corporate risk management derivative instruments outstanding:

	At December 31, 2010	2009
Commodity contracts, primarily crude oil (millions of barrels)*	**35**	54
Foreign exchange contracts (millions of U.S. Dollars)	**1,025**	872
Interest rate swaps (millions of U.S. Dollars)	**310**	—

* *Principally reflects volumes associated with the offsetting crude oil positions.*

During 2008, the Corporation closed Brent crude oil cash flow hedges covering 24,000 barrels per day through 2012, by entering into offsetting contracts with the same counterparty. As a result, the valuation of those contracts is no longer subject to change due to price fluctuations. There were no other open hedges of crude oil or natural gas production at December 31, 2010. Hedging activities decreased Exploration and Production Sales and other operating revenue by $338 million in 2010, $337 million in 2009 and $423 million in 2008.

At December 31, 2010, the after-tax deferred losses in Accumulated other comprehensive income relating to the closed Brent crude oil hedges were $638 million ($941 million at December 31, 2009). The Corporation estimates that approximately $330 million of this amount will be reclassified into earnings over the next twelve months. The pre-tax amount of deferred hedge losses is reflected in Accounts payable and the related income tax benefits are recorded as Deferred income tax assets on the balance sheet.

At December 31, 2010, the Corporation had interest rate swaps with a gross notional amount of $310 million, 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. For the year ended December 31, 2010, the Corporation recorded an increase of $8 million in the fair value of interest rate swaps and a corresponding increase in the carrying value of the hedged fixed-rate debt.

Foreign exchange contracts are not designated as hedges. Gains or losses on foreign exchange contracts are recognized immediately in Other, net in Revenues and non-operating income.

Net pre-tax gains (losses) on derivative contracts used for Corporate risk management and not designated as hedges amounted to the following:

	Year Ended December 31, 2010	2009
	(Millions of dollars)	
Commodity	**$ (7)**	$ 9
Foreign exchange	**(7)**	86
Total	**$ (14)**	$ 95

Trading Activities: Trading activities are conducted principally through a trading partnership in which the Corporation has a 50% voting interest. This consolidated entity intends to generate earnings through various strategies primarily using energy commodities, securities and derivatives. The Corporation also takes trading positions for its own account.

The table below shows the gross volume of derivative instruments outstanding relating to trading activities:

	At December 31,	
	2010	**2009**
Commodity Contracts		
Crude oil and refined products (millions of barrels)	**3,328**	2,251
Natural gas (millions of mcf)	**4,699**	6,927
Electricity (millions of megawatt hours)	**79**	6
Other Contracts (millions of U.S. Dollars)		
Interest rate	**205**	495
Foreign exchange	**506**	335

Pre-tax gains (losses) recorded in Sales and other operating revenues from trading activities amounted to the following:

	Year Ended December 31,	
	2010	**2009**
	(Millions of dollars)	
Commodity	**$ 88**	$ 196
Foreign exchange	**5**	23
Interest rate and other	**10**	17
Total	**$ 103**	$ 236

Fair Value Measurements: The Corporation determines fair value in accordance with the fair value measurements accounting standard (ASC 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).

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 Level 2 and 3 derivatives 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, 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 financial asset or liability presented below is based on the lowest significant input level within this fair value hierarchy.

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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

	Level 1	Level 2	Level 3	Collateral and counterparty netting	Balance
			(Millions of dollars)		
December 31, 2010					
Assets					
Derivative contracts					
Commodity	$ 65	$ 1,308	$ 883	$ (304)	$ 1,952
Foreign exchange	—	1	—	—	1
Other	—	17	—	—	17
Collateral and counterparty netting	(1)	(274)	(19)	(213)	(507)
Total derivative contracts	64	1,052	864	(517)	1,463
Other assets measured at fair value on a recurring basis	20	49	3	—	72
Total assets	$ 84	$ 1,101	$ 867	$ (517)	$ 1,535
Liabilities					
Derivative contracts					
Commodity	$ (324)	$ (2,519)	$ (474)	$ 304	$ (3,013)
Foreign exchange	—	(12)	—	—	(12)
Other	—	(10)	—	—	(10)
Collateral and counterparty netting	1	274	19	34	328
Total derivative contracts	(323)	(2,267)	(455)	338	(2,707)
Other liabilities measured at fair value on a recurring basis	—	—	—	—	—
Total liabilities	$ (323)	$ (2,267)	$ (455)	$ 338	$ (2,707)

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	Level 1	Level 2	Level 3	Collateral and counterparty netting	Balance
			(Millions of dollars)		
December 31, 2009					
Assets					
Derivative contracts					
Commodity	$ 46	$ 1,137	$ 119	$ (40)	$ 1,262
Other	—	3	—	—	3
Collateral and counterparty netting	—	(1)	—	(326)	(327)
Total derivative contracts	46	1,139	119	(366)	938
Other assets measured at fair value on a recurring basis	37	21	5	—	63
Total assets	$ 83	$ 1,160	$ 124	$ (366)	$ 1,001
Liabilities					
Derivative contracts					
Commodity	$ (151)	$ (2,880)	$ (36)	$ 40	$ (3,027)
Foreign exchange	—	(23)	—	—	(23)
Other	—	(8)	—	—	(8)
Collateral and counterparty netting	—	1	—	280	281
Total derivative contracts	(151)	(2,910)	(36)	320	(2,777)
Other liabilities measured at fair value on a recurring basis	—	(66)	(4)	—	(70)
Total liabilities	$ (151)	$(2,976)	$ (40)	$ 320	$ (2,847)

The following table provides changes in financial assets and liabilities that are measured at fair value based on Level 3 inputs:

	Year Ended December 31, 2010	Year Ended December 31, 2009
	(Millions of dollars)	
Balance at beginning of period	**$ 84**	$ 149
Unrealized gains (losses)		
Included in earnings	**169**	103
Included in other comprehensive income	**101**	15
Purchases, sales or other settlements during the period	**83**	(144)
Transfers into Level 3	**30**	—
Transfers out of Level 3	**(55)**	(39)
Balance at end of period	**$ 412**	$ 84

Effective January 1, 2010, the Corporation’s policy is to recognize transfers in and transfers out as of the end of each reporting period. During the year ended December 31, 2010, transfers into Level 1 and Level 2 were net assets of $14 million and $312 million, respectively, and transfers out of Level 1 and Level 2 were net assets of $28 million and net liabilities of $329 million, respectively. Transfers into Level 1 and 2 from Levels 2 and 3, respectively primarily resulted from instruments that became more actively traded as they moved closer to maturity. Transfers into Level 2 and 3 from Levels 1 and 2, respectively were due to the increased significance of the lower level inputs to the instrument's fair value.

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, 2010 and December 31, 2009. Fixed-rate, long-term debt had a carrying value of $5,569 million compared with a fair value of $6,353 million at December 31, 2010, and a carrying value of $4,467 million compared with a fair value of $5,073 million at December 31, 2009.

The table below reflects the gross and net fair values of the Corporation's risk management and trading derivative instruments:

	Accounts Receivable	Accounts Payable
	(Millions of dollars)	
December 31, 2010		
Derivative contracts designated as hedging instruments		
Commodity	**$ 225**	**$ (483)**
Other	**10**	**(2)**
Total derivative contracts designated as hedging instruments	**235**	**(485)**
Derivative contracts not designated as hedging instruments*		
Commodity	**11,581**	**(12,383)**
Foreign exchange	**7**	**(19)**
Other	**31**	**(32)**
Total derivative contracts not designated as hedging instruments	**11,619**	**(12,434)**
Gross fair value of derivative contracts	**11,854**	**(12,919)**
Master netting arrangements	**(10,178)**	**10,178**
Cash collateral (received) posted	**(213)**	**34**
Net fair value of derivative contracts	**$ 1,463**	**$ (2,707)**
December 31, 2009		
Derivative contracts designated as hedging instruments		
Commodity	$ 748	$ (1,166)
Derivative contracts not designated as hedging instruments*		
Commodity	9,145	(10,493)
Foreign exchange	3	(26)
Other	12	(14)
Total derivative contracts not designated as hedging instruments	9,160	(10,533)
Gross fair value of derivative contracts	9,908	(11,699)
Master netting arrangements	(8,653)	8,653
Cash collateral (received) posted	(317)	269
Net fair value of derivative contracts	$ 938	$ (2,777)

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

The Corporation generally enters into master netting arrangements to mitigate counterparty credit risk. Master netting arrangements are standardized contracts that govern all specified transactions with the same counterparty and allow the Corporation to terminate all contracts upon occurrence of certain events, such as a counterparty's default or bankruptcy. Where these arrangements provide the right of offset and the Corporation's intent and practice is to offset amounts in the case of contract terminations, the Corporation records fair value on a net basis.

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. The Corporation's net receivables at December 31, 2010 are concentrated with the following counterparty and customer industry segments: Integrated Oil Companies — 22%, Government Entities — 14%, Manufacturing — 10% and Services — 10%. 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, 2010 and 2009, the Corporation held cash from counterparties of $213 million and $317 million, respectively. The Corporation posted cash to counterparties at December 31, 2010 and 2009 of $34 million and $269 million, respectively.

At December 31, 2010, the Corporation had a total of $2,082 million of outstanding letters of credit, primarily issued to satisfy margin requirements. 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, 2010, the net liability related to derivatives with contingent collateral provisions was approximately $1,692 million before cash collateral posted of approximately $16 million. At December 31, 2010, all three major credit rating agencies that rate the Corporation's debt had assigned an investment grade rating. If two of the three agencies were to downgrade the Corporation's rating to below investment grade, as of December 31, 2010, the Corporation would be required to post additional collateral of approximately $385 million.

17. Guarantees and Contingencies

At December 31, 2010, the Corporation's guarantees include $150 million of HOVENSA's crude oil purchases and $15 million of HOVENSA's senior debt obligations. In addition, the Corporation has $81 million in letters of credit for which it is contingently liable. As a result, the maximum potential amount of future payments that the Corporation could be required to make under its guarantees is $246 million at December 31, 2010 ($236 million at December 31, 2009). The Corporation also has a contingent purchase obligation expiring in April 2012, to acquire the remaining interest in WilcoHess, a retail gasoline station joint venture. As of December 31, 2010, the estimated value of the purchase obligation is approximately $190 million.

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 is 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, additional cases were settled, and three new cases were filed. The six unresolved cases consist of five cases that have been consolidated for pre-trial purposes in the Southern District of New York as part of a multi-district litigation proceeding and an action brought in state court by the State of New Hampshire. In 2007, a pre-tax charge of $40 million was recorded to cover all of the known MTBE cases against the Corporation.

Over the last several years, many refiners have entered into consent agreements to resolve the United States Environmental Protection Agency's (EPA) assertions that refining facilities were modified or expanded without complying with New Source Review regulations that require permits and new emission controls in certain circumstances and other regulations that impose emissions control requirements. These consent agreements, which arise out of an EPA enforcement initiative focusing on petroleum refiners and utilities, have typically imposed substantial civil fines and penalties and required (i) significant capital expenditures to install emissions control equipment over a three to eight year time period and (ii) changes to operations which resulted in increased operating costs. The capital expenditures, penalties and supplemental environmental projects for individual refineries covered by the settlements can vary significantly, depending on the size and configuration of the refinery, the circumstances of the alleged modifications and whether the refinery has previously installed more advanced pollution controls. In January 2011, HOVENSA signed a Consent Decree with EPA to resolve its claims. Under the terms of the Consent Decree, HOVENSA will pay a penalty of approximately $5 million and spend approximately $700 million over the next 10 years to install equipment and implement additional operating procedures at the HOVENSA refinery to reduce emissions. In addition, the Consent Decree requires HOVENSA to spend approximately $5 million to fund an environmental project to be determined at a later date by the Virgin Islands and $500,000 to assist the Virgin Islands Water and Power Authority with monitoring. The Consent Decree has been lodged with the United States District Court for the Virgin Islands and approval is pending. In addition, substantial progress has been made towards resolving this matter for the Port Reading refining facility, which is not expected to have a material adverse impact on the Corporation's financial position or results of operations.

The United States Deep Water Royalty Relief Act of 1995 (the Act) implemented a royalty relief program that relieves eligible leases issued between November 28, 1995 and November 28, 2000 from paying royalties on deepwater production in Federal Outer Continental Shelf lands. The Act does not impose any price thresholds in order to qualify for the royalty relief. The U.S. Minerals Management Service (MMS, predecessor to the Bureau of Ocean Energy Management, Regulation and Enforcement) created regulations that included pricing requirements to qualify for the royalty relief provided in the Act. During the period from 2003 to 2009, the Corporation accrued the royalties imposed by the MMS regulations. The legality of the thresholds imposed by the MMS was challenged in the federal courts and, in October 2009, the U.S. Supreme Court decided not to review the appellate court's decision against the MMS. As a result, the Corporation recognized a pre-tax gain of $143 million ($89 million after income taxes) in 2009 to reverse all previously recorded royalties. The pre-tax gain is reported in Other, net within the Statement of Consolidated Income.

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 will not have a material adverse effect on the financial condition of the Corporation, although the outcome of such proceedings could be material to the Corporation's results of operations and cash flows for a particular period depending on, among other things, the level of the Corporation's net income for such period.

18. Segment Information

The Corporation has two operating segments that comprise the structure used by senior management to make key operating decisions and assess performance. These are (1) Exploration and Production and (2) Marketing and Refining. The Exploration and Production segment explores for, develops, produces, purchases, transports and sells crude oil and natural gas. The Marketing and Refining segment manufactures refined petroleum products and purchases, markets and trades refined petroleum products, natural gas and electricity.

The following table presents financial data by operating segment for each of the three years ended December 31:

	Exploration and Production	Marketing and Refining	Corporate and Interest	Consolidated(a)
	(Millions of dollars)			
2010				
Operating revenues				
Total operating revenues(b)	$ 9,119	$ 24,885	$ 1	
Less: Transfers between affiliates	143	—	—	
Operating revenues from unaffiliated customers	$ 8,976	$ 24,885	$ 1	$ 33,862
Net income (loss) attributable to Hess Corporation	$ 2,736	$ (231)	$ (380)	$ 2,125
Income (loss) from equity investment in HOVENSA L.L.C.	$ —	$ (522)	$ —	$ (522)
Interest expense	—	—	361	361
Depreciation, depletion and amortization	2,222	82	13	2,317
Asset impairments	532	—	—	532
Provision (benefit) for income taxes	1,417	4	(248)	1,173
Investments in affiliates	57	386	—	443
Identifiable assets	28,242	6,377	777	35,396
Capital employed(c)	19,803	2,715	(126)	22,392
Capital expenditures	5,394	82	16	5,492

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	Exploration and Production	Marketing and Refining	Corporate and Interest	Consolidated(a)
		(Millions of dollars)		
2009				
Operating revenues				
Total operating revenues(b)	$ 7,259	$ 22,464	$ 1	
Less: Transfers between affiliates	110	—	—	
Operating revenues from unaffiliated customers	$ 7,149	$ 22,464	$ 1	$ 29,614
Net income (loss) attributable to Hess Corporation	$ 1,042	$ 127	$ (429)	$ 740
Income (loss) from equity investment in HOVENSA L.L.C.	$ —	$ (229)	$ —	$ (229)
Interest expense	—	—	360	360
Depreciation, depletion and amortization	2,113	79	8	2,200
Asset impairments	54	—	—	54
Provision (benefit) for income taxes	944	24	(253)	715
Investments in affiliates	57	856	—	913
Identifiable assets	21,810	6,388	1,267	29,465
Capital employed(c)	14,163	2,979	853	17,995
Capital expenditures	2,800	83	35	2,918
2008				
Operating revenues				
Total operating revenues(b)	$ 10,095	$ 31,273	$ 3	
Less: Transfers between affiliates	237	—	—	
Operating revenues from unaffiliated customers	$ 9,858	$ 31,273	$ 3	$ 41,134
Net income (loss) attributable to Hess Corporation	$ 2,423	$ 277	$ (340)	$ 2,360
Income (loss) from equity investment in HOVENSA L.L.C.	$ —	$ 44	$ —	$ 44
Interest expense	—	—	267	267
Depreciation, depletion and amortization	1,922	74	3	1,999
Asset impairments	30	—	—	30
Provision (benefit) for income taxes	2,365	162	(187)	2,340
Investments in affiliates	57	1,070	—	1,127
Identifiable assets	19,506	6,680	2,403	28,589
Capital employed(c)	12,945	3,178	223	16,346
Capital expenditures	4,251	149	38	4,438

(a) After elimination of transactions between affiliates, which are valued at approximate market prices.

(b) Sales and operating revenues are reported net of excise and similar taxes in the consolidated statement of income, which amounted to approximately $2,200 million, $2,100 million and $2,200 million in 2010, 2009 and 2008, respectively.

(c) Calculated as equity plus debt.

Financial information by major geographic area for each of the three years ended December 31, 2010:

	United States	Europe	Africa	Asia and Other	Consolidated
			(Millions of dollars)		
2010					
Operating revenues	**$ 28,066**	**$ 2,109**	**$ 2,271**	**$ 1,416**	**$ 33,862**
Property, plant and equipment (net)	**8,343**	**6,764***	**2,573**	**3,447**	**21,127**
2009					
Operating revenues	$ 24,611	$ 1,771	$ 1,898	$ 1,334	$ 29,614
Property, plant and equipment (net)	5,792	3,930*	3,617	3,288	16,627
2008					
Operating revenues	$ 33,202	$ 3,488	$ 3,173	$ 1,271	$ 41,134
Property, plant and equipment (net)	5,319	3,674*	4,139	3,139	16,271

* *Of the total Europe property, plant and equipment (net), Norway represented $5,002 million, $2,049 million and $1,372 million in 2010, 2009 and 2008, respectively.*

19. Related Party Transactions

The following table presents the Corporation's related party transactions for the year-ended December 31:

	2010	2009	2008
		(Millions of dollars)	
Purchases of petroleum products:			
HOVENSA*	**$ 4,307**	$ 3,659	$ 6,589
Sales of petroleum products and crude oil:			
WilcoHess	**2,113**	1,634	2,590
HOVENSA	**607**	530	701

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

	2010	2009
	(Millions of dollars)	
WilcoHess	**$ 110**	$ 82
HOVENSA, net	**(107)**	36

* *Corporation has agreed to purchase 50% of HOVENSA's production of refined products at market prices, after sales by HOVENSA to unaffiliated parties.*

20. Subsequent Event

In February 2011, the Corporation completed the previously announced sale of a package of natural gas producing assets in the United Kingdom North Sea including its interests in the Easington Catchment Area, the Bacton Area, the Everest Field and the Lomond Field for approximately $350 million, after closing adjustments. The sale of the Corporation's interest in the CATS pipeline is expected to close in the second quarter of 2011.

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.

The Corporation produces crude oil, natural gas liquids and/or natural gas principally in Algeria, Azerbaijan, Denmark, Equatorial Guinea, Gabon (until September 2010), Indonesia, Libya, Malaysia, Norway, Russia, Thailand, the United Kingdom and the United States. Exploration activities are also conducted, or are planned, in 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
			(Millions of dollars)		
2010					
Property acquisitions(a)					
Unproved	**$ 1,887**	**$ 1,849**	**$ 38**	**$ —**	**$ —**
Proved	**1,015**	**443**	**572**	**—**	**—**
Exploration	**915**	**185**	**58**	**164**	**508**
Production and development capital expenditures(b)	**2,654**	**1,088**	**850**	**289**	**427**
2009					
Property acquisitions					
Unproved	$ 188	$ 184	$ 2	$ —	$ 2
Proved	74	—	—	—	74
Exploration	938	206	69	225	438
Production and development capital expenditures(b)	1,918	807	513	255	343
2008					
Property acquisitions					
Unproved	$ 684	$ 642	$ —	$ —	$ 42
Proved	300	87	—	210	3
Exploration	1,134	408	121	275	330
Production and development capital expenditures(b)	2,867	1,042	881	451	493

(a) Includes wells, equipment and facilities acquired with proved reserves and excludes properties acquired in non-cash property exchanges. In 2010, acquisitions include $652 million, representing the non-cash portion of the purchase price for American Oil & Gas Inc., primarily through the issuance of common stock.

(b) Includes $62 million, $(9) million and $344 million in 2010, 2009 and 2008, respectively, related to the accruals and revisions for asset retirement obligations except obligations acquired in non-cash property exchanges.

(c) In 2010, costs incurred in oil and gas producing activities in Norway, excluding non-monetary exchanges, were as follows (millions of dollars):

Property acquisitions(a)	
Unproved	*$ 14*
Proved	*572*
Exploration	*12*
Production and development capital expenditures(b)	*469*

Capitalized Costs Relating to Oil and Gas Producing Activities

	At December 31, 2010	2009
	(Millions of dollars)	
Unproved properties	$ 3,796	$ 2,347
Proved properties	3,496	3,121
Wells, equipment and related facilities	26,064	22,118
Total costs	33,356	27,586
Less: reserve for depreciation, depletion, amortization and lease impairment	13,553	12,273
Net capitalized costs	$19,803	$ 15,313

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, 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 Exploration and Production operations reported in Management's Discussion and Analysis of Financial Condition and Results of Operations and in Note 18, Segment Information, in the notes to the financial statements.

For the Years Ended December 31	Total	United States	Europe(a)	Africa	Asia and Other
			(Millions of dollars)		
2010					
Sales and other operating revenues					
Unaffiliated customers	$ 8,601	$2,310	$ 2,251	$2,750	$ 1,290
Inter-company	143	143	—	—	—
Total revenues	8,744	2,453	2,251	2,750	1,290
Costs and expenses					
Production expenses, including related taxes	1,924	489	727	455	253
Exploration expenses, including dry holes and lease impairment(b)	865	364	49	143	309
General, administrative and other expenses	281	161	48	20	52
Depreciation, depletion and amortization	2,222	649	463	772	338
Asset impairments	532	—	—	532	—
Total costs and expenses	5,824	1,663	1,287	1,922	952
Results of operations before income taxes	2,920	790	964	828	338
Provision for income taxes	1,583	305	477	580	221
Results of operations	$1,337	$ 485	$ 487	$ 248	$ 117

For the Years Ended December 31	Total	United States	Europe	Africa	Asia and Other
			(Millions of dollars)		
2009					
Sales and other operating revenues					
Unaffiliated customers	$ 6,725	$ 1,501	$ 1,827	$ 2,193	$ 1,204
Inter-company	110	110	—	—	—
Total revenues	6,835	1,611	1,827	2,193	1,204
Costs and expenses					
Production expenses, including related taxes(c)	1,805	431	642	480	252
Exploration expenses, including dry holes and lease impairment	829	383	75	159	212
General, administrative and other expenses	255	130	45	22	58
Depreciation, depletion and amortization	2,113	503	419	821	370
Asset impairments	54	—	54	—	—
Total costs and expenses	5,056	1,447	1,235	1,482	892
Results of operations before income taxes	1,779	164	592	711	312
Provision for income taxes	904	64	185	514	141
Results of operations	$ 875	$ 100	$ 407	$ 197	$ 171
2008					
Sales and other operating revenues					
Unaffiliated customers	$9,569	$ 1,415	$ 3,435	$ 3,580	$1,139
Inter-company	237	237	—	—	—
Total revenues	9,806	1,652	3,435	3,580	1,139
Costs and expenses					
Production expenses, including related taxes(d)	1,872	373	811	465	223
Exploration expenses, including dry holes and lease impairment	725	305	45	186	189
General, administrative and other expenses	302	159	86	19	38
Depreciation, depletion and amortization	1,922	225	574	888	235
Asset impairments	30	13	17	—	—
Total costs and expenses	4,851	1,075	1,533	1,558	685
Results of operations before income taxes	4,955	577	1,902	2,022	454
Provision for income taxes	2,490	223	920	1,181	166
Results of operations	$ 2,465	$ 354	$ 982	$ 841	$ 288

(a) In 2010, results of operations for oil and gas producing activities in Norway were as follows (millions of dollars):

Sales and other operating revenues — Unaffiliated customers	*$524*
Costs and expenses	
Production expenses, including related taxes	*149*
Exploration expenses, including dry holes and lease impairment	*12*
General, administrative and other expenses	*9*
Depreciation, depletion and amortization	*133*
Total costs and expenses	*303*
Results of operations before income taxes	*221*
Provision for income taxes	*154*
Results of operations	*$ 67*

(b) Includes $101 million ($64 million after income taxes) for dry hole expense in Egypt and Brazil.

(c) Includes $20 million ($15 million after income taxes) for reductions in carrying value of materials inventory in Equatorial Guinea.

(d) Includes $15 million ($9 million after income taxes) for Gulf of Mexico hurricane related costs.

Oil and Gas Reserves

The Corporation's proved oil and gas reserves are calculated in accordance with SEC regulations and the requirements of the FASB. 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 standard engineering and geoscience methods generally recognized in the petroleum industry. 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 on page 14 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 Senior 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 below). 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 is Mr. Scott Heck, Senior Vice President of E&P Technology. Mr. Heck is a member of the Society of Petroleum Engineers and has over 30 years of experience in the oil and gas industry with a BS degree in Petroleum Engineering. His experience includes over 15 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. Heck manages, focuses on oil and gas industry subsurface and reservoir engineering technologies and evaluation techniques. Mr. Heck is also responsible for the Corporation's Global Reserves group, which is the internal organization responsible for establishing the policies and processes used within the operating units to estimate reserves and perform internal technical reserve audits and reviews.

Reserves Audit

The Corporation engaged the consulting firm of DeGolyer and MacNaughton (D&M) to perform an audit of the internally prepared reserve estimates on certain fields aggregating 76% of 2010 year-end reported reserve quantities on a barrel of oil equivalent basis (80% in 2009). 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 2, 2011, 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, 2010 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 1% of total 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.

Adoption of new SEC requirements in 2009

The SEC issued a final rule on oil and gas reserve estimation and disclosure effective for year-end 2009 reporting. The SEC's final rule was designed to modernize and update the oil and gas reserve disclosure requirements to align them with current industry practices and changes in technology. In January 2010, the FASB issued its final Accounting Standards Update, Extractive Industries — Oil and Gas (ASC 932), which principally conformed existing FASB standards to the new SEC guidelines. Effective with these changes, the product prices used in the estimation of oil and gas reserves were the average oil and gas selling prices during the twelve month period prior to the reporting date determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, except for prices set in contractual arrangements. In 2008, reserves were estimated using year-end oil and gas prices.

Since it was not practical to calculate reserve estimates under both the old and new reserve estimation standards as of year-end 2009, it was not possible to precisely measure the effect of adopting the new SEC requirements on total proved reserves. However, the Corporation estimates that the effect of initially applying the new rules, primarily due to application of the new reserve definitions and the consideration of permitted technology, was to increase year-end 2009 total proved reserves by approximately 2%. The change in reserve estimates resulting from applying the new rules is included in the table below as 2009 revisions and additions to proved reserves.

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Following are the Corporation's proved reserves for the three years ended December 31, 2010:

	Crude Oil, Condensate and Natural Gas Liquids (Millions of barrels)					Natural Gas (Millions of mcf)			
	United States	Europe(g)	Africa	Asia	Total	United States	Europe(g)	Asia and Africa(h)	Total
Net Proved Developed and Undeveloped Reserves									
At January 1, 2008	204	329	285	67	885	270	656	1,742	2,668
Revisions of previous estimates(b)	9	30	83	25	147	22	84	188	294
Extensions, discoveries and other additions	26	5	1	—	32	18	—	65	83
Improved recovery	1	—	—	—	1	—	—	—	—
Purchases of minerals in place	2	—	—	—	2	—	—	—	—
Sales of minerals in place	—	—	—	—	—	—	—	—	—
Production	(15)	(32)	(45)	(5)	(97)	(34)	(101)	(137)	(272)
At December 31, 2008(a)	227	332	324	87	970(c)	276	639	1,858	2,773
Revisions of previous estimates(b)	22	28	34	(7)	77	46	66	83	195
Extensions, discoveries and other additions	26	1	—	—	27	23	—	—	23
Improved recovery	—	—	—	—	—	—	—	—	—
Purchases of minerals in place	—	—	—	—	—	—	—	101	101
Sales of minerals in place	—	—	—	—	—	—	(1)	—	(1)
Production	(26)	(31)	(44)	(6)	(107)	(39)	(62)	(169)	(270)
At December 31, 2009	249	330	314	74	967(c)	306	642	1,873	2,821
Revisions of previous estimates(b)	**68**	**14**	**22**	**(1)**	**103**	**(7)**	**(9)**	**(23)**	**(39)**
Extensions, discoveries and other additions	**3**	**19**	**—**	**1**	**23**	**14**	**15**	**1**	**30**
Improved recovery	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Purchases of minerals in place	**16**	**150**	**—**	**—**	**166**	**13**	**129**	**—**	**142**
Sales of minerals in place	**—**	**(13)**	**(25)**	**(5)**	**(43)**	**—**	**(4)**	**(89)**	**(93)**
Production	**(32)**	**(34)**	**(41)**	**(5)**	**(112)**	**(46)**	**(54)**	**(163)**	**(263)**
At December 31, 2010	**304**	**466**	**270**	**64**	**1,104(c)**	**280(d)**	**719**	**1,599**	**2,598**
Net Proved Developed Reserves(e)									
At January 1, 2008	101	201	201	15	518	199	519	654	1,372
At December 31, 2008	119	192	237	23	571	202	502	727	1,431
At December 31, 2009	154	171	241	27	593	205	417	923	1,545
At December 31, 2010	**180**	**210**	**215**	**22**	**627**	**199**	**424**	**692**	**1,315**
Net Proved Undeveloped Reserves(f)									
At January 1, 2008	103	128	84	52	367	71	137	1,088	1,296
At December 31, 2008	108	140	87	64	399	74	137	1,131	1,342
At December 31, 2009	95	159	73	47	374	101	225	950	1,276
At December 31, 2010	**124**	**256**	**55**	**42**	**477**	**81**	**295**	**907**	**1,283**

(a) Proved reserves in 2008 were determined by D&M, an independent petroleum engineering consulting firm.

(b) Includes the impact of changes in selling prices on the reserve estimates for each year for production sharing contracts with cost recovery provisions. In 2010, revisions included reductions of approximately 11 million barrels of crude oil and 62 million mcf of natural gas relating to higher selling prices. In 2009, revisions included reductions of approximately 18 million barrels of crude oil and 102 million mcf of natural gas relating to higher selling prices. In 2008, revisions included increases of approximately 59 million barrels of crude oil and 104 million mcf of natural gas relating to lower selling prices.

(c) Includes 15 million barrels in 2010, 17 million barrels in 2009 and 16 million barrels in 2008 of crude oil reserves relating to noncontrolling interest owners of corporate joint ventures.

(d) Excludes approximately 340 million mcf of carbon dioxide gas for sale or use in company operations.

(e) Of the total crude oil and natural gas liquids net proved developed reserves at December 31, 2010, 54 million barrels relate to natural gas liquids, 41 million barrels at December 31, 2009, 36 million barrels at December 31, 2008 and 33 million barrels at January 1, 2008.

(f) Of the total crude oil and natural gas liquids net proved undeveloped reserves at December 31, 2010, 48 million barrels relate to natural gas liquids, 30 million barrels at December 31, 2009, 22 million barrels at December 31, 2008 and 21 million barrels at January 1, 2008.

(g) In 2010, proved reserves in Norway were as follows:

	Crude Oil and Natural Gas Liquids (Millions of barrels)	Natural Gas (Millions of mcf)
At January 1, 2010	*136*	*287*
Revisions of previous estimates	*(16)*	*(1)*
Purchases of minerals in place	*150*	*130*
Production	*(6)*	*(12)*
At December 31, 2010	*264*	*404*
Net Proved Developed Reserves at December 31, 2010	*97*	*157*
Net Proved Undeveloped Reserves at December 31, 2010	*167*	*247*

(h) Natural gas reserves in Africa were 63 million mcf in 2010, 71 million mcf in 2009 and 69 million mcf in 2008.

Proved undeveloped reserves

The December 31, 2010 oil and gas reserve estimates disclosed above include 477 million barrels of liquid hydrocarbons and 1,283 million mcf of natural gas, or an aggregate of 691 million barrels of oil equivalent (mmboe), classified as proved undeveloped reserves. Overall volumes of proved undeveloped reserves increased by 104 mmboe compared with year-end 2009. Proved undeveloped reserves increased by 119 mmboe in 2010 from acquisitions in Norway and the Bakken oil shale play in North Dakota. Approximately 30 mmboe of proved undeveloped reserves in Indonesia, Gabon and the United Kingdom were disposed of in asset sales and exchanges. Additions and revisions in proved undeveloped reserves from existing fields amounted to 73 mmboe, primarily in the United States, Denmark, Libya and JDA. These increases resulted from ongoing technical assessments, performance evaluations and development planning. In 2010, 58 mmboe were converted from proved undeveloped reserves to developed resulting from continuing development activity and new wells in Libya, Russia, the Bakken in North Dakota, the Llano Field in the Gulf of Mexico, the Pailin Field in Thailand and the JDA. The Corporation estimates that capital expenditures of approximately $600 million were incurred to convert proved undeveloped reserves to developed during 2010.

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 175 mmboe or 11% of total 2010 proved reserves. Substantially all of the proved undeveloped reserves in excess of five years old relate to five offshore producing assets. Four natural gas projects in the JDA, Indonesia and Norway are being developed in phases to satisfy long-term natural gas sales contracts and an oil project in Azerbaijan is continuing to be developed in phases. A summary of the development status of each of the five projects follows:

- JDA — This natural gas project in the Gulf of Thailand currently has a central processing platform and six wellhead platforms. A seventh wellhead platform is under construction and the operator plans to begin construction of two additional wellhead platforms in 2011.
- Pangkah — This natural gas and oil project offshore Java, Indonesia currently has one producing offshore wellhead platform and onshore production facilities. A second wellhead platform has been installed and is currently supporting drilling operations. In addition, a central processing platform is currently under construction and is expected to be installed in 2011 to expand oil and water handling capacity.
- Natuna A — This natural gas project offshore Sumatra, Indonesia currently has one wellhead platform, a central processing facility and a floating, storage and offloading vessel. The operator is constructing a second wellhead platform and a separate central processing platform which is expected to be in service in 2011. Additional wellhead platforms and subsea well tie-backs are in the field development plan.

- Snohvit — This liquefied natural gas project offshore Norway currently has processing and liquefaction facilities on Melkoya Island with subsea wells tied-back to the facilities. Future development will continue based on available production capacity to meet contracted gas sales volumes.
- ACG — This oil project offshore Azerbaijan in the Caspian Sea has seven operational platforms that have been completed over multiple phases of development. The operator began construction on another production platform in 2010.

Production sharing contracts

The Corporation's proved reserves include crude oil and natural gas reserves relating to long-term supply 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, 2010 are presented separately below, as well as volumes produced and received during 2010, 2009 and 2008 from these production sharing contracts.

	Crude Oil, Condensate and Natural Gas Liquids (Millions of barrels)					Natural Gas (Millions of mcf)			
	United States	Europe	Africa	Asia	Total	United States	Europe	Asia and Africa	Total
Production Sharing Contracts									
Proved Reserves*									
At December 31, 2008	—	—	188	82	270	—	—	1,604	1,604
At December 31, 2009	—	—	161	68	229	—	—	1,599	1,599
At December 31, 2010	**—**	**—**	**108**	**57**	**165**	**—**	**—**	**1,316**	**1,316**
Production									
2008	—	—	37	4	41	—	—	103	103
2009	—	—	36	5	41	—	—	136	136
2010	**—**	**—**	**33**	**4**	**37**	**—**	**—**	**130**	**130**

* *Includes natural gas liquids of 7 million barrels in 2010, 11 million barrels in 2009 and 12 million barrels in 2008.*

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
			(Millions of dollars)		
2010					
Future revenues	**$ 91,336**	**$21,112**	**$ 36,157**	**$ 21,150**	**$ 12,917**
Less:					
Future production costs	**21,635**	**6,155**	**9,536**	**3,332**	**2,612**
Future development costs	**13,554**	**3,178**	**6,534**	**1,269**	**2,573**
Future income tax expenses	**30,250**	**4,423**	**11,745**	**12,173**	**1,909**
	65,439	**13,756**	**27,815**	**16,774**	**7,094**
Future net cash flows	**25,897**	**7,356**	**8,342**	**4,376**	**5,823**
Less: discount at 10% annual rate	**10,195**	**3,764**	**3,361**	**1,028**	**2,042**
Standardized measure of discounted future net cash flows	**$ 15,702**	**$ 3,592**	**$ 4,981**	**$ 3,348**	**$ 3,781**
2009					
Future revenues	$65,275	$ 14,047	$ 20,298	$18,615	$12,315
Less:					
Future production costs	18,336	4,037	7,289	4,154	2,856
Future development costs	11,041	2,532	3,829	1,798	2,882
Future income tax expenses	17,976	2,744	5,114	8,601	1,517
	47,353	9,313	16,232	14,553	7,255
Future net cash flows	17,922	4,734	4,066	4,062	5,060
Less: discount at 10% annual rate	6,521	2,106	1,653	841	1,921
Standardized measure of discounted future net cash flows	$ 11,401	$ 2,628	$ 2,413	$ 3,221	$ 3,139
2008					
Future revenues	$ 46,846	$ 9,801	$15,757	$ 12,332	$ 8,956
Less:					
Future production costs	15,884	3,422	5,998	3,763	2,701
Future development costs	10,649	1,983	4,014	1,781	2,871
Future income tax expenses	9,299	1,467	2,741	4,440	651
	35,832	6,872	12,753	9,984	6,223
Future net cash flows	11,014	2,929	3,004	2,348	2,733
Less: discount at 10% annual rate	4,050	1,602	984	493	971
Standardized measure of discounted future net cash flows	$ 6,964	$ 1,327	$ 2,020	$ 1,855	$ 1,762

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* *In 2010, the standardized measure of discounted future net cash flows relating to proved reserves in Norway were as follows (millions of dollars):*

Future revenues	*$23,115*
Less:	
Future production costs	*4,399*
Future development costs	*3,426*
Future income tax expenses	*9,908*
	17,733
Future net cash flows	*5,382*
Less: discount at 10% annual rate	*2,156*
Standardized measure of discounted future net cash flows	*$ 3,226*

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

For the Years Ended December 31	2010	2009	2008
		(Millions of dollars)	
Standardized measure of discounted future net cash flows at beginning of year	**$11,401**	$ 6,964	$ 21,905
Changes during the year			
Sales and transfers of oil and gas produced during the year, net of production costs	**(6,820)**	(5,030)	(7,934)
Development costs incurred during year	**2,592**	1,927	2,523
Net changes in prices and production costs applicable to future production	**7,970**	7,484	(28,627)
Net change in estimated future development costs	**(1,678)**	(227)	(1,056)
Extensions and discoveries (including improved recovery) of oil and gas reserves, less related costs	**356**	426	334
Revisions of previous oil and gas reserve estimates	**1,885**	1,855	1,730
Net purchases (sales) of minerals in place, before income taxes	**3,193**	165	18
Accretion of discount	**2,011**	1,235	4,109
Net change in income taxes	**(5,848)**	(4,061)	13,859
Revision in rate or timing of future production and other changes	**640**	663	103
Total	**4,301**	4,437	(14,941)
Standardized measure of discounted future net cash flows at end of year	**$15,702**	$11,401	$ 6,964

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES

QUARTERLY FINANCIAL DATA
(Unaudited)

Quarterly results of operations for the years ended December 31:

	Sales and Other Operating Revenues	Gross Profit(a)	Net Income (Loss) Attributable to Hess Corporation	Diluted Net Income (Loss) per Share
	(Million of dollars, except per share data)			
2010				
First	**$ 9,259**	**$ 1,395**	**$ 538(b)**	**$ 1.65**
Second	**7,732**	**1,093**	**375**	**1.15**
Third	**7,864**	**672**	**1,154(c)**	**3.52**
Fourth	**9,007**	**1,288**	**58(d)**	**.18**
2009				
First	$ 6,915	$ 533	$ (59)(e)	$ (.18)
Second	6,751	756	100(f)	.31
Third	7,270	832	341(g)	1.05
Fourth	8,678	1,282	358(h)	1.10

(a) Gross profit represents sales and other operating revenues, less cost of products sold, production expenses, marketing expenses, other operating expenses, depreciation, depletion and amortization and asset impairments.

(b) Includes an after-tax gain of $58 million related to an asset sale, partially offset by an after-tax charge of $7 million related to the repurchase of fixed-rate notes.

(c) Includes an after-tax gain of $1,072 million related to an asset exchange, partially offset by after-tax charges of $347 million related to an asset impairment.

(d) Includes an after-tax charge of $289 million relating to the Corporation's impairment of its equity investment in HOVENSA and an after-tax charge of $51 million related to dry hole costs.

(e) Includes after-tax charges of $13 million related to asset impairments in the United Kingdom North Sea and $16 million for retirement benefits and employee severance costs.

(f) Includes after-tax charges of $31 million to reduce the carrying value of production equipment in the United Kingdom North Sea and materials inventory in Equatorial Guinea and the United States.

(g) Includes after-tax gains of $101 million primarily relating to the resolution of a royalty dispute.

(h) Includes after-tax charges of $34 million for the repurchase of fixed-rate notes and $10 million for pension plan settlements related to employee retirements.

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, 2010, 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, 2010.

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, 2010 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 annual meeting of stockholders to be held on May 4, 2011.

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 annual meeting of stockholders to be held on May 4, 2011.

Executive Officers of the Registrant

The following table presents information as of February 1, 2011 regarding executive officers of the Registrant:

Name	Age	Office Held*	Year Individual Became an Executive Officer
John B. Hess	56	Chairman of the Board, Chief Executive Officer and Director	1983
Gregory P. Hill	49	Executive Vice President and President of Worldwide Exploration and Production and Director	2009
F. Borden Walker	57	Executive Vice President and President of Marketing and Refining and Director	1996
Timothy B. Goodell	53	Senior Vice President and General Counsel	2009
Lawrence H. Ornstein	59	Senior Vice President	1995
John P. Rielly	48	Senior Vice President and Chief Financial Officer	2002
John J. Scelfo	53	Senior Vice President	2004
Mykel J. Ziolo	58	Senior Vice President	2009
Robert M. Biglin	46	Vice President and Treasurer	2010

* *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 5, 2010, except for Mr. Biglin, who was elected effective September 1, 2010. The first meeting of Directors following the next annual meeting of stockholders of the Registrant is scheduled to be held May 4, 2011.*

Except for Messrs. Hill and Goodell, 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. Prior to joining the Corporation, Mr. Hill served in senior executive positions in exploration and production operations at Royal Dutch Shell and its subsidiaries, where he was employed for 25 years. Before joining the Corporation in 2009, Mr. Goodell was a partner in the law firm of White & Case LLP.

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 annual meeting of stockholders to be held on May 4, 2011.

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 annual meeting of stockholders to be held on May 4, 2011.

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 annual meeting of stockholders to be held on May 4, 2011.

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 annual meeting of stockholders to be held on May 4, 2011.

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)	By-Laws of Registrant incorporated by reference to Exhibit 3.1 of Form 8-K of Registrant filed on February 8, 2011.
4(1)	Five-Year Credit Agreement dated as of December 10, 2004, as amended and restated as of May 12, 2006, 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(4) of Form 10-Q of Registrant for the three months ended June 30, 2006.
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)	Extension and Amendment Agreement between the Government of the Virgin Islands and Hess Oil Virgin Islands Corp. incorporated by reference to Exhibit 10(4) of Form 10-Q of Registrant for the three months ended June 30, 1981.
10(2)	Restated Second Extension and Amendment Agreement dated July 27, 1990 between Hess Oil Virgin Islands Corp. and the Government of the Virgin Islands incorporated by reference to Exhibit 19 of Form 10-Q of Registrant for the three months ended September 30, 1990.
10(3)	Technical Clarifying Amendment dated as of November 17, 1993 to Restated Second Extension and Amendment Agreement between the Government of the Virgin Islands and Hess Oil Virgin Islands Corp. incorporated by reference to Exhibit 10(3) of Form 10-K of Registrant for the fiscal year ended December 31, 1993.
10(4)	Third Extension and Amendment Agreement dated April 15, 1998 and effective October 30, 1998 among Hess Oil Virgin Islands Corp., PDVSA V.I., Inc., HOVENSA L.L.C. and the Government of the Virgin Islands incorporated by reference to Exhibit 10(4) of Form 10-K of Registrant for the fiscal year ended December 31, 1998.
10(5)*	Incentive Cash Bonus Plan description incorporated by reference to Item 5.02 of Form 8-K of Registrant filed on February 8, 2011.
10(6)*	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(7)*	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(8)*	Performance Incentive Plan for Senior Officers, incorporated by reference to Exhibit (10) of Form 10-Q of Registrant for the three months ended June 30, 2006.
10(9)*	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(10)*	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(11)*	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(12)*	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(13)*	2008 Long Term Incentive Plan, incorporated by reference to Annex B to Registrant's definitive proxy statement filed on March 27, 2008.
10(14)*	First Amendment dated March 3, 2010 and approved May 5, 2010 to Registrant's 2008 Long-Term Incentive Plan, incorporated by reference to Registrant's definitive proxy statement dated March 25, 2010.
10(15)*	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(16)*	Compensation program description for non-employee directors, incorporated by reference to Item 1.01 of Form 8-K of Registrant filed on January 4, 2007.
10(17)*	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(18)*	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(19)*	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(20)*	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(21)*	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(22)*	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(23)	Asset Purchase and Contribution Agreement dated as of October 26, 1998, among PDVSA V.I., Inc., Hess Oil Virgin Islands Corp. and HOVENSA L.L.C. (including Glossary of definitions) incorporated by reference to Exhibit 2.1 of Form 8-K of Registrant filed on November 13, 1998.
10(24)	Amended and Restated Limited Liability Company Agreement of HOVENSA L.L.C. dated as of October 30, 1998 incorporated by reference to Exhibit 10.1 of Form 8-K of Registrant filed on November 13, 1998.
21	Subsidiaries of Registrant.
23(1)	Consent of Ernst & Young LLP, Independent Registered Public Accounting Firm, dated February 25, 2011, to the incorporation by reference in Registrant's Registration Statements (Form S-3 No. 333-157606, and Form S-8 Nos. 333-43569, 333-94851, 333-115844, 333-150992 and 333-167076), of its reports relating to Registrant's financial statements.
23(2)	Consent of DeGolyer and MacNaughton dated February 25, 2011.
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 2, 2011, on proved reserves audit as of December 31, 2010 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 Label 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, 2010, Registrant filed or furnished the following reports on Form 8-K:

1. Filing dated October 27, 2010 reporting under Items 2.02 and 9.01, a news release dated October 27, 2010 reporting results for the third quarter of 2010.

2. Filing dated November 8, 2010 reporting under Item 9.01, exhibits of opinions of White & Case LLP as to the legality of notes registered on Form S-3ASR and incorporated by reference therein.

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 25th day of February 2011.

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, Chairman of the Board and Chief Executive Officer (Principal Executive Officer)	February 25, 2011
/s/ Samuel W. Bodman **Samuel W. Bodman**	Director	February 25, 2011
/s/ Nicholas F. Brady **Nicholas F. Brady**	Director	February 25, 2011
/s/ Gregory P. Hill **Gregory P. Hill**	Director	February 25, 2011
/s/ Edith E. Holiday **Edith E. Holiday**	Director	February 25, 2011
/s/ Thomas H. Kean **Thomas H. Kean**	Director	February 25, 2011
/s/ Risa Lavizzo-Mourey **Risa Lavizzo-Mourey**	Director	February 25, 2011
/s/ Craig G. Matthews **Craig G. Matthews**	Director	February 25, 2011
/s/ John H. Mullin **John H. Mullin**	Director	February 25, 2011
/s/ Frank A. Olson **Frank A. Olson**	Director	February 25, 2011
/s/ John P. Rielly **John P. Rielly**	Senior Vice President and Chief Financial Officer (Principal Financial and Accounting Officer)	February 25, 2011
/s/ Ernst H. von Metzsch **Ernst H. von Metzsch**	Director	February 25, 2011
/s/ F. Borden Walker **F. Borden Walker**	Director	February 25, 2011
/s/ Robert N. Wilson **Robert N. Wilson**	Director	February 25, 2011

Schedule II

HESS CORPORATION AND CONSOLIDATED SUBSIDIARIES

VALUATION AND QUALIFYING ACCOUNTS

For the Years Ended December 31, 2010, 2009 and 2008

		Additions			
Description	Balance January 1	Charged to Costs and Expenses	Charged to Other Accounts	Deductions from Reserves	Balance December 31
			(In millions)		
2010					
Losses on receivables	**$ 54**	**$ 9**	**$ 1**	**$ 6**	**$ 58**
2009					
Losses on receivables	$ 46	$ 13	$ —	$ 5	$ 54
2008					
Losses on receivables	$ 41	$ 9	$ —	$ 4	$ 46

EXHIBIT INDEX

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* *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 (Luxembourg) Exploration and Production Holding S.à.r.l.	Luxembourg
Hess (Netherlands) Oil & Gas Holdings C.V.	The Netherlands
Hess (Netherlands) U.S. GOM Ventures B.V	The Netherlands
Hess Capital Services Corporation	Delaware
Hess Egypt West Mediterranean Limited	Cayman Islands
Hess Energy Exploration Limited	Delaware
Hess Equatorial Guinea Inc.	Cayman Islands
Hess International Holdings Corporation	Delaware
Hess International Holdings Limited	Cayman Islands
Hess Libya (Waha) Limited	Cayman Islands
Hess Limited	United Kingdom
Hess Norge AS	Norway
Hess Oil and Gas Holdings Inc.	Cayman Islands
Hess Oil Company of Thailand (JDA) Limited	Cayman Islands
Hess Oil Virgin Islands Corp.	Virgin Islands
Hess UK Investments Limited	Cayman Islands
Hess West Africa 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, and

(6) Registration Statement (Form S-3 No. 333-157606) of Hess Corporation;

of our reports dated February 25, 2011, 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, included in this Annual Report (Form 10-K) for the year ended December 31, 2010.

/s/ Ernst & Young, LLP
New York, New York
February 25, 2011

EXHIBIT 23(2)

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

February 25, 2011

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, under the heading "Oil and Gas Reserves-Reserves Audit" and to the inclusion of our third party letter report dated February 2, 2011, containing our opinion on the proved reserves attributable to certain properties owned by Hess Corporation, as of December 31, 2010, (our "Report") as an exhibit in Hess Corporation's Annual Report on Form 10-K for the year ended December 31, 2010. We also consent to the incorporation by reference of our Report in the Registration Statements filed by Hess Corporation on Form S-3 (No. 333-157606) and Form S-8 (No. 333-43569, No. 333-94851, No. 333-115844, No. 333-150992 and No. 333-167076).

Very truly yours,

By /s/ DeGolyer and MacNaughton

DEGOLYER AND MACNAUGHTON

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
Chairman of the Board and
Chief Executive Officer

Date: February 25, 2011

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 25, 2011

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, 2010 as filed with the Securities and Exchange Commission on the date hereof (the Report), I, John B. Hess, Chairman of the Board and 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
Chairman of the Board and
Chief Executive Officer

Date: February 25, 2011

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, 2010 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 25, 2011

DeGolyer and MacNaughton
5OO I Spring Valley Road
Suite 800 East
Dallas, Texas 75244

February 2, 2011

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

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, 2010, of certain selected properties of Hess Corporation (Hess) to determine the reasonableness of Hess estimates. The audit was completed on February 2, 2011. Hess has represented to us that these properties account for approximately 76 percent on a net equivalent barrel basis of Hess' net proved reserves, as of December 31, 2010. We have reviewed information provided to us by Hess that it represents to be Hess' estimates of the net reserves, as of December 31, 2010, for the same properties as those which we evaluated.

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, 2010. 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, except in Russia, where Hess owns 85 percent of a consolidated corporate joint venture. As a result, Hess net reserves include 15 percent of the Russian joint venture reserves not owned by Hess.

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 Petroleum Information/Dwights LLC; Copyright 2010 Petroleum Information/Dwights LLC. 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, 2010, and which represent approximately 76 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, 2010			
	Oil and Condensate (MMbbl)	**Natural Gas Liquids (MMbbl)**	**Natural Gas (Bcf)**	**Oil Equivalent (MMboe)**
United States	168.0	27.8	174.9	224.9
Norway	239.0	22.4	403.8	328.7
Europe (excluding Norway and including Russia)	141.9	0.0	79.1	155.1
Africa	251.7	0.0	62.3	262.1
Asia	24.1	7.0	1,041.7	204.7
Total	**824.7**	**57.2**	**1,761.8**	**1,175.5**

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 estimated net proved reserves prepared by Hess as shown in the table above comply with the definitions and disclosure guidelines of Paragraphs 932-235-50-4, 932-235-50-6 through 932-235-50-9 of the Accounting Standards Update 932-235-50, *Extractive Industries — Oil and Gas (Topic 932): Oil and Gas Reserve Estimation and Disclosures* (January 2010) of the Financial Accounting Standards Board and Rules 4-10(a) (l)-(32) of Regulation S-X and Items 1201, 1202(a)(l), (2), (3), (4) and 1203 of Regulation S-K of the Securities and Exchange Commission (SEC) and the reserves estimation methodologies employed are appropriate.

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

In comparing the detailed net proved reserves estimates by field prepared by us and by Hess, we have found differences, both positive and negative, resulting in an aggregate difference of less than 1 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, 2010, 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.

Definition of Reserves

Proved reserves classifications used in this report are in accordance with the reserves definitions of Rules 4-10(a) (l)-(32) of Regulation S-X of the SEC of the United States. 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 $79.432 per barrel for West Texas Intermediate and $79.023 per barrel for Dated Brent. Hess supplied appropriate differentials by field to the relevant reference prices and the prices were held constant thereafter. The volume weighted average price was $77.84 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 was $51.07 per barrel.

Natural Gas Prices

Hess has represented that the non-contracted natural gas prices were based on a 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 $4.456 per thousand cubic feet and the UK International Petroleum Exchange reference price was $6.203 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 average weighted gas price for all gas was $4.63 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, 2010, 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 for over 70 years. 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.

President
DeGolyer and MacNaughton

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 President of DeGolyer and MacNaughton, which company did prepare the letter report dated February 2, 2011 on the proved reserves audit of certain properties attributable to Hess Corporation, and that I, as President, 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 36 years of experience in oil and gas reservoir studies and reserves evaluations.

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

President
DeGolyer and MacNaughton