NOBLE ENERGY INC
Form 10-K
February 27, 2008

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

(Mark One)

x ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2007

or

o 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: 001-07964
NOBLE ENERGY, INC.
(Exact name of registrant as specified in its charter)

Delaware	73-0785597
(State of incorporation)	(I.R.S. employer identification number)
100 Glenborough Drive, Suite 100	
Houston, Texas	77067
(Address of principal executive offices)	(Zip Code)

(281) 872-3100
(Registrant's telephone number, including area code)

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

Title of each class	Name of each exchange on which registered
Common Stock, $3.33-1/3 par value	New York Stock Exchange
Preferred Stock Purchase Rights	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. x Yes o No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. o Yes x 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. x Yes o 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 the 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. x

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 definitions of "accelerated filer", "large accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.
(Check one):

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

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

Aggregate market value of Common Stock held by nonaffiliates as of June 29, 2007: $10,563,558,607.
Number of shares of Common Stock outstanding as of February 12, 2008: 171,835,490.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Registrant's definitive proxy statement for the 2008 Annual Meeting of Stockholders to be held on April 22, 2008, which will be filed with the Securities and Exchange Commission within 120 days after December 31, 2007, are incorporated by reference into Part III.

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PART I

Items 1 and 2. Business and Properties.

This Annual Report on Form 10-K and the documents incorporated herein by reference contain forward-looking statements based on expectations, estimates and projections as of the date of this filing. These statements by their nature are subject to risks, uncertainties and assumptions and are influenced by various factors. As a consequence, actual results may differ materially from those expressed in the forward-looking statements. For more information, see Item 1A. Risk Factors—Disclosure Regarding Forward-Looking Statements of this Form 10-K.

General

Noble Energy, Inc. ("Noble Energy", "we" or "us") is a Delaware corporation, formed in 1969, that has been publicly traded on the New York Stock Exchange ("NYSE") since 1980. We are an independent energy company that has been engaged in the acquisition, exploration, development, production and marketing of crude oil and natural gas since 1932. In this report, unless otherwise indicated or where the context otherwise requires, information includes that of Noble Energy and its subsidiaries. Exploration activities include geophysical and geological evaluation and exploratory drilling on properties for which we have exploration rights. We operate throughout major basins in the United States ("US") including Colorado's Wattenberg field and Piceance basin, the Mid-continent area of western Oklahoma and the Texas Panhandle, the San Juan basin in New Mexico, the Gulf Coast and the deepwater Gulf of Mexico. In addition, we conduct business internationally in China, Ecuador, the Mediterranean Sea, the North Sea, West Africa (Equatorial Guinea and Cameroon) and in other areas.

Strategy

We are a worldwide producer of crude oil and natural gas. Our strategy is to achieve growth in earnings and cash flow through the development of a high quality portfolio of producing assets that is balanced between US and international projects. Strategic acquisitions (Patina Oil & Gas Corporation ("Patina") in 2005 and U.S. Exploration Holdings, Inc. ("U.S. Exploration") in 2006), along with additional capital investment have resulted in substantial growth in the last five years. Acquisitions and capital investment, combined with the sale of non-core assets, have allowed us to achieve a strategic objective of enhancing our US asset portfolio, resulting in a company with assets and capabilities that include growing US basins coupled with a significant portfolio of international properties. Crude oil and natural gas sales volumes have doubled since 2003. Our reserve base, which includes both US and international sources at 58% US and 42% international, has almost doubled in the same period. We are now a larger, more diversified company with greater opportunities for both US and international growth. See Item 6. Selected Financial Data for additional financial and operating information for fiscal years 2003-2007.

Proved Reserves

As of December 31, 2007, we had estimated proved reserves of 3.3 Tcf of natural gas and 329 MMBbls of crude oil. On a combined basis, these proved reserves were equivalent to 880 MMBoe, an increase of 5% over the prior year. At December 31, 2007, 74% of reserves were proved developed reserves.

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Proved reserves estimates at December 31, 2007 were as follows:

	December 31, 2007		
	Proved Developed Reserves	Proved Undeveloped Reserves	Total Proved Reserves
United States			
Natural gas (Bcf)	1,259	581	1,840
Crude oil (MMBbls)	129	78	207
Total US (MMBoe)	339	175	514
International			
Natural gas (Bcf)	1,297	170	1,467
Crude oil (MMBbls)	100	22	122
Total International (MMBoe)	316	50	366
Worldwide			
Natural gas (Bcf)	2,556	751	3,307
Crude oil (MMBbls)	229	100	329
Total Worldwide (MMBoe)	655	225	880

Proved oil and gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions. For additional information regarding estimates of crude oil and natural gas reserves, including estimates of proved and proved developed reserves, the standardized measure of discounted future net cash flows, and the changes in discounted future net cash flows, see Item 8. Financial Statements and Supplementary Data—Supplemental Oil and Gas Information (Unaudited) and Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Policies and Estimates—Reserves.

Engineers in our Houston, Denver and London offices prepare all reserve estimates for our different geographical regions. These reserve estimates are reviewed and approved by senior engineering staff and division management with final approval by the Director of Asset Development and certain members of senior management. During each of the years 2007, 2006 and 2005, we retained Netherland, Sewell & Associates, Inc. ("NSAI"), independent third-party reserve engineers, to perform reserve audits of proved reserves. A "reserve audit", as we use the term, is a process involving an independent third-party engineering firm's visits, collection of any and all required geologic, geophysical, engineering and economic data, and such firm's complete external preparation of reserve estimates. Our use of the term "reserve audit" is intended only to refer to the collective application of the procedures which NSAI was engaged to perform. The term "reserve audit" may be defined and used differently by other companies.

The reserve audit for 2007 included a detailed review of 16 of our major international, deepwater Gulf of Mexico and US fields, which covered approximately 71% of US proved reserves and 96% of international proved reserves (81% of total proved reserves). The reserve audit for 2006 included a detailed review of 14 of our major international, deepwater Gulf of Mexico and US fields, which covered approximately 80% of our total proved reserves. The reserve audit for 2005 included a detailed review of 11 of our major international, deepwater Gulf of Mexico and US fields, which covered approximately 72% of our total proved reserves.

In connection with the 2007 reserve audit, NSAI prepared its own estimates of our proved reserves. In order to prepare its estimates of proved reserves, NSAI examined our estimates with respect to reserve quantities, future producing rates, future net revenue, and the present value of such future net revenue. NSAI also examined our estimates with respect to reserve categorization, using the definitions for proved reserves set forth in Regulation S-X Rule 4-10(a) and subsequent Securities and Exchange Commission ("SEC") staff interpretations and guidance. In the conduct of the reserve audit, NSAI did not independently verify the accuracy and completeness of information and data furnished by us with respect to ownership interests, oil and gas production, well test data, historical costs of operation and development, product prices, or any agreements relating to current and future operations of the fields and sales of production. However, if in the course of the examination something came to the attention of NSAI which brought into question the validity or sufficiency of any such information or data, NSAI did not rely on such information or data until it had satisfactorily resolved its questions relating thereto or had independently verified such information or data. NSAI determined that our estimates of reserves conform to the guidelines of the SEC, including the criteria of "reasonable certainty," as it pertains to expectations about the recoverability of reserves in future years, under existing economic and operating conditions, consistent with the definition in Rule 4-10(a)(2) of Regulation S-X. NSAI issued an unqualified audit opinion on our proved reserves at December 31, 2007, based upon its evaluation. Its opinion concluded that our estimates of proved reserves were, in the aggregate, reasonable and have been prepared in accordance with generally accepted petroleum engineering and evaluation principles.

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The fields that NSAI audits include our most significant fields and are chosen by senior engineering staff and division management with final approval by the Director of Asset Development and certain members of senior management. We usually include all deepwater Gulf of Mexico fields, all international fields that require reports by requirement of the host government, all fields that require sanctioning by our Board of Directors, and other major fields. No significant fields were excluded from the December 31, 2007 reserve audit.

When compared on a field-by-field basis, some of our estimates are greater and some are less than the estimates of NSAI. Given the inherent uncertainties and judgments that go into estimating proved reserves, differences between internal and external estimates are to be expected. On a quantity basis, the NSAI field estimates ranged from 21,966 MBoe above to 16,882 MBoe below as compared with our estimates. On a percentage basis, the NSAI field estimates ranged from 9% above our estimates to 42% below our estimates. Differences between our estimates and those of NSAI are reviewed for accuracy but are not further analyzed unless the aggregate variance is greater than 10%. At December 31, 2007, reserves differences, in the aggregate, were less than 13,200 MBoe, or 2%.

Since January 1, 2007, no crude oil or natural gas reserve information has been filed with, or included in any report to any federal authority or agency other than the SEC and the Energy Information Administration ("EIA") of the US Department of Energy. We file Form 23, including reserve and other information, with the EIA.

Acquisition and Divestiture Activities

We maintain an ongoing portfolio optimization program. We may engage in acquisitions of additional crude oil or natural gas properties and related assets through either direct acquisitions of the assets or acquisitions of entities owning the assets. We may also divest non-core assets in order to optimize our property portfolio.

In December 2007, we entered into an agreement to sell our interest in Argentina for a sales price of $117.5 million, effective July 1, 2007. We expect the sale, which is subject to regulatory and partner approvals, to close in 2008. Crude oil reserves for the Argentina properties totaled 7 MMBbls at December 31, 2007.

In 2006, we sold all of our Gulf of Mexico shelf properties except for the Main Pass area, which is undergoing redevelopment studies. As of the effective date of the sale, proved reserves for the Gulf of Mexico properties sold totaled approximately 7 MMBbls of crude oil and 110 Bcf of natural gas. Deepwater Gulf of Mexico and Gulf Coast onshore areas remain core areas and are more aligned with our long-term business strategies. See Item 8. Financial Statements and Supplementary Data—Note 3—Acquisitions and Divestitures.

In 2006, we acquired U.S. Exploration, a privately held corporation, for $412 million plus liabilities assumed. U.S. Exploration's reserves and production are located in Colorado's Wattenberg field. This acquisition significantly expanded our operations in one of our core areas. Proved reserves of U.S. Exploration at the time of acquisition were approximately 234 Bcfe, of which 38% of the reserves were proved developed and 55% of the reserves were natural gas. Proved crude oil and natural gas properties were valued at $413 million and unproved properties were valued at $131 million. See Item 8. Financial Statements and Supplementary Data—Note 3—Acquisitions and Divestitures.

In 2005, we acquired Patina through merger ("Patina Merger") for a total purchase price of $4.9 billion. Patina's long-lived crude oil and natural gas reserves provide a significant inventory of low-risk opportunities that balanced our portfolio. Patina's proved reserves at the time of acquisition were estimated to be approximately 1.6 Tcfe, of which 72% of the reserves were proved developed and 67% of the reserves were natural gas. Proved crude oil and natural gas properties were valued at $2.6 billion and unproved properties were valued at $1.1 billion. See Item 8. Financial Statements and Supplementary Data—Note 3—Acquisitions and Divestitures.

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Crude Oil and Natural Gas Properties and Activities

We search for crude oil and natural gas properties, seek to acquire exploration rights in areas of interest and conduct exploratory activities. These activities include geophysical and geological evaluation and exploratory drilling, where appropriate, on properties for which we have acquired exploration rights. Our properties consist primarily of interests in developed and undeveloped crude oil and natural gas leases. We also own natural gas processing plants and natural gas gathering and other crude oil and natural gas related pipeline systems.

United States

We have been engaged in crude oil and natural gas exploration, exploitation and development activities throughout onshore US since 1932 and in the Gulf of Mexico since 1968. The Patina Merger and the acquisition of U.S. Exploration have significantly increased the breadth of our onshore operations, especially in the Rocky Mountain and Mid-continent areas. These two acquisitions have provided us with a multi-year inventory of exploitation and development opportunities. In 2007, we continued to expand our acreage position with the acquisition of approximately 290,000 net acres in the Piceance, Niobrara, and New Albany Shale areas. US operations accounted for 58% of our 2007 consolidated sales volumes and 58% of total proved reserves at December 31, 2007. Approximately 60% of the proved reserves are natural gas and 40% are crude oil. Our onshore US portfolio at December 31, 2007 included 1,308,823 gross developed acres and 1,234,858 gross undeveloped acres. We also hold interests in 97 offshore blocks in the Gulf of Mexico. In 2008, we plan to invest approximately $1.2 billion, or 74%, of budgeted capital in the US.

Sales of production and estimates of proved reserves for our significant US operating areas were as follows:

	Year Ended December 31, 2007 Sales Volumes			December 31, 2007 Proved Reserves		
	Natural Gas (MMcf)	Crude Oil (MBbls)	Total (MBoe)	Natural Gas (Bcf)	Crude Oil (MMBbls)	Total (MMBoe)
Northern Region						
Wattenberg	59,670	4,674	14,619	893	109	258
Piceance	7,797	7	1,307	183	-	31
Niobrara	7,897	-	1,316	98	-	16
Other	9,392	53	1,618	139	1	24
Total	84,756	4,734	18,860	1,313	110	329
Southern Region						
Deepwater Gulf of Mexico	18,722	5,847	8,967	79	21	34
Mid-continent	30,760	3,340	8,467	341	51	108
Gulf Coast onshore and other	16,219	1,530	4,233	107	25	43
Total	65,701	10,717	21,667	527	97	185
Total United States	150,457	15,451	40,527	1,840	207	514

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Additional information for our significant US operating areas is as follows:

	Year Ended December 31, 2007 Gross Wells Drilled/ Participated in	December 31, 2007 Gross Productive Wells
Northern Region		
Wattenberg	508	5,161
Piceance	55	112
Niobrara	125	744
Other	56	1,239
Total	744	7,256
Southern Region		
Deepwater Gulf of Mexico	6	13
Mid-continent	147	3,981
Gulf Coast onshore and other	38	457
Total	191	4,451
Total United States	935	11,707

Northern Region—The Northern region consists of our operations in the Rocky Mountain area, which includes the D-J (Wattenberg field), San Juan, Wind River, and Piceance basins, as well as the Niobrara, Bowdoin and Siberia Ridge fields. The addition of Patina and U.S. Exploration assets, particularly in the Wattenberg field, combined with our legacy operations in the Bowdoin field, the Niobrara trend, the Wind River basin and Piceance basin, have made the Rocky Mountains one of our core operating areas. We are currently running 13 drilling rigs and 24 completion/workover units. We plan to invest approximately $744 million, or 62% of budgeted US capital in the Northern region during 2008.

Wattenberg Field—The Wattenberg field (approximately 97% operated working interest), our largest US asset, continues to grow production and reserves. In 2007, sales of production from this field accounted for 36% of total US sales volumes. Wattenberg field proved reserves accounted for 50% of US proved reserves at December 31, 2007.

We acquired working interests in the Wattenberg field through the Patina Merger in 2005 and acquisition of U.S. Exploration in 2006. Located in the D-J basin of north central Colorado, the Wattenberg field provides us with a substantial future project inventory. One of the most attractive features of the field is the presence of multiple productive formations, which include the Codell, Niobrara and J-Sand formations, as well as the D-Sand, Dakota and the shallower Shannon, Sussex and Parkman formations.

Drilling in the Wattenberg field is considered lower risk from the perspective of finding crude oil and natural gas reserves, with 99.8% of the wells drilled in 2007 encountering sufficient quantities of reserves to be completed as economic producers. In May 1998, the Colorado Oil and Gas Conservation Commission (“COGCC”) adopted the “Greater Wattenberg Area Special Well Location Rule 318A” which allows all formations in the Wattenberg field to be drilled, produced and commingled from any or all of ten “potential drilling locations” on a 320-acre parcel. A “commingled” well is one which produces crude oil from two or more formations or zones through a common string of casing and tubing. In December 2005, the COGCC amended Rule 318A providing for an effective well density of one well per 20 acres in a designated portion of the Greater Wattenberg Area to more effectively drain the reservoir. The amendment applies only to the Niobrara, Codell and J-Sand formations and became effective in March 2006.

We are currently running seven drilling rigs and 17 completion units in the Wattenberg field. Our current field activities are focused primarily on the development of J-Sand, Codell and Niobrara reserves through drilling new wells or deepening within existing wellbores, recompleting the Codell formation within existing J-Sand wells, refracturing or trifracturing existing Codell wells and refracturing or recompleting the Niobrara formation within existing Codell wells. A refracture consists of the restimulation of a producing formation within an existing wellbore to enhance production and add incremental reserves. A trifracture is effectively a refracture of a refracture. These projects and continued success with our production enhancement program, which includes well workovers, reactivations, and commingling of zones, allow us to increase production and add proved reserves to what is considered a mature field. During 2007, we drilled or participated in 508 development wells, with a 99.8% success rate, and added approximately 244 Bcfe of proved reserves in the Wattenberg field. Approximately 58% of these reserve additions were natural gas. We also grew production from an average of 227 MMcfe per day for 2006 to 240 MMcfe per day for 2007. We plan to drill approximately 480 wells in 2008 (of which 337 will be combination Codell/Niobrara new drills). We also plan to participate in 120 non-operated drilling projects in 2008. We have a substantial project inventory remaining and plan to perform approximately 340 projects including refractures, trifractures, and recompletions during 2008.

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Other Rocky Mountain areas include:

Niobrara Trend—The Niobrara trend (approximately 87% operated working interest) is located in eastern Colorado and extends into Kansas and Nebraska. During 2007, we expanded our acreage position with the acquisition of 160,000 net acres. We are currently running two drilling rigs and three completion units. During 2007, we drilled or participated in 125 wells with a 79% success rate, and our activity resulted in the addition of 19 Bcfe of proved reserves. We plan to drill 300 wells in 2008.

Piceance Basin—The Piceance basin in western Colorado (approximately 96% operated working interest) is another rapidly growing area for us. During 2007, we added 10,500 net acres to our position. We are currently running four drilling rigs and three completion units. We drilled or participated in 55 development wells during 2007, 100% of which were successful, and our activity resulted in the addition of 83 Bcfe of proved reserves. We plan to drill over 100 wells during 2008.

Other—We are also active in the Bowdoin field (approximately 60% operated working interest), located in north central Montana; the San Juan basin (approximately 81% operated working interest), located in northwestern New Mexico and southwestern Colorado; and the Wind River basin (approximately 56% operated working interest), located in central Wyoming. During 2007 we drilled or participated in a total of 56 development wells in these areas, 100% of which were successful. We plan to drill approximately 60 wells and recomplete 190 wells during 2008.

Southern Region—The Southern region includes the Gulf Coast onshore, West and East Texas, Louisiana, and the deepwater Gulf of Mexico, as well as the Mid-continent area (the Texas Panhandle and parts of Oklahoma, Kansas, Arkansas, Illinois and Indiana). The Gulf Coast and deepwater Gulf of Mexico are core US operating areas. During 2006, we sold all of our Gulf of Mexico shelf properties except for the Main Pass area. The sale of our shelf properties allows us to migrate future investments and growth from the Gulf of Mexico shelf to the deepwater Gulf of Mexico which we believe is an area of higher potential. We plan to invest approximately $460 million, or 38% of budgeted US capital, in the Southern region during 2008, with approximately 67% in the deepwater Gulf of Mexico, and the remainder to the Gulf Coast and the Mid-continent areas.

Deepwater Gulf of Mexico—Deepwater Gulf of Mexico accounted for 22% of 2007 US sales volumes and 7% of US proved reserves at December 31, 2007. During 2007, we continued to focus on the growth of our deepwater Gulf of Mexico business highlighted by a successful exploration discovery at Isabela and a successful sidetrack-appraisal well at our 2006 Raton discovery. We also completed successful development drilling programs in our Ticonderoga and Swordfish fields. Deepwater Gulf of Mexico activity resulted in proved reserve additions of 12 MMBoe during 2007. Participation in the 2007 Central Gulf of Mexico Outer Continental Shelf Sale resulted in our being awarded eight new deepwater Gulf of Mexico leases totaling $50 million.

At year-end, development planning was underway for Isabela (Mississippi Canyon Block 562, 33% working interest). We have also acquired an interest in adjacent acreage with additional exploration potential on Mississippi Canyon Blocks 519 and 563 (23.25% working interest). We plan to drill a well on Block 519 (Santa Cruz Prospect) in 2008 pending rig availability. In total there are three prospects on the combined leasehold that, conceptually, would be co-developed in a subsea tieback to an existing production facility.

Other 2007 exploration drilling included the Mississippi Canyon Block 568 #1 (Robusto Prospect, 20% working interest) and the East Breaks Block 465 #1 (Lost Ark South Prospect, 98.4% working interest), neither of which encountered hydrocarbons in commercial quantities.

During 2007 we saw an extremely active deepwater Gulf of Mexico development program. At our Raton project in Mississippi Canyon Block 248 (66.67% operated working interest), we successfully sidetracked and completed the 248 #1 discovery well drilled in 2006. At year-end the project had moved into the development stage and is slated for subsea tieback and first production in the second quarter of 2008.

At our operated Swordfish project (85% working interest), we drilled and completed a sidetrack to Viosca Knoll Block 917 #1 well and began gas production from this well at year end. At the Ticonderoga development in Green Canyon Block 768 (50% working interest, non-operated), the #3 and #1 ST4 wells were drilled and completed to extend and enhance production from the field. Both are slated for first production in the first quarter of 2008.

At the Lost Ark project in East Breaks Blocks 421 and 464 (48.4% operated working interest), the 421 #1 well, which had reached the end of its productive life, was plugged and abandoned, and the 464 #1 well was completed and put on production to develop the remaining reserves at the field.

We are currently evaluating a possible sidetrack-appraisal well to be drilled at the Raton South oil discovery in Mississippi Canyon Block 292 during late 2008 (originally drilled in 2006). The Redrock natural gas/condensate discovery, also drilled in 2006, is currently considered a co-development candidate to a successful sidetrack-appraisal well at Raton South. Additional key exploration activity planned for 2008 includes a well at the Mississippi Canyon Block 948, Gunflint prospect, (50% working interest), in the second half of 2008.

Mid-continent— A significant area of activity in Mid-continent is the Granite Wash development, located in the Texas Panhandle. We drilled or participated in 53 development wells in 2007, 100% of which were successful. The potential for horizontal drilling is currently being evaluated. Another significant area in Mid-continent is the ongoing Southern Oklahoma development. In 2007 we drilled or participated in 45 wells resulting in additional incremental production of 1,515 Boepd.

In addition, we contintue to selectively increase our acreage position in resource plays, including shale plays. We have accumulated over 179,000 acres in the New Albany Shale. During 2007, we drilled 16 New Albany Shale wells. Currently nine are producing and seven are in the progress of pipeline connection. The Paxton facility, which we operate, will serve the majority of wells in the Paxton field. We plan to have an active drilling program during 2008.

Other Mid-continent areas include parts of Texas, Oklahoma, Kansas, Illinois, Indiana, and Arkansas. During 2007, we drilled or participated in a total of 33 wells. We plan to drill or participate in 60 wells in the Mid-continent area during 2008.

Gulf Coast Onshore— During late 2007, we began a six well program at Oliver Creek in Shelby County, Texas to develop the Travis Peak reservoir as well as test deeper Cotton Valley horizons. We have completed one Travis Peak well and are currently completing the second Travis Peak well. The deeper Cotton Valley horizons are being tested in two additional wells currently being drilled or completed. Two additional wells remain in the current six well program. Additional drilling is planned for later in 2008.

International

International operations are significant to our business, accounting for 42% of consolidated sales volumes in 2007, and 42% of total proved reserves at December 31, 2007. International proved reserves are approximately 67% natural gas and 33% crude oil. Operations in Equatorial Guinea, Cameroon, Ecuador, China and Suriname are conducted in accordance with the terms of production sharing contracts. In 2008, we plan to invest approximately $392 million, or 24%, of budgeted capital in our international locations.

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Additional information for our significant international operating areas is as follows:

	Year Ended December 31, 2007 Sales Volumes			December 31, 2007 Proved Reserves		
	Natural Gas (MMcf)	Crude Oil (MBbls)	Total (MBoe)	Natural Gas (Bcf)	Crude Oil (MMBbls)	Total (MMBoe)
International						
West Africa	48,349	5,500	13,558	941	82	239
North Sea	2,276	4,564	4,943	19	25	28
Israel	40,449	-	6,742	319	-	53
Ecuador	9,385	-	1,564	188	-	31
China	-	1,402	1,402	-	8	8
Argentina	-	1,034	1,034	-	7	7
Total consolidated	100,459	12,500	29,243	1,467	122	366
Equity investees:						
Condensate (MBbls)	-	670	670			
LPG (MBbls)	-	2,135	2,135			
Total	100,459	15,305	32,048			
Equity investee share of methanol sales (Kgal)			160,540			

Wells drilled in 2007 and productive wells at December 31, 2007 in our international operating areas were as follows:

	Year Ended December 31, 2007 Gross Wells Drilled/ Participated in	December 31, 2007 Gross Productive Wells
International		
West Africa	7	20
North Sea	2	22
Israel	1	8
Ecuador	-	5
China	-	16
Argentina	50	732
Total International	60	803

West Africa (Equatorial Guinea and Cameroon)—Operations in West Africa accounted for 46% of 2007 consolidated international sales volumes and 65% of international proved reserves at December 31, 2007. At December 31, 2007, we held 45,203 gross developed acres and 850,197 gross undeveloped acres in Equatorial Guinea and 1,125,000 gross undeveloped acres in Cameroon.

We began investing in West Africa in the early 1990’s. Activities center around our 34% non-operated working interest in the Alba field, offshore Equatorial Guinea, which is one of our most significant assets. Operations include the Alba field and related production and condensate facilities, a methanol plant (located on Bioko Island), and an onshore LPG processing plant where additional condensate is produced. The methanol plant was originally designed to produce commercial grade methanol at a rate of 2,500 MTpd gross. As a result of various upgrade efforts, the plant is now capable of producing up to 3,000 MTpd gross.

We sell our share of natural gas production from the Alba field to the LPG plant, the methanol plant and an LNG plant. The LPG plant is owned by Alba Plant LLC ("Alba Plant") in which we have a 28% interest accounted for by the equity method. The methanol plant is owned by Atlantic Methanol Production Company, LLC ("AMPCO") in which we have a 45% interest accounted for by the equity method. The methanol plant purchases natural gas from the Alba field under a contract that runs through 2026. AMPCO subsequently markets the produced methanol to customers in the US and northwestern Europe. We sell our share of condensate produced in the Alba field and from the LPG plant under short-term contracts at market-based prices.

Our exploration activities in West Africa center around Blocks O and I offshore Equatorial Guinea and the PH-77 license offshore the Republic of Cameroon. We are the technical operator on Blocks O and I (45% and 40% working interest, respectively) and the operator on the PH-77 license (50% working interest). We drilled seven wells in the area during 2007 resulting in three new discoveries and three successful appraisal wells:

Benita – The I-1 well, testing the Benita prospect, resulted in a new gas-condensate discovery on Block I.

Benita appraisal – The I-2 appraisal well on Block I encountered crude oil. Testing has been deferred in order to secure an additional drilling rig that will be capable of further appraisal drilling downdip in the Benita oil column, which is in deeper water. It is expected that a rig will be available for drilling the additional Benita appraisal well in the first quarter of 2008.

Yolanda – The I-3 well, testing the Yolanda prospect, resulted in another new gas-condensate discovery on Block I.

I-4 – The I-4 well on Block I was a successful well on trend with the 2005 Belinda discovery on Block O.

Adriana – The O-2 exploration well (the Adriana Southwest prospect) on Block O offshore Equatorial Guinea did not contain commercial hydrocarbons. The well was plugged and abandoned.

Belinda appraisal – The O-3 appraisal well on Block O successfully extended the Belinda discovery by establishing significant downdip resources.

YoYo – The YoYo-1 well resulted in a new gas-condensate discovery on the PH-77 license offshore the Republic of Cameroon. Additional appraisal work is necessary to verify the areal extent of the discovery. There was also a secondary target, in which commercial hydrocarbons were not found.

In 2008, we plan to have an active exploration and appraisal drilling program for both Blocks I and O as we assess our options to commercialize our discoveries in the region.

Effective November 2006, the government of Equatorial Guinea enacted a new hydrocarbons law (the "2006 Hydrocarbons Law") governing petroleum operations in Equatorial Guinea. The governmental agency responsible for the energy industry was given the authority to renegotiate any contract for the purpose of adapting any terms and conditions that are inconsistent with the new law. At this time we are uncertain what economic impact this law will have on our operations in Equatorial Guinea.

North Sea—Operations in the North Sea (the Netherlands, Norway and the UK) comprise another core international asset, and we have been conducting business there since 1996. We have working interests in 23 licenses with working interests ranging from 7% to 100%. We are the operator of four blocks, covered by three licenses. The North Sea accounted for 17% of 2007 consolidated international sales volumes and 8% of international proved reserves at December 31, 2007. At December 31, 2007, we held 48,230 gross developed acres and 836,625 gross undeveloped acres.

In January 2007, production began at the non-operated Dumbarton development (30% working interest) in Blocks 15/20a and 15/20b in the UK sector of the North Sea. Dumbarton, a re-development of the Donan field, included subsea tie-back to the GP III, a floating production, storage and offloading vessel in which we own a 30% interest. We expect to continue the development of Dumbarton in 2008 with phases 2a and 2b. In addition, we will participate in the development of the Lochranza prospect, which will also consist of a subsea tie-back to the GP III.

Exploration efforts continued in 2007 as we and our partners successfully completed an appraisal well on the Flyndre Block (22.5% working interest) in the UK sector of the North Sea. We also participated in a successful exploration well at Selkirk in Block 22/22b P233 (30.5% working interest), also in the UK sector of the North Sea.

Mediterranean Sea (Israel)—Operations in Israel accounted for 23% of 2007 consolidated international sales volumes and 14% of international proved reserves at December 31, 2007. At December 31, 2007, we held 123,552 gross developed acres and 1,183,479 gross undeveloped acres located between 10 and 60 miles offshore Israel in water depths ranging from 700 feet to 5,500 feet. Our leasehold position in Israel includes one preliminary permit, two leases and three licenses, and we are the operator.

We have been operating in the Mediterranean Sea, offshore Israel, since 1998, and our 47% working interest in the Mari-B field is one of our core international assets. The Mari-B field is the first offshore natural gas production facility in the State of Israel. During 2007, we completed the Mari-B #7, which is designed to produce twice what a normal Mari-B well produces in Israel, or approximately 200 MMcfpd of natural gas. The Mari-B#7 well has resulted in peak field deliverability of 600 MMcfpd.

Natural gas sales began in 2004 and have been increasing steadily as Israel's natural gas infrastructure has developed. In 2007, our gas sales volumes increased 19% over 2006 volumes and 67% over 2005 volumes. During 2007 we completed construction of a permanent onshore receiving terminal in Ashdod for distribution of natural gas from the Mari-B field to purchasers. Commissioning of the terminal is expected in early 2008. We also began selling natural gas to a desalinization plant and a paper mill in 2007. Additional natural gas sales in 2008 will depend on the timing of onshore pipeline construction and plant conversion, which should allow the Israel Electric Corporation Limited power plants at Gezer and Hagit to consume gas.

Exploration activities continue in Israel. We are in the process of securing a rig and intend to drill one exploration well testing the Tamar prospect (33% working interest), offshore northern Israel, in 2008.

Ecuador—Operations in Ecuador accounted for 5% of 2007 consolidated international sales volumes and 8% of international proved reserves at December 31, 2007. The concession covers 12,355 gross developed acres and 851,771 gross undeveloped acres.

We have been operating in Ecuador since 1996. We are currently utilizing the natural gas from the Amistad field (offshore Ecuador) to generate electricity through a 100%-owned natural gas-fired power plant, located near the city of Machala. The Machala power plant, which began operating in 2002, is a single cycle generator with a capacity of 130 MW from twin turbines. It is the only natural gas-fired commercial power generator in Ecuador and currently one of the lowest cost producers of thermal power in the country. The Machala power plant connects to the Amistad field via a 40-mile pipeline. During 2007, power generation totaled 911,830 MW hours.

Other International—Other international includes China, Argentina and Suriname.

We have been engaged in exploration and development activities in China since 1996 and production began in 2003. We are operator of the Cheng Dao Xi field (57% working interest), which is located in the shallow water of the southern Bohai Bay. During 2007, activities consisted primarily of workover projects. China accounted for 5% of 2007 consolidated international sales volumes and 2% of international proved reserves at December 31, 2007. At December 31, 2007, we held 7,413 gross developed acres and no undeveloped acres.

We continue to work with our Chinese partner (Shengli) to obtain governmental approval of the Supplemental Development Plan, designed to further develop the Cheng Dao Xi field through additional drilling and facilities construction.

Our producing properties in Argentina are located in southern Argentina in the El Tordillo field (13% working interest), which is characterized by secondary recovery crude oil production. During 2007, we participated in the drilling of 50 gross (6.7 net) development wells. Argentina accounted for 4% of 2007 consolidated international sales volumes and 2% of international proved reserves at December 31, 2007. At December 31, 2007, we held 113,325 gross developed acres and no undeveloped acres in Argentina.

In December 2007, we entered into an agreement to sell our interest in Argentina for a sales price of $117.5 million, effective July 1, 2007. We expect the sale, which is subject to regulatory and partner approvals, to close in 2008. Crude oil reserves for the Argentina properties totaled 7 MMBbls at December 31, 2007.

Suriname, a country located on the northern coast of South America, represents a new exploration area for us. We have entered into participation agreements on non-operated Block 30 (60% working interest) and on Block 32 (100% working interest), which combined cover approximately 7.7 million gross acres offshore. We expect to participate in the drilling of one well on the West Tapir prospect on Block 30 in 2008.

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Sales Volumes, Price and Cost Data—Sales volumes, price and cost data are as follows:

	Sales Volumes (1)		Average Sales Price		Average Production Cost
	Natural Gas	Crude Oil	Natural Gas	Crude Oil	Per BOE
	MMcf	MBbls	Per Mcf (2)	Per Bbl (2)	(3)
Year Ended December 31, 2007					
United States	150,457	15,451	$ 7.51	$ 53.22	$ 8.49
West Africa (4) (5)	48,349	5,500	0.29	71.27	2.89
North Sea	2,276	4,564	6.54	76.47	9.81
Israel	40,449	-	2.79	-	1.14
Other International (6)	9,385	2,436	-	53.69	12.06
Total Consolidated Operations	250,916	27,951	5.26	60.61	6.99
Equity Investee (7)	-	2,805	-	55.09	
Total	250,916	30,756	$ 5.26	$ 60.10	
Year Ended December 31, 2006					
United States	164,875	16,715	$ 6.61	$ 50.68	$ 8.12
West Africa (4) (5)	16,579	6,519	0.37	62.51	2.86
North Sea	2,967	1,357	8.00	67.43	10.08
Israel	33,906	-	2.72	-	1.60
Other International (6)	9,041	2,752	0.96	52.05	9.74
Total Consolidated Operations	227,368	27,343	5.55	54.47	6.97
Equity Investee (7)	-	2,931	-	45.83	
Total	227,368	30,274	$ 5.55	$ 53.64	
Year Ended December 31, 2005					
United States	125,543	9,468	$ 7.43	$ 46.67	$ 7.39
West Africa (4) (5)	23,938	6,492	0.25	42.51	2.93
North Sea	3,394	1,964	5.93	52.68	7.54
Israel	24,228	-	2.68	-	2.11
Other International (6)	8,389	2,866	1.10	42.37	7.15
Total Consolidated Operations	185,492	20,790	5.78	45.35	6.06
Equity Investee (7)	-	1,183	-	43.43	
Total	185,492	21,973	$ 5.78	$ 45.25	

(1) 2007 volumes include the effect of crude oil sales less than volumes produced of 165 MBbls in Equatorial Guinea, 112 MBbls in the North Sea and 48 MBbls in other international. 2006 volumes include the effect of crude oil sales in excess of volumes produced of 195 MBbls in Equatorial Guinea, less than volumes produced of 99 MBbls in the North Sea, and in excess of volumes produced of 18 MBbls in other international. The variance between production from the field and sales volumes is attributable to the timing of liquid hydrocarbon tanker liftings. Sales volumes equal production volumes in 2005.

(2) Average natural gas sales prices in the US reflect an increase of $1.12 per Mcf (2007), and reductions of $0.25 per Mcf (2006) and $0.77 per Mcf (2005) from hedging activities. Average crude oil sales prices for the US reflect reductions of $13.68 per Bbl (2007), $11.41 per Bbl (2006) and $8.03 per Bbl (2005) from hedging activities. Average crude oil sales prices for West Africa reflect reductions of $2.19 (2007) and $9.93 (2005) from hedging activities. We did not hedge West Africa crude oil sales in 2006.

(3) Average production costs include oil and gas operating costs, workover and repair expense, production and ad valorem taxes, and transportation expense.

(4) Natural gas from the Alba field in Equatorial Guinea is under contract for $0.25 per MMBtu to a methanol plant, an LPG plant and an LNG facility. Sales to these plants are based on a BTU equivalent and then converted to a dry gas equivalent volume. The methanol and LPG plants are owned by affiliated entities accounted for under the equity method of accounting. The volumes produced by the LPG plant are included in the crude oil information. For 2007 and 2006, the price on an Mcf basis has been adjusted to reflect the Btu content of gas sales.

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(5) Equatorial Guinea natural gas volumes include sales to the LNG facility of 78,090 Mcfpd for 2007. There were no natural gas sales to the LNG facility before 2007.
(6) Other International natural gas volumes include Ecuador and Argentina. Although Ecuador natural gas volumes are included in Other International production, they are excluded from average natural gas sales prices. We own 100% of the natural gas-to-power project in Ecuador and intercompany natural gas sales are eliminated. Natural gas production volumes associated with the gas-to-power project were 9,385 MMcf for 2007, 8,933 MMcf for 2006 and 8,321 MMcf for 2005. Other International oil includes China and Argentina.
(7) Volumes represent sales of condensate and LPG from the Alba plant in Equatorial Guinea. LPG volumes were 2,135 MBbls in 2007, 2,297 MBbls in 2006 and 850 MBbls in 2005.

Revenues from sales of crude oil and natural gas and from gathering, marketing and processing have accounted for 90% or more of consolidated revenues for each of the last three fiscal years.

At December 31, 2007, our operated properties accounted for approximately 62% of our total production. Being the operator of a property improves our ability to directly influence production levels and the timing of projects, while also enhancing our control over operating expenses and capital expenditures.

Productive Wells—The number of productive crude oil and natural gas wells in which we held an interest as of December 31, 2007 is as follows:

	Crude Oil Wells		Natural Gas Wells		Total	
	Gross	Net	Gross	Net	Gross	Net
United States - Onshore	7,055	5,997.8	4,609	3,134.5	11,664	9,132.3
United States - Offshore	28	26.1	15	8.1	43	34.2
West Africa	1	0.4	19	7.2	20	7.6
North Sea	15	2.7	7	0.7	22	3.4
Israel	-	-	8	3.8	8	3.8
Ecuador	-	-	5	5.0	5	5.0
China	16	9.1	-	-	16	9.1
Argentina	732	95.4	-	-	732	95.4
Total	7,847	6,131.5	4,663	3,159.3	12,510	9,290.8
Multiple Completions	8	5.9	14	3.6	22	9.5

Productive wells are producing wells and wells capable of production. A gross well is a well in which a working interest is owned. The number of gross wells is the total number of wells in which a working interest is owned. A net well is deemed to exist when the sum of fractional ownership working interests in gross wells equals one. The number of net wells is the sum of the fractional working interests owned in gross wells expressed as whole numbers and fractions thereof. One or more completions in the same borehole are counted as one well in this table.

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Developed and Undeveloped Acreage—Developed and undeveloped acreage (including both leases and concessions) held at December 31, 2007 was as follows:

	Developed Acreage		Undeveloped Acreage	
	Gross	Net	Gross	Net
United States				
Onshore	1,308,823	835,445	1,234,858	786,391
Offshore	147,945	94,964	485,258	227,627
Total United States	1,456,768	930,409	1,720,116	1,014,018
Equatorial Guinea	45,203	15,727	850,197	379,026
Cameroon	-	-	1,125,000	562,500
North Sea (1)	48,230	5,671	836,625	339,151
Israel	123,552	58,142	1,183,479	532,818
China	7,413	4,225	-	-
Ecuador	12,355	12,355	851,771	851,771
Argentina	113,325	15,548	-	-
Suriname	-	-	7,740,328	6,362,864
Total International	350,078	111,668	12,587,400	9,028,130
Total Worldwide (2)	1,806,846	1,042,077	14,307,516	10,042,148

(1) The North Sea includes acreage in the UK, the Netherlands and Norway. In 2008, we entered into an agreement, subject to regulatory approval, to sell our interest in the Norway acreage consisting of 411,065 gross (126,607 net) undeveloped acres.

(2) If production is not established, approximately 731,079 gross acres (433,236 net acres) will expire during 2008, 424,734 gross acres (193,554 net acres) will expire during 2009, and 683,274 gross acres (367,949 net acres) will expire during 2010.

Developed acreage includes leases that contain wells capable of production. A gross acre is an acre in which a working interest is owned. A net acre is deemed to exist when the sum of fractional ownership working interests in gross acres equals one. The number of net acres is the sum of the fractional working interests owned in gross acres expressed as whole numbers and fractions thereof. Undeveloped acreage is considered to be those leased acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of crude oil and natural gas regardless of whether or not such acreage contains proved reserves.

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Drilling Activity—The results of crude oil and natural gas wells drilled and completed for each of the last three years were as follows:

	Net Exploratory Wells			Net Development Wells		
	Productive	Dry	Total	Productive (1)	Dry	Total
Year Ended December 31, 2007						
United States	14.2	4.5	18.7	757.6	27.6	785.2
West Africa	2.6	0.5	3.1	-	-	-
North Sea	0.5	-	0.5	-	-	-
Israel	-	-	-	0.4	-	0.4
Argentina	-	0.1	0.1	6.7	-	6.7
Total	17.3	5.1	22.4	764.7	27.6	792.3
Year Ended December 31, 2006						
United States	6.3	9.0	15.3	666.6	5.5	672.1
West Africa	-	0.4	0.4	1.8	-	1.8
North Sea	-	-	-	1.1	-	1.1
Argentina	-	-	-	7.6	-	7.6
Total	6.3	9.4	15.7	677.1	5.5	682.6
Year Ended December 31, 2005						
United States	4.7	10.7	15.4	488.1	25.9	514.0
West Africa	-	-	-	0.3	-	0.3
North Sea	-	0.2	0.2	-	-	-
Argentina	-	-	-	7.7	-	7.7
Total	4.7	10.9	15.6	496.1	25.9	522.0

(1) Does not include wells drilled but not yet completed.

A productive well is an exploratory or a development well that is not a dry well. A dry well (hole) is an exploratory or a development well found to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.

An exploratory well is a well drilled to find and produce crude oil or natural gas in an unproved area, to find a new reservoir in a field previously found to be productive of crude oil or natural gas in another reservoir, or to extend a known reservoir. A development well, for purposes of the table above and as defined in the rules and regulations of the SEC, is a well drilled within the proved area of a crude oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive. The number of wells drilled refers to the number of wells completed at any time during the respective year, regardless of when drilling was initiated. Completion refers to the installation of permanent equipment for the production of crude oil or natural gas, or in the case of a dry hole, to the reporting of abandonment to the appropriate agency.

In addition to the wells drilled and completed during 2007 included in the table above, at December 31, 2007, we were drilling or completing 2 gross (1.0 net) development wells offshore US, 223 gross (192.3 net) development wells and 4 gross (3.3 net) exploratory wells onshore US and one gross (0.1 net) development well in Argentina.

Marketing Activities—We seek opportunities to enhance the value of our US natural gas production by marketing directly to end-users and aggregating natural gas to be sold to natural gas marketers and pipelines. We also engage in the purchase and sale of third-party crude oil and natural gas production. Such third-party production may be purchased from non-operators who own working interests in our wells or from other producers' properties in which we own no interest.

Natural gas produced in the US is sold predominately under short-term or long-term contracts at market-based prices. In Equatorial Guinea and Israel, we sell natural gas to end-users under long-term contracts at negotiated prices. During 2007, approximately 12% of natural gas sales were made pursuant to long-term contracts.

Crude oil and condensate produced in the US and foreign locations is generally sold under short-term contracts at market-based prices adjusted for location and quality. In China, we sell crude oil into the local market under a long term contract at market-based prices. Crude oil and condensate are distributed through pipelines and by trucks or tankers to gatherers, transportation companies and refineries.

Significant Purchaser—Marathon Petroleum Supply Company ("Marathon") was the largest single non-affiliated purchaser of 2007 production and purchased our share of condensate from the Alba field in Equatorial Guinea. Sales to Marathon accounted for 18% of 2007 crude oil sales, or 10% of 2007 total oil and gas sales. No other single non-affiliated purchaser accounted for 10% or more of crude oil and natural gas sales in 2007. We believe that the loss of any one purchaser would not have a material effect on our financial position or results of operations since there are numerous potential purchasers of our production.

Hedging Activities—Commodity prices remained volatile during 2007 and prices for crude oil and natural gas are affected by a variety of factors beyond our control. We have used derivative instruments, and expect to do so in the future, to achieve a more predictable cash flow by reducing our exposure to commodity price fluctuations. For additional information, see Item 1A. Risk Factors—Hedging transactions may limit our potential gains, Item 7A. Quantitative and Qualitative Disclosures About Market Risk, and Item 8. Financial Statements and Supplementary Data—Note 12—Derivative Instruments and Hedging Activities.

Regulations

Government Regulation—Exploration for, and production and sale of, crude oil and natural gas are extensively regulated at the international, federal, state and local levels. Crude oil and natural gas development and production activities are subject to various laws and regulations (and orders of regulatory bodies pursuant thereto) governing a wide variety of matters, including, among others, allowable rates of production, prevention of waste and pollution and protection of the environment. Laws affecting the crude oil and natural gas industry are under constant review for amendment or expansion and frequently increase the regulatory burden on companies. Our ability to economically produce and sell crude oil and natural gas is affected by a number of legal and regulatory factors, including federal, state and local laws and regulations in the US and laws and regulations of foreign nations. Many of these governmental bodies have issued rules and regulations that are often difficult and costly to comply with, and that carry substantial penalties for failure to comply. These laws, regulations and orders may restrict the rate of crude oil and natural gas production below the rate that would otherwise exist in the absence of such laws, regulations and orders. The regulatory burden on the crude oil and natural gas industry increases our costs of doing business and consequently affects our profitability.

Environmental Matters—As a developer, owner and operator of crude oil and natural gas properties, we are subject to various federal, state, local and foreign country laws and regulations relating to the discharge of materials into, and the protection of, the environment. We must take into account the cost of complying with environmental regulations in planning, designing, drilling, operating and abandoning wells. In most instances, the regulatory requirements relate to the handling and disposal of drilling and production waste products, water and air pollution control procedures, and the remediation of petroleum-product contamination. Under state and federal laws, we could be required to remove or remediate previously disposed wastes, including wastes disposed of or released by us or prior owners or operators in accordance with current laws or otherwise, to suspend or cease operations in contaminated areas, or to perform remedial well plugging operations or cleanups to prevent future contamination. The US Environmental Protection Agency and various state agencies have limited the disposal options for hazardous and non-hazardous wastes. The owner and operator of a site, and persons that treated, disposed of or arranged for the disposal of hazardous substances found at a site, may be liable, without regard to fault or the legality of the original conduct, for the release of a hazardous substance into the environment. The US Environmental Protection Agency, state environmental agencies and, in some cases, third parties are authorized to take actions in response to threats to human health or the environment and to seek to recover from responsible classes of persons the costs of such action. Furthermore, certain wastes generated by our crude oil and natural gas operations that are currently exempt from treatment as hazardous wastes may in the future be designated as hazardous wastes and, therefore, be subject to considerably more rigorous and costly operating and disposal requirements. See Item 1A. Risk Factors—We are subject to various governmental regulations and environmental risks that may cause us to incur substantial costs.

Federal and state occupational safety and health laws require us to organize information about hazardous materials used, released or produced in our operations. Certain portions of this information must be provided to employees, state and local governmental authorities and local citizens. We are also subject to the requirements and reporting set forth in federal workplace standards.

Certain state or local laws or regulations and common law may impose liabilities in addition to, or restrictions more stringent than, those described herein.

We have made and will continue to make expenditures in our efforts to comply with environmental requirements. We do not believe that we have, to date, expended material amounts in connection with such activities or that compliance with such requirements will have a material adverse effect upon our capital expenditures, earnings or competitive position. Although such requirements do have a substantial impact upon the crude oil and natural gas industry, they do not appear to affect us to any greater or lesser extent than other companies in the industry.

Competition

The crude oil and natural gas industry is highly competitive. We encounter competition from other crude oil and natural gas companies in all areas of operations, including the acquisition of seismic and lease rights on crude oil and natural gas properties and for the labor and equipment required for exploration and development of those properties. Our competitors include major integrated crude oil and natural gas companies and numerous independent crude oil and natural gas companies, individuals and drilling and income programs. Many of our competitors are large, well established companies. Such companies may be able to pay more for seismic and lease rights on crude oil and natural gas properties and exploratory prospects and to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. Our ability to acquire additional properties and to discover reserves in the future will be dependent upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. See Item 1A. Risk Factors—We face significant competition and many of our competitors have resources in excess of our available resources.

Geographical Data

We have operations throughout the world and manage our operations by country. Information is grouped into five components that are all primarily in the business of crude oil and natural gas acquisition, exploration, development and production: United States, West Africa, North Sea, Israel, and Other International, Corporate and Marketing. For more information, see Item 8. Financial Statements and Supplementary Data—Note 15—Segment Information.

Employees

Our total number of employees increased during the year from 1,243 at December 31, 2006 to 1,398 at December 31, 2007. The 2007 year-end employee count includes 181 foreign nationals working as employees in Ecuador, China, Israel, the UK, Equatorial Guinea, Cameroon and Suriname.

Offices

Our principal corporate office, including our offices for US and international operations, is located at 100 Glenborough Drive, Suite 100, Houston, Texas 77067-3610. We maintain additional offices in Ardmore, Oklahoma and Denver, Colorado and in China, Cameroon, Ecuador, Equatorial Guinea, Israel, Suriname and the UK.

Title to Properties

We believe that our title to the various interests set forth above is satisfactory and consistent with generally accepted industry standards, subject to exceptions that are not so material as to detract substantially from the value of the interests or materially interfere with their use in our operations. Individual properties may be subject to burdens such as royalty, overriding royalty and other outstanding interests customary in the industry. In addition, interests may be subject to obligations or duties under applicable laws or burdens such as production payments, net profits interest, liens incident to operating agreements and for current taxes, development obligations under crude oil and natural gas leases or capital commitments under production sharing contracts or exploration licenses.

Available Information

Our website address is www.nobleenergyinc.com. Available on this website under "Investor Relations—Investor Relations Menu—SEC Filings," free of charge, are our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, Forms 3, 4 and 5 filed on behalf of directors and officers and amendments to those reports as soon as reasonably practicable after such materials are electronically filed with or furnished to the SEC.

Also posted on our website, and available in print upon request made by any stockholder to the Investor Relations Department, are charters for our Audit Committee; Compensation, Benefits and Stock Option Committee; Corporate Governance and Nominating Committee; and Environment, Health and Safety Committee. Copies of the Code of Business Conduct and Ethics, and the Code of Ethics for Chief Executive and Senior Financial Officers (the "Codes") are posted on our website under the "Corporate Governance" section. Within the time period required by the SEC and the NYSE, as applicable, we will post on our website any modifications to the Codes and any waivers applicable to senior officers as defined in the applicable Code, as required by the Sarbanes-Oxley Act of 2002.

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In 2007, we submitted the annual certification of our Chief Executive Officer regarding compliance with the NYSE's corporate governance listing standards, pursuant to Section 303A.12(a) of the NYSE Listed Company Manual.

Item 1A. Risk Factors.

Crude oil and natural gas prices are volatile and a substantial reduction in these prices could adversely affect our results and the price of our common stock.

Our revenues, operating results and future rate of growth depend highly upon the prices we receive for our crude oil and natural gas production. Historically, the markets for crude oil and natural gas have been volatile and are likely to continue to be volatile in the future. The markets and prices for crude oil and natural gas depend on factors beyond our control. These factors include demand for crude oil and natural gas, which fluctuates with changes in market and economic conditions, and other factors, including:

- worldwide and domestic supplies of crude oil and natural gas;
- actions taken by foreign oil and gas producing nations;
- political conditions and events (including instability or armed conflict) in crude oil producing or natural gas producing regions;
- the level of global crude oil and natural gas inventories;
- the price and level of foreign imports;
- the price and availability of alternative fuels;
- the availability of pipeline capacity and infrastructure;
- the availability of crude oil transportation and refining capacity;
- weather conditions;
- electricity dispatch;
- domestic and foreign governmental regulations and taxes; and
- the overall economic environment.

Significant declines in crude oil and natural gas prices for an extended period may have the following effects on our business:

- limiting our financial condition, liquidity, ability to finance planned capital expenditures and results of operations;
- reducing the amount of crude oil and natural gas that we can produce economically;
- causing us to delay or postpone some of our capital projects;
- reducing our revenues, operating income and cash flow;
- reducing the carrying value of our crude oil and natural gas properties; or
- limiting our access to sources of capital, such as equity and long-term debt.

Estimates of crude oil and natural gas reserves are not precise.

There are numerous uncertainties inherent in estimating crude oil and natural gas reserves and their value, including many factors that are beyond our control. Reservoir engineering is a subjective process of estimating underground accumulations of crude oil and natural gas that cannot be measured in an exact manner. Our reserve estimates are based on year-end commodity prices; therefore, reserve quantities will change when actual prices increase or decrease. The estimates depend on a number of factors and assumptions that may vary considerably from actual results, including:

- historical production from the area compared with production from other areas;
- the assumed effects of regulations by governmental agencies;
- assumptions concerning future crude oil and natural gas prices;
- future operating costs;
- severance and excise taxes;
- development costs; and
- workover and remedial costs.

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For these reasons, estimates of the economically recoverable quantities of crude oil and natural gas attributable to any particular group of properties, classifications of those reserves based on risk of recovery and estimates of the future net cash flows expected from them prepared by different engineers or by the same engineers but at different times may vary substantially. Accordingly, reserve estimates may be subject to upward or downward adjustment, and actual production, revenue and expenditures with respect to our reserves likely will vary, possibly materially, from estimates.

Additionally, because some of our reserve estimates are calculated using volumetric analysis, those estimates are less reliable than the estimates based on a lengthy production history. Volumetric analysis involves estimating the volume of a reservoir based on the net feet of pay of the structure and an estimation of the area covered by the structure. In addition, realization or recognition of proved undeveloped reserves will depend on our development schedule and plans. A change in future development plans for proved undeveloped reserves could cause the discontinuation of the classification of these reserves as proved.

Failure to fund continued capital expenditures could adversely affect our properties.

Our acquisition, exploration, and development activities require substantial capital expenditures. Historically, we have funded our capital expenditures through a combination of cash flows from operations, our revolving bank credit facility and debt and equity issuances. Future cash flows are subject to a number of variables, such as the level of production from existing wells, prices of crude oil and natural gas, and our success in finding, developing and producing new reserves. If revenue were to decrease as a result of lower crude oil and natural gas prices or decreased production, and our access to capital were limited, we would have a reduced ability to replace our reserves, resulting in a decrease in production over time. If our cash flow from operations is not sufficient to meet our obligations and fund our capital budget, we may not be able to access debt, equity or other methods of financing on an economic basis to meet these requirements. If we are not able to fund our capital expenditures, interests in some properties might be reduced or forfeited as a result.

A recession or an economic slowdown could have a material adverse impact on our financial position, results of operations and cash flows.

The oil and gas industry is cyclical in nature and tends to reflect general economic conditions. Currently, the US economy is slowing and may be headed toward a recession. A recession may lead to significant fluctuations in demand and pricing for our crude oil and natural gas production. If we were to continue development of our property interests after a decline in the prices of crude oil and natural gas had occurred, our profitability may be significantly affected by decreased demand and lower commodity prices. In addition, our future access to capital could be limited due to tightening credit markets.

Our international operations may be adversely affected by economic and political developments.

We have significant international crude oil and natural gas operations. These operations may be adversely affected by political and economic developments, including the following:

- war, terrorist acts and civil disturbances;
- loss of revenue, property and equipment as a result of actions taken by foreign crude oil and natural gas producing nations, such as expropriation or nationalization of assets and renegotiation, modification or nullification of existing contracts, such as may occur pursuant to the hydrocarbons law enacted in 2006 by the government of Equatorial Guinea;
- changes in taxation policies;
-

- laws and policies of the US and foreign jurisdictions affecting foreign investment, taxation, trade and business conduct;
- foreign exchange restrictions;
- international monetary fluctuations and changes in the value of the US dollar; and
- other hazards arising out of foreign governmental sovereignty over areas in which we conduct operations.

Exploration, development and production risks and natural disasters could result in liability exposure or the loss of production and revenues.

Our operations are subject to hazards and risks inherent in the drilling, production and transportation of crude oil and natural gas, including:

- pipeline ruptures and spills;
- fires;
- explosions, blowouts and cratering;
- formations with abnormal pressures;
- equipment malfunctions;
- hurricanes; and
- other natural disasters.

Any of these can result in loss of hydrocarbons, environmental pollution and other damage to our properties or the properties of others.

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Exploration and development drilling may not result in commercially productive reserves.

We do not always encounter commercially productive reservoirs through our drilling operations. The wells we drill or participate in may not be productive and we may not recover all or any portion of our investment in those wells. The seismic data and other technologies we use do not allow us to know conclusively prior to drilling a well that crude oil or natural gas is present or may be produced economically. The cost of drilling, completing and operating a well is often uncertain, and cost factors can adversely affect the economics of a project. Our efforts will be unprofitable if we drill dry holes or wells that are productive but do not produce enough reserves to return a profit after drilling, operating and other costs. Further, our drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, including:

- unexpected drilling conditions;
- title problems;
- pressure or other irregularities in formations;
- equipment failures or accidents;
- adverse weather conditions;
- compliance with environmental and other governmental requirements; and
- increases in the cost of, or shortages or delays in the availability of, drilling rigs and equipment.

We may be unable to make attractive acquisitions or integrate acquired businesses and/or assets, and any inability to do so may disrupt our business.

One aspect of our business strategy calls for acquisitions of businesses and assets that complement or expand our current business. We cannot provide assurance that we will be able to identify attractive acquisition opportunities. Even if we do identify attractive opportunities, we cannot provide assurance that we will be able to complete the acquisition of them or do so on commercially acceptable terms. Additionally, if we acquire another business, we could have difficulty integrating its operations, systems, management and other personnel and technology with our own. These difficulties could disrupt ongoing business, distract management and employees, increase expenses and adversely affect results of operations. Even if these difficulties could be overcome, we cannot provide assurance that the anticipated benefits of any acquisition would be realized.

We are subject to various governmental regulations and environmental risks that may cause us to incur substantial costs.

From time to time, in varying degrees, political developments and federal and state laws and regulations affect our operations. In particular, price controls, taxes and other laws relating to the crude oil and natural gas industry, changes in these laws and changes in administrative regulations have affected and in the future could affect crude oil and natural gas production, operations and economics. We cannot predict how agencies or courts will interpret existing laws and regulations or the effect these adoptions and interpretations may have on our business or financial condition.

Our business is subject to laws and regulations promulgated by international, federal, state and local authorities relating to the exploration for, and the development, production and marketing of, crude oil and natural gas, as well as safety matters. Legal requirements are frequently changed and subject to interpretation and we are unable to predict the ultimate cost of compliance with these requirements or their effect on our operations. We may be required to make significant expenditures to comply with governmental laws and regulations.

Our operations are subject to complex international, federal, state and local environmental laws and regulations including in the case of federal laws, the Comprehensive Environmental Response, Compensation and Liability Act, as amended, the Resource Conservation and Recovery Act, as amended, the Oil Pollution Act of 1990, the Clean Air Act and the Clean Water Act. Environmental laws and regulations change frequently and the implementation of new, or the modification of, existing laws or regulations could negatively impact our operations. The discharge of natural gas, crude oil, or other pollutants into the air, soil or water may give rise to significant liabilities on our part to the government and third parties and may require us to incur substantial costs of remediation.

Potential regulations regarding climate change could alter the way we conduct our business.

As awareness of climate change issues increases, governments around the world are beginning to address the issue. This may result in new environmental regulations that may unfavorably impact us, our suppliers, and our customers. The cost of meeting these requirements may have an adverse impact on our financial condition, results of operations and cash flows.

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The unavailability or high cost of drilling rigs, equipment, supplies, personnel and other oil field services could adversely affect our ability to execute our exploration and development plans on a timely basis and within our budget.

Our industry is cyclical and, from time to time, there is a shortage of drilling rigs, equipment, supplies or qualified personnel. During these periods, the costs of rigs, equipment and supplies are substantially greater and their availability may be limited. As a result of increasing levels of exploration and production in response to strong demand for crude oil and natural gas, the demand for oilfield services and the costs of these services have increased. Additionally, these services may not be available on commercially reasonable terms.

We may not have enough insurance to cover all of the risks we face, which could result in significant financial exposure.

Exploration for and production of crude oil and natural gas can be hazardous, involving natural disasters and other unfortuitous events such as blowouts, cratering, fire and explosion and loss of well control which can result in damage to or destruction of wells or production facilities, injury to persons, loss of life, or damage to property and the environment. In accordance with industry practices, we maintain insurance against many, but not all, potential perils confronting our operations and in coverage amounts and deductible levels that we believe to be prudent. Consistent with that profile, our insurance program is structured to provide us financial protection from unfavorable loss severity resulting from damages to or the loss of physical assets or loss of human life, liability claims of third parties, and business interruption (loss of production) attributed to certain assets. Although we believe the coverages and amounts of insurance carried are adequate, we may not have sufficient protection against some of the risks we face, because we chose not to insure certain risks, insurance is not available on commercially reasonable terms or actual losses exceed coverage limits. If an event occurs that is not covered by insurance or not fully protected by insured limits, it could have an adverse impact on our financial condition, results of operations and cash flows.

We face significant competition and many of our competitors have resources in excess of our available resources.

We operate in the highly competitive areas of crude oil and natural gas exploration, exploitation, acquisition and production. We face intense competition from a large number of independent, technology-driven companies as well as both major and other independent crude oil and natural gas companies in a number of areas such as:

- seeking to acquire desirable producing properties or new leases for future exploration;
- marketing our crude oil and natural gas production;
- seeking to acquire the equipment and expertise necessary to operate and develop properties; and
- attracting and retaining employees with certain skills.

Many of our competitors have financial and other resources substantially in excess of those available to us. This highly competitive environment could have an adverse impact on our business.

Our level of indebtedness may limit our financial flexibility.

As of December 31, 2007, we had long-term indebtedness of $1.9 billion (excluding unamortized discount), with $1.2 billion drawn under our bank credit facility. Our indebtedness represented 28% of our total book capitalization at December 31, 2007.

Our level of indebtedness affects our operations in several ways, including the following:

-

a portion of our cash flows from operating activities must be used to service our indebtedness and is not available for other purposes;

- we may be at a competitive disadvantage as compared to similar companies that have less debt;
- the covenants contained in the agreements governing our outstanding indebtedness and future indebtedness may limit our ability to borrow additional funds, pay dividends and make certain investments and may also affect our flexibility in planning for, and reacting to, changes in the economy and in our industry;
- additional financing in the future for working capital, capital expenditures, acquisitions, general corporate or other purposes may have higher costs and more restrictive covenants;

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- changes in the credit ratings of our debt may negatively affect the cost, terms, conditions and availability of future financing, and lower ratings will increase the interest rate and fees we pay on our revolving credit facility; and
- we may be more vulnerable to general adverse economic and industry conditions.

We may incur additional debt in order to fund our acquisition, exploration and development activities. A higher level of indebtedness increases the risk that we may default on our debt obligations. Our ability to meet our debt obligations and reduce our level of indebtedness depends on future performance. General economic conditions, crude oil and natural gas prices and financial, business and other factors will affect our operations and our future performance. Many of these factors are beyond our control and we may not be able to generate sufficient cash flow to pay the interest on our debt, and future working capital, borrowings and equity financing may not be available to pay or refinance such debt.

Hedging transactions may limit our potential gains.

In order to manage our exposure to price risks in the marketing of our crude oil and natural gas, we enter into crude oil and natural gas price hedging arrangements with respect to a portion of our expected production. Our hedges, consisting of a series of contracts, are limited in duration, usually for periods of one to four years. While intended to reduce the effects of volatile crude oil and natural gas prices, such transactions may limit our potential gains if crude oil and natural gas prices rise over the price established by the arrangements. In trying to manage our exposure to price risk, we may end up hedging too much or too little, depending upon how our crude oil or natural gas volumes and our production mix fluctuate in the future. In addition, hedging transactions may expose us to the risk of financial loss in certain circumstances, including instances in which our production is less than expected; there is a widening of price basis differentials between delivery points for our production and the delivery point assumed in the hedge arrangement; the counterparties to our future contracts fail to perform under the contracts; or a sudden unexpected event materially impacts crude oil or natural gas prices. We cannot assure that our hedging transactions will reduce the risk or minimize the effect of any decline in crude oil or natural gas prices.

Information technology systems implementation issues could disrupt our internal operations, increase our costs and adversely affect our financial results or our ability to report our financial results.

We are currently in the process of implementing a new Enterprise Resource Planning software system to replace our various legacy systems. Our implementation is based on a phased approach, the first phase of which was implemented fourth quarter 2007. We expect to implement additional phases during 2008. As a part of this effort, we are transitioning data and changing processes and this may be more expensive, time consuming and resource intensive than planned. Any disruptions that may occur in the implementation or operation of this system or any future systems could increase our expenses and adversely affect our ability to report in an accurate and timely manner our financial position, results of operations and cash flows and to otherwise operate our business.

Provisions in our Certificate of Incorporation and Delaware law may inhibit a takeover of us.

Under our Certificate of Incorporation, our Board of Directors is authorized to issue shares of our common or preferred stock without approval of our stockholders. Issuance of these shares could make it more difficult to acquire us without the approval of our Board of Directors as more shares would have to be acquired to gain control. In addition, Delaware law imposes restrictions on mergers and other business combinations between us and any holder of 15% or more of our outstanding common stock. These provisions may deter hostile takeover attempts that could result in an acquisition of us that would have been financially beneficial to our stockholders.

Disclosure Regarding Forward-Looking Statements

This annual report on Form 10-K and the documents incorporated by reference in this report contain forward-looking statements within the meaning of the federal securities laws. Forward-looking statements give our current expectations or forecasts of future events. These forward-looking statements include, among others, the following:

- our growth strategies;
- our ability to successfully and economically explore for and develop crude oil and natural gas resources;
- anticipated trends in our business;
- our future results of operations;
- our liquidity and ability to finance our acquisition, exploration and development activities;
- market conditions in the oil and gas industry;

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- our ability to make and integrate acquisitions; and
- the impact of governmental regulation.

Forward-looking statements are typically identified by use of terms such as “may,” “will,” “expect,” “anticipate,” “estimate” a similar words, although some forward-looking statements may be expressed differently. These forward-looking statements are made based upon management’s current plans, expectations, estimates, assumptions and beliefs concerning future events impacting us and therefore involve a number of risks and uncertainties. We caution that forward-looking statements are not guarantees and that actual results could differ materially from those expressed or implied in the forward-looking statements. You should consider carefully the statements under Item 1A. Risk Factors and other sections of this report, which describe factors that could cause our actual results to differ from those set forth in the forward-looking statements.

ItemUnresolved Staff Comments.
1B.

None.

ItemLegal Proceedings.
3.

We are among a group of eighteen defendants named in a lawsuit filed August 23, 2002 by Dore Energy Corporation under Docket Number 10-16202 in the 38th Judicial District Court, Cameron Parish, Louisiana. The lawsuit alleges damage to property owned by Dore resulting from oil and gas activities dating to the 1930’s. Our predecessor, Samedan Oil Corporation, operated on a portion of the property from 1989 to 1999. Dore has delivered documents alleging approximately $140 million in damages. Trial is currently set for April 14, 2008. We intend to vigorously defend against these allegations and believe that our share of damages, if any, will not have a material adverse effect on our results of operations, financial condition or liquidity.

The Illinois Environmental Protection Agency (“IEPA”) issued a notice of violation to Equinox Oil Company on September 25, 2001 alleging violation of air emission and permitting regulations for a facility known as the Zif Gas Plant located near Clay City, Illinois. On January 17, 2007, the IEPA re-issued written notices of these alleged violations in the name of Equinox’s successors in interest, and our wholly-owned subsidiaries, Elysium Energy, LLC and Noble Energy Production, Inc. On March 16, 2007, the IEPA accepted our compliance commitment agreement wherein we agreed to pay a delayed permit fee, install an incineration/caustic scrubber emissions control system at the site, and fund a supplemental environmental project (“SEP”) in the nearby community. At this time, we expect no additional monies to be expended other than these amounts for which we have fully accrued. As of December 31, 2007, this matter has been concluded.

We are involved in various legal proceedings, including the foregoing matters, in the ordinary course of business. These proceedings are subject to the uncertainties inherent in any litigation. We are defending ourselves vigorously in all such matters and we do not believe that the ultimate disposition of such proceedings will have a material adverse effect on our consolidated financial position, results of operations or cash flows.

ItemSubmission of Matters to a Vote of Security Holders.
4.

There were no matters submitted to a vote of security holders during the fourth quarter of 2007.

Executive Officers

The following table sets forth certain information, as of February 25, 2008, with respect to our executive officers.

Name	Age	Position
Charles D. Davidson (1)	57	Chairman of the Board, President, Chief Executive Officer and Director
David L. Stover (2)	50	Executive Vice President, Chief Operating Officer
Chris Tong (3)	51	Senior Vice President, Chief Financial Officer
Alan R. Bullington (4)	56	Senior Vice President, International
Susan M. Cunningham (5)	52	Senior Vice President, Exploration
Arnold J. Johnson (6)	52	Vice President, General Counsel and Secretary
Andrea Lee Robison (7)	49	Vice President, Human Resources

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(1) Charles D. Davidson was elected President and Chief Executive Officer of Noble Energy in October 2000 and Chairman of the Board in April 2001. Prior to October 2000, he served as President and Chief Executive Officer of Vastar Resources, Inc. from March 1997 to September 2000 (Chairman from April 2000) and was a Vastar Director from March 1994 to September 2000. From September 1993 to March 1997, he served as a Senior Vice President of Vastar. From 1972 to October 1993, he held various positions with ARCO.

(2) David L. Stover was elected Executive Vice President and Chief Operating Officer of Noble Energy on August 1, 2006. Prior thereto, he served as Senior Vice President of North America and Business Development from July 2004 through July 2006. He served as Noble Energy's Vice President of Business Development from December 2002 through June 2004. Previous to his employment with Noble Energy, he was employed by BP America, Inc. as Vice President, Gulf of Mexico Shelf from September 2000 to August 2002. Prior to joining BP, Mr. Stover was employed by Vastar, as Area Manager for Gulf of Mexico Shelf from April 1999 to September 2000, and prior thereto, as Area Manager for Oklahoma/Arklatex from January 1994 to April 1999. From 1979 to 1994, he held various positions with ARCO.

(3) Chris Tong was elected a Senior Vice President and Chief Financial Officer of Noble Energy on January 1, 2005. Prior to January 1, 2005, he had served as Senior Vice President and Chief Financial Officer for Magnum Hunter Resources, Inc. since August 1997. Prior thereto, he was Senior Vice President of Finance of Tejas Acadian Holding Company and its subsidiaries including Tejas Gas Corp., Acadian Gas Corporation and Transok, Inc., all of which were wholly-owned subsidiaries of Tejas Gas Corporation. Mr. Tong held these positions since August 1996, and served in other treasury positions with Tejas beginning August 1989. From 1980 to 1989, Mr. Tong served in various energy lending capacities with several commercial banking institutions. Prior to his banking career, Mr. Tong served over a year with Superior Oil Company as a Reservoir Engineering Assistant.

(4) Alan R. Bullington was elected a Vice President of Noble Energy on April 24, 2001 and a Senior Vice President of Noble Energy on July 27, 2004 and is currently responsible for Noble Energy's International Division. Prior thereto, he served as Vice President and General Manager, International Division of Samedan Oil Corporation beginning January 1, 1998. Prior thereto, he served as Manager-International Operations and Exploration and as Manager-International Operations. Prior to his employment with Samedan in 1990, he held various management positions within the exploration and production division of Texas Eastern Transmission Company.

(5) Susan M. Cunningham was elected a Senior Vice President of Noble Energy in April 2001 and is currently responsible for our world-wide exploration. Prior to joining Noble Energy, Ms. Cunningham was Texaco's Vice President of worldwide exploration from April 2000 to March 2001. From 1997 through 1999, she was employed by Statoil, beginning in 1997 as Exploration Manager for deepwater Gulf of Mexico, appointed a Vice President in 1998 and responsible, in 1999, for Statoil's West Africa exploration efforts. She joined Amoco in 1980 as a geologist and held various exploration and development positions until 1997.

(6) Arnold J. Johnson was elected Vice President, General Counsel and Secretary of Noble Energy on February 1, 2004. Prior thereto, he served as Associate General Counsel and Assistant Secretary of Noble Energy from January 2001 through January 2004. Previous to his employment with Noble Energy, he served as Senior Counsel for BP America, Inc. from October 2000 to January 2001. Mr. Johnson held several positions as an attorney for Vastar and ARCO from March 1989 through September 2000, most recently as Assistant General Counsel and Assistant Secretary of Vastar from 1997 through 2000. From 1980 to March 1989, he held various positions with ARCO.

(7)

Andrea Lee Robison was elected to the position of Vice President of Noble Energy on November 1, 2007 and is responsible for Human Resources. Prior thereto, she served as Director of Human Resources from May 2002 through October 2007. Prior to joining us, Ms. Robison was Manager of Human Resources for the Gulf of Mexico Shelf for BP America, Inc. from September 2000 through April 2002. Prior to her employment at BP, she served as HR Director at Vastar from 1997 through September 2000, and Compensation Consultant from January 1994 through 1996. From 1980 through 1993 she held various positions with ARCO.

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PART II

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

Common Stock. Our common stock, $3.33 1/3 par value, is listed and traded on the NYSE under the symbol "NBL." The declaration and payment of dividends are at the discretion of our Board of Directors and the amount thereof will depend on our results of operations, financial condition, contractual restrictions, cash requirements, future prospects and other factors deemed relevant by the Board of Directors.

Stock Prices and Dividends by Quarters. The high and low sales price per share of common stock on the NYSE and quarterly dividends paid per share were as follows:

	High	Low	Dividends Per Share
2006			
First quarter	$ 46.91	$ 38.32	$ 0.050
Second quarter	49.33	36.14	0.075
Third quarter	51.71	41.80	0.075
Fourth quarter	54.64	41.77	0.075
2007			
First quarter	$ 60.69	$ 46.33	$ 0.075
Second quarter	65.50	58.81	0.120
Third quarter	70.55	58.17	0.120
Fourth quarter	81.64	69.69	0.120

On January 22, 2008, the Board of Directors declared a quarterly cash dividend of 12.0 cents per common share, which was paid February 19, 2008 to shareholders of record on February 4, 2008.

Transfer Agent and Registrar. The transfer agent and registrar for the common stock is Wells Fargo Bank, N.A., 161 North Concord Exchange, South St. Paul, MN, 55075.

Stockholders' Profile. Pursuant to the records of the transfer agent, as of February 12, 2008, the number of holders of record of common stock was 817.

Stock Repurchases. We did not repurchase any of our common stock during the fourth quarter of 2007.

Equity Compensation Plan Information. The following table summarizes information regarding the number of shares of our common stock that are available for issuance under all of our existing equity compensation plans as of December 31, 2007.

	Number of securities to be issued upon exercise of	Weighted-average exercise price of outstanding options, warrants	Number of securities remaining available for future issuance under equity compensation plans (excluding securities

Plan Category	outstanding options (a)		and rights (b)	reflected in column (a)) (c)
Equity compensation plans approved by security holders	6,175,061	$	32.98	6,713,971
Equity compensation plans not approved by security holders	-		-	-
Total	6,175,061	$	32.98	6,713,971

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Stock Performance Graph. This graph shows our cumulative total shareholder return over the five-year period from December 31, 2002, to December 31, 2007. The graph also shows the cumulative total returns for the same five-year period of the S&P 500 Index, an old peer group of companies and a new peer group of companies. The companies in the old peer group, which has been adjusted for the effects of industry consolidation, consist of Anadarko Petroleum Corp., Apache Corp., Chesapeake Energy Corp., Devon Energy Corp., EOG Resources, Inc., Forest Oil Corp., Murphy Oil Corp., Newfield Exploration Company, Pioneer Natural Resources Company, Stone Energy Corp., and XTO Energy Inc. The companies in the new peer group consist of Anadarko Petroleum Corp., Apache Corp., Cabot Oil & Gas Corp., Chesapeake Energy Corp., Devon Energy Corp., EOG Resources, Inc., Forest Oil Corp., Murphy Oil Corp., Newfield Exploration Company, Pioneer Natural Resources Company, Plains Exploration and Production Company, Range Resources Corp., Southwestern Energy Company, and XTO Energy Inc. The changes in peer group were made as a result of industry consolidation and pursuant to a resolution adopted by the Compensation, Benefits and Stock Option Committee of the Board of Directors. The comparison assumes $100 was invested on December 31, 2002, in our common stock, in the S&P 500 Index and in our old and new peer groups and assumes that all of the dividends were reinvested.

	12/02	12/03	12/04	12/05	12/06	12/07
Noble Energy, Inc.	100.00	118.88	165.66	217.40	266.26	434.46
S&P 500	100.00	128.68	142.69	149.70	173.34	182.87
New Peer Group	100.00	129.82	174.50	278.18	276.86	403.91
Old Peer Group	100.00	129.53	170.44	267.61	260.17	375.03

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Item 6. Selected Financial Data.

	Year Ended December 31,				
	2007	2006 (1)	2005 (2)	2004	2003
	(in thousands, except share amounts)				
Revenues and Income					
Total revenues	$ 3,272,030	$ 2,940,082	$ 2,186,723	$ 1,351,051	$ 1,008,226
Income from continuing operations	943,870	678,428	645,720	313,850	89,892
Net income	943,870	678,428	645,720	328,710	77,992
Per Share Data					
Basic earnings per share -					
Income from continuing operations	$ 5.52	$ 3.86	$ 4.20	$ 2.69	$ 0.79
Net income	5.52	3.86	4.20	2.82	0.68
Cash dividends	0.435	0.275	0.150	0.100	0.085
Year-end stock price	80.66	49.07	40.30	30.83	22.22
Basic weighted average shares outstanding	171,078	175,707	153,773	116,550	113,928
Cash Flows					
Net cash provided by operating activities	2,016,573	1,730,306	1,239,878	708,186	602,770
Additions to property, plant and equipment	1,414,515	1,357,039	785,610	553,643	511,434
Acquisitions	-	412,257	1,111,099	-	-
Financial Position					
Property, plant, and equipment, net	$ 7,944,464	$ 7,170,757	$ 6,198,916	$ 2,180,715	$ 2,046,909
Goodwill	760,496	781,290	862,868	-	-
Total assets	10,830,896	9,588,625	8,878,033	3,435,784	2,820,800
Long-term obligations -					
Long-term debt	1,851,087	1,800,810	2,030,533	880,256	776,021
Deferred income taxes	1,983,833	1,758,452	1,201,191	180,415	161,912
Asset retirement obligations	130,956	127,689	278,540	175,415	101,804
Derivative instruments	82,803	328,875	757,509	9,678	7,400
Other deferred credits and noncurrent liabilities	337,667	274,720	279,971	69,479	72,776
Shareholders' equity	4,808,807	4,113,817	3,090,144	1,459,988	1,073,573
Operations Information					
Natural gas sales (Mcfpd)	687,444	622,927	508,195	366,965	336,611
Average realized price ($/Mcf) (3)	$ 5.26	$ 5.55	$ 5.78	$ 4.76	$ 4.19
Crude oil sales (Bopd)	76,581	74,915	56,958	44,481	35,101
Average realized price ($/Bbl) (3)	$ 60.61	$ 54.47	$ 45.35	$ 34.48	$ 27.67
Equity investee sales (Bopd)	7,684	8,032	3,240	894	913
Average realized price ($/Bbl)	$ 55.09	$ 45.83	$ 43.43	$ 32.01	$ 25.47
Proved Reserves					
Natural gas reserves (Bcf)	3,307	3,231	3,091	1,987	1,642
Crude oil reserves (MMBbl)	329	296	291	193	183
Total reserves (MMBoe)	880	835	806	525	457
Number of employees	1,398	1,243	1,171	559	583

(1) Includes effect of acquisition of U.S. Exploration and sale of Gulf of Mexico shelf properties. See Item 8. Financial Statements and Supplementary Data—Note 3—Acquisitions and Divestitures for additional information.

(2) Includes effect of Patina Merger. See Item 8. Financial Statements and Supplementary Data—Note 3—Acquisitions and Divestitures for additional information.

(3) Prices include effects of oil and gas hedging activities. See Item 8. Financial Statements and Supplementary Data—Note 12—Derivative Instruments and Hedging Activities.

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

We are an independent energy company engaged in the acquisition, exploration, development, production and marketing of crude oil and natural gas domestically and internationally. We operate throughout major basins in the US including Colorado's Wattenberg field and Piceance basin, the Mid-continent area of western Oklahoma and the Texas Panhandle, the San Juan basin in New Mexico, the Gulf Coast and the deepwater Gulf of Mexico. We also conduct business internationally, in China, Ecuador, the Mediterranean Sea, the North Sea, West Africa (Equatorial Guinea and Cameroon) and in other areas.

Our accompanying consolidated financial statements, including the notes thereto, contain detailed information that should be referred to in conjunction with the following discussion.

EXECUTIVE OVERVIEW

We are a worldwide producer of crude oil and natural gas. Our strategy is to achieve growth in earnings and cash flow through the development of a high quality portfolio of producing assets that is diversified between US and international projects. The Patina Merger, purchase of U.S. Exploration and sale of Gulf of Mexico shelf properties have allowed us to achieve a strategic objective of enhancing our US asset portfolio. The result is a company with assets and capabilities that include growing US basins coupled with a significant portfolio of international properties. Our reserve base includes both US and international sources at 58% US and 42% international. We are now a larger, more diversified company with greater opportunities for both US and international growth.

2007 was a strong year for us, both financially and operationally. Significant financial results included the following:

- net income of $944 million, a 39% increase over 2006 net income;
- diluted earnings per share of $5.45, a 44% increase over 2006;
- cash flow provided by operating activities of $2.0 billion, a 17% increase over 2006; and
- completion of a $500 million common stock repurchase program begun in 2006.

Significant operational highlights included the following:

- eight successful exploration wells drilled internationally, six offshore West Africa and two in the North Sea;
- deepwater Gulf of Mexico exploration success at Isabela (Mississippi Canyon Block 562);
- commencement of production and continued ramp-up at the Dumbarton development and successful exploratory appraisal well drilled at the Flyndre prospect in the UK sector of the North Sea;
- completion of the Mari-B #7 well and record natural gas sales in Israel;
- continued success of development program in the US Wattenberg field; and
- acquisition of approximately 290,000 net acres onshore US in the Piceance basin, Niobrara trend and New Albany Shale areas.

Sale of Argentina—In December 2007, we entered into an agreement to sell our interest in Argentina for a sales price of $117.5 million, effective July 1, 2007. We expect the sale, which is subject to regulatory and partner approvals, to close in 2008.

Equatorial Guinea 2006 Hydrocarbons Law—Effective November 2006, the government of Equatorial Guinea enacted the 2006 Hydrocarbons Law governing petroleum operations in Equatorial Guinea. The governmental agency responsible for the energy industry was given the authority to renegotiate any contract for the purpose of adapting any terms and conditions that are inconsistent with the new law. At this time we are uncertain what economic impact this law will have on our operations in Equatorial Guinea.

2008 OUTLOOK

We expect crude oil and natural gas production to increase in 2008 compared to 2007. Factors which may impact our expected year-over-year increase in production include:

- higher sales of natural gas from the Alba field in Equatorial Guinea; and
- growing production from the D-J and Piceance basins, where we are continuing active drilling programs;

offset by:

- natural field decline in the Gulf Coast area.

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Factors which may impact our expected production profile include:

- potential hurricane-related volume curtailments in the Gulf of Mexico and Gulf Coast areas;
- potential winter storm-related volume curtailments in the Northern region of our US operations;
- potential pipeline and processing facility capacity constraints in the Rocky Mountain area of our US operations;
- infrastructure development in Israel;
- potential downtime at the methanol, LPG and/or LNG facilities in Equatorial Guinea;
- seasonal variations in rainfall in Ecuador that affect our natural gas-to-power project; and
- timing of capital expenditures, as discussed below, which are expected to result in near-term production.

2008 Budget—We have budgeted capital expenditures of approximately $1.6 billion for 2008. Approximately 24% of the 2008 capital budget has been allocated to exploration opportunities and 76% has been allocated to production, development and other projects. US spending is budgeted for $1.2 billion, international expenditures are budgeted for $392 million and corporate expenditures are budgeted for $27 million. The 2008 budget does not include the impact of possible asset purchases. We expect that the 2008 capital budget will be funded primarily from cash flows from operations and borrowings under our revolving credit facility. We will evaluate the level of capital spending throughout the year based on drilling results, commodity prices, cash flows from operations and property acquisitions and divestitures.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The preparation of the consolidated financial statements requires our management to make a number of estimates and assumptions relating to the reported amounts of assets and liabilities and the disclosures of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the period. When alternatives exist among various accounting methods, the choice of accounting method can have a significant impact on reported amounts. The following is a discussion of the accounting policies, estimates and judgments which management believes are most significant in the application of generally accepted accounting principles used in the preparation of the consolidated financial statements.

Purchase Price Allocation—As a result of the Patina Merger in 2005 and the acquisition of U.S. Exploration in 2006, we acquired assets and assumed liabilities in transactions accounted for as purchases. In connection with a purchase business combination, the acquiring company must allocate the cost of the acquisition to assets acquired and liabilities assumed based on fair values as of the acquisition date. Deferred taxes must be recorded for any differences between the assigned values and tax bases of assets and liabilities. Any excess of purchase price over amounts assigned to assets and liabilities is recorded as goodwill. The amount of goodwill recorded in any particular business combination can vary significantly depending upon the value attributed to assets acquired and liabilities assumed.

In estimating the fair values of assets acquired and liabilities assumed we made various assumptions. The most significant assumptions related to the estimated fair values assigned to proved and unproved crude oil and natural gas properties. To estimate the fair values of these properties, we prepared estimates of crude oil and natural gas reserves. We estimated future prices to apply to the estimated reserve quantities acquired, and estimated future operating and development costs, to arrive at estimates of future net cash flows. For estimated proved reserves, the future net cash flows were discounted using a market-based weighted average cost of capital rate determined appropriate at the time of the merger. The market-based weighted average cost of capital rate was subjected to additional project-specific risking factors. To compensate for the inherent risk of estimating and valuing unproved reserves, the discounted future net cash flows of probable and possible reserves were reduced by additional risk-weighting factors.

Estimated deferred taxes were based on available information concerning the tax basis of assets acquired and liabilities assumed and loss carryforwards at the merger date, although such estimates may change in the future as additional information becomes known.

While the estimates of fair value for the assets acquired and liabilities assumed have no effect on our cash flows, they can have an effect on the future results of operations. Generally, higher fair values assigned to crude oil and natural gas properties result in higher future depreciation, depletion and amortization ("DD&A") expense, which results in decreased future net earnings. Also, a higher fair value assigned to crude oil and natural gas properties, based on higher estimates of future crude oil and natural gas prices, could increase the likelihood of impairment in the event of lower commodity prices or higher operating or development costs than those originally used to determine fair value. Impairment would have no effect on cash flows but would result in a decrease in net income for the period in which the impairment is recorded.

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Goodwill—As of December 31, 2007, the consolidated balance sheet included $760 million of goodwill, all of which has been assigned to the US reporting unit. Goodwill is not amortized to earnings but is tested, at least annually, for impairment at the reporting unit level. We conduct the goodwill impairment test as of December 31 of each year. Other events and changes in circumstances may also require goodwill to be tested for impairment between annual measurement dates. If the carrying value of goodwill is determined to be impaired, the amount of goodwill is reduced and a corresponding charge is made to earnings in the period in which the goodwill is determined to be impaired.

The impairment assessment requires management to make estimates regarding the fair value of the reporting unit to which goodwill has been assigned. The fair value of the US reporting unit was determined using a combination of the income approach and the market approach. Under the income approach, the fair value of the reporting unit is estimated based on the present value of expected future cash flows. Under the market approach, the fair value is estimated based on selected financial metrics.

The income approach is dependent on a number of factors including estimates of forecasted revenue and operating costs, proved reserves, as well as the success of future exploration for and development of unproved reserves, appropriate discount rates and other variables. Downward revisions of estimated reserve quantities, increases in future cost estimates, divestiture of a significant component of the reporting unit, or sustained decreases in natural gas or crude oil prices could lead to an impairment of all or a portion of goodwill in future periods. Under the market approach, we make certain judgments about the selection of comparable companies, comparable recent company and asset transactions and transaction premiums. Although we have based the fair value estimate on assumptions we believe to be reasonable, those assumptions are inherently unpredictable and uncertain and actual results could differ from the estimate. In 2007, no goodwill impairment was recognized.

When we dispose of a reporting unit or a portion of a reporting unit that constitutes a business, we include goodwill associated with that business in the carrying amount of the business in order to determine the gain or loss on disposal. The amount of goodwill to be included in that carrying amount is based on the relative fair value of the business to be disposed of and the portion of the reporting unit that will be retained. During 2006, we allocated $100 million of US reporting unit goodwill to the carrying amount of our Gulf of Mexico shelf properties sold. The amount of goodwill allocated to the carrying amount of a business can significantly impact the amount of gain or loss recognized on the sale of that business.

Reserves—All of the reserve data in this Form 10-K are estimates. Estimates of our crude oil and natural gas reserves are prepared by our engineers in accordance with guidelines established by the SEC. Reservoir engineering is a subjective process of estimating underground accumulations of crude oil and natural gas. There are numerous uncertainties inherent in estimating quantities of proved crude oil and natural gas reserves. Uncertainties include the projection of future production rates and the expected timing of development expenditures. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. As a result, reserve estimates may be different from the quantities of crude oil and natural gas that are ultimately recovered. Estimates of proved crude oil and natural gas reserves significantly affect our DD&A expense. For example, if estimates of proved reserves decline, the DD&A rate will increase, resulting in a decrease in net income. A decline in estimates of proved reserves could also trigger an impairment analysis to determine if the carrying amount of crude oil and natural gas properties exceeds fair value and could result in an impairment charge, which would reduce earnings. In addition, a decline in estimates of proved reserves could trigger a goodwill impairment analysis.

Oil and Gas Properties—We account for crude oil and natural gas properties under the successful efforts method of accounting. The alternative method of accounting for crude oil and natural gas properties is the full cost method. Under the successful efforts method, costs to acquire mineral interests in crude oil and natural gas properties, to drill and equip exploratory wells that find proved reserves and to drill and equip development wells are capitalized. Proved property acquisition costs are amortized to operations by the unit-of-production method on a property-by-property basis based on total proved crude oil and natural gas reserves as estimated by our engineers. Costs to drill and equip exploratory wells that find proved reserves and to drill and equip development wells are also amortized to operations by the unit-of-production method on a property-by-property basis. They are amortized based on proved developed crude oil and natural gas reserves. Application of the successful efforts method results in the expensing of certain costs including geological and geophysical costs, exploratory dry holes and delay rentals, during the periods the costs are incurred. Under the full cost method, these costs are capitalized as assets and charged to earnings in future periods as a component of DD&A expense. In addition, under the full cost method capitalized costs are accumulated in pools on a country-by-country basis. DD&A is computed on a country-by-country basis, and capitalized costs are limited on the same basis through the application of a ceiling test. We believe the successful efforts method is the most appropriate method to use in accounting for our crude oil and natural gas properties as this method is better aligned with our business strategy. If we had used the full cost method, our financial position and results of operations could have been significantly different.

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Exploratory Well Costs—In accordance with the successful efforts method of accounting, the costs associated with drilling an exploratory well may be capitalized temporarily, or "suspended," pending a determination of whether commercial quantities of crude oil or natural gas have been discovered. We will carry the costs of an exploratory well as an asset if the well found a sufficient quantity of reserves to justify its completion as a producing well and as long as we are making sufficient progress assessing the reserves and the economic and operating viability of the project. For certain capital-intensive deepwater Gulf of Mexico or international projects, it may take more than one year to evaluate the future potential of the exploration well and make a determination of its economic viability. Our ability to move forward on a project may be dependent on gaining access to transportation or processing facilities or obtaining permits and government or partner approval, the timing of which is beyond our control. In such cases, exploratory well costs remain suspended as long as we are actively pursuing access to necessary facilities and access to such permits and approvals and believe they will be obtained. Management assesses the status of suspended exploratory well costs on a quarterly basis. These costs may be charged to exploration expense in future periods if we decide not to pursue additional exploratory or development activities. At December 31, 2007, the balance of property, plant and equipment included $249 million of suspended exploratory well costs, $62 million of which had been capitalized for a period greater than one year. The wells relating to these suspended costs continue to be evaluated by various means including additional seismic work, drilling additional wells, or evaluating the potential of the exploration wells. For more information, see Item 8. Financial Statements and Supplementary Data—Note 5—Capitalized Exploratory Well Costs.

Impairment of Proved Oil and Gas Properties—We assess proved crude oil and natural gas properties for possible impairment when events or circumstances indicate that the recorded carrying value of the properties may not be recoverable. We recognize an impairment loss as a result of a triggering event and when the estimated undiscounted future cash flows from a property are less than the carrying value. If impairment is indicated, the cash flows are discounted at a rate approximate to our cost of capital and compared to the carrying value for determining the amount of the impairment loss to record. Estimated future cash flows are based on management's expectations for the future and include estimates of crude oil and natural gas reserves and future commodity prices and operating costs. Downward revisions in estimates of reserve quantities or expectations of falling commodity prices or rising operating costs could result in a reduction in undiscounted future cash flows and could indicate property impairment. We recorded approximately $4 million of impairments in 2007, primarily related to adjustment of the carrying value of properties to their fair values.

Impairment of Unproved Oil and Gas Properties—We also perform periodic assessments of individually significant unproved crude oil and natural gas properties for impairment. Cash flows used in the impairment analysis are determined based upon management's estimates of natural gas and crude oil reserves, future commodity prices and future costs to extract the reserves. Downward revisions in estimated reserve quantities, reductions in commodity prices, or increases in estimated costs could cause a reduction in the value of an unproved property and, therefore, could also cause a reduction in the carrying amounts of the property. If undiscounted future net cash flows are less than the carrying value of the property, indicating impairment, the cash flows are discounted at a rate approximate to our cost of capital and compared to the carrying value for determining the amount of the impairment loss to record. The estimated prices used in the cash flow analysis are determined by management based on forward price curves for the related commodities, adjusted for average historical location and quality differentials. Estimates of cash flows related to probable and possible reserves are reduced by additional risk-weighting factors. Due to the volatility of natural gas and crude oil prices, these cash flow estimates are inherently imprecise. Management's assessment of the results of exploration activities, availability of funds for future activities and the current and projected political climate in areas in which we operate also impact the amounts and timing of impairment provisions. During 2007, we recorded impairments of significant unproved oil and gas properties totaling approximately $3 million in exploration expense.

Asset Retirement Obligation—Our asset retirement obligations (“ARO”) consist of estimated costs of dismantlement, removal, site reclamation and similar activities associated with our oil and gas properties. Statement of Financial Accounting Standards ("SFAS") No. 143, “Accounting for Asset Retirement Obligations,” requires that the discounted fair value of a liability for an ARO be recognized in the period in which it is incurred with the associated asset retirement cost capitalized as part of the carrying cost of the oil and gas asset. The recognition of an ARO requires that management make numerous estimates, assumptions and judgments regarding such factors as the existence of a legal obligation for an ARO; estimated probabilities, amounts and timing of settlements; the credit-adjusted risk-free rate to be used; and inflation rates. In periods subsequent to initial measurement of the ARO, we must recognize period-to-period changes in the liability resulting from the passage of time and revisions to either the timing or the amount of the original estimate of undiscounted cash flows. Increases in the ARO liability due to passage of time impact net income as accretion expense. The related capitalized cost, including revisions thereto, is charged to expense through DD&A. See Item 8. Financial Statements and Supplementary Data—Note 6—Asset Retirement Obligations.

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Involuntary Conversions—When an involuntary conversion occurs, such as the destruction of oil and gas producing assets by a hurricane, a loss is accrued by a charge to income if the amount of loss can be reasonably estimated. An asset relating to insurance recovery is recognized only when realization of the claim for recovery of a loss recognized in the financial statements is deemed probable. A gain (recovery of a loss not yet recognized in the financial statements or an amount recovered in excess of a loss recognized in the financial statements) is not recognized until the insurance reimbursement has been received.

Management must make a number of estimates and assumptions relating to these gain and loss accruals. These include estimated costs of salvage, clean-up, restoration, redevelopment or abandonment and estimated amounts of insurance recoveries. The amount of an insurance recovery may be limited if total industry claims are in excess of the insurance carrier's ceiling limitation per event. A significant amount of time may be necessary for an insurance carrier to review all related claims for an event and determine the company-specific claim limitation on the final recovery. In addition, we may continue to incur costs, submit claims and receive reimbursements over a multi-year period.

The estimates involved in this process can have significant effects on reported amounts of net income. A decrease in the estimated amount of insurance recoveries will result in an increase in the involuntary conversion loss, which will result in a decrease in net income. An increase in estimated costs of salvage, if not covered by insurance, will also result in an increase in the involuntary conversion loss, which will result in a decrease in net income. Unreimbursed losses will have a negative effect on our cash flows. During the first half of 2007, several factors contributed to an increase in our estimated cleanup costs for damage related to Hurricanes Ivan and Katrina. These factors included cost escalation due to weather delays and an increase in effort for the design and construction of the deck lifting barge and mooring system, as well as additional costs for the actual deck lifting activities. These increases caused the total project costs, combined with net book value of the assets destroyed, to exceed certain insurance coverage limitations. As a result, we recorded $51 million as a loss on involuntary conversion during 2007. See Item 8. Financial Statements and Supplementary Data—Note 4—Effect of Gulf Coast Hurricanes.

Derivative Instruments and Hedging Activities—We use various derivative instruments to minimize the impact of commodity price fluctuations on forecasted sales of crude oil and natural gas production. We also use derivative instruments in connection with purchases and sales of third-party production to lock in profits or limit exposure to commodity price risk. In addition, we have used derivative instruments in connection with acquisitions and certain price-sensitive projects. Management exercises significant judgment in determining types of instruments to be used, production volumes to be hedged, prices at which to hedge and the counterparties' creditworthiness. We account for derivative instruments under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities, as amended". For derivative instruments that qualify as cash flow hedges, changes in fair value, to the extent the hedge is effective, are recognized in accumulated other comprehensive income or loss ("AOCL") until the hedged forecasted transaction is recognized in earnings. Therefore, prior to settlement of the derivative instruments, changes in the fair market value of those derivative instruments can cause significant increases or decreases in AOCL. For derivative instruments that do not qualify as cash flow hedges, changes in fair value are reported in current period net income and therefore can result in significant increases or decreases in current period net income. All hedge ineffectiveness is recognized in the current period in net income. Ineffectiveness is the amount of gains or losses from derivative instruments which are not offset by corresponding and opposite gains or losses on the expected future transaction. Regression analysis is performed on initial assessment of the hedge and subsequently every quarter thereafter in order to determine that the hedge instrument will be or has been highly effective in offsetting gains or losses on the future transaction. As discussed in Item 8—Financial Statements and Supplementary Data—Note 2—Summary of Significant Accounting Policies, we voluntarily discontinued cash flow hedge accounting for our commodity derivative instruments, effective January 1, 2008. Such a change did not affect our net assets or cash flows at December 31, 2007 and will not require adjustments to our previously reported financial statements. However, the use of mark-to-market accounting for our commodity derivatives will likely add volatility to our reported earnings. We occasionally enter into forward contracts or swap agreements to hedge exposure to interest rate risk. Changes in fair value of interest rate swaps or interest rate "locks" used as cash flow hedges are reported in AOCL, to the extent the hedge is effective, until the forecasted transaction occurs, at which time they are recorded as adjustments to interest expense over the term of the related notes. See Item 8. Financial Statements and Supplementary Data—Note 12—Derivatives and Hedging Activities.

Income Tax Expense and Deferred Tax Assets—We are subject to income and other taxes in numerous taxing jurisdictions worldwide. For financial reporting purposes, we provide taxes at rates applicable for the appropriate tax jurisdictions. Estimates of amounts of income tax to be recorded involve interpretation of complex tax laws, assessment of the effects of foreign taxes on domestic taxes, and estimates regarding the timing and amounts of future repatriation of earnings from controlled foreign corporations.

The consolidated balance sheets include deferred tax assets. Deferred tax assets arise when expenses are recognized in the financial statements before they are recognized in the tax returns or when income items are recognized in the tax return before they are recognized in the financial statements. Deferred tax assets also arise when operating losses or tax credits are available to offset tax payments due in future years. Ultimately, realization of a deferred tax asset depends on the existence of sufficient taxable income within the future periods to absorb future deductible temporary differences, loss carryforwards or credits. In assessing the realizability of deferred tax assets, management must consider whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. Management considers all available evidence (both positive and negative) in determining whether a valuation allowance is required. Such evidence includes the scheduled reversal of deferred tax liabilities, projected future taxable income and tax planning strategies in making this assessment, and judgment is required in considering the relative weight of negative and positive evidence. We continue to monitor facts and circumstances in the reassessment of the likelihood that operating loss carryforwards, credits and other deferred tax assets will be utilized prior to their expiration. As a result, we may determine, and we have determined in the past, that a deferred tax asset valuation allowance should be established. Any increases or decreases in a deferred tax asset valuation allowance would impact net income through offsetting changes in income tax expense.

Allowance for Doubtful Accounts—We assess the recoverability of all material trade and other receivables to determine their collectibility on a quarterly basis. We accrue a reserve on a receivable when, based on management's judgment, it is probable that a receivable will not be collected and the amount of such reserve may be reasonably estimated. In determining the amount of the reserve, management must analyze the aging of accounts receivable at the date of the consolidated financial statements and assess collectibility based on historic results, current collection trends and an evaluation of economic conditions. Over the last three years, we have increased the allowance by approximately $40 million to cover potentially uncollectible balances related to the Ecuador power operations. Certain entities purchasing electricity in Ecuador have been slow to pay amounts due us. We are pursuing various strategies to protect our interests including international arbitration and litigation. However, if estimates are inaccurate, we may incur gains or losses that could have a material effect on our results of operations.

Benefit Plans—We sponsor a qualified defined benefit pension plan, a non-qualified defined benefit pension plan ("restoration plan"), and other postretirement benefit plans. The actuarial determination of the projected benefit obligations and related benefit expense requires that certain assumptions be made regarding such variables as expected return on plan assets, discount rates, rates of future compensation increases, estimated future employee turnover rates and retirement dates, distribution election rates, mortality rates, retiree utilization rates for health care services and health care cost trend rates. The selection of assumptions requires considerable judgment concerning future events and has a significant impact on the amount of the obligations recorded in the consolidated balance sheets and on the amount of expense included in the consolidated statements of operations.

We base our determination of the asset return component of pension expense on a market-related valuation of assets, which reduces year-to-year volatility. This market-related valuation recognizes investment gains or losses over a five-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return based on the fair value of assets. Since the market-related value of assets recognizes gains or losses over a five-year period, the future value of assets will be impacted as previously deferred gains or losses are recorded. As of January 1, 2007, cumulative asset gains of approximately $3 million remained to be recognized in the calculation of the market-related value of assets.

In selecting the assumption for expected long-term rate of return on assets, we consider the average rate of earnings expected on the funds invested or to be invested to provide for plan benefits included in the projected benefit obligations. This includes considering the returns being earned by the plan assets and the rates of return expected to be available for reinvestment. We assume that the long-term asset mix will be consistent with the target asset allocation of 70% equity and 30% fixed income, with a range of plus or minus 10% acceptable degree of variation in asset allocation. A 1% decrease in the expected return on plan assets assumption would have increased 2007 net periodic benefit cost by approximately $1 million. The expected return assumption used for 2007 was 8.25%.

In selecting a discount rate, employers may look to rates of return on high quality fixed-income investments available as of the year-end measurement date and expected to be available during the period to maturity of the pension benefits. In order to determine an appropriate December 31, 2007 discount rate, we performed an analysis of the Citigroup Pension Discount Curve (the "CPDC") for each of our plans. The CPDC uses spot rates that represent the equivalent yield on high quality, zero coupon bonds for specific maturities. We used these rates to develop an equivalent single discount rate based on our plans' expected future benefit payment streams and duration of plan liabilities. A 1% increase in the discount rate assumption would have decreased 2007 net periodic benefit cost by $4 million and decreased the benefit obligation for the combined plans by $17 million at December 31, 2007. A 1% decrease in the discount rate assumption would have increased 2007 net periodic benefit cost by $5 million and increased the benefit obligation for the combined plans by $20 million at December 31, 2007. The assumed discount rate used to determine net periodic benefit cost for 2007 was 5.75%. The assumed discount rate used to determine the benefit obligations at December 31, 2007 was 6.5% for our defined benefit pension and restoration plans and 6.25% for our medical and life plans.

Effective January 1, 2008, the defined benefit pension plan and restoration plans were amended in order to provide a lump sum option. Certain assumptions were made regarding the percentage of active participants who would elect the lump sum option upon future termination and the percentage of existing deferred vested participants who would elect the lump sum option during 2008. In addition, the amounts of lump sum payments are affected by mortality and interest rate assumptions. The lump sum option increased the projected benefit obligation by $5.5 million at December 31, 2007 and will increase 2008 net periodic benefit cost by approximately $1 million.

We adopted SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106 and 132(R), as of December 31, 2006. See Item 8. Financial Statements and Supplementary Data—Note 11—Benefit Plans.

Recently Issued Pronouncements—See Item 8. Financial Statements and Supplementary Data—Note 16—Recently Issued Pronouncements.

LIQUIDITY AND CAPITAL RESOURCES

Overview

Our primary cash needs are to fund capital expenditures related to the acquisition, exploration and development of crude oil and natural gas properties, to repay outstanding borrowings or to pay other contractual commitments and interest payments on debt and to pay dividends. Our traditional sources of liquidity are cash on hand, cash flows from operations and available borrowing capacity under credit facilities. Funds may also be generated from occasional sales of non-strategic crude oil and natural gas assets. We had $660 million in cash and cash equivalents at December 31, 2007, compared with $153 million at December 31, 2006. Substantially all of this cash is located in our foreign subsidiaries and would be subject to additional US income taxes if repatriated. The cash is denominated in US dollars and is invested in highly liquid, investment-grade securities with original maturities of three months or less at the time of purchase. We currently intend to use our international cash to fund international projects, including the development of West Africa.

We are monitoring the current conditions in the credit markets. We have reviewed the creditworthiness of the banks and financial institutions with which we maintain our investments as well as the securities underlying our investments. Thus far, our liquidity and financial position have not been affected. We believe that losses from nonperformance are unlikely to occur; however, we are not able to predict sudden changes in creditworthiness.

Our ratio of debt-to-book capital has decreased from 30% at December 31, 2006, to 28% at December 31, 2007. We define our ratio of debt-to-book capital as total debt (which includes both long-term debt, excluding unamortized discount, and short-term borrowings) divided by the sum of total debt plus shareholders' equity. Significant changes in our financial position causing a change in the ratio of debt-to-book capital include:

- a $75 million increase in total debt from the balance at December 31, 2006;
- a $944 million increase in shareholders' equity from current year net income;
- a $102 million decrease in shareholders' equity due to repurchase of common stock; and
- a $144 million decrease in shareholders' equity (effected by an increase in AOCL) primarily related to an increase in deferred hedging losses.

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Cash Flows

Summary cash flow information is as follows:

	Year Ended December 31,		
	2007	2006	2005
	(in thousands)		
Total cash provided by (used in):			
Operating activities	$ 2,016,573	$ 1,730,306	$ 1,239,878
Investing activities	(1,403,089)	(1,098,339)	(1,892,488)
Financing activities	(107,029)	(588,880)	583,137
Increase (decrease) in cash and cash equivalents	$ 506,455	$ 43,087	$ (69,473)

Operating Activities—Net cash provided by operating activities increased $286 million, or 17% during 2007 as compared with 2006. The increase was due primarily to higher average realized crude oil prices and higher average realized US natural gas prices. These increases were partially offset by higher exploration expense and general and administrative ("G&A") expense. In addition, cash flows from operating activities in 2007 included dividends from equity method investments, which had been classified as investing cash flows in 2006. See Results of Operations—Income from Equity Method Investees.

Net cash provided by operating activities increased $490 million, or 40%, during 2006 as compared with 2005. The increase was due primarily to higher sales volumes and higher average realized crude oil prices, offset by lower average realized US natural gas prices and increases in total production costs, G&A expense and interest expense.

Investing Activities—The primary use of cash in investing activities is for capital spending, which may be offset by proceeds from property sales or dividends from equity method investees. Net cash used in investing activities increased $305 million, or 28% during 2007 as compared with 2006. The change was due primarily to a decrease in divestiture activity in 2007 as compared with 2006, when we sold our Gulf of Mexico shelf properties. In addition, investing cash inflows were reduced in 2007 because distributions received from equity method investees were included in operating cash flows. See Results of Operations—Income from Equity Method Investees.

Net cash used in investing activities decreased $794 million, or 42% during 2006 as compared with 2005. The decrease was due primarily to a decrease in acquisition activity in 2006 as compared to the Patina Merger in 2005 and an increase in divestiture activity in 2006, due to the sale of our Gulf of Mexico shelf properties, which provided investing cash inflows in 2006.

Financing Activities—Net cash used in financing activities decreased $482 million during 2007 as compared with 2006. The change was due to net increases in the credit facility during 2007 as compared with payments being made to decrease outstanding debt during 2006. In 2007 there was also a net decrease of $297 million in amounts used to repurchase common stock as compared with 2006. Cash flows were provided by financing activities in 2005, as compared with 2006, and totaled $583 million. In 2005, cash was provided by borrowings under the credit facility and exercise of stock options, partially offset by dividend payments and the repayment of debt acquired in the Patina Merger.

Acquisition, Capital and Other Exploration Expenditures

Expenditure information (on an accrual basis) is as follows:

	Year Ended December 31,		
	2007	2006	2005
		(in thousands)	
Acquisition, Capital and Other Exploration Expenditures			
Lease acquisition of unproved property	$ 145,326	$ 53,652	$ 16,793
Exploration expenditures	371,758	203,035	161,515
Development expenditures	1,185,385	1,054,780	662,585
Corporate and other expenditures	36,361	35,069	21,478
Total consolidated capital expenditures	1,738,830	1,346,536	862,371
Our share of equity investee development costs	516	580	27,639
Total	$ 1,739,346	$ 1,347,116	$ 890,010

Total capital expenditures during 2007 increased $392 million, or 29%, as compared with 2006. The increase was due to lease acquisition in the US, exploratory activities in West Africa and the North Sea, and increased development activity in the Northern region and Gulf of Mexico area of our US operations. Total capital expenditures during 2006 increased $457 million, or 51%, as compared with 2005. The increase was primarily due to development expenditures in the US and the North Sea. Capital expenditures for 2005 included $275 million of post-merger exploration and development-related expenditures on Patina properties.

As a result of the U.S. Exploration acquisition in 2006, we allocated $413 million to proved properties and $131 million to unproved properties. As a result of the Patina Merger in 2005, we allocated $2.6 billion to proved properties and $1.1 billion to unproved properties.

Insurance Recoveries

See Item 8. Financial Statements and Supplementary Data—Note 4—Effect of Gulf Coast Hurricanes.

Our corporate insurance program provides up to $260 million property damage coverage per loss event. However, our insurance carrier's aggregation limit for catastrophic windstorm events is $750 million. If an insured catastrophic loss event occurs, we could still recover less than our stated limits should the total aggregate losses realized by our carrier exceed its $750 million aggregation limit applicable to any single loss event.

We carry additional property damage and control of well coverage for our deepwater Gulf of Mexico and remaining Gulf of Mexico shelf properties. This additional insurance provides coverage only for claims in excess of $100 million, which exceed the $260 million property damage coverage or where the $260 million property damage coverage is reduced by application of the $750 million aggregation limit. We carry business interruption insurance for certain international locations. Effective June 2007, we no longer carry business interruption insurance for our Gulf of Mexico operations.

Financing Activities

Long-Term Debt—Our long-term debt totaled $1.9 billion (excluding unamortized discount) at December 31, 2007. Maturities range from 2009 to 2097. Our principal source of liquidity is an unsecured revolving credit facility (the "Credit Facility"). In November 2007, we extended the Credit Facility until December 9, 2012. The commitment is $2.1 billion until December 9, 2011 at which time the commitment reduces to $1.8 billion. The Credit Facility (i) provides for Credit Facility fee rates that range from 5 basis points to 15 basis points per year depending upon our credit rating, (ii) makes available short-term loans up to an aggregate amount of $300 million and (iii) provides for interest rates that are based upon the Eurodollar rate plus a margin that ranges from 20 basis points to 70 basis points depending upon our credit rating and utilization of the Credit Facility.

The Credit Facility contains customary representations and warranties and affirmative and negative covenants. The Credit Facility requires that our total debt to capitalization ratio (as defined in the credit agreement), expressed as a percentage, not exceed 60% at any time. A violation of this covenant could result in a default under the Credit Facility, which would permit the participating banks to restrict our ability to access the Credit Facility and require the immediate repayment of any outstanding advances under the Credit Facility. At December 31, 2007, the total debt to capitalization ratio was 28%, calculated for this purpose as total debt divided by the sum of total debt plus shareholders' equity.

The Credit Facility is with certain commercial lending institutions and is available for general corporate purposes. At December 31, 2007, $1.2 billion in borrowings were outstanding under the Credit Facility. The weighted average interest rate applicable to borrowings under the Credit Facility at December 31, 2007 was 5.28%.

We also have $650 million of fixed-rate debt outstanding at December 31, 2007 with a weighted average interest rate of 6.92%. Maturities range from 2014 to 2097.

Installment Payments Due—During 2007, we purchased working interests in oil and gas properties in the Piceance basin of western Colorado for $75 million. After making an initial cash payment of $25 million, we owe $50 million in the form of installment payments to the seller. Installments of $25 million each are due on May 12, 2008 and May 11, 2009. The amount due in 2008 is included in short-term borrowings and the amount due in 2009 is included in long-term debt in the consolidated balance sheets. Interest on the unpaid amounts is due quarterly. Interest accrues at a LIBOR rate plus .30%. The interest rate was 5.53% at December 31, 2007.

Short-Term Borrowings—Our Credit Facility is supplemented by short-term borrowings under various uncommitted credit lines used for working capital purposes. Uncommitted credit lines may be offered by certain banks from time to time at rates negotiated at the time of borrowing. Other than the installment payments discussed above, there were no short-term borrowings outstanding at December 31, 2007.

Interest Rate Locks—We occasionally enter into forward contracts or swap agreements to hedge exposure to interest rate risk. As of December 31, 2007, we had entered into two interest rate locks which are scheduled to expire third quarter 2008. See Item 8. Financial Statements and Supplementary Data—Note 7—Debt.

Cash Interest Payments—We made cash interest payments, net of capitalized interest, of $105 million in 2007, $106 million in 2006 and $84 million in 2005.

Common Stock Repurchase Program—During 2007 we completed a common stock repurchase program authorized by our Board of Directors in 2006. We repurchased two million shares of our common stock at an aggregate cost of $101 million in 2007 and 8.4 million shares of our common stock at an aggregate cost of $399 million in 2006, resulting in a total of 10.4 million shares acquired at an average price of $48.17 per share.

Dividends—We paid cash dividends totaling 43.5 cents per common share in 2007, 27.5 cents per common share in 2006 and 15 cents per common share in 2005. On January 22, 2008, the Board of Directors declared a quarterly cash dividend of 12.0 cents per common share, which was paid February 19, 2008 to shareholders of record on February 4, 2008. The amount of future dividends will be determined on a quarterly basis at the discretion of the Board of Directors and will depend on earnings, financial condition, capital requirements and other factors.

Exercise of Stock Options—Proceeds from the exercise of stock options totaled $25 million in 2007, $63 million in 2006 and $68 million in 2005. Proceeds received from the exercise of stock options fluctuate primarily based on the number of options exercised which is influenced by the price at which our common stock trades on the NYSE in relation to the exercise price of the options issued.

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Off-Balance Sheet Arrangements

We may enter into off-balance sheet arrangements and transactions that can give rise to material off-balance sheet obligations. As of December 31, 2007, the material off-balance sheet arrangements and transactions that we have entered into included drilling service contracts, operating lease agreements, undrawn letters of credit and derivative contracts. Other than the off-balance sheet arrangements listed above, we have no transactions, arrangements or other relationships with unconsolidated entities or other persons that are reasonably likely to materially affect our liquidity or availability of or requirements for capital resources. See Contractual Obligations below for more information regarding off-balance sheet arrangements.

Contractual Obligations

The following table summarizes certain contractual obligations that are reflected in the consolidated balance sheets and/or disclosed in the accompanying notes. See Item 8. Financial Statements and Supplementary Data—Notes to Consolidated Financial Statements.

	Payments Due by Period				
	Total	2008	2009 and 2010	2011 and 2012	2013 and Beyond
			(in thousands)		
Long-term debt (excludes interest) (1)	$ 1,880,000	$ 25,000	$ 25,000	$ 1,180,000	$ 650,000
Drilling and equipment obligations (2) :					
United States drilling and equipment	462,759	181,337	173,935	107,487	-
International drilling and equipment	68,170	68,170	-	-	-
Purchase obligations (3)	194,419	194,419	-	-	-
Throughput agreement (4)	95,000	-	38,000	38,000	19,000
Operating lease obligations (5) :					
Office buildings and facilities	52,894	7,289	14,495	13,247	17,863
Oil and gas operations equipment	12,074	5,467	6,607	-	-
Other long-term liabilities (6) :					
Asset retirement obligations (7)	144,288	13,332	12,443	13,034	105,479
Derivative instruments (8)	603,133	525,159	77,974	-	-
Total contractual obligations	$ 3,512,737	$ 1,020,173	$ 348,454	$ 1,351,768	$ 792,342

(1) Based on the total debt balance outstanding at December 31, 2007, scheduled maturities and interest rates in effect at December 31, 2007, our cash payments for interest would be $109 million in 2008, $108 million in 2009, $107 million in 2010, $107 million in 2011, $107 million in 2012 and $990 million for the remaining years for a total of $1.5 billion. See Item 8. Financial Statements and Supplementary Data—Note 7—Debt for additional information regarding our long-term debt obligations.

(2) Drilling and equipment obligations represent contractual agreements with third party service providers to procure drilling rigs and other related equipment for developmental and exploratory drilling facilities. See Item 8. Financial Statements and Supplementary Data—Note 14—Commitments and Contingencies for additional information regarding our drilling and equipment obligations.

(3) Purchase obligations represent agreements to purchase goods or services that are enforceable, are legally binding and specify all significant terms, including fixed and minimum quantities to be purchased; fixed, minimum or variable price provisions; and the approximate timing of the transaction. See Item 8. Financial Statements and Supplementary Data—Note 14—Commitments and Contingencies for additional information regarding our purchase obligations.

(4) In January 2007, we entered into a five-year throughput agreement. The transporting pipeline is expected to be completed and operational in 2009. See Item 8. Financial Statements and Supplementary Data—Note 14—Commitments and Contingencies for additional information regarding our throughput agreement.

(5) Operating lease obligations represent non-cancelable leases for office buildings and facilities and oil and gas operations equipment used in our daily operations. See Item 8. Financial Statements and Supplementary Data

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—Note 14—Commitments and Contingencies for additional information regarding our operating lease obligations.

(6) The table does not include our deferred compensation liabilities of $225 million and our accrued benefit costs of $51 million as specific payment dates are unknown. See Item 8. Financial Statements and Supplementary Data—Note 11—Benefit Plans for additional information on our deferred compensation liability and our accrued benefit costs.

(7) Asset retirement obligations are discounted. See Item 8. Financial Statements and Supplementary Data—Note 6—Asset Retirement Obligations for additional information on our asset retirement obligations.

(8) See Item 8. Financial Statements and Supplementary Data—Note 12—Derivative Instruments and Hedging Activities for additional information on our derivative instrument obligations.

We accrued approximately $12 million as of December 31, 2007, for an insurance contingency due to our membership in Oil Insurance Limited (OIL). OIL is a mutual insurance company which insures specific property, pollution liability and other catastrophic risks. As part of our membership, we are contractually committed to pay termination fees should we elect to withdraw from OIL. We do not anticipate withdrawing from OIL; however, the potential termination fee is calculated annually based on OIL' s past losses and the liability reflecting this potential charge has been accrued.

In addition, in the ordinary course of business, we maintain letters of credit in support of certain performance obligations of our subsidiaries. Outstanding letters of credit totaled approximately $1 million at December 31, 2007.

Other

Contributions to Pension and Other Postretirement Benefit Plans—We made contributions to the pension, restoration and other postretirement benefit plans totaling $12 million during 2007, $36 million during 2006, and $14 million during 2005. The actual return on plan assets was $13 million in both 2007 and 2006. The investment return has tended to follow market performance. In August 2006, the Pension Protection Act of 2006 (the Act) was signed into law. Certain provisions of this Act changed the calculation related to the maximum contribution amount deductible for income tax purposes and require that pension plans become fully funded over a seven-year period beginning in 2008. As a result of previous contributions made to the pension plan, there are no required contributions expected during 2008. We may, however, make additional contributions to our pension plan. We expect to make contributions of $4 million to the unfunded restoration and medical and life plans in 2008. This amount is equal to the benefits expected to be paid by those plans.

Income Taxes—We made cash payments for income taxes, net of refunds, of $149 million during 2007, $115 million during 2006 and $122 million during 2005.

Contingencies—During 2007, we paid a total of $56 million to settle legal proceedings; these amounts had been accrued previously. During 2006 and 2005, no significant payments were made to settle any legal proceedings. We regularly analyze current information and accrue for probable liabilities on the disposition of certain matters, as necessary. Liabilities for loss contingencies arising from claims, assessments, litigation or other sources are recorded when it is probable that a liability has been incurred and the amount can be reasonably estimated.

RESULTS OF OPERATIONS

Net Income

Net income for 2007 was $944 million, a 39% increase over 2006. Factors contributing to the increase in net income from 2006 to 2007 included:

- a $332 million, or 11%, increase in total revenues, due primarily to higher average realized crude oil prices and higher average realized US natural gas prices and an increase in income from equity method investees;
- a $395 million decrease in loss on derivative instruments; and

offset by:

- a $208 million decrease in gains from asset sales;
- a $105 million increase in DD&A expense;
- a $51 million loss on involuntary conversion expense; and
- a $51 million increase in oil and gas exploration expense.

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Net income for 2006 was $678 million, a 5% increase over 2005. Factors contributing to the increase in net income from 2005 to 2006 included:

- a $753 million, or 34%, increase in total revenues, driven primarily by a full year of Patina operations and nine months of U.S. Exploration operations and higher average realized oil prices;
- an increase of $215 million in gains from asset sales;

offset by:

- an increase in loss on derivative instruments of $360 million; and
- a $232 million increase in DD&A expense.

Natural Gas Information

	Year Ended December 31,		
	2007	2006	2005
		(in thousands)	
Natural gas sales	$ 1,271,866	$ 1,211,782	$ 1,023,644

Average daily natural gas sales volumes and average realized sales prices were as follows:

	Year Ended December 31,					
	2007		2006		2005	
	Mcfpd	$/Mcf	Mcfpd	$/Mcf	Mcfpd	$/Mcf
United States (1)	412,212	$ 7.51	451,712	$ 6.61	343,953	$ 7.43
West Africa (2)	132,464	0.29	45,422	0.37	65,581	0.25
North Sea	6,235	6.54	8,130	8.00	9,299	5.93
Israel	110,820	2.79	92,894	2.72	66,377	2.68
Ecuador (3)	25,713	-	24,475	-	22,795	-
Other International	-	-	294	0.96	190	1.10
Total	687,444	$ 5.26	622,927	$ 5.55	508,195	$ 5.78

(1) Reflects an increase of $1.12 per Mcf in 2007 and reductions of $0.25 per Mcf in 2006 and $0.77 per Mcf in 2005 from hedging activities.

(2) Natural gas from the Alba field in Equatorial Guinea is under contract for $0.25 per MMBtu to a methanol plant, an LPG plant and an LNG facility. The methanol and LPG plants are owned by affiliated entities accounted for under the equity method of accounting. The volumes sold by the LPG plant are included in the table below under crude oil information. Natural gas volumes include sales to an LNG facility of 78,090 Mcfpd 2007; there were no natural gas sales to the LNG facility before 2007. The natural gas sold to the LNG facility and methanol plant has a lower Btu content than the natural gas sold to the LPG plant. As a result of the natural gas volumes sold to the LNG plant in 2007, the average price received on an Mcf basis is lower. For 2007 and 2006, the price on an Mcf basis has been adjusted to reflect the Btu content on gas sales.

(3) The natural gas-to-power project in Ecuador is 100% owned by one of our subsidiaries, and intercompany natural gas sales are eliminated for accounting purposes. Electricity sales included in total revenues totaled $71 million in 2007, $72 million in 2006 and $74 million in 2005.

2007 Compared with 2006—Natural gas sales increased a net $60 million, or 5%, during 2007 as compared with 2006. The increase was affected by both volume and price changes. In the US, natural gas sales increased $40 million from the previous year despite lower sales volumes. Deepwater Gulf of Mexico volumes were slightly higher than 2006, while development activity in the Piceance basin and a full year of production from U.S. Exploration properties acquired in 2006 resulted in increased production in the Northern region. However, the Gulf Coast onshore area had lower production due to natural field decline, and there was a loss of production due to the sale of our Gulf of Mexico shelf properties in 2006. The Northern region also experienced a temporary decline in production due to third party processing downtime and inclement weather. The net production decrease was more than offset by a 14% increase in average realized natural gas prices.

Internationally, West Africa natural gas sales increased $8 million from the previous year. Natural gas volumes were higher due to increased sales of natural gas from the Alba field in Equatorial Guinea; however, the effect of higher production was somewhat offset by lower average realized gas prices. In the North Sea, natural gas production decreased 23% as compared with the prior year primarily due to natural field decline. Lower production, combined with lower average realized prices, resulted in a $9 million decrease in North Sea natural gas sales. In Israel, natural gas sales increased $21 million due to record sales volumes. There was a full year of sales to Israeli Electric Company's Reading power plant in Tel Aviv, as well as the start up of sales to a desalinization plant and a paper mill.

2006 Compared with 2005—Natural gas sales increased a net $188 million, or 18%, during 2006 as compared with 2005. Again, the change was caused by both significant volume and price changes. In the US natural gas sales increased by $157 million from the previous year due to additional US production from Patina properties acquired in 2005 and from U.S. Exploration properties acquired in May 2006. In addition, there were increases in deepwater Gulf of Mexico production where three new developments came on stream at Swordfish, Ticonderoga and Lorien. However, increases due to higher gas sales volumes were partially offset by lower average realized prices.

Internationally, West Africa natural gas sales were flat year-to-year; however, there was a decline in sales volumes due to the turnaround of the AMPCO methanol plant in Equatorial Guinea. The turnaround lasted 57 days and was followed by reduced production levels caused by 35 days of compressor repairs. The production decline was completely offset by an increase in average realized natural gas prices. In the North Sea, natural field decline resulted in reduced sales volumes, but this reduction was more than offset by the increase in average realized prices. Israel experienced a $4 million increase in natural gas sales primarily due to increased demand from Israel Electric Corporation Limited, a full year of sales to Bazan Oil Refinery and commencement of natural gas sales to the Reading power plant in Tel Aviv, Israel.

Natural Gas Hedging Activities—Natural gas sales are net of the effects of derivative contracts that are accounted for as cash flow hedges and included an increase of $169 million in 2007, and a reduction of $42 million in 2006 and $97 million in 2005 from hedging activities. Natural gas sales in 2007 include a $182 million non-cash increase related to hedge contracts that were redesignated at the time of the Gulf of Mexico shelf property sale in 2006 and settled during 2007. See Item 8.Financial Statements and Supplementary Data—Note 12—Derivative Instruments and Hedging Activities.

Crude Oil Information

	Year Ended December 31,		
	2007	2006	2005
		(in thousands)	
Crude oil sales	$ 1,694,233	$ 1,489,459	$ 942,778

Average daily crude oil sales volumes and average realized sales prices were as follows:

	Year Ended December 31,							
	2007			2006			2005	
	Production (1)	Sales		Production (1)	Sales		Sales (2)	
	Bopd	Bopd	$/Bbl	Bopd	Bopd	$/Bbl	Bopd	$/Bbl
United States (3)	42,332	42,332	$ 53.22	45,798	45,798	$ 50.68	25,941	$ 46.67

West Africa (4)	15,523	15,070		71.27	17,326	17,860		62.51	17,786		42.51
North Sea	12,813	12,505		76.47	3,988	3,717		67.43	5,380		52.68
Other International (5)	6,806	6,674		53.69	7,491	7,540		52.05	7,851		42.37
Total Consolidated Operations	77,474	76,581		60.61	74,603	74,915		54.47	56,958		45.35
Equity Investees (6)	8,014	7,684		55.09	7,531	8,032		45.83	3,240		43.43
Total	85,488	84,265	$	60.10	82,134	82,947	$	53.64	60,198	$	45.25

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(1) The variance between production and sales volumes is attributable to the timing of liquid hydrocarbon tanker liftings.
(2) Sales volumes equal production volumes in 2005.
(3) Reflects reductions of $13.68 per Bbl in 2007, $11.41 per Bbl in 2006 and $8.03 per Bbl in 2005 from hedging activities.
(4) Reflects reductions of $2.19 per Bbl in 2007 and $9.93 per Bbl in 2005 from hedging activities. We did not hedge West Africa crude oil sales in 2006.
(5) Other international includes China and Argentina.
(6) Volumes represent sales of condensate and LPG from the Alba plant in Equatorial Guinea. LPG sales volumes totaled 5,848 Bopd in 2007, 6,294 Bopd in 2006 and 2,328 Bopd in 2005.

2007 Compared with 2006—Crude oil sales increased a net $205 million, or 14%, during 2007 as compared with 2006. The increase was affected by both volume and price changes. In the US, crude oil sales declined by $25 million from the previous year. Deepwater Gulf of Mexico volumes were lower due to well performance, third-party facility restrictions and storm shut-in. The Gulf Coast onshore area had lower production due to natural field decline, and there was a loss of production due to the sale of our Gulf of Mexico shelf properties in 2006. Northern region production was negatively impacted by severe winter weather in the Rocky Mountains during the first and fourth quarters of 2007. However, development activity in the Wattenberg field, as well as a full year of production from U.S. Exploration properties acquired in 2006, resulted in increased production in our Northern region, and the overall US volume decline was partially offset by higher average realized prices.

Internationally, West Africa crude oil sales declined by $15 million from the previous year. Volumes declined due to increased downtime and lower condensate yields in Equatorial Guinea, but the decline was offset by substantially higher average realized crude oil prices. In January 2007, production began at the Dumbarton development in the North Sea, and, as a result, crude oil production was more than triple that of the prior year. North Sea crude oil sales increased $257 million over 2006 due to the increased volumes and, to a lesser extent, higher average realized prices. Other international crude oil sales declined $12 million. China experienced lower volumes due to facility downtime and natural field decline.

2006 Compared with 2005—Crude oil sales increased a net $547 million, or 58%, during 2006 as compared with 2005. Again, the increase was caused by significant volume and price changes. In the US crude oil sales increased by $405 million from the previous year due to additional US production from Patina properties acquired in 2005 and from U.S. Exploration properties acquired in May 2006. In addition, there were increases in deepwater Gulf of Mexico production where three new developments came on stream at Swordfish, Ticonderoga and Lorien.

Internationally, higher average realized prices resulted in an increase of $132 million in West Africa crude oil sales and contributed to most of the $22 million increase in other international crude oil sales. The North Sea experienced a $12 million decrease in crude oil sales. Natural field decline and timing of tanker liftings resulted in lower sales volumes, the effect of which was mitigated by an increase in average realized crude oil prices.

Crude Oil Hedging Activities—Crude oil sales are net of the effects of derivative contracts that are accounted for as cash flow hedges and included a reduction of $223 million in 2007, $191 million in 2006 and $140 million in 2005 from hedging activities. See Item 8. Financial Statements and Supplementary Data—Note 12—Derivative Instruments and Hedging Activities.

Commodity Derivative Instruments and Hedging Activities

We use various derivative instruments in connection with anticipated crude oil and natural gas sales to minimize the impact of product price fluctuations. Such instruments include variable to fixed price swaps, costless collars and basis swaps. Although these derivative instruments expose us to credit risk, we monitor the creditworthiness of counterparties and believe that losses from nonperformance are unlikely to occur. Hedging gains and losses related to crude oil and natural gas production are recorded in oil and gas sales. See Item 7A. Quantitative and Qualitative Disclosures About Market Risk—Commodity Price Risk and Item 8—Financial Statements and Supplementary Data—Note 12—Derivative Instruments and Hedging Activities.

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Income from Equity Method Investees

We own a 45% interest in AMPCO, which owns and operates a methanol plant and related facilities and a 28% interest in Alba Plant, which owns and operates an LPG processing plant. The plants and related facilities are located in Equatorial Guinea. We account for investments in entities that we do not control but over which we exert significant influence using the equity method of accounting. Our share of operations of equity method investees was as follows:

	Year Ended December 31,		
	2007	2006	2005
Net income (in thousands):			
AMPCO and affiliates	$ 82,877	$ 38,024	$ 56,896
Alba Plant	128,051	101,338	33,916
Distributions/dividends (in thousands):			
AMPCO and affiliates	96,483	37,350	59,625
Alba Plant	132,251	155,158	-
Sales volumes (1):			
Methanol (Kgal)	160,540	109,942	162,446
Condensate (Bopd)	1,836	1,738	912
LPG (Bpd)	5,848	6,294	2,328
Production volumes (1):			
Condensate (Bopd)	1,860	1,730	912
LPG (Bpd)	6,148	5,801	2,328
Average realized prices:			
Methanol (per gallon)	$ 1.09	$ 0.90	$ 0.77
Condensate (per Bbl)	74.87	66.60	55.76
LPG (per Bbl)	48.87	40.10	38.63

(1) The variance between production and sales volumes is attributable to the timing of liquid hydrocarbon tanker liftings.

Net income from AMPCO and affiliates increased substantially in 2007 relative to 2006 due to a 46% increase in methanol sales volumes and a 21% increase in average realized methanol prices. The increase in methanol sales volumes was due to a 57-day shutdown of methanol production for the plant turnaround that occurred during May and June 2006 followed by 35 days of compressor repairs.

Net income from AMPCO and affiliates decreased 33% in 2006 relative to 2005 due to a 32% decrease in methanol sales volumes offset by a 17% increase in average realized methanol prices. The decrease in methanol sales volumes was due to the 57-day shutdown of methanol production for the plant turnaround that occurred during May and June 2006 followed by 35 days of compressor repairs. No such shutdown or plant turnaround occurred during 2005.

Net income from Alba Plant increased 26% in 2007 relative to 2006 due to a 22% increase in average realized LPG prices and a 12% increase in average realized condensate prices.

Net income from Alba Plant increased substantially in 2006 relative to 2005 due to an almost threefold increase in LPG sales volumes, an almost twofold increase in condensate sales volumes and a 19% increase in average realized condensate prices. The increases in LPG and condensate sales volumes reflected the completion and ramp up to full production of the Phase 2B liquids expansion project.

For 2007, $132 million received from Alba Plant was classified within operating cash flows as a dividend from equity method investee as compared with 2006 in which the distributions were classified within investing cash flows as a repayment of a loan. The change in classification was the result of all outstanding loans being repaid to us by Alba Plant in December 2006.

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Costs and Expenses

Production Costs—Production costs were as follows:

	Total (in thousands)	United States	West Africa	North Sea	Israel	Other Int'l/ Corporate (2)
Year Ended December 31, 2007						
Oil and gas operating costs (1)	$ 299,622	$ 190,723	$ 39,222	$ 37,987	$ 7,712	$ 23,978
Workover and repair expense	22,830	22,516	-	-	-	314
Lease operating expense	322,452	213,239	39,222	37,987	7,712	24,292
Production and ad valorem taxes	113,547	91,225	-	-	-	22,322
Transportation expense	51,699	39,542	-	10,523	-	1,634
Total production costs	$ 487,698	$ 344,006	$ 39,222	$ 48,510	$ 7,712	$ 48,248
Year Ended December 31, 2006						
Oil and gas operating costs (1)	$ 270,136	$ 205,348	$ 26,557	$ 11,655	$ 9,066	$ 17,510
Workover and repair expense	46,951	46,793	-	-	-	158
Lease operating expense	317,087	252,141	26,557	11,655	9,066	17,668
Production and ad valorem taxes	108,979	85,960	-	-	-	23,019
Transportation expense	28,542	20,728	-	7,010	-	804
Total production costs	$ 454,608	$ 358,829	$ 26,557	$ 18,665	$ 9,066	$ 41,491
Year Ended December 31, 2005						
Oil and gas operating costs (1)	$ 203,833	$ 136,087	$ 30,661	$ 12,244	$ 8,504	$ 16,337
Workover and repair expense	14,027	13,734	-	259	-	34
Lease operating expense	217,860	149,821	30,661	12,503	8,504	16,371
Production and ad valorem taxes	78,703	65,428	-	-	-	13,275
Transportation expense	16,764	9,350	-	6,562	-	852
Total production costs	$ 313,327	$ 224,599	$ 30,661	$ 19,065	$ 8,504	$ 30,498

(1) Oil and gas operating costs include labor, fuel, repairs, replacements, saltwater disposal and other related lifting costs.
(2) Other international includes Ecuador, China and Argentina.

Oil and gas operating costs increased $29 million, or 11%, from 2006 to 2007. The increase is primarily the result of expanded operations in Equatorial Guinea and the North Sea.

Oil and gas operating costs increased $66 million, or 33%, from 2005 to 2006 primarily as a result of our expanded operations. Three new deepwater Gulf of Mexico development projects came online between December 2005 and April 2006. Fiscal year 2006 represented a full year of Patina operations, and we acquired U.S. Exploration in 2006. In addition, the high commodity price environment resulted in higher service, contract labor and fuel costs. Insurance costs were also higher in 2006 due in part to increased rates for property damage coverage combined with the added costs of providing business interruption coverage on deepwater Gulf of Mexico assets.

Workover and repair expense decreased $24 million during 2007 as compared with 2006. The decrease was primarily due to a reduction in hurricane-related repair expense, which totaled $30 million in 2006 and $1 million in 2007.

Workover and repair expense increased $33 million during 2006 as compared with 2005. Expense for 2006 included $30 million ($0.45 per BOE) of hurricane-related repair expense.

Production and ad valorem tax expense increased $5 million, or 4%, during 2007 as compared with 2006 and increased $30 million, or 38%, during 2006 as compared with 2005. The increase reflects additional production from U.S. Exploration and Patina properties. These properties have proportionately more production subject to such taxes.

Transportation expense increased $23 million, or 81%, during 2007 as compared with 2006. The increase was due primarily due to changes in the terms of certain sales contracts for Northern region production and increased production in the North Sea. Transportation expense increased $12 million, or 70%, during 2006 as compared with 2005. The increase was primarily due to a full year of Patina operations and U.S. Exploration.

Selected expenses on a per BOE of sales volume basis were as follows:

	Year Ended December 31,		
	2007	2006	2005
Oil and gas operating costs	$ 4.29	$ 4.14	$ 3.94
Workover and repair expense	0.33	0.72	0.27
Lease operating costs	4.62	4.86	4.21
Production and ad valorem taxes	1.63	1.67	1.52
Transportation expense	0.74	0.44	0.33
Total production costs (1) (2)	$ 6.99	$ 6.97	$ 6.06

(1) Consolidated unit rates exclude sales volumes and costs attributable to equity method investees.

(2) Sales volumes include natural gas sales to an LNG facility in Equatorial Guinea that began late first quarter of 2007. The inclusion of these volumes reduced the unit rate by $0.51 per BOE for 2007.

The unit rates of total production costs per BOE, converting gas to oil on the basis of six Mcf per barrel, have been increasing year-over-year since 2005. The increases are due to rising third-party costs, including insurance, hurricane-related repair expense, and higher production taxes.

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Oil and Gas Exploration Expense—Exploration expense was as follows:

	Total	United States	West Africa	North Sea	Israel	Other Int'l/ Corporate (1)
			(in thousands)			
Year Ended December 31, 2007						
Dry hole expense	$ 90,210	$ 49,473	$ 40,399	$ 5	$ -	$ 333
Unproved lease amortization	16,013	15,176	-	103	-	734
Seismic	64,856	55,258	939	8,184	691	(216)
Staff expense	45,030	11,900	2,106	8,318	645	22,061
Other	2,973	2,423	100	340	82	28
Total exploration expense	$ 219,082	$ 134,230	$ 43,544	$ 16,950	$ 1,418	$ 22,940
Year Ended December 31, 2006						
Dry hole expense	$ 70,325	$ 66,150	$ 46	$ 4,129	$ -	$ -
Unproved lease amortization	18,836	18,823	-	13	-	-
Seismic	37,676	29,320	4,204	685	3	3,464
Staff expense	38,861	12,710	2,887	4,816	250	18,198
Other	2,226	1,083	192	879	33	39
Total exploration expense	$ 167,924	$ 128,086	$ 7,329	$ 10,522	$ 286	$ 21,701
Year Ended December 31, 2005						
Dry hole expense	$ 98,015	$ 95,678	$ 1,403	$ 932	$ 2	$ -
Unproved lease amortization	17,855	17,855	-	-	-	-
Seismic	21,761	11,631	316	1,544	-	8,270
Staff expense	34,945	16,255	3,760	2,690	189	12,051
Other	5,850	4,974	(16)	819	32	41
Total exploration expense	$ 178,426	$ 146,393	$ 5,463	$ 5,985	$ 223	$ 20,362

(1) Other international includes Ecuador, China, Argentina and Surname.

Exploration expense increased $51 million, or 30% during 2007 as compared with 2006. US dry hole expense decreased $17 million due to a reduction in the number of dry holes drilled during 2007. Dry hole expense increased $40 million in West Africa and included amounts related to a dry exploratory well in Equatorial Guinea and expense related to a secondary target of an exploration well in Cameroon in which commercial hydrocarbons were not found. Seismic expense increased a net $27 million during 2007 as compared with 2006, primarily due to increases in US seismic expense incurred in support of the 2007 Central Gulf of Mexico Outer Continental Shelf Sale. Staff expense increased a net $6 million primarily due to new venture activity.

Exploration expense decreased $11 million, or 6% during 2006 as compared with 2005. US dry hole expense was $30 million less due to the reduction in the number of dry holes drilled. US seismic expense increased $18 million due primarily to the expansion of our deepwater Gulf of Mexico 3D seismic database. In addition, other international staff expense increased $6 million due to new venture activity.

Exploration expense included stock-based compensation expense of $2 million in 2007 and $1 million in 2006.

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Depreciation, Depletion and Amortization Expense—DD&A expense was as follows:

	Year Ended December 31,		
	2007	2006	2005
		(in thousands)	
United States	$ 574,001	$ 543,431	$ 311,153
West Africa	25,315	23,620	27,121
North Sea	79,450	8,123	9,888
Israel	17,842	13,947	11,188
Other International, corporate, and other	31,373	33,487	31,194
Total DD&A expense	$ 727,981	$ 622,608	$ 390,544
Unit rate of DD&A per BOE (1) (2)	$ 10.43	$ 9.54	$ 7.55

(1) Consolidated unit rates exclude sales volumes and costs attributable to equity method investees.
(2) Sales volumes include natural gas sales to an LNG facility in Equatorial Guinea that began late first quarter of 2007. The inclusion of these volumes reduced the unit rate by $0.62 per BOE for 2007.

Total DD&A expense has been increasing since 2005 primarily due to higher production volumes. The increase in the unit rate for 2007 as compared with 2006 was primarily due to higher acquisition and development costs in the the US and the Dumbarton North Sea development. The increase in the unit rate for 2006 as compared with 2005 was primarily due to the change in the mix of our production volumes, in particular, deepwater Gulf of Mexico production.

DD&A expense includes abandoned assets cost of $5 million in 2007, $1 million in 2006 and $11 million in 2005.

General and Administrative Expense—General and administrative ("G&A") expense was as follows:

	Year Ended December 31,		
	2007	2006	2005
General and administrative expense (in thousands)	$ 206,378	$ 164,541	$ 100,125
Unit rate per BOE (1) (2)	$ 2.96	$ 2.52	$ 1.94

(1) Consolidated unit rates exclude sales volumes and costs attributable to equity method investees.
(2) Sales volumes include natural gas sales to an LNG facility in Equatorial Guinea that began late first quarter of 2007. The inclusion of these volumes reduced the unit rate by $0.21 per BOE for 2007.

G&A expense increased $42 million, or 25%, during 2007 as compared with 2006 due to higher salaries and wages, including incentive compensation programs, resulting from an increase in the number of employees and results exceeding targeted performance goals. In addition, the effects of adoption of SFAS No. 123(R), "Share-Based Payment" ("SFAS 123(R)"), combined with additional equity-based awards, resulted in a $14 million increase in stock-based compensation expense included in G&A during 2007. Stock-based compensation expense included in G&A totaled $25 million in 2007.

G&A expense increased $64 million, or 64% during 2006 as compared with 2005. The increase was due to higher salaries and wages and the inclusion of a full year of G&A expense related to Patina operations. Salaries and wages also reflected wage inflation due to a tight labor market and expanded activity across the industry driven by higher commodity prices. In addition, the effects of adoption of SFAS 123(R), combined with additional equity-based awards, resulted in a $7 million increase in stock-based compensation expense included in G&A during 2006. Stock-based compensation expense included in G&A was $11 million in 2006 as compared with $4 million in 2005.

G&A includes actuarially-computed net periodic benefit cost related to pension and other postretirement benefit plans of $17 million in 2007, $19 million in 2006 and $11 million in 2005.

Interest Expense and Capitalized Interest—Interest expense and capitalized interest were as follows:

	Year Ended December 31,		
	2007	2006	2005
		(in thousands)	
Interest expense, net	$ 112,957	$ 117,045	$ 87,541
Capitalized interest	16,595	12,515	8,684

Interest expense, net of capitalized interest, decreased in 2007 primarily due to a declining rate of interest applicable to the Credit Facility from 5.69% at December 31, 2006 to 5.28% at December 31, 2007. Interest expense, net of capitalized interest, increased in 2006 due to additional borrowings related to the Patina Merger and acquisition of U.S. Exploration and to increases in the interest rate applicable to the Credit Facility from 4.82% at December 31, 2005 to 5.69% at December 31, 2006.

Interest is capitalized on development projects using an interest rate equivalent to the average rate paid on long-term debt. Capitalized interest is included in the cost of oil and gas assets and amortized with other costs on a unit-of-production basis. The majority of the capitalized interest related to long lead-time projects in West Africa, the North Sea and deepwater Gulf of Mexico in 2007; the North Sea and deepwater Gulf of Mexico in 2006; and deepwater Gulf of Mexico and projects in West Africa in 2005.

We occasionally enter into forward contracts or swap agreements to hedge exposure to interest rate risk. At December 31, 2007, AOCL included a deferred loss of $4 million, net of tax, related to interest rate swaps. $3 million of this amount is being reclassified into earnings, at the rate of $0.8 million per year, as an adjustment to interest expense over the term of our 5-1/4% senior notes due 2014. The remaining $1 million loss relates to interest rate locks that will expire in third quarter 2008. See Item 8. Financial Statements and Supplementary Data—Note 12—Derivative Instruments and Hedging Activities.

(Gain) Loss on Derivative Instruments—See Item 8. Financial Statements and Supplementary Data—Note 12—Derivative Instruments and Hedging Activities.

Gain on Sale of Assets—See Item 8. Financial Statements and Supplementary Data—Note 3—Acquisitions and Divestitures.

Loss on Involuntary Conversion—See Item 8. Financial Statements and Supplementary Data—Note 4—Effect of Gulf Coast Hurricanes.

Electricity Sales—Ecuador Integrated Power Project—Through our subsidiaries, EDC Ecuador Ltd. and MachalaPower Cia. Ltda., we have a 100% ownership interest in an integrated natural gas-to-power project. The project includes the Amistad natural gas field, offshore Ecuador, which supplies fuel to the Machala power plant. Electricity sales are included in other revenues and electricity generation expense is included in other expense, net in the consolidated statements of operations.

Operating data is as follows:

	Year Ended December 31,		
	2007	2006	2005
Electricity sales (in thousands)	$ 70,916	$ 71,603	$ 74,228
Electricity generation expense (in thousands)	56,552	59,494	53,137

Operating income (in thousands)	14,364	12,109	21,091
Power generation (MW)	911,830	865,983	799,160
Average power price ($/Kwh)	$ 0.078	$ 0.083	$ 0.093

The volume of natural gas produced and electric power generated in Ecuador are related to thermal electricity demand in Ecuador which typically declines at the onset of the rainy season. When Ecuador has sufficient rainfall to allow hydroelectric power producers to provide base load power, we provide electricity only to meet peak demand. As seasonal rains subside, we experience increasing demand for thermal electricity.

Electricity generation expense includes net increases in the allowance for doubtful accounts of $14 million in 2007, $15 million in 2006 and $11 million in 2005. These increases have been made to cover potentially uncollectible balances related to the Ecuador power operations. Certain entities purchasing electricity in Ecuador have been slow to pay amounts due us. We are pursuing various strategies to protect our interests including international arbitration and litigation.

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Gathering, Marketing and Processing—We market a portion of our US natural gas production, as well as certain third-party natural gas. We sell natural gas directly to end-users, natural gas marketers, industrial users, interstate and intrastate pipelines, power generators and local distribution companies. We also market certain third-party crude oil. Gathering, marketing and processing ("GMP") proceeds are included in other revenues and GMP expenses are included in other expense, net in the consolidated statements of operations. Gross margin from GMP activities was as follows:

	Year Ended December 31,		
	2007	2006	2005
		(in thousands)	
GMP proceeds	$ 24,087	$ 27,876	$ 55,261
GMP expenses	17,539	18,664	28,067
Gross margin	$ 6,548	$ 9,212	$ 27,194

We employ derivative instruments in connection with purchases and sales of third-party production to lock in profits or limit exposure to commodity price risk. Most of the purchases we make are on an index basis. However, purchasers in the markets in which we sell often require fixed or NYMEX-related pricing. We record gains and losses on these derivative instruments using mark-to-market accounting. Gains (losses) were de minimis for 2007, 2006 and 2005. GMP proceeds for 2005 includes a gain of $11 million for the sale of certain gas sales and transportation contractual assets.

Deferred Compensation Expense—In connection with the Patina Merger, we acquired the assets and assumed the liabilities related to a deferred compensation plan. The assets of the deferred compensation plan are held in a rabbi trust and include shares of our common stock and mutual fund investments. At December 31, 2007, 45% of the market value of the assets in the rabbi trust related to our common stock. Deferred compensation expense totaled $34 million, $16 million and $15 million for 2007, 2006, and 2005, respectively. See Item 8. Financial Statements and Supplementary Data—Note 11—Benefit Plans.

Impairment of Operating Assets—We recorded impairments of $4 million in 2007, $9 million in 2006 and $5 million in 2005, primarily related to downward reserve revisions on proved US oil and gas properties and/or adjustment of the carrying value of properties to their fair values. Impairment expense is included in other expense, net in the consolidated statements of operations.

Income Taxes—The income tax provision was as follows:

	Year Ended December 31,		
	2007	2006	2005
Income tax provision (in thousands)	$ 423,697	$ 417,789	$ 322,940
Effective rate	31.0%	38.1%	33.3%

Several factors resulted in a decrease in our effective tax rate for 2007. The major factor was that, in 2006, $100 million of goodwill write-off associated with the sale of the Gulf of Mexico shelf properties was not deductible, which increased the rate for 2006. Other factors were an increase in deferred tax assets arising from foreign tax credits, a decrease in the Chinese tax rate, and the realization of additional income from equity method investees which is a favorable permanent difference in calculating the income tax expense.

Our effective tax rate increased significantly in 2006 from 2005 due to several factors. The most significant factor was the nondeductible goodwill write-off of $100 million related to the sale of the Gulf of Mexico shelf properties discussed in the preceding paragraph. The rate was also impacted by decreases in our US deferred tax assets arising from future foreign tax credits due to changes in the limitation on our ability to claim foreign tax credits. In addition, a change in UK tax law increased our UK tax expense in 2006. Offsetting these increases was a reduction in the effective tax rate due to an increase in earnings from equity method investees, which is a favorable permanent difference in calculating income tax expense.

The 2005 effective tax rate was impacted by our ability to claim a foreign tax credit for the income taxes paid by foreign branch operations, as well as a benefit realized on the repatriation of foreign earnings under the American Jobs Creation Act of 2004.

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ItemQuantitative and Qualitative Disclosures About Market Risk.
7A.

Commodity Price Risk

Derivative Instruments Held for Non-Trading Purposes - We are exposed to market risk in the normal course of business operations. We believe that we are well positioned with our mix of crude oil and natural gas reserves to take advantage of future price increases that may occur. However, the uncertainty of crude oil and natural gas prices continues to impact the oil and gas industry. Due to the volatility of crude oil and natural gas prices, we have used derivative instruments as a means of managing our exposure to commodity price changes.

At December 31, 2007, we had entered into variable to fixed price swaps, costless collars and basis swaps related to crude oil and natural gas sales. See Item 8. Financial Statements and Supplementary Data— Note 12—Derivative Instruments and Hedging Activities.

As of December 31, 2007, we had a net unrealized loss of $408 million (pre-tax) related to crude oil and natural gas derivative instruments entered into for hedging purposes. A net unrealized loss of $255 million, net of tax, is recorded in AOCL in the consolidated balance sheets. We will reclassify the loss to earnings as adjustments to revenue when future sales occur.

Interest Rate Risk

We are exposed to interest rate risk related to our variable and fixed interest rate debt. As of December 31, 2007, we had $1.9 billion (excluding unamortized discount) of long-term debt outstanding. Of this amount, $650 million was fixed-rate debt with a weighted average interest rate of 6.92%. We believe that anticipated near term changes in interest rates will not have a material effect on the fair value of our fixed-rate debt and will not expose us to the risk of earnings or cash flow loss.

The remainder of our long-term debt, $1.2 billion at December 31, 2007, was variable-rate debt. We also had $25 million of current installment payments at December 31, 2007. Variable rate debt exposes us to the risk of earnings or cash flow loss due to increases in market interest rates. We estimate that a hypothetical 25 basis point change in the floating interest rates applicable to the December 31, 2007 balance of variable-rate debt would result in a change in annual interest expense of approximately $3 million.

We occasionally enter into forward contracts or swap agreements to hedge exposure to interest rate risk. Changes in fair value of interest rate swaps or interest rate "locks" used as cash flow hedges are reported in AOCL, to the extent the hedge is effective, until the forecasted transaction occurs, at which time they are recorded as adjustments to interest expense. At December 31, 2007, AOCL included $4 million, net of tax, related to interest rate locks. A portion of this amount is being reclassified into earnings as adjustments to interest expense over the term of our 5¼% Senior Notes due April 2014. The remainder relates to interest rate locks that are scheduled to settle during third quarter 2008. See Item 8. Financial Statements and Supplementary Data-Note 12-Derivative Instruments and Hedging Activities.

We are also exposed to interest rate risk related to our short-term investments. As of December 31, 2007, substantially all of our cash was invested in highly liquid, short-term investment-grade securities with original maturities of three months or less at the time of purchase. A hypothetical 25 basis point change in the floating interest rates applicable to the December 31, 2007 balance would result in a change in annual interest income of approximately $2 million.

Foreign Currency Risk

We have not entered into foreign currency derivatives. The US dollar is considered the functional currency for each of our international operations. Transactions that are completed in a foreign currency are remeasured into US dollars and recorded in the financial statements at the prevailing currency exchange rates. We do not have any significant monetary assets or liabilities denominated in a foreign currency other than our foreign deferred tax liabilities in certain foreign tax jurisdictions. An increase in exchange rates between the US dollar and the currency of the foreign tax jurisdiction in which these liabilities are located could result in the use of additional cash to settle these liabilities. However, transaction gains or losses were not material in any of the periods presented. We do not believe we are currently exposed to any material risk of loss on this basis. Such gains or losses are included in other expense, net in the consolidated statements of operations.

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Item 8. Financial Statements and Supplementary Data.

INDEX TO FINANCIAL STATEMENTS

Consolidated Financial Statements of Noble Energy, Inc.

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Management's Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting. Our internal control over financial reporting is a process designed under the supervision of our Chief Executive Officer and Chief Financial Officer to provide reasonable assurance regarding the reliability of financial reporting and the preparation of consolidated financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America.

Because of its inherent limitations, internal control over financial reporting may not detect or prevent misstatements. Projections of any evaluation of the 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 processes may deteriorate.

As of December 31, 2007, our management assessed the effectiveness of our internal control over financial reporting based on the criteria for effective internal control over financial reporting established in "Internal Control—Integrated Framework," issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the assessment, management determined that we maintained effective internal control over financial reporting as of December 31, 2007, based on those criteria. Management included in its assessment of internal control over financial reporting all consolidated entities.

KPMG LLP, the independent registered public accounting firm that audited our consolidated financial statements included in this Annual Report on Form 10-K, has issued an attestation report on the effectiveness of internal control over financial reporting as of December 31, 2007 which is included herein.

Noble Energy, Inc.

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Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders
Noble Energy, Inc.:

We have audited the accompanying consolidated balance sheets of Noble Energy, Inc. and subsidiaries as of December 31, 2007 and 2006, and the related consolidated statements of operations, shareholders' equity, comprehensive income (loss), and cash flows for each of the years in the three-year period ended December 31, 2007. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We did not audit the financial statements for the periods referred to below of the Alba Plant LLC (Alba) and the Atlantic Methanol Production Company, LLC (AMPCO), the investments in which, as disclosed in Note 13 of the consolidated financial statements are accounted for by the equity method of accounting. The Company's investment in Alba as of December 31, 2007 and 2006 was $142.5 million and $146.1 million, respectively, and the equity in earnings in Alba was $128.1 million and $101.3 million for the years ended December 31, 2007 and 2006, respectively. The equity in earnings for AMPCO was $54.9 million for the year ended December 31, 2005. The financial statements of Alba as of December 31, 2007 and 2006 and for the years then ended and AMPCO for the year ended December 31, 2005 were audited by other auditors whose reports have been furnished to us, and our opinion, insofar as it relates to the amounts included for Alba and AMPCO, is based solely on the report of the other auditors.

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 and the report of the other auditors provide a reasonable basis for our opinion.

In our opinion, based on our audits and the reports of the other auditors, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Noble Energy, Inc. and subsidiaries as of December 31, 2007 and 2006, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2007, in conformity with U.S. generally accepted accounting principles.

As discussed in Note 2 to the consolidated financial statements, effective January 1, 2006, the Company changed its method of accounting for stock-based compensation. As also discussed in Note 2 to the consolidated financial statements, effective December 31, 2006, the Company changed its method of accounting for defined benefit pension and other postretirement plans.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Noble Energy, Inc.'s internal control over financial reporting as of December 31, 2007, based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 25, 2008 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

KPMG LLP

Houston, Texas

February 25, 2008

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Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders
Noble Energy, Inc.:

We have audited Noble Energy, Inc.'s internal control over financial reporting as of December 31, 2007, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Noble Energy, Inc.'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 Company'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, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included 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, Noble Energy, Inc. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Noble Energy, Inc. and subsidiaries as of December 31, 2007 and 2006, and the related consolidated statements of operations, shareholders' equity, comprehensive income (loss), and cash flows for each of the years in the three-year period ended December 31, 2007, and our report dated February 25, 2008 expressed an unqualified opinion on those consolidated financial statements.

KPMG LLP

Houston, Texas
February 25, 2008

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Noble Energy, Inc. and Subsidiaries
Consolidated Balance Sheets
(in thousands, except share amounts)

	December 31, 2007	December 31, 2006
ASSETS		
Current Assets		
Cash and cash equivalents	$ 659,863	$ 153,408
Accounts receivable - trade, net	594,009	586,882
Deferred income taxes	130,571	99,835
Assets held for sale	82,122	164
Probable insurance claims	2,184	101,233
Other current assets	100,518	127,024
Total current assets	1,569,267	1,068,546
Property, plant and equipment		
Oil and gas properties (successful efforts method of accounting)	10,216,484	8,867,639
Other property, plant and equipment	112,339	79,646
	10,328,823	8,947,285
Accumulated depreciation, depletion and amortization	(2,384,359)	(1,776,528)
Total property, plant and equipment, net	7,944,464	7,170,757
Other noncurrent assets	556,669	568,032
Goodwill	760,496	781,290
Total Assets	$ 10,830,896	$ 9,588,625
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts payable - trade	$ 780,915	$ 518,609
Derivative instruments	540,217	254,625
Income taxes	51,785	107,136
Current installment of long-term debt	25,000	-
Asset retirement obligations	13,332	68,500
Other current liabilities	224,494	235,392
Total current liabilities	1,635,743	1,184,262
Deferred income taxes	1,983,833	1,758,452
Asset retirement obligations	130,956	127,689
Derivative instruments	82,803	328,875
Other noncurrent liabilities	337,667	274,720
Long-term debt	1,851,087	1,800,810
Total Liabilities	6,022,089	5,474,808
Commitments and Contingencies		
Shareholders' Equity		
Preferred stock - par value $1.00; 4,000,000 shares authorized,none issued	-	-
Common stock - par value $3.33 1/3; 250,000,000 shares authorized; 190,814,309 and 188,808,087 shares issued, respectively	636,046	629,360
Capital in excess of par value	2,105,895	2,041,048
Accumulated other comprehensive loss	(284,185)	(140,509)

Treasury stock, at cost: 18,580,865 and 16,574,384 shares, respectively	(612,976)	(511,443)
Retained earnings	2,964,027	2,095,361
Total Shareholders' Equity	4,808,807	4,113,817
Total Liabilities and Shareholders' Equity	$ 10,830,896	$ 9,588,625

The accompanying notes are an integral part of these financial statements

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Noble Energy, Inc. and Subsidiaries
Consolidated Statements of Operations
(in thousands, except per share amounts)

	Year Ended December 31,		
	2007	2006	2005
Revenues			
Oil and gas sales	$ 2,966,099	$ 2,701,241	$ 1,966,422
Income from equity method investees	210,928	139,362	90,812
Other revenues	95,003	99,479	129,489
Total Revenues	3,272,030	2,940,082	2,186,723
Costs and Expenses			
Lease operating costs	322,452	317,087	217,860
Production and ad valorem taxes	113,547	108,979	78,703
Transportation expense	51,699	28,542	16,764
Exploration expense	219,082	167,924	178,426
Depreciation, depletion and amortization	727,981	622,608	390,544
General and administrative	206,378	164,541	100,125
Accretion of discount on asset retirement obligations	8,125	10,797	11,214
Interest, net of amount capitalized	112,957	117,045	87,541
(Gain) loss on derivative instruments	(2,520)	392,367	32,680
Gain on sale of assets	(11,854)	(219,577)	(4,201)
Loss on involuntary conversion	51,406	-	1,000
Other expense, net	105,210	133,552	107,407
Total Costs and Expenses	1,904,463	1,843,865	1,218,063
Income Before Taxes	1,367,567	1,096,217	968,660
Income Tax Provision	423,697	417,789	322,940
Net Income	$ 943,870	$ 678,428	$ 645,720
Earnings Per Share			
Basic	$ 5.52	$ 3.86	$ 4.20
Diluted	$ 5.45	$ 3.79	$ 4.12
Weighted average number of shares outstanding			
Basic	171,078	175,707	153,773
Diluted	173,344	179,044	156,759

The accompanying notes are an integral part of these financial statements

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Noble Energy, Inc. and Subsidiaries
Consolidated Statements of Cash Flows
(in thousands)

	Year Ended December 31, 2007	2006	2005
Cash Flows from Operating Activities			
Net income	$ 943,870	$ 678,428	$ 645,720
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization - oil and gas production	727,981	622,608	390,544
Depreciation, depletion and amortization - electricity generation	14,277	16,319	16,476
Dry hole expense	90,210	70,325	98,015
Impairment of operating assets	3,661	8,525	5,368
Amortization of unproved leasehold costs	16,013	18,923	17,855
Stock-based compensation expense	26,825	11,816	3,467
Gain on sale of assets	(11,854)	(219,577)	(4,201)
Deferred income taxes	291,881	194,261	183,770
Accretion of discount on asset retirement obligations	8,125	10,797	11,214
Increase in allowance for doubtful accounts	15,272	15,891	5,551
Income from equity method investees	(210,928)	(139,362)	(90,812)
Dividends from equity method investees	226,634	37,350	59,625
Deferred compensation expense	33,526	15,936	14,980
Non-cash (gain) loss on derivative instruments	(184,944)	415,298	32,680
Loss on involuntary conversion	51,406	-	1,000
Other	(1,733)	21,509	(40,421)
Changes in operating assets and liabilities, net of acquisition:			
Increase in accounts receivable	(21,609)	(32,348)	(73,940)
Decrease (increase) in other current assets	8,048	(4,954)	(28,254)
Decrease (increase) in probable insurance claims	108,075	139,590	(25,306)
Increase (decrease) in accounts payable	19,278	(11,151)	20,747
Decrease in other current liabilities	(137,441)	(139,878)	(4,200)
Net Cash Provided by Operating Activities	2,016,573	1,730,306	1,239,878
Cash Flows From Investing Activities			
Additions to property, plant and equipment	(1,414,515)	(1,357,039)	(785,610)
Acquisition of U.S. Exploration, net of cash acquired	-	(412,257)	-
Acquisiton of Patina, net of cash acquired	-	-	(1,111,099)
Proceeds from sale of property, plant and equipment	9,326	519,567	13,179
Investments in equity method investees	-	(3,768)	(13,927)
Distributions from equity method investees	2,100	155,158	4,969
Net Cash Used in Investing Activities	(1,403,089)	(1,098,339)	(1,892,488)
Cash Flows From Financing Activities			
Exercise of stock options	24,636	62,613	67,657
Excess tax benefits from stock-based awards	20,072	26,106	-
Cash dividends paid	(75,204)	(48,924)	(23,655)
Purchase of treasury stock	(101,533)	(398,675)	-
Proceeds from credit facilities	280,000	480,000	3,335,333

Repayment of credit facilities		(255,000)		(605,000)	(2,140,333)
Repayment of term loans		-		(105,000)	(45,000)
Repayment of Patina debt		-		-	(610,865)
Net Cash Provided by (Used in) Financing Activities		(107,029)		(588,880)	583,137
Increase (Decrease) in Cash and Cash Equivalents		506,455		43,087	(69,473)
Cash and Cash Equivalents at Beginning of Period		153,408		110,321	179,794
Cash and Cash Equivalents at End of Period	$	659,863	$	153,408	$ 110,321

The accompanying notes are an integral part of these financial statements

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Noble Energy, Inc. and Subsidiaries
Consolidated Statements of Shareholders' Equity
(in thousands)

	Common Stock	Capital in Excess of Par Value	Deferred Compensation - Restricted Stock	Accumulated Other Comprehensive Loss	Treasury Stock at Cost	Retained Earnings	Total Shareholders' Equity
December 31, 2004	$ 417,152	$ 291,458	$ (1,671)	$ (14,787)	$ (75,956)	$ 843,792	$ 1,459,988
Net income	-	-	-	-	-	645,720	645,720
Patina Merger	185,568	1,576,799	-	-	(73,203)	-	1,689,164
Exercise of stock options	13,013	54,644	-	-	-	-	67,657
Tax benefits related to exercise of stock options	-	15,407	-	-	-	-	15,407
Restricted stock awards, net	578	6,506	(7,084)	-	-	-	-
Amortization of restricted stock	-	-	3,467	-	-	-	3,467
Cash dividends ($0.15 per share)	-	-	-	-	-	(23,655)	(23,655)
Rabbi trust shares sold	-	90	-	-	683	-	773
Other	-	335	-	-	-	-	335
Oil and gas cash flow hedges:							
Realized amounts reclassified into earnings	-	-	-	154,500	-	-	154,500
Unrealized amounts reclassified into earnings	-	-	-	33,638	-	-	33,638
Unrealized change in fair value	-	-	-	(945,033)	-	-	(945,033)
Net change in other	-	-	-	(11,817)	-	-	(11,817)
Other comprehensive loss				(768,712)			
December 31, 2005	616,311	1,945,239	(5,288)	(783,499)	(148,476)	1,465,857	3,090,144
Net income	-	-	-	-	-	678,428	678,428
Adoption of SFAS 123(R), net of tax	-	(5,288)	5,288	-	-	-	-
Stock-based compensation expense	-	11,816	-	-	-	-	11,816
Exercise of stock options	12,829	49,784	-	-	-	-	62,613
	-	26,106	-	-	-	-	26,106

Tax benefits related to exercise of stock options							
Restricted stock awards, net	220	(220)	-	-	-	-	-
Cash dividends ($0.275 per share)	-	-	-	-	-	(48,924)	(48,924)
Purchase of treasury stock	-	-	-	-	(398,675)	-	(398,675)
Rabbi trust shares sold	-	13,611	-	-	35,708	-	49,319
Oil and gas cash flow hedges:							
Realized amounts reclassified into earnings	-	-	-	145,035	-	-	145,035
Unrealized amounts reclassified into earnings	-	-	-	264,520	-	-	264,520
Unrealized change in fair value	-	-	-	249,974	-	-	249,974
Net change in other	-	-	-	16,862	-	-	16,862
Other comprehensive income				676,391			
Adoption of SFAS 158, net of tax	-	-	-	(33,401)	-	-	(33,401)
December 31, 2006	629,360	2,041,048	-	(140,509)	(511,443)	2,095,361	4,113,817
Net income	-	-	-	-	-	943,870	943,870
Stock-based compensation expense	-	26,825	-	-	-	-	26,825
Exercise of stock options	4,930	19,706	-	-	-	-	24,636
Tax benefits related to exercise of stock options	-	20,072	-	-	-	-	20,072
Restricted stock awards, net	1,756	(1,756)	-	-	-	-	-
Cash dividends ($0.435 per share)	-	-	-	-	-	(75,204)	(75,204)
Purchase of treasury stock	-	-	-	-	(101,533)	-	(101,533)
Oil and gas cash flow hedges:							
Realized amounts reclassified into earnings	-	-	-	33,761	-	-	33,761
Unrealized change in fair value	-	-	-	(184,254)	-	-	(184,254)
Net change in other	-	-	-	6,817	-	-	6,817
				(143,676)			

Other comprehensive loss													
December 31, 2007	$	636,046	$	2,105,895	$	-	$	(284,185)	$	(612,976)	$	2,964,027	$	4,808,807

The accompanying notes are an integral part of these financial statements

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Noble Energy, Inc. and Subsidiaries
Consolidated Statements of Comprehensive Income (Loss)
(in thousands)

	Year Ended December 31,		
	2007	2006	2005
Net income	$ 943,870	$ 678,428	$ 645,720
Other items of comprehensive income (loss)			
Oil and gas cash flow hedges:			
Realized amounts reclassified into earnings	54,105	232,428	237,692
Less tax provision	(20,344)	(87,393)	(83,192)
Unrealized amounts reclassified into earnings	-	423,910	51,750
Less tax provision	-	(159,390)	(18,112)
Unrealized change in fair value	(295,279)	351,637	(1,453,897)
Less tax provision	111,025	(101,663)	508,864
Interest rate cash flow hedges:			
Realized amounts reclassified into earnings	758	758	757
Less tax provision	(285)	(121)	(265)
Unrealized change in fair value	(1,203)	-	-
Less tax provision	452	-	-
Net change in other	11,369	25,002	(18,937)
Less tax provision	(4,274)	(8,777)	6,628
Other comprehensive income (loss)	(143,676)	676,391	(768,712)
Comprehensive income (loss)	$ 800,194	$ 1,354,819	$ (122,992)

The accompanying notes are an integral part of these financial statements

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Dollar amounts in tables, unless otherwise indicated, are in thousands, except per share amounts)

Note 1—Nature of Operations

Noble Energy, Inc. (“Noble Energy”, “we” or “us”) is an independent energy company engaged in the acquisition, exploration, development, production and marketing of crude oil and natural gas. We have exploration, exploitation and production operations domestically and internationally. We operate throughout major basins in the US including Colorado’s Wattenberg field and Piceance basin, the Mid-continent area of western Oklahoma and the Texas Panhandle, the San Juan basin in New Mexico, the Gulf Coast and the deepwater Gulf of Mexico. In addition, we conduct business internationally in China, Ecuador, the Mediterranean Sea, the North Sea, West Africa (Equatorial Guinea and Cameroon) and in other areas. In 2005, we merged with Patina Oil & Gas Corporation (“Patina”) and in 2006 we acquired U.S. Exploration Holdings, Inc. (“U.S. Exploration”).

Note 2—Summary of Significant Accounting Policies

Basis of Presentation and Consolidation—Accounting policies used by us and our subsidiaries conform to accounting principles generally accepted in the US. Significant policies are discussed below. Our consolidated accounts include our accounts and the accounts of our wholly-owned subsidiaries. We use the equity method of accounting for investments in entities that we do not control but over which we exert significant influence. We carry equity method investments at our share of net assets of the equity investees plus our loans and advances. Differences in the basis of the investment and the separate net asset value of the investee, if any, are amortized into income over the remaining useful life of the underlying assets. All significant intercompany balances and transactions have been eliminated upon consolidation.

Use of Estimates—The preparation of consolidated financial statements in conformity with accounting principles generally accepted in the US (GAAP) requires us to make a number of estimates and assumptions relating to the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period.

Estimates of crude oil and natural gas reserves are the most significant of our estimates. All of the reserve data in this Form 10-K are estimates. Reservoir engineering is a subjective process of estimating underground accumulations of crude oil and natural gas. There are numerous uncertainties inherent in estimating quantities of proved crude oil and natural gas reserves. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. As a result, reserve estimates may be different from the quantities of crude oil and natural gas that are ultimately recovered. Engineers in our Houston, Denver and London offices prepare all reserve estimates for our different geographical regions. These reserve estimates are reviewed and approved by senior engineering staff and division management with final approval by the Director of Asset Development and certain members of senior management. See Supplemental Oil and Gas Information.

Other items subject to estimates and assumptions include the carrying amounts of property, plant and equipment and goodwill, asset retirement obligations, valuation allowances for receivables and deferred income tax assets, valuation of derivative instruments, and obligations related to employee benefits. Actual results could differ significantly from those estimates.

Foreign Currency—The US dollar is considered the functional currency for each of our international operations. Transactions that are completed in foreign currencies are remeasured into US dollars and recorded in the financial statements at prevailing foreign exchange rates. Transaction gains or losses were not material in any of the periods presented and are included in other expense, net on the statements of operations.

Allowance for Doubtful Accounts—We routinely assess the recoverability of all material trade and other receivables to determine their collectibility. We accrue a reserve on a receivable when, based on management's judgment, it is probable that a receivable will not be collected and the amount of such reserve may be reasonably estimated. Changes in the allowance for doubtful accounts are as follows:

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	Year Ended December 31, 2007	2006	2005
	(in thousands)		
Balance at beginning of period	$ 34,535	$ 18,644	$ 13,093
Charged to expense	14,183	19,404	14,688
Deductions and other	1,089	(3,513)	(9,137)
Balance at end of period	$ 49,807	$ 34,535	$ 18,644

Amounts charged to expense include $14 million in 2007, $15 million in 2006 and $11 million in 2005 to cover potentially uncollectible balances related to Ecuador power operations. These amounts are included in electricity generation expense. Certain entities purchasing electricity in Ecuador have been slow to pay amounts due us. We are pursuing various strategies to protect our interests including international arbitration and litigation. The allowance was also increased by $2 million in 2006 and $1 million in 2005 to record various provisions related to our US business. In addition, in 2005 the allowance was decreased due to the final write-off of certain allowances recorded in prior years ($6 million).

Materials and Supplies Inventories—Materials and supplies inventories, consisting principally of tubular goods and production equipment, are stated at the lower of cost or market.

Property, Plant and Equipment—

Successful Efforts Method—We account for crude oil and natural gas properties under the successful efforts method of accounting. Under this method, costs to acquire mineral interests in crude oil and natural gas properties, to drill and equip exploratory wells that find proved reserves and to drill and equip development wells are capitalized. Capitalized costs of producing crude oil and natural gas properties are amortized to operations by the unit-of-production method based on proved crude oil and natural gas reserves on a property-by-property basis as estimated by our engineers. Upon sale or retirement of depreciable or depletable property, the cost and related accumulated DD&A are eliminated from the accounts and the resulting gain or loss is recognized. Repairs and maintenance are expensed as incurred.

Proved Property Impairment—In accordance with SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," we review proved oil and gas properties and other long-lived assets for impairment when events and circumstances indicate a decline in the recoverability of the carrying value of such properties, such as a downward revision of the reserve estimates or sustained decrease in commodity prices. We estimate the future cash flows expected in connection with the properties and compare such future cash flows to the carrying amount of the properties to determine if the carrying amount is recoverable. When the carrying amounts of the properties exceed their estimated undiscounted future cash flows, the carrying amount of the properties is reduced to their estimated fair value. The factors used to determine fair value include, but are not limited to, estimates of proved reserves, future commodity prices and operating expenses, timing of future production, future capital expenditures and a risk-adjusted discount rate. We recorded impairments of approximately $4 million in 2007, $9 million in 2006 and $5 million in 2005, primarily related to downward reserve revisions on US properties and/or adjustment of the carrying value of properties to their fair values.

Unproved Property Impairment—We also periodically assess individually significant unproved properties for impairment of value and recognize a loss at the time of impairment by providing an impairment allowance. Cash flows used in the impairment analysis are determined based on management's estimates of crude oil and natural gas reserves, future commodity prices and future costs to extract the reserves. Cash flow estimates related to probable and possible reserves are reduced by additional risk-weighting factors. Other individually insignificant unproved properties are amortized on a composite method based on our experience of successful drilling and average holding period. We recorded impairments of individually significant unproved properties of approximately $3 million in 2007,

$1 million in 2006, and $3 million in 2005 and included the amounts in exploration expense.

Properties Acquired in Business Combinations—In determining the fair values of proved and unproved properties acquired in business combinations, we prepare estimates of crude oil and natural gas reserves. We estimate future prices to apply to the estimated reserve quantities acquired, and estimate future operating and development costs, to arrive at estimates of future net cash flows. For the fair value assigned to proved reserves, the future net cash flows are discounted using a market-based weighted average cost of capital rate determined appropriate at the time of the business combination. To compensate for the inherent risk of estimating and valuing unproved reserves, the discounted future net cash flows of probable and possible reserves are reduced by additional risk-weighting factors.

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Exploration Costs—Geological and geophysical costs, delay rentals, amortization of unproved leasehold costs, and costs to drill exploratory wells that do not find proved reserves are expensed as oil and gas exploration. We carry the costs of an exploratory well as an asset if the well finds a sufficient quantity of reserves to justify its capitalization as a producing well and as long as we are making sufficient progress assessing the reserves and the economic and operating viability of the project. For certain capital-intensive deepwater Gulf of Mexico or international projects, it may take us more than one year to evaluate the future potential of the exploration well and make a determination of its economic viability. Our ability to move forward on a project may be dependent on gaining access to transportation or processing facilities or obtaining permits and government or partner approval, the timing of which is beyond our control. In such cases, exploratory well costs remain suspended as long as we are actively pursuing access to necessary facilities and access to such permits and approvals and believe they will be obtained. We assess the status of suspended exploratory well costs on a quarterly basis. See Note 5—Capitalized Exploratory Well Costs.

Other Property—Other property includes autos, trucks, airplane, office furniture and computer equipment and other fixed assets. These items are recorded at cost and are depreciated on the straight-line method based on expected lives of the individual assets or group of assets, which range from three to seven years.

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Balance Sheet Information—Additional balance sheet information is as follows:

	December 31, 2007	December 31, 2006
	(in thousands)	
Other Current Assets		
Derivative instruments	$ 15,058	$ 35,242
Materials and supplies inventories	60,479	46,973
Prepaid expenses and other	24,981	44,809
Total	$ 100,518	$ 127,024
Other Noncurrent Assets		
Equity method investments	$ 357,129	$ 373,372
Mutual fund investments	123,779	116,314
Probable insurance claims	37,475	46,500
Derivative instruments	4,829	2,862
Other assets	33,457	28,984
Total	$ 556,669	$ 568,032
Other Current Liabilities		
Accrued and other current liabilities	$ 206,435	$ 219,885
Interest payable	18,059	15,507
Total	$ 224,494	$ 235,392
Other Noncurrent Liabilities		
Deferred compensation liabilities	$ 225,098	$ 173,253
Accrued benefit costs	50,972	58,491
Other noncurrent liabilities	61,597	42,976
Total	$ 337,667	$ 274,720

Statement of Operations Information—Other revenues and other expense, net consist of the following:

	Year Ended December 31, 2007	2006	2005
		(in thousands)	
Other Revenues			
Electricity sales	$ 70,916	$ 71,603	$ 74,228
Gathering, marketing and processing	24,087	27,876	55,261
Total	$ 95,003	$ 99,479	$ 129,489
Other Expense, net			
Electricity generation (1)	$ 56,552	$ 59,494	$ 53,137
Gathering, marketing and processing	17,539	18,664	28,067
Deferred compensation expense	33,526	15,936	14,980
Impairment of operating assets	3,661	8,525	5,368
Other	(6,068)	30,933	5,855
Total	$ 105,210	$ 133,552	$ 107,407

(1) See Allowance for Doubtful Accounts above.

Supplementary Disclosures of Cash Flow Information—Additional cash flow information is as follows:

	Year Ended December 31, 2007	2006	2005
	(in thousands)		
Cash paid during the year for:			
Interest (net of amount capitalized)	$ 104,910	$ 105,769	$ 83,860
Income taxes paid, net	149,058	115,398	121,687
Non-cash financing and investing activities:			
Issuance of notes for property interests	50,000	-	-
Issuance of common stock and options and liabilities assumed in Patina Merger	-	-	3,783,306

Goodwill—Goodwill represents the excess of the cost of an acquired entity over the net amounts assigned to assets acquired and liabilities assumed. We account for goodwill in accordance with SFAS No. 142, "Goodwill and Other Intangible Assets" ("SFAS 142"). Goodwill is not amortized to earnings but is tested annually during the fourth quarter or whenever events or changes in circumstances indicate that the carrying value may not be recoverable. No goodwill impairment was indicated as of December 31, 2007. Changes in the carrying amount of goodwill are as follows:

	Year Ended December 31, 2007	2006
	(in thousands)	
Balance at beginning of period	$ 781,290	$ 862,868
Goodwill associated with acquisitions	(15,091)	27,711
Goodwill associated with sale of Gulf of Mexico shelf properties	-	(100,000)
Tax benefits on stock options exercised	(5,703)	(9,289)
Balance at end of period	$ 760,496	$ 781,290

In accordance with Emerging Issues Task Force ("EITF") Abstract Issue No. 00-23, "Issues Related to the Accounting for Stock Compensation under APB Opinion No. 25 and FASB Interpretation No. 44", we reduce the amount of goodwill originally recorded for deferred tax assets associated with the exercise of fully-vested stock options assumed in conjunction with the Patina Merger to the extent that the stock-based compensation expense reported for tax purposes does not exceed the fair value of the awards recognized as part of the total purchase price.

Income Taxes—Income taxes are accounted for under the asset and liability method. Deferred tax assets and liabilities are recognized when items of income and expense are recognized in the financial statements in different periods than when recognized in the tax return. Deferred tax assets arise when expenses are recognized in the financial statements before the tax returns or when income items are recognized in the tax return prior to the financial statements. Deferred tax assets also arise when operating losses or tax credits are available to offset tax payments due in future years. Deferred tax liabilities arise when income items are recognized in the financial statements before the tax returns or when expenses are recognized in the tax return prior to the financial statements. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the date when the change in the tax rate was passed.

Fair Value of Financial Instruments—The following methods and assumptions were used to estimate the fair values for each class of financial instruments. The fair value of a financial instrument is the amount at which the instrument could be exchanged in a current transaction between two willing parties.

Cash, Cash Equivalents, Accounts Receivable and Accounts Payable—The carrying amounts approximate fair value due to the short-term nature or maturity of the instruments.

Mutual Funds—The fair value is based on published market prices.

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Debt—The fair value of debt is estimated based on the published market prices for the same or similar issues. The carrying amounts and estimated fair values of debt instruments are as follows:

	December 31,			
	2007		2006	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in thousands)			
Total debt, net of discount	$ 1,876,087	$ 1,919,990	$ 1,800,810	$ 1,852,890

See Note 7—Debt.

Derivative Instruments—The fair value estimates for commodity fixed price swaps, basis swaps and costless collars use published market prices for the underlying commodities and discount rates to determine discounted expected future cash flows as of the date of the estimate. See Note 12—Derivative Instruments and Hedging Activities.

Capitalization of Interest—We capitalize interest costs associated with the development and construction of significant properties or projects to bring them to a condition and location necessary for their intended use, which for crude oil and natural gas assets is at first production from the field. Interest is capitalized using an interest rate equivalent to the average rate we pay on long-term debt, including the credit facility and bonds. Capitalized interest is included in the cost of oil and gas assets and amortized with other costs on a unit-of-production basis. Capitalized interest totaled $17 million in 2007, $13 million in 2006 and $9 million in 2005.

Statement of Cash Flows—For purposes of reporting cash flows, cash and cash equivalents include unrestricted cash on hand and investments purchased with original maturities of three months or less.

Basic and Diluted Earnings Per Share—Basic earnings per share (“EPS”) of common stock have been computed on the basis of the weighted average number of shares outstanding during each period. The diluted EPS of common stock includes the effect of outstanding common stock equivalents. The calculation of basic and diluted EPS is as follows:

	Year Ended December 31,					
	2007		2006		2005	
	Income	Shares	Income	Shares	Income	Shares
	(in thousands, except per share amounts)					
Net income available to common shareholders	$ 943,870	171,078	$ 678,428	175,707	$ 645,720	153,773
Basic EPS	$ 5.52		$ 3.86		$ 4.20	
Net income available to common shareholders	$ 943,870	171,078	$ 678,428	175,707	$ 645,720	153,773
Effect of dilutive stock options and restricted stock awards	-	2,266	-	3,337	-	2,986
Adjusted net income and shares	$ 943,870	173,344	$ 678,428	179,044	$ 645,720	156,759
Diluted EPS	$ 5.45		$ 3.79		$ 4.12	

Options, restricted stock and shares of our common stock held in a rabbi trust excluded from the EPS calculation above as they were antidilutive are as follows:

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	Weighted Outstanding Awards and Shares		Weighted Average Exercise Price
	(in thousands, except per share amounts)		
Year Ended December 31, 2007			
Stock options	1,014	$	52.41
Noble Energy common stock held in rabbi trust and shares of restricted stock	1,102		-
Total excluded from diluted EPS calculation	2,116		
Year Ended December 31, 2006			
Stock options	675	$	45.19
Noble Energy common stock held in rabbi trust and shares of restricted stock	1,276		-
Total excluded from diluted EPS calculation	1,951		
Year Ended December 31, 2005			
Stock options	48	$	41.47
Noble Energy common stock held in rabbi trust	1,360		-
Total excluded from diluted EPS calculation	1,408		

Accounting for Uncertainty in Income Taxes – We adopted FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes, an interpretation of FASB Statement No. 109" ("FIN 48") as of January 1, 2007. FIN 48 clarifies the accounting for uncertainty in income taxes recognized in a company's financial statements in accordance with SFAS No. 109, "Accounting for Income Taxes". FIN 48 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. FIN 48 also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure, and transition. We also adopted FASB Staff Position No. FIN 48-1, "Definition of Settlement in FASB Interpretation No.48" ("FSP FIN 48-1") as of January 1, 2007. FSP FIN 48-1 provides that a company's tax position will be considered settled if the taxing authority has completed its examination, the company does not plan to appeal, and it is remote that the taxing authority would reexamine the tax position in the future. The adoption of FIN 48 and FSP FIN 48-1 had no effect on our financial position or results of operations. See Note 8—Income Taxes.

Accounting for Stock-Based Compensation—Through December 31, 2005, we accounted for stock-based compensation plans under the intrinsic value recognition and measurement principles of APB Opinion No. 25, "Accounting for Stock Issued to Employees" ("APB 25"), and related Interpretations. As of January 1, 2006, we adopted SFAS No. 123(R), "Share-Based Payment" ("SFAS 123(R)"). SFAS 123(R) revised SFAS No. 123, "Accounting for Stock-Based Compensation" and nullified APB 25 and its related implementation guidance. SFAS 123(R) requires companies to measure the grant-date fair value of stock options and other stock-based compensation issued to employees and expense the fair value over the requisite service period of the award. SFAS 123(R) became effective for interim or annual periods beginning January 1, 2006. In accordance with the modified prospective transition method, prior period amounts have not been restated. See Note 9—Stock-Based Compensation.

Accounting for Defined Benefit Pension and Other Postretirement Plans—In September 2006, the Financial Accounting Standards Board (the "FASB") issued SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132(R)" ("SFAS 158"). SFAS 158 requires plan sponsors of defined benefit pension and other postretirement benefit plans to recognize the funded status of their postretirement benefit plans in the statement of financial position, measure the fair value of plan assets and benefit obligations as of the date of the fiscal year-end statement of financial position, and provide additional disclosures. We adopted SFAS 158 as of December 31, 2006, and the effect of adoption on our financial condition at December 31, 2006 was included in our consolidated balance sheets. Adoption of SFAS 158 had no effect on our results of operations for the year ended December 31, 2006. See Note 11—Benefit Plans.

Adoption of Staff Accounting Bulletin No. 108—In September 2006, the Securities and Exchange Commission ("SEC") issued Staff Accounting Bulletin No. 108 ("SAB 108"). SAB 108 expresses the SEC staff's views regarding the process of quantifying financial statement misstatements. The SEC staff believes registrants should quantify errors using both a balance sheet and an income statement approach and evaluate whether either approach results in quantifying a misstatement that, when all relevant quantitative and qualitative factors are considered, is material. SAB 108 is effective for fiscal years ending on or after November 15, 2006. We adopted SAB 108 as of December 31, 2006. Adoption of SAB 108 had no effect on our financial position or results of operations.

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Treasury Stock—We record treasury stock purchases at cost, which includes incremental direct transaction costs. Amounts are recorded as reductions in shareholders' equity.

Revenue Recognition and Imbalances—We record revenues from the sales of crude oil and natural gas when the product is delivered at a fixed or determinable price, title has transferred and collectibility is reasonably assured.

When we have an interest with other producers in properties from which natural gas is produced, we use the entitlements method to account for any imbalances. Imbalances occur when we sell more or less product than we are entitled to under our ownership percentage. Revenue is recognized only on the entitlement percentage of volumes sold. Any amount that we sell in excess of our entitlement is treated as a liability and is not recognized as revenue. Any amount of entitlement in excess of the amount we sell is recognized as revenue and a receivable is accrued. We record the noncurrent portion of the liability in other deferred credits and noncurrent liabilities, and the current portion of the liability in other current liabilities. We record the noncurrent portion of the receivable in other assets and the current portion of the receivable in other current assets. Imbalance liabilities were $10 million and $17 million at December 31, 2007 and 2006, respectively. Imbalance receivables were $13 million and $18 million at December 31, 2007 and 2006, respectively.

Revenues derived from electricity generation are recognized when power is transmitted or delivered, the price is fixed and determinable and collectibility is reasonably assured.

We also engage in the purchase and sale of third-party crude oil and natural gas. We record third-party sales, net of cost of goods sold, as gathering, marketing and processing revenues when the product is delivered or the contract is net settled at a fixed or determinable price, title has transferred and collectibility is reasonably assured.

Derivative Instruments and Hedging Activities—We use various derivative instruments in connection with anticipated crude oil and natural gas sales to minimize the impact of commodity price fluctuations. Such instruments include variable to fixed NYMEX price swaps, costless collars and variable to fixed price basis swaps. We account for derivative instruments and hedging activities in accordance with SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities, as amended," ("SFAS 133"). SFAS 133 established accounting and reporting standards requiring every derivative instrument (including certain derivative instruments embedded in other contracts) to be recorded on the balance sheet as either an asset or liability measured at fair value. SFAS 133 requires that changes in the derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met. Under cash flow hedge accounting, gains and losses are reflected in shareholders' equity as accumulated other comprehensive income or loss ("AOCL") until the forecasted transaction occurs. The derivative's gains and losses are then offset against related results on the hedged transaction on the statements of operations. Gains and losses from derivative instruments related to crude oil and natural gas sales and which qualify for hedge accounting treatment are recorded in oil and gas sales in the consolidated statements of operations upon sale of the associated commodity.

SFAS 133 also requires that a company formally document, designate and assess the effectiveness of transactions that receive hedge accounting. Only derivative instruments that are expected to be highly effective in offsetting anticipated gains or losses on the hedged cash flows and that are subsequently documented to have been highly effective can qualify for hedge accounting. Effectiveness must be assessed both at inception of the hedge and on an ongoing basis. Any ineffectiveness in hedging instruments whereby gains or losses do not exactly offset anticipated gains or losses of hedged cash flows is measured and recognized in earnings in the period in which it occurs. We assess hedge effectiveness quarterly based on total changes in the derivative's fair value and using regression analysis. A hedge is considered effective if certain statistical tests are met. We record hedge ineffectiveness in loss on derivative instruments. See Note 12—Derivative Instruments and Hedging Activities.

Through December 31, 2007, we elected to designate the majority of our crude oil and natural gas derivative instruments as cash flow hedges. Effective January 1, 2008, we discontinued cash flow hedge accounting on all existing commodity derivative instruments. We voluntarily made this change to provide greater flexibility in our use of derivative instruments. From January 1, 2008 forward, we will recognize all gains and losses on such instruments in earnings in the period in which they occur. Net derivative losses that were deferred in AOCL as of December 31, 2007, will be reclassified to earnings in future periods as the original hedged transactions affect earnings. The discontinuance of cash flow hedge accounting for commodity derivative instruments did not affect our net assets or cash flows at December 31, 2007 and does not require adjustments to our previously reported financial statements.

Related Party Transaction—We entered into a consulting agreement with a former officer of Patina who now serves as a member of our Board of Directors. Pursuant to the consulting agreement, the Board member served as a consultant to the combined company for a period of 12 months following the merger (May 16, 2005) in exchange for a monthly retainer of $50,000. We paid total consulting fees of $225,806 during 2006 and $374,194 during 2005. We also reimbursed his office space rent of $72,000 in 2006 and $45,000 in 2005.

Contingencies—We are subject to legal proceedings, claims and liabilities that arise in the ordinary course of business. We accrue for losses associated with legal claims when such losses are considered probable and the amounts can be reasonably estimated.

We self-insure the medical and dental coverage provided to certain employees, certain workers' compensation and the first $1 million of general liability coverage. Liabilities are accrued for self-insured claims, or when estimated losses exceed coverage limits, and when sufficient information is available to reasonably estimate the amount of the loss.

Electricity Generation—Ecuador Integrated Power Project—Through our subsidiaries, EDC Ecuador Ltd. and MachalaPower Cia. Ltda., we have a 100% ownership interest in an integrated natural gas-to-power project. The project includes the Amistad natural gas field, offshore Ecuador, which supplies natural gas to fuel the Machala power plant located in Machala, Ecuador. The revenues attributable to the natural gas-to-power project are included in other revenues and the expenses (including DD&A) are included in other expense, net.

Concentration of Market Risk—During 2007, Marathon Petroleum Supply Company ("Marathon") was the largest single non-affiliated purchaser of production and accounted for 18% of crude oil sales, or 10% of total oil and gas sales. During 2006, Trafigura Beheer B.V. was the largest single non-affiliated purchaser of production and accounted for 28% of crude oil sales, or 15% of total oil and gas sales. Shell Trading (US) Company accounted for 18% of 2006 crude oil sales or 10% of 2006 total oil and gas sales. During 2005, Glencore Energy U.K., Ltd. was the largest single non-affiliated purchaser of production and accounted for 24% of crude oil sales, or 11% of total oil and gas sales. We believe the loss of any one purchaser would not have a material effect on our financial position or results of operation since there are numerous potential purchasers of our production.

Concentration of Credit Risk—Certain of our financial instruments, including cash equivalents, trade receivables and derivative instruments, may expose us to credit risk. Substantially all of our cash at December 31, 2007 is located in our foreign subsidiaries. The cash is denominated in US dollars and in invested in highly liquid, investment-grade securities with original maturities of three months or less at the time of purchase. Although our cash and cash equivalents are deposited with major international banks and financial institutions, concentrations of cash in certain foreign locations may increase credit risk. We monitor the creditworthiness of the banks and financial institutions with which we invest and review the securities underlying our investment accounts. We believe that losses from nonperformance are unlikely to occur; however, we are not able to predict sudden changes in creditworthiness.

Our trade receivables result primarily from sales of crude oil and natural gas production and joint interest billings to our partners. The trade receivables reflect a broad national and international customer base, which limits our exposure to concentrations of credit risk. The majority of these receivables have payment terms of 30 days or less, and we continually monitor the creditworthiness of the counterparties.

We use crude oil and gas derivative instruments to mitigate the effects of commodity price fluctuations and these derivative instruments expose us to counterparty credit risk. Our counterparties are major banks or financial institutions. We engage in master netting arrangements to mitigate credit risk with counterparties as these agreements permit the amounts owed to others to be offset against amounts due us. We monitor the creditworthiness of our counterparties and believe that losses from nonperformance are unlikely to occur. However, we are not able to predict sudden changes in counterparties' creditworthiness.

Reclassification—Certain reclassifications have been made to the 2006 and 2005 consolidated financial statements to conform to the 2007 presentation. These reclassifications are not material to the financial statements.

Note 3—Acquisitions and Divestitures

Sale of Argentina—In December 2007, we entered into an agreement to sell our interest in Argentina for a sales price of $117.5 million, effective July 1, 2007. We expect the sale, which is subject to regulatory and partner approvals, to close in 2008. The Argentina assets had a net book value of $82 million at December 31, 2007 and are classified as assets held for sale in the consolidated balance sheets. The Argentina operations, financial position and cash flows are not material and have not been reflected as discontinued operations.

Sale of Gulf of Mexico Shelf Properties—In 2006, we completed the sale of our Gulf of Mexico shelf properties. The sale included essentially all of our properties in the Gulf of Mexico shelf except for our interest in the Main Pass area, which we have retained. Pretax cash proceeds from the sale totaled $506 million including proceeds received from parties who exercised preferential rights to purchase certain minor properties. We recorded a pretax gain of $211 million from the sale. The net book value of properties sold totaled $229 million. Asset retirement obligations of $45 million, related to the Gulf of Mexico shelf properties, were also included in the sale. In accordance with SFAS 142, we allocated $100 million of our US reporting unit goodwill to the sale. The property disposition did not qualify for accounting as discontinued operations, in accordance with EITF 03-13, "Applying the Conditions in Paragraph 42 of FASB Statement No. 144 in Determining Whether to Report Discontinued Operations". This is due to the migration of our investment and operations to the deepwater Gulf of Mexico which we believe is an area of higher potential.

As a result of the sale, we recognized a pretax charge of $399 million related to cash flow hedge losses which were reclassified from AOCL to earnings. This reclassification reflected the mark-to-market value of the cash flow hedges that related to Gulf of Mexico shelf production. See Note 12—Derivative Instruments and Hedging Activities.

Purchase of U.S. Exploration Holdings, Inc.—In 2006, we purchased the common stock of U.S. Exploration, a privately held corporation, for a cash purchase price of $412 million plus liabilities assumed. U.S. Exploration's reserves and production are located in Colorado's Wattenberg field. The total purchase price was allocated to the assets acquired and liabilities assumed based on fair values at the acquisition date as follows:

- $413 million to proved oil and gas properties;
- $131 million to unproved oil and gas properties;
- $34 million to goodwill; and
- $172 million to deferred income taxes.

Patina Merger—In 2005, we completed the Patina Merger. Patina was an independent energy company engaged in the acquisition, development and exploitation of crude oil and natural gas properties within the continental US. Patina's properties and oil and gas reserves are located principally in relatively long-lived fields with established production histories. The properties are concentrated primarily in the Wattenberg field of Colorado's D-J basin, the Mid-continent area of western Oklahoma and the Texas Panhandle, and the San Juan basin in New Mexico. We acquired the common stock of Patina for a total purchase price of approximately $4.9 billion, which was comprised primarily of cash and our common stock, plus liabilities assumed. In exchange for Patina's common stock and stock options held by Patina's employees, we issued 55.7 million shares of stock valued at $1.7 billion, issued options valued at $105 million, paid $1.1 billion in cash to Patina shareholders and assumed debt of $611 million and deferred taxes of $1.1 billion. The total purchase price was allocated to the assets acquired and liabilities assumed based on fair values at the merger date as follows:

- $2.6 billion to proved oil and gas properties;
- $1.1 billion to unproved oil and gas properties;

- $875 million to goodwill; and
- $1.1 billion to deferred income taxes.

The following pro forma condensed combined financial information for the year ended December 31, 2005 was derived from our historical financial statements and those of Patina and gives effect to the merger as if it had occurred on January 1, 2005. The financial information has been included for comparative purposes and is not necessarily indicative of the results that might have occurred had the merger taken place as of the dates indicated and is not intended to be a projection of future results.

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		Year Ended December 31, 2005 (in thousands, except per share amounts)
Revenues	$	2,434,677
Net income		693,091
Earnings per share:		
Basic	$	4.03
Diluted		3.98

Note 4—Effect of Gulf Coast Hurricanes

We have completed our cleanup activities relating to damage to the Main Pass assets caused by Hurricane Ivan in 2004 and Katrina in 2005. During third quarter 2007, we completed the lifting and removal of the four platform decks that were sheared from their supporting structures during the hurricanes. During the first half of 2007, several factors contributed to an increase in our estimated cleanup costs for damage related to Hurricanes Ivan and Katrina. These factors included cost escalation due to weather delays and an increase in effort for the design and construction of the deck lifting barge and mooring system, as well as additional costs for the actual deck lifting activities. These increases caused the total project costs, combined with net book value of the assets destroyed, to exceed certain insurance coverage limitations. As a result, we recorded $51 million as a loss on involuntary conversion during 2007.

Through December 31, 2007, we received $310 million of insurance recoveries related to damage caused by Hurricanes Ivan and Katrina. As of December 31, 2007, we recorded probable insurance claims of $40 million. We are currently assessing the scope and timing of our redevelopment of the Main Pass properties. Ultimate recovery of our insurance claim is associated with redevelopment or possible settlement resolution with our insurance providers.

Insurance reimbursements received to date have been for cleanup and repair costs and are included in cash flows from operating activities.

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Note 5—Capitalized Exploratory Well Costs

We capitalize exploratory well costs until a determination is made that the well has found proved reserves or is deemed noncommercial, in which case the well costs are immediately charged to exploration expense.

Changes in capitalized exploratory well costs are as follows and exclude amounts that were capitalized and subsequently expensed in the same period:

	Year Ended December 31,		
	2007	2006	2005
		(in thousands)	
Capitalized exploratory well costs, beginning of period	$ 80,359	$ 35,228	$ 62,724
Additions to capitalized exploratory well costs pending determination of proved reserves	182,271	62,580	33,671
Reclassified to property, plant and equipment based on determination of proved reserves	(7,143)	(16,762)	(52,138)
Capitalized exploratory well costs charged to expense	(6,454)	(687)	(9,029)
Capitalized exploratory well costs, end of period	$ 249,033	$ 80,359	$ 35,228

The following table provides an aging of capitalized exploratory well costs (suspended well costs) based on the date the drilling was completed and the number of projects for which exploratory well costs have been capitalized for a period greater than one year since the completion of drilling:

	December 31,		
	2007	2006	2005
		(in thousands)	
Capitalized exploratory well costs that have been capitalized for a period of one year or less	$ 187,101	$ 58,493	$ 35,228
Capitalized exploratory well costs that have been capitalized for a period greater than one year after completion of drilling	61,932	21,866	-
Balance at end of period	$ 249,033	$ 80,359	$ 35,228
Number of projects that have exploratory well costs that have been capitalized for a period greater than one year after completion of drilling	6	4	-

The following table provides a further aging of those exploratory well costs that have been capitalized for a period greater than one year since the completion of drilling as of December 31, 2007:

		Suspended Since	
	Total	2006	2005
		(in thousands)	
Project:			
Raton South (Deepwater Gulf of Mexico)	$ 23,374	$ 23,374	$ -
Redrock (Deepwater Gulf of Mexico)	17,133	17,133	-
Blocks O and I (West Africa)	19,039	-	19,039
Other	2,386	2,386	-

Total capitalized exploratory well costs that have been capitalized for a period greater than one year after completion of drilling	$	61,932	$	42,893	$	19,039

Exploratory well costs capitalized for more than one year at December 31, 2007 included six projects, two of which included activity in the deepwater Gulf of Mexico. One project relates to Raton South (Mississippi Canyon Block 292) and includes approximately $23 million of suspended exploratory well costs. We are currently evaluating a possible sidetrack-appraisal well to be drilled during late 2008 or 2009. The other project relates to Redrock (Mississippi Canyon 248) and includes approximately $17 million of suspended exploratory well costs. Redrock is currently considered a co-development candidate to a successful sidetrack-appraisal well at Raton South.

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We also incurred exploratory well costs for projects, Block O and Block I, in West Africa. These exploratory well costs totaled approximately $19 million. Since drilling the initial well for the project, additional seismic work has been completed and appraisal wells have been drilled to further evaluate this discovery. In 2008, the West Africa development team will proceed with a program to further define the resources in this area such that an optimal development program may be designed. In addition to the amount of exploratory well costs that have been capitalized for a period greater than one year for the Block O and Block I projects, we incurred $137 million related to the six successful wells drilled in West Africa during 2007.

The remaining two projects, which total approximately $2 million, continue to be evaluated by various means including additional seismic work, drilling additional wells and evaluating the potential of the exploration wells.

Note 6—Asset Retirement Obligations

Asset retirement obligations consist of estimated costs of dismantlement, removal, site reclamation and similar activities associated with our oil and gas properties. An asset retirement obligation and the related asset retirement cost are recorded when an asset is first constructed or purchased. The asset retirement cost is determined and discounted to present value using a credit-adjusted risk-free rate. After initial recording the liability is increased for the passage of time, with the increase being reflected as accretion expense in the statement of operations. Subsequent adjustments in the cost estimate are reflected in the liability and the amounts continue to be amortized over the useful life of the related long-lived asset.

Changes in asset retirement obligations are as follows:

	Year Ended December 31, 2007 (in thousands)	
Asset retirement obligations, beginning of period	$	196,189
Liabilities incurred in current period		8,927
Liabilities settled in current period		(176,961)
Revisions		108,008
Accretion expense		8,125
Asset retirement obligations, end of period	$	144,288
Current portion	$	13,332
Noncurrent portion		130,956

Approximately $125 million of liabilities settled and $64 million of revisions related to hurricane damage to the Gulf of Mexico Main Pass assets. The remainder of the liabilities settled and revisions resulted primarily from changes in estimated timing of actual abandonment and overall cost increases for Gulf of Mexico assets. See Note 4—Effect of Gulf Coast Hurricanes.

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Note 7—Debt

Our debt consists of the following:

	December 31,			
	2007		2006	
	Debt	Interest Rate	Debt	Interest Rate
	(in thousands, except percentages)			
$2.1 billion Credit Facility	$ 1,180,000	5.28	$ 1,155,000	5.69
5 ¼% Senior Notes, due April 2014	200,000	5.25	200,000	5.25
7 ¼% Notes, due October 2023	100,000	7.25	100,000	7.25
8% Senior Notes, due April 2027	250,000	8.00	250,000	8.00
7 ¼% Senior Debentures, due August 2097	100,000	7.25	100,000	7.25
Installment payments, due May 2009	25,000	5.53	-	-
Long-term debt	1,855,000		1,805,000	
Installment payments - current portion	25,000	5.53	-	-
Total debt	1,880,000		1,805,000	
Unamortized discount	(3,913)		(4,190)	
Total debt, net of discount	$ 1,876,087		$ 1,800,810	

All of our long-term debt is senior unsecured debt and is, therefore, pari passu with respect to the payment of both principal and interest. The indenture documents of each of the 7¼% Notes, the 8% Senior Notes and the 7¼% Senior Debentures provide that we may prepay the instruments by creating a defeasance trust. The defeasance provisions require that the trust be funded with securities sufficient, in the opinion of a nationally recognized accounting firm, to pay all scheduled principal and interest due under the respective agreements. Interest on each of these issues is payable semi-annually.

Credit Facility—In November 2007, we extended our bank revolving credit facility (the “Credit Facility”) until December 9, 2012. The commitment is $2.1 billion until December 9, 2011 at which time the commitment reduces to $1.8 billion. The Credit Facility (i) provides for Credit Facility fee rates that range from 5 basis points to 15 basis points per year depending upon our credit rating, (ii) makes available short-term loans up to an aggregate amount of $300 million and (iii) provides for interest rates that are based upon the Eurodollar rate plus a margin that ranges from 20 basis points to 70 basis points depending upon our credit rating and utilization of the Credit Facility. The Credit Facility requires that our total debt to capitalization ratio (as defined in the credit agreement), expressed as a percentage, not exceed 60% at any time. A violation of this covenant could result in a default under the Credit Facility, which would permit the participating banks to restrict our ability to access the Credit Facility and require the immediate repayment of any outstanding advances under the Credit Facility. The Credit Facility is with certain commercial lending institutions and is available for general corporate purposes.

Certain lenders that are a party to the Credit Facility have in the past performed investment banking, financial advisory, lending or commercial banking services for us, for which they have received customary compensation and reimbursement of expenses. Debt issuance costs of approximately $3 million remain and are being amortized to expense over the life of the Credit Facility.

The Credit Facility does not restrict the payment of dividends on our common stock, except, if after giving effect thereto, an Event of Default shall have occurred and be continuing or been caused thereby.

Installment Payments Due—During 2007, we purchased working interests in oil and gas properties in the Piceance basin of western Colorado for $75 million. After making a cash payment of $25 million at closing, we owe $50 million in the form of installment payments to the seller. Installments of $25 million each are due on May 12, 2008 and May 11, 2009. The amount due in 2008 is included in short-term borrowings and the amount due in 2009 is included in long-term debt in the consolidated balance sheets. Interest on the unpaid amounts is due quarterly. Interest accrues at a LIBOR rate plus .30%. The interest rate was 5.53% at December 31, 2007.

Debt Repayments—During 2006, we prepaid the $105 million balance remaining on certain term loans due 2009. The interest rates on the term loans were based on a Eurodollar rate plus a margin of between 60 to 130 basis points depending upon our credit rating. Interest was payable periodically based on the tenor of the underlying Eurodollar rate selected at the time of a rate reset.

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Annual Maturities—Annual maturities of outstanding debt are as follows:

	(in thousands)
2008	$ 25,000
2009	25,000
2010	-
2011	-
2012	1,180,000
Thereafter	650,000
Total	$ 1,880,000

Short-Term Borrowings—Our credit agreement is supplemented by short-term borrowings under various uncommitted credit lines used for working capital purposes. Uncommitted credit lines may be offered by certain banks from time to time at rates negotiated at the time of borrowing. Other than the installment payments discussed above, no short-term borrowings were outstanding at December 31, 2007 or 2006.

Note 8—Income Taxes

Components of income before income taxes are as follows:

	Year Ended December 31,		
	2007	2006	2005
		(in thousands)	
Domestic	$ 480,200	$ 402,111	$ 426,756
Foreign	887,367	694,106	541,904
Total	$ 1,367,567	$ 1,096,217	$ 968,660

The income tax provision consists of the following:

	Year Ended December 31,		
	2007	2006	2005
		(in thousands)	
Current taxes:			
Federal	$ 6,409	$ 79,680	$ 48,293
State	506	5,577	-
Foreign	124,901	138,271	90,877
Total current	131,816	223,528	139,170
Deferred taxes:			
Federal	185,503	144,143	119,953
State	6,283	4,641	14,073
Foreign	100,095	45,477	49,744
Total deferred	291,881	194,261	183,770
Total income tax provision	$ 423,697	$ 417,789	$ 322,940

A reconciliation of the federal statutory tax rate to the effective tax rate is as follows:

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	Year Ended December 31,		
	2007	2006	2005
	(amounts in percentages)		
Federal statutory rate	35.0	35.0	35.0
Effect of:			
Earnings of equity method investees	(5.4)	(4.2)	(3.2)
State taxes, net of federal benefit	0.5	1.3	1.3
Difference between US and foreign rates	1.6	2.2	3.5
Nondeductible goodwill	-	3.1	-
AJCA repatriation benefit	-	-	(3.7)
Other, net	(0.7)	0.7	0.4
Effective rate	31.0	38.1	33.3

Deferred tax assets and liabilities resulted from the following:

	December 31,	
	2007	2006
	(in thousands)	
Deferred tax assets:		
Loss carryforwards	$ 20,571	$ 90,387
Accrued expenses	26,227	34,083
Allowance for doubtful accounts	3,566	2,917
Fair value of derivative contracts	176,750	185,667
Postretirement benefits	10,233	14,578
Deferred compensation	60,993	55,880
Foreign tax credits	82,037	63,707
Other	14,037	3,577
Total deferred tax assets	394,414	450,796
Valuation allowance - foreign losses	(18,174)	(9,876)
Valuation allowance - foreign tax credits	(56,619)	(63,708)
Net deferred tax assets	319,621	377,212
Deferred tax liabilities:		
Property, plant and equipment, principally due to differences in depreciation, amortization, lease impairment and abandonments	(2,183,950)	(2,034,877)
Other	11,067	(952)
Total deferred tax liability	(2,172,883)	(2,035,829)
Net deferred tax liability	$ (1,853,262)	$ (1,658,617)

Net deferred tax liabilities were classified in the consolidated balance sheet as follows:

	December 31,	
	2007	2006
	(in thousands)	
Deferred income tax asset	$ 130,571	$ 99,835
Deferred income tax liability	(1,983,833)	(1,758,452)
Net deferred tax liability	$ (1,853,262)	$ (1,658,617)

In assessing the realizability of deferred tax assets, we consider whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible.

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We consider the scheduled reversal of deferred tax liabilities, projected future taxable income and tax planning strategies in making this assessment. Based upon the level of historical taxable income and projections for future taxable income over the periods in which the deferred tax assets are deductible, we believe it is more likely than not that we will realize the benefits of these deductible differences at December 31, 2007. The amount of the deferred tax asset considered realizable could be reduced in the future if estimates of future taxable income during the carryforward period are reduced.

We have recognized deferred tax assets associated with foreign loss carryforwards. The tax effect of these carryforwards decreased from $90 million in 2006 to $18 million in 2007. These losses were incurred on our projects in Suriname and other new venture activities which are not yet commercial. Therefore, a valuation allowance was provided against the full amount of the deferred tax asset. In 2006, we incurred a large taxable loss in the UK from accelerated write-offs allowed on our Dumbarton field development. No valuation allowance was provided against this loss carryforward, and it was fully utilized in 2007. Starting in 2005, we were able to claim a foreign tax credit for US federal income tax purposes and expect to be in a credit position for the next several years. Therefore, we have recorded a deferred tax asset for certain foreign taxes paid in 2005 and 2006 that cannot be claimed as a credit in those years because of limitations imposed by the Internal Revenue Code. A valuation allowance of $11 million has been provided against this deferred tax asset. We have also recorded a deferred tax asset of $71 million for the future foreign tax credits associated with deferred tax liabilities recorded by foreign branch operations. A valuation allowance of $46 million has been provided against this deferred tax asset.

Several factors resulted in a decrease in our effective tax rate for 2007. The major factor was that, in 2006, $100 million of goodwill write-off associated with the sale of the Gulf of Mexico shelf properties was not deductible, which increased the rate for that year. Other factors were an increase in deferred tax assets arising from foreign tax credits, a decrease in the Chinese tax rate, and the realization of additional income from equity method investees which is a favorable permanent difference in calculating the income tax expense.

The American Jobs Creation Act ("AJCA"), enacted in 2004, created a temporary incentive for US corporations to repatriate accumulated income earned abroad by providing for an 85% dividends-received deduction for certain dividends from controlled foreign corporations. In July 2005, we completed an evaluation of the effects of the repatriation provision, and our Board of Directors approved a plan to repatriate $118 million in earnings of our methanol subsidiary during the third quarter 2005. Because we had provided US tax on most of the methanol subsidiary's earnings at 35% through December 31, 2004, repatriation under the Act resulted in a net tax benefit of $35 million recorded in the third quarter 2005.

We have not recorded US deferred income taxes on the remaining undistributed earnings of foreign subsidiaries as of December 31, 2007. As of December 31, 2007, the accumulated undistributed earnings of the consolidated foreign subsidiaries were approximately $902 million. Upon distribution of these earnings in the form of dividends or otherwise, we would likely be subject to US income taxes and foreign withholding taxes. It is not practicable, however, to estimate the amount of taxes that may be payable on the eventual remittance of these earnings because of the possible application of US foreign tax credits. Although we are currently claiming foreign tax credits, we may not be in a credit position when any future remittance of foreign earnings takes place, or the limitations imposed by the Internal Revenue Code and IRS Regulations may not allow the credits to be utilized during the applicable carryback and carryforward periods.

During 2007, China's legislature, the National People's Congress, enacted the China Corporate Income Tax Law. This new legislation will decrease our tax rate in China from 33% to 25% starting in 2008. The deferred tax liability for China as of December 31, 2006 was revised during 2007 to reflect the new rate, which decreased deferred tax expense by $2 million.

Adoption of FIN 48 and FSP FIN 48-1—As discussed in Note 2—Significant Accounting Policies, we adopted FIN 48 and FSP FIN 48-1 as of January 1, 2007. The adoption had no effect on our financial position or results of operations. As of January 1, 2007, the total amount of unrecognized tax benefits was $400,000, all of which would affect our effective tax rate if recognized. There was no change in the amount of unrecognized tax benefits through December 31, 2007. We do not expect that the total amount of unrecognized tax benefits will significantly increase or decrease during the next 12 months.

In our major tax jurisdictions, the earliest years remaining open to examination are as follows: US – 2004, Equatorial Guinea – 2006, China – 2006, Israel – 2000, UK – 2006 and the Netherlands – 2005.

We recognize interest and penalties related to unrecognized tax benefits which have been claimed on tax returns in income tax expense. We did not accrue interest or penalties at December 31, 2007, because the jurisdiction in which we have unrecognized tax benefits does not currently impose interest on underpayments of tax, and we believe that we are below the minimum statutory threshold for imposition of penalties.

Note 9—Stock-Based Compensation

As discussed in Note 2—Summary of Significant Accounting Policies, effective January 1, 2006, we adopted the fair value recognition provisions for stock-based awards granted to employees using the modified prospective application method provided by SFAS 123(R). Accordingly, prior period amounts have not been restated. SFAS 123(R) requires companies to recognize in the statement of operations the grant-date fair value of stock options and other stock-based compensation issued to employees and was effective for interim or annual periods beginning January 1, 2006. We recognize the expense of all stock-based awards on a straight-line basis over the employee's requisite service period (generally the vesting period of the award).

We recognized total stock-based compensation expense as follows:

	Year Ended December 31,		
	2007	2006	2005
		(in thousands)	
Stock-based compensation expense included in:			
General and administrative expense	$ 25,136	$ 10,720	$ 4,008
Exploration expense and other	1,689	1,096	-
Total stock-based compensation expense	$ 26,825	$ 11,816	$ 4,008
Tax benefit recognized	$ 10,086	$ 4,443	$ 1,403

Pro Forma Information—The following table illustrates the effect on net income and earnings per share if we had applied the fair value recognition provisions of SFAS 123(R) to stock-based employee compensation in all periods presented. The actual and pro forma net income and earnings per share for 2007 and 2006 below are the same since we adopted SFAS 123(R) as of January 1, 2006. The 2007 and 2006 amounts are presented for comparison to the prior year.

	Year Ended December 31,		
	2007 (actual)	2006 (actual)	2005 (pro forma) (unaudited)
	(in thousands, except per share amounts)		
Net income, as reported	$ 943,870	$ 678,428	$ 645,720
Add: Stock-based compensation cost recognized, net of tax	16,739	7,373	2,605
Deduct: Stock-based employee compensation expense determined under fair value based method for all awards, net of tax	(16,739)	(7,373)	(6,150)
Pro forma net income	$ 943,870	$ 678,428	$ 642,175
Earnings per share:			
Basic - as reported	$ 5.52	$ 3.86	$ 4.20
Basic - pro forma	5.52	3.86	4.18
Diluted - as reported	5.45	3.79	4.12
Diluted - pro forma	5.45	3.79	4.10

Total stock-based compensation expense determined under the fair value based method for all awards for 2005 has been recalculated using revised expected term assumptions. The impact on pro forma earnings and pro forma earnings per share was not significant.

Stock Option and Restricted Stock Plans and Incentive Plan—Our stock option and restricted stock plans (the “Plans”) and incentive plan are described below.

1992 Stock Option and Restricted Stock Plan

Under the Noble Energy, Inc. 1992 Stock Option and Restricted Stock Plan, as amended (the "1992 Plan"), the Compensation, Benefits and Stock Option Committee of the Board of Directors (the "Committee") may grant stock options and award restricted stock to our officers or other employees and those of our subsidiaries. During 2007, our stockholders approved an amendment to the 1992 Plan that increased the maximum number of shares of our common stock that may be issued from 18,500,000 to 22,000,000 shares. At December 31, 2007, 11,229,753 shares of common stock were reserved for issuance, including 6,063,665 shares available for future grants and awards, under the 1992 Plan.

1992 Plan Stock Options—Stock options are issued with an exercise price equal to the market price of our common stock on the date of grant, and are subject to such other terms and conditions as may be determined by the Committee. Unless granted by the Committee for a shorter term, the options expire ten years from the grant date. Option grants generally vest ratably over a three-year period.

1992 Plan Restricted Stock—Restricted stock awards made under the 1992 Plan are subject to such restrictions, terms and conditions, including forfeitures, if any, as may be determined by the Committee. Restricted Stock awards generally vest over periods of one to three years.

2004 Long-Term Incentive Plan

Under the Noble Energy, Inc. 2004 Long-Term Incentive Plan (the "2004 LTIP"), the Committee may make incentive awards to our key employees and those of our subsidiaries. Incentive compensation is based upon the attainment of specific market and performance goals established by the Committee. Awards may be in the form of stock options or restricted stock or in the form of performance units or other incentive measurements providing for the payment of bonuses in cash, or in any combination thereof, as determined by the Committee in its discretion. Stock options granted and restricted stock awarded under the 2004 LTIP are granted and awarded pursuant to the terms of the 1992 Plan. These awards are accounted for in accordance with the provisions of SFAS 123(R) which provides for the grant-date fair value of the awards to be recognized in the income statement over the service period. Our cash based performance units are accounted for under SFAS No. 5, "Accounting for Contingencies" and are excluded from the provisions of SFAS 123(R).

2005 Stock Plan for Non-Employee Directors

The 2005 Stock Plan for Non-Employee Directors of Noble Energy, Inc. (the "2005 Plan") provides for grants of stock options and awards of restricted stock to our non-employee directors. The 2005 Plan superseded and replaced the 1988 Nonqualified Stock Option Plan for Non-Employee Directors. The total number of shares of common stock that may be issued under the 2005 Plan is 800,000. At December 31, 2007, 774,561 shares of common stock were reserved for issuance, including 650,306 shares available for future grants and awards under the 2005 Plan.

2005 Plan Stock Options—The 2005 Plan provides for the granting to a non-employee director of 11,200 stock options on the date of election to the Board of Directors, annual grants of 2,800 options per non-employee director on February 1 of each year, and discretionary grants by the Board of Directors (up to a maximum of 11,200 options per non-employee director granted in any one year). Options are issued with an exercise price equal to the market price of our common stock on the date of grant and may be exercised one year after the date of grant. The options expire ten years from the date of grant.

2005 Plan Restricted Stock—The 2005 Plan also provides for the granting to a non-employee director of 4,800 shares of restricted stock on the date of election to the Board of Directors, annual awards of 1,200 shares of restricted stock per non-employee director on February 1 of each year, and discretionary grants by the Board of Directors (up to a maximum of 4,800 shares of restricted stock per non-employee director awarded in any one year). Restricted stock is restricted for a period of at least one year from the date of grant.

1988 Nonqualified Stock Option Plan for Non-Employee Directors

The 1988 Nonqualified Stock Option Plan for Non-Employee Directors of Noble Energy, Inc., as amended, (the "1988 Plan") provided for the issuance of stock options to our non-employee directors. Options issued under the 1988 Plan may be exercised one year after grant and expire ten years from the grant date. The 1988 Plan provided for the granting of a fixed number of stock options to each non-employee director annually (10,000 stock options for the first calendar year of service and 5,000 stock options for each year thereafter) on February 1 of each year. The 1988 Plan was terminated in 2005. No options can be granted under the 1988 Plan after its termination.

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Patina Stock Option Plans

Patina maintained a shareholder approved stock option plan for employees (the “Patina Employee Plan”) that provided for the issuance of options at prices not less than fair market value at the date of grant. Patina also maintained a shareholder approved stock grant and option plan for non-employee directors (the “Patina Directors’ Plan”). The Patina Directors’ Plan provided for stock options to be granted to each non-employee director upon appointment and upon annual re-election thereafter. Upon completion of the Patina Merger, all unvested stock options outstanding under the Patina Employee Plan and the Patina Directors’ Plan became fully vested, and all outstanding options were converted into options to purchase our common stock. The Patina options expire five years from the date of grant. See Note 3—Acquisitions and Divestitures.

Stock Option Grants—The fair value of each stock option granted was estimated on the date of grant using a Black-Scholes-Merton option valuation model that uses the assumptions noted in the following table. The expected term represents the period of time that options granted are expected to be outstanding. The hypothetical midpoint scenario we use considers the actual exercise and post-vesting cancellation history of stock-based compensation historical trends to develop expectations for future periods. Expected volatility represents the extent to which our stock price is expected to fluctuate between the grant date and the anticipated term of the award. We use a blended ratio of the historical volatility of our common stock for a period equal to the expected term of the option and the implied volatility from exchange-traded options on our common stock. The risk-free rate is based on a weighting of five and seven year US Treasury securities as of the year ended prior to the date of grant to arrive at an approximated 5.5-year risk free rate of return. The dividend yield represents the value of our stock’s annualized dividend as compared to our stock’s average price for the three-year period ended prior to the date of grant. It is calculated by dividing one full year of our expected dividends by our average stock price over the three-year period ended prior to the date of grant. The assumptions used in valuing stock options are as follows:

	Year Ended December 31,		
	2007	2006	2005
	(weighted averages)		
Expected term (in years)	5.5	5.5	5.5
Expected volatility	29.6%	31.8%	21.5%
Risk-free rate	4.7%	4.7%	4.6%
Expected dividend yield	0.6%	0.8%	0.4%

Stock option activity was as follows:

	Options	Weighted Average Exercise Price (per share)	Weighted Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value (in thousands)
Outstanding at December 31, 2006	6,211,750	$ 24.24		
Granted	1,557,919	53.79		
Exercised	(1,479,040)	16.66		
Forfeited/Canceled	(115,568)	49.21		
Outstanding at December 31, 2007	6,175,061	$ 32.98	5.5	$ 287,768
Exercisable at December 31, 2007	4,083,097	$ 24.29	3.8	$ 225,499

The weighted-average grant-date fair value of options granted was $18.77 in 2007, $16.09 in 2006 and $12.17 in 2005. The total intrinsic value of options exercised was $68 million in 2007, $118 million in 2006 and $78 million in 2005.

As of December 31, 2007, $23 million of compensation cost related to unvested stock options granted under the Plans remained to be recognized. The cost is expected to be recognized over a weighted-average period of 1.4 years. We issue new shares of common stock to settle option exercises. Dividends are not paid on unexercised options.

Restricted Stock Awards—Awards of time-vested restricted stock are valued at the price of our common stock at the date of award. The fair values of market-based restricted stock awards are estimated on the date of award using a Monte Carlo valuation model that uses the assumptions in the following table. The Monte Carlo model is based on random projections of stock price paths and must be repeated numerous times to achieve a probabilistic assessment. Expected volatility represents the extent to which our stock price is expected to fluctuate between now and the award's anticipated term. We use the historical volatility of our common stock for the three-year period ended prior to the date of award. The risk-free rate is based on a three-year period from US Treasury securities as of the year ended prior to the date of award. The assumptions used in valuing the market based restricted stock awards are as follows:

	Year Ended December 31,	
	2006	2005
Number of simulations	100,000	100,000
Expected volatility	28.4%	29.6%
Risk-free rate	4.4%	3.3%

Restricted stock activity was as follows:

	Shares Subject to Service Conditions	Weighted Average Grant Date Fair Value (per share)	Shares Subject to Market Conditions	Weighted Average Grant Date Fair Value (per share)
Outstanding at December 31, 2006	73,095	$ 35.85	204,250	$ 29.27
Granted	547,818	53.92	-	-
Vested	(37,475)	42.99	(75,325)	22.23
Forfeited	(15,848)	53.42	(4,788)	40.51
Outstanding at December 31, 2007	567,590	$ 52.33	124,137	$ 33.11

The total fair value of restricted stock that vested was $6 million in 2007 and $2 million in 2006.

As of December 31, 2007, $20 million of compensation cost related to unvested restricted stock awarded under the Plans remained to be recognized. The cost is expected to be recognized over a weighted-average period of two years. Common stock dividends accrue on restricted stock grants and are paid upon vesting. We issue new shares of common stock when awarding restricted stock.

Note 10—Additional Shareholders' Equity Information

Activity in shares of our common stock and treasury stock was as follows:

	Year Ended December 31,	
	2007	2006
Common stock shares issued		
Shares at beginning of period	188,808,087	184,893,510
Exercise of common stock options	1,479,040	3,848,521
Restricted stock awards, net of forfeitures	527,182	66,056
Shares at end of period	190,814,309	188,808,087
Treasury stock		

Shares at beginning of period	16,574,384	9,268,932
Shares repurchased	2,006,481	8,373,400
Rabbi trust shares sold	-	(1,067,948)
Shares at end of period	18,580,865	16,574,384

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During 2007, we completed a $500 million common stock repurchase program begun in 2006.

Accumulated other comprehensive loss in the shareholders' equity section of the balance sheet included:

	Accumulated Other Comprehensive Loss			
	Oil and Gas Cash Flow Hedges	Interest Rate Lock Cash Flow Hedges	Minimum Pension Liability and Other	Total
	(in thousands)			
December 31, 2004	$ (6,939)	$ (4,577)	$ (3,271)	$ (14,787)
Cash flow hedges				
Realized amounts reclassified into earnings	154,500	492	-	154,992
Unrealized amounts reclassified into earnings	33,638	-	-	33,638
Unrealized change in fair value	(945,033)	-	-	(945,033)
Net change in minimum pension liability and other	-	-	(12,309)	(12,309)
December 31, 2005	(763,834)	(4,085)	(15,580)	(783,499)
Cash flow hedges				
Realized amounts reclassified into earnings	145,035	637	-	145,672
Unrealized amounts reclassified into earnings	264,520	-	-	264,520
Unrealized change in fair value	249,974	-	-	249,974
Net change in minimum pension liability and other	-	-	16,225	16,225
Adoption of SFAS 158	-	-	(33,401)	(33,401)
December 31, 2006	(104,305)	(3,448)	(32,756)	(140,509)
Cash flow hedges				
Realized amounts reclassified into earnings	33,761	473	2,000	36,234
Unrealized change in fair value	(184,254)	(751)		(185,005)
Net change in other	-	-	5,095	5,095
December 31, 2007	$ (254,798)	$ (3,726)	$ (25,661)	$ (284,185)

The effective income tax rate applied to AOCL increased from 35% at December 31, 2005 to 37.6% at December 31, 2006 and remained 37.6% at December 31, 2007.

Note 11—Benefit Plans

Pension Plan and Other Postretirement Benefit Plans—We have a noncontributory, tax-qualified defined benefit pension plan covering employees who were hired prior to May 1, 2006. The benefits are based on an employee's years of service and average earnings for the 60 consecutive calendar months of highest compensation. Our funding policy has been to make annual contributions equal to at least the minimum required contribution, but no greater than the maximum deductible for federal income tax purposes. We also have an unfunded, nonqualified restoration plan that provides the pension plan formula benefits that cannot be provided by the qualified pension plan because of pay deferrals and the compensation and benefit limitations imposed on the pension plan by the Internal Revenue Code of 1986, as amended. We sponsor other plans for the benefit of our employees and retirees, which include medical and life insurance benefits. We use a December 31 measurement date for the plans.

Former Patina employees began participation in the pension plan and the restoration plan on January 1, 2006, with vesting service from their original Patina hire date and credited service for benefit accruals starting January 1, 2006.

Additionally, all former Patina employees were covered under the medical and life insurance plans effective January 1, 2006.

On December 31, 2006, we adopted SFAS 158, which required us to recognize the funded status (the difference between the fair value of plan assets and the benefit obligation) of our defined benefit pension, restoration and other postretirement benefit plans in the consolidated balance sheet, with a corresponding adjustment to AOCL, net of tax. The adjustment to AOCL at adoption represented the unrecognized net actuarial loss, unrecognized prior service cost, and unrecognized net transition obligation remaining from the initial adoption of SFAS No. 87, “Employers’ Accounting for Pensions” and SFAS No. 106, “Employers’ Accounting for Post-Retirement Benefits Other Than Pensions”. These amounts are currently being recognized as net periodic benefit cost pursuant to our historical accounting policy for amortizing such amounts. Further, actuarial gains and losses that arise in periods subsequent to adoption and are not recognized as net periodic benefit cost in the same periods are recognized as a component of AOCL. The adoption of SFAS 158 had no effect on our consolidated statements of operations for the year ended December 31, 2006, for any prior period presented, or for any periods subsequent to adoption.

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Changes in the benefit obligation and plan assets of the pension, restoration and other postretirement benefit plans are as follows at December 31:

	Retirement and Restoration Plan		Medical and Life Plan	
	2007	2006	2007	2006
	(in thousands)			
Change in benefit obligation				
Benefit obligation at beginning of year	$ 175,154	$ 168,301	$ 22,373	$ 27,223
Service cost	11,671	11,781	1,962	2,207
Interest cost	9,978	9,550	1,191	1,377
Plan participants' contributions	-	-	332	272
Amendments	7,836	(8,327)	-	(5,711)
Benefits paid	(6,513)	(6,169)	(830)	(795)
Actuarial (gain) loss	(10,633)	18	(2,640)	(2,200)
Benefit obligation at end of year	187,493	175,154	22,388	22,373
Change in plan assets				
Fair value of plan assets at beginning of year	136,890	94,832	-	-
Actual return on plan assets	12,982	12,593	-	-
Employer contributions	11,395	35,634	498	523
Plan participants' contributions	-	-	332	272
Benefits paid	(6,513)	(6,169)	(830)	(795)
Fair value of plan assets at end of year	154,754	136,890	-	-
Funded status				
Funded status at end of year	(32,739)	(38,264)	(22,388)	(22,373)
Net amount recognized in consolidated balance sheets (after adoption of FAS 158)	(32,739)	(38,264)	(22,388)	(22,373)
Amounts recognized in consolidated balance sheets consist of:				
Current liabilities	(2,958)	(1,205)	(1,197)	(941)
Noncurrent liabilities	(29,781)	(37,059)	(21,191)	(21,432)
Net amount recognized in consolidated balance sheets (after adoption of FAS 158)	(32,739)	(38,264)	(22,388)	(22,373)
Amounts not yet reflected in net periodic benefit cost and included in AOCL				
Transition obligation	(614)	(854)	-	-
Prior service (cost) credit	(2,981)	5,372	5,746	6,672
Accumulated loss	(34,051)	(49,978)	(13,691)	(17,384)
AOCL	(37,646)	(45,460)	(7,945)	(10,712)
Cumulative employer contributions in excess of net periodic benefit cost	4,907	7,196	(14,443)	(11,661)
Net amount recognized in consolidated balance sheet (after adoption of FAS 158)	$ (32,739)	(38,264)	$ (22,388)	(22,373)
Change in AOCL due to adoption of FAS 158				
Additional minimum liability (before FAS 158)		(2,708)		-
Intangible asset (before FAS 158)		65		-
AOCL (before FAS 158)		(2,643)		-

Net increase in AOCL	$ (42,817)	$ (10,712)

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Net periodic benefit cost recognized for the pension, restoration and other postretirement benefit plans is provided in the table below.

	Retirement and Restoration Plan Year Ended December 31,			Medical and Life Plan Year Ended December 31,		
	2007	2006	2005	2007	2006	2005
			(in thousands)			
Components of net periodic benefit cost						
Service cost	$ 11,671	$ 11,781	$ 6,372	$ 1,962	$ 2,207	$ 963
Interest cost	9,978	9,550	7,807	1,191	1,377	943
Expected return on plan assets	(11,045)	(9,320)	(7,094)	-	-	-
Amortization of transition obligation	240	239	24	-	-	-
Amortization of prior service (credit) cost	(516)	(220)	398	(925)	(439)	(236)
Amortization of net loss	3,354	2,912	1,034	1,053	1,170	760
Net periodic benefit cost	$ 13,682	$ 14,942	$ 8,541	$ 3,281	$ 4,315	$ 2,430
Other changes recognized in AOCL						
Prior service cost arising during period	$ 7,836	*	*	$ -	*	*
Net gain arising during period	(12,571)	*	*	(2,639)	*	*
Amortization of transition obligation	(240)	*	*	-	*	*
Amortization of prior service credit	516	*	*	925	*	*
Amortization of net loss	(3,354)	*	*	(1,053)	*	*
Total recognized in AOCL	$ (7,813)	*	*	$ (2,767)	*	*
Expected amortizations for next fiscal year						
Amortization of transition obligation	240	240	*	-	-	*
Amortization of prior service cost (credit)	191	(516)	*	(925)	(925)	*
Amortization of net loss	1,668	3,221	*	854	1,211	*
Additional Information						
Increase in minimum liability included in AOCL	*	*	$ 21,638	*	*	-
Weighted-average assumptions used to determine benefit obligations						
Discount rate	6.50%	5.75%	5.50%	6.25%	5.75%	5.50%
Rate of compensation increase	5.00%	5.00%	5.00%	-	-	-
Weighted-average assumptions used to determine net periodic benefit costs						

Discount rate (1)	5.75%	5.50% / 6.25%	6.00%	5.75%	5.50% / 6.25%	5.75%
Expected long-term rate of return on plan assets	8.25%	8.25%	8.25%	-	-	-
Rate of compensation increase	5.00%	5.00%	4.00%	-	-	-

*Not applicable due to change in method of accounting for defined benefit and other post retirement plans.

(1) The net periodic benefit cost was remeasured at May 1, 2006 using a discount rate of 6.25%, due to changes in plan provisions.

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Additional disclosures are as follows:

	Retirement and Restoration Plan			
	2007		2006	
	(in thousands)			
Accumulated benefit obligation	$	162,595	$	142,136
Information for pension plans with projected benefit obligations in excess of plan assets				
Projected benefit obligation	$	187,493	$	175,154
Fair value of plan assets		154,754		136,890
Information for pension plans with accumulated benefit obligations in excess of plan assets				
Accumulated benefit obligation	$	25,131	$	20,542
Fair value of plan assets		-		-

In selecting the assumption for expected long-term rate of return on assets, we consider the average rate of earnings expected on the funds to be invested to provide for plan benefits. This includes considering the plan's asset allocation, historical returns on these types of assets, the current economic environment and the expected returns likely to be earned over the life of the plan. We assume the long-term asset mix will be consistent with a target asset allocation of 70% equity and 30% fixed income, with a range of plus or minus 10% acceptable degree of variation in the plan's asset allocation. Based on these factors we expect pension assets will earn an average of 8.25% per annum over the life of the plan. No plan assets are expected to be returned to us during 2008.

In order to determine an appropriate discount rate at December 31, 2007, we performed an analysis of the Citigroup Pension Discount Curve (the "CPDC") as of that date for each of our plans. The CPDC uses spot rates that represent the equivalent yield on high quality, zero coupon bonds for specific maturities. We used these rates to develop an equivalent single discount rate based on our plans' expected future benefit payment streams and duration of plan liabilities. A 1% increase in the discount rate would have resulted in a decrease in net periodic benefit cost of $4 million in 2007. A 1% decrease in the discount rate would have resulted in an increase in net periodic benefit cost of $5 million in 2007.

Assumed health care cost trend rates were as follows at December 31:

	2007	2006
Health care cost trend rate assumed for next year	9%	10%
Rate to which the cost trend rate is assumed to decline (ultimate trend rate)	5%	5%
Year rate reaches ultimate trend rate	2012	2012

Assumed health care cost trend rates have a significant effect on the amounts reported for health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effects:

	1% Increase		1% Decrease	
	(in thousands)			
Effect on total service and interest cost components for 2007	$	390	$	(341)
Effect on year-end 2007 postretirement benefit obligation		2,270		(2,025)

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Weighted-average asset allocations for the tax-qualified defined benefit pension plan are as follows:

	Target Allocation	Plan Assets	
	2008	2007	2006
Asset Category			
Equity Securities	70%	70%	70%
Fixed income	30%	30%	28%
Other	-	-	2%
Total	100%	100%	100%

The investment policy for the tax-qualified defined benefit pension plan is determined by an employee benefits committee (“the committee”) with input from a third-party investment consultant. Based on a review of historical rates of return achieved by equity and fixed income investments in various combinations over multi-year holding periods and an evaluation of the probabilities of achieving acceptable real rates of return, the committee has determined the target asset allocation deemed most appropriate to meet the immediate and future benefit payment requirements for the plan and to provide a diversification strategy which reduces market and interest rate risk. A 1% increase (decrease) in the expected return on plan assets would have resulted in a (decrease) increase, respectively, in net periodic benefit cost of $1 million in 2007.

We base our determination of the asset return component of pension expense on a market-related valuation of assets, which reduces year-to-year volatility. This market-related valuation recognizes investment gains or losses over a five-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return based on the fair value of assets. Since the market-related value of assets recognizes gains or losses over a five-year period, the future value of assets will be impacted as previously deferred gains or losses are recorded. As of January 1, 2007, we had cumulative asset gains of approximately $3 million, which remain to be recognized in the calculation of the market-related value of assets.

Contributions—As a result of previous contributions made to the pension plan, there are no required contributions expected during 2008. We may, however, make additional contributions to our pension plan as determined by the committee. We expect to make cash contributions of approximately $4 million to the unfunded restoration and medical and life plans during 2008. This amount equals expected benefit payments from those plans. (unaudited).

Estimated Future Benefit Payments—As of December 31, 2007, the following future benefit payments are expected to be paid:

	Retirement and Restoration Plan	Medical and Life Plan
	(in thousands)	
2008	$ 25,049	$ 1,197
2009	12,000	1,370
2010	13,586	1,499
2011	16,722	1,914
2012	18,507	2,198
Years 2013 to 2017	99,516	14,280

The estimate of expected future benefit payments is based on the same assumptions used to measure the benefit obligation at December 31, 2007 and includes estimated future employee service.

401(k) Plan—We sponsor a 401(k) savings plan. All regular employees are eligible to participate. We make contributions to match employee contributions up to the first 6% of compensation deferred into the plan, and certain profit sharing contributions for employees hired on or after May 1, 2006, based upon their ages and salaries. We made cash contributions of $6 million in 2007, $4 million in 2006 and $5 million in 2005.

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Deferred Compensation Plan—In connection with the Patina Merger, we acquired the assets and assumed the liabilities related to a Patina shareholder-approved non-qualified deferred compensation plan. This plan was available to officers and certain managers of Patina and allowed participants to defer all or a portion of their salary and annual bonuses (either in cash or common stock). Participant-directed investments are held in a rabbi trust and are available to satisfy the claims of our creditors in the event of bankruptcy or insolvency. Participants may elect to receive distributions in either cash or shares of our common stock. We account for the deferred compensation plan in accordance with EITF 97-14, "Accounting for Deferred Compensation Arrangements Where Amounts Earned are Held in a Rabbi Trust and Invested." Components of the rabbi trust are as follows:

	December 31,	
	2007	2006
	(in thousands)	
Rabbi trust assets		
Mutual fund investments	$ 106,581	$ 100,767
Noble Energy common stock (at market value)	87,554	54,027
Total rabbi trust assets	194,135	154,794
Liability under Patina deferred compensation plan	$ 194,135	$ 154,794
Number of shares of Noble Energy common stock held by rabbi trust	1,101,032	1,101,032

Assets of the rabbi trust, other than our common stock, are invested in certain mutual funds that cover an investment spectrum ranging from equities to money market instruments. These mutual funds have published market prices and are reported at market value. We account for these investments in accordance with SFAS No. 115, "Accounting for Certain Investments in Debt and Equity Securities." The mutual funds are included in the mutual funds account in other noncurrent assets in the consolidated balance sheets. Shares of our common stock held by the rabbi trust are accounted for as treasury stock in the shareholders' equity section of the consolidated balance sheets. The amounts payable to the plan participants are included in other noncurrent liabilities in the consolidated balance sheets and include the market value of the shares of our common stock. One million shares, or 91%, of the common stock held in the plan at December 31, 2007 and 2006 were attributable to a member of our Board of Directors. Plan participants sold no shares of common stock during 2007, 1,067,948 shares during 2006 and 20,434 shares during 2005. Proceeds were invested in mutual funds. Distributions to Plan participants totaled $2 million in 2007, $0.5 million in 2006 and $1 million in 2005.

In accordance with EITF 97-14, all fluctuations in market value of the deferred compensation liability have been reflected in other expense, net in the consolidated statements of operations. The market value of the liability increased $41 million in 2007, $28 million in 2006 and $18 million in 2005. The increases in the liability included the appreciation in the market value of our common stock of $34 million in 2007, $16 million in 2006 and $15 million in 2005. The increases in the liability also included the appreciation in the market value of the rabbi trust mutual fund investments of $7 million in 2007, $12 million in 2006 and $3 million in 2005. Net deferred compensation expense totaled $34 million, $16 million and $15 million in 2007, 2006 and 2005, respectively.

Note 12—Derivative Instruments and Hedging Activities

Cash Flow Hedges—We use various derivative instruments in connection with anticipated crude oil and natural gas sales to mitigate the variability of cash flows associated with commodity price fluctuations. Such instruments include variable to fixed price swaps, costless collars and basis swaps. While these instruments mitigate the cash flow risk of future reductions in commodity prices they may also curtail benefits from future increases in commodity prices. We account for derivative instruments and hedging activities in accordance with SFAS 133 and elected to designate the majority of our commodity derivative instruments as cash flow hedges through December 31, 2007. As discussed in

Note 2—Summary of Significant Accounting Policies, we voluntarily discontinued cash flow hedge accounting for our commodity derivative instruments, effective January 1, 2008.

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(Gain) loss on derivative instruments includes the following:

	Year Ended December 31, 2007	2006	2005
	(in thousands)		
Ineffectiveness (gains) losses	$ (2,520)	$ 9,502	$ 930
Reclassified from AOCL	-	423,910	51,750
Mark-to-market gain on derivative instruments not accounted for as cash flow hedges	-	(41,045)	(20,000)
(Gain) loss on derivative instruments	$ (2,520)	$ 392,367	$ 32,680

If it becomes probable that the hedging instrument is no longer highly effective, the hedging instrument loses hedge accounting treatment. All current mark-to-market gains and losses are recorded in earnings and all accumulated gains or losses recorded in AOCL related to the hedging instrument are also reclassified to earnings. During 2006, we reclassified a pretax charge of $399 million from AOCL to earnings when it became probable that forecasted crude oil and natural gas sales would not occur due to the sale of Gulf of Mexico shelf properties. 2006 also included a mark-to-market gain of $39 million and the reclassification a pretax charge of $25 million from AOCL to earnings due to the impacts of Hurricanes Katrina and Rita on the timing of forecasted Gulf of Mexico production. During 2005, we recognized a mark-to-market gain of $20 million and reclassified a pretax charge of $52 million from AOCL to earnings due to the impact of Hurricanes Katrina and Rita on forecasted Gulf of Mexico production.

Effects of cash flow hedges included in oil and gas sales were as follows:

	Year Ended December 31, 2007	2006	2005
	(in thousands)		
Decrease in crude oil sales	(223,347)	(190,730)	(140,486)
Increase (decrease) in natural gas sales	169,242	(41,698)	(97,206)
Total decrease in crude oil and natural gas sales	$ (54,105)	$ (232,428)	$ (237,692)

As of December 31, 2007, we had entered into, and designated as cash flow hedges, the following variable to fixed price swap derivative instruments related to natural gas and crude oil sales as follows:

	Natural Gas		Crude Oil	
Production Period	MMBtupd	Average Price per MMBtu	Bopd	Average price per Bbl
2008 (NYMEX)	170,000	$ 5.66	16,500	$ 38.23
2008 (Brent)	-	-	2,000	88.18
2009 (NYMEX)	-	-	7,000	86.67
2009 (Brent)	-	-	2,000	87.98

On January 2, 2008, we entered into additional NYMEX variable to fixed price swap derivative instruments for 1,000 Bpd of crude oil at an average price per Bbl of $90.50 for 2009.

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As of December 31, 2007, we had entered into the following basis swap derivative instruments related to natural gas sales. These basis swaps were combined with NYMEX variable to fixed swaps and designated as cash flow hedges:

Production Period	MMBtupd	Average Differential per MMBtu
2008 (CIG (1) vs. NYMEX)	100,000	$ 1.66
2008 (ANR (2) vs. NYMEX)	40,000	1.01
2008 (PEPL (3) vs. NYMEX)	10,000	0.98

(1) Colorado Interstate Gas – Northern System
(2) ANR Oklahoma Pipeline
(3) Panhandle Eastern Pipe Line

As of December 31, 2007, we had entered into, and designated as cash flow hedges, the following costless collar derivative instruments related to crude oil and natural sales as follows:

	Natural Gas			Crude Oil		
		Average Price per MMBtu			Average Price per Bbl	
Production Period	MMBtupd	Floor	Ceiling	Bopd	Floor	Ceiling
2008 (NYMEX)	-	$ -	$ -	3,100	$ 60.00	$ 72.40
2008 (CIG)	14,000	6.75	8.70	-	-	-
2008 (Brent)	-	-	-	4,074	45.00	66.52
2009 (NYMEX)	-	-	-	3,700	60.00	70.00
2009 (CIG)	15,000	6.00	9.90	-	-	-
2009 (Brent)	-	-	-	3,074	45.00	63.04
2010 (NYMEX)	-	-	-	3,500	55.00	73.80
2010 (CIG)	15,000	6.25	8.10	-	-	-

The costless collar, fixed price swap and basis swap contracts entitle us (floating price payor) to receive settlement from the counterparty (fixed price payor) for each calculation period in amounts, if any, by which the settlement price for the scheduled trading days applicable for each calculation period is less than the fixed price or floor price. We would pay the counterparty if the settlement price for the scheduled trading day applicable for each calculation period is more than the fixed price or ceiling price. The amount payable by us, if the floating price is above the fixed or ceiling price, is the product of the notional quantity per calculation period and the excess, if any, of the floating price over the fixed or ceiling price in respect of each calculation period. The amount payable by the counterparty, if the floating price is below the fixed or floor price, is the product of the notional quantity per calculation period and the excess, if any, of the fixed or floor price over the floating price in respect of each calculation period.

AOCL—As of December 31, 2007 and 2006, the balance in AOCL included net deferred losses of $255 million and $104 million, respectively, related to the fair value of crude oil and natural gas derivative instruments accounted for as cash flow hedges. The net deferred losses are net of deferred income tax benefits of $153 million and $63 million, respectively. Approximately $206 million of these deferred losses, net of tax, will be reclassified to earnings during the next twelve months as the forecasted transactions occur, and will be recorded as a reduction in oil and gas sales of approximately $331 million before tax. All forecasted transactions currently being hedged are expected to occur by

December 2010.

Other Derivative Instruments—In addition to the derivative instruments described above, we may employ derivative instruments in connection with purchases and sales of production in order to establish a fixed margin and mitigate the risk of price volatility. Most of the purchases are on an index basis. However, purchasers in the markets in which we sell often require fixed or NYMEX-related pricing. We may use a derivative instrument to convert the fixed or NYMEX sale to an index basis thereby determining the margin and minimizing the risk of price volatility.

Receivables/Payables Related to Crude Oil and Natural Gas Derivative Instruments—The fair values of derivative instruments included in the consolidated balance sheets are as follows:

	December 31, 2007	2006
	(in thousands)	
Crude oil and natural gas derivative instruments		
Current asset	$ 15,058	$ 35,242
Long-term asset	4,829	2,862
Current liability	(540,217)	(254,625)
Long-term liability	(82,803)	(328,875)

Interest Rate Lock—We occasionally enter into forward contracts or swap agreements to hedge exposure to interest rate risk. Changes in fair value of interest rate swaps or interest rate "locks" used as cash flow hedges are reported in AOCL, to the extent the hedge is effective, until the forecasted transaction occurs, at which time they are recorded as adjustments to interest expense over the term of the related notes. At December 31, 2007, AOCL included a deferred loss of $4 million, net of tax, related to interest rate swaps. $3 million of this amount is being reclassified into earnings, at the rate of $0.8 million per year, as an adjustment to interest expense over the term of our 5¼% senior notes due 2014. The remaining $1 million deferred loss relates to two $500 million notional amount interest rate locks based on five and ten year US Treasury rates of 3.55% and 4.15% respectively. The locks expire in September 2008.

Note 13—Equity Method Investments

Investments accounted for under the equity method consist primarily of the following:

- 45% interest in Atlantic Methanol Production Company, LLC ("AMPCO"), which owns and operates a methanol plant and related facilities in Equatorial Guinea; and
- 28% interest in Alba Plant LLC ("Alba Plant"), which owns and operates a liquefied petroleum gas processing plant in Equatorial Guinea.

Construction of the Alba Plant was funded primarily through advances by us and other owners in exchange for notes payable by the Alba Plant. The notes were scheduled to mature on December 31, 2011 and bore interest at the 90-day LIBOR rate plus 3%. The notes were repaid in 2006.

Equity method investments are included in other noncurrent assets in the consolidated balance sheets, and our share of earnings is reported as income from equity method investees in the consolidated statements of operations. Our share of income taxes incurred directly by the equity method investees is reported in income from equity method investments and is not included in our income tax provision in our consolidated statements of operations. At December 31, 2007, our retained earnings included $151 million related to the undistributed earnings of equity method investees.

The carrying value of our equity method investments is $29 million higher than the underlying net assets of the investees. A portion of the basis difference is being amortized into income over the remaining useful lives of the underlying net assets and the remainder is being recovered through distributions.

Equity method investments are as follows:

	December 31,			
	2007		2006	
	(in thousands)			
Equity method investments				
AMPCO	$	199,605	$	211,325
Alba Plant		142,540		146,051
Other		14,984		15,996
Total equity method investments	$	357,129	$	373,372

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Summarized, 100% combined financial information for equity method investees is as follows:

	December 31,			
	2007		2006	
	(in thousands)			
Balance sheet information				
Current assets	$	408,000	$	252,201
Noncurrent assets		813,601		857,465
Current liabilities		273,164		171,028
Noncurrent liabilities		31,278		2,385

	Year Ended December 31,					
	2007		2006		2005	
	(in thousands)					
Statements of operations information						
Operating revenues	$	934,419	$	702,556	$	464,000
Less cost of goods sold		220,101		202,304		136,508
Gross margin		714,318		500,252		327,492
Less other expense		36,486		47,487		35,798
Less income tax expense		44,150		23,451		67,142
Net income	$	633,682	$	429,314	$	224,552

Note 14—Commitments and Contingencies

Legal Proceedings— We are among a group of eighteen defendants named in a lawsuit filed August 23, 2002 by Dore Energy Corporation under Docket Number 10-16202 in the 38th Judicial District Court, Cameron Parish, Louisiana. The lawsuit alleges damage to property owned by Dore resulting from oil and gas activities dating to the 1930's. Our predecessor, Samedan Oil Corporation, operated on a portion of the property from 1989 to 1999. Dore has delivered documents alleging approximately $140 million in damages. Trial is currently set for April 14, 2008. We intend to vigorously defend against these allegations and believe that our share of damages, if any, will not have a material adverse effect on our results of operations, financial condition or liquidity.

The Illinois Environmental Protection Agency ("IEPA") issued a notice of violation to Equinox Oil Company on September 25, 2001 alleging violation of air emission and permitting regulations for a facility known as the Zif Gas Plant located near Clay City, Illinois. On January 17, 2007, the IEPA re-issued written notices of these alleged violations in the name of Equinox's successors in interest, and our wholly-owned subsidiaries, Elysium Energy, LLC and Noble Energy Production, Inc. On March 16, 2007, the IEPA accepted our compliance commitment agreement wherein we agreed to pay a delayed permit fee, install an incineration/caustic scrubber emissions control system at the site, and fund a supplemental environmental project ("SEP") in the nearby community. At this time, we expect no additional monies to be expended other than these amounts for which we have fully accrued. As of December 31, 2007, this matter has been concluded.

We are involved in various legal proceedings in the ordinary course of business. These proceedings are subject to the uncertainties inherent in any litigation. We are defending ourselves vigorously in all such matters and we do not believe that the ultimate disposition of such proceedings will have a material adverse effect on our consolidated financial position, results of operations or cash flows.

Non-Cancelable Leases and Other Commitments—We hold leases and other commitments for drilling rigs, buildings, equipment and other properties. Rental expense for office buildings and oil and gas operations equipment was approximately $13 million in 2007, $12 million in 2006 and $10 million in 2005.

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Minimum commitments as of December 31, 2007 consist of the following:

	Drilling and Equipment, and Purchase Obligations	Throughput Agreement	Office Buildings and Facilities (in thousands)	Oil and Gas Operations Equipment	Total
2008	$ 443,926	$ -	$ 7,289	$ 5,467	$ 456,682
2009	94,444	19,000	7,426	4,448	125,318
2010	79,491	19,000	7,069	2,159	107,719
2011	65,715	19,000	6,736	-	91,451
2012	41,772	19,000	6,511	-	67,283
2013 and thereafter	-	19,000	17,863	-	36,863
Total	$ 725,348	$ 95,000	$ 52,894	$ 12,074	$ 885,316

Note 15—Segment Information

We have operations throughout the world and manage our operations by country. The following information is grouped into five components that are all primarily in the business of natural gas and crude oil exploration and production: the United States; West Africa; the North Sea; Israel; and Other International, Corporate and Marketing. Other International includes Argentina, China, Ecuador and Suriname.

Accounting policies for geographical segments are the same as those described in the summary of significant accounting policies. Transfers between segments are accounted for at market value. We do not consider interest income and expense or income tax benefit or expense in our evaluation of the performance of geographical segments.

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	Total		United States		West Africa		North Sea		Israel		Other Int'l, Corporate & Marketing
					(in thousands)						
Year Ended December 31, 2007											
Revenues from third parties	$	3,061,102	$	1,609,626	$	405,988	$	363,886	$	113,001	$ 568,601
Intersegment revenue		-		342,809		-		-		-	(342,809)
Income from equity method investees		210,928		-		210,928		-		-	-
Total Revenues		3,272,030		1,952,435		616,916		363,886		113,001	225,792
DD&A		727,981		574,001		25,315		79,450		17,842	31,373
Gain on derivative instruments		(2,520)		(2,520)		-		-		-	-
Loss on involuntary conversion		51,406		51,406		-		-		-	-
Income (loss) before taxes		1,367,567		809,806		517,450		220,779		86,022	(266,490)
Investments in equity method investees		357,129		357,129		-		-		-	-
Additions to long-lived assets		990,861		877,941		23,155		40,969		24,716	24,080
Total assets at December 31, 2007 (1)		10,830,896		7,917,771		1,354,604		562,140		268,386	727,995
Year Ended December 31, 2006											
Revenues from third parties	$	2,800,720	$	1,510,689	$	413,682	$	115,232	$	92,373	$ 668,744
Intersegment revenue		-		425,901		-		-		-	(425,901)
Income from equity method investees		139,362		-		139,362		-		-	-
Total Revenues		2,940,082		1,936,590		553,044		115,232		92,373	242,843
DD&A		622,608		543,431		23,620		8,123		13,947	33,487
Loss on derivative instruments		392,367		392,367		-		-		-	-
Income (loss) before taxes		1,096,217		631,087		493,777		72,803		71,318	(172,768)
Investments in equity method investees		373,372		-		373,372		-		-	-
Additions to long-lived assets		1,916,139		1,615,435		35,121		234,877		841	29,865
		9,588,625		7,224,920		960,357		343,236		256,913	803,199

Total assets at December 31, 2006 (1)						
Year Ended December 31, 2005						
Revenues from third parties	$ 2,095,911	$ 913,564	$ 281,902	$ 123,584	$ 65,050	$ 711,811
Intersegment revenue	-	460,808	-	-	-	(460,808)
Income from equity method investees	90,812	-	90,812	-	-	-
Total Revenues	2,186,723	1,374,372	372,714	123,584	65,050	251,003
DD&A	390,544	311,153	27,121	9,888	11,188	31,194
Loss on derivative instruments	32,680	32,680	-	-	-	-
Loss on involuntary conversion	1,000	1,000	-	-	-	-
Income (loss) before taxes	968,660	585,988	309,239	88,524	46,468	(61,559)
Investments in equity method investees	420,362	-	420,362	-	-	-
Additions to long-lived assets	4,382,005	4,345,604	2,738	15,287	5,928	12,448
Total assets at December 31, 2005 (1)	8,878,033	6,577,853	877,409	146,311	266,312	1,010,148

(1) The US reporting unit includes goodwill of $760 million at December 31, 2007, $781 million at December 31, 2006 and $863 million at December 31, 2005.

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Note 16—Recently Issued Pronouncements

SFAS 141(R) and SFAS 160 – In December 2007, the FASB issued SFAS 141(R), "Business Combinations" (SFAS 141(R)") and SFAS 160, "Noncontrolling Interests in Consolidated Financial Statements" (SFAS 160"). These statements require most identifiable assets, liabilities and noncontrolling interests to be recorded at full fair value and require noncontrolling interests to be reported as a component of equity. Both statements are effective for periods beginning on or after December 15, 2008, and earlier adoption is prohibited. SFAS 141(R) will be applied to business combinations occurring after the effective date and SFAS 160 will be applied prospectively to all noncontrolling interests, including any that arose before the effective date. We are currently evaluating the provisions of SFAS 141(R) and SFAS 160 and assessing the impact, if any, they may have on our financial position and results of operations.

SFAS 157—Statement of Financial Accounting Standards No. 157, "Fair Value Measurements" ("SFAS 157"), establishes a single authoritative definition of fair value based upon the assumptions market participants would use when pricing an asset or liability and creates a fair value hierarchy that prioritizes the information used to develop those assumptions. Under the standard, additional disclosures are required, including disclosures of fair value measurements by level within the fair value hierarchy. SFAS 157 is effective for fair value measures already required or permitted by other standards for fiscal years beginning after November 15, 2007 and interim periods within those fiscal years. For non-financial assets and liabilities, the adoption of SFAS No. 157 has been deferred until January 1, 2009. We are adopting SFAS 157 as of January 1, 2008 and are currently in the process of determining the effects of adoption, such as the effect of incorporating our own credit standing in the measurement of certain liabilities. We do not expect that the final effects of adoption will have a significant impact on our consolidated financial statements.

SFAS 159—In February 2007, the FASB issued SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities" ("SFAS 159"). SFAS 159 provides companies with an option to report selected financial assets and liabilities at fair value. SFAS 159 is effective as of the beginning of an entity's first fiscal year beginning after November 15, 2007. We adopted SFAS 159 as of January 1, 2008. Adoption had no effect on our financial position or results of operations as we made no elections to report selected financial assets or liabilities at fair value.

FSP FIN 39-1—In April 2007, the FASB issued FSP FIN 39-1, "An Amendment of FASB Interpretation No. 39" ("FSP FIN 39-1"). FSP FIN 39-1 allows companies to offset fair value amounts recognized for derivative instruments and the fair value amounts recognized for the right to reclaim cash collateral or the obligation to return cash collateral. The cash collateral must arise from derivative instruments recognized at fair value that are executed with the same counterparty under a master netting arrangement. A company must make an accounting policy decision whether or not to offset fair value amounts. FSP FIN 39-1 is effective for fiscal years beginning after November 15, 2007 and is to be applied retrospectively. We are currently evaluating the provisions of FSP FIN 39-1 and assessing the impact it may have on our financial position and results of operations.

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Supplemental Oil and Gas Information (Unaudited)

In accordance with SFAS No. 69, “Disclosures about Oil and Gas Producing Activities” (“SFAS 69”), and regulations of the SEC, we are making the following supplemental disclosures about our crude oil and natural gas exploration and production operations.

There are numerous uncertainties inherent in estimating quantities of proved crude oil and natural gas reserves. Crude oil and natural gas reserve engineering is a subjective process of estimating underground accumulations of crude oil and natural gas that cannot be precisely measured. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment.

Engineers in our Houston, Denver and London offices prepare all reserve estimates for our different geographical regions. These reserve estimates are reviewed and approved by senior engineering staff and division management with final approval by the Director of Asset Development and certain members of senior management. During each of the years 2007, 2006 and 2005, we retained Netherland, Sewell & Associates, Inc. (“NSAI”), independent third-party reserve engineers, to perform reserve audits of proved reserves. The reserve audit for 2007 included a detailed review of 16 of our major international, deepwater Gulf of Mexico and US fields, which covered approximately 71% of US proved reserves and 96% of international proved reserves (81% of total proved reserves). The reserve audit for 2006 included a detailed review of 14 of our major international, deepwater Gulf of Mexico and US fields, which covered approximately 80% of our total proved reserves. The reserve audit for 2005 included a detailed review of 11 of our major international, deepwater Gulf of Mexico and US fields, which covered approximately 72% of our total proved reserves. See Items 1 and 2. Business and Properties—Proved Reserves.

Results of drilling, testing and production subsequent to the date of the estimate may justify revision of such estimate. Accordingly, reserve estimates are often different from the quantities of crude oil and natural gas that are ultimately recovered.

Our supplemental disclosures are grouped by geographic area and include the United States, West Africa (Equatorial Guinea and Cameroon), Israel, Ecuador, North Sea and Other International (Argentina, China and Suriname). Operations in Equatorial Guinea, Cameroon, Ecuador, China and Suriname are conducted in accordance with the terms of production sharing contracts.

The following definitions apply to the terms used in the paragraphs above:

Reserve Estimate. The determination of an estimate of a quantity of oil or gas reserves that are thought to exist at a certain date, considering existing prices and reservoir conditions.

Reserve Audit. The process involving an independent third-party engineering firm’s visits, collection of any and all required geologic, geophysical, engineering and economic data, and such firm’s complete external preparation of reserve estimates.

The following definitions apply to our categories of proved reserves:

Proved Reserves. Proved oil and gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions (i.e., prices and costs as of the date the estimate is made). Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions.

Proved Developed Reserves. Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

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

For complete definitions of proved natural gas, natural gas liquids and crude oil reserves, refer to Regulation S-X, Rule 4-10(a)(2), (3) and (4).

Proved Gas Reserves (Unaudited)

The following reserve schedule was developed by our reserve engineers and sets forth the changes in estimated quantities of proved natural gas reserves:

	Natural Gas and Casinghead Gas (MMcf)						
	United States	West Africa	Israel	Ecuador	North Sea	Other Int'l (1)	Total
Proved reserves as of:							
December 31, 2004	519,735	917,409	417,293	119,341	11,714	1,369	1,986,861
Revisions of previous estimates (2)	18,644	7,732	481	32,800	3,200	(1,301)	61,556
Extensions, discoveries and other additions (3)	144,335	-	-	-	-	-	144,335
Purchase of minerals in place (4)	1,083,959	-	-	-	-	-	1,083,959
Sale of minerals in place	-	-	-	-	-	-	-
Production	(125,543)	(23,938)	(24,228)	(8,321)	(3,394)	(68)	(185,492)
December 31, 2005	1,641,130	901,203	393,546	143,820	11,520	-	3,091,219
Revisions of previous estimates (5)	(82,371)	57,543	260	32,927	10,485	278	19,122
Extensions, discoveries and other additions (6)	314,140	-	-	-	-		314,140
Purchase of minerals in place (7)	141,610	2,532	-	-	-	-	144,142
Sale of minerals in place (8)	(110,486)	-	-	-	-	-	(110,486)
Production	(164,830)	(16,579)	(33,906)	(8,933)	(2,967)	(108)	(227,323)
December 31, 2006	1,739,193	944,699	359,900	167,814	19,038	170	3,230,814
Revisions of previous estimates (9)	(67,003)	44,256	(52)	29,872	(1,062)	(170)	5,841

Extensions, discoveries and other additions (10)	315,687	-	-	-	3,086	-	318,773
Purchase of minerals in place	2,957	-	-	-	-	-	2,957
Sale of minerals in place	(1)	-	-	-	-	-	(1)
Production	(150,457)	(48,349)	(40,449)	(9,385)	(2,276)	-	(250,916)
December 31, 2007	1,840,376	940,606	319,399	188,301	18,786	-	3,307,468
Proved developed reserves as of:							
December 31, 2004	430,513	447,347	360,428	119,341	11,714	1,118	1,370,461
December 31, 2005	1,278,788	431,142	336,681	143,820	11,520	-	2,201,951
December 31, 2006	1,255,271	359,691	303,035	167,814	19,038	170	2,105,019
December 31, 2007	1,259,331	830,191	262,534	188,301	15,700	-	2,556,057

(1) Other International includes Argentina. We have entered into an agreement to sell our interest in Argentina effective July 1, 2007. We expect the sale, which is subject to regulatory and partner approvals, to close in 2008.
(2) Increases for Ecuador are due to better than expected performance.
(3) The increase in US proved reserves includes 57 Bcf in the Wattenberg field and 40 Bcf in the Mid-continent area, primarily due to infill drilling activities.
(4) Purchase of minerals in place is the result of the Patina Merger. See Note 3—Acquisitions and Divestitures.
(5) Increases for Ecuador and North Sea are due to better than expected performance.
(6) The increase in US proved reserves includes 140 Bcf in the Wattenberg field, 77 Bcf in the Piceance basin and 55 Bcf in the Mid-continent area, primarily due to infill drilling activities.
(7) Purchase of minerals in place includes 128 Bcf acquired in the purchase of U.S. Exploration. See Note 3—Acquisitions and Divestitures.
(8) Sale of minerals in place is primarily due to sale of Gulf of Mexico shelf properties. See Note 3—Acquisitions and Divestitures.
(9) The negative revisions within the US are primarily due to 103 Bcf of natural gas being reflected in the proved oil reserve table as NGLs, partially offset by positive revisions resulting from an increase in commodity price. West Africa's positive revisions are primarily due to additional production allowances related to LNG sales. Positive revisions in Ecuador are related to better than expected well performance.
(10) The increase in US proved reserves includes 142 Bcf in the Wattenberg field, 83 Bcf in the Piceance basin and 19 Bcf in the Niobrara trend, primarily due to infill drilling activities.

Proved Oil Reserves (Unaudited)

The following reserve schedule was developed by our reserve engineers and sets forth the changes in estimated quantities of proved crude oil reserves:

	Crude Oil, Condensate and NGLs (MBbls)				
	United States	West Africa	North Sea	Other Int'l (1)	Total
Proved reserves as of:					
December 31, 2004	55,066	108,730	9,336	20,332	193,464
Revisions of previous estimates	4,192	(120)	278	168	4,518
Extensions, discoveries and other additions (2)	11,272	-	12,955	-	24,227
Purchase of minerals in place (3)	90,594	-	-	-	90,594
Sale of minerals in place	-	-	-	-	-
Production (9)	(9,468)	(7,675)	(1,964)	(2,866)	(21,973)
December 31, 2005	151,656	100,935	20,605	17,634	290,830
Revisions of previous estimates	(193)	(1,327)	(396)	124	(1,792)
Extensions, discoveries and other additions (4)	23,037	-	-	1,794	24,831
Purchase of minerals in place (5)	19,328	138	-	-	19,466
Sale of minerals in place (6)	(6,971)	-	-	-	(6,971)
Production (9)	(16,715)	(9,450)	(1,357)	(2,752)	(30,274)
December 31, 2006	170,142	90,296	18,852	16,800	296,090
Revisions of previous estimates (7)	27,998	229	776	(132)	28,871
Extensions, discoveries and other additions (8)	26,634	-	10,094	-	36,728
Purchase of minerals in place	-	-	-	-	-
Sale of minerals in place	(1,903)	-	-	-	(1,903)
Production (9)	(15,451)	(8,305)	(4,564)	(2,436)	(30,756)
December 31, 2007	207,420	82,220	25,158	14,232	329,030
Proved developed reserves as of:					
December 31, 2004	32,390	108,730	9,336	18,040	168,496
December 31, 2005	114,223	100,935	7,650	15,623	238,431
December 31, 2006	114,505	90,296	18,852	15,936	239,589
December 31, 2007	128,879	71,409	15,064	13,688	229,040

(1) Other International includes China and Argentina. We have entered into an agreement to sell our interest in Argentina effective July 1, 2007. We expect the sale, which is subject to regulatory and partner approvals, to close in 2008. Argentina crude oil reserves totaled 6,759 MBbls at December 31, 2007.

(2) The increase in total proved reserves includes 6 MMBbl in the US Wattenberg field, primarily due to infill drilling activities, 3 MMBbl in the deepwater Gulf of Mexico Lorien field and 13 MMBbl in the North Sea Dumbarton field.
(3) Purchase of minerals in place is the result of the Patina Merger. See Note 3—Acquisitions and Divestitures.
(4) The increase in US proved reserves includes 14 MMBbl in the Wattenberg field, primarily due to infill drilling activities.
(5) Purchase of minerals in place includes 18 MMBbl acquired in the purchase of U.S. Exploration. See Note 3—Acquisitions and Divestitures.
(6) Sale of minerals in place is primarily due to the sale of Gulf of Mexico shelf properties. See Note 3—Acquisitions and Divestitures.
(7) The positive revisions within the US are primarily due to 29 MMBls of NGLs, previously recorded in proved natural gas reserves, being reflected in proved oil reserves, partially offset by negative revisions within the US Southern region related to less than expected well performance.
(8) The increase in proved reserves includes 17 MMBbl in the US Wattenberg field, primarily due to infill drilling activities, 8 MMBbl in the deepwater Gulf of Mexico and 10 MMBbl in the North Sea Dumbarton field area.
(9) West Africa production includes sales from the Alba field to the Alba LPG plant of 2,805 MBbls in 2007, 2,931 MBbls in 2006 and 1,183 MBbls in 2005.

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Results of Operations for Oil and Gas Producing Activities (Unaudited)

Aggregate results of operations in connection with crude oil and natural gas producing activities are as follows:

	United States	West Africa	Israel	Ecuador (in thousands)	North Sea	Other Int'l (1)	Total
Year Ended December 31, 2007							
Revenues	$ 1,952,435	$ 405,988	$ 113,001	$ 35,137	$ 363,886	$ 130,789	$ 3,001,236
Production costs (2)	317,984	39,222	7,711	3,203	37,987	44,339	450,446
Transportation	39,542	-	-	-	10,523	1,634	51,699
E&P corporate	31,902	3,309	1,687	3,193	3,572	2,870	46,533
Exploration expense	122,339	43,544	1,418	215	16,847	2,781	187,144
DD&A	589,705	24,949	17,805	10,353	79,380	20,413	742,605
Impairment of operating assets	3,661	-	-	-	-	-	3,661
Accretion expense	5,969	109	450	167	1,346	84	8,125
Income before income taxes	841,333	294,855	83,930	18,006	214,231	58,668	1,511,023
Income tax expense	191,427	83,685	14,339	3,582	113,860	9,713	416,606
Results of operations from producing activities (excluding corporate overhead and interest costs)	$ 649,906	$ 211,170	$ 69,591	$ 14,424	$ 100,371	$ 48,955	$ 1,094,417
Our share of Alba Plant's results of operations from producing activities	$ -	$ 128,051	$ -	$ -	$ -	$ -	$ 128,051
Year Ended December 31, 2006							
Revenues	$ 1,936,590	$ 413,682	$ 92,373	$ 33,575	$ 115,232	$ 143,364	$ 2,734,816
Production costs (2)	338,655	26,556	9,066	3,021	11,655	39,596	428,549
Transportation	20,729	-	-	-	7,010	803	28,542
E&P corporate	60,710	4,656	111	3,102	3,346	2,118	74,043
Exploration expense	113,015	7,329	286	228	10,499	11,311	142,668
DD&A	561,948	23,402	13,911	11,611	8,045	25,685	644,602
Impairment of operating assets	8,525	-	-	-	-	-	8,525
Accretion expense	8,861	104	452	221	1,159	-	10,797
Income before income taxes	824,147	351,635	68,547	15,392	73,518	63,851	1,397,090
Income tax expense	313,011	125,493	19,810	3,848	42,111	23,368	527,641
Results of operations from producting	$ 511,136	$ 226,142	$ 48,737	$ 11,544	$ 31,407	$ 40,483	$ 869,449

activities (exluding corporate overhead and interest costs)							
Our share of Alba Plant's results of operations from producing activities	$ -	$ 101,338	$ -	$ -	$ -	$ -	$ 101,338
Year Ended December 31, 2005							
Revenues	$ 1,374,374	$ 281,901	$ 65,050	$ 31,868	$ 123,583	$ 121,514	$ 1,998,290
Production costs (2)	216,478	30,659	8,504	3,000	12,503	28,796	299,940
Transportation	9,350	-	-	-	6,562	852	16,764
E&P corporate	34,162	435	188	2,611	2,591	947	40,934
Exploration expense	130,018	5,463	223	341	5,985	12,680	154,710
DD&A	328,645	26,978	11,120	12,246	9,866	24,237	413,092
Impairment of operating assets	5,368	-	-	-	-	-	5,368
Accretion expense	9,590	51	281	158	1,134	-	11,214
Income (loss) before income taxes	640,763	218,315	44,734	13,512	84,942	54,002	1,056,268
Income tax expense	140,916	76,518	7,752	3,378	36,834	21,033	286,431
Results of operations from producing results of operations from producing activities	$ 499,847	$ 141,797	$ 36,982	$ 10,134	$ 48,108	$ 32,969	$ 769,837
Our share of Alba Plant's results of operations from producing activities	$ -	$ 33,916	$ -	$ -	$ -	$ -	$ 33,916

(1) Other International includes China, Argentina and Suriname.

(2) Production costs consist of oil and gas operations expense, production and ad valorem taxes, plus general and administrative expense supporting oil and gas operations.

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Costs Incurred in Oil and Gas Property Acquisition, Exploration and Development Activities (Unaudited) (1)

Costs incurred in connection with crude oil and natural gas acquisition, exploration and development are as follows:

	United States	West Africa	Israel	Ecuador	North Sea	Other Int'l (2)	Total
				(in thousands)			
Year Ended December 31, 2007							
Property acquisition costs							
Proved	$ 11,239	$ -	$ -	$ -	$ -	$ -	$ 11,239
Unproved	144,422	-	-	-	-	900	145,322
Total acquisition costs	155,661	-	-	-	-	900	156,561
Exploration costs	184,412	179,043	2,515	215	51,564	2,770	420,519
Development costs (4) (5) (6)	1,081,221	15,185	24,523	29	46,926	22,966	1,190,850
Total consolidated operations	$ 1,421,294	$ 194,228	$ 27,038	$ 244	$ 98,490	$ 26,636	$ 1,767,930
Our share of Alba Plant's development costs	$ -	$ 516	$ -	$ -	$ -	$ -	$ 516
Year Ended December 31, 2006							
Property acquisition costs							
Proved (3)	$ 514,294	$ 7,971	$ -	$ -	$ -	$ -	$ 522,265
Unproved (3)	157,141	25,500	1,000	-	831	-	184,472
Total acquisition costs	671,435	33,471	1,000	-	831	-	706,737
Exploration costs	204,787	13,076	286	228	18,185	11,311	247,873
Development costs (4) (5)	784,877	6,933	13,869	48	231,484	21,649	1,058,860
Total consolidated operations	$ 1,661,099	$ 53,480	$ 15,155	$ 276	$ 250,500	$ 32,960	$ 2,013,470
Our share of Alba Plant's development costs	$ -	$ 580	$ -	$ -	$ -	$ -	$ 580
Year Ended December 31, 2005							
Property acquisition costs							
Proved (3)	$ 2,642,572	$ -	$ -	$ -	$ -	$ -	$ 2,642,572
Unproved (3)	1,084,545	-	-	-	140	250	1,084,935
Total acquisition costs	3,727,117	-	-	-	140	250	3,727,507
Exploration costs	164,820	18,126	223	341	6,308	12,680	202,498
Development costs (4) (5) (6)	657,858	2,738	5,928	(1,660)	19,729	13,858	698,451

Total consolidated operations	$	4,549,795	$	20,864	$	6,151	$	(1,319)	$	26,177	$	26,788	$	4,628,456
Our share of Alba Plant's development costs	$	-	$	27,639	$	-	$	-	$	-	$	-	$	27,639

(1) Costs incurred include capitalized and expensed items.

(2) Other International includes China, Argentina and Suriname.

(3) Includes amounts allocated from the U.S. Exploration acquisition (2006) and the Patina Merger (2005). See Note 3—Acquisitions and Divestitures.

(4) US development costs include increases in asset retirement obligations of $24 million in 2007, $4 million in 2006 and $39 million in 2005. US asset retirement costs of $33 million in 2006 and $66 million in 2005 were incurred as a result of hurricane damage and are excluded from the costs incurred schedule above as we expected to recover the costs from insurance proceeds. See Note 4—Effect of Gulf Coast Hurricanes.

(5) Worldwide development costs include amounts spent to develop proved undeveloped reserves of $1.0 billion in 2007, $768 million in 2006 and $471 million in 2005. Worldwide development costs also include $191 million spent on a floating production, storage and offloading vessel in the North Sea Dumbarton field in 2006.

(6) North Sea development costs include increases in asset retirement obligations of $4 million in 2007 and $5 million in 2005.

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Capitalized Costs Relating to Oil and Gas Producing Activities (Unaudited)

Aggregate capitalized costs relating to crude oil and natural gas producing activities, including asset retirement costs and related accumulated DD&A, are as follows:

	December 31,	
	2007	2006
	(in thousands)	
Unproved oil and gas properties (1)	$ 1,164,707	$ 1,053,254
Proved oil and gas properties (2)	8,903,163	7,671,806
Total oil and gas properties	10,067,870	8,725,060
Accumulated DD&A	(2,280,789)	(1,707,895)
Net capitalized costs	$ 7,787,081	$ 7,017,165
Our share of Alba Plant net capitalized costs	$ 117,212	$ 124,454

(1) Unproved oil and gas properties includes $628 million and $823 million at December 31, 2007 and 2006, respectively, remaining from the allocation of costs to unproved properties acquired in the Patina Merger and the acquisition of U.S. Exploration.

(2) Proved oil and gas properties include asset retirement costs of $91 million and $49 million at December 31, 2007 and 2006, respectively.

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

The following information is based on our best estimate of the required data for the Standardized Measure of Discounted Future Net Cash Flows as of December 31, 2007, 2006 and 2005 in accordance with SFAS 69. The standard requires the use of a 10% discount rate. This information is not the fair market value nor does it represent the expected present value of future cash flows of our proved oil and gas reserves:

	United States	West Africa	Israel	Ecuador	North Sea	Other Int'l (1)	Total
				(in millions)			
December 31, 2007							
Future cash inflows (2)	$ 30,733	$ 6,935	$ 858	$ 704	$ 2,492	$ 879	$ 42,601
Future production costs (3)	5,936	1,112	180	174	516	335	8,253
Future development costs	3,136	202	88	12	200	15	3,653
Future income tax expense	6,622	1,348	146	115	881	125	9,237
Future net cash flows	15,039	4,273	444	403	895	404	21,458
10% annual discount for estimated timing of cash flows	7,398	1,705	163	227	221	93	9,807
Standardized measure of discounted future net cash flows	$ 7,641	$ 2,568	$ 281	$ 176	$ 674	$ 311	$ 11,651
December 31, 2006							
Future cash inflows (2)	$ 18,948	$ 4,904	$ 972	$ 629	$ 1,225	$ 808	$ 27,486
Future production costs (3)	4,551	738	146	162	327	187	6,111
Future development costs	2,846	80	90	12	35	28	3,091
Future income tax expense	3,422	1,348	187	130	435	177	5,699
Future net cash flows	8,129	2,738	549	325	428	416	12,585
10% annual discount for estimated timing of cash flows	3,966	1,132	215	170	95	120	5,698
Standardized measure of discounted future net cash flows	$ 4,163	$ 1,606	$ 334	$ 155	$ 333	$ 296	$ 6,887
December 31, 2005							
Future cash inflows (2)	$ 22,931	$ 5,436	$ 1,031	$ 539	$ 1,267	$ 868	$ 32,072
Future production costs (3)	5,099	556	154	47	352	290	6,498
Future development costs	1,887	92	88	12	184	37	2,300
Future income tax expense	4,645	1,589	182	142	381	159	7,098
Future net cash flows	11,300	3,199	607	338	350	382	16,176
	5,201	1,554	236	162	138	114	7,405

10% annual discount for estimated timing of cash flows							
Standardized measure of discounted future net cash flows	$ 6,099	$ 1,645	$ 371	$ 176	$ 212	$ 268	$ 8,771

(1) Other International includes China and Argentina. We have entered into an agreement to sell our interest in Argentina effective July 1, 2007. We expect the sale, which is subject to regulatory and partner approvals, to close in 2008. Argentina's standardized measure of discounted future net cash flows totaled $66 million at December 31, 2007.

(2) The standardized measure of discounted future net cash flows for 2007, 2006 and 2005 does not include cash flows relating to anticipated future methanol or power sales.

(3) Production costs include oil and gas operations expense, production and ad valorem taxes, transportation costs and general and administrative expense supporting oil and gas operations.

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Future cash inflows are computed by applying year-end prices, adjusted for location and quality differentials on a property-by-property basis, to year-end quantities of proved reserves, except in those instances where fixed and determinable price changes are provided by contractual arrangements at year-end. The discounted future cash flow estimates do not include the effects of derivative instruments. Average prices per region are as follows:

	United States	West Africa	Israel	Ecuador	North Sea	Other Int'l (1)	Total
December 31, 2007							
Average crude oil price per Bbl	$ 88.00	$ 81.26	$ -	$ -	$ 93.79	$ 61.72	$ 85.62
Average natural gas price per Mcf	6.78	0.27	2.69	3.74	7.07	-	4.36
December 31, 2006							
Average crude oil price per Bbl	$ 57.02	$ 51.49	$ -	$ -	$ 57.81	$ 48.04	$ 54.87
Average natural gas price per Mcf	5.32	0.27	2.70	3.75	7.11	0.85	3.48
December 31, 2005							
Average crude oil price per Bbl	$ 58.20	$ 51.62	$ -	$ -	$ 58.47	$ 49.23	$ 55.39
Average natural gas price per Mcf	8.59	0.25	2.62	3.75	5.39	-	5.16

(1) Other International includes China and Argentina.

We estimate that a $1.00 per Bbl change in the average price of crude oil or a $.10 per Mcf change in the average price of natural gas from the year-end prices at December 31, 2007 would change the discounted future net cash flows before income taxes by approximately $176 million or $154 million, respectively.

Future production and development costs, which include dismantlement and restoration expense, are computed by estimating the expenditures to be incurred in developing and producing the proved crude oil and natural gas reserves at the end of the year, based on year-end costs, and assuming continuation of existing economic conditions.

Future development costs include amounts that we expect to spend to develop proved undeveloped reserves of $671 million in 2008, $715 million in 2009 and $408 million in 2010.

Future income tax expense is computed by applying the appropriate year-end statutory tax rates to the estimated future pretax net cash flows relating to proved crude oil and natural gas reserves, less the tax bases of the properties involved. Future income tax expense gives effect to tax credits and allowances, but does not reflect the impact of general and administrative costs and exploration expenses of ongoing operations.

Imbalance receivables and liabilities are as follows:

	Year Ended December 31, 2007	2006	2005
	(in thousands)		
Imbalance receivables	$ 12,640	$ 18,389	$ 18,100

Imbalance liabilities	10,288	16,750	34,600

Imbalance receivables and imbalance liabilities have been excluded from the standardized measure of discounted future net cash flows.

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Sources of Changes in Discounted Future Net Cash Flows (Unaudited)

Principal changes in the aggregate standardized measure of discounted future net cash flows attributable to proved crude oil and natural gas reserves are as follows:

	Year Ended December 31,		
	2007	2006	2005
	(in millions)		
Standardized measure of discounted future net cash flows at the beginning of the year	$ 6,887	$ 8,771	$ 3,342
Changes in standardized measure of dicounted future net cash flows:			
Sales of oil and gas produced, net of production costs	(2,427)	(2,177)	(1,563)
Net changes in prices and production costs	5,266	(2,788)	2,160
Extensions, discoveries and improved recovery, less related costs	1,635	769	1,173
Changes in estimated future development costs	(775)	(558)	(912)
Development costs incurred during the period	1,189	1,076	751
Revisions of previous quantity estimates	1,276	(92)	273
Purchases of minerals in place	6	573	4,720
Sales of minerals in place	(95)	(579)	-
Accretion of discount	1,006	1,274	519
Net change in income taxes	(1,900)	777	(2,099)
Change in timing of estimated future production and other	(417)	(159)	407
Aggregate change in standardized measure of discounted future net cash flows	4,764	(1,884)	5,429
Standardized measure of discounted future net cash flows at the end of the year	$ 11,651	$ 6,887	$ 8,771

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Supplemental Quarterly Financial Information (Unaudited)

Supplemental quarterly financial information is as follows:

	Quarter Ended				
	March 31,	June 30,	September 30,	December 31,	Total
	(in thousands except per share amounts)				
2007 (1)					
Revenues	$ 742,545	$ 794,213	$ 813,811	$ 921,461	$ 3,272,030
Income before taxes	303,852	293,101	343,277	427,337	1,367,567
Net income	211,812	209,105	222,675	300,278	943,870
Earnings per share:					
Basic	1.24	1.22	1.30	1.75	5.52
Diluted	1.22	1.21	1.28	1.73	5.45
2006 (2)					
Revenues	$ 711,997	$ 772,580	$ 741,319	$ 714,186	$ 2,940,082
Income before taxes	349,353	(44,865)	544,966	246,763	1,096,217
Net income	226,087	(30,705)	318,064	164,982	678,428
Earnings per share:					
Basic	1.28	(0.17)	1.80	0.95	3.86
Diluted	1.26	(0.17)	1.75	0.94	3.79

(1) First quarter 2007 includes a loss on involuntary conversion of $13 million and second quarter 2007 includes a loss on involuntary conversion of $38 million. See Note 3—Effect of Gulf Coast Hurricanes.

(2) First quarter 2006 includes a mark-to-market gain of $39 million due to a loss of cash flow hedge accounting treatment for certain derivative instruments, and a loss of $25 million related to amounts previously recorded in AOCL due to a delay in the timing of production. Second quarter 2006 includes a loss of $399 million related to amounts previously recorded in AOCL due to the sale of Gulf of Mexico shelf properties. Third quarter 2006 includes a gain of $204 million from the sale of Gulf of Mexico shelf properties. Fourth quarter 2006 includes an additional gain of $7 million from the sale of Gulf of Mexico Shelf properties. See Note 3—Acquisitions and Divestitures and Note 12—Derivative Instruments and Hedging Activities.

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

None.

Item 9A. Controls and Procedures.

Evaluation of Disclosure Controls and Procedures

We maintain disclosure controls and procedures that are designed to ensure that information required to be disclosed by us in the reports we file or furnish to the SEC under the Securities Act of 1934, as amended, is recorded, processed, summarized and reported within the time periods specified by the SEC's rules and forms, and that information is accumulated and communicated to management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure.

Our principal executive officer and principal financial officer have evaluated the effectiveness of our “disclosure controls and procedures,” as such term is defined in Rule 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, as amended, as of the end of the period covered by this Annual Report on Form 10-K. Based upon their evaluation, they have concluded that our disclosure controls and procedures are effective.

In designing and evaluating our disclosure controls and procedures, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable, and not absolute, assurance that the objectives of the control system will be met. In addition, the design of any control system is based in part upon certain assumptions about the likelihood of future events and the application of judgment in evaluating the cost-benefit relationship of possible controls and procedures. Because of these and other inherent limitations of control systems, there is only reasonable assurance that our controls will succeed in achieving their goals under all potential future conditions.

Management's Annual Report on Internal Control over Financial Reporting

The management report called for by Item 308(a) of Regulation S-K is incorporated herein by reference to Management's Report on Internal Control over Financial Reporting, included in Item 8. Financial Statements and Supplementary Data.

The independent auditor's attestation report called for by Item 308(b) of Regulation S-K is incorporated herein by reference to Report of Independent Registered Public Accounting Firm (Internal Control Over Financial Reporting), included in Item 8. Financial Statements and Supplementary Data.

Changes in Internal Control over Financial Reporting

During the fourth quarter of 2007, we implemented the first phase of a new Enterprise Resource Planning (ERP) software system to replace our various legacy systems. As appropriate, we modified the design and documentation of internal control processes and procedures relating to the new system. We believe that the new ERP system has strengthened and will continue to fortify our internal controls over financial reporting as additional phases are put to use; however, there are inherent risks in implementing any new system that could impact our financial reporting. See Item 1A. Risk Factors—Information technology systems implementation issues could disrupt our internal operations, increase our costs and adversely affect our financial results or our ability to report our financial results.

In the event that issues arise, we have manual procedures in place which would facilitate our continued recording and reporting of results from the new ERP system. However, because of its inherent limitations, internal control over financial reporting may not detect or prevent misstatements. Projections of any evaluation of the 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.

We will continue to monitor, test, and appraise the impact and effect of the new ERP system on our internal controls and procedures as additional phases and features of the system are implemented. There were no changes in internal controls over financial reporting that occurred during the most recent fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting, except as described above.

ItemOther Information.
9B.
None.

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PART III

Item 10. Directors, Executive Officers and Corporate Governance.

The information required by this item is incorporated herein by reference to the 2008 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2007.

Item 11. Executive Compensation.

The information required by this item is incorporated herein by reference to the 2008 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2007.

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

The information required by this item is incorporated herein by reference to the 2008 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2007.

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

The information required by this item is incorporated herein by reference to the 2008 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2007.

Item 14. Principal Accounting Fees and Services.

The information required by this item is incorporated herein by reference to the 2008 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2007.

PART IV

Item 15. Exhibits, Financial Statements Schedules.

(a) The following documents are filed as a part of this report:

(3) Exhibits: The exhibits required to be filed by this Item 15 are set forth in the Index to Exhibits accompanying this report.

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.

	NOBLE ENERGY, INC. (Registrant)
Date: February 27, 2008	By: /s/ Charles D. Davidson Charles D. Davidson, Chairman of the Board, President, Chief Executive Officer and Director
Date: February 27, 2008	By: /s/ Chris Tong Chris Tong, Senior Vice President, Chief Financial Officer
Date: February 27, 2008	By: /s/ Frederick B. Bruning Frederick B. Bruning, Vice President, Chief Accounting 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	Capacity in which signed	Date
/s/ Charles D. Davidson Charles D. Davidson	Chairman of the Board, President, Chief Executive Officer and Director (Principal Executive Officer)	February 27, 2008
/s/ Chris Tong Chris Tong	Senior Vice President, Chief Financial Officer (Principal Financial Officer)	February 27, 2008
/s/ Frederick B. Bruning Frederick B. Bruning	Vice President, Chief Accounting Officer (Principal Accounting Officer)	February 27, 2008
/s/ Jeffrey L. Berenson Jeffrey L. Berenson	Director	February 27, 2008
/s/ Michael A. Cawley Michael A. Cawley	Director	February 27, 2008
/s/ Edward F. Cox	Director	February 27, 2008

Edward F. Cox

/s/ Thomas J. Edelman Thomas J. Edelman	Director	February 27, 2008
/s/ Kirby L. Hedrick Kirby L. Hedrick	Director	February 27, 2008
/s/ Scott D. Urban Scott D. Urban	Director	February 27, 2008
/s/ William T. Van Kleef William T. Van Kleef	Director	February 27, 2008

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INDEX TO EXHIBITS

Exhibit Number	Exhibit **
3.1	— Certificate of Incorporation, as amended, of the Registrant as currently in effect (filed as Exhibit 3.2 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 1987 and incorporated herein by reference).
3.2	— Composite copy of Bylaws of the Registrant as currently in effect (filed as Exhibit 3.1 to the Registrant's Current Report on Form 8-K (Date of Event: January 29, 2002) dated February 8, 2002 and incorporated herein by reference).
4.1	— Certificate of Designations of Series A Junior Participating Preferred Stock of the Registrant dated August 27, 1997 (filed as Exhibit A of Exhibit 4.1 to the Registrant's Registration Statement on Form 8-A filed on August 28, 1997 and incorporated herein by reference).
4.2	— Certificate of Designations of Series B Mandatorily Convertible Preferred Stock of the Registrant dated November 9, 1999 (filed as Exhibit 3.4 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 1999 and incorporated herein by reference).
4.3	— Indenture dated as of October 14, 1993 between the Registrant and U.S. Trust Company of Texas, N.A., as Trustee, relating to the Registrant's 7 1/4% Notes Due 2023, including form of the Registrant's 7 1/4% Notes Due 2023 (filed as Exhibit 4.1 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 1993 and incorporated herein by reference).
4.4	— Indenture relating to Senior Debt Securities dated as of April 1, 1997 between the Registrant and U.S. Trust Company of Texas, N.A., as Trustee (filed as Exhibit 4.1 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 1997 and incorporated herein by reference).
4.5	— First Indenture Supplement relating to $250 million of the Registrant's 8% Senior Notes Due 2027 dated as of April 1, 1997 between the Registrant and U.S. Trust Company of Texas, N.A., as Trustee (filed as Exhibit 4.2 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 1997 and incorporated herein by reference).
4.6	— Second Indenture Supplement, between the Company and U.S. Trust Company of Texas, N.A. as trustee, relating to $100 million of the Registrant's 7 1/4% Senior Debentures Due 2097 dated as of August 1, 1997 (filed as Exhibit 4.1 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 1997 and incorporated herein by reference).
4.7	— Third Indenture Supplement relating to $200 million of the Registrant's 5.25% Notes due 2014 dated April 19, 2004 between the Company and the

Bank of New York Trust Company, N.A., as successor trustee to U.S. Trust Company of Texas, N.A. (filed as Exhibit 4.1 to the Company's Registration Statement on Form S-4 (Registration No. 333-116092) and incorporated herein by reference).

10.1 *	— Restoration of Retirement Income Plan for Certain Participants in the Noble Energy, Inc. Retirement Plan dated September 21, 1994, effective as of May 19, 1994 (filed as Exhibit 10.5 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 1994 and incorporated herein by reference).
10.2 *	— Amendment No. 1 to the Restoration of Retirement Income Plan for Certain Participants in the Noble Affiliates Retirement Plan executed March 26, 2002 (filed as Exhibit 10.2 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2002 and incorporated herein by reference).
10.3 *	— Noble Energy, Inc. Restoration Trust effective August 1, 2002 (filed as Exhibit 10.3 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2002 and incorporated herein by reference).
10.4 *	— Noble Energy, Inc. Deferred Compensation Plan (formerly known as the Noble Affiliates Thrift Restoration Plan dated May 9, 1994) as restated effective August 1, 2001 (filed as Exhibit 10.4 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2002 and incorporated herein by reference).
10.5 *	— Noble Energy, Inc. 1992 Stock Option and Restricted Stock Plan, as amended, dated April 25, 2005, and approved by the stockholders of the Company on April 29, 2003 (filed as Exhibit 10.2 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 2005 and incorporated herein by reference).
10.6 *	— Form of Nonqualified Stock Option Agreement under the Noble Energy, Inc. 1992 Stock Option and Restricted Stock Plan (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K (Date of Event: February 1, 2005) filed February 7, 2005 and incorporated herein by reference).
10.7 *	— Form of Restricted Stock Agreement under the Noble Energy, Inc. 1992 Stock Option and Restricted Stock Plan (filed as Exhibit 10.2 to the Registrant's Current Report on Form 8-K (Date of Event: February 1, 2005) filed February 7, 2005 and incorporated herein by reference).
10.8 *	— 1988 Nonqualified Stock Option Plan for Non-Employee Directors of the Registrant, as amended and restated, effective as of April 27, 2004 (filed as Exhibit 10.2 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2004 and incorporated herein by reference).
10.9 *	— Noble Energy, Inc. Non-Employee Director Fee Deferral Plan dated April 25, 2002 and effective as of April 23, 2002 (filed as Exhibit 10.1 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended

March 31, 2002 and incorporated herein by reference).

10.10*	—	Form of Indemnity Agreement entered into between the Registrant and each of the Registrant's directors and bylaw officers (filed as Exhibit 10.18 to the Registrant's Annual Report of Form 10-K for the year ended December 31, 1995 and incorporated herein by reference).
10.11	—	Guaranty of the Registrant dated October 28, 1982, guaranteeing certain obligations of Samedan (filed as Exhibit 10.12 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 1993 and incorporated herein by reference).
10.12	—	Stock Purchase Agreement dated as of July 1, 1996, between Samedan Oil Corporation and Enterprise Diversified Holdings Incorporated (filed as Exhibit 2.1 to the Registrant's Current Report on Form 8-K (Date of Event: July 31, 1996) dated August 13, 1996 and incorporated herein by reference).

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INDEX TO EXHIBITS

Exhibit Number		Exhibit **
10.13	—	Noble Preferred Stock Remarketing and Registration Rights Agreement dated as of November 10, 1999 by and among the Registrant, Noble Share Trust, The Chase Manhattan Bank, and Donaldson, Lufkin & Jenrette Securities Corporation (filed as Exhibit 10.15 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 1999 and incorporated herein by reference).
10.14*	—	Letter agreement dated February 1, 2002 between the Registrant and Charles D. Davidson, terminating Mr. Davidson's employment agreement and entering into the attached Change of Control Agreement (filed as Exhibit 10.17 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2001 and incorporated herein by reference).
10.15*	—	Form of Change of Control Agreement entered into between the Registrant and each of the Registrant's officers, with schedule setting forth differences in Change of Control Agreements (filed as Exhibit 10.1 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2004 and incorporated herein by reference).
10.16	—	364-day Credit Agreement dated as of November 27, 2002 among the Registrant, as borrower, JPMorgan Chase Bank, as the administrative agent for the lenders, Wachovia Bank, National Association, as the syndication agent for the lenders, Societe Generale, Citibank, N.A., Deutsche Bank Ag New York Branch, and The Royal Bank of Scotland PLC, as co-documentation agents, and certain commercial lending institutions, as lenders, (filed as Exhibit 10.19 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2002 and incorporated herein by reference).
10.17	—	364-day Credit Agreement dated as of October 30, 2003 among the Registrant, as borrower, JPMorgan Chase Bank, as the administrative agent for the lenders, Wachovia Bank, National Association, as the syndication agent for the lenders, Societe Generale, Deutsche Bank Ag New York Branch, and The Royal Bank of Scotland PLC, as co-documentation agents, and certain commercial lending institutions, as lenders (filed as Exhibit 10.20 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2003 and incorporated herein by reference).
10.18	—	Term Loan Agreement dated as of January 30, 2004 among Noble Energy Mediterranean Ltd., as borrower, Sumitomo Mitsui Banking Corporation, as initial lender and agent for the lenders, and certain commercial lending institutions, as lenders (filed as Exhibit 99.1 to the Registrant's Current Report on Form 8-K (Date of Event: January 30, 2004) filed May 10, 2004 and incorporated herein by reference).
10.19	—	

Guaranty of the Company dated January 30, 2004 guaranteeing obligations of Noble Energy Mediterranean, Ltd. under the Term Loan Agreement dated January 30, 2004 (filed as Exhibit 99.2 to the Registrant's Current Report on Form 8-K (Date of Event: January 30, 2004) filed May 10, 2004 and incorporated herein by reference).

10.20 — Term Loan Agreement dated as of February 2, 2004 among Noble Energy Mediterranean Ltd., as borrower, Bank One, NA, as agent for the lenders, and certain commercial lending institutions, as lenders (filed as Exhibit 99.3 to the Registrant's Current Report on Form 8-K (Date of Event: January 30, 2004) filed May 10, 2004 and incorporated herein by reference).

10.21 — Guaranty of the Company dated February 2, 2004 guaranteeing obligations of Noble Energy Mediterranean, Ltd. under the Term Loan Agreement dated February 2, 2004 (filed as Exhibit 99.4 to the Registrant's Current Report on Form 8-K (Date of Event: January 30, 2004) filed May 10, 2004 and incorporated herein by reference).

10.22 — Term Loan Agreement dated as of February 4, 2004 among Noble Energy Mediterranean Ltd., as borrower, The Royal Bank of Scotland Finance (Ireland), as agent for the lenders and as the initial lender (filed as Exhibit 99.5 to the Registrant's Current Report on Form 8-K (Date of Event: January 30, 2004) filed May 10, 2004 and incorporated herein by reference).

10.23 — Guaranty of the Company dated February 4, 2004 guaranteeing obligations of Noble Energy Mediterranean, Ltd. under the Term Loan Agreement dated February 4, 2004 (filed as Exhibit 99.6 to the Registrant's Current Report on Form 8-K (Date of Event: January 30, 2004) filed May 10, 2004 and incorporated herein by reference).

10.24* — Noble Energy, Inc. 2004 Long-Term Incentive Plan effective as of January 1, 2004 (filed as Exhibit 10.1 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2004 and incorporated herein by reference).

10.25* — Form of Performance Units Agreement under the Noble Energy, Inc. 2004 Long-Term Incentive Program (filed as Exhibit 10.3 to the Registrant's Current Report on Form 8-K (Date of Event: February 1, 2005) filed February 7, 2005 and incorporated herein by reference).

10.26 — Purchase and Sale Agreement, dated February 7, 2006, among Noble Energy Production, Inc., U.S. Exploration Holdings, LLC, U.S. Exploration Holdings, Inc. and United States Exploration, Inc., filed herewith (filed as Exhibit 10.28 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2005 and incorporated herein by reference).

10.27 — $2.1 billion Five-Year Credit Agreement, dated December 9, 2005, among Noble Energy, Inc., JPMorgan Chase Bank, N.A., as administrative agent, Wachovia Bank, National Association and The Royal Bank of Scotland PLC, as co-syndication agents, Deutsche Bank Securities Inc. and Citibank, N.A., as co-documentation agents, and certain other commercial lending institutions named therein (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K (Date of Event: December 9, 2005), filed December 14, 2005 and incorporated herein by reference).

10.28	— $2.1 billion Five-Year Credit Agreement, dated November 30, 2006, among Noble Energy, Inc., JPMorgan Chase Bank, N.A., as administrative agent, Wachovia Bank, National Association and The Royal Bank of Scotland PLC, as co-syndication agents, Deutsche Bank Securities Inc., Citibank, N.A. and The Bank of Tokyo-Mitsubishi UFJ, Ltd., as co-documentation agents, and certain other commercial lending institutions named therein (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K (Date of Event: November 30, 2006), filed December 6, 2006 and incorporated herein by reference).
10.29*	— Noble Energy, Inc. 2005 Non-Employee Director Fee Deferral Plan, dated December 5, 2005 and effective as of January 1, 2005 (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K (Date of Event: December 5, 2005), filed December 8, 2005 and incorporated herein by reference).
10.30*	— Amendment No. 1 to the Noble Energy, Inc. Non-Employee Director Fee Deferral Plan, dated December 5, 2005 and effective as of January 1, 2005 (filed as Exhibit 10.2 to the Registrant's Current Report on Form 8-K (Date of Event: December 5, 2005), filed December 8, 2005 and incorporated herein by reference).

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Exhibit Number		Exhibit **
10.31*	—	Consulting Agreement, dated May 9, 2005 but commencing May 16, 2005, by and between Noble Energy, Inc. and Thomas J. Edelman (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K (Date of Event: May 16, 2005), filed May 20, 2005 and incorporated herein by reference).
10.32*	—	2005 Stock Plan for Non-Employee Directors of Noble Energy, Inc. (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K (Date of Event: April 26, 2005) filed April 29, 2005 and incorporated herein by reference).
10.33*	—	Form of Stock Option Agreement under the Noble Energy, Inc. 2005 Non-Employee Director Stock Plan (filed as Exhibit 10.1 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2005 and incorporated herein by reference).
10.34*	—	Form of Restricted Stock Agreement under the Noble Energy, Inc. 2005 Non-Employee Director Stock Plan (filed as Exhibit 10.2 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2005 and incorporated herein by reference).
10.35*	—	Form of Restricted Stock Agreement under the Noble Energy, Inc. 1992 Stock Option and Restricted Stock Plan entered into by certain executive officers and key employees of the Company on May 16, 2005 and August 1, 2005, respectively (filed as Exhibit 10.4 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2005 and incorporated herein by reference).
10.36	—	Purchase and Sale Agreement dated May 15, 2006 by and between the Company and Coldren Resources LP (filed as Exhibit 10.1 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2006 and incorporated herein by reference).
10.37*	—	Noble Energy, Inc. Change of Control Severance Plan for Executives (filed as Exhibit 10.1 to the Registrant's Current Report on Form 8-K (Date of Event: October 24, 2006) filed October 30, 2006 and incorporated herein by reference).
10.38*	—	Noble Energy, Inc. 1992 Stock Option and Restricted Stock Plan (as amended through April 24, 2007), (filed as exhibit 10.1 to Registrant's Current Report on Form 8-K (Date of Event: April 24, 2007) filed April 30, 2007 and incorporated herein by reference).

10.39*	—	Noble Energy, Inc. 2005 Non-Employee Director Fee Deferral Plan (as amended effective January 1, 2008) filed herewith.
10.40*	—	Noble Energy, Inc. Change of Control Severance Plan for Executives (as amended effective January 1, 2008) filed herewith.
10.41*	—	Noble Energy, Inc. Change of Control Agreement (as amended effective January 1, 2008) filed herewith.
10.42*	—	Noble Energy, Inc. 2004 Long-Term Incentive Plan (as amended effective January 1, 2008) filed herewith.
10.43*	—	Amendment to the 2006 Performance Units Agreement (as amended effective January 1, 2008) filed herewith.
10.44*	—	Noble Energy, Inc. 2005 Deferred Compensation Plan (as amended effective January 1, 2008) filed herewith.
10.45*	—	Noble Energy, Inc. Retirement Restoration Plan (as amended effective December 1, 2007) filed herewith.
21	—	Subsidiaries, filed herewith.
23.1	—	Consent of Independent Registered Public Accounting Firm—KPMG LLP, filed herewith.
23.2	—	Consent of Independent Registered Public Accounting Firm—PricewaterhouseCoopers LLP, filed herewith.
23.3	—	Consent of Independent Registered Public Accounting Firm—UHY LLP, filed herewith.
23.4	—	Consent of Netherland, Sewell & Associates, Inc., filed herewith.
31.1	—	Certification of the Company's Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 7241).
31.2	—	Certification of the Company's Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 7241).
32.1	—	Certification of the Company's Chief Executive Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 1350).
32.2	—	Certification of the Company's Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. Section 1350).

99.1	—	Report of Independent Public Accounting Firm—PricewaterhouseCoopers LLP, filed herewith.
99.2	—	Report of Independent Public Accounting Firm—UHY LLP, filed herewith.
99.3	—	Report of Netherland, Sewell & Associates, Inc, filed herewith.

* Management contract or compensatory plan or arrangement required to be filed as an exhibit hereto.

** Copies of exhibits will be furnished upon prepayment of 25 cents per page. Requests should be addressed to the Senior Vice President and Chief Financial Officer, Noble Energy, Inc., 100 Glenborough Drive, Suite 100, Houston, Texas 77067.

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GLOSSARY

In this report, the following abbreviations are used:

Bbl(s)	Barrel(s)
MBbls	Thousand barrels
MMBbls	Million barrels
Bpd	Barrels per day
Bopd	Barrels oil per day
Boe	Barrels oil equivalent
MBoe	Thousand barrels oil equivalent
MMBoe	Million barrels oil equivalent
Boepd	Barrels oil equivalent per day
Kgal	Thousand gallons
KW	Kilowatt
KWh	Kilowatt hours
MW	Megawatt
Mcf	Thousand cubic feet
MMcf	Million cubic feet
Bcf	Billion cubic feet
Tcf	Trillion cubic feet
Mcfpd	Thousand cubic feet per day
MMcfpd	Million cubic feet per day
Mcfe	Thousand cubic feet equivalent
MMcfe	Million cubic feet equivalent
Bcfe	Billion cubic feet equivalent
BTU	British thermal unit
MMBtu	Million British thermal units
MMBtupd	Million British thermal units per day
Btupcf	British thermal unit per cubic foot
MT	Metric tons
MTpd	Metric tons per day
LNG	Liquefied natural gas
LPG	Liquefied petroleum gas
NGL	Natural gas liquid