NUEVO ENERGY CO
Form 10-K
March 10, 2004

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

(Mark One)

þ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2003

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 1-10537

Nuevo Energy Company

(Exact Name of Registrant as Specified in Its Charter)

Delaware *(State or Other Jurisdiction of Incorporation or Organization)*	**76-0304436** *(I.R.S. Employer Identification No.)*
1021 Main, Suite 2100, Houston, Texas *(Address of Principal Executive Offices)*	**77002** *(Zip code)*

Registrant s telephone number, including area code:

(713) 652-0706

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

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, par value $.01 per share	New York Stock Exchange
$2.875 Term Convertible Securities, Series A	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 whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes o No þ

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

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b.2 of the Act). Yes þ No o

The aggregate market value of the voting stock held by non-affiliates of the registrant:

As of June 30, 2003, the aggregate market value of the voting stock of the registrant held by non-affiliates of the registrant was approximately $336.9 million.

The number of shares outstanding of each of the registrant s classes of Common Stock as of the latest practicable date:

As of February 27, 2004, number of shares of Common Stock outstanding: 20,318,979

DOCUMENTS INCORPORATED BY REFERENCE:

None

TABLE OF CONTENTS

Table of Contents

NUEVO ENERGY COMPANY

TABLE OF CONTENTS

Table of Contents

PART I

Item 1. *Business*

General

Background

Nuevo Energy became a public company in 1990 and is engaged in the acquisition, exploitation, exploration, development and production of crude oil and natural gas. Our core areas in the U.S. are onshore and offshore California and West Texas. We also have international crude oil production in the Republic of Congo.

We are the largest independent oil and gas exploration and production company in California. At year-end 2003, approximately 86% of our proved reserves were in California (58% onshore and 28% offshore) which have a long reserve life and shallow production decline curves. Our California production was approximately 82% of our 2003 oil and gas production. The high asset concentration combined with a high proportion of operated properties enables us to control the timing of exploitation and development expenditures.

In September 2002, we created a new core area in West Texas principally with natural gas reserves through the acquisition of Athanor Resources, Inc. (Athanor). In 2003, approximately 41% of our natural gas production was from West Texas and it accounted for 7% of our proved reserves and 38% of our proved natural gas reserves at year-end 2003. We are the operator of the Pakenham field, which has significant exploitation and exploration inventory.

Our only international producing property is offshore the Republic of Congo, which had approximately 7% of our proved reserves at year-end 2003. This property is non-operated and provides a stable production profile with approximately 10% of our 2003 production.

In 2003 we continued to maintain our strategy of disciplined allocation of capital and reduced long-term debt with proceeds from sales of non-core assets and operating cash flows. We sold $132 million of non-core assets in 2003. We also redeemed approximately $185 million of our 9 1/2% Senior Subordinated Notes.

Recent Developments

On February 12, 2004, we entered into a definitive agreement with Plains Exploration & Production Company (Plains) pursuant to which it is anticipated we will be merged with Plains or alternatively become a wholly owned subsidiary of Plains. Under the terms of the transaction, our stockholders will receive 1.765 shares of Plains common stock in exchange for each share of Nuevo s common stock. Following the merger, our stockholders are expected to own 47% of the combined company. The transaction is subject to approval by the stockholders of both Plains and Nuevo and other customary closing conditions including regulatory review under the Hart-Scott-Rodino Antitrust Improvement Act of 1976. The transaction is expected to close in the second quarter of 2004.

Our annual report on Form 10-K, quarterly reports on Form 10-Q and current reports on Form 8-K are made available on our website at www.nuevoenergy.com.

As used in this annual report, the words we , our , us , Nuevo and the Company refer to Nuevo Energy Company, except as otherwise specified, and to our subsidiaries.

Table of Contents

Reserves

The following table details our estimated net proved reserves at December 31, 2003 as set forth in the report prepared by Ryder Scott Company L.P. (Ryder Scott), our independent petroleum engineers, in accordance with criteria prescribed by the Securities and Exchange Commission:

	Net Proved Reserves		
	Crude Oil And Liquids (MBbls)	**Natural Gas (MMcf)**	**MBOE**
U.S. Properties			
California Fields			
Cymric	71,209	5,465	72,120
Point Pedernales	21,858	5,181	22,722
Midway-Sunset	19,485		19,485
Santa Clara	10,777	14,871	13,256
South Belridge	12,408	2,582	12,838
Dos Cuadras	8,401	5,215	9,270
Buena Vista	2,336	27,807	6,971
Huntington Beach	6,510	505	6,594
Other	8,605	41,117	15,457
Total California	161,589	102,743	178,713
West Texas			
Pakenham	3,835	57,883	13,482
Other	328	5,740	1,285
Total West Texas	4,163	63,623	14,767
Total U.S. Properties	165,752	166,366	193,480
Foreign Properties			
Yombo, Congo	14,098		14,098
Other	221	805	355
Total Foreign Properties	14,319	805	14,453
Total Properties	180,071	167,171	207,933

Oil and Gas Operations

Domestic Operations

The following discussion pertains to our domestic oil and gas assets that are held for continuing use and, accordingly, does not include the Brea-Olinda, Orcutt and Union Island fields which were sold in 2003 and are reflected as discontinued operations.

Our domestic operations are concentrated in three areas: California onshore, California offshore and West Texas. At December 31, 2003, our U.S. proved reserves totaled approximately 193.5 MMBOE or 93% of our total proved reserve base. During 2003, domestic production averaged 44.0 MBOE/day, or 90% of total production.

We continue to increase the value of our domestic oil and gas assets through development drilling, workovers, recompletions, secondary and tertiary recovery operations and other production enhancement techniques to maximize current production and the ultimate recovery of reserves. Capital additions to our domestic oil and gas properties excluding acquisitions was $59.2 million in 2003 and are currently budgeted at approximately $65 to $70 million in 2004. The main focus of our 2004 exploitation program will be directed towards our thermal properties onshore California and Pakenham in West Texas.

California Onshore. Net proved reserves were 120.2 MMBOE at December 31, 2003, and production averaged 26.1 MBOE/day in 2003. Our main California onshore properties include interests in the Cymric, Midway-Sunset and Belridge fields in the San Joaquin Basin in Kern County, California which utilize thermal operations to maximize current production and the ultimate recovery of reserves. We own a 100% working interest (93% net revenue) in our properties in the Cymric field and the entire working interest and an average net revenue interest of approximately 97% in our properties in the Midway-Sunset field. Production is from several zones in the Cymric field, including the Tulare, Diatomite and Point of Rocks formations and the Antelope Shale. The Midway-Sunset field produces from five zones with the Potter Sand and the thermal Diatomite accounting for the majority of the total production. We operate the deeper zones of the Belridge field in fee with 100% working and net revenue interests. Production from the Belridge field is from the Tulare formation.

California Offshore. Net proved reserves were 58.5 MMBOE at December 31, 2003, and production averaged 14.2 MBOE/day in 2003. Offshore California, we operate 12 platforms, 10 in federal waters and 2 in state waters. The Point Pedernales, Dos Cuadras and East Dos Cuadras, and Santa Clara fields are our largest fields. We purchased the remaining third-party interest in the Point Pedernales field in 2003, and now own a 100% working interest (80% net revenue) in this field which is located 3.5 miles offshore Santa Barbara County, California, in federal waters. Production is from the Monterey Shale at depths from 3,500-5,150 feet. The Dos Cuadras and East Dos Cuadras fields are located offshore five and one-half miles from Santa Barbara in the Santa Barbara Channel. We operate three platforms with a 50% working interest (42% net revenue) and a fourth platform with a 67.5% working interest (56% net revenue). We have a 100% working interest (83% net revenue) in the Santa Clara field.

West Texas. We have properties located in West Texas with a total proved reserve base of 14.8 MMBOE at December 31, 2003, and production averaged 22.5 MMcfe/day in 2003. The main asset is the Pakenham field in Terrell County, Texas. We are the operator of the Pakenham field and own approximately a 98% working interest (73% net revenue) in this field.

International Operations

At December 31, 2003, our estimated international net proved reserves totaled 14.5 MMBOE. During 2003, our international production averaged 4.8 MBOE/day. See Risk Factors and Cautionary Statement for Purposes of the Safe Harbor Provisions of the Private Securities Litigation Reform Act of 1995 for a discussion of the risks of our international investments.

Congo. Our international reserves and production consist primarily of a non-operating 50% working interest (37.5% average net revenue) in the Yombo oil field located in the Marine 1 Permit offshore the Republic of Congo in West Africa (Congo). Estimated net proved reserves of the Yombo oil field as of December 31, 2003 were 14.1 MMBbl, and production during 2003 averaged 4.8 MBOE/day. The properties are located 27 miles offshore in approximately 370 feet of water. We also own a 50% interest in a converted super tanker with storage capacity of over one million barrels of oil for use as a floating production, storage and off loading vessel (FPSO). Our production is converted on the FPSO to No. 6 fuel oil with less than 0.3% sulfur content. We also have a 50% interest in the Masseko field which is currently under renewed analysis for possible development by a subsidiary of Perenco, the operator. Should circumstances change in the future, we may pursue development of the field.

During 2003, Yombo production declined at a rate less than 7%, which is a significantly lower decline than the historic 12% annual decline. The field is currently fully developed, with all well slots being utilized. However, adding additional slots or utilizing low rate producing wells to side track for potential future infill development opportunities is possible.

Tunisia. We have a 42.86% participating interest in the 768,900 acre Fejaj Permit located onshore central Tunisia. In 2002, Chott Fejaj #3-A well was deepened from 3,532 meters to a total depth of 4,637

Table of Contents

meters to evaluate the pre-Jurassic section of the Chott Fejaj structure. This well was subsequently plugged and abandoned as a dry hole. We will relinquish our permit in 2004.

Canada. We acquired a 50% working interest in 22,140 acres in the Marten Hills heavy oil play in Alberta, Canada for approximately $0.4 million in 2000. The cyclic steaming potential of the acreage was evaluated in 2001, determined to be non-commercial, and we relinquished the acreage in 2002.

Ghana. In 2001, we relinquished our 1.9 million acre Accra-Keta Permit offshore the Republic of Ghana and recorded an impairment of $1.0 million. The Permit was relinquished prior to the commencement of the second phase of the work program. We were the operator of this Permit and held a 50% working interest.

Drilling Activities

The following discussion pertains to our oil and gas assets that are held for continuing use and, accordingly, does not include the Brea-Olinda, Orcutt Hill and Union Island fields which were sold in 2003.

Acreage

The following table sets forth the acres of developed and undeveloped oil and gas properties in which we held an interest as of December 31, 2003. Undeveloped acreage are leased acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and gas, regardless of whether or not such acreage contains proved reserves. A gross acre refers to the number of acres in which we directly own a working interest. The number of net acres is the sum of the fractional ownership of working interests we directly own in the gross acres expressed as a whole number. A net acre is deemed to exist when the sum of our fractional ownership of working interests in gross acres equals one.

	Gross	Net
Developed Acreage	211,762	139,806
Undeveloped Acreage	1,042,000	461,948
Total	1,253,762	601,754

The following table sets forth our undeveloped acreage at December 31, 2003:

	Gross	Net
California	230,409	111,729
West Texas	4,691	4,691
Congo, West Africa:		
Marine 1 Permit	38,000	19,000
Tunisia, North Africa	768,900	326,528
Total	1,042,000	461,948

Productive Wells

The following table sets forth our gross and net interests in productive oil and gas wells at December 31, 2003. Productive wells are producing wells and wells capable of production.

	Gross	Net
Oil Wells	2,271	1,729
Gas Wells	281	225
Total	2,552	1,954

Drilling Activity

Our drilling activities in 2003 were in the continental United States and offshore California in state and federal waters.

The following table details the results of our drilling activity, net to our interest, for the last three calendar years. Gross wells are the number of wells in which we own a direct working interest. The number of net wells is the sum of the fractional ownership of working interests we directly own in gross wells.

	Exploratory Wells					
	Gross			Net		
	Productive	Dry Holes	Total	Productive	Dry Holes	Total
2001	1	8	9	1.00	4.95	5.95
2002		1	1		0.43	0.43
2003						

	Development Wells					
	Gross			Net		
	Productive	Dry Holes	Total	Productive	Dry Holes	Total
2001	101	1	102	95.98	1.00	96.98
2002	104	3	107	104.00	3.00	107.00
2003	81	5	86	80.60	5.00	85.60

In 2003, we continued development of our Cymric field onshore California by drilling 23 development wells. This field contains 35% of our total net proved equivalent reserves as of December 31, 2003. Nine additional wells are planned for 2004. Thirty development wells were drilled in our most underdeveloped area, the Belridge field, in 2003. This field contains 6% of our total net proved equivalent reserves. Twenty-six development wells are planned for 2004. Twenty-one development wells were drilled in the Midway-Sunset field in 2003. Net proved equivalent reserves for this field contain 9% of our total net proved equivalent reserves. Six additional wells are planned for 2004, four of which target a frontier area. Although no new wells were drilled in 2003, four development wells are planned in 2004 at the Buena Vista Hills field. The Buena Vista Hills field is our largest California gas producing field and contains 3% of our total net proved equivalent reserves.

During 2003, we implemented a nine well development program at our West Texas Pakenham field. The program consisted of six shallow Wolfcamp completions, three thrusted completions and one well which failed to reach the Ellenburger objective. During the drilling of the initial Ellenburger well, we encountered unfavorable borehole conditions, forcing us to abandon the wellbore. Early in the fourth quarter of 2003, we spudded an Ellenburger replacement well. The plans for 2004 include the drilling of eight development wells, and the completion of our first Ellenburger well.

Acquisitions and Divestitures of Oil and Gas Producing Properties

We have, from time to time, been an active participant in the market for oil and gas properties. We also seek to divest lower growth assets at times when those assets are valued highly by the marketplace.

Acquisitions

Year	Property	Acquisition Price
		(In millions)
2003	Point Pedernales 20% interest	$ 0.7
2002	Athanor Resources (Pakenham field)	101.4
2001	Kern County properties southeast of Cymric	28.5

Table of Contents

Divestitures

Year	Property	Sales Price
		(In millions)
2003	Brea-Olinda	$59.0
2003	Orcutt Hill	12.9
2003	Union Island	10.5
2002	Eastern Properties located in Texas, Alabama and Louisiana	9.0
2000	Las Cinegas	4.6

Real Estate

In 1996, along with our acquisition of certain California oil and gas properties, we acquired tracts of land in Orange and Santa Barbara Counties in California, and nearly 8,000 acres of agricultural property in the central valley of California.

In 2003, we sold a significant portion of our real estate portfolio. On December 30, 2003, we sold our 810 acre Tonner Hills residential development property to affiliates of Shea Homes Limited Partnership and Standard Pacific Corp. for approximately $47 million. We received $16 million of the purchase price on the sale date, and we anticipate receiving $22.5 million of the purchase price by no later than March 29, 2004. The remaining $8.5 million of the purchase price will be received by us when certain habitat restoration work is completed by us. Because of the continuing involvement with Tonner Hills, we have not recorded this transaction as a sale in 2003.

In a separate transaction on December 30, 2003, we sold an office building and contiguous acreage in Orcutt, Santa Barbara County, California to a private entity for approximately $2.9 million. We still own approximately 596 acres of real estate in Santa Barbara County, California which is generally unaffected by oil field operations. As of December 31, 2003 this acreage remained classified as an asset held for sale.

Markets

The markets for hydrocarbons continue to be quite volatile. Our financial condition, operating results, future growth and the carrying value of our oil and gas properties are substantially dependent on oil and gas prices. The ability to maintain or increase our borrowing capacity and to obtain additional capital on attractive terms is also substantially dependent upon oil and gas prices. Prices for oil and gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and gas, market uncertainty and a variety of additional factors beyond our control. These factors include weather conditions in the United States, the condition of the United States economy, the actions of the Organization of Petroleum Exporting Countries, governmental regulation, political stability in the Middle East and elsewhere, the foreign supply of oil and gas, the price of foreign oil imports and the availability of alternate fuel sources. Any substantial and extended decline in the price of oil and gas could have an adverse effect on the carrying value of our proved reserves, borrowing capacity, our ability to obtain additional capital, and our revenues, profitability and cash flows from operations.

The price of natural gas and the threat of electrical disruptions are factors that can create volatility in our California oil operations. Since we consume natural gas to generate steam for our thermal operations, in 2002, we entered into certain natural gas purchase contracts and hedged our crude oil sales to protect the economic margin on a portion of our thermal oil production beginning in 2003.

In California, we generate a total of 15 Megawatts (MW) of power at various sites and consume approximately 65% in our operations. Three turbines in Kern County produce 12 MW of power and cogenerate 15% of our total steam needs in thermal operation. By self-generating power consumption in Kern County, we have reduced our exposure to rising electricity prices. With the exception of the Point Pedernales field, for which we have contracted for firm electric power, most of our facilities receive power under interruptible service contracts. Considering the fact that California has experienced shortages of electricity in the past and some of our facilities receive interruptible service, we could experience periodic power interruptions. In addition, the State of California could increase power costs, change existing rules or impose new rules or regulations with respect to power that could impact our operating costs.

Table of Contents

Production of California San Joaquin Valley heavy oil (defined herein as those fields which produce primarily 15° API quality crude oil or heavier through thermal operations) constituted 51% of our total 2003 crude output. In addition, properties which produce primarily other grades of relatively heavy oil (generally, 20° API or heavier, but produced through non-thermal operations) constituted 14% of our total 2003 crude output. The market price for California heavy oil differs from the established market indices for oil elsewhere in the U.S., due principally to the higher transportation and refining costs associated with heavy oil. We entered into a 15-year contract, effective January 1, 2000, to sell all of our current and future California crude oil production to ConocoPhillips. The contract provides pricing based on a fixed percentage of the NYMEX crude oil price for each type of crude oil that we produce in California. Effective January 1, 2003, we renegotiated this contract relative to our Point Pedernales production, and increased our NYMEX price realization 14.5%. Effective January 1, 2004, the entire contract pricing relationship was renegotiated increasing our effective price realization by approximately 11% on all crude oil purchased by ConocoPhillips which is 85% of our California crude oil production. While the contract does not reduce our exposure to price volatility, it does effectively eliminate the risk of widening basis differential between the NYMEX price and the field price of our California oil production. In doing so, the contract makes it substantially easier for us to hedge our realized prices. The ConocoPhillips contract permits us, under certain circumstances, to separately market up to 10% of our California crude oil production. We exercised this right each year and have sold 5,000 BOPD of our San Joaquin Valley oil production to a third party under a one-year contract containing NYMEX pricing.

Our Yombo field production in Marine 1 Permit offshore Congo produces a relatively heavy crude oil (16-20° API gravity) which is processed into a low-sulfur, No. 6 fuel oil product for sale to worldwide markets. Production from this property constituted 11% of our total 2003 oil production. The market for residual fuel oil differs from the markets for WTI and other benchmark crudes due to its primary use as an industrial or utility fuel versus the higher value transportation fuel component, which is produced from refining most grades of crude oil.

Sales to ConocoPhillips Corporation accounted for 65%, 73% and 63% of 2003, 2002 and 2001 oil and gas revenues. Sales to Valero Marketing accounted for 11% of 2003 oil and gas revenues and sales to Torch Energy Marketing (TEMI) accounted for 23% of 2001. In January 2003, we brought in house the marketing of our oil production. Effective January 2004, we terminated our contract with Coral Energy for the marketing of natural gas which function has also been brought in house. The loss of any single significant customer or contract could have a material adverse short-term effect. However, our management does not believe that the loss of any single significant customer or contract would materially affect our business in the long-term.

Regulation

Oil and Gas Regulation

The availability of a ready market for oil and gas production depends upon numerous factors beyond our control. These factors include state and federal regulation of oil and gas production and transportation, as well as regulations governing environmental quality and pollution control, state limits on allowable rates of production by a well or proration unit, the amount of oil and gas available for sale, the availability of adequate pipeline and other transportation and processing facilities and the marketing of competitive fuels. For example, a productive gas well may be shut-in because of an over-supply of gas or lack of an available gas pipeline in the areas in which we may conduct operations. State and federal regulations are generally intended to prevent waste of oil and gas, protect rights to produce oil and gas between owners in a common reservoir, and control contamination of the environment. Pipelines and gas plants are also subject to the jurisdiction of various Federal, state and local agencies which may affect the rates at which they are able to process or transport gas from our properties.

Our sales of natural gas are affected by the availability, terms and costs of transportation. The rates, terms and conditions applicable to the interstate transportation of gas by pipelines are regulated by the Federal Energy Regulatory Commission (FERC) under the Natural Gas Acts (NGA), as well as under Section 311 of the Natural Gas Policy Act (NGPA). Since 1985, the FERC has implemented regulations intended to increase competition within the gas industry by making gas transportation more accessible to gas buyers and sellers on an open-access, non-discriminatory basis.

Our sales of oil are also affected by the availability, terms and costs of transportation. The rates, terms, and conditions applicable to the interstate transportation of oil by pipelines are regulated by the FERC under the Interstate Commerce Act. FERC has implemented a simplified and generally applicable ratemaking methodology for interstate oil pipelines to fulfill the requirements of Title VIII of the Energy Policy Act of 1992 comprised of an indexing system to establish ceilings on interstate oil pipeline rates. The FERC has announced several important transportation-related policy statements and rule changes, including a statement of policy and final rule issued February 25, 2000 concerning alternatives to its traditional cost-of-service rate-making methodology to establish the rates interstate pipelines may charge for their services. The final rule revises FERC s pricing policy and current regulatory framework to improve the efficiency of the market and further enhance competition in natural gas markets.

With respect to transportation of natural gas on the Outer Continental Shelf (OCS), the FERC requires, as a part of its regulation under the Outer Continental Shelf Lands Act (OCSLA), that all pipelines provide open and non-discriminatory access to both owner and non-owner shippers. Although to date the FERC has imposed light-handed regulation on offshore facilities that meet its traditional test of gathering status, it has the authority to exercise jurisdiction under the OCSLA over gathering facilities, if necessary, to permit non-discriminatory access to service. For those facilities transporting natural gas across the OCS that are not considered to be gathering facilities, the rates, terms and conditions applicable to this transportation are regulated by FERC under the NGA and NGPA, as well as the OCSLA. With respect to the transportation of oil and condensate on or across the OCS, the FERC requires, as part of its regulation under the OCSLA, that all pipelines provide open and non-discriminatory access to both owner and non-owner shippers. Accordingly, the FERC has the authority to exercise jurisdiction under the OCSLA, if necessary, to permit non-discriminatory access to service.

In the event we conduct operations on federal, state or Indian oil and gas leases, such operations must comply with numerous regulatory restrictions, including various nondiscrimination statutes, royalty and related valuation requirements, and certain of such operations must be conducted pursuant to certain on-site security regulations and other appropriate permits issued by the Bureau of Land Management (BLM) or Minerals Management Service (MMS) or other appropriate federal or state agencies.

Our OCS leases in federal waters are administered by the MMS and require compliance with detailed MMS regulations and orders. The MMS has promulgated regulations implementing restrictions on various production-related activities, including restricting the flaring or venting of natural gas. Under certain circumstances, the MMS may require any of our operations on federal leases to be suspended or terminated. Any such suspension or termination could materially and adversely affect our financial condition and operations. On March 15, 2000, the MMS issued a final rule effective June 1, 2000, that amends its regulations governing the calculation of royalties and the valuation of crude oil produced from federal leases. Among other matters, this rule amends the valuation procedure for the sale of federal royalty oil by eliminating posted prices as a measure of value and relying instead on arm s length sales prices and spot market prices as market value indicators. Because we generally sell our production to third parties and pay royalties based on proceeds actually received from the sale of production from federal leases, it is not anticipated that this final rule will have a substantial impact on us.

The Mineral Leasing Act of 1920 (Mineral Act) prohibits direct or indirect ownership of any interest in federal onshore oil and gas leases by a foreign citizen of a country that denies similar or like privileges to citizens of the United States. Such restrictions on citizens of a non-reciprocal country include ownership or holding or controlling stock in a corporation that holds a federal onshore oil and gas lease. If this restriction is violated, the corporation s lease can be canceled in a proceeding instituted by the United States Attorney General. Although the regulations of the BLM (which administers the Mineral Act) provide for agency designations of non-reciprocal countries, there are presently no such designations in effect. We own interests in numerous federal onshore oil and gas leases. It is possible that holders of equity interests in us may be citizens of foreign countries, which at some time in the future might be determined to be non-reciprocal under the Mineral Act.

Table of Contents

Our pipelines used to gather and transport our oil and gas are subject to regulation by the Department of Transportation (DOT) under the Hazardous Liquids Pipeline Safety Act of 1979, as amended (HLPSA) relating to the design, installation, testing, construction, operation, replacement and management of pipeline facilities. The HLPSA requires us and other pipeline operators to comply with regulations issued pursuant to HLPSA designed to permit access to and allowing copying of records and to make certain reports and provide information as required by the Secretary of Transportation.

The Pipeline Safety Act of 1992 (The Pipeline Safety Act) amends the HLPSA in several important respects. It requires the Research and Special Programs Administration (RSPA) of DOT to consider environmental impacts, as well as its traditional public safety mandate, when developing pipeline safety regulations. In addition, the Pipeline Safety Act mandates the establishment by DOT of pipeline operator qualification rules requiring minimum training requirements for operators, and requires that pipeline operators provide maps and records to RSPA. It also authorizes RSPA to require certain pipeline modifications as well as operational and maintenance changes. We believe our pipelines are in substantial compliance with HLPSA and the Pipeline Safety Act. Nonetheless, significant expenses would be incurred if new or additional safety measures are required.

Environmental Regulation

General. Our activities are subject to existing federal, state and local laws and regulations governing environmental quality and pollution control in the United States and may be subject to laws and regulations of the Republic of Congo, West Africa. It is anticipated that, absent the occurrence of an extraordinary event, compliance with existing federal, state and local laws, rules and regulations governing the release of materials in the environment or otherwise relating to the protection of the environment will not have a material effect upon our operations, capital expenditures, earnings or competitive position.

Our activities with respect to exploration, drilling and production from wells, natural gas facilities, including the operation and construction of pipelines, plants and other facilities for transporting, processing, treating or storing natural gas and other products, are subject to stringent environmental regulation by state and federal authorities including the Environmental Protection Agency (EPA). Such regulation can increase the cost of planning, designing, installing and operating such facilities. In most instances, the regulatory requirements relate to water and air pollution control measures. (See Note 13 to the Notes to the Consolidated Financial Statements).

With respect to our oil and gas operations in California, we have significant exit cost liabilities. These liabilities include costs for dismantlement, rehabilitation and abandonment. We are not indemnified for any part of these exit costs. (See Note 3 to the Notes to the Consolidated Financial Statements).

Waste Disposal. We currently own or lease, and have in the past owned or leased, numerous properties that have been used for production of oil and gas for many years. Although we utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons or other wastes may have been disposed of or released on or under the properties that we currently own or lease or properties that we have in the past owned or leased. In addition, many of these properties have been operated by third parties over whom we had no control as to such entities treatment of hydrocarbons or other wastes or the manner in which such substances may have been disposed of or released. State and federal laws applicable to oil and gas wastes and properties have become stricter. Under new laws, we could be required to remediate property, including ground water, containing or impacted by previously disposed wastes (including wastes disposed of or released by prior owners or operators) or to perform remedial plugging operations to prevent future or mitigate existing contamination.

We may generate wastes, including hazardous wastes that are subject to the federal Resource Conservation and Recovery Act (RCRA) and comparable state statutes. The EPA has limited the disposal options for certain wastes that are designated as hazardous under RCRA (Hazardous Wastes). Furthermore, it is possible that certain wastes generated by our oil and 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 more rigorous and costly operating and disposal requirements.

Table of Contents

Superfund. The federal Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), also known as the Superfund law, generally imposes joint and several liability for costs of investigation and remediation and for natural resource damages, without regard to fault or the legality of the original conduct, on certain classes of persons with respect to the release into the environment of substances designated under CERCLA as hazardous substances (Hazardous Substances). These classes of persons or so-called potentially responsible parties (PRP s) include the current and certain past owners and operators of a facility where there is or has been a release or threat of release of a Hazardous Substance and persons who disposed of or arranged for the disposal of the Hazardous Substances found at such a facility. CERCLA also authorizes the EPA and, in some cases, third parties to take actions in response to threats to the public health or the environment and to seek to recover from the PRP s the costs of such action. Although CERCLA generally exempts petroleum from the definition of Hazardous Substances in the course of our operations, we may have generated and may generate wastes that fall within CERCLA s definition of Hazardous Substances. We may also be an owner of facilities on which Hazardous Substances have been released by previous owners or operators. We may be responsible under CERCLA for all or part of the costs to clean up facilities at which such substances have been released and for natural resource damages. Crude oil exempt under Superfund may be modified increasing compliance costs. We have not, to our knowledge been named a PRP under CERCLA nor do we know of any prior owners or operators of our properties that are named as PRP s related to their ownership or operation of such property.

Air Emissions. Our operations are subject to local, state and federal regulations for the control of emissions of air pollution. Local air quality districts do much of the air quality regulation of sources in California. California requires new and modified sources of air pollutants to obtain permits prior to commencing construction. Major sources of air pollutants are subject to more stringent, federally imposed permitting requirements, including additional permits. Because of the severity of the ozone (smog) problems in portions of California, the state has the most severe restrictions on the emissions of volatile organic compounds (VOC) and nitrogen oxides (Nox) of any state. Producing wells, gas plants and electric generating facilities, all of which are owned by us generate VOC and Nox. Some of our producing wells are in counties that are designated as nonattainment for ozone and are therefore potentially subject to restrictive emission limitations and permitting requirements. If the ozone problems in the state are not resolved by the deadlines imposed by the federal Clean Air Act (2005 2010), or on schedule to meet the standards even more restrictive requirements may be imposed including financial penalties based upon the quantity of ozone producing emissions. California also operates a stringent program to control hazardous (toxic) air pollutants, which might require installation of additional controls. Administrative enforcement actions for failure to comply strictly with air pollution regulations or permits are generally resolved by payment of monetary fines and correction of any identified deficiencies. Alternatively, regulatory agencies could require us to forego construction, modification or operation of certain air emission sources, although we believe that in the latter cases we would have enough permitted or permittable capacity to continue our operations without a material adverse effect on any particular producing field.

Clean Water Act. The Clean Water Act (CWA) imposes restrictions and strict controls regarding the discharge of wastes, including produced waters and other oil and natural gas wastes, into waters of the United States, a term broadly defined. These controls have become more stringent over the years, and it is probable that additional restrictions will be imposed in the future. Permits must be obtained to discharge pollutants into federal waters. The CWA provides for civil, criminal and administrative penalties for unauthorized discharges of oil, hazardous substances and other pollutants. It imposes substantial potential liability for the costs of removal or remediation associated with discharges of oil or hazardous substances. State laws governing discharges to water also provide varying civil, criminal and administrative penalties and impose liabilities in the case of a discharge of petroleum or it derivatives, or other hazardous substances, into state waters. In addition, the EPA has promulgated regulations that may require us to obtain permits to discharge storm water runoff, including discharges associated with construction activities. In the event of an unauthorized discharge of wastes, we may be liable for penalties and costs.

Oil Pollution Act. The Oil Pollution Act of 1990 (OPA), which amends and augments oil spill provisions of CWA, imposes certain duties and liabilities on certain responsible parties related to the prevention of oil spills and damages resulting from such spills in United States waters and adjoining shorelines.

Table of Contents

A liable   responsible party   includes the owner or operator of a facility or vessel, that is a source of an oil discharge or poses the substantial threat of discharge, or the lessee or permittee of the area in which a facility covered by OPA is located. OPA assigns joint and several liability, without regard to fault, to each liable party for oil removal costs, remediation of environmental damage and a variety of public and private damages. Few defenses exist to the liability imposed by OPA. In the event of an oil discharge, or substantial threat of discharge from our properties, vessels and pipelines, we may be liable for costs and damages.

The OPA also imposes ongoing requirements on a responsible party, including proof of financial responsibility to cover at least some costs of a potential spill. Certain amendments to the OPA that were enacted in 1996 require owners and operators of offshore facilities that have a worst case oil spill potential of more than 1,000 barrels to demonstrate financial responsibility in amounts ranging from $10 million in specified state waters and $35 million in federal outer continental shelf waters, with higher amounts, up to $150 million based upon worst case oil-spill discharge volume calculations. We believe that we currently have established adequate proof of financial responsibility for our offshore facilities.

California Coastal Act. The California Coastal Act regulates the conservation and development of California s coastal resources. The California Coastal Commission (The Commission) works with local government to make permit decisions for new development in certain coastal areas and reviews local coastal programs, such as land use restrictions. The Commission also works with the California State Office of Oil Spill Prevention and Response to protect against and respond to coastal oil spills. The Commission has direct regulatory authority over offshore oil and gas development within the State s three mile jurisdiction and has authority, through the Federal Coastal Zone Management Act, over federally permitted projects that affect the State s coastal zone resources. We conduct activities that may be subject to the California Coastal Act and the jurisdiction of The Commission.

Our management believes that we are in substantial compliance with current applicable environmental laws and regulations and that continued compliance will not have a material adverse impact on us.

Competition

We operate in the highly competitive areas of oil and gas exploration, development and production. The availability of funds and information relating to a property, the standards established by us for the minimum projected return on investment and the availability of alternate fuel sources are factors that affect our ability to compete in the marketplace. Competitors include major integrated oil companies and a substantial number of independent energy companies, many of which possess greater financial and other resources. We compete to acquire producing properties, exploration leases, licenses, concessions and marketing agreements.

Personnel

At December 31, 2003, we had 397 full time employees.

Item 2. ***Properties***

A description of our properties is included in Item 1, Business, and is incorporated herein by reference.

Item 3. ***Legal Proceedings***

See Item 7, Management s Discussion and Analysis of Financial Condition and Results of Operations, which is incorporated herein by reference.

Item 4. ***Submission of matters to a vote of security holders***

None.

Table of Contents

PART II

Item 5. ***Market for the Registrant s Common Equity and Related Stockholder Matters***

Our common stock is traded on the New York Stock Exchange under the Symbol NEV. On February 27, 2004, we had 20,318,979 shares of common stock outstanding. There were approximately 927 stockholders of record and approximately 3,378 additional beneficial owners as of February 27, 2004. We have not paid dividends on our common stock and do not anticipate paying cash dividends in the immediate future. In addition, certain restrictions contained in our financing arrangements restrict the payment of dividends. See Note 9 to the Notes to Consolidated Financial Statements. The high and low recorded prices of our common stock during 2003 and 2002 are presented in the following table.

	Market Price	
	High	**Low**
2003		
First Quarter	$ 13.55	$ 10.63
Second Quarter	18.01	12.55
Third Quarter	19.65	15.73
Fourth Quarter	24.95	18.69
2002		
First Quarter	$ 15.58	$ 13.15
Second Quarter	16.45	13.60
Third Quarter	15.90	9.00
Fourth Quarter	14.55	10.56

Treasury Stock Repurchases

Our Board of Directors had authorized the open market repurchase of up to 5.6 million shares of common stock. Repurchases may be made at times and at prices deemed appropriate by management and consistent with the authorization of our Board. There have been no shares repurchased since 2001. As of December 31, 2003, we had 3.5 million shares of treasury stock, which shares will be cancelled should the merger with Plains be consummated.

Shareholder Rights Plan

In 1997, we adopted a Shareholder Rights Plan (Rights Plan) to protect our shareholders from coercive or unfair takeover tactics. In February 2004, the Board of Directors approved the amendment of the rights plan to permit a merger with Plains without triggering the provisions of the rights plan.

Executive Compensation Plan

In 1997, we adopted a plan to encourage senior executives to personally invest in our common stock, and to regularly review executives ownership versus targeted ownership objectives. These incentives include a deferred compensation plan that gives key executives the ability to defer all or a portion of their salaries and bonuses and invest in our common stock or make other investments at the employee s discretion. All common stock acquired is held in a benefit trust. Target levels of ownership are based on multiples of base salary and are administered by the Compensation Committee of the Board of Directors. The deferred compensation plan applies to certain highly compensated employees and all executives at a level of Vice President and above. The deferred compensation plan was amended in 2003 to offer a 15% discount on investments in our common stock up to $30,000 annually.

Table of Contents

Item 6. ***Selected Financial Data***

The following selected financial data should be read in conjunction with the consolidated financial statements and supplementary information included in Item 8, Financial Statements and Supplementary Data.

	As of and for the Years ended December 31,				
	2003	2002	2001	2000	1999
	(In thousands, except per share data)				
Operating Results Data					
Revenues					
Oil and gas revenues	$369,975	$307,831	$310,806	$268,799	$208,003
Other	1,362	4,070	273	2,358	4,778
Total revenues	371,337	311,901	311,079	271,157	212,781
Costs and expenses					
Lease operating expense	159,832	132,954	160,086	135,087	120,328
Exploration	2,115	4,541	22,058	9,774	14,017
Depreciation, depletion, amortization and accretion	70,810	73,128	70,554	58,248	69,703
Impairments[1]			103,490		
General and administrative	28,457	25,877	36,904	32,974	32,266
Interest expense	29,793	37,943	43,006	37,472	33,110
Loss on early extinguishment of debt[2]	12,578				
Dividends on TECONS[3]	6,613	6,613	6,613	6,613	6,613
Income (loss) from continuing operations	37,089	23,079	(91,371)	(6,878)	25,415
Income (loss) from discontinued operations, including gain/loss on disposal, net of income taxes	5,894	(10,804)	12,200	19,309	6,027
Cumulative effect of a change in accounting principle, net of income tax[4]	8,496			(796)	
Net income (loss)[5]	51,479	12,275	(79,171)	11,635	31,442
Earnings Per Share					
Basic	2.66	0.70	(4.73)	0.67	1.62
Diluted	2.62	0.69	(4.73)	0.64	1.61
Financial Position Data					
Total assets	$844,976	$855,171	$839,812	$848,024	$760,030
Senior Subordinated Notes	225,000	409,577	409,577	409,727	259,750
Bank Credit Facility	15,000	28,700	41,500		81,000
Long-term liability to unconsolidated affiliate[3]	115,000				
Total debt	355,000	438,277	451,077	409,727	340,750
Interest rate swaps fair value adjustment	(153)	2,161	(633)		
Interest rate swaps termination gain[6]	14,364	11,673			
Long-term debt	369,211	452,111	450,444	409,727	340,750
Company-Obligated Mandatorily Redeemable Convertible Preferred Securities of Nuevo Financing I		115,000	115,000	115,000	115,000

(TECONS)[3]

(1) The impairment in 2001 related to our Santa Clara, Huntington Beach, Pitas Point, Masseko (Congo) and Point Pedernales fields and certain other oil and gas properties.

Table of Contents

(2) During 2003, we repaid $184.6 million of our 9 1/2% Senior Subordinated Notes due in 2006 and 2008 and paid a premium of $8.7 million to call the notes prior to their maturity. Additionally, we expensed the unamortized financing costs related to the retired notes of $3.9 million.

(3) The adoption of FIN 46R, *Consolidation of Variable Interest Entities*, at December 31, 2003 required us to deconsolidate our investment in Nuevo Financing I and our TECONS. See Note 2 to the Notes to the Consolidated Financial Statements. As a result, our 5 3/4% Convertible Subordinated Debentures due December 15, 2026 are included in our long-term debt as long-term liability to an unconsolidated affiliate at December 31, 2003. Additionally, dividends on the TECONS will no longer be reported in our results of operations but instead will be reflected as interest expense on long-term liability to unconsolidated affiliate.

(4) In January 2003, we adopted SFAS No. 143. In connection with the initial application, we recorded a cumulative effect of change in accounting principle, net of taxes, of approximately $8.5 million as an increase to income. (See Note 3 to Consolidated Financial Statements).

(5) No common stock dividends have been declared since our formation. See Note 7 to the Notes to Consolidated Financial Statements concerning restrictions on the payment of common stock dividends.

(6) During 2003 and 2002 we terminated interest rate swap agreements that hedged our 9 1/2% and 9 3/8% Senior Subordinated Notes resulting in a termination gain of $14.4 million in 2003 and $11.7 million in 2002.

Table of Contents

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

Nuevo Energy is engaged in the acquisition, exploitation, development, exploration and production of crude oil and natural gas. Our core areas in the U.S. are onshore and offshore California and West Texas. We also have international crude oil production offshore the Republic of Congo. The following review should be read in conjunction with our Consolidated Financial Statements and Notes thereto.

Proposed Merger with Plains Exploration and Production Company

On February 12, 2004, we entered into an agreement and plan of merger under the terms of which it is anticipated that we will be merged with Plains Exploration & Production Company (Plains) or alternatively become a wholly owned subsidiary of Plains. Under the terms of the agreement, our stockholders will receive 1.765 shares of Plains common stock in exchange for each Nuevo common share. Following the merger, it is expected that our stockholders will own 47% of the combined company. The proposed merger is subject to approval by the stockholders of both companies as well as other customary closing conditions.

Executive Summary 2003 Operational and Financial Highlights

In 2003, we increased production from continuing operations by 4% to 48,800 BOE per day compared to 2002, while at the same time maintaining discipline over capital spending. In fact, our capital spending (excluding acquisitions) was $66.7 million in 2003 compared to $80.2 million in 2002. Both crude oil and natural gas prices were up in 2003 compared to 2002. Our realized crude oil and liquids price increased 11% from 2002, and our realized natural gas price was up 46% versus 2002. Strong commodity prices combined with higher production contributed to a 19% increase in revenues and a 61% increase in income from continuing operations.

Within this environment we achieved our top priorities for the year of monetizing non-core assets and transforming our balance sheet by reducing our long-term debt. In 2003, we sold three non-core oil and gas properties in California: Brea-Olinda ($59.0 million), Orcutt Hill ($12.9 million) and Union Island ($10.5 million). In addition, in December 2003 we sold two real estate properties in California: the Tonner Hills development project ($47 million) and the Orcutt office building and contiguous acreage ($2.9 million). With regard to the $47 million sales price for Tonner Hills, we received $16 million in December, we expect to receive $22.5 million in late March 2004, and we will receive $8.5 million when we complete habitat restoration activities.

We used the cash proceeds from these non-core asset sales, combined with net cash from operating activities, to transform our balance sheet by reducing long-term debt by $198.3 million during 2003. We redeemed $184.6 million of our high cost debt (9 1/2% Notes) and paid down $13.7 million of our bank debt. This debt reduction reduced our interest expense in 2003 by $8.2 million compared to 2002. We did, however, incur $12.6 million in costs associated with the early extinguishment of our Notes.

In addition to debt reduction, our balance sheet was also aided by the higher commodity prices and increased production as we recorded net income of $51.5 million and increased stockholders equity by $47.6 million during 2003.

Table of Contents

Results of Operations

Our results of operations are significantly affected by fluctuations in oil and gas prices. The following table reflects our production and average prices for crude oil and natural gas:

	Year Ended December 31,		
	2003	2002	2001
Crude Oil and Liquids			
Sales Volumes (MBbls/d)			
Domestic	37.6	36.5	36.0
International	4.8	5.1	5.2
Total	42.4	41.6	41.2
Sales Prices ($/Bbl)			
Unhedged	$ 23.19	$ 18.83	$ 19.01
Hedged	20.30	18.21	15.84
Revenues ($/thousands)			
Domestic	$315,619	$254,877	$250,627
International	42,953	31,967	36,015
Marketing Fees	(6)	(936)	(957)
Hedging	(44,681)	(9,414)	(47,558)
Total	$313,885	$276,494	$238,127
Natural Gas			
Sales Volumes (MMcf/d)			
Domestic	38.5	31.5	27.2
Sales Prices ($/Mcf)			
Unhedged	$ 4.14	$ 2.73	$ 7.31
Hedged	3.99	2.72	N/A
Revenues ($/thousands)			
Domestic	$ 58,924	$ 32,176	$ 73,617
Marketing Fees	(697)	(790)	(938)
Hedging	(2,137)	(49)	
Total	$ 56,090	$ 31,337	$ 72,679

Year Ended December 31, 2003 Compared to Year Ended December 31, 2002

We reported net income of $51.5 million, or $2.62 per diluted share for 2003 as compared to net income of $12.3 million, or $0.69 per diluted share for 2002.

Revenues

Oil and Gas Revenues. Oil and gas revenues increased 20% to $370.0 million in 2003 from $307.8 in 2002, due to higher oil and gas prices and volumes. The realized oil price was $20.30 per Bbl, an increase of $2.09 per Bbl from 2002. Crude oil production averaged 42.4 MBbls/day in 2003, an increase of 0.8 MBbls/day from 2002. The increased production was due to a full year of production from the Athanor acquisition

(Pakenham field), additional interest purchased in our Point Pedernales property offshore California and the results of our drilling program onshore California in our Belridge Field. The increase was offset by natural production decline in onshore and offshore California and production curtailed for our drilling and workover program onshore California. We incurred hedging losses related to oil sales of $44.7 million in

Table of Contents

2003 compared to hedging losses of $9.4 in 2002. In 2002, we implemented a new hedging strategy based on our pricing model which provides that we hedge an increased amount of production as market prices increase. Our pricing model did not plan for market prices to climb near historical highs; as a result, we fully hedged the amount of oil permitted under our hedging strategy as prices continued to rise. The hedge loss is determined by comparing year end market price to hedge price. Natural gas production averaged 38.5 MMcf/day in 2003, an increase of 22% from 31.5 MMcf/day in 2002 primarily due to a full year of production from the Athanor acquisition, partially offset by production declines from our offshore California properties. The realized natural gas price in 2003 was $3.99 per Mcf, up 47% from $2.72 in 2002. Our hedging of gas production commenced with our acquisition of Athanor and we had a hedging loss related to natural gas sales of $2.1 million in 2003; our loss is due to events similar to our oil hedge loss.

Other Revenue. Other revenue of $1.4 million in 2003 was $2.7 million lower than 2002 which included the receipt of $3.0 million of business interruption insurance recoveries.

Costs and Expenses

	2003	2002	Variance Amount	Variance Percentage
Lease operating expenses	$159,832	$132,954	$26,878	20%
Exploration costs	2,115	4,541	(2,426)	(53%)
Depletion, depreciation, amortization and accretion	70,810	73,128	(2,318)	(3%)
General and administrative	28,457	25,877	2,580	10%
Loss on assets held for sale		1,253	(1,253)	(100%)
Other	1,256	1,930	(674)	(35%)
Loss (gain) on disposition of properties	(5,824)	(16,588)	10,764	(65%)
	$256,646	$223,095	$33,551	15%
Lease Operating Expense per BOE	$ 8.98	$ 7.77	$ 1.21	16%
Domestic	9.31	8.03	1.28	16%
International	5.96	5.71	0.25	4%

Costs and Expenses. Lease operating expenses (LOE) of $159.8 million in 2003 increased 20% from 2002. The increase in LOE is primarily due to the increase in the cost of producing steam, which uses natural gas as a feedstock and is injected into reservoirs to facilitate the production of heavy California oil. Additionally, LOE increased due to a full year of field costs included for the Pakenham field and additional interest purchased in the Point Pedernales field. Exploration costs of $2.1 million in 2003 were $2.4 million lower than 2002 as the $2.3 million write off of the Anaguid permit in Tunisia was included in 2002. Depreciation, depletion, amortization and accretion (DD&A) was $70.8 million in 2003 compared to $73.1 million in 2002. The decrease is primarily due to a reduction in the depletion rate from $4.28 per BOE in 2002 to $3.98 per BOE in 2003, caused by sales of assets with higher cost per BOE which was partially offset by increased production without a corresponding increase in proved reserves. The decrease in the depletion rate is also offset by accretion of asset retirement obligation of approximately $9.1 million as a result of the implementation of SFAS No. 143, *Accounting for Asset Retirement Obligations*, which we adopted on January 1, 2003. General and administrative costs increased to approximately $28.5 million in 2003 from $25.9 million in 2002 due to higher employee expenses related to the attainment of bonus targets, and non-cash costs associated with the issuance of restricted stock in January 2003. Both incentives related to our improved performance.

Gain on Disposition of Properties. Our net gain from the disposition of properties in 2003 of $5.8 million included $4.5 million from the release of escrow related to the sale of Ventura properties in 1999, and $1.5 million from sale of our Orcutt office building in California.

Table of Contents

Derivative Loss. Our derivative loss in 2003 was approximately $5.8 million, primarily made up of mark to market on derivative instruments that do not qualify as a hedge under SFAS 133.

Interest Expense. Interest expense of approximately $29.8 million, a decrease of $8.1 million from $37.9 million in 2002 is due to the repayment of $184.6 million of 9 1/2% Senior Subordinated Notes due in 2006 and 2008.

Loss from the Early Extinguishment of Debt. During 2003, we repaid $184.6 million of our 9 1/2% Senior Subordinated Notes due in 2006 and 2008 and paid a premium of $8.7 million to call the notes prior to their maturity. Additionally, we expensed the unamortized financing costs related to the retired notes of $3.9 million.

Dividends on TECONS. Dividends on the TECONS were $6.6 million in 2003 and 2002. The TECONS pay dividends at a rate of 5.75% (See Note 10 to the Notes to Consolidated Financial Statements.)

Income Tax. Income tax expense was $23.1 million including current tax of $2.1 million in 2003 compared to $16.7 million in 2002 which had $1.3 million of current tax. Our effective income tax rate was 39.2% in 2003 and 41.7% in 2002.

Discontinued Operations. We had income from discontinued operations of $5.9 million in 2003 compared to a loss of $10.8 million in 2002. In 2003, we sold our Brea-Olinda, Union Island and Orcutt Hill properties located onshore California. We had total revenue from operations of these properties of $11.4 million, a gain on sale of Union Island of $7.9 million and loss on sale of Orcutt Hill of $4.6 million. In 2002, the income from discontinued operations consisted of after-tax operating income from our Eastern properties which were sold in 2002 and operating income from the Brea-Olinda, Union Island and Orcutt Hill properties.

Cumulative Effect of Change in Accounting Principle. In January 2003, we adopted SFAS No. 143. In connection with the initial application, we recorded a cumulative effect of change in accounting principle, net of taxes, of $8.5 million as an increase to income (See Note 3 to the Consolidated Financial Statements). As a result of adopting FIN46R, *Consolidation of Variable Interest Entities,* at December 31, 2003, we are required to deconsolidate the Nuevo Financing I Business Trust which issued our TECONS. As a result, our 5.75% Convertible Subordinated Debentures due December 15, 2026 are included in our long-term debt as a long-term liability to an unconsolidated affiliate. Additionally, dividends on the TECONS will no longer be reported in our results of operations and instead will be reflected as interest expense on long-term liability to unconsolidated affiliate beginning in 2004.

Year Ended December 31, 2002 Compared to Year Ended December 31, 2001

We reported net income of $12.3 million, or $0.69 per diluted share for 2002 as compared to a net loss of $79.2 million, or ($4.73) per diluted share in 2001.

Revenues

Oil and Gas Revenues. Oil and gas revenues were $307.8 million in 2002 compared to $310.8 million in 2001 principally due to lower natural gas prices in 2002 which were partially offset by higher crude oil prices realized, lower hedging losses and higher crude oil and natural gas production in 2002. The realized oil price in 2002 was $18.21 per Bbl, an increase of $2.37 per Bbl from 2001. Crude oil production averaged 41.6 MBbls/day in 2002, an increase of 0.4 MBbls/day from 2001. The increased production was due to higher production at Point Pedernales and Santa Clara due to improved performance which was partially offset by lower production at Cymric where production was curtailed for well repairs. We reported a hedging loss related to crude oil sales of $9.4 million in 2002 compared to a hedging loss of $47.6 million in 2001. Natural gas production averaged 31.5 MMcf per day in 2002, an increase of 16% from 27.2 MMcf per day in 2001 primarily due to production from the Pakenham field acquired in September 2002. The realized natural gas price in 2002 was $2.72 per Mcf, which decreased 63% from $7.31 per Mcf in 2001.

Table of Contents

Other Revenue. Other revenue of $4.1 million in 2002 was $3.8 million higher than 2001 principally due to $3.0 million of business interruption insurance recoveries received in 2002, related to the repair of our pipelines at the Point Pedernales field.

Costs and Expenses

	2002	2001	Variance Amount	Variance Percentage
Lease operating expenses	$132,954	$160,086	$ (27,132)	(17%)
Exploration costs	4,541	22,058	(17,517)	(79%)
Depletion, depreciation and amortization	73,128	70,554	2,574	4%
Impairment of oil and gas properties		103,490	(103,490)	(100%)
General and administrative	25,877	36,904	(11,027)	(30%)
Restructuring and severance charges		4,859	(4,859)	(100%)
Loss on assets held for sale	1,253	3,494	(2,241)	(64%)
Other	1,930	14,928	(12,998)	(87%)
Loss (gain) on disposition of properties	(16,588)	(882)	(15,706)	1781%
	$223,095	$415,491	$(192,396)	(46%)
Lease Operating Expense per BOE	$ 7.77	$ 9.59	$ (1.82)	(19%)
Domestic	8.03	9.87	(1.84)	(19%)
International	5.71	7.44	(1.73)	(23%)

Costs and Expenses. Lease operating expenses (LOE) of $133.0 million in 2002 decreased 17% from 2001. We use gas as a feedstock to generate steam which is injected into reservoirs to facilitate the production of heavy California oil. Excluding the cost of steam used in our oil production operations, LOE decreased 12% in 2002 compared to 2001. Exploration costs of $4.5 million in 2002 were $17.6 million lower than $22.1 million in 2001. The 2002 exploration costs included a $2.3 million non-cash write off of the Anaguid permit in Tunisia which was conveyed to third parties while the 2001 costs included $14.1 million of dry hole costs. Depreciation, depletion and amortization (DD&A) was $73.1 million in 2002 compared to $70.6 million in the prior year primarily due to higher production and a higher DD&A rate. The DD&A rate was $4.28 per BOE in 2002 compared to $4.23 per BOE in 2001. We had no impairments in 2002 compared to $103.5 million in 2001. The impairment in 2001 related to our Santa Clara, Huntington Beach, Pitas Point, Masseko (Congo) and Point Pedernales fields and certain other oil and gas properties. Due to lower outsourcing costs, legal fees and project costs, general and administrative expense of $25.9 million in 2002 was $11.0 million lower than 2001. In 2002, there were no restructuring and severance charges as compared to $4.9 million in 2001. The 2001 restructuring charges of $4.9 million were related to the termination of two outsourcing contracts and the reorganization of our exploration and production operations. Other expenses were $1.9 million in 2002 compared to $14.9 million in 2001 which included the termination of hedging contracts with Enron and various consulting and legal costs.

Loss on Assets Held for Sale. In 2002, we made the decision to sell certain real estate in California. Accordingly, we transferred the underlying net book value of this real estate to assets held for sale and recorded a $1.3 million loss, representing the write down to its estimated fair market value, less costs to sell. In 2001, we made the decision not to proceed with our power plant project in Santa Barbara and Kern County California and transferred our remaining equipment to assets held for sale and recorded a $3.5 million loss representing the write down to estimated fair market value less estimated costs to sell these assets. (See Note 5 to the Consolidated Financial Statements.)

Gain on Disposition of Properties. Our net gain from the sales of assets for 2002 of $16.6 million was primarily related to the settlement agreement with ExxonMobil, where we conveyed to them our interest in the Santa Ynez Unit, our non-consent interest in the adjacent Pescado field and relinquished our right to participate in the Sacate field, all of which were classified as unproved properties. In 2001, the gain on

Table of Contents

disposition of properties of $0.9 million is primarily related to the gain of $1.1 million from our sale of a parcel of real estate in Brea, California.

Derivative Gain (Loss). Our derivative loss was in 2002 $4.7 million primarily comprised of mark-to-market losses on derivatives which did not qualify as hedges under SFAS 133 and ineffectiveness on hedges.

Interest Expense. Interest expense of $37.9 million in 2002 decreased 12% compared to interest expense of $43.0 million in 2001 due to the benefit of our interest rate swaps in 2002 of $5.4 million.

Dividends on TECONS. Dividends on the TECONS were $6.6 million in 2002 and 2001. The TECONS pay dividends at a rate of 5 3/4%. (See Note 8 to the Notes to Consolidated Financial Statements.)

Income Tax. We had income tax expense of $16.7 million including current tax of $1.3 million in 2002 compared to a tax benefit of $61.1 million in 2001 which had no current tax. The current tax relates to California State income tax which deferred the use of net operating losses for two years. Our effective income tax rate was 41.7% in 2002 and 40.1% in 2001.

Discontinued Operations. We had a loss from discontinued operations of $10.8 million in 2002 compared to income of $12.2 million in 2001. In 2002, we sold our properties located in Texas, Alabama and Louisiana (Eastern properties) for approximately $9.0 million and recognized a $0.9 million after-tax loss. We also made the decision to sell our Brea-Olinda field in California in 2002 and recognized a $30.5 million loss in connection with writing down the associated assets to their estimated fair value less our costs to sell them. In 2001 the income from discontinued operations consists of after-tax operating income from our Eastern properties, Brea-Olinda, Union Island and Orcutt fields.

Capital Resources and Liquidity

Our principal requirements for cash, other than working capital needs for existing operations, are costs of development of oil and gas properties, retirement of higher cost debt and the acquisition of oil and gas properties. We have historically funded our development program, debt repayments and acquisitions with cash flow from operations, bank financing, public and private placements of debt and equity securities, property divestitures and joint ventures with industry participants. We believe that our liquidity and capital resources are sufficient to meet our obligations.

At December 31, 2003, our current liabilities exceeded our current assets due primarily to the mark-to- market on our price risk management activities, which resulted in a current liability of $35 million. We anticipate paying our hedging liability with cash from operations.

Cash flow

	2003	2002	2001
		(In thousands)	
Net cash provided by operating activities	$ 165,781	$ 122,728	$ 88,894
Net cash provided by (used in) investing activities	36,043	(114,514)	(164,093)
Net cash provided by (used in) financing activities	(200,595)	(10,277)	42,862

Year Ended December 31, 2003 Compared to Year Ended December 31, 2002

Operating cash flow increased due to revenue increases as a result of improved pricing for oil and natural gas and increased production from our properties, which was partially offset by increased lease operating costs. Oil and liquids prices improved 11%, while production improved 2%. Gas prices improved 47% while production improved approximately 22%. Lease operating costs increased $26.9 million primarily due to higher steam costs and field costs for our Pakenham field purchased in 2002 and acquisition of an additional interest in Point Pedernales.

We generated $36.0 million of cash flow from investing activities during 2003 as a result of asset sales of approximately $101 million, an increase from $74 million in the prior year, as a result of the sale of our Brea-

21

Olinda, Union Island and Orcutt Hill properties. Additionally, less cash was used in additions to oil and gas properties as management continues to contain costs and be selective in spending. 2002 cash used included $61 million to purchase Athanor, and no similar acquisition was made in 2003.

Cash used in financing activities increased $190.3 million due to the repayment of the 9 1/2% Senior Subordinated Notes due 2006 and 2008 and bank debt, which was partially offset by an increase in proceeds from issuance of common stock of approximately $5.1 million.

Year Ended December 31, 2002 Compared to December 31, 2001

Operating cash flow improved due to containment of cash operating expenses, including lease operating, exploration and general and administrative expenses. Lease operating expense decreased $27.1 million, exploration expense decreased $17.5 million and general and administrative expense decreased $11.0 million principally due to the termination of the California exploration program and terminating outsource agreements for the California field operations, accounting, treasury and land administration.

Cash flow used in investing activities decreased due a $58.8 million reduction in additions to oil and gas properties, offset by a $32.9 million increase in acquisitions in 2002. The reduction in additions to oil and gas properties resulted from the implementation of a more disciplined capital allocation process. In 2002 we acquired Athanor resources for $61.3 million cash plus other consideration, compared to 2001 purchase of additional acreage in Kern County, California for $28.5 million. Additionally, proceeds from the sale of properties increased $20.8 million in 2002, as a result of the sale of our Eastern properties.

Asset Dispositions

Proceeds from asset dispositions were $101 million, $27 million and $6 million during 2003, 2002 and 2001 as management has actively sought buyers for our non-core and marginal assets. In 2003, we sold three non-core oil and gas properties in California: Brea-Olinda ($59.0 million), Orcutt Hill ($12.9 million) and Union Island ($10.5 million).

We disposed of a significant portion of our remaining real estate portfolio in 2003, including our Tonner Hills residential development property for approximately $47 million on December 30, 2003. We received $16 million of the purchase price on the sale date, which we included in other current liabilities as a deposit related to the purchase. We anticipate receiving an additional $22.5 million on March 29, 2004, and this amount will also be reflected as a deposit. The remaining $8.5 million will be received by us once we have completed certain habitat restoration. Because of the continuing involvement with Tonner Hills, we have not recorded this transaction as a sale in 2003. We currently have assets held for sale of approximately $38.3 million including $36.3 million related to Tonner Hills and $2.0 million related to parcels of real estate in California which we expect to sell in 2004.

Credit Facility

Our bank credit facility provides for secured revolving credit availability including issuance of letters of credit of up to $250 million from a bank group led by Bank of America, NA; Bank One, NA and Bank of Montreal, and expires on June 7, 2005. At year end 2003, we had $15 million outstanding under the Credit Facility and two letters of credit outstanding in the amount of $1.6 million. Amounts borrowed under the credit facility bear interest at a rate of 2.02%.

Availability under the Credit Facility is determined pursuant to a semi-annual borrowing base determination which establishes the maximum borrowings that may be outstanding under the Credit Facility. The borrowing base is determined by a 60% vote of participant banks (two-thirds in the event of an increase in the borrowing base), each of which bases its judgment on: (i) the present value of our oil and gas reserves based on their own assumptions regarding future prices, production, costs, risk factors and discount rates, and (ii) projected cash flow coverage ratios calculated under varying scenarios. If amounts outstanding under the Credit Facility exceed the borrowing base, as redetermined from time to time, we would be required to repay such excess over a defined period of time. We have a $200.0 million borrowing base under our Credit Facility with $183.4 million available at December 31, 2003.

Our Credit Agreement has covenants which limit certain restricted payments and investments, guarantees and indebtedness, prepayments of subordinated and certain other indebtedness, mergers and consolidations, on certain types of acquisitions and on the issuance of certain securities by subsidiaries, liens, sales of properties, transactions with affiliates, derivative contracts and debt in subsidiaries. We are also required to maintain certain financial ratios and conditions, including without limitation, an EBITDAX to fixed charge coverage ratio and a funded debt to capitalization ratio. At December 31, 2003, we were in compliance with all covenants of the Credit Agreement.

EBITDAX to fixed charge coverage ratio. At December 31, 2003, based on bank covenants, the EBITDAX to fixed charge coverage ratio was 5.0x, compared to 3.7x in 2002 and 2.7x in 2001. Our Credit Agreement requires the EBITDAX to fixed charge coverage ratio to be 2.0x at December 31, 2003.

Funded debt to capitalization ratio. At December 31, 2003, based on bank covenants, total capitalization is approximately $635 million, consisting of approximately $240 million of debt and approximately $395 million of equity, resulting in a debt to capitalization ratio of 38% compared to 57% in 2002 and 62% in 2001. The improvement in our debt to capitalization ratio is due to the repayment of approximately $183 million of our 9 1/2% Senior Subordinated Debt due 2008 and the remaining $2 million of our 9 1/2% Senior Subordinated Debt due 2006. The improvement in our debt to capitalization ratio in 2002 from 2001 is due to a reduction in the credit facility of approximately $13 million, increased common stock outstanding as a result of the Athanor acquisition of approximately $20 million and improved net income, resulting in an increase in retained earnings of approximately $12 million.

During February 2004, we repaid the remaining $75 million on our 9 1/2% Senior Subordinated Debt due 2008, which will improve our funded debt to capitalization ratio.

Senior Subordinated Notes

At December 31, 2003 we had senior subordinated notes outstanding of $225 million, including $75 million of our 9 1/2% Senior Subordinated Notes due June 1, 2008 and $150 million of our 9 3/8% Senior Subordinated Notes due October 1, 2010. We repaid the remaining $75 million of 9 1/2% Senior Subordinated Notes in February 2004.

The 9 3/8% Senior Subordinated Notes are redeemable, in whole or in part, at our option, on or after October 2005, under certain conditions. We are not required to make mandatory redemption or sinking fund payments with respect to these Notes. The indenture contains covenants that, among other things, limit our ability to incur additional indebtedness, limit restricted payments, limit issuances and sales of capital stock by restricted subsidiaries, limit dispositions of proceeds from asset sales, limit dividends and other payment restrictions affecting restricted subsidiaries, and restrict mergers, consolidations or sales of assets.

Long-term Liability to Unconsolidated Affiliate

In December 1996, we issued $115 million of 5 3/4% Convertible Subordinated Debentures due December 15, 2026, which were issued to Nuevo Financing I Business Trust, a wholly owned subsidiary, to facilitate the offering of the TECONS. Interest on these Debentures accrues at 5 3/4% per annum and is payable quarterly on March 15, June 15, September 15 and December 15. The Debentures are redeemable, in whole or in part, at our option, upon not less than 30 or more than 60 days notice, on or after December 15, 1999, under certain conditions. We are required to redeem the Debentures at 100% in the event of a tax or legal structure change as defined in the agreement. The holder of the Debentures has the right, exercisable at any time prior to the close of business on December 15, 2026, to convert the principal amount into shares of our common stock at a conversion rate of 0.8421 shares for each Debenture, subject to adjustment under certain circumstances. We are not required to make sinking fund payments with respect to the Debentures.

Table of Contents

Interest Rate Swap

During the fourth quarter of 2003, we entered into an interest rate swap agreement with a notional amount of $100 million, to hedge a portion of the fair value of our 9 3/8% Senior Subordinated Notes due 2010. This swap is designated as fair value hedge and is reflected as a decrease in long-term debt of $0.2 million as of December 31, 2003, with a corresponding increase in long-term liabilities. Under the terms of the agreement, the counterparty pays us a weighted average fixed annual rate of 9 3/8% on total notional amount of $100 million, and we pay the counterparty a variable annual rate equal to the six-month LIBOR rate plus a weighted average rate of 5.02%.

Common Stock

Our Board of Directors has authorized the issuance of up to 50.0 million shares, and at December 31, 2003 we have approximately 23.2 million shares issued and 19.7 million shares outstanding.

Our Board of Directors has authorized the open market repurchase of up to 5.6 million shares of common stock. Repurchases may be made at times and at prices deemed appropriate by management and consistent with the authorization of our Board. There were no shares repurchased in 2003. As of December 31, 2003, we had 3.5 million shares of treasury stock.

Joint Venture Formation

The exploration and development of oil and gas reserves requires substantial capital expenditures. In order to reduce our investment in a particular project, we may form joint ventures and seek joint venture partners to share the costs.

Contractual Cash Obligations

The following table summarizes our contractual cash obligations by payment due date:

	Total	Less than 1 Year	1-3 Years	4-5 Years	After 5 Years
			(In thousands)		
Long-term debt	$340,000	$	$	$ 75,000	$265,000
Operating leases	6,079	1,492	2,701	1,616	270
Capital commitments	5,470	75	5,395		
Asset retirement obligation	102,921		11,038	34,918	56,965
Total contractual cash obligations	$454,470	$1,567	$19,134	$111,534	$322,235

Long-term Debt

The following table details our long-term debt (excluding outstanding borrowings under our bank credit facility and interest rate swaps) at December 31, 2003:

	(In thousands)
9 3/8% Senior Subordinated Notes due 2010	$150,000
9 1/2% Senior Subordinated Notes due 2008	75,000
Long-term liability to unconsolidated affiliate	115,000
Long-term debt	$340,000

See Note 9 to the Consolidated Financial Statements for a description of our long-term debt and see Note 13 to the Consolidated Financial Statements for a description of our operating leases.

Table of Contents

Capital Commitments

At December 31, 2003, we had $5.5 million of capital commitments related to real estate in California. Our other planned capital projects are discretionary in nature, with no substantial capital commitments made in advance of the actual expenditures.

Commercial Commitments

The following table summarizes our Commercial Commitments by date of expiration.

		Amount of Commitment Expiration Per Period			
	Total Amount Committed	**Less than 1 Year**	**1 3 Years**	**4 5 Years**	**After 5 Years**
			(In thousands)		
Bank credit facility	$15,000	$	$15,000	$	$
Letters of credit	1,565		1,565		
Total commercial commitments	$16,565	$	$16,565	$	$

See Note 9 to the Consolidated Financial Statements for a description of our bank credit facility and letters of credit.

Critical Accounting Policies and Estimates

Our discussion and analysis of our financial condition and results of operations is based upon our consolidated financial statements which have been prepared in accordance with accounting principles generally accepted in the United States of America (GAAP). The preparation of our financial statements requires us to make estimates and judgments that affect the reported amount of assets, liabilities, revenues and expenses. We consider an accounting estimate to be critical if (1) it requires assumptions to be made that were uncertain at the time the estimate was made; and (2) changes in the estimate or different estimates that could have been selected could have a material impact on our results of operations or financial condition. We believe the following critical accounting policies reflect our significant estimates and judgments used in the preparation of our financial statements:

Property, Plant and Equipment. We account for our crude oil and natural gas operations using the successful efforts method of accounting. Under this method of accounting, all costs associated with oil and gas lease acquisition costs, successful exploratory wells and all development wells are capitalized and amortized on a unit-of-production basis over the remaining life of proved developed reserves and proved reserves on a field basis. Unproved leasehold costs are capitalized pending the results of exploration efforts. Exploration costs, including geological and geophysical expenses, exploratory dry holes and delay rentals, are charged to expense when incurred.

Proved reserves are the estimated quantities of crude oil, condensate and natural gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions at the end of the respective years. Proved developed reserves are those reserves expected to be recovered through existing equipment and operating methods.

Our rate of recording depreciation, depletion and amortization expense (DD&A) and our tests of impairment of proved properties are impacted by our estimation of proved reserves. There are numerous uncertainties in estimating crude oil and natural gas reserve quantities, projecting future production rates and projecting the timing of future development expenditures. Oil and gas reserve engineering must be recognized as a subjective process of estimating underground accumulations of oil and gas that cannot be measured in an exact way and estimates of other engineers might differ materially from those of Ryder Scott. The accuracy of any reserve estimate is a function of the quantity of available data and of engineering and geological interpretation and judgment. Accordingly, these estimates are subject to change as additional information becomes available.

We review our proved properties at the field level when management determines that events or circumstances indicate that the recorded carrying value of the properties may not be recoverable. If the carrying amount of an asset exceeds the sum of the undiscounted estimated future net cash flows, we recognize impairment expense equal to the difference between the carrying value and the fair value of the asset which is estimated to be the expected present value of future net cash flows from proved reserves, utilizing a risk-free rate of return. Unproved leasehold costs are reviewed periodically and a loss is recognized to the extent, if any, that the cost of the property has been impaired.

Reduction in reserve estimates may result in increased DD&A expense and increased impairment of proved properties. Additionally, availability under our credit facility is determined in part by the present value of our oil and gas reserves based on our bankers assumptions regarding future prices, production, costs, risk factors and discount rates. If amounts outstanding under the credit facility exceed the borrowing base, we would be required to repay such excess over a period of time, which would affect our financial condition.

Goodwill. We recorded goodwill in connection with the purchase of Athanor. Goodwill was attributed to a premium paid for Athanor because the acquisition added a new core area with increasing growth opportunities, diversified our asset base with higher margin natural gas properties and was financed with a component of equity. SFAS No. 142 requires that goodwill of a reporting unit be tested for impairment annually at a reporting unit level. The reporting unit used to evaluate and measure goodwill for impairment is determined primarily from the manner in which the business is managed. A reporting unit is an operating segment or a component which is one level below an operating segment. A component is a reporting unit if the component constitutes a business for which discrete financial information is available and segment management regularly reviews the operating results of that component. However, two or more components of an operating segment shall be aggregated and deemed a single reporting unit if the components have similar economic characteristics. An operating segment is deemed to be a reporting unit if all of its components are economically similar.

We have identified four operating segments, Onshore California, Offshore California, West Texas and Congo. Components within these operating segments are oil and gas producing fields. We have determined that the oil and gas producing fields do not constitute individual businesses as they share exploration and production field personnel within their geographic area. Additionally, we believe that the components within each of our operating segments, the oil and gas producing fields, are economically similar as (1) the nature of the products and services, (2) the nature of the production process, (3) the type of class of customer for the products and services, (4) the methods used to distribute their products or provide their services and (5) the nature of the regulatory environment are similar. As a result, the goodwill has been assigned to the West Texas operating segment, which we consider to be a reporting unit. If the company were to reorganize or revise its manner of managing the assets, the reporting unit could change, and if the reporting unit were determined to be at a lower level, recognition of goodwill impairment may result that did not occur with the reporting unit at a higher level.

The fair value of each reporting unit that has goodwill is determined and compared to the carrying amount of the reporting unit. We determined the fair value of the reporting unit by comparing it to recent sales prices of similar oil and gas reserves. The selection of a valuation methodology and inputs to determine the fair value of the reporting unit require judgment, since we rely on oil and gas reserve reports are subject to changes as disclosed under property, plant and equipment. Changes to the valuation method, failure to replace oil and gas reserves at the same or better rate than they are produced, or decline in sales prices of oil and gas producing assets, could result in the impairment of goodwill. We performed our goodwill impairment test in the fourth quarter, which resulted in no impairment. We would also perform testing at interim dates upon the occurrence of significant events including potential impairment; a significant adverse change in legal factors or business climate; adverse action or assessment by a regulator; a more-likely-than-not expectation that a reporting unit will be sold; significant adverse trends in current and future oil and gas prices; nationalization of any of the Company s oil and gas properties; or, significant increases in a reporting unit s carrying value relative to its fair value.

Asset Retirement Obligations. The computation of our asset retirement obligations was prepared in accordance with SFAS No. 143, *Accounting for Asset Retirement Obligations,* which requires us to record the fair value of liabilities for retirement obligations of long-lived assets. Our asset retirement obligations arise from the requirement that we must pay our share to plug and abandon our oil and gas wells and offshore platforms, and facilities.

Our computation of asset retirement obligations requires us to make assumptions and judgments concerning whether we have a legal obligation, the settlement amount, timing of the settlement, inflation factors, credit adjusted discount rate and changes in the legal, regulatory, environmental and political environments. Estimating the future cost of asset retirement is difficult due to the long time period over which the costs will be incurred and the rapid changes in environmental law and technologies available for the removal of assets. We estimated our liability based on the best information available to us at this time. Revisions to the liability could occur due to changes in the timing and actual plugging and abandonment costs.

Derivative Financial Instruments and Price Risk Management Activities. We use price risk management activities to manage non-trading market risks. We use derivative financial instruments such as swaps, collars and put options to hedge the impact of market price risk exposures on our crude oil and natural gas production, natural gas purchases and to mitigate our exposure to interest rate risk. We account for our derivatives under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities,* and have designated derivative instruments that qualify for hedge accounting as cash flow hedges for commodity related contracts and fair value hedges for interest rate contracts. Derivatives that do not qualify for hedge accounting are carried on the balance sheet at fair value, and changes in fair value are recognized in earnings.

The estimation of fair values for our hedging derivatives requires judgment. We estimate the fair values of our derivatives on a monthly basis using market based quotes. The market based quotes are compared to the prices fixed by the hedge agreements, and resulting estimated future cash inflows (outflows) over the lives of the hedges are discounted using our current borrowing rates under our revolving credit facility. These pricing and discounting variables are sensitive to market volatility as well as changes in future price forecasts, regional price differentials and interest rates. Currently, all of our derivative instruments are hedges of the price of crude oil and natural gas production and interest rates. We are not involved in any derivative trading activities.

SFAS No. 133 is complex and subject to interpretation in its application. In 1998, the FASB established the Derivative Implementation Group task force to consider and publish interpretations of issues arising from the implementation of SFAS No. 133. As additional issues are reviewed, it is possible that interpretations could affect our method of accounting for derivatives, which could affect our results of operations and financial condition.

Income Taxes. Currently payable income taxes represent the liability related to our income tax return for the current year. Deferred income taxes, accounted for under the asset and liability method of accounting for income taxes, are recognized for the tax consequences of temporary differences by applying enacted statutory tax rates applicable to future years to differences between the financial statement carrying amounts and the tax basis of existing assets and liabilities. Our computation of deferred tax assets or liabilities includes determining whether the differences in the financial statement carrying amount and tax basis are permanent or temporary, the timing of the reversal of temporary differences and the statutory tax rate to be used. Changes in current tax laws and applicable statutory tax rates could affect the valuation of deferred tax assets and liabilities, impacting the income tax provisions. The effect on deferred taxes of a change in tax rates is recognized in income in the period the change occurs. In late 2003, we became a current taxpayer in Congo.

We periodically assess, by tax jurisdiction, the ability to realize recorded deferred tax assets based on our assessment of future earnings outlook. Significant declines in taxable income could materially impact the realizable value of deferred tax assets.

New Accounting Pronouncements

See Item 1, Financial Statements, Note 2, which is incorporated herein by reference.

Contingencies and Other Matters

See Item 1, Financial Statements Note 13, which is incorporated herein by reference.

Table of Contents

RISK FACTORS AND CAUTIONARY STATEMENT FOR PURPOSES OF THE SAFE HARBOR

PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995

This report contains or incorporates by reference forward looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, Section 21E of the Securities Exchange Act of 1934 and the Private Securities Litigation Reform Act of 1995. All statements other than statements of historical facts included in this document, including without limitation, statements in Item 7, Management s Discussion and Analysis of Financial Condition and Results of Operations regarding our financial position, estimated quantities and net present values of reserves, business strategy, plans and objectives of our management for future operations and covenant compliance, are forward looking statements. We can give no assurances that the assumptions upon which such forward-looking statements are based will prove to be correct. Important factors that could cause actual results to differ materially from our expectations are included throughout this document. The Cautionary Statements expressly qualify all subsequent written and oral forward-looking statements attributable to us or persons acting on our behalf.

Volatility of Oil and Gas Prices

Prices for oil and gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and gas, market uncertainty and a variety of additional factors beyond our control. These factors include but are not limited to weather conditions in the United States, the condition of the United States economy, the actions of the Organization of Petroleum Exporting Countries (OPEC), governmental regulation, political stability in the Middle East and elsewhere, the foreign supply of oil and gas, the price of foreign oil imports and the availability of alternate fuel sources and transportation interruption. Any substantial and extended decline in the price of oil or gas would have an adverse effect on the carrying value of our proved reserves, borrowing capacity, our ability to obtain additional capital, and our revenues, profitability and cash flows from operations.

Volatile oil and gas prices make it difficult to estimate the value of producing properties for acquisition and divestiture and often cause disruption in the market for oil and gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for and project the return on acquisitions and development and exploitation projects.

Pricing of Heavy Oil Production

A portion of our production is California heavy oil. The market price for California heavy oil differs substantially from the established market indices for oil and gas, principally due to the higher transportation and refining costs associated with heavy oil. As a result, the price received for heavy oil is generally lower than the price for medium and light oil, and the production costs associated with heavy oil are relatively higher than for lighter grades. The margin (sales price minus production costs) on heavy oil sales is generally less than that of lighter oil, and the effect of material price decreases will more adversely affect the profitability of heavy oil production compared with lighter grades of oil. (See Risk Management and Hedging Policy below for discussion of our crude oil sales contract which expires in 2013).

Reserve Replacement Risks

Our future performance depends upon the ability to find, develop and acquire additional oil and gas reserves that are economically recoverable. Without successful exploration, exploitation or acquisition activities, our reserves and revenues will decline. No assurances can be given that we will be able to find and develop or acquire additional reserves at an acceptable cost.

The successful acquisition and development of oil and gas properties requires an assessment of recoverable reserves, future oil and gas prices and operating costs, potential environmental and other liabilities and other factors. Such assessments are necessarily inexact and their accuracy inherently uncertain. In addition, no assurances can be given that our exploitation and development activities will result in any increase in reserves. Our operations may be curtailed, delayed or canceled as a result of lack of adequate capital and other factors, such as title problems, weather, compliance with governmental regulations or price controls, mechanical difficulties or shortages or delays in the delivery of equipment. In addition, the costs of exploitation and development may materially exceed initial estimates.

Substantial Capital Requirements

We make, and will continue to make, substantial capital expenditures for the exploitation, exploration, acquisition and production of oil and gas reserves. Historically, these expenditures were financed with cash generated by operations, proceeds from bank borrowings and the proceeds of debt and equity issuances. We believe that we will have sufficient cash provided by operating activities and borrowings under our bank credit facility to fund planned capital expenditures. If revenues or our borrowing base decrease as a result of lower oil and gas prices, operating difficulties or declines in reserves, we may have limited ability to expend the capital necessary to undertake or complete future drilling programs. There can be no assurance that additional debt or equity financing or cash generated by operations will be available to meet these requirements.

Uncertainty of Estimates of Reserves and Future Net Cash Flows

Estimates of economically recoverable oil and gas reserves and of future net cash flows are based upon a number of variable factors and assumptions, all of which are to some degree speculative and may vary considerably from actual results. Therefore, actual production, revenues, taxes, and development and operating expenditures may not occur as estimated. Future results of operations will depend upon our ability to develop, produce and sell our oil and gas reserves. The reserve data included herein are estimates only and are subject to many uncertainties. Actual quantities of oil and gas may differ considerably from the amounts set forth herein. In addition, different reserve engineers may make different estimates of reserve quantities and cash flows based upon the same available data.

Operating Risks

Our operations are subject to risks inherent in the oil and gas industry, such as blowouts, cratering, explosions, uncontrollable flows of oil, gas or well fluids, fires, pollution, earthquakes and other environmental risks. These risks could result in substantial losses due to injury and loss of life, severe damage to and destruction of property and equipment, pollution and other environmental damage and suspension of operations. Our offshore operations are subject to a variety of operating risks peculiar to the marine environment, such as hurricanes or other adverse weather conditions, to more extensive governmental regulation, including regulations that may, in certain circumstances, impose strict liability for pollution damage, and to interruption or termination of operations by governmental authorities based on environmental or other considerations. Our operations could result in liability for personal injuries, property damage, oil spills, discharge of hazardous materials, remediation and clean-up costs and other environmental damages. We could be liable for environmental damages caused by previous property owners. As a result, substantial liabilities to third parties or governmental entities may be incurred, the payment of which could have a material adverse effect on our financial condition and results of operations. We maintain insurance coverage for our operations, including limited coverage for sudden environmental damages and for existing contamination, but do not believe that insurance coverage for environmental damages that occur over time or insurance coverage for the full potential liability that could be caused by sudden environmental damages is available at a reasonable cost, and we may be subject to liability or may lose substantial portions of our properties in the event of certain environmental damages.

Foreign Investments

Our foreign investments involve risks typically associated with investments in emerging markets such as uncertain political, economic, legal and tax environments and expropriation and nationalization of assets. We attempt to conduct our business and financial affairs so as to protect against political and economic risks applicable to operations in the various countries where we operate, but there can be no assurance that we will be successful in protecting against such risks.

Our international assets and operations are subject to various political, economic and other uncertainties, including, among other things, the risks of war, expropriation, nationalization, renegotiation or nullification of existing contracts, taxation policies, foreign exchange restrictions, changing political conditions, international monetary fluctuations, currency controls and foreign governmental regulations that favor or require the awarding of drilling contracts to local contractors or require foreign contractors to employ citizens of, or purchase supplies from, a particular jurisdiction. In addition, if a dispute arises with foreign operations, we may be subject to the exclusive jurisdiction of foreign courts or may not be successful in subjecting foreign persons, especially foreign oil ministries and national oil companies, to the jurisdiction of the United States.

Our private ownership of oil and gas reserves under oil and gas leases in the United States differs distinctly from our ownership of foreign oil and gas properties. In the foreign countries in which we do business, the state generally retains ownership of the minerals and consequently retains control of (and in many cases, participates in) the exploration and production of hydrocarbon reserves. Accordingly, operations outside the United States, and estimates of reserves attributable to properties located outside the United States, may be materially affected by host governments through royalty payments, export taxes and regulations, surcharges, value added taxes, production bonuses and other charges.

Risk Management and Hedging Policy

Our risk management policy is based on the view that oil prices revert to a mean price over the long term. To the extent that future markets over a forward 18 to 24 month period are significantly higher than long term norms, we will hedge production volumes up to certain maximums set forth in our oil hedging policy approved by our Board in March 2002 and modified in September 2003. Maximum hedged volumes increase as the price of oil increases. Variations from this policy require Board approval. The risk management policy states that hedging activity that is speculative or otherwise unrelated to our normal business activities is considered inappropriate. We recognize the risks inherent in price management. In order to minimize such risk, we have instituted a set of controls addressing approval authority, trading limits and other control procedures. All hedging activity is the responsibility of our Senior Vice President of Planning and Asset Management. In addition, Internal Audit, which independently reports to the Audit Committee, reviews our risk management activity.

We reduce our exposure to price volatility by hedging our production through swaps, options and other commodity derivative instruments. In a typical swap transaction, we will have the right to receive from the counterparty to the hedge the excess of the fixed price specified in the hedge contract and a floating price based on a market index, multiplied by the quantity hedged. If the floating price exceeds the fixed price, we are required to pay the counterparty the difference. We would be required to pay the counterparty the difference between such prices regardless of whether our production was sufficient to cover the quantities specified in the hedge. Since there is not an established pricing index for hedges of California heavy crude oil production, and the cash market for heavy oil production in California tends to vary widely from index prices typically used in oil hedges, we have entered into a physical sales contract to tie our California production to a traded NYMEX index. As such, in February 2000, we entered into a 15-year contract, effective January 1, 2000, to sell substantially all of our current and future California crude oil production to ConocoPhillips Corporation. The contract provides pricing based on a fixed percentage of the NYMEX crude oil price for each type of crude oil that we produce in California. Consequently, the actual price received by the Company as a percentage of NYMEX will vary with our production mix. Effective January 1, 2004, the pricing was increased and based on our current production mix, the price we receive for our California oil production is expected to average approximately 82% of WTI for 2004. While the contract does not reduce our exposure to price volatility, it does effectively eliminate the basis differential risk between the NYMEX price and the field price of our California oil production, thereby facilitating the ability to effectively hedge our realized prices.

Insurance

The ability to secure certain insurance coverages at prices that we consider reasonable may be impacted and other coverages or endorsements may not be made available. No assurance can be given that we will be able to duplicate our current insurance package when our policies come up for renewal.

Table of Contents

Our Pending Merger with Plains

Our pending merger with Plains may not be consummated. The merger agreement requires, among other things, adoption of the merger agreement by our stockholders and approval by Plains s stockholders of the issuance of shares of Plains common stock to our stockholders pursuant to the merger agreement. The merger agreement also requires termination or expiration of the waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976.

Even if the merger is consummated, our stockholders may not realize the anticipated benefits expected to result from the combination. To be successful following the merger, management of the combined company will need to combine and integrate our operations and the operations of Plains into one company. Because of the size, complexity and asset base of each company, integration will be a difficult process that will require substantial management attention that could detract attention from the day-to-day business of the combined company. If we and Plains cannot be integrated successfully, some of the expected benefits of the merger, including expected cost savings, may not be realized. Moreover, any difficulties associated with the transition and integration process could have an adverse effect on the revenue, level of expenses and operating results of the combined company. In addition, the combined company may not realize the accretion to various financial measurements that we expect to result from the merger. Finally, the combined company s debt level is expected to be significant and will be higher than our debt level on a stand-alone basis.

Competition/ Markets for Production

We operate in the highly competitive areas of oil and gas exploration, exploitation, development and production. The availability of funds and information relating to a property, the minimum projected return on investment, the availability of alternate fuel sources and the intermediate transportation of oil and gas are factors which affect our ability to compete in the marketplace. Our competitors include major integrated oil companies and a substantial number of independent energy companies, many of which possess greater financial and other resources than we do.

Our heavy crude oil production in California requires special processing treatment available only from a limited number of refineries. Substantial damage to such a refinery or closures or reductions in capacity due to financial or other factors could adversely affect the market for our heavy crude oil production.

Table of Contents

Item 7A. ***Quantitative and Qualitative Disclosures about Market Risk***

We are exposed to market risk, including adverse changes in commodity prices and interest rates.

Commodity Price Risk. We produce and sell crude oil, natural gas and natural gas liquids, therefore our operating results can be significantly affected by fluctuations in commodity prices caused by changing market forces. We reduce our exposure to price volatility by hedging our production through swaps, put options, collars and other commodity derivative instruments. In a typical swap transaction, if the floating price is less than the fixed price, we will have the right to receive from the counterparty to the hedge the excess of the fixed price specified in the hedge contract and a floating price based on a market index, multiplied by the quantity hedged. If the floating price exceeds the fixed price, we are required to pay the counterparty the difference. In a typical put option contract, we purchase the right to receive from the counterparty the difference, if any, between a fixed price specified in the option less a floating market price. If the floating price is above the fixed price, we are not entitled to a payment. A collar contract works similarly as a put; however, we are required to pay the difference between the floating price and ceiling strike price of the collar if the floating price exceeds the ceiling price. Quantities covered by crude hedges are based on West Texas Intermediate (WTI) barrels. Prices received for our production are expected to average 82% of WTI, therefore, each WTI barrel effectively hedges 1.22 barrels of our production. We use hedge accounting for these instruments, and settlements of gains or losses on these contracts are reported as a component of oil and gas revenues and operating cash flows in the period realized. These agreements expose us to counterparty credit risk to the extent that the counterparty is unable to meet their settlement commitments to us.

At December 31, 2003, we had entered into the following cash flow hedges:

	Crude Oil			Natural Gas		
	Bbls/ day	$/Bbl	Index	MMbtu/day	$/MMbtu	Index
Swaps for Sales						
2004						
1st Qtr	19,800	$25.71	WTI	16,500	$4.93	Waha & Socal
2nd Qtr	19,500	25.71	WTI	14,500	4.65	Waha & Socal
3rd Qtr	19,800	25.71	WTI	10,500	4.50	Waha & Socal
4th Qtr	21,000	25.98	WTI	14,500	4.64	Waha & Socal
2005						
1st Qtr	17,500	24.88	WTI	13,000	4.75	Waha & Socal
2nd Qtr	14,500	24.67	WTI	9,500	4.66	Waha
3rd Qtr	4,500	22.14	WTI	9,500	4.40	Waha
4th Qtr	4,500	22.14	WTI	9,500	4.40	Waha
Swaps for Purchases						
2004				8,000	3.91	Socal
2005				8,000	3.85	Socal

At December 31, 2003, the fair market value of these hedge positions was a loss of $40.5 million. A 10% increase in the underlying commodity prices would increase this loss by $33.1 million.

Table of Contents

Derivative Instruments Not Designated as Hedges

In August 2003, we entered into three-way collars that are not designated as hedging instruments and are marked-to-market with changes in fair value recognized currently as a derivative gain/loss.

	Bbls/day	Index	Weighted Average Price		
Three-Way Collars[1]					
2004					
(Jan - Dec)	8,000	WTI	$ 19.28	24.00	31.00

(1) A Three-Way Collar combines a sold put, a purchased put and a sold call. The purchased put and sold put establish a floating minimum price and the sold call establishes a maximum price we will receive for the volumes under contract.

In December 2001, Enron Corp. (Enron) and certain of its affiliates filed voluntary petitions for reorganization under Chapter 11 of the United States Bankruptcy Code. Once a deterioration in creditworthiness creates uncertainty as to whether the future cash flows from the hedging instrument will be highly effective in offsetting the hedged risk, the derivative instrument is no longer considered highly effective and no longer qualifies for hedge accounting treatment. At such time, the fair value of the derivative asset or liability is adjusted to its new fair value, with the change in value being charged to current earnings.

We entered into call spreads in 2001 and 2000 with the anticipation of using the proceeds to offset the Unocal Contingent payment. (See Note 13.) Subsequent to entering into the call spreads, the market fell and as a result, offsetting call spreads were purchased to economically nullify the trade. All of our existing call spreads had been offset through the purchase of a mirror spread, however, the call spread with Enron was cancelled. (See above discussion). The remaining mirror call spread is not designated as a hedging instrument and is marked-to-market with changes in fair value recognized currently as derivative gain/loss. At December 31, 2003, the call spread matured and we subsequently paid $4.6 million in settlement of the obligation.

Subsequent to December 31, 2003, we entered into the following cash flow hedges utilizing swap agreements:

Crude Oil Hedges	Volume MBbls/day	WTI Price ($Bbl.)	
Collars			
2005			
1st Qtr.	4,300	$ 31.75	27.00
2nd Qtr.	6,800	30.40	27.00
3rd Qtr.	14,400	30.03	26.00
4th Qtr.	14,000	29.33	26.00

Interest Rate Risk. We may enter into financial instruments such as interest rate swaps to manage the impact of changes in interest rates. Our exposure to changes in interest rates results primarily from our long-term debt with both fixed and floating interest rates.

In late December 2001 and early 2002, we entered into three interest rate swap agreements with notional amounts totaling $200.0 million to hedge the fair value of our 9 1/2% Notes due 2008 and our 9 3/8% Notes due 2010. These swaps were designated as fair value hedges and as interest rates fluctuated, the change in value of these instruments was reflected as an increase or decrease of long-term debt with a corresponding increase in long-term assets or liabilities.

In late August and early September 2002, we terminated our swap transactions relating to these Notes. As a result of these terminations, we received accrued interest of $2.2 million and the present value of the swap option of $9.6 million on our 9 3/8% Notes and $0.5 million in accrued interest and the present value of the swap option of $2.5 million on our 9 1/2% Notes. The remaining gain of $9.6 million on our 9 3/8% Notes and $2.5 million on our 9 1/2% Notes continues to be reflected as an increase of long-term debt and is being amortized as a reduction to interest expense over the life of the Notes. During the twelve months ended December 31, 2003, we had amortized $0.9 million and $0.4 million, respectively.

Following the termination of the three interest rate swaps reference above, in late August and early November 2002, we entered into two new interest rate swap agreements with notional amounts totaling $100.0 million, to hedge a portion of the fair value of our 9 3/8% Notes due 2010. These swaps were also designated and accounted for as fair value hedges.

In May 2003, we terminated our swap transactions relating to these Notes. As a result of these terminations, we received accrued interest of $0.4 million and the present value of the swap option of $4.1 million. The remaining gain of $4.1 million continues to be reflected as an increase of long-term debt and is being amortized as a reduction to interest expense over the life of the Notes. Through December 31, 2003, we had amortized $0.2 million.

In late October 2003, we entered into an interest rate swap agreement with a notional amount of $100.0 million, to hedge a portion of the fair value of our 9 3/8% Notes due 2010. This swap is designated as a fair value hedge and is reflected as a decrease in long-term debt of $0.2 million as of December 31, 2003, with a corresponding increase in long-term liabilities. Under the terms of the agreement, the counterparty pays us a weighted average fixed annual rate of 9 3/8% on total notional amount of $100.0 million, and we pay the counterparty a variable annual rate equal to the six-month LIBOR rate plus a weighted average rate of 5.02%.

The fair market value of the aggregate of all our hedging instruments was a loss of approximately $74 million at February 27, 2004.

The following table presents principal amounts and the related average interest rates (exclusive of fair value hedges) by year of maturity for our debt obligations at December 31, 2003:

	2004	2005	2006	2007	Thereafter	Total	Fair Value
				(In thousands, except percentages)			
Long-term debt							
Variable rate	$	$15,000				$ 15,000	$ 15,000
Average interest rate		2.89%				2.89%	
Fixed rate					$340,000	$340,000	$338,894
Average interest rate					8.18%	8.18%	

Table of Contents

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

INDEX TO FINANCIAL STATEMENTS AND SCHEDULES

Table of Contents

INDEPENDENT AUDITORS REPORT

The Board of Directors and Stockholders

Nuevo Energy Company:

We have audited the accompanying consolidated balance sheets of Nuevo Energy Company and subsidiaries as of December 31, 2003 and 2002, and the related consolidated statements of income, stockholders equity, cash flows and comprehensive income for each of the years in the three-year period ended December 31, 2003. 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 conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Nuevo Energy Company and subsidiaries as of December 31, 2003 and 2002, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2003 in conformity with accounting principles generally accepted in the United States of America.

As discussed in note 2, effective January 1, 2001, the Company changed its method of accounting for derivative instruments. As discussed in note 3, effective January 1, 2003, the Company changed its method of accounting for asset retirement obligations. As discussed in note 2, effective December 31, 2003, the Company changed its method of accounting for certain convertible subordinated debentures.

KPMG LLP

Houston, Texas
March 5, 2004

Table of Contents

NUEVO ENERGY COMPANY

CONSOLIDATED STATEMENTS OF INCOME

(In thousands, except per share data)

	Year Ended December 31,		
	2003	**2002**	**2001**
Revenues			
Crude oil and liquids	$313,885	$276,494	$ 238,127
Natural gas	56,090	31,337	72,679
Other	1,362	4,070	273
	371,337	311,901	311,079
Costs and Expenses			
Lease operating expenses	159,832	132,954	160,086
Exploration costs	2,115	4,541	22,058
Depreciation, depletion, amortization and accretion	70,810	73,128	70,554
Impairment of oil and gas properties			103,490
General and administrative expenses	28,457	25,877	36,904
Restructuring and severance charges			4,859
Loss on assets held for sale		1,253	3,494
Other	1,256	1,930	14,928
Gain on disposition of properties	(5,824)	(16,588)	(882)
	256,646	223,095	415,491
Operating Income (Loss)	114,691	88,806	(104,412)
Derivative gain (loss)	(5,842)	(4,746)	226
Interest income	342	266	1,311
Interest expense	(29,793)	(37,943)	(43,006)
Loss on early extinguishment of debt	(12,578)		
Dividends on TECONS	(6,613)	(6,613)	(6,613)
Income (Loss) From Continuing Operations Before Income Taxes	60,207	39,770	(152,494)
Income Tax Expense (Benefit)			
Current	2,086	1,330	
Deferred	21,032	15,361	(61,123)
	23,118	16,691	(61,123)
Income (Loss) From Continuing Operations	37,089	23,079	(91,371)
Income (loss) from discontinued operations, including gain/loss on disposal, net of income taxes	5,894	(10,804)	12,200
Cumulative effect of a change in accounting principle, net of income taxes	8,496		
Net Income (Loss)	$ 51,479	$ 12,275	$ (79,171)
Earnings Per Share:			
Basic			
Income (Loss) from continuing operations	$ 1.92	$ 1.31	$ (5.46)

Income (Loss) from discontinued operations, net of income taxes	0.30	(0.61)	0.73
Cumulative effect of a change in accounting principle, net of income tax benefit	0.44		
Net income (loss)	$ 2.66	$ 0.70	$ (4.73)
Diluted			
Income (Loss) from continuing operations	$ 1.89	$ 1.30	$ (5.46)
Income (Loss) from discontinued operations, net of income taxes	0.30	(0.61)	0.73
Cumulative effect of a change in accounting principle, net of income tax benefit	0.43		
Net income (loss)	$ 2.62	$ 0.69	$ (4.73)
Weighted Average Shares Outstanding:			
Basic	19,355	17,651	16,735
Diluted	19,627	17,790	16,735

See accompanying notes.

Table of Contents

NUEVO ENERGY COMPANY

CONSOLIDATED BALANCE SHEETS

(In thousands, except share amounts)

	December 31, 2003	December 31, 2002
ASSETS		
Current assets		
Cash and cash equivalents	$ 6,276	$ 5,047
Accounts receivable, net of allowance of $216 in 2003 and $626 in 2002	39,729	40,945
Inventory	5,741	7,326
Assets held for sale	38,290	92,738
Deferred income taxes	11,906	7,683
Prepaid expenses and other	4,489	3,862
Total current assets	106,431	157,601
Property and equipment, at cost		
Land	5,224	5,224
Oil and gas properties (successful efforts method)	1,031,202	951,258
Gas plant and other facilities	15,126	14,303
	1,051,552	970,785
Accumulated depreciation, depletion and amortization	(355,311)	(357,072)
Total property and equipment, net	696,241	613,713
Deferred income taxes	17,404	43,258
Goodwill	17,121	19,664
Other assets	7,779	20,935
Total assets	$ 844,976	$ 855,171

See accompanying notes.

Table of Contents

NUEVO ENERGY COMPANY

CONSOLIDATED BALANCE SHEETS (Continued)

(In thousands, except share amounts)

	December 31,	
	2003	**2002**
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities		
Accounts payable	$ 38,707	$ 34,323
Accrued interest	3,663	5,169
Accrued drilling costs	5,568	8,035
Accrued lease operating costs	13,558	15,598
Price risk management activities	35,005	20,884
Other accrued liabilities	42,447	16,735
Total current liabilities	138,948	100,744
Long-Term debt		
Senior subordinated notes	225,000	409,577
Bank credit facility	15,000	28,700
Long-term liability to unconsolidated affiliate	115,000	
Total debt	355,000	438,277
Interest rate swaps fair value adjustment	(153)	2,161
Interest rate swaps termination gain	14,364	11,673
Long-term debt	369,211	452,111
Asset retirement obligation	102,921	
Price risk management activities	10,512	4,198
Other long-term liabilities	1,555	8,842
Company-obligated mandatorily redeemable convertible preferred securities of Nuevo Financing I (TECONS)		115,000
Commitments and contingencies (Note 13)		
Stockholders equity		
Preferred stock, $1.00 par value, 10,000,000 shares authorized; 7% Cumulative Convertible Preferred Stock, none issued and outstanding		
Common stock, $0.01 par value, 50,000,000 shares authorized, 23,151,781 and 23,048,388 shares issued and 19,682,494 and 19,110,102 shares outstanding, respectively	232	230
Additional paid-in capital	397,628	388,479
Treasury stock, at cost, 3,469,287 and 3,867,691 shares, respectively	(68,048)	(75,683)
Deferred stock compensation and other	(6,512)	(605)
Accumulated other comprehensive income	(24,614)	(11,468)
Accumulated deficit	(76,857)	(126,677)
Total stockholders equity	221,829	174,276
Total liabilities and stockholders equity	$844,976	$ 855,171

See accompanying notes.

Table of Contents

NUEVO ENERGY COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In thousands)

	Year Ended December 31,		
	2003	**2002**	**2001**
Cash flows from operating activities			
Net income (loss)	$ 51,479	$ 12,275	$ (79,171)
Adjustments to reconcile net income (loss) to net cash provided by operating activities			
Depreciation, depletion, amortization and accretion	70,810	73,128	70,554
Deferred income taxes	21,032	15,361	(61,123)
Dry hole costs	271	297	14,138
Amortization of debt financing costs	1,909	2,532	2,399
Loss on early extinguishment of debt	12,578		
Impairment of oil and gas properties			103,490
Net gain on sales of assets	(5,824)	(16,588)	(882)
Loss on assets held for sale		1,253	3,494
Non-cash effect of discontinued operations	471	30,317	13,767
Cumulative effect of a change in accounting principle	(8,496)		
Other	8,138	8,540	6,911
Working capital changes, net of non-cash transactions			
Accounts receivable	1,780	9,341	23,043
Accounts payable	7,797	(6,578)	9,876
Accrued liabilities and other	3,836	(7,150)	(17,602)
Net cash provided by operating activities	165,781	122,728	88,894
Cash flows from investing activities			
Additions to oil and gas properties	(61,636)	(74,472)	(133,228)
Acquisition of Athanor Resources, Inc.		(61,312)	
Acquisitions of oil and gas properties			(28,456)
Proceeds from sales of properties	85,002	26,968	6,145
Deposit received on real estate sale	15,931		
Other proceeds	1,841		
Additions to other properties	(5,095)	(5,698)	(8,554)
Net cash provided by (used in) investing activities	36,043	(114,514)	(164,093)
Cash flows from financing activities			
Net borrowings of credit facility	(13,700)	(12,800)	41,500
Payments of long-term debt	(184,577)		(150)
Premium paid for redemption of notes	(8,692)		
Proceeds from exercise of stock options	6,374	1,229	3,694
Purchase of treasury shares			(2,085)
Other		1,294	(97)
Net cash provided by (used in) financing activities	(200,595)	(10,277)	42,862

Increase (decrease) in cash and cash equivalents	1,229	(2,063)	(32,337)
Cash and cash equivalents			
Beginning of year	5,047	7,110	39,447
End of year	$ 6,276	$ 5,047	$ 7,110

See accompanying notes.

Table of Contents

NUEVO ENERGY COMPANY

CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY

(In thousands)

	2003		2002		2001	
	Shares	**Amount**	**Shares**	**Amount**	**Shares**	**Amount**
Common Stock						
Balance, beginning of year	19,110	$ 230	16,880	$ 209	16,632	$ 206
Issuances and purchases of common stock						
Acquisition of Athanor Resources, Inc.			1,970	20		
Employee stock compensation and plans	572	2	260	1	376	3
Purchase of treasury stock					(128)	
Balance, end of year	19,682	$ 232	19,110	$ 230	16,880	$ 209
Additional Paid-In Capital						
Balance, beginning of year		$ 388,479		$ 366,792		$ 361,643
Acquisition of Athanor Resources, Inc.				20,066		
Exercise of stock options		1,413		1,785		4,463
Employee stock compensation and plans		7,736		(164)		686
Balance, end of year		$ 397,628		$ 388,479		$ 366,792
Accumulated Deficit						
Balance, beginning of year		$(126,677)		$(138,952)		$ (59,781)
Loss on issue of treasury shares		(1,659)				
Net income (loss)		51,479		12,275		(79,171)
Balance, end of year		$ (76,857)		$(126,677)		$(138,952)
Accumulated Other Comprehensive Income						
Balance, beginning of year		$ (11,468)		$ 11,534		$
Other comprehensive income		(13,146)		(23,002)		11,534
Balance, end of year		$ (24,614)		$ (11,468)		$ 11,534
Treasury Stock						
Balance, beginning of year		$ (75,683)		$ (75,855)		$ (74,703)
Issuance related to employee stock compensation and plans		7,635		172		933
Purchase of treasury stock						(2,085)
		$ (68,048)		$ (75,683)		$ (75,855)
Deferred Compensation and Other						
Balance, beginning of year		$ (605)		$ (3,821)		$ (4,248)

Deferred compensation	(5,466)	1,422	(300)
Stock acquired by benefit trust	(441)	(172)	(933)
Withdrawal from benefit trust		1,966	1,660
Balance, end of year	$ (6,512)	$ (605)	$ (3,821)
Total Stockholders Equity	$ 221,829	$ 174,276	$ 159,907

See accompanying notes.

41

Table of Contents

NUEVO ENERGY COMPANY

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(In thousands)

	Year Ended December 31,		
	2003	**2002**	**2001**
Comprehensive Income			
Net income (loss)	$ 51,479	$ 12,275	$ (79,171)
Unrealized gains (losses) from cash flow hedging activity:			
Cumulative effect transition adjustment (net of income tax benefit of $10,784 in 2001)			(15,976)
Reclassification adjustment of settled contracts (net of income taxes of $18,390 in 2003, $3,262 in 2002 and $19,202 in 2001)	28,523	4,753	28,446
Changes in fair value of derivative instruments during the period (net of income tax benefit of $26,866 in 2003, $19,049 in 2002 and $632 in 2001)	(41,669)	(27,755)	(936)
Other comprehensive income	(13,146)	(23,002)	11,534
Comprehensive income	$ 38,333	$ (10,727)	$ (67,637)

See accompanying notes.

Table of Contents

NUEVO ENERGY COMPANY

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. Organization

Nuevo Energy Company (Nuevo) was formed as a Delaware corporation on March 2, 1990, to acquire the businesses of certain public and private partnerships (collectively Predecessor Partnerships). On July 9, 1990, the plan of consolidation (Plan of Consolidation) was approved by limited partners owning a majority of units of limited partner interests in the partnerships whereby the net assets of the Predecessor Partnerships, which were subject to the Plan of Consolidation, were exchanged for Common Stock of Nuevo (Common Stock). All references to the Company include Nuevo and its majority and wholly-owned subsidiaries, unless otherwise indicated or the context indicates otherwise.

We are engaged in the acquisition, exploitation, development, exploration and production of crude oil and natural gas. Our principal oil and gas properties are located domestically onshore and offshore California and West Texas, and internationally offshore the Republic of Congo, West Africa.

We have entered into a definitive agreement to be merged with Plains Exploration & Production Company (Plains) in a stock transaction valued at approximately $945 million, based on Plains closing price on February 11, 2004. If completed, Plains will issue up to 37.4 million shares to our stockholders and assume $234 million of net debt (as of December 31, 2003) and $115 million of Trust Convertible Preferred Securities. Under the terms of the transaction, our stockholders will receive 1.765 shares of Plains common stock for each share of our common stock.

The transaction is expected to qualify as a tax free reorganization under Section 368(a) and is expected to be tax free to Plains stockholders and tax free for the stock consideration received by our stockholders. The Boards of Directors of both companies have approved the merger agreement and each has recommended it to their respective stockholders for approval. Consummation of the transaction is subject to shareholder approval from both companies and other customary conditions.

2. Summary of Significant Accounting Policies

Principles of Consolidation

Our consolidated financial statements include the accounts of Nuevo and our majority and wholly-owned subsidiaries. All significant intercompany accounts and transactions have been eliminated in consolidation.

As a result of adopting FIN 46R, *Consolidation of Variable Interest Entities,* at December 31, 2003, we are required to deconsolidate our wholly owned Nuevo Financing I Business Trust subsidiary. See New Accounting Pronouncements.

Oil and Gas Properties

We use the successful efforts method to account for our investments in oil and gas properties. Under the successful efforts method, oil and gas lease acquisition costs and intangible drilling costs associated with exploration efforts that result in the discovery of proved reserves and costs associated with development drilling, whether or not successful, are capitalized when incurred. When a proved property is sold, ceases to produce or is abandoned, a gain or loss is recognized. When an entire interest in an unproved property is sold for cash or cash equivalent, a gain or loss is recognized, taking into consideration any recorded impairment. When a partial interest in an unproved property is sold, the amount received is treated as a reduction of the cost of the interest retained.

Costs of successful wells, development dry holes and proved leases are capitalized and depleted on a unit-of-production basis over the remaining proved reserves. Capitalized drilling costs are depleted on a unit-of-production basis over the lives of the remaining proved developed reserves. See Note 3 for a discussion of the provisions of SFAS No. 143, which was adopted effective January 1, 2003.

Table of Contents

NUEVO ENERGY COMPANY

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets* requires that long-lived assets that are to be disposed of by sale be measured at the lower of book value or fair value less cost to sell. The standard also expanded the scope of discontinued operations to include all components of an entity with operations that can be distinguished from the rest of the entity and that will be eliminated from the ongoing operations of the entity in a disposal transaction. We adopted the provisions of this statement effective January 1, 2002 and have presented certain property dispositions as discontinued operations in accordance with SFAS No. 144. (See Note 5).

We review our long-lived assets to be held and used, including proved oil and gas properties accounted for using the successful efforts method of accounting, on a depletable unit basis whenever events or circumstances indicate that the carrying value of those assets may not be recoverable. SFAS No. 144 requires an impairment loss to be recognized when the carrying amount of an asset exceeds the sum of the undiscounted estimated future net cash flows and we recognize an impairment loss equal to the difference between the carrying value and the fair value of the asset. Fair value is estimated to be the expected present value of future net cash flows from proved reserves, utilizing a risk-free rate of return. Also, in accordance with SFAS No. 144, when the proved properties are classified as held for sale, if the carrying amount of the assets is greater than their fair market value less our estimated costs to sell them, the difference, if significant, is recognized as a loss in that period and the associated results of operations are accounted for as discontinued. We recorded impairments required to be taken in 2003 and 2002 on properties designated as assets held for sale. During 2001, we recorded an impairment totaling $103.5 million on our Santa Clara, Huntington Beach, Pitas Point, Masseko (Congo) and Point Pedernales fields and certain other oil and gas properties.

Unproved leasehold costs are capitalized pending the results of exploration efforts. Significant unproved leasehold costs are reviewed periodically and a loss is recognized to the extent, if any, that the cost of the property has been impaired. Exploration costs, including geological and geophysical expenses, exploratory dry holes and delay rentals, are charged to expense as incurred.

Interest costs associated with non-producing leases and exploration and development projects were capitalized only for the period that activities were in progress to bring these projects to their intended use. The capitalization rates were based on our weighted average cost of funds used to finance expenditures. We capitalized $1.6 million, $1.9 million and $2.5 million of interest costs in 2003, 2002 and 2001.

Any reference to oil and gas reserve information in the Notes to the Consolidated Financial Statements is unaudited.

Derivative Financial Instruments and Price Risk Management Activities

We use price risk management activities to manage non-trading market risks. We use derivative financial instruments such as swaps, collars and put options to hedge the impact market price risk exposures on our crude oil and natural gas production and to mitigate our exposure to interest rate risk.

All of our derivative instruments are recognized on the balance sheet at their fair value. We currently use swaps, collars and put options to hedge our exposure to material changes in the future price of crude oil and natural gas and interest rate swaps to hedge the fair value of our long-term debt.

On the date we enter into a derivative contract, we designate the derivative as either a hedge of the fair value of a recognized asset, liability or firm commitment (fair value hedge), as a hedge of the variability of cash flows to be received or paid (cash flow hedge), or elect not to designate the derivative as a hedge. Changes in the fair value of a derivative that is highly effective as, and that is designated and qualifies as, a fair value hedge, along with the change in fair value of the hedged asset or liability that is attributable to the hedged risk (including losses or gains on firm commitments), are recorded in current period earnings. Changes in the fair value of a cash flow hedge are recorded in other comprehensive income (loss) until the

NUEVO ENERGY COMPANY

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

hedged transaction occurs. At December 31, 2003, we had cash flow hedges, fair value hedges and derivatives not designated as a hedge. (See Note 14.)

We formally document all relationships between hedging instruments and hedged items, as well as its risk-management objective and strategy for undertaking various hedge transactions. This process includes linking all derivatives that are designated as cash flow hedges to forecasted transactions. We also formally assess, both at the hedge s inception and on an ongoing basis, whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in cash flows of hedged transactions. When it is determined that a derivative is not highly effective as a hedge or that it has ceased to be a highly effective hedge, we discontinue hedge accounting prospectively.

When hedge accounting is discontinued because it is probable that a forecasted transaction will not occur, the derivative will continue to be carried on the balance sheet at its fair value, and gains and losses that were accumulated in other comprehensive income will be recognized in earnings immediately. In all other situations in which hedge accounting is discontinued, the derivative will be carried at its fair value on the balance sheet, with changes in its fair value recognized in earnings prospectively.

At December 31, 2003, we had recorded $24.6 million, net of related taxes of $15.9 million, of cumulative hedging losses in other comprehensive income, which will be reclassified to earnings within the next 12 months. The amounts ultimately reclassified to earnings will vary due to changes in the fair value of the open derivative contracts prior to settlement.

As a result of hedging transactions, oil and gas revenues were reduced by $46.8 million, $9.4 million and $47.6 million in 2003, 2002 and 2001. The portion of our derivative financial instruments that were ineffective or did not qualify for hedge accounting totaled $5.8 million in 2003 and was recorded in derivative gain/loss in the accompanying consolidated statements of income.

Goodwill and Other Intangible Assets

SFAS No. 142, *Goodwill and Other Intangible Assets* requires discontinuing amortization of goodwill after 2001 and requires that goodwill be tested at least annually for impairment. The impairment test requires allocating goodwill and all other assets and liabilities to business levels referred to as reporting units. The fair value of each reporting unit that has goodwill is determined and compared to the book value of the reporting unit. If the fair value of the reporting unit is less than the book value (including goodwill), then a second test is performed to determine the amount of the impairment.

If the second test is necessary, the fair value of the reporting unit s individual assets and liabilities is deducted from the fair value of the reporting unit. This difference represents the implied fair value of goodwill, which is compared to the book value of the reporting unit s goodwill. Any excess of the book value of goodwill over the implied fair value of goodwill is the amount of the impairment.

The goodwill impairment test is performed annually, and also at interim dates upon the occurrence of significant events. Significant events include: a significant adverse change in legal factors or business climate; an adverse action or assessment by a regulator; a more-likely-than-not expectation that a reporting unit or significant portion of a reporting unit will be sold; significant adverse trends in current and future oil and gas prices; nationalization of any of the Company s oil and gas properties; or, significant increases in a reporting unit s carrying value relative to its fair value.

We recorded $17.1 million of goodwill in connection with our acquisition of Athanor Resources, Inc. in 2002 (See Note 12). The goodwill is recorded in our West Texas reporting unit. The annual impairment test is performed in the fourth quarter of each year, or more often if required.

Table of Contents

NUEVO ENERGY COMPANY

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Comprehensive Income

Comprehensive income includes net income and all changes in other comprehensive income. Changes in other comprehensive income include changes in the fair value of derivatives designated as cash flow hedges.

Environmental Liabilities

Environmental expenditures that relate to current or future revenues are expensed or capitalized as appropriate. Expenditures that relate to an existing condition caused by past operations, and do not contribute to current or future revenue generation, are expensed. Liabilities are recorded when environmental assessments and/or clean-ups are probable, and the costs can be reasonably estimated. Generally, the timing of these accruals coincides with our commitment to a formal plan of action. As of December 31, 2003, we had accrued approximately $0.6 million for future environmental expenditures.

Contingencies

We recognize liabilities for contingencies when we have an exposure that, when fully analyzed, indicates it is both probable and that the amount can be reasonably estimated. Funds spent to remedy these contingencies are charged against a reserve, if one exists, or expensed.

Inventory

Our inventory is valued at the lower of cost or market, with cost being determined on a first-in, first-out (FIFO) method. We had crude oil inventory in the Congo of $2.5 million and $3.0 million at December 31, 2003 and 2002. Our materials and supplies inventory totaled $3.2 million and $4.3 million at December 31, 2003 and 2002.

Recognition of Crude Oil and Natural Gas Revenue

Crude oil and natural gas revenue is recognized when title to the commodities produced passes to the purchaser. We use the entitlement method for recording sales of crude oil and natural gas from producing wells. Under the entitlement method, revenue is recorded based on our net revenue interest in production. Deliveries of crude oil and natural gas in excess of our net revenue interests are recorded as liabilities and under-deliveries are recorded as assets. Production imbalances are recorded at the lower of the sales price in effect at the time of production or the current market value. Substantially all such amounts are anticipated to be settled with production in future periods. At December 31, 2003 and 2002, our imbalances were insignificant.

Income Taxes

Deferred income taxes are accounted for under the asset and liability method of accounting for income taxes. Under this method, deferred income taxes are recognized for the tax consequences of temporary differences by applying enacted statutory tax rates applicable to future years to differences between the financial statement carrying amounts and the tax basis of existing assets and liabilities. The effect on deferred taxes of a change in tax rates is recognized in income in the period the change occurs.

Statements of Cash Flows

For cash flow presentation purposes, we consider all highly liquid money market instruments with an original maturity of three months or less to be cash equivalents. Interest paid in cash, including amounts capitalized, for 2003, 2002, and 2001 was $31.4 million, $35.4 million, and $38.3 million. Net amounts paid (refunded) in cash for income taxes for 2003, 2002, and 2001 were $1.8 million, $(1.5) million, and $0.4 million.

NUEVO ENERGY COMPANY

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Use of Estimates

In order to prepare these financial statements in conformity with accounting principles generally accepted in the United States of America, our management has made a number of estimates and assumptions relating to the reporting of assets and liabilities and the disclosure of contingent assets and liabilities, as well as reserve information, which affects the depletion calculation. Actual results could differ from those estimates.

Stock-Based Compensation

We account for stock compensation plans under the intrinsic value method of Accounting Principles Board Opinion No. 25, *Accounting for Stock Issued to Employees.* No compensation expense is recognized for stock options that had an exercise price equal to their market value of the underlying common stock on the date of grant. As allowed by SFAS No. 123, *Accounting for Stock-Based Compensation,* we have continued to apply APB Opinion No. 25 for purposes of determining net income. In December 2002, the FASB issued SFAS No. 148, *Accounting for Stock-Based Compensation Transition and Disclosure an amendment of FASB Statement No. 123* to provide alternative methods of transition for a voluntary change to the fair value based method of accounting for stock-based employee compensation. Additionally, the statement amends the disclosure requirements of SFAS No. 123 to require prominent disclosures in both annual and interim financial statements about the method of accounting for stock-based employee compensation and the effect of the method used on reported results. Had compensation expense for stock-based compensation been determined based on the fair value at the date of grant, our net income and earnings per share would have been as follows:

	Year Ended December 31,		
	2003	2002	2001
	(In thousands, except per share data)		
Net income (loss) as reported	$51,479	$12,275	$(79,171)
Add:			
Stock based employee compensation expense included in reported net income, net of related income tax	1,079	755	310
Deduct:			
Total stock based employee compensation expense determined under fair value based method for all awards, net of related income tax	(2,115)	(4,777)	(4,316)
Pro forma net income (loss)	$50,443	$ 8,253	$(83,177)
Earnings per share:			
Basic as reported	$ 2.66	$ 0.70	$ (4.73)
Basic pro forma	2.61	0.47	(4.97)
Diluted as reported	2.62	0.69	(4.73)
Diluted pro forma	2.57	0.46	(4.97)

The weighted-average fair value of options granted during 2003, 2002 and 2001 was $9.87, $8.20 and $6.23. The fair value of each option grant is estimated on the date of grant using the Black-Scholes option-pricing model with the following weighted-average assumptions: expected stock price volatility of 44.5% in 2003 and 2002 and 54.5% in 2001; risk free interest of 4% in 2003, 2002 and 2001; and average expected option lives of eight years in 2003 and 2002 and three years in 2001.

We granted 372,574, 25,465 and 47,520 shares of restricted stock in 2003, 2002 and 2001. The weighted-average fair value of restricted common stock granted during 2003, 2002 and 2001 was $19.15, $13.99 and $14.43, respectively.

Table of Contents

NUEVO ENERGY COMPANY

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Functional Currency

Our functional currency for all operations is the U.S. dollar.

Reclassifications

Certain reclassifications of prior period amounts have been made to conform to the current presentation. The unaudited quarterly data footnote (Note 17) also reflects reclassifications to conform with current presentation. These reclassifications had no effect on net income or earnings per share.

New Accounting Pronouncements

Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity. In May 2003, the FASB issued SFAS No. 150, *Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity.* SFAS No. 150 establishes standards for how an issuer classifies and measures three classes of freestanding financial instruments (mandatorily redeemable instruments, instruments with repurchase obligations, instruments with obligations to issue a variable number of shares) with characteristics of both liabilities and equity. Instruments within the scope of the statement must be classified as liabilities on the balance sheet. SFAS No. 150 was effective for all freestanding financial instruments entered into or modified after May 31, 2003, and otherwise was effective at the beginning of the first interim period beginning after June 15, 2003. We have not entered into any financial instruments within the scope of SFAS No. 150 since May 31, 2003, nor do we currently hold any significant financial instruments within the scope. SFAS No. 150 does not apply to convertible bonds, consequently our TECONS are not within the scope of SFAS No. 150.

Guarantor s Accounting and Disclosure Requirements. The FASB issued Interpretation No. 45 (FIN 45), *Guarantor s Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of the Indebtedness of Others,* in November 2002, which clarifies the requirements of SFAS No. 5, *Accounting for Contingencies,* relating to a guarantor s accounting for and disclosures of certain guarantees issued. FIN 45 requires enhanced disclosures for certain guarantees. It also requires that certain guarantees issued or modified after December 31, 2002, including certain third-party guarantees, be recorded initially on the balance sheet at fair value. For guarantees issued on or before December 31, 2002, liabilities are recorded when and if payments become probable and estimable. We adopted FIN 45 effective January 1, 2003, and have included the disclosure requirements of FIN 45 in Note 13 to the consolidated financial statements. The adoption of FIN 45 had no effect on our consolidated financial position, results of operations or cash flows.

Consolidation of Variable Interest Entities. In December 2003, the FASB issued Interpretation No. 46 (revised December 2003), (FIN 46R), *Consolidation of Variable Interest Entities* (VIE s), replacing Interpretation No. 46 (FIN 46), *Consolidation of Variable Interest Entities,* an interpretation of Accounting Research Bulletin No. 51, issued in January 2003. FIN 46R was issued to replace FIN 46 and to provide clarification of key terms, additional exemptions for application and an extended initial application period. FIN 46R requires certain VIEs be consolidated by the primary beneficiary of the entity if the equity investors in the entity do not have the characteristics of a controlling financial interest or do not have sufficient equity at risk for the entity to finance its activities without additional subordinated financial support from other parties. FIN 46 was effective for all VIEs created or acquired after January 31, 2003. For VIEs created or acquired prior to February 1, 2003, the provisions of FIN 46 was required to be applied for the first interim or annual period beginning after June 15, 2003. We had no contractual relationship or other business relationship with a variable interest entity and therefore the adoption of FIN 46 had no effect on our consolidated financial position, results of operations or cash flows.

We adopted FIN 46R on December 31, 2003. As a result of adopting FIN 46R, we were required to deconsolidate our Nuevo Financing I business trust and our TECONS. Accordingly, our 5 3/4% Convertible

Table of Contents

NUEVO ENERGY COMPANY

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Subordinated Debentures due December 15, 2026, have been included in long-term liabilities as a long-term liability to an unconsolidated affiliate at December 31, 2003. Beginning in 2004, dividends on the TECONS will no longer be reported in our results of operations; instead, we will be reflecting the dividends as interest expense on the income statement.

The FASB issued SFAS No. 141, *Business Combinations,* and SFAS No. 142, *Goodwill and Other Intangible Assets* in June 2001. We adopted the provisions of these statements on July 1, 2001 and January 1, 2002, respectively. SFAS No. 141 requires all business combinations initiated after June 30, 2001 to be accounted for using the purchase method. SFAS No. 142 addresses accounting and reporting of acquired goodwill and other intangible assets. This statement requires that, at a minimum, all intangible assets be aggregated and presented as a separate line item on the balance sheet. A reporting issue has arisen regarding the application of certain provisions of SFAS No. 141 and SFAS No. 142 for companies in the extractive industries, including oil and gas companies. The issue is whether SFAS No. 142 requires registrants to classify the costs of mineral rights associated with extracting oil and gas as intangible assets in the balance sheet, apart from other capitalized oil and gas property costs, and to provide specific footnote disclosures.

The Emerging Issues Task Force has added the treatment of oil and gas mineral rights to an upcoming agenda which may result in a change in how we are currently classifying these costs. Historically, we have included the costs of mineral rights associated with extracting oil and gas as a component of oil and gas properties pursuant to the provisions of SFAS No. 19, *Financial Accounting and Reporting by Oil and Gas Companies.* If it is ultimately determined that SFAS No. 142 requires these costs to be classified as a separate intangible asset line item on the balance sheet, we would be required to reclassify approximately $95 million and $101 million at December 31, 2003 and December 31, 2002, respectively, out of oil and gas properties into a separate intangible assets line item on the balance sheet. To calculate these amounts, we deducted our estimate of the fair value of tangible oil and gas equipment acquired in the merger with Athanor Resources, Inc. in 2002 from the amount of the purchase price allocated to property, plant and equipment. Our results of operations would not be affected since such intangible assets would continue to be depleted and assessed for impairment in accordance with successful efforts accounting rules. The classification of these costs as intangible assets would not have any impact on our compliance with the covenants under our debt agreements.

3. Asset Retirement Obligations

SFAS No. 143, *Accounting for Asset Retirement Obligations* requires a liability to be recorded relating to the eventual retirement and removal of assets used in our business. The liability is discounted to its present value, with a corresponding increase to the related asset value. Over the life of the asset, the liability will be accreted to its future value and eventually extinguished when the asset is taken out of service. We adopted the provisions of SFAS No. 143 on January 1, 2003 to record our asset retirement obligation to plug and abandon oil and gas wells, offshore platforms and facilities. In connection with the initial application of SFAS No. 143, we recorded a cumulative effect of change in accounting principle, net of taxes, of $8.5 million as an increase to net income. In addition, we recorded an asset retirement obligation for oil and gas properties and equipment

Table of Contents

NUEVO ENERGY COMPANY

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

of $92.7 million. The following table rolls forward our asset retirement obligation in accordance with the provisions of SFAS No. 143:

	Year Ended December 31, 2003
	(In thousands)
Beginning asset retirement obligation	$ 92,680
Liabilities incurred during period(1)	2,643
Liabilities settled during period	(1,159)
Accretion expense	9,089
Revisions	(332)
Ending asset retirement obligation	$ 102,921

(1) Consists of $2.4 million related to acquisitions and $0.2 million associated with new domestic wells drilled.

The following table summarizes the pro forma basis as required by SFAS No. 143, had we adopted the provisions of SFAS No. 143 prior to January 1, 2003:

Adoption Date	Pro forma Asset Retirement Obligation
	(In thousands)
December 31, 2002	$92,680
December 31, 2001	84,182
January 1, 2001	76,461

In addition, pro forma net income and earnings per share for the years ended December 31, 2002 and 2001 for the change in accounting had SFAS No. 143 been implemented during these periods would have been as follows:

	2002	2001
	(In thousands, except per share data)	
Net income (loss)		
As reported	$ 12,275	$ (79,171)
Pro forma	14,799	(75,607)
Net income (loss) per share reported		
Basic	0.70	(4.73)
Diluted	0.69	(4.73)
Net income (loss) per share pro forma		
Basic	0.84	(4.52)
Diluted	0.83	(4.52)

4. Earnings Per Share

EPS Computation

SFAS No. 128, *Earnings per Share,* requires a reconciliation of the numerator (income) and denominator (shares) of the basic EPS computation to the numerator and denominator of the diluted EPS computation. In 2001, the weighted average shares held by benefit trust of 145,000 are not included in the calculation of diluted loss per share due to their anti-dilutive effect. In 2001, stock options were excluded from the calculation of diluted loss per share due to their anti-dilutive effect. We had 0.9 million and 2.1 million

Table of Contents

NUEVO ENERGY COMPANY

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

stock options in 2003 and 2002 which were not included in the calculation of diluted earnings per share because the option exercise price exceeded the average market price. We also have 2.3 million Term Convertible Securities, Series A (TECONS) that were not included in the calculation of diluted earnings (loss) per share in 2003, 2002 or 2001 due to their anti-dilutive effect. The reconciliation is as follows:

	For the Year Ended December 31,					
	2003		2002		2001	
	Net Income	Common Shares	Net Income	Common Shares	Net Loss	Common Shares
	(In thousands)					
Income (loss) before cumulative effect available for Common shares Basic	$42,983	19,355	$12,275	17,651	$(79,171)	16,735
Effect of dilutive securities:						
Stock options		146		52		
Restricted stock		126		24		
Shares held by Benefit Trust			(8)	63		
Income (loss) before cumulative effect available for Common shares Diluted	$42,983	19,627	$12,267	17,790	$(79,171)	16,735

5. Discontinued Operations

We sold our Eastern properties located in Texas, Alabama and Louisiana in 2002 and sold our Brea-Olinda, Union Island and Orcutt Hill oil and gas properties located in California in 2003. The historical results of operations of these properties are classified as discontinued operations in our statements of income. The following table reflects revenue, gain/loss on disposition and pre-tax income for the periods presented:

	Year Ended December 31,		
	2003	2002	2001
	(In thousands)		
Brea-Olinda			
Revenue	$ 3,246	$ 16,390	$18,005
Loss on disposition	(31)	(30,466)	
Pre-tax income (loss)	2,675	(22,465)	7,731
Union Island			
Revenue	1,575	2,431	7,189
Gain on disposition	7,889		
Pre-tax income	9,302	1,518	5,799
Orcutt Hill			
Revenue	6,609	8,724	9,039
Loss on disposition	(4,578)		
Pre-tax income (loss)	(1,662)	2,389	2,229
Eastern Properties			

Revenue	3,216	8,330
Loss on disposition	(1,045)	
Pre-tax income (loss)	(157)	4,607

NUEVO ENERGY COMPANY

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

6. Accounts Receivable

Our accounts receivable and allowance for doubtful accounts consisted of the following at December 31:

	2003	2002
	(In thousands)	
Oil and gas sales	$32,604	$31,551
Joint interest billings	2,584	4,070
Other	4,541	5,324
	$39,729	$40,945
Allowance for doubtful accounts	$ 216	$ 626

7. Stockholders Equity

Common and Preferred Stock

Our Certificate of Incorporation authorizes the issuance of up to 50 million shares of Common Stock and 10 million shares of Preferred Stock, the terms, preferences, rights and restrictions of which are established by our Board of Directors. All shares of Common Stock have equal voting rights of one vote per share on all matters to be voted upon by stockholders. Cumulative voting for the election of directors is not permitted. Certain restrictions contained in our loan agreements limit the amount of dividends that may be declared. Under the terms of the most restrictive covenant in our indenture for the 9 1/2% Senior Subordinated Notes due 2008 described in Note 9, we and our restricted subsidiaries had $20.5 million available for the payment of dividends and share repurchases at December 31, 2003. We have not paid dividends on our Common Stock and do not anticipate the payment of cash dividends in the immediate future.

Treasury Stock Repurchases

Our Board of Directors has authorized the open market repurchase of up to 5.6 million shares of common stock. Repurchases may be made at times and at prices deemed appropriate by management and consistent with the authorization of our Board. There were no shares repurchased during 2003. As of December 31, 2003, we had 3.5 million shares of treasury stock.

Shareholder Rights Plan

In 1997, we adopted a Shareholder Rights Plan to protect our shareholders from coercive or unfair takeover tactics. Under the Shareholder Rights Plan, each outstanding share and each share of subsequently issued common stock has attached to it one Right. Generally, in the event a person or group (Acquiring Person) acquires or announces an intention to acquire beneficial ownership of 15% or more of the outstanding shares of common stock without our prior consent, or we are acquired in a merger or other business combination, or 50% or more of our assets or earning power is sold, each holder of a Right will have the right to receive, upon exercise of the Right, that number of shares of common stock of the acquiring company, which at the time of such transaction will have a market price of two times the exercise price of the Right. We may redeem the Right for $.01 at any time before a person or group becomes an Acquiring Person without prior approval. The Rights will expire on March 21, 2007, subject to earlier redemption by us.

In 2000, we amended the Shareholder Rights Plan to provide that if we receive and consummate a transaction pursuant to a qualifying offer, the provisions of the Shareholder Rights Plan are not triggered. In general, a qualifying offer is an all cash, fully-funded tender offer for all outstanding common shares by a person who, at the commencement of the offer, beneficially owns less than five percent of the outstanding common shares. A qualifying offer must remain open for at least 120 days, must be conditioned on the person

NUEVO ENERGY COMPANY

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

commencing the qualifying offer acquiring at least 75% of the outstanding common shares and the per share consideration must exceed the greater of (1) 135% of the highest closing price of the common shares during the one-year period prior to the commencement of the qualifying offer or (2) 150% of the average closing price of the common shares during the 20 day period prior to the commencement of the qualifying offer.

In February 2004, the Board of Directors approved the amendment of the plan to permit a merger with Plains without triggering the provisions of the plan.

Executive Compensation Plan

In 1997, we adopted a plan to encourage senior executives to personally invest in our stock, and to regularly review executives ownership versus targeted ownership objectives. These incentives include a deferred compensation plan (the Plan) that gives key executives the ability to defer all or a portion of their salaries and bonuses and invest in our common stock or make other investments at the employee s discretion. The Plan was amended in 2003 to offer a 15% discount on investments in our common stock up to $30,000 annually. Stock is held in a benefit trust and stock acquired at a discount is restricted for a two-year period. Target levels of ownership are based on multiples of base salary and are administered by the Compensation Committee of the Board of Directors. Upon withdrawal from the Plan, the obligation to the employee is settled with the invested assets. The Plan applies to certain highly compensated employees and all executives at a level of Vice-President and above. The stock held in the benefit trust (99,369 shares, 70,595 shares and 122,995 shares at December 31, 2003, 2002 and 2001) was accounted for as a liability at market value, with any changes in market value charged or credited to general and administrative expense until July 2002. Using this approach, we recorded a net benefit of $0.2 million in 2001 related to deferred compensation. In July 2002, the Plan was further amended to remove the right to receive withdrawals in cash resulting in a reclassification of the $1.1 million liability into shareholders equity. The deferred compensation obligation is now classified in shareholders equity and changes in the fair value of the obligation are not recognized.

Director Compensation

Non-employee directors may elect to receive all or part of an annual cash retainer of $30,000 in restricted shares of our Common Stock at a 33% increase in value. The election must be made in increments of 25% ($7,500). Therefore, for each $7,500 of compensation for which the election is exercised, the director would receive $9,975 in restricted stock. Beginning in 2003, each non-employee director also receives a semi-annual grant of 2,125 restricted shares of our common stock. All restricted shares are subject to a three-year restricted period. Directors have the option of deferring delivery of restricted shares beyond the three-year period. Directors also receive $1,000 for each committee meeting attended while committee chairpersons receive $1,500. Directors may also elect to receive restricted shares for committee meetings at a 33% discount.

Stock Incentive Plans

In 1990, we established the 1990 Stock Option Plan; in 1993, the Board of Directors adopted the Nuevo Energy Company 1993 Stock Incentive Plan; and in 1999, the Board of Directors adopted the Nuevo Energy Company 1999 Stock Incentive Plan (collectively, the Stock Incentive Plans). In 2001, the Board of Directors adopted the 2001 Stock Incentive Plan as well as individual incentive plans to induce Janet F. Clark, our former Senior Vice President and Chief Financial Officer and George B. Nilsen, our Senior Vice President, Planning and Asset Management to accept employment with us. The purpose of the Stock Incentive Plans is to provide our directors and key employees with performance incentives and to provide a means of encouraging these individuals to own our stock.

In November 2002, the Compensation Committee of the Board of Directors approved an increase of 250,000 shares under the 2001 Stock Incentive Plan, increasing the total maximum number of incentive shares available under the Stock Incentive Plans to 5,250,000 shares. Options or Restricted Shares are granted

Table of Contents

NUEVO ENERGY COMPANY

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

under the Stock Incentive Plans on the basis of the grantee s contribution to us. No option may exceed a term of more than ten years. Options granted under the Stock Incentive Plans may be either incentive stock options or options that do not qualify as incentive stock options. Our Compensation Committee is authorized to designate the recipients of options, the dates of grants, the number of shares subject to options, the option price, the terms of payment upon exercise of the options, and the time during which the options may be exercised. Options for officers vest over a term of one to three years, as specified by the Compensation Committee. Officers who have met their targeted stock ownership requirement receive accelerated vesting on all options issued prior to October 15, 2001. The Company granted 10,500 options in 2003 and all the remaining incentive grants were made in the form of Restricted Shares.

The following table details the summary of activity in the stock option plans during the three years ended 2003:

	Options	Weighted-Average Exercise Price
Outstanding at January 1, 2001	2,772,918	$21.94
Granted	875,026	15.51
Exercised	(287,000)	12.93
Canceled	(102,525)	33.88
Outstanding at December 31, 2001	3,258,419	20.62
Granted	487,750	14.79
Exercised	(105,675)	11.99
Canceled	(938,245)	29.13
Outstanding at December 31, 2002	2,702,249	16.96
Granted	10,500	16.12
Exercised	(408,328)	15.61
Canceled	(390,031)	15.77
Outstanding at December 31, 2003	1,914,390	17.49

We had options exercisable of 1,560,730 (weighted average exercise price of $18.01), 2,053,416 (weighted average exercise price of $17.89) and 2,728,494 (weighted average exercise price of $21.80) at December 31, 2003, 2002 and 2001. Detail of stock options outstanding and options exercisable at December 31, 2003 follows:

	Outstanding			Exercisable	
Range of Exercise Prices	Number	Weighted- Average Remaining Life (Years)	Weighted- Average Exercise Price	Number	Weighted- Average Exercise Price
$10.31 to $15.42	895,065	7.68	$13.66	609,571	$13.09
$15.50 to $19.12	739,525	5.64	16.82	671,359	16.84
$20.38 to $29.88	149,800	2.09	25.02	149,800	25.02
$34.00 to $47.88	130,000	3.80	38.99	130,000	38.99
	1,914,390			1,560,730	

Table of Contents

NUEVO ENERGY COMPANY

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

8. Company-Obligated Mandatorily Redeemable Convertible Preferred Securities of Nuevo Financing I

On December 23, 1996, the Company and Nuevo Financing I, a statutory business trust formed under the laws of the state of Delaware and wholly owned by us, (the Trust), closed the offering of 2.3 million TECONS on behalf of the Trust. The price to the public was $50.00 per TECONS. Distributions began to accumulate from December 23, 1996, and are payable quarterly on March 15, June 15, September 15, and December 15, at an annual rate of $2.875 per TECONS. Each TECONS is convertible at any time prior to the close of business on December 15, 2026, at the option of the holder into shares of common stock at the rate of 0.8421 shares of common stock for each TECONS, subject to adjustment. The sole asset of the Trust as the obligor on the TECONS is $118.6 million aggregate principal amount of 5 3/4% Convertible Subordinated Debentures (Debentures) of the Company due December 15, 2026. The Debentures were issued by us to the Trust to facilitate the offering of the TECONS. The TECONS must be redeemed for $50.00 per TECONS plus accrued and unpaid dividends on December 15, 2026. We own the Trust Common Securities which have an aggregate liquidation value of 3% of the total capital of the Trust. We will receive this amount from the Trust upon liquidation. We guarantee the Trust s obligations under the TECONS.

The balance sheet of the Trust at December 31, 2003 (dollars in thousands) is as follows:

Receivable from Nuevo Energy Company	$118,557
Total Assets	$118,557
TECONS	$115,000
Trust Common Securities owned by Nuevo Energy Company	3,557
Total Liabilities and Equity	$118,557

We offset the Trust Common Securities against the balance in the receivable as we will receive the liquidation value of the Trust Common Securities.

The Trust pays interest on the $115.0 million and receives interest on $118.6 million due from Nuevo Energy Company. The excess interest income received will be paid to us as the owner of the Trust Common Securities.

As a result of adopting FIN 46R, *Consolidation of Variable Interest Entities*, at December 31, 2003, we were required to deconsolidate our Nuevo Financing I Business Trust. See Note 2.

NUEVO ENERGY COMPANY

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

9. Long-Term Debt

Our long-term debt consisted of the following:

	December 31,	
	2003	2002
	(In thousands)	
9 3/8% Senior Subordinated Notes due 2010	$150,000	$150,000
9 1/2% Senior Subordinated Notes due 2008[1]	75,000	257,210
9 1/2% Senior Subordinated Notes due 2006		2,367
Long-term liability to unconsolidated affiliate	115,000	
Bank credit facility (2.02% at December 31, 2003 and 3.11% at December 31, 2002)	15,000	28,700
Total debt	355,000	438,277
Interest rate swaps fair value adjustment	(153)	2,161
Interest rate swaps termination gain	14,364	11,673
Long-term debt	$369,211	$452,111

(1) Redeemed February 27, 2004.

9 3/8% Notes due 2010

On September 26, 2000, we issued $150.0 million of 9 3/8% Senior Subordinated Notes due October 1, 2010. Interest accrues at 9 3/8% per annum and is payable semi-annually in arrears on April 1 and October 1. The Notes are redeemable, in whole or in part, at our option, on or after October 1, 2005, under certain conditions. We are not required to make mandatory redemption or sinking fund payments with respect to these Notes. The indenture contains covenants that, among other things, limit our ability to incur additional indebtedness, limit restricted payments, limit issuances and sales of capital stock by restricted subsidiaries, limit dispositions of proceeds from asset sales, limit dividends and other payment restrictions affecting restricted subsidiaries, and restrict mergers, consolidations or sales of assets. The Notes are unsecured general obligations, and are subordinated in right of payment to all existing and future senior indebtedness. In the event of a defined change in control, we will be required to make an offer to repurchase all outstanding 9 3/8% Notes at 101% of the principal amount, plus accrued and unpaid interest to the date of redemption.

9 1/2% Notes due 2008

In July 1999, we authorized a new issuance of $260.0 million of 9 1/2% Senior Subordinated Notes due June 1, 2008. In August 1999, we exchanged $157.5 million of our 9 1/2% Notes due 2006 and $99.9 million of our 8 7/8% Senior Subordinated Notes due 2008. In connection with the exchange offers, we solicited consents to proposed amendments to the indentures under which the exchanged notes were issued. The exchange was accounted for as a debt modification and the consideration we paid to the holders of the exchanged 9 1/2% Notes due 2006 was $4.7 million and was accounted for as deferred financing costs.

Interest on these Notes accrues at the rate of 9 1/2% per annum and is payable semi-annually in arrears on June 1 and December 1. These Notes are redeemable, in whole or in part, at our option, on or after June 1, 2003, under certain conditions. In 2003, we redeemed $182.2 million of these notes at 104.75% of the principal amount plus accrued and unpaid interest. We recorded a $12.6 million loss on early extinguishment of debt consisting of an $8.7 million call premium and a $3.9 million write-off of deferred financing costs. We are not required to make mandatory redemption or sinking fund payments on these Notes. The indenture contains covenants that, among other things, limit our ability to incur additional indebtedness, limit restricted

56

Table of Contents

NUEVO ENERGY COMPANY

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

payments, limit issuances and sales of capital stock by restricted subsidiaries, limit dispositions of proceeds from asset sales, limit dividends and other payment restrictions affecting restricted subsidiaries, and restrict mergers, consolidations or sales of assets. The 9 1/2% Notes are unsecured general obligations, and are subordinated in right of payment to all of our existing and future senior indebtedness. In the event of a defined change in control, we will be required to make an offer to repurchase all outstanding Notes at 101% of the principal amount, plus accrued and unpaid interest to the date of redemption. In February 2004, we redeemed in full the remaining $75.0 million of these Notes at 104.75% of the principal amount plus accrued and unpaid interest.

9 1/2% Notes due 2006

In April 1996, we issued $160.0 million of 9 1/2% Notes and in August 1999, we exchanged $157.5 million of these Notes for 9 1/2% Notes due 2008 and have repurchased some of the Notes in the open market. Interest on these Notes accrues at the rate of 9 1/2% per annum and is payable semi-annually in arrears on April 15 and October 15 and were redeemable, in whole or in part, at our option, on or after April 15, 2001, under certain conditions. The Notes are unsecured general obligations, and are subordinated in right of payment to all existing and future senior indebtedness. In April 2003, we redeemed in full the remaining $2.4 million of these Notes at 101.58% of the principal amount plus accrued and unpaid interest.

Long-term Liability to Unconsolidated Affiliate

In December 1996, we issued $115.0 million of 5 3/4% Convertible Subordinated Debentures due December 15, 2026, to Nuevo Financing I business trust to facilitate the offering of the TECONS in December 1996. Interest on these Debentures accrues at 5 3/4% per annum and is payable quarterly on March 15, June 15, September 15 and December 15. The Debentures are redeemable, in whole or in part, at our option, upon not less than 30 or more than 60 days notice, on or after December 15, 1999, under certain conditions. We are required to redeem the Debentures at 100% in the event the tax or legal structure changes as defined in the agreement. The holder of the Debentures has the right, exercisable at any time prior to close of business on December 15, 2026, to convert the principal amount into shares of our common stock at a conversion rate of 0.8421 shares for each Debenture, subject to adjustment under certain circumstances. We are not required to make sinking fund payments with respect to the Debentures.

Interest Rate Swaps

We entered into interest rate swaps in 2003, 2002 and 2001. (See Note 14.)

Bank Credit Facility

Our Third Amended and Restated Credit Agreement, dated June 7, 2000, as amended, provides for secured revolving credit availability of up to $250 million and issuance of letters of credit from a bank group led by Bank of America, N.A., Bank One, NA, and Bank of Montreal until its expiration on June 7, 2005. At December 31, 2003, we had $15.0 million under the Credit Facility and two letters of credit outstanding in the amount of $1.6 million.

Availability under the Credit Facility is determined pursuant to a semi-annual borrowing base determination which establishes the maximum borrowings that may be outstanding under the credit facility. The borrowing base is determined by a 60% vote of participant banks (two-thirds in the event of an increase in the borrowing base), each of which bases its judgement on: (i) the present value of our oil and gas reserves based on their own assumptions regarding future prices, production, costs, risk factors and discount rates, and (ii) projected cash flow coverage ratios calculated under varying scenarios. If amounts outstanding under the credit facility exceed the borrowing base, as redetermined from time to time, we would be required to repay

Table of Contents

NUEVO ENERGY COMPANY

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

such excess over a defined period of time. We have a $200 million borrowing base under our Credit Facility with $183.4 million available at December 31, 2003 and had outstanding $16.6 million under the agreement.

Amounts outstanding under the credit facility bear interest at a rate equal to LIBOR plus an amount which varies according to our Indebtedness to Capitalization ratio (as defined in the Credit Agreement). The weighted average interest rate was 2.9% in 2003 and 3.6% in 2002.

Our Credit Agreement has covenants which limit certain restricted payments and investments, guarantees and indebtedness, prepayments of subordinated and certain other indebtedness, mergers and consolidations, on certain types of acquisitions and on the issuance of certain securities by subsidiaries, liens, sales of properties, transactions with affiliates, derivative contracts and debt in subsidiaries. We are also required to maintain certain financial ratios and conditions, including without limitation an EBITDAX (earnings before interest, taxes, depreciation, depletion, amortization and exploration expenses) to fixed charge coverage ratio and a funded debt to capitalization ratio. At December 31, 2003, we were in compliance with all covenants of the Credit Agreement.

The amount of scheduled debt maturities during the next five years and thereafter as of December 31, 2003 is as follows (amounts in thousands):

2004	$
2005	15,000
2006	
2007	
2008(1)	75,000
Thereafter	265,000
Total debt maturities	$355,000

(1) Redeemed February 27, 2004.

Based upon the quoted market price, the fair value of the 9 3/8% Notes was estimated to be $165.8 million and $149.4 million at December 31, 2003 and 2002; the fair value of the 9 1/2% Notes due 2008 was estimated to be $78.8 million and $264.0 million at December 31, 2003 and 2002, and the fair value of the 9 1/2% Notes due 2006 was estimated to be $2.4 million at December 31, 2002. The fair value of the long-term liability to unconsolidated affiliate is $94.3 million at December 31, 2003. The carrying amount of the credit facility approximates its fair value at December 31, 2003.

10. Income Taxes

The components of income before income taxes and cumulative effect of change in accounting principle for each of the three years in the period ended December 31, 2003, are as follows:

	2003	2002	2001
United States	$35,085	$28,254	$(144,143)
Foreign	25,122	11,516	(8,351)
Income from continuing operations before income taxes	$60,207	$39,770	$(152,494)

Table of Contents

NUEVO ENERGY COMPANY

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Income tax expense (benefit) is summarized as follows:

	Year Ended December 31,		
	2003	2002	2001
	(In thousands)		
Current			
Federal	$ 341	$	$
State	276	1,330	
Foreign	1,469		
	2,086	1,330	
Deferred			
Federal	19,590	14,023	(49,015)
State	4,321	1,338	(12,108)
Foreign	(2,879)		
	21,032	15,361	(61,123)
Total income tax expense (benefit)	$ 23,118	$ 16,691	$ (61,123)

We recorded income tax expense (benefit) of $4.4 million, $(7.9) million and $8.2 million in 2003, 2002 and 2001 related to discontinued operations. We recorded a tax expense of $5.7 million related to a cumulative effect of a change in accounting principle in 2003 (see Note 3). A deferred tax benefit related to the exercise of employee stock options of approximately $0.6 million, $0.5 million and $0.8 million was allocated directly to additional paid-in capital in 2003, 2002 and 2001.

Total income tax expense (benefit) differs from the amount computed by applying the federal income tax rate to income (loss) before income taxes and cumulative effect. The reasons for these differences are as follows:

	Year Ended December 31,		
	2003	2002	2001
Statutory federal income tax rate	35.0%	35.0%	(35.0)%
Increase (decrease) in tax rate resulting from:			
State income taxes, net of federal benefit	5.0	6.6	(5.2)
Nondeductible travel and entertainment and other	0.3	0.1	0.1
Foreign income taxes net of federal benefit	(1.1)		
	39.2%	41.7%	(40.1)%

Table of Contents

NUEVO ENERGY COMPANY

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The tax effects of temporary differences that result in significant portions of the deferred income tax assets and liabilities and a description of the financial statement items creating these differences are as follows:

	December 31,	
	2003	2002
	(In thousands)	
Net operating loss carryforwards	$ 44,835	$ 74,640
Alternative minimum tax credit carryforwards	781	200
Other accrued liabilities		1,205
Commodity hedging contracts	15,870	7,871
State income taxes		2,298
Foreign income taxes	1,871	
Total deferred income tax assets	63,357	86,214
Less: valuation allowance		(804)
Net deferred income tax assets	63,357	85,410
Property and equipment	(30,667)	(33,798)
Equity in foreign subsidiaries	(585)	(671)
Other accrued liabilities	(1,545)	
State income taxes	(1,250)	
Total deferred income tax liabilities	(34,047)	(34,469)
Net deferred income tax asset	$ 29,310	$ 50,941

At December 31, 2003, we had a net operating loss carryforward for regular tax purposes of approximately $128.1 million, which will begin expiring in 2018. Alternative minimum tax credit carryforwards of $0.8 million do not expire and may be applied to reduce regular income tax to an amount not less than the alternative minimum tax payable in any one year. For all periods presented we concluded that based upon available estimates and tax planning strategies, it was more likely than not that all of the recorded deferred tax assets would be realized. In 2003, we reversed a valuation allowance of a $0.8 million relating to a capital loss carryover due to its realization in 2003.

11. Segments

Our operations consist of the acquisition, exploitation, exploration, development and production of crude oil and natural gas. We have four operating segments, Onshore California, Offshore California, West Texas and Congo because, in accordance with SFAS No. 131, these are the segments that (1) engage in business activities from which revenues are earned and expenses are incurred, (2) whose operating results are regularly reviewed by our chief operating decision maker to make decisions about resources to be allocated to the segment and assess its performance and (3) for which discrete financial information is available.

We have aggregated Onshore California, Offshore California and West Texas into our domestic segment, which is a reportable segment. We have aggregated these three operating segments because we believe these operating segments have similar economic characteristics in the following areas as outlined in SFAS No. 131: (1) the nature of the products and services, (2) the nature of the production process, (3) the type of class of customer for the products and services, (4) the methods used to distribute their products or provide their services and (5) the nature of the regulatory environment.

60

NUEVO ENERGY COMPANY

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Our reportable segments are domestic, foreign and other. Financial information by reportable segment is presented below:

	2003			
	Domestic	Foreign	Other(1)	Total
	(In thousands)			
Revenues	$327,009	$42,966	$ 1,362	$371,337
Depreciation, depletion, amortization and accretion	62,919	5,847	2,044	70,810
Income (loss) from continuing operations before income tax	119,964	25,122	(84,879)	60,207
Capital expenditures	64,798	1,205	728	66,731
Total assets	646,436	45,416	153,124	844,976

	2002			
	Domestic	Foreign	Other(1)	Total
	(In thousands)			
Revenues	$275,853	$31,978	$ 4,070	$311,901
Depreciation, depletion and amortization	64,562	6,198	2,368	73,128
Income (loss) from continuing operations before income tax	104,649	11,516	(76,395)	39,770
Capital expenditures	137,002	1,524	2,956	141,482
Total assets	557,421	52,269	245,481	855,171

	2001			
	Domestic	Foreign	Other(1)	Total
	(In thousands)			
Revenues	$274,786	$36,020	$ 273	$ 311,079
Depreciation, depletion and amortization	58,347	10,381	1,826	70,554
Income (loss) from continuing operations before income tax	(37,869)	(8,351)	(106,274)	(152,494)
Capital expenditures	148,329	20,647	1,262	170,238
Total assets	548,186	56,404	235,222	839,812

(1) Other includes corporate income and expenses.

Credit Risks due to Certain Concentrations

In 2003, 2002 and 2001, we had one customer under domestic segment that accounted for 65%, 73%, and 63% of oil and gas revenues. In 2003 we had another customer under domestic segment that accounted for 11% of oil and gas revenues and in 2001 we had another domestic segment customer that accounted for 23% of oil and gas revenues.

We entered into a 15-year contract, effective January 1, 2000, to sell all of our current and future California crude oil production to ConocoPhillips. The contract provides pricing based on a fixed percentage of the NYMEX crude oil price for each type of crude oil that we produce in California. Effective January 1, 2003, we renegotiated this contract relative to our Point Arguello production, effectively increasing our price by 14.5% on the NYMEX price. Effective January 1, 2004, we renegotiated our NYMEX relationship for all production sold to ConocoPhillips increasing our effective realization by approximately 11%. While the contract does not reduce our exposure to price volatility, it does effectively eliminate the risk of widening basis differential between the NYMEX price and the field price of our California oil production. In doing so, the

NUEVO ENERGY COMPANY

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

contract makes it substantially easier for us to hedge our realized prices. The ConocoPhillips contract permits, under certain circumstances, to separately market up to ten percent of our California crude production. We exercised this right and sold 5,000 BOPD of our San Joaquin Valley oil production to a third party under a two-year contract containing NYMEX pricing in 2003 and under a one-year contract containing NYMEX pricing in 2002 and 2001.

Our revenues are derived principally from uncollateralized sales to customers in the oil and gas industry, therefore, customers may be similarly affected by changes in economic and other conditions within the industry. We have not experienced significant credit losses in such sales. Sales of oil and gas to ConocoPhillips are similarly uncollateralized.

12. Acquisition of Athanor Resources, Inc.

We acquired Athanor Resources, Inc. (Athanor) in September 2002, in a transaction valued at $101.4 million, which included the combination of $61.3 million of available cash and additional borrowings, the issuance of approximately $20.1 million of our common stock (approximately 2.0 million shares) to Athanor stockholders, and the fair value of the net liabilities assumed of approximately $20.0 million.

The acquisition was accounted for using the purchase method of accounting. The purchase price was finalized during the second quarter of 2003, and the following table summarizes the fair value of the assets acquired and liabilities assumed at the date of acquisition.

	(In thousands)
Current assets	$ 4,426
Property, plant and equipment	102,801
Goodwill	17,121
Total assets acquired	124,348
Current liabilities	4,474
Long-term debt	20,000
Deferred tax liability	18,477
Total liabilities assumed	42,951
Net assets acquired	$ 81,397

The allocation of the purchase price resulted in $17.1 million allocated to goodwill which is not expected to be deductible for tax purposes.

The acquisition included certain non-cash investing and financing activities not reflected in the Consolidated Statement of Cash Flows for the year ended December 31, 2002, as follows:

	(In thousands)
Common stock issued	$20,086
Long-term debt assumed	20,000

Subsequent to the acquisition, the long-term debt of $20.0 million was repaid.

The following unaudited pro forma condensed income statement information has been prepared as if the acquisition had occurred at the beginning of the periods presented. The historical results of operations have been adjusted to reflect the difference between Athanor s historical depletion, depreciation and amortization

NUEVO ENERGY COMPANY

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

and the expense calculated based on the value allocated to the assets acquired. The information presented is not necessarily indicative of the results of future operations of the combined companies.

	2002	2001
	(In thousands, except per share data)	
Revenues	$ 327,458	$ 344,256
Income (loss) from continuing operations	24,952	(82,432)
Net income (loss)	14,148	(70,228)
Earnings per share		
Basic		
Income (loss) from continuing operations	1.31	(4.41)
Net income (loss)	0.74	(3.75)
Diluted		
Income (loss) from continuing operations	1.30	(4.41)
Net income (loss)	0.74	(3.75)

13. Commitments and Contingencies

Legal Proceedings and Other Matters

We acquired properties from Unocal in 1996 and are obligated to make a contingent payment based on net proceeds received, less certain deductions, on oil sold through 2004 if oil prices exceed thresholds set forth in the purchase and sale agreement with Unocal. Any contingent payments paid or accrued are accounted for as a purchase price adjustment to oil and gas properties. We paid $10.8 million to Unocal in 2002 attributable to calendar year 2001 and recorded the payment as an increase in oil and gas properties. In March 2003, we advised Unocal that we had failed to take deductions to proceeds received that we believe are permitted by the agreement. Application of these deductions results in no payment due for either calendar year 2001 or 2002. Unocal disputes this position for both years. We filed suit against Unocal to recover the 2001 payment, secure a declaration of the appropriate deduction methodology to be applied for 2002 through 2004 and to recover attorneys fees. Unocal has answered and filed a counterclaim claiming breach of contract and anticipatory breach of contract seeking $16.0 million for 2002, a declaration of the appropriate deduction methodology payment of amounts attributable to 2003 and 2004 and attorneys fees. While the outcome of this matter is not presently determinable, its resolution is not expected to have a material impact on our results of operations, financial condition or liquidity.

We have asserted a claim against Torch Energy Advisors for matters arising out of our former outsourcing arrangement. Among other demands, we have requested the return of a $2.0 million working capital advance. Torch has asserted claims for indemnity and payment of certain fees it asserts are owed to them. These outstanding issues will be arbitrated and are not expected to have a material impact on our results of operations, financial condition or liquidity.

On December 18, 2002, a lawsuit was filed by Hills for Everyone, a non-profit corporation, against Orange County and Nuevo Energy Company challenging the adequacy of the Environment Impact Report for our Tonner Hills project. The suit sought to compel Orange County to set aside its decision to adopt the Environment Impact Report and sought additional environmental analysis and mitigation measures. We contested the litigation. During the second quarter of 2003, we entered into a settlement agreement with Hills for Everyone and Orange County ending the litigation. The settlement did not have a material impact on the project or our results of operations, financial condition or liquidity.

NUEVO ENERGY COMPANY

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Commitments and Contingencies

On December 30, 2003, we sold our Tonner Hills residential development property for approximately $47 million. We received $16 million of the purchase price on the date of the sale and anticipate receiving an additional $22.5 million on March 29, 2004. The $16 million is currently reported in other liabilities, and the $22.5 million will be reported in other liabilities as these amounts are accounted for as deposits until certain habitat restoration outlined in the purchase and sales agreement completed by us.

On September 14, 2001, during an annual inspection, we discovered fractures in the heat affected zone of certain flanges on our pipeline that connects the Point Pedernales field with onshore processing facilities. We voluntarily elected to shut-in production in the field while repairs were being made. The daily net production from this field was approximately 5,000 barrels of crude oil and 1.2 MMcf of natural gas, representing approximately 11% of our daily production. We replaced the damaged flanges, as well as others which had not shown signs of damage. We resumed production in January 2002. During the third quarter 2002 we reached a final agreement with our underwriters with respect to our business interruption claim. Accordingly, we recognized $3.0 million of business interruption recoveries during the third quarter 2002 which is classified in other revenue and received payment on this claim by year-end 2002. As of December 31, 2003, all outstanding claims have been settled.

On June 15, 2001, we experienced a failure of a carbon dioxide treatment vessel at the Rincon Onshore Separation Facility (ROSF) located in Ventura County, California. There were no injuries associated with this event. Crude oil and natural gas produced from three fields offshore California are transported onshore by pipeline to the ROSF plant where crude oil and water are separated and treated, and carbon dioxide is removed from the natural gas stream. The daily net production associated with these fields at the time of the incident was approximately 3,000 barrels of crude oil and 2.4 MMcf of natural gas, representing approximately 6% of our daily production. In early July 2001, crude oil production resumed and full gas sales resumed by mid August 2001. Insurance claims relating to the cost of repair and business interruption (less a 30-day waiting period) were settled in the second quarter of 2003, and we recognized income of $2.3 million in connection with the insurance settlement.

On September 22, 2000, we were named as a defendant in the lawsuit *Thomas Wachtell et al. versus Nuevo Energy Company in the Superior Court of Los Angeles County, California.* We settled this lawsuit in June 2002 for, among other matters, making a payment to plaintiffs of $3.4 million, and receiving from plaintiffs certain interests in properties and extinguishing certain contract rights of plaintiffs. We established a reserve for this contingency in 2001 and the settlement payment did not have a material impact on our results of operations or financial position.

On April 5, 2000, we filed a lawsuit against ExxonMobil Corporation in the United States District Court for the Central District of California, Western Division regarding our 50% interest in the Sacate field, offshore Santa Barbara County, California. We settled this lawsuit in June 2002. Under the terms of the settlement agreement, we received $16.5 million from ExxonMobil and conveyed to them our interest in the Santa Ynez Unit, our non-consent interest in the adjacent Pescado field and relinquished our right to participate in the Sacate field and recorded a $15.3 million gain related to the sale of this unproved property.

In September 1997, there was a spill of crude oil into the Santa Barbara Channel from a pipeline that connects our Point Pedernales field with shore-based processing facilities. The volume of the spill was estimated to be 163 barrels of oil. Repairs were completed by the end of 1997, and production recommenced in December 1997. The costs of the clean up and the cost to repair the pipeline were covered by our insurance, less a deductible of $0.1 million. As of December 31, 2003 all significant outstanding claims have been settled. We expect that the final insurance settlements related to these claims will be insignificant. We are awaiting final disposition of certain insurance claims that have been submitted to our carriers.

NUEVO ENERGY COMPANY

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Our acquisition agreement to purchase the two subsidiaries owning interests in the Yombo field offshore Congo contains a provision for contingent royalty to be paid by us to the seller if certain conditions are met. Under this provision we will pay to the seller an amount equal to $2.8 million, increased by 7% per year from 1995, if we recover from our Yombo field production an amount greater than the sum of our capital costs, our operating costs, and $27.0 million, which entire amount increases 27% annually. We currently estimate that we could reach payout as early as 2005.

Our foreign investments involve risks typically associated with investments in emerging markets such as an uncertain political, economic, legal and tax environment and expropriation and nationalization of assets. In addition, if a dispute arises in our foreign operations, we may be subject to the exclusive jurisdiction of foreign courts or may not be successful in subjecting foreign persons to the jurisdiction of the United States. We attempt to conduct our business and financial affairs so as to protect against political and economic risks applicable to operations in the various countries where we operate, but there can be no assurance that we will be successful in so protecting ourselves. A portion of our investment in the Congo is insured through political risk insurance provided by Overseas Private Investment Company (OPIC). The political risk insurance through OPIC covers up to $25.0 million relating to expropriation, which is the maximum coverage available through OPIC. During 1997, a new government was established in the Congo. Although the political situation in the Congo has not to date had a material adverse effect on our operations in the Congo, no assurances can be made that continued political unrest in West Africa will not have a material adverse effect on us or our operations in the Congo in the future.

In connection with our February 1995 acquisitions of two subsidiaries owning interests in the Yombo field offshore Congo, we and a wholly-owned subsidiary of CMS NOMECO Oil & Gas Co. (CMS) agreed with the seller of the subsidiaries not to claim certain tax losses (dual consolidated losses) incurred by such subsidiaries prior to the acquisitions. Under the tax law in the Congo, as it existed when this acquisition took place, if an entity is acquired in its entirety and that entity has certain tax attributes, for example tax loss carryforwards from operations in the Republic of Congo, the subsequent owners of that entity can continue to utilize those losses without restriction. Pursuant to the agreement, we and CMS may be liable to the seller for the recapture of dual consolidated losses (net operating losses of any domestic corporation that are subject to an income tax of a foreign country without regard to the source of its income or on a residence basis) utilized by the seller in years prior to the acquisitions if certain triggering events occur, including: (i) a disposition by either us or CMS of its respective Congo subsidiary, (ii) either Congo subsidiary s sale of its interest in the Yombo field, (iii) the acquisition of us or CMS by another consolidated group or (iv) the failure of CMS s Congo subsidiary or us to continue as a member of its respective consolidated group.

A triggering event will not occur, however, if a subsequent purchaser enters into certain agreements specified in the consolidated return regulations intended to ensure that such dual consolidated losses will not be claimed. The only time limit associated with the occurrence of a triggering event relates to the utilization of a dual consolidated loss in a foreign jurisdiction. A dual consolidated loss that is utilized to offset income in a foreign jurisdiction is only subject to recapture for 15 years following the year in which the dual consolidated loss was incurred for U.S. income tax purposes. We and CMS have agreed among ourselves that the party responsible for the triggering event shall indemnify the other for any liability to the seller as a result of such triggering event. Our potential direct liability could be as much as $25.1 million if a triggering event with respect to us occurs. Additionally, we believe that CMS s liability (for which we would be jointly liable with an indemnification right against CMS) could be as much as $42.8 million. CMS sold their interest in the Yombo field in 2002, to a U.S. subsidiary of Perenco, S.A. (Perenco). The sale was not a triggering event as both CMS and Perenco filed a request for a Closing Agreement with the Internal Revenue Service in accordance with the U.S. consolidated tax return regulations prior to the sale. Further, we do not expect a triggering event to occur with respect to Nuevo, CMS or Perenco, and do not believe the agreement will have a material adverse effect upon us. We do not expect that the proposed merger with Plains will be a triggering event.

Table of Contents

NUEVO ENERGY COMPANY

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

In 1996, the Congo government requested that the convention governing the Marine I Exploitation Permit be converted to a Production Sharing Agreement (PSA). We are under no obligation to convert to a PSA, and our existing convention is valid and protected by law. Our position is that any conversion to a PSA should have no detrimental impact to us, otherwise, we will not agree to any such conversion. Discussions with the government have been ongoing intermittently since early 1997. To date, no final agreement has been reached concerning conversion to a PSA.

We have been named as a defendant in certain other lawsuits incidental to our business. These actions and claims in the aggregate seek damages against us and are subject to the inherent uncertainties in any litigation. We are defending ourselves vigorously in all such matters. We have reserved an amount that we deem adequate to cover any potential losses related to these matters to the extent the losses are deemed probable and estimable. This amount is reviewed periodically and changes may be made, as appropriate. Any additional costs related to these potential losses are not expected to be material to our operating results, financial condition or liquidity.

Guarantees Related to Assets or Obligations of Third Parties.

We have indemnified certain third parties for future environmental remediation costs that may be incurred for properties that we purchased or properties that we sold to a third party. The properties may or may not require environmental remediation and if we are determined to be responsible, our indemnities may require us, among other matters, to pay for the remediation costs. We are not able to determine the maximum potential amount, if any, of future payments that we could be required to make under these indemnifications primarily due to the following: the indefinite term of the majority of these indemnities; the unknown extent of possible contamination; the conditional nature of our responsibility under certain indemnities; uncertainties related to the timing of the remediation work; possible changes in laws governing the remediation process; the unknown number of claims that may be made and changes in remediation technology.

We have performance obligations in the ordinary course of business that are secured by surety bonds or letters of credit. These surety bonds and letters of credit are issued by financial institutions and are required to be reimbursed if drawn upon. At December 31, 2003, we had surety bonds of $39.7 million and letters of credit of $1.6 million.

We have guaranteed the payment of the Nuevo Financing I TECONS issued December 1996. The TECONS are supported by our 5 3/4% Convertible Debentures, which are included on our balance sheet as long-term liabilities to unconsolidated affiliate.

In the ordinary course of business, we have provided indemnifications and guarantees that are not explicitly defined whose terms range in duration. We do not believe that these will have a material effect on our results of operation, financial condition or liquidity.

Operating Leases

We have operating leases in the normal course of business, which include those for office space, operating facilities and office equipment, with varying terms from 2004 to 2009. Total rental expense under the agreements was $1.5 million in 2003, $1.3 million in 2002 and $1.1 million in 2001. The rental expense is recorded in general and administrative expense. At December 31, 2003, our total commitments under operating leases were approximately $6.1 million.

Table of Contents

NUEVO ENERGY COMPANY

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Minimum annual rental commitments at December 31, 2003, were as follows:

	Operating Leases
	(In thousands)
2004	$1,492
2005	1,487
2006	1,214
2007	808
2008	808
Thereafter	270
Total	$6,079

14. Financial Instruments

We have entered into commodity swaps, collars, put options and interest rate swaps. The commodity swaps, collars and put options are designated as cash flow hedges and the interest rate swaps are designated as fair value hedges in accordance with SFAS 133. Quantities covered by crude hedges are based on West Texas Intermediate (WTI) barrels. Our production is expected to average 82% of WTI, therefore, each WTI barrel hedges 1.22 barrels of our production.

Derivative Instruments Designated as Cash Flow Hedges

At December 31, 2003, we had entered into the following cash flow hedges:

	Crude Oil			Natural Gas		
	Bbls/ day	$/Bbl	Index	MMbtu/day	$/MMbtu	Index
Swaps for Sales						
2004						
1st Qtr	19,800	25.71	WTI	16,500	4.93	Waha & Socal
2nd Qtr	19,500	25.71	WTI	14,500	4.65	Waha & Socal
3rd Qtr	19,800	25.71	WTI	10,500	4.50	Waha & Socal
4th Qtr	21,000	25.98	WTI	14,500	4.64	Waha & Socal
2005						
1st Qtr	17,500	24.88	WTI	13,000	4.75	Waha & Socal
2nd Qtr	14,500	24.67	WTI	9,500	4.66	Waha
3rd Qtr	4,500	22.14	WTI	9,500	4.40	Waha
4th Qtr	4,500	22.14	WTI	9,500	4.40	Waha
Swaps for Purchases						
2004				8,000	3.91	Socal
2005				8,000	3.85	Socal

At December 31, 2003, the fair market value of these hedge positions is a loss of $40.5 million. All of these agreements expose us to counterparty credit risk to the extent that the counterparty is unable to meet its settlement commitments.

67

NUEVO ENERGY COMPANY

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Derivative Instruments Designated as Fair Value Hedges

In late December 2001 and early 2002, we entered into three interest rate swap agreements with notional amounts totaling $200 million to hedge the fair value of our 9 1/2% Notes due 2008 and our 9 3/8% Notes due 2010. These swaps were designated as fair value hedges and as interest rates fluctuated, the change in value of these instruments was reflected as an increase or decrease of long-term debt with a corresponding increase in long-term assets or liabilities.

In late August and early September 2002, we terminated our swap transactions relating to these Notes. As a result of these terminations, we received accrued interest of $2.2 million and the present value of the swap option of $9.6 million on our 9 3/8% Notes and $0.5 million in accrued interest and the present value of the swap option of $2.5 million on our 9 1/2% Notes. The gain of $9.6 million on our 9 3/8% Notes and $2.5 million on our 9 1/2% Notes is reflected as an increase of long-term debt and will be amortized as a reduction to interest expense over the life of the Notes. During the twelve months ended December 31, 2003, we amortized $1.3 million as a reduction of interest expense.

Following the termination of the three interest rate swaps referenced above, in late August and early November 2002, we entered into two new interest rate swap agreements with notional amounts totaling $100.0 million, to hedge a portion of the fair value of our 9 3/8% Notes due 2010. These swaps were also designated and accounted for as fair value hedges.

In May 2003, we terminated our swap transactions relating to these Notes. As a result of these terminations, we received accrued interest of $0.4 million and the present value of the swap option of $4.1 million. The remaining gain of $4.1 million continues to be reflected as an increase of long-term debt and is being amortized as a reduction to interest expense over the life of the Notes. Through December 31,2003, we had amortized $0.2 million.

In late October 2003, we entered into an interest rate swap agreement with a notional amount of $100 million, to hedge a portion of the fair value of our 9 3/8% Notes due 2010. This swap is designated as a fair value hedge and is reflected as a decrease in long-term debt of $0.2 million as of December 31,2003, with a corresponding increase in long-term liabilities. Under the terms of the agreement, the counterparty pays us a weighted average fixed annual rate of 9 3/8% on total notional amount of $100 million, and we pay the counterparty a variable annual rate equal to the six-month LIBOR rate plus a weighted average rate of 5.02%.

Derivative Instruments Not Designated as Hedges

In December 2001, Enron Corp. (Enron) and certain of its affiliates filed voluntary petitions for reorganization under Chapter 11 of the United States Bankruptcy Code. As a result, we recorded a $7.6 million charge in the fourth quarter of 2001: $1.2 million related to the November and December 2001 crude oil price swaps, $0.9 million related to the Enron call spread (see below), and $5.5 million related to the fair value of open hedges of second, third and fourth quarter 2002 crude oil production. Once a deterioration in creditworthiness creates uncertainty as to whether the future cash flows from the hedging instrument will be highly effective in offsetting the hedged risk, the derivative instrument is no longer considered highly effective and no longer qualifies for hedge accounting treatment. At such time, the fair value of the derivative asset or liability is adjusted to its new fair value, with the change in value being charged to current earnings. The net gain or loss of the derivative instruments previously reported in other comprehensive income remains in accumulated other comprehensive income and is reclassified into earnings during the period in which the originally designated hedge items affect earnings. The $2.2 million deferred gain in Other Comprehensive Income at December 31, 2001 was reclassified into earnings in 2002.

In 2001 and 2000, we entered into call spreads with the anticipation of using the proceeds to offset the Unocal Contingent payment. (See Note 13.) Subsequent to entering into the call spreads, the market fell and as a result, offsetting call spreads were purchased to economically nullify the trade. All of our existing call

Table of Contents

NUEVO ENERGY COMPANY

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

spreads had been offset through the purchase of a mirror spread, however, the call spread with Enron was cancelled. (See above discussion). The remaining mirror call spread is not designated as a hedging instrument and is marked-to-market with changes in fair value recognized currently as derivative gain/loss. For the twelve months ended December 31, 2003, we recognized $1.8 million as a derivative loss. At December 31, 2003, the call spread matured for $4.6 million.

In August 2003, we entered into three-way collars that are not designated as hedging instruments and are marked-to-market with changes in fair value recognized currently as a derivative gain/loss. During the twelve months ended December 31, 2003, we recorded a $4.1 million derivative loss and recorded the fair value of the derivative loss at December 31, 2003, totaling $4.1 million as a liability.

	Bbls/ day	Index	Weighted Average Price
Three-Way Collars(1)			
2004			
(Jan Dec)	8,000	WTI	$ 19.28 24.00 31.00

(1) A Three-Way Collar combines a sold put, a purchased put and a sold call. The purchased put and sold put establish a floating minimum price and the sold call establishes a maximum price we will receive for the volumes under contract.

Fair Values of Financial Instruments

Fair value for cash, short-term investments, receivables and payables approximates carrying value. The following table details the carrying values and approximate fair values of our other investments, derivative financial instruments and long-term debt at December 31, 2003 and 2002.

	December 31, 2003		December 31, 2002	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In thousands)			
Derivative Instruments				
Commodity price swaps	$ (40,484)	$ (40,484)	$ (22,311)	$ (22,311)
Interest rate swaps	(153)	(153)	2,161	2,161
Long-term debt (see Note 9)(1)	340,000	338,894	409,577	415,833
TECONS			115,000	64,400

(1) As a result of adopting FIN46R, *Consolidation of Variable Interest Entities,* at December 31, 2003, we are required to deconsolidate our wholly owned Nuevo Financing I business trust which issued our TECONS. We are including the long-term liability to unconsolidated affiliate in long-term debt.

The fair value of our long-term debt and TECONS were determined based upon interest rates currently available to us for borrowing with similar terms at December 31, 2003 and 2002.

15. Supplemental Information (Unaudited)

Oil and Gas Producing Activities

Included herein is information with respect to oil and gas acquisition, exploration, development and production activities, which is based on estimates of year-end oil and gas reserve quantities and estimates of future development costs and production schedules. Reserve quantities and future production as of December 31, 2003, and for previous years, are based primarily on reserve reports prepared by the independent

69

NUEVO ENERGY COMPANY

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

petroleum engineering firm of Ryder Scott Company L.P. These estimates are inherently imprecise and subject to substantial revision.

Estimates of future net cash flows from proved reserves of gas, oil, condensate and natural gas liquids (NGL) were made in accordance with SFAS No. 69, *Disclosures about Oil and Gas Producing Activities.* The estimates are based on the NYMEX cash price at year-end 2003, of $32.55 per Bbl and $5.97 per MMbtu adjusted for basis differences, and are adjusted for the effects of contractual agreements with Unocal and Amoco in connection with the California and Congo property acquisitions (see Note 13).

Estimated future cash inflows are reduced by estimated future development and production costs based on year-end cost levels, assuming continuation of existing economic conditions, and by estimated future income tax expense. Tax expense is calculated by applying the existing statutory tax rates, including any known future changes, to the pre-tax net cash flows, less depreciation of the tax basis of the properties and depletion allowances applicable to the gas, oil, condensate and NGL production. Because the disclosure requirements are standardized, significant changes can occur in these estimates based upon oil and gas prices currently in effect. The results of these disclosures should not be construed to represent the fair market value of our oil and gas properties. A market value determination would include many additional factors including: (i) anticipated future increases or decreases in oil and gas prices and production and development costs; (ii) an allowance for return on investment; (iii) the value of additional reserves, not considered proved at the present, which may be recovered as a result of further exploration and development activities; and (iv) other business risks.

Costs Incurred

The following table sets forth the costs incurred in property acquisition and development activities:

	Domestic	Foreign	Total
		(In thousands)	
2003			
Property acquisition	$ 830	$	$ 830
Exploration	100	926	1,026
Development	55,788	1,206	56,994
Asset retirement obligation	3,374		3,374
	$ 60,092	$ 2,132	$ 62,224
2002			
Property acquisition	$107,064	$	$107,064
Exploration	357	1,244	1,601
Development	52,531	1,527	54,058
	$159,952	$ 2,771	$162,723
2001			
Property acquisition	$ 47,266	$ 47	$ 47,313
Exploration	16,004	4,703	20,707
Development	100,721	20,222	120,943
	$163,991	$24,972	$188,963

NUEVO ENERGY COMPANY

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Pro forma costs incurred for the years ended December 31, 2002 and 2001, for the change in accounting had SFAS No. 143 been implemented during these periods would have been $0.4 million and $0.9 million respectively, associated with property acquisitions and new domestic wells drilled.

---

(1) Includes capitalized interest directly related to development activities of $1.6 million, $1.9 million and $2.5 million in 2003, 2002 and 2001, respectively.

Capitalized Costs

The following table sets forth the capitalized costs relating to oil and gas activities and the associated accumulated depreciation, depletion and amortization:

	Domestic	Foreign	Total
		(In thousands)	
2003			
Proved properties	$ 911,722	$ 93,166	$ 1,004,888
Unproved properties	26,314		26,314
Total capitalized costs	938,036	93,166	1,031,202
Accumulated depreciation, depletion and amortization	(294,833)	(50,258)	(345,091)
Net capitalized costs	$ 643,203	$ 42,908	$ 686,111
2002			
Proved properties	$ 829,839	$ 92,964	$ 922,803
Unproved properties	28,369	86	28,455
Total capitalized costs	858,208	93,050	951,258
Accumulated depreciation, depletion and amortization	(304,740)	(44,155)	(348,895)
Net capitalized costs	$ 553,468	$ 48,895	$ 602,363
2001			
Proved properties	$ 893,215	$ 91,437	$ 984,652
Unproved properties	27,117	2,660	29,777
Total capitalized costs	920,332	94,097	1,014,429
Accumulated depreciation, depletion and amortization	(378,644)	(37,693)	(416,337)
Net capitalized costs	$ 541,688	$ 56,404	$ 598,092

We have included asset retirement costs in total capitalized costs and the related accumulated allocation of the asset retirement costs in accumulated depreciation, depletion and amortization for the year ended December 31, 2003. Pro forma basis as required by SFAS No. 143, had we adopted the provisions of SFAS No. 143 prior to January 1, 2003, net capitalized costs would have been as follows:

Adoption Date	Pro forma Asset Retirement Obligation
	(In thousands)
December 31, 2002	$92,680
December 31, 2001	84,182
January 1, 2001	76,461

Table of Contents

NUEVO ENERGY COMPANY

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Results of operations for producing activities

	Domestic	Foreign	Total
		(In thousands)	
2003			
Revenues from oil and gas producing activities	$ 327,009	$ 42,966	$ 369,975
Production costs	(149,261)	(10,571)	(159,832)
Exploration costs	(689)	(1,426)	(2,115)
Depreciation, depletion, amortization and accretion	(62,919)	(5,847)	(68,766)
Income (loss) before income tax	114,140	25,122	139,262
Income tax (provision) benefit	(43,830)	(9,647)	(53,477)
Results of operations from producing activities (excluding corporate overhead and interest costs)	$ 70,310	$ 15,475	$ 85,785
2002			
Revenues from oil and gas producing activities	$ 275,853	$ 31,978	$ 307,831
Production costs	(122,207)	(10,747)	(132,954)
Exploration costs	(1,024)	(3,517)	(4,541)
Depreciation, depletion and amortization	(64,562)	(6,198)	(70,760)
Income (loss) before income tax	88,060	11,516	99,576
Income tax (provision) benefit	(36,721)	(4,802)	(41,523)
Results of operations from producing activities (excluding corporate overhead and interest costs)	$ 51,339	$ 6,714	$ 58,053
2001			
Revenues from oil and gas producing activities	$ 274,786	$ 36,020	$ 310,806
Production costs	(146,058)	(14,028)	(160,086)
Exploration costs	(16,170)	(5,888)	(22,058)
Depreciation, depletion and amortization	(58,347)	(10,381)	(68,728)
Provision for impairment of oil and gas properties	(89,466)	(14,024)	(103,490)
Income (loss) before income tax	(35,255)	(8,301)	(43,556)
Income tax (provision) benefit	14,148	3,318	17,466
Results of operations from producing activities (excluding corporate overhead and interest costs)	$ (21,107)	$ (4,983)	$ (26,090)

Pro forma results of operations from producing activities for 2002 and 2001 for the change in accounting had SFAS No. 143 been implemented during these periods would have been $60,577 and $(22,526), respectively.

* Results of operations represent results from continuing operations.

Table of Contents

NUEVO ENERGY COMPANY

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Our estimated total proved and proved developed reserves of oil and gas are as follows:

	Crude Oil and Liquids (MBbl)(1)			Natural Gas (MMcf)(1)		
	Domestic	Foreign	Total	Domestic	Foreign	Total
2003						
Proved reserves at beginning of year	206,237	14,100	220,337	173,844	841	174,685
Revisions of previous estimates	1,336	1,983	3,319	21,028	16	21,044
Extensions and discoveries	3,977		3,977	10,746		10,746
Production	(14,111)	(1,764)	(15,875)	(14,394)	(52)	(14,446)
Sales of reserves in-place	(35,636)		(35,636)	(25,531)		(25,531)
Purchase of reserves in-place	3,949		3,949	673		673
Proved reserves at end of year	165,752	14,319	180,071	166,366	805	167,171
Proved developed reserves						
Beginning of year	187,735	14,100	201,835	139,609	841	140,450
End of year	150,098	14,319	164,417	124,916	805	125,721
2002						
Proved reserves at beginning of year	199,014	15,844	214,858	111,363	1,129	112,492
Revisions of previous estimates	18,015	131	18,146	16,213	(236)	15,977
Extensions and discoveries				2,564		2,564
Production	(14,640)	(1,875)	(16,515)	(13,460)	(52)	(13,512)
Sales of reserves in-place	(168)		(168)	(4,829)		(4,829)
Purchase of reserves in-place	4,016		4,016	61,993		61,993
Proved reserves at end of year	206,237	14,100	220,337	173,844	841	174,685
Proved developed reserves						
Beginning of year	169,507	15,844	185,351	92,890	1,129	94,019
End of year	187,735	14,100	201,835	139,609	841	140,450
2001						
Proved reserves at beginning of year	196,692	23,202	219,894	165,977		165,977
Revisions of previous estimates	15,164	(5,478)	9,686	(55,422)		(55,422)
Extensions and discoveries	311		311	578	1,129	1,707
Production	(14,536)	(1,880)	(16,416)	(12,750)		(12,750)
Sales of reserves in-place						
Purchase of reserves in-place	1,383		1,383	12,980		12,980
Proved reserves at end of year	199,014	15,844	214,858	111,363	1,129	112,492
Proved developed reserves						

Beginning of year	160,039	11,013	171,052	122,500		122,500
End of year	169,507	15,844	185,351	92,890	1,129	94,019

(1) Reserves and production from discontinued operations are included in this table

73

Table of Contents

NUEVO ENERGY COMPANY

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Discounted future net cash flows

The standardized measure of discounted future net cash flows and changes therein are shown below:

	Domestic	Foreign	Total
		(In thousands)	
2003			
Future cash inflows	$ 5,104,116	$ 347,147	$ 5,451,263
Future production costs	(2,274,483)	(210,207)	(2,484,690)
Future development costs(1)	(415,090)	(1,730)	(416,820)
Future net inflows before income tax	2,414,543	135,210	2,549,753
Future income taxes	(733,350)	(35,750)	(769,100)
Future net cash flows	1,681,193	99,460	1,780,653
10% discount factor	(632,055)	(27,250)	(659,305)
Standardized measure of discounted future net cash flows	$ 1,049,138	$ 72,210	$ 1,121,348
2002			
Future cash inflows	$ 5,290,440	$ 343,406	$ 5,633,846
Future production costs	(2,435,730)	(169,832)	(2,605,562)
Future development costs	(392,746)	(4,406)	(397,152)
Future net inflows before income tax	2,461,964	169,168	2,631,132
Future income taxes	(690,501)	(48,777)	(739,278)
Future net cash flows	1,771,463	120,391	1,891,854
10% discount factor	(693,830)	(28,738)	(722,568)
Standardized measure of discounted future net cash flows	$ 1,077,633	$ 91,653	$ 1,169,286
2001			
Future cash inflows	$ 3,182,420	$ 248,569	$ 3,430,989
Future production costs	(1,773,397)	(123,628)	(1,897,025)
Future development costs	(382,412)	(6,863)	(389,275)
Future net inflows before income tax	1,026,611	118,078	1,144,689
Future income taxes	(149,564)	(25,237)	(174,801)
Future net cash flows	877,047	92,841	969,888
10% discount factor	(366,050)	(24,152)	(390,202)
Standardized measure of discounted future net cash flows	$ 510,997	$ 68,689	$ 579,686

(1) Includes $162.8 million of undiscounted future asset retirement expenditures estimated as of December 31, 2003, using current estimates of future abandonment costs. At December 31, 2002 and at December 31, 2001 $168.9 million and $108.5 million, respectively, is included in undiscounted future development costs for future abandonment costs. See Note 3 for corresponding information regarding discounted asset retirement obligations.

Table of Contents

NUEVO ENERGY COMPANY

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following are the principal sources of change in the standardized measure of discounted future net cash flows:

	Domestic	Foreign	Total
		(In thousands)	
2003			
Standardized measure beginning of year	$1,077,633	$ 91,653	$1,169,286
Sales, net of production costs	(177,748)	(32,395)	(210,143)
Purchases of reserves in-place	18,855		18,855
Net change in prices and production costs	261,120	(17,894)	243,226
Extensions, discoveries and improved recovery, net of future production and development costs	31,001		31,001
Changes in estimated future development costs	(30,096)	1,428	(28,668)
Development costs incurred	37,499	1,206	38,705
Revisions of quantity estimates	37,186	13,486	50,672
Accretion of discount	130,558	12,127	142,685
Net change in income taxes	(84,031)	12,036	(71,995)
Sales of reserves in-place	(160,577)		(160,577)
Changes in production rates and other	(92,262)	(9,437)	(101,699)
Standardized measure end of year	$1,049,138	$ 72,210	$1,121,348
2002			
Standardized measure beginning of year	$ 510,997	$ 68,689	$ 579,686
Sales, net of production costs	(170,357)	(21,368)	(191,725)
Purchases of reserves in-place	119,143		119,143
Net change in prices and production costs	560,784	45,408	606,192
Extensions, discoveries and improved recovery, net of future production and development costs	9,149		9,149
Changes in estimated future development costs	29,946	449	30,395
Development costs incurred	31,123	1,527	32,650
Revisions of quantity estimates	120,287	736	121,023
Accretion of discount	51,100	7,782	58,882
Net change in income taxes	(227,948)	(20,484)	(248,432)
Sales reserves in-place	(5,245)		(5,245)
Changes in production rates and other	48,654	8,914	57,568
Standardized measure end of year	$1,077,633	$ 91,653	$1,169,286
2001			
Standardized measure beginning of year	$1,149,562	$105,327	$1,254,889
Sales, net of production costs	(154,785)	(21,899)	(176,684)
Purchases of reserves in-place	13,759		13,759
Net change in prices and production costs	(904,288)	(56,360)	(960,648)
Extensions, discoveries and improved recovery, net of future production and development costs	2,750	114	2,864
Changes in estimated future development costs	(61,735)	16,455	(45,280)
Development costs incurred	62,817	16,100	78,917
Revisions of quantity estimates	20,906	(25,804)	(4,898)
Accretion of discount	151,060	13,861	164,921
Net change in income taxes	361,041	24,150	385,191
Sales of reserves in-place			

Changes in production rates and other	(130,090)	(3,255)	(133,345)
Standardized measure end of year	$ 510,997	$ 68,689	$ 579,686

Table of Contents

NUEVO ENERGY COMPANY

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

16. Selected Quarterly Financial Data (Unaudited)

	2003				
	1st Qtr	2nd Qtr	3rd Qtr	4th Qtr	Year
	(In thousands, except per share data)				
Revenues	$98,250	$94,521	$87,834	$90,732	$371,337
Income from operations	32,947	32,966	23,380	25,398	114,691
Income from continuing operations	12,663	6,612	9,392	8,422	37,089
Income from discontinued operations, net of income tax	4,554	770	640	(70)	5,894
Cumulative effect of change in Accounting Principle	8,496				8,496
Net Income	25,713	7,382	10,032	8,352	51,479
Basic earnings per share[1]					
Continuing operations	$ 0.66	$ 0.34	$ 0.49	$ 0.43	$ 1.92
Discontinued operations	0.24	0.04	0.03		0.30
Cumulative effect of change in Accounting Principle net of income tax	0.44				0.44
Net income	$ 1.34	$ 0.38	$ 0.52	$ 0.43	$ 2.66
Diluted earnings per share[1]					
Continuing operations	$ 0.65	$ 0.34	$ 0.48	$ 0.42	$ 1.89
Discontinued operations	0.24	0.04	0.03		0.30
Cumulative effect of change in Accounting Principle net of income tax	0.44				0.43
Net income	$ 1.33	$ 0.38	$ 0.51	$ 0.42	$ 2.62

	2002[2]				
	1st Qtr	2nd Qtr	3rd Qtr	4th Qtr[3]	Year
	(In thousands, except per share data)				
Revenues	$70,968	$77,491	$84,250	$ 79,192	$311,901
Income from operations	11,929	35,511	20,982	20,384	88,806
Income from continuing operations	373	14,587	3,857	4,262	23,079
Income (loss) from discontinued operations, net of income tax	1,089	1,979	2,298	(16,170)	(10,804)
Net Income (loss)	1,462	16,566	6,155	(11,908)	12,275
Basic earnings (loss) per share[1]					
Continuing operations	$ 0.02	$ 0.85	$ 0.22	$ 0.22	$ 1.31
Discontinued operations	0.07	0.12	0.13	(0.84)	(0.61)
Net income (loss)	$ 0.09	$ 0.97	$ 0.35	$ (0.62)	$ 0.70

Diluted earnings (loss) per share[1]					
Continuing operations	$ 0.01	$ 0.84	$ 0.22	$ 0.22	$ 1.30
Discontinued operations	0.07	0.12	0.13	(0.84)	(0.61)
Net income (loss)	$ 0.08	$ 0.96	$ 0.35	$ (0.62)	$ 0.69

(1) The sum of the individual quarterly net income (loss) per common share may not agree with year-to-date net income (loss) per common share as each quarterly computation is based on the weighted average number of common shares outstanding during that period.

(2) Components of the 2002 quarters were revised due to a reclassification of sold properties to discontinued operations.

(3) Fourth quarter 2002 results include a $17.8 million after-tax write down of assets held for sale in discontinued operations.

Table of Contents

INDEPENDENT AUDITORS REPORT ON

CONSOLIDATED FINANCIAL STATEMENT SCHEDULE

To the Board of Directors and Stockholders

Nuevo Energy Company:

Under date of March 5, 2004, we reported on the consolidated balance sheets of Nuevo Energy Company as of December 31, 2003 and 2002, and the related consolidated statements of income, stockholders equity, cash flows and comprehensive income for each of the years in the three-year period ended December 31, 2003. In connection with our audits of the aforementioned consolidated financial statements, we also audited the related consolidated financial statement schedule. This consolidated financial statement schedule is the responsibility of the Company s management. Our responsibility is to express an opinion on the consolidated financial statement schedule based on our audits.

In our opinion, the consolidated financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

KPMG LLP

Houston, Texas
March 5, 2004

Table of Contents

SCHEDULE II

NUEVO ENERGY COMPANY

VALUATION AND QUALIFYING ACCOUNTS
Years Ended December 31, 2003, 2002 and 2001
(In thousands)

		Additions			
	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
2003					
Allowance for doubtful accounts	$ 626	$ 18	$	$428	$ 216
Valuation allowance on deferred taxes	804			804	
2002					
Allowance for doubtful accounts	1,280			654	626
Valuation allowance on deferred taxes	1,777			973	804
2001					
Allowance for doubtful accounts	766	1,314		800	1,280
Valuation allowance on deferred taxes	1,777				1,777

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

The term disclosure controls and procedures is defined in Rule 13a-14(c) of the Securities Exchange Act of 1934, or the Exchange Act. This term refers to the controls and procedures of a company that are designed to ensure that information required to be disclosed by a company in the reports that it files under the Exchange Act is recorded, processed, summarized and reported within required time periods. Our Chief Executive Officer and our Chief Financial Officer have evaluated the effectiveness of our disclosure controls and procedures as of a date within 90 days before the filing of the annual report, and they have concluded that as of that date, our disclosure controls and procedures were effective at ensuring that required information will be disclosed on a timely basis in our reports filed under the Exchange Act.

Change in Internal Controls

We maintain a system of internal controls that are designed to provide reasonable assurance that our books and records accurately reflect our transactions and that our established policies and procedures are followed. There were no significant changes to our internal controls or in other factors that could significantly affect our internal controls subsequent to the date of their evaluation by our Chief Executive Officer and our Chief Financial Officer, including any corrective actions with regard to significant deficiencies and material weaknesses.

PART III

On February 12, 2004, we entered into a definitive agreement to be merged with Plains in a stock for stock transaction (the Merger). A special meeting of the stockholders of the Company will be held to consider and approve the Merger. The special meeting will be scheduled as soon as practical after the registration statement filed in connection with the transaction is effective and regulatory review under the Hart-Scott-Rodino Antitrust Improvement Act of 1976 is completed. The annual meeting of stockholders of the Company scheduled for May 12, 2004 will be postponed pending the outcome of the special meeting and, if the Merger is approved and completed will not be held, and no definitive proxy statement will be distributed to stockholders or filed with the SEC.

Item 10. ***Directors and Executive Officers of the Registrant***

The following is information about our directors and executive officers. The Board of Directors has an independent Audit Committee, and its members are noted below. Mr. Haasbeek is an Audit Committee Financial Expert and is independent pursuant to applicable rules and regulations. The Company has also adopted a Code of Ethics for its senior financial officers, a copy of which may be found on the Company s website.

Directors:

Isaac Arnold, Jr.
68 years old
Director since 1990
Lead Director: Appointed 2003
Board committees: Nominating and Governance (Chairperson)
Relationship to Nuevo: None, other than as a director

Table of Contents

Biographical Information

Mr. Arnold has been a director of Legacy Holding Company since 1989 and Legacy Trust Company since 1997. He has been a director of Cullen Center Bank & Trust since its inception in 1969 and is a director of Cullen/ Frost Bankers, Inc. Mr. Arnold is a trustee of the Museum of Fine Arts and The Texas Heart Institute. Mr. Arnold received his B.B.A. from the University of Houston in 1959.

Charles M. Elson
44 years old
Director since 1998
Board committees: Compensation (chairperson), Nominating and Governance
Relationship to Nuevo: None, other than as a director

Biographical Information

Mr. Elson has been the Edgar S. Woolard Jr. Professor of Corporate Governance and the Director of the Center for Corporate Governance at the University of Delaware since 2000. He was a professor of law at Stetson University College of Law from 1990 until 2001 and serves of counsel to the national law firm of Holland & Knight LLP (since 1995). He is a member of the American Law Institute and the Advisory Council and Commissions on Director Compensation, Audit Committees, and Director Professionalism of the National Association of Corporate Directors. Mr. Elson is widely regarded as an expert on corporate governance and has served on panels and blue ribbon commissions on such issues as executive compensation, director compensation, director professionalism, chief executive officer succession and others. He was a trustee of Talledega College and is a Salvatori Fellow of the Heritage Foundation. Mr. Elson currently serves as a director of Auto Zone, Inc., an automobile parts retailer, a position he has held since 2000 and Alderwoods Group, a health care services provider, a position he has held since 2002. He also served as a director of Circon Corporation, a medical products manufacturer, from 1997 until its sale in 1999. Mr. Elson received his B.A. from Harvard College in 1981 and his J.D. from the University of Virginia in 1985.

Robert L. Gerry III
66 years old
Director since 1990
Board committees: Audit, and Compensation
Relationship to Nuevo: Served as Nuevo s vice chairman from
1994 to 1997 and president and chief operating officer from
1990 to 1994

Biographical Information

Since 1997, Mr. Gerry has been chairman and chief executive officer of Vaalco Energy, Inc., a publicly traded independent oil and gas company which does not compete with Nuevo. From 1994 to 1997, Mr. Gerry was vice chairman of Nuevo. Prior to that, he was president and chief operating officer of Nuevo since its formation in 1990. Mr. Gerry currently serves as a trustee of Texas Children s Hospital.

J. Frank Haasbeek
69 years old
Director since late 2002
Board committees: Audit (Chairperson and Audit Committee Financial Expert) and Compensation
Relationship to Nuevo: None, other than as a director

Biographical Information

Mr. Haasbeek served as president and chief executive officer of International Transquip Industries, Inc. from 1991 through 2002. He has held various executive positions including president and chief executive officer of Hurricane Industries, vice president, administration and finance with Reading and

Bates Construction Company and chief financial officer and director of Cope Allman International Ltd. Mr. Haasbeek began his career as an auditor at Deloitte, Haskins and Sells in Canada and France and is a graduate of the University of Manitoba, in Winnipeg, Canada with accreditation as a chartered accountant.

James T. Jongebloed

62 years old

Director since 2002

Board committees: Audit

Relationship to Nuevo: None, other than as a director

Biographical Information

Mr. Jongebloed served as chairman, president and chief executive officer of Pool Energy Services Company, an oilfield services company, from 1994 through 1999. Mr. Jongebloed resigned his position after Pool Energy merged with Nabors Industries, Inc. in November 1999. From 1989 to 1994, he served as Pool Energy s president and chief executive officer and as president of international operations from 1981 to 1989. From 1978 to 1981, Mr. Jongebloed served as executive vice president of western hemisphere operations for Pool Energy. Mr. Jongebloed served as vice president for western operations from 1976 to 1978 and from 1973 to 1976 as vice president and general counsel for Atwood Oceanics, Inc., an offshore drilling contractor. In the late sixties and early seventies, Mr. Jongebloed served as senior project engineer and as a process engineer for Fluor Corporation, an engineering and construction contractor. Mr. Jongebloed currently serves on the board of directors of Lufkin Industries, Inc., Studio of the Americas, Houston Athletic Foundation and is an advisory board member of Spindletop International, a charitable organization. Mr. Jongebloed received his B.S. degree from the University of Houston in 1966 and his J.D. from South Texas College of Law in 1971. He also attended the Management Program at Rice University.

James L. Payne

66 years old

Director since 2001

Board committees: None

Relationship to Nuevo: Chairman, president and chief executive

officer of Nuevo

Biographical Information

James L. Payne joined Nuevo Energy Company as chairman, president and chief executive officer in October 2001. Prior to joining Nuevo, Mr. Payne was vice chairman of Devon Energy Corporation from September 2000 until his retirement in January 2001. Prior to the merger with Devon Energy in August 2000, he served as chairman and chief executive officer of Santa Fe Snyder Corporation. Prior to the May 1999 merger of Santa Fe Energy Resources and Snyder Oil Corporation, Mr. Payne served as chairman and chief executive officer of Santa Fe Energy Resources. In 1982 he joined Santa Fe Energy Corporation, a wholly owned subsidiary of Santa Fe Pacific Corporation, as senior vice president exploration and land and was named president in 1986 and chairman and chief executive officer in 1990 when the company became publicly traded. Prior to Mr. Payne s career with Santa Fe, he spent twenty-three years with Chevron Oil in various domestic and international exploration and management positions.

Mr. Payne graduated from the Colorado School of Mines in 1959 with a degree in geophysical engineering and he received the Cecil H. Green Award in Geophysics upon graduation. In 1974 he received an M.B.A. from Golden Gate University and in 1983 he completed the Stanford Executive Program. In 1993 he became a School of Mines Distinguished Achievement Medalist.

Mr. Payne serves on the board of BJ Services Company, Global Industries, Ltd. and Nabors Industries, Inc. He also serves on the board of the Domestic Petroleum Council, the Independent

Table of Contents

Petroleum Association of America (IPAA), the Palmer Drug Abuse Program and the Offshore Energy Center and serves as a member of the President s Council of the Colorado School of Mines. Mr. Payne is a member of the Society of Exploration Geophysicists and the American Association of Petroleum Geologists.

Gary R. Petersen

56 years old

Director since 1990

Board committees: Compensation, Nominating and Governance

Relationship to Nuevo: None, other than as a director

Biographical Information

Mr. Petersen is a co-founder and is a partner of EnCap Investments, L.L.C., a firm which provides private equity to the energy industry. From 1984 to 1988, he served as senior vice president and manager of the corporate finance division of the energy banking group for RepublicBanc Houston. From 1979 to 1984, he was executive vice president and a director of Nicklos Oil and Gas Company. He also served as a group vice president in the petroleum and minerals division of RepublicBanc Dallas. He is a member of the board of Equus II Incorporated and Plains All American Pipeline L.P. Mr. Petersen received his B.B.A. from Texas Tech University in 1968 and his M.B.A. from Texas Tech University in 1970.

Sheryl K. Pressler

53 years old

Director since 2002

Board committees: Audit, Compensation, Nominating and Governance

Relationship to Nuevo: None, other than as a director

Biographical Information

Ms. Pressler has been a self-employed investment and strategy consultant in Atlanta, Georgia since 2001. From 2000 to 2001, she was the chief executive officer for Lend Lease Real Estate Investments United States, a subsidiary of Lend Lease Corporation, an Australian real estate services company. From 1994 to 2000, she was the chief investment officer for the California Public Employees Retirement System (CalPERS), the nation s largest public pension fund. From 1981 to 1994, she was responsible for the management of the Retirement Funds for the McDonnell Douglas Corporation. Since 1999, Ms. Pressler has been a director of the California HealthCare Foundation. Ms. Pressler is currently a director of Stillwater Mining Company, a position she has held since 2002. Ms. Pressler received her B.A. in Philosophy from Webster University and her M.B.A. from Washington University.

Executive Officers

Phillip A. Gobe, 51, joined us as chief operating officer in February 2001. He is responsible for managing our domestic and international exploitation and exploration operations. Prior to coming to us, Mr. Gobe had been the senior vice president for production for Vastar Resources, Inc. since 1997. From 1976 to 1997, Mr. Gobe worked for Atlantic Richfield Company and its subsidiaries in positions of increasing responsibility, primarily in the Gulf of Mexico and Alaska. Among his positions were vice president for human resources and public affairs for ARCO International Oil & Gas from 1995 to 1997, vice president for human resources for ARCO Alaska, Inc. from 1993 to 1995 and operations manager for ARCO Alaska in Prudhoe Bay, Alaska from 1991 to 1993. Mr. Gobe is a graduate of the University of Texas at Austin and holds an M.B.A. from the University of Southwestern Louisiana.

Bruce K. Murchison, 53, joined us as vice president and general counsel in June 1999. In December 2001, he became senior vice president. During 1998 and 1999, he had been a consultant to Plains Resources senior management on transactional matters. From 1994 to 1998, he served as president of Celeron Corporation, the energy subsidiary of the Goodyear Tire and Rubber Company and operator of the 1,200-mile All American Pipeline System. Prior to assuming duties as president of Celeron,

Table of Contents

Mr. Murchison was Celeron s general counsel for six years. From 1991 to 1994, in addition to his general counsel responsibilities at Celeron, he was chief operating officer of All American Pipeline Company. He joined Goodyear as an attorney in 1985 and from 1981 to 1985, Mr. Murchison practiced corporate law and litigation at Texaco Inc. Mr. Murchison received a B.A. from Lafayette College and holds a J.D. from St. John s School of Law.

George B. Nilsen, 48, joined us as senior vice president of planning and asset management in December 2001. Prior to joining us, Mr. Nilsen was an independent consultant for small independent exploration and production companies. From 1987 to 2000, Mr. Nilsen held various domestic and international management positions in engineering and operations, most recently as division manager gulf division and corporate manager exploration and production for Santa Fe Snyder Corporation and its predecessor, Santa Fe Energy Resources, Inc. Mr. Nilsen began his career with Santa Fe in California and then transferred to Midland, Texas as engineering manager. Subsequently, he worked in Argentina and Ecuador in various management positions helping Santa Fe to establish its international program. Prior to joining Santa Fe, Mr. Nilsen worked for over ten years in Bakersfield, California for Petro-Lewis Corporation and Gulf Oil Company in various engineering and operations positions. Mr. Nilsen is a graduate of Bucknell University with a B.S. in chemical engineering.

John P. McGinnis, 43, joined us as vice president exploration in August 1999. Prior to joining us, Dr. McGinnis worked for Amerada Hess Corporation from 1995 to 1999, most recently as division explorationist, and for Tenneco Oil Company from 1984 to 1988 as an exploration geophysicist. In 1995 Dr. McGinnis received his Ph.D. in Marine Geology and Geophysics from Columbia University and holds a B.S. in geology and an M.S. in geophysics, both from Purdue University.

Michael S. Wilkes, 53, joined us as vice president and controller in March 2003. Effective March 2004, Mr. Wilkes became Chief Financial Officer, a position he held on an interim basis since December 2003. Prior to joining us, Mr. Wilkes worked from 1981 to 2000 in various financial and management positions with increasing responsibility, most recently as vice president and controller, with Santa Fe Snyder Corporation, and its predecessor Santa Fe Energy Resources, Inc. Mr. Wilkes is a graduate of Midwestern State University, and is a Certified Public Accountant.

All of our executive officers and directors are United States citizens.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Exchange Act requires certain of our executive officers and all directors and more than ten percent stockholders of our equity securities (collectively, Reporting Persons) to file an initial report of ownership (Form 3) and reports of changes of ownership (Forms 4 and 5) with the SEC. These reporting persons are required to furnish us with copies of all Section 16(a) reports that they file.

To our knowledge, based solely upon a review of Section 16(a) reports furnished to us for the fiscal year ended December 31, 2003 and written representations from Reporting Persons that no other reports were required, we believe that all Reporting Persons complied with all applicable Section 16(a) filing requirements during the fiscal year ended December 31, 2003, except that Form 4 was filed late for Sheryl K. Pressler in connection with an original paper filing which subsequently had to be filed electronically.

Table of Contents

Item 11. ***Executive Compensation***

The following summary compensation table includes cash compensation for the past three years for our chief executive officer and our four other most highly compensated executive officers in 2003.

NUEVO ENERGY COMPANY

Summary Compensation Table

Name and Principal Position	Year	Salary	Bonus[1]	Restricted Stock Awards[2]	Long-Term Compensation Options	All Other Compensation
James L. Payne	2003	$ 27,099(3)	$	$ 1,450,200		$ 64,090(3)
Chairman, President and Chief	2002	26,061(3)		669,000	200,000	41,791(3)
Executive Officer	2001					9,073(3)
Phillip A. Gobe	2003	275,000	222,750	604,250		
Chief Operating Officer	2002	275,000	137,500	111,500	50,000	
	2001	232,339(4)	116,404		170,000(5)	
Bruce K. Murchison	2003	173,250	140,333	483,400		
Senior Vice President and	2002	173,250	87,625	111,500	50,000	
General Counsel	2001	173,250	43,312		30,001	
Janet F. Clark	2003	195,000	157,950			
Senior Vice President and Chief	2002	195,000	97,500	167,250	25,000	
Financial Officer	2001	13,375(6)	3,339		150,000(7)	
George B. Nilsen	2003	175,000	141,750	362,550		
Senior Vice President of	2002	175,000	87,500	167,250	15,000	
Planning and Asset Management	2001	12,003(8)	2,996		75,000(9)	

(1) Incentive bonuses for the calendar year 2002 were paid in February 2003, and for the calendar year 2003 were paid in February 2004.

(2) The restricted stock included in this table represents the fair market value of the entire restricted stock award on the date of grants. All restricted stock grants for 2003 were made on December 31, 2003. All restricted stock grants have restrictions that lapse in equal annual increments during the three year period following the grant date. However, the Company anticipates that the Merger will be completed and at the effective time of the Merger, all restrictions on restricted stock will lapse and the restricted stock will be treated in the manner provided under the terms of the Merger.

(3) Mr. Payne was elected chairman, president and chief executive officer in October 2001. In 2003, Mr. Payne received his entire compensation in shares of our common stock, except for $18,000 constituting the amount that permitted a valid tax-deferred contribution to the Company s 401(k) Plan, and $9,099 of imputed income. In 2002, Mr. Payne received his entire compensation in shares of our common stock except for $26,061 being the sum of an amount that permitted a valid tax-deferred contribution to the Company s 401(k) Plan of $12,000 in 2002, $12,000 in 2003 and $2,061 of imputed income. In 2003, Mr. Payne earned 64,090 shares of common stock based on a share equivalent of $400,000 annual salary and $324,000 bonus. He was awarded 26,643 shares during the first three quarters of 2003, and 8,258 and 29,189 on January 4 and February 11, 2004, respectively. In 2002 Mr. Payne earned 41,791 shares of stock based on a share equivalent of $400,000 annual salary and $200,000 bonus. He was awarded 20,403 shares during the first three quarters of 2002 and 6,017 and 15,371 on January 2 and February 20, 2003, respectively. In 2001, Mr. Payne earned 9,073 shares prorated on the time actually worked.

(4) Mr. Gobe was hired by us in February 2001. Information regarding Mr. Gobe for 2001 is for the period during which he was employed by us.

(5) Mr. Gobe was granted 150,000 options in February 2001 as part of his employment agreement.

(6) Ms. Clark became an employee in December 2001. Information regarding Ms. Clark for 2001 is for the period during which she was employed by Nuevo. Ms. Clark resigned from Nuevo effective January 5, 2004.

Table of Contents

(7) Ms. Clark was granted 150,000 options in December 2001 as part of the compensation package offered to her to join Nuevo.

(8) Mr. Nilsen was hired by Nuevo in December 2001. Information regarding Mr. Nilsen for 2001 is for the period during which he was employed by Nuevo.

(9) Mr. Nilsen was granted 75,000 options in December 2001 as part of the compensation package offered to him to join Nuevo.

The following table shows the number of options owned by our executives named in the Summary Compensation Table and key executives as of December 31, 2003. Options in the column marked unexercisable are subject to vesting and will be forfeited if the named executive s employment with us is terminated for certain reasons.

Name	Number of Shares Acquired on Exercise	Value Realized	Number of Unexercised Options		Value of Unexercised in-the-money Options at December 31, 2003(1)	
			Exercisable	Unexercisable	Exercisable	Unexercisable
James L. Payne		$	66,667	133,333	$ 586,003	$ 1,171,997
Phillip A Gobe			130,000	90,000	997,834	718,666
Bruce K. Murchison			129,793	33,333	1,102,829	292,997
Janet F. Clark			158,334	16,666	1,898,756	146,494
George B. Nilsen			80,000	10,000	956,700	87,900
John P. McGinnis			109,230		866,939	
Michael S. Wilkes						

(1) Based on $24.17 per share which was the closing price per share of our common stock on the New York Stock Exchange Composite Tape on December 31, 2003.

EQUITY COMPENSATION PLAN INFORMATION

The following table sets forth information about the Common Stock that may be issued under all of the Company s existing equity compensation plans as of December 31, 2003:

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance
Equity compensation plans approved by security holders	2,348,859	$ 17.68	202,219
Equity compensation plans not approved by security holders			
Total	2,348,859	$ 17.68	202,219

All of our existing equity compensation plans have been approved by our stockholders.

COMPENSATION COMMITTEE REPORT:

Our compensation committee consists of five directors who are not employees or executive officers of the company. The members of the compensation committee in 2003 were Mr. Elson, who was chairperson and Messrs. Petersen, Gerry, Haasbeek and Ms. Pressler.

Our Executive Compensation Program

Our executive compensation program reflects a policy of attracting and retaining highly qualified executives who strive to achieve outstanding individual performance and who collectively seek outstanding corporate and share price performance compared to that of peer group companies. The committee believes that Nuevo should seek executives who desire a work environment characterized by a high level of at-risk compensation, which rewards excellent performance and aligns overall compensation with the objectives of our stockholders. In 2001 and 2002, Towers Perrin was retained to assist in the review of our existing compensation design. In 2003, the Company retained Towers Perrin to assess the competitive position of Nuevo s executive compensation program and to evaluate recommended modifications. The committee retained Frederic W. Cook & Company to provide an independent assessment of management recommendations. Accordingly, the compensation program adopted by us for our executives consists of the following elements:

Base salary. It is our position that base salaries should be competitive with the pay practices followed by our peer group.

Incentive bonus. Bonuses are awarded at the discretion of the compensation committee. It is our goal that base pay and annual incentive bonus should be at or near the 50th percentile of our peer group. With respect to bonus compensation in 2003, the committee followed its historic policy of allocating a specific portion of the total compensation paid to executive officers as at-risk compensation in order to emphasize pay for performance. In 2003, the incentive bonus was based on four measures: stock price performance against the Company s peer group, sale of non-core assets, acquisitions and meeting or exceeding stated financial plan objectives including production. In order to promote team focus, all employee bonuses in 2004 are tied to share performance, attainment of production goals, reserve replacement and reserve replacement cost. In 2003, our executive management could earn a target bonus of 50% of base salary if all goals are attained. The 2003 plan provided for a maximum payout of 100% of base salary and a minimum payout of 0% of base salary. The 2004 plan increased the target bonus to 100% of base salary for Mr. Payne and 75% of base salary for all other executives. The 2004 plan provides for a maximum payout of 200% for Mr. Payne and 150% for all other senior executives.

Stock based compensation. We believe that the issuance of stock based compensation properly aligns the interests of employees with our stockholders. The number of incentive shares granted to an employee is based on the committee s view of the employee s ability to positively impact the value of our results.

During 1997, the compensation committee established a stock ownership program for our senior executives that provides incentives for each executive to achieve and maintain targeted level of ownership of our common stock. Target levels of stock ownership are set by the compensation committee for each executive. Counted against this stock ownership are shares owned directly by the executive or owned beneficially through an immediate family member, shares acquired through the exercise of options and shares acquired through our deferred compensation and 401(k) plans. Shares that may be received upon exercise of options do not count toward the ownership objectives. Under the program, each executive s progress toward meeting stated ownership objectives is an important element of each executive s performance review. Upon meeting and maintaining the ownership target, the executive is eligible to receive an accelerated vesting schedule on all options granted on or before October 15, 2001.

Overview

In 2003, the Company continued to generate cash flow from operating activities significantly in excess of its working capital requirements. In addition, the Company successfully pursued its strategy of monetizing non-core assets. As a result, available cash from operations and proceeds from property sales were contributed to retirement of $184.6 million of long term debt.

In determining compensation, the compensation committee continues to review on an individual level each executive s leadership in his area of expertise, and also evaluates years of service, experience level, position and general economic and industry conditions. However, no specific weighting is assigned to these factors. The committee also studies peer group compensation levels for comparable positions. The committee did not approve any executive salary increases for 2001, 2002 or 2003. Effective January 2004, the compensation committee approved salary adjustments for the senior executive management team other than Mr. Payne. In addition, the committee approved a 2004 merit increase for non-executive employees. The base salary paid to each of our executives is as follows:

James L. Payne	$400,000
Chief Executive Officer and President	
Phillip A. Gobe	$300,000
Chief Operating Officer	
Bruce K. Murchison	$220,000
Senior Vice President Administration and General Counsel	
George B. Nilsen	$200,000
Senior Vice President of Planning and Asset Management	
Michael S. Wilkes	$180,000
Chief Financial Officer	

Mr. Payne receives both his salary and bonus in shares of our common stock.

Stock Based Compensation

The compensation committee believes the stock options that it has granted in the past, and the stock based compensation granted in 2003, serve a valuable purpose by attracting and retaining key executives, and encouraging increased job performance by the recipients of such grants. The committee does not base the number of awards granted to executive officers on a predetermined formula, but rather on each individual s accomplishments, level of responsibility, and impact on our performance for the year.

Messrs. Payne, Gobe, Murchison, Nilsen and Wilkes were granted a total of 60,000, 25,000, 20,000, 15,000 and 15,000 restricted shares in 2003 respectively, which shares vest ratably over a three-year term.

Executive Employment Contracts

In October 2001, we entered into a compensation agreement with Mr. Payne, our chairman, president and chief executive officer. The agreement provides that Mr. Payne is employed on an at will basis and that his compensation will be paid in the form of our common stock in the following manner:

Base Salary. In 2003, Mr. Payne received a base salary at the rate of $400,000 per year. In 2004, this base salary will be paid as 16,549 shares of our common stock. Such payment is made to Mr. Payne quarterly.

Annual Bonus. In 2004, Mr. Payne can earn an annual bonus between $0 and $800,000, paid in the form of common stock. In 2001, Mr. Payne received 3,024 shares based on the portion of the year that he had worked. In 2003, he received 15,371 shares which is the bonus attributable to 2002. In 2004, Mr. Payne received 29,189 shares of our common stock which was attributable to 2003 performance.

Other. The agreement provided for reimbursement of certain temporary rental costs incurred by Mr. Payne in the initial three-month period.

The employment contract that we entered into with Mr. Gobe in February, 2001 expired in February, 2003. Mr. Gobe and other key executives without employment contracts are entitled to the benefit discussed below if the executive is terminated without cause.

In 1999, we entered into an employment agreement with Bruce K. Murchison. In the event that Mr. Murchison s employment is terminated for reasons other than just cause or his voluntary resignation, Mr. Murchison is entitled to receive two times his annual salary and average bonus. In addition, the

Table of Contents

outstanding stock options held by Mr. Murchison would vest and he would have 365 days to exercise the options.

In 1999, we also entered into an employment agreement with John P. McGinnis. Mr. McGinnis s contract was identical to that of Mr. Murchison.

In May 2002, the compensation committee adopted by resolution a benefit to designated key executives without employment agreements if such executive is terminated without cause. In the event of such termination, the executive is entitled to receive two weeks of base salary for each year of service and one week of base salary for each $10,000 of annual income. In addition, such employee s stock options vest with 365 days to exercise. In 2003, the compensation committee approved an amendment to this benefit by permitting the vesting of any unvested restricted shares in the event of a termination without cause.

Long-Term Incentive Plan Awards

We do not have a long-term incentive plan for our employees, other than the 1990 stock option plan, the 1993 stock incentive plan and the 1999 stock incentive plan. In addition, we adopted a broadly based plan in August 2001 under which 200,000 shares could be issued. This plan was amended in October 2002 to provide issuance of up to 450,000 shares. Under the 1990 stock option plan and the 1993 stock incentive plan, our executive officers, directors and employees are eligible to receive awards of stock options or of shares of stock or other awards which have a value which increases or decreases with the price of our stock. In addition to the awards under the 1990 stock option plan and the 1993 stock incentive plan, the 1999 stock incentive plan and the 2001 broadly based stock incentive plan permit the award of restricted stock, restricted stock units, performance share awards and performance units. We adopted individual stock incentive plans for Ms. Clark, our former Chief Financial Officer, and Mr. Nilsen as inducements for employment. Ms. Clark s plan provided for the issuance of 150,000 stock options, while Mr. Nilsen s plan provided for the issuance of 75,000 stock options. All long-term incentive awards are designed to generate an increased incentive to contribute to our future success resulting in our enhanced value for the benefit of our stockholders.

Change in Control Benefit

On December 6, 2000, the board of directors adopted a resolution that would provide our key executive officers certain benefits in the event of termination of employment without cause within two years of a change of control. We are obligated to pay a termination benefit of three times the sum of base salary and average annual bonus, and continue medical benefits for our key executives for a period of 18 months. In the event that any benefit received in a change of control subjects the executive to the excise tax imposed by Section 4999 of the Internal Revenue Code, the executive is entitled to a tax gross up payment. The benefit also results in the vesting of all unvested incentive stock grants. This benefit is in lieu of any other severance or termination benefit that might otherwise be owed under an employment contract or our severance plan. The board authorized that this benefit be formalized in separate Severance Protection Agreements with each key executive officer.

Deferred Compensation Plan

During 1997, we adopted the Nuevo Energy Deferred Compensation Plan to encourage senior executive officers to personally invest in our shares. Executives at the level of vice president and above are eligible to participate in the plan. The plan allows those executives designated by the committee to defer all or a portion of their annual salaries and bonuses. The plan was amended in December 2001 to provide the executives the alternative of investing in our common stock, a money market account or other investment alternatives. The amended plan also removed the 25% discount to market price that had previously been contained in the deferred compensation plan for purchase of our common stock. In 2003, we permitted executives to contribute up to $30,000 to purchase of Nuevo common stock at a 15% discount, effectively allowing executives to enjoy the 15% discount extended to employees.

The compensation committee establishes stock ownership targets for each of the company s executives other than Mr. Payne who receives all of his compensation in our common stock. The executive may satisfy the ownership requirement by directly investing in our common or by indirectly investing in us through our 401(k) plan and deferred compensation plan. The actual investment does not include shares, which may be issued pursuant to stock options. The actual investment and target investment for each executive as of February 27, 2004 is as follows:

Name	Actual Investment	Target Investment
Phillip A. Gobe	$639,653	$825,000
George B. Nilsen	278,414	350,000
Bruce K. Murchison	538,726	320,000
John P. McGinnis	317,432	280,000

Revisions to Stock Based Compensation

Director Compensation. In 1999, the compensation committee adopted changes to the compensation paid to non-employee directors in order to encourage greater stock ownership by directors and to bring director compensation in line with the compensation paid by peer group companies.

Each non-officer director is entitled to receive an annual cash retainer of $30,000, but may elect to receive all or a portion of the retainer in shares of restricted stock. Elections are made in 25% increments and, to encourage director ownership, the director receives a 33% increase in value for the amount invested in restricted stock. For example, a director will receive $9,975 in restricted stock for each $7,500 of compensation invested. Four of our directors elected to receive all restricted shares, two directors elected to receive a cash retainer and one took a combination of cash and restricted shares in 2003.

In addition to the retainer, from 1999 until 2002, non-officer directors received a semi-annual grant of 1,250 restricted shares of our common stock and 1,750 ten-year options to purchase common stock. Beginning in 2003, non-officer directors will receive a semi-annual grant of 2,215 restricted shares of our common stock subject to a three-year restricted period and directors will have the option to roll over this period until their retirement from the board. Upon recommendation of the compensation committee, the board eliminated the semi-annual grant of 1,750 ten-year options to purchase the company s stock. The board approved the recommendation that directors receive $1,000 and committee chairpersons receive $1,500 for each committee meeting attended.

CHARLES M. ELSON, CHAIRMAN

ISAAC ARNOLD, JR.
GARY R. PETERSEN
SHERYL K. PRESSLER

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

The following tables set forth information regarding the beneficial ownership of Nuevo common stock as of February 27, 2004 (unless such date is indicated otherwise in the footnotes below) by:

each current director and executive officer of the Company;

all current executive officers and directors of the Company as a group; and

each person known by the Company to own beneficially more than 5% of the outstanding shares of the Company s common stock.

Beneficial ownership has been determined in accordance with applicable SEC rules, under which a person is deemed to be the beneficial owner of securities if he or she has or shares voting power or investment power with respect to such securities or has the right to acquire beneficial ownership within 60 days.

Table of Contents

Unless otherwise indicated, to the knowledge of Nuevo, the persons listed in the tables below have sole voting and investment powers with respect to the shares indicated. The address of the Company s directors and officers is 1021 Main Street, Suite 2100, Houston, Texas 77002.

The percentages are based on 20,318,979 shares of Nuevo Common Stock issued and outstanding as of February 27, 2004.

Five Percent Stockholders:

	Number of Shares	Ownership Percentage
Franklin Resources, Inc.	1,522,912	7.5(1)
Franklin Advisers, Inc.		
Charles B. Johnson		
Rupert H. Johnson, Jr.		
One Franklin Parkway		
San Mateo, California 94403		
Artisan Partners Limited Partnership	1,468,701	7.2(2)
Artisan Investment Corporation		
Andrew A. Ziegler		
Carlene M. Ziegler		
1000 North Water Street, #1770		
Milwaukee, Wisconsin 53202		
Barclays Global Investors, NA	2,400,590	11.8(3)
Barclays Bank PLC		
Barclays Global Fund Advisors		
45 Fremont Street		
San Francisco, California 94105		
Wellington Management Company, LLP	1,331,324	6.6(4)
75 State Street		
Boston, Massachusetts 02109		

Members of the Board of Directors who are not employees:

	Shares Beneficially Owned				
	Outstanding	Under Stock Options**	Restricted Stock	Total	Percent
Isaac Arnold, Jr.	44,825	44,000	30,458	119,283	*
Charles M. Elson	4,028	25,250	23,888	53,166	*
Robert L. Gerry III	937	131,500	9,250	141,687	*
J. Frank Haasbeek			7,362	7,362	*
James T. Jongebloed		3,500	8,650	12,150	*
Gary R. Petersen	8,003	15,000	12,065	35,068	*
Sheryl K. Pressler		3,500	12,796	16,296	*

Table of Contents

Executive Officers:

	Shares Beneficially Owned						
	Outstanding	Under 401(k)/ESP Plans	Under Stock Options**	Under Deferred Compensation	Restricted Stock	Total	Percent
James L. Payne	144,954	5,526	66,667	3,952	100,000	321,099	1.58
Phillip A. Gobe		6,727	130,000	32,687	31,666	201,080	*
Bruce K. Murchison	300	3,788	99,792	30,541	26,666	161,087	*
George B. Nilsen	2,500	4,341	55,000	10,793	25,000	97,634	*
John P. McGinnis		3,332	91,230	19,317	9,000	122,879	*
Michael S. Wilkes		447			20,000	20,447	*

All Directors and Executive Officers as a Group:

Total	Percent
1,309,238	6.4

Footnotes:

* Under 1%.

** Stock options include only options which may be exercised within 60 days.

(1) Based on the Schedule 13G filed by Franklin Resources, Inc., Charles B. Johnson, Rupert H. Johnson, Jr. and Franklin Advisers, Inc. with the SEC on February 10, 2004, Franklin Advisers, Inc. is reported to have sole voting and dispositive power over 1,434,012 shares and Franklin Advisory Services, LLC has sole voting and dispositive power over 88,900 shares. Franklin Advisers, Inc. and Franklin Advisory Services, LLC are both wholly owned investment advisory subsidiaries of Franklin Resources, Inc. Each of Messrs. Charles B. Johnson and Rupert H. Johnson, Jr. own in excess of 10% of the outstanding common stock of Franklin Resources, Inc. As the principal shareholders of Franklin Resources, Inc., each of Messrs. Charles B. Johnson and Rupert H. Johnson, Jr. may be deemed for certain purposes to be beneficial owners of the shares beneficially owned by Franklin Resources, Inc. Shares beneficially owned by Franklin Resources, Inc. include 1,434,012 shares which may be received upon conversion of our outstanding term convertible securities

(2) Based on the Schedule 13G filed by Artisan Partners Limited Partnership (Artisan Partners) with the SEC on January 23, 2004, Artisan Partners is an investment adviser registered under section 203 of the Investment Advisers Act of 1940. Artisan Investment Corporation (Artisan Corp.) is the General Partner of Artisan Partners and Mr. Ziegler and Ms. Ziegler are the principal stockholders of Artisan Corp. Artisan Corp. reported shared dispositive and shared voting power with respect to all 1,468,701 shares. The shares reported herein have been acquired on behalf of discretionary clients of Artisan Partners. Persons other than Artisan Partners are entitled to receive all dividends from, and proceeds from the sale of, those shares. To the knowledge of Artisan Partners, Artisan Corp., Mr. Ziegler or Ms. Ziegler, none of such persons has an economic interest in more than five percent of the class of stock.

(3) Based on the Schedule 13G filed by Barclays Global Investors, NA. (Barclays Global Investors) et al with the SEC on February 13, 2004, Barclays Global Investors and Barclays Bank PLC are banks as defined in section 3(a)(6) of the Securities Exchange Act of 1934. Barclays Global Investors has sole voting and dispositive power of 1,793,918 shares, and shares voting and dispositive over 268,928 shares, and Barclays Bank PLC has sole voting and dispositive power of 9,700 shares. Barclays Global Fund Advisors, an investment adviser under section 240.13d (b)(1)(ii)(E) has sole vesting and dispositive power of 328,044 shares. The shares reported are held in trust accounts for the economic benefit of the beneficiaries of those accounts.

(4) Based on the Schedule 13G filed by the Wellington Management Company, LLP (WMC) with the SEC on February 13, 2004, WMC is reported to share voting power with respect to 703,430 shares and

dispositive power with respect to 1,331,324 shares. These securities are beneficially owned by WMC in its capacity as investment adviser and are owned of record by the clients of WMC. Those clients have the right to receive, or the power to direct the receipt of, dividends from, or the proceeds from the sale of, such securities. No such client is known to have such right or power with respect to more than five percent of this class of securities.

Item 13. ***Certain Relationships and Related Transactions***

None.

Item 14. ***Principal Accountant Fees and Services***

Fees Paid to Independent Public Accountants

The Audit Committee has reviewed the audit and non-audit fees that Nuevo Energy Company has paid to the independent public accountants for purposes of considering whether such fees are compatible with maintaining the auditor s independence.

Audit Fees. Fees for services rendered by KPMG LLP for the reviews of Forms 10-Q and for the audits of the financial statements of Nuevo Energy Company were $439 thousand for 2002 and $383 thousand for 2003.

Audit-Related Fees. The aggregate fees billed for all audit-related services rendered by KPMG LLP to Nuevo Energy Company consisted of $58 thousand of fees for 2003. Specific services for Nuevo Energy Company in both years include consultations, financial accounting and reporting standards.

Tax Related Fees. Aggregate fees billed for all tax related services rendered by KPMG LLP to Nuevo Energy Company consisted of $231 thousand in 2002 and $12 thousand in 2003.

The Audit Committee has adopted a pre-approval policy regarding audit and non-audit fees. The policy provides that the Audit Committee is to pre-approve the audit and non-audit services performed by the independent auditor to assure that the provision of such services does not impair the auditor s independence. The services to be pre-approved under the policy include annual audit services provided by the independent auditor, services which are reasonably related to the performance of the review or audit of our financial statements by the independent auditor, tax services and all other related services. The Audit Committee periodically establishes pre-approval levels for all services to be provided by the independent auditor under the policy. Any proposed services which exceed these pre-approval levels require specific pre-approval by the Audit Committee.

Table of Contents

PART IV

Item 15. ***Exhibits, Financial Statement Schedules and Reports on Form 8-K***

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

(b) *Reports on Form 8-K:*

Date	Event Reported
March 5, 2004	Press release announcing appointment of Chief Financial Officer
March 4, 2004	Press release announcing fourth quarter 2003 earnings
February 12, 2004	Agreement and Plan of Merger with Plains Exploration & Production Company and press release announcing the agreement
January 28, 2004	Press release announcing the final redemption of 9 1/2% Senior Subordinated Notes
January 5, 2004	Press release announcing the significant increase in realized pricing for California crude oil production
January 5, 2004	Press release announcing the sale of California real estate properties
December 3, 2003	Press release announcing appointment of Interim Chief Financial Officer
November 12, 2003	Press release announcing third quarter 2003 earnings

NUEVO ENERGY COMPANY

EXHIBIT LIST

December 31, 2003

Each exhibit identified below is filed as a part of this report. Exhibits not incorporated by reference to a prior filing are designated by an asterisk; all exhibits not so designated are incorporated herein by reference to a prior filing as indicated. Exhibits designated with a + constitute a management contract or compensatory plan or arrangement required to be filed as an exhibit to this report pursuant to Item 14 (c) of Form 10-K.

(2) Plan of Acquisition, Reorganization, Arrangement, Liquidation or Succession.

2.1 Agreement and Plan of Merger dated September 18, 2002 by and among Athanor Resources, Inc., Athanor B.V., Nuevo Energy Company, Nuevo Texas Inc., Yorktown Energy Partners III, L.P., Yorktown Energy IV, L.P., Yorktown Partners LLC, SAFIC S.A., Charles de Mestral, J. Ross Craft, Montana Oil and Gas, Ltd., David A. Badley, James S. Scott, Glenn Reed, Doug Allison and Mohamed Yaich (Exhibit 2.1 to our Form 8-K dated September 19, 2002).

2.2 Agreement and Plan of Merger dated February 12, 2004, by and among Plains Exploration & Production Company, PXP California, Inc. and Nuevo Energy Company (Exhibit 2.1 to our Form 8-K filed on February 12, 2004).

(3) Articles of Incorporation and bylaws.

3.1 Certificate of Incorporation of Nuevo Energy Company (Exhibit 3.1 to our 1999 Second Quarter Form 10-Q).

3.2 Certificate of Amendment to the Certificate of Incorporation of Nuevo Energy Company (Exhibit 3.2 to our 1999 Second Quarter Form 10-Q).

3.3 Bylaws of Nuevo Energy Company (Exhibit 3.3 to our 1999 Second Quarter Form 10-Q).

3.4 Amendment to section 3.1 of the Bylaws of Nuevo Energy Company (Exhibit 3.4 to our 1999 Second Quarter Form 10-Q).

(4) Instruments defining the rights of security holders, including indentures.

4.1 Specimen Stock Certificate (Exhibit 4.1 to our Form S-4 (No. 33-33873) filed under the Securities Act of 1933).

4.2 Indenture dated April 1, 1996 among Nuevo Energy Company as Issuer, various Subsidiaries as the Guarantors, and State Street Bank and Trust Company as the Trustee 9 1/2% Senior Subordinated Notes due 2006. (Incorporated by reference from Form S-3 (No. 333-1504).

4.3 Form of Amended and Restated Declaration of Trust dated December 23, 1996, among the Company, as Sponsor, Wilmington Trust Company, as Institutional Trustee and Delaware Trustee, and Michael D. Watford, Robert L. Gerry, III and Robert M. King, as Regular Trustees. (Exhibit 4.1 to our Form 8-K filed on December 23, 1996).

4.4 Form of Subordinated Indenture dated as of November 25, 1996, between the Company and Wilmington Trust Company, as Indenture Trustee. (Exhibit 4.2 to Form 8-K filed on December 23, 1996).

4.5 Form of First Supplemental Indenture dated December 23, 1996, between the Company and Wilmington Trust Company, as Indenture Trustee. (Exhibit 4.3 to Form 8-K filed on December 23, 1996).

4.6 Form of Preferred Securities Guarantee Agreement dated as of December 23, 1996, between the Company and Wilmington Trust Company, as Guarantee Trustee. (Exhibit 4.4 to Form 8-K filed on December 23, 1996).

4.7 Form of Certificate representing TECONS. (Exhibit 4.5 to Form 8-K filed on December 23, 1996).

4.8 Shareholder Rights Plan, dated March 5, 1997, between Nuevo Energy Company and American Stock Transfer & Trust Company, as Rights Agent (Exhibit 1 to our Form 8-A filed on April 1, 1997).

*4.9 First Amendment to the Shareholder Rights Plan, dated January 10, 2000, between Nuevo Energy Company and American Stock Transfer & Trust Company.

4.10 Second Amendment to the Shareholder Rights Plan, dated February 12, 2004, between Nuevo Energy Company and American Stock Transfer & Trust Company (Exhibit 99.1 to our Form 8-A/A filed on February 27, 2004).

4.11 Release and Termination of Subsidiary Guarantees with respect to the 9 1/2% Senior Subordinated Notes due 2006. (Exhibit 4.11 to our 1997 Form 10-K)

4.12 Second Supplemental Indenture to the Indenture dated April 1, 1996, dated August 9, 1999 between Nuevo Energy Company and State Street Bank and Trust Company 9 1/2% Senior Subordinated Notes due 2006 (Exhibit 4.10 to our Form S-4 (No. 333-90235) filed on November 3, 1999).

4.13 Indenture dated as of August 20, 1999, between Nuevo Energy Company and State Street Bank Trust Company, as Trustee (Exhibit 4.11 to our Form S-4 (No. 333-90235) filed on November 3, 1999).

4.14 Registration Agreement dated August 20, 1999, between Nuevo Energy Company, Banc of America Securities LLC and Salomon Smith Barney Inc. (Exhibit 4.12 to our Form S-4 (No. 333-90235) filed on November 3, 1999).

4.15 Indenture dated September 26, 2000, between Nuevo Energy Company and State Street Bank and Trust Company as the Trustee 9 3/8% Senior subordinated Notes due 2010 (Exhibit 4.12 to our 2000 Third Quarter Form 10-Q).

4.16 Registration Agreement dated September 26, 2000, between Nuevo Energy Company and Banc of America Securities LLC, Banc One Capital Markets, Inc. and J.P. Morgan & Co. (Exhibit 4.13 to our 2000 Third Quarter Form 10-Q).

(10) Material Contracts.

10.1 Third Restated Credit Agreement dated June 7, 2000, between Nuevo Energy Company (Borrower) and Bank of America N.A. (Administrative Agent), Bank One, NA (Syndication Agent), Bank of Montreal (Documentation Agent) and certain lenders (Exhibit 10.1 to our 2000 Second Quarter Form 10-Q).

10.2 1990 Stock Option Plan, as amended (Exhibit 10.8 to our Form S-1 dated July 13, 1992).

10.3 1993 Stock Incentive Plan, as amended (Exhibit 4.2 to our Form S-8 (No. 333-21063) filed on February 4, 1997.)

10.4 1999 Stock Incentive Plan (Exhibit 99.1 to our Form S-8 (No. 333-87899) filed on September 28, 1999).

10.5 Nuevo Energy Company Deferred Compensation Plan (Exhibit 99 to our Form S-8 (No. 333-51217) filed on April 28, 1998).

10.6 Stock Purchase Agreement, dated as of June 30, 1994, among Amoco Production Company (APC), Walter International Inc. (Walter), Walter Congo Holdings, Inc. (Walter Holdings), Walter International Congo, Inc. (before the merger Walter Congo and after the merger Old Walter Congo), Nuevo, Nuevo Holding and The Nuevo Congo Company (before the merger, Nuevo Congo and after the merger, Old Nuevo Congo). (Exhibit 2.1 to Form 8-K dated March 10, 1995).

10.7 Amendment to Stock Purchase Agreement dated as of September 19, 1994, among APC, Walter Congo, Nuevo Congo, Walter Holdings, Nuevo Holding, Walter and Nuevo. (Exhibit 2.2 to Form 8-K dated March 10, 1995).

10.8 Second Amendment to Stock Purchase Agreement dated as of October 15, 1994, among APC, Walter Congo, Nuevo Congo, Walter Holdings, Nuevo Holding, Walter and Nuevo. (Exhibit 2.3 to Form 8-K dated March 10, 1995).

10.9 Third Amendment to Stock Purchase Agreement dated as of December 2, 1994, among APC, Walter Congo, Nuevo Congo, Walter Holdings, Nuevo Holding, Walter and Nuevo. (Exhibit 2.4 to Form 8-K dated March 10, 1995.)

10.10 Fourth Amendment to Stock Purchase Agreement dated as of February 23, 1995, among APC, Walter Congo, Nuevo Congo, Walter Holdings, Nuevo Holding, Walter and Nuevo. (Exhibit 2.5 to Form 8-K dated March 10, 1995).

10.11 Tax Agreement dated as of February 23, 1995, executed by APC, Amoco Congo Exploration Company (ACEC), Amoco Congo Production Company (ACPC), Walter, Walter Holdings, Walter Congo, Nuevo, Nuevo Holding and Nuevo Congo. (Exhibit 2.6 to Form 8-K dated March 10, 1995).

10.12 Agreement and Plan of Merger executed by Nuevo Congo, Nuevo Holding and APC dated February 24, 1995. (Exhibit 2.7 to Form 8-K dated March 10, 1995).

10.13 Finance Agreement dated as of December 28, 1994, among Nuevo Holding, Nuevo Congo and The Overseas Private Investment Corporation (OPIC). (Exhibit 2.8 to Form 8-K dated March 10, 1995).

10.14 Subordination Agreement dated December 28, 1994, among Nuevo Congo, Nuevo Holding, Walter Congo, Walter Holdings and APC. (Exhibit 2.9 to Form 8-K dated March 10, 1995).

10.15 Guaranty covering the obligations of Nuevo Congo and Walter Congo under the Stock Purchase Agreement dated February 24, 1995, executed by Walter and Nuevo. (Exhibit 2.10 to Form 8-K dated March 10, 1995).

10.16 Inter-Purchaser Agreement dated as of December 28, 1994, among Walter, Old Walter Congo, Walter Holdings, Nuevo, Old Nuevo Congo and Nuevo Holding. (Exhibit 2.11 to Form 8-K dated March 10, 1995).

10.17 Latent ORRI Contract dated February 25, 1995, among Walter, Walter Holdings, Walter Congo, Nuevo, Nuevo Holding and Nuevo Congo. (Exhibit 2.12 to Form 8-K dated March 10, 1995).

10.18 Latent Working Interest Contract dated February 25, 1995, among Walter, Walter Holdings, Walter Congo, Nuevo, Nuevo Holding and Nuevo Congo. (Exhibit 2.13 to Form 8-K dated March 10, 1995).

10.19 Asset Purchase Agreement dated as of February 16, 1996 between Nuevo Energy Company, the Purchaser, and Union Oil Company of California as Seller. (Exhibit 2.1 to Form S-3 (No. 333-1504).

10.20 Asset Purchase Agreement dated as of April 4, 1997, by and among Torch California Company and Express Acquisition Company, as Sellers, and Nuevo Energy Company, as Purchaser. (Exhibit 2.2 to Form S-3 (No. 333-1504)).

10.21 Purchase and Sale Agreement dated October 16, 1998 between Nuevo Energy Company (Seller) and Samson Lone Star Limited Partnership (Buyer). (Exhibit 10.28 to our 1998 Form 10-K).

10.22 Master Services Agreement among the Company and Torch Energy Advisors Incorporated, Torch Operating Company, Torch Energy Marketing, Inc., and Novistar, Inc. dated January 1, 1999. (Exhibit 10.29 to our 1998 Form 10-K).

Table of Contents

10.23 Employment Agreement with Bruce Murchison dated June 1, 1999. (Exhibit 10.27 to our 1999 Third Quarter Form 10-Q).

10.24 Employment Agreement with John P. McGinnis dated July 15, 1999. (Exhibit 10.28 to our 1999 Third Quarter Form 10-Q).

10.25 Crude Oil Purchase Agreement dated February 4, 2000 between Nuevo Energy Company and Tosco Corporation. (Exhibit 10.1 to Form 8-K dated March 23, 2000).

10.26 Severance Protection Agreement dated March 25, 2001. (Exhibit 10.31 to our 2000 Form 10-K).

10.27 Amendment to 1999 Stock Incentive Plan (Exhibit 99.1 to our Form S-8, filed on October 21, 2001).

10.28 2001 Stock Incentive Plan (Exhibit 99.1 to our Form S-8, filed on October 21, 2001).

10.29 Employment Agreement with James L. Payne dated October 15, 2001. (Exhibit 10.1 to our 2001 Third Quarter Form 10-Q).

10.30 Janet F. Clark Stock Option Plan (Exhibit 10.35 to our 2001 Form 10-K).

10.31 George B. Nilsen Stock Option Plan (Exhibit 10.36 to our 2001 Form 10-K).

10.32 Registration Rights Agreement dated September 18, 2002 by and among Nuevo Energy Company, Yorktown Energy Partners III, L.P., Yorktown Energy IV, L.P., Yorktown Partners LLC, SAFIC S.A., Charles de Mestral, J. Ross Craft, Montana Oil and Gas, Ltd., David A. Badley, James S. Scott, Glenn Reed, Doug Allison and Mohamed Yaich (Exhibit 10.1 to our Form 8-K dated September 19, 2002).

10.33 Amendment to the 2001 Stock Incentive Plan (Exhibit 99.1 to our Form S-8 dated November 1, 2002).

10.34 First Amendment to Employment Agreement with James L. Payne dated September 11, 2002.

10.35 Key Executive Terminated Without Cause Agreement.

*10.36 Purchase and Sale Agreement, dated February 28, 2003, between Nuevo Energy Company and BlackSand Partners, L.P.

*10.37 Purchase and Sale Agreement, dated December 30, 2003, between Nuevo Energy Company and Tonner Hills SSP, LLC and Tonner Hills 680 LLC.

*12.1 Computation of Earnings to Fixed Charges and Ratio of Earnings to Combined Fixed Charges and Preferred Stock Dividends

*21 Subsidiaries of the Registrant

(23) Consents of experts and counsel

*23.1 Consent of KPMG LLP

*23.2 Consent of Ryder Scott Company L.P.

(31) Certifications pursuant to Section 302 of the Sarbanes-Oxley Act of 2002

*31.1 Certification of Chief Executive Officer of Nuevo Energy Company pursuant to Section 302 of the Sarbanes-Oxley Act of 2002

*31.2 Certification of Chief Financial Officer of Nuevo Energy Company pursuant to Section 302 of the Sarbanes-Oxley Act of 2002

(32) Certifications pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

*32.1 Certification of Chief Executive Officer of Nuevo Energy Company pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

*32.2 Certification of Chief Financial Officer of Nuevo Energy Company pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

Table of Contents

GLOSSARY OF OIL AND GAS TERMS

Terms used to describe quantities of oil and natural gas

Bbl One stock tank barrel, or 42 US gallons liquid volume, of crude oil or other liquid hydrocarbons.

Bcf One billion cubic feet of natural gas.

Bcfe One billion cubic feet of natural gas equivalent.

BOE One barrel of oil equivalent, converting gas to oil at the ratio of 6 Mcf of gas to 1 Bbl of oil.

BOPD One barrel of oil per day.

MBbl One thousand Bbls.

Mcf One thousand cubic feet of natural gas.

MMBbl One million Bbls of oil or other liquid hydrocarbons.

MMcf One million cubic feet of natural gas.

MBOE One thousand BOE.

MMBOE One million BOE.

Terms used to describe the Company s interests in wells and acreage

Gross oil and gas wells or acres The Company s gross wells or gross acres represent the total number of wells or acres in which the Company owns a working interest.

Net oil and gas wells or acres Determined by multiplying gross oil and natural gas wells or acres by the working interest that the Company owns in such wells or acres represented by the underlying properties.

Terms used to assign a present value to the Company s reserves

Standard measure of proved reserves The present value, discounted at 10%, of the pre-tax future net cash flows attributable to estimated net proved reserves. The Company calculates this amount by assuming that it will sell the oil and gas production attributable to the proved reserves estimated in its independent engineer s reserve report for the prices it received for the production on the date of the report, unless it had a contractual arrangement specific to a property to sell the production for a different price. The Company also assumes that the cost to produce the reserves will remain constant at the costs prevailing on the date of the report. The assumed costs are subtracted from the assumed revenues resulting in a stream of future net cash flows. Estimated future income taxes using rates in effect on the date of the report are deducted from the net cash flow stream. The after- tax cash flows are discounted at 10% to result in the standardized measure of the Company s proved reserves. The standardized measure of the Company s proved reserves is disclosed in the Company s audited financial statements in Note 18.

Pre-tax discounted present value The discounted present value of proved reserves is identical to the standardized measure, except that estimated future income taxes are not deducted in calculating future net cash flows. The Company discloses the discounted present value without deducting estimated income taxes to provide what it believes is a better basis for comparison of its reserves to the producers who may have different tax rates.

Terms used to classify our reserve quantities

Proved reserves The estimated quantities of crude oil, natural gas and natural gas liquids which, upon analysis of geological and engineering data, appear with reasonable certainty to be recoverable in the future from known oil and natural gas reservoirs under existing economic and operating conditions.

The SEC definition of proved oil and gas reserves, per Article 4-10(a)(2) of Regulation S-X, is as follows:

Proved oil and gas 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.

(a) Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation test. The area of a reservoir considered proved includes (A) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any; and (B) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.

(b) Reserves which can be produced economically through application of improved recovery, techniques (such as fluid injection) are included in the proved classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.

(c) Estimates of proved reserves do not include the following: (1) oil that may become available from known reservoirs, but is classified separately as indicated additional reserves ; (2) crude oil, natural gas, and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors; (3) crude oil, natural gas, and natural gas liquids, that may occur in undrilled prospects; and (4) crude oil, natural gas, and natural gas liquids, that may be recovered from oil shales, coal, gilsonite and other such sources.

Proved developed reserves Proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

Proved undeveloped reserves Proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required.

Terms which describe the cost to acquire the Company s reserves

Finding costs The Company s finding costs compare the amount the Company spent to acquire, explore and develop its oil and gas properties, explore for oil and gas and to drill and complete wells during a period, with the increases in reserves during the period. This amount is calculated by dividing the net change in the Company s evaluated oil and property costs during a period by the change in proved reserves plus production over the same period. The Company s finding costs as of December 31 of any year represent the average finding costs over the three-year period ending December 31 of that year.

Terms which describe the productive life of a property or group of properties

Reserve life index A measure of the productive life of an oil and gas property or a group of oil and gas properties, expressed in years. Reserve life index for the years ended December 31, 2003, 2002 or 2001 equal the estimated net proved reserves attributable to a property or group of properties divided by production from the property or group of properties for the four fiscal quarters preceding the date as of which the proved reserves were estimated.

Terms used to describe the legal ownership of the Company s oil and gas properties

Royalty interest A real property interest entitling the owner to receive a specified portion of the gross proceeds of the sale of oil and natural gas production or, if the conveyance creating the interest provides, a specific portion of oil and natural gas produced, without any deduction for the costs to explore for, develop or produce the oil and natural gas. A royalty interest owner has no right to consent to or approve the operation and development of the property, while the owners of the working interests have the exclusive right to exploit the mineral on the land.

Working interest A real property interest entitling the owner to receive a specified percentage of the proceeds of the sale of oil and natural gas production or a percentage of the production, but requiring the owner of the working interest to bear the cost to explore for, develop and produce such oil and natural gas. A working interest owner who owns a portion of the working interest may participate either as operator or by voting his percentage interest to approve or disapprove the appointment of an operator and drilling and other major activities in connection with the development and operation of a property.

Net revenue interest A real property interest entitling the owner to receive a specified percentage of the proceeds of the sale of oil and natural gas production or a percentage of the production, net of royalty interests and costs to explore for, develop and produce such oil and natural gas.

Terms used to describe seismic operations

Seismic data Oil and gas companies use seismic data as their principal source of information to locate oil and gas deposits, both to aid in exploration for new deposits and to manage or enhance production from known reservoirs. To gather seismic data, an energy source is used to send sound waves into the subsurface strata. These waves are reflected back to the surface by underground formations, where they are detected by geophones which digitize and record the reflected waves. Computers are then used to process the raw data to develop an image of underground formations.

2-D seismic data 2-D seismic survey data has been the standard acquisition technique used to image geologic formations over a broad area. 2-D seismic data is collected by a single line of energy sources which reflect seismic waves to a single line of geophones. When processed, 2-D seismic data produces an image of a single vertical plane of sub-surface data.

3-D seismic 3-D seismic data is collected using a grid of energy sources, which are generally spread over several miles. A 3-D survey produces a three dimensional image of the subsurface geology by collecting seismic data along parallel lines and creating a cube of information that can be divided into various planes, thus improving visualization. Consequently, 3-D seismic data is a more reliable indicator of potential oil and natural gas reservoirs in the area evaluated than 2-D seismic data.

The Company s miscellaneous definitions

Infill drilling Infill drilling is the drilling of an additional well or additional wells in excess of those provided for by a spacing order in order to more adequately drain a reservoir.

No. 6 fuel oil (Bunker) No. 6 fuel oil is a heavy residual fuel oil used by ships, industry, and for large-scale heating installations.

Upstream oil and gas properties Upstream is a term used in describing operations performed before those at a point of reference. Production is an upstream operation and marketing is a downstream operation when the refinery is used as a point of reference. On a gas pipeline, gathering activities are considered to have ended when gas reaches a central point for delivery into a single line, and facilities used before this point of reference are upstream facilities used in gathering, whereas facilities employed after commingling at the central point and employed to make ultimate delivery of the gas are downstream facilities.

Table of Contents

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) 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.

NUEVO ENERGY COMPANY
(Registrant)

By: /s/ JAMES L. PAYNE

James L. Payne
Chairman, President and Chief Executive Officer

Date: March 10, 2004

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

	Signature	Title	Date
By:	/s/ JAMES L. PAYNE James L. Payne	Chairman, President and Chief Executive Officer (Principal Executive Officer)	March 10, 2004
By:	/s/ MICHAEL S. WILKES Michael S. Wilkes	Chief Financial Officer (Principal Financial and Accounting Officer)	March 10, 2004
By:	/s/ ISAAC ARNOLD, JR. Isaac Arnold, Jr.	Director	March 10, 2004
By:	/s/ CHARLES M. ELSON Charles M. Elson	Director	March 10, 2004
By:	/s/ ROBERT L GERRY III Robert L Gerry III	Director	March 10, 2004
By:	/s/ J. FRANK HAASBEEK J. Frank Haasbeek	Director	March 10, 2004
By:	/s/ JAMES T. JONGEBLOED James T. Jongebloed	Director	March 10, 2004
By:	/s/ GARY R. PETERSEN Gary R. Petersen	Director	March 10, 2004

By:	/s/ SHERYL K. PRESSLER	Director	March 10, 2004
	Sheryl K. Pressler		

Table of Contents

EXHIBIT INDEX

Each exhibit identified below is filed as a part of this report. Exhibits not incorporated by reference to a prior filing are designated by an asterisk; all exhibits not so designated are incorporated herein by reference to a prior filing as indicated. Exhibits designated with a + constitute a management contract or compensatory plan or arrangement required to be filed as an exhibit to this report pursuant to Item 14 (c) of Form 10-K.

(2) Plan of Acquisition, Reorganization, Arrangement, Liquidation or Succession.

2.1 Agreement and Plan of Merger dated September 18, 2002 by and among Athanor Resources, Inc., Athanor B.V., Nuevo Energy Company, Nuevo Texas Inc., Yorktown Energy Partners III, L.P., Yorktown Energy IV, L.P., Yorktown Partners LLC, SAFIC S.A., Charles de Mestral, J. Ross Craft, Montana Oil and Gas, Ltd., David A. Badley, James S. Scott, Glenn Reed, Doug Allison and Mohamed Yaich (Exhibit 2.1 to our Form 8-K dated September 19, 2002).

2.2 Agreement and Plan of Merger dated February 12, 2004, by and among Plains Exploration & Production Company, PXP California, Inc. and Nuevo Energy Company (Exhibit 2.1 to our Form 8-K filed on February 12, 2004).

(3) Articles of Incorporation and bylaws.

3.1 Certificate of Incorporation of Nuevo Energy Company (Exhibit 3.1 to our 1999 Second Quarter Form 10-Q).

3.2 Certificate of Amendment to the Certificate of Incorporation of Nuevo Energy Company (Exhibit 3.2 to our 1999 Second Quarter Form 10-Q).

3.3 Bylaws of Nuevo Energy Company (Exhibit 3.3 to our 1999 Second Quarter Form 10-Q).

3.4 Amendment to section 3.1 of the Bylaws of Nuevo Energy Company (Exhibit 3.4 to our 1999 Second Quarter Form 10-Q).

(4) Instruments defining the rights of security holders, including indentures.

4.1 Specimen Stock Certificate (Exhibit 4.1 to our Form S-4 (No. 33-33873) filed under the Securities Act of 1933).

4.2 Indenture dated April 1, 1996 among Nuevo Energy Company as Issuer, various Subsidiaries as the Guarantors, and State Street Bank and Trust Company as the Trustee 9 1/2% Senior Subordinated Notes due 2006. (Incorporated by reference from Form S-3 (No. 333-1504).

4.3 Form of Amended and Restated Declaration of Trust dated December 23, 1996, among the Company, as Sponsor, Wilmington Trust Company, as Institutional Trustee and Delaware Trustee, and Michael D. Watford, Robert L. Gerry, III and Robert M. King, as Regular Trustees. (Exhibit 4.1 to our Form 8-K filed on December 23, 1996).

4.4 Form of Subordinated Indenture dated as of November 25, 1996, between the Company and Wilmington Trust Company, as Indenture Trustee. (Exhibit 4.2 to Form 8-K filed on December 23, 1996).

4.5 Form of First Supplemental Indenture dated December 23, 1996, between the Company and Wilmington Trust Company, as Indenture Trustee. (Exhibit 4.3 to Form 8-K filed on December 23, 1996).

4.6 Form of Preferred Securities Guarantee Agreement dated as of December 23, 1996, between the Company and Wilmington Trust Company, as Guarantee Trustee. (Exhibit 4.4 to Form 8-K filed on December 23, 1996).

4.7 Form of Certificate representing TECONS. (Exhibit 4.5 to Form 8-K filed on December 23, 1996).

4.8 Shareholder Rights Plan, dated March 5, 1997, between Nuevo Energy Company and American Stock Transfer & Trust Company, as Rights Agent (Exhibit 1 to our Form 8-A filed on April 1, 1997).

Table of Contents

*4.9 First Amendment to the Shareholder Rights Plan, dated January 10, 2000, between Nuevo Energy Company and American Stock Transfer & Trust Company.

4.10 Second Amendment to the Shareholder Rights Plan, dated February 12, 2004, between Nuevo Energy Company and American Stock Transfer & Trust Company (Exhibit 99.1 to our Form 8-A/A filed on February 27, 2004).

4.11 Release and Termination of Subsidiary Guarantees with respect to the 9 1/2% Senior Subordinated Notes due 2006. (Exhibit 4.11 to our 1997 Form 10-K)

4.12 Second Supplemental Indenture to the Indenture dated April 1, 1996, dated August 9, 1999 between Nuevo Energy Company and State Street Bank and Trust Company 9 1/2% Senior Subordinated Notes due 2006 (Exhibit 4.10 to our Form S-4 (No. 333-90235) filed on November 3, 1999).

4.13 Indenture dated as of August 20, 1999, between Nuevo Energy Company and State Street Bank Trust Company, as Trustee (Exhibit 4.11 to our Form S-4 (No. 333-90235) filed on November 3, 1999).

4.14 Registration Agreement dated August 20, 1999, between Nuevo Energy Company, Banc of America Securities LLC and Salomon Smith Barney Inc. (Exhibit 4.12 to our Form S-4 (No. 333-90235) filed on November 3, 1999).

4.15 Indenture dated September 26, 2000, between Nuevo Energy Company and State Street Bank and Trust Company as the Trustee 9 3/8% Senior subordinated Notes due 2010 (Exhibit 4.12 to our 2000 Third Quarter Form 10-Q).

4.16 Registration Agreement dated September 26, 2000, between Nuevo Energy Company and Banc of America Securities LLC, Banc One Capital Markets, Inc. and J.P. Morgan & Co. (Exhibit 4.13 to our 2000 Third Quarter Form 10-Q).

(10) Material Contracts.

10.1 Third Restated Credit Agreement dated June 7, 2000, between Nuevo Energy Company (Borrower) and Bank of America N.A. (Administrative Agent), Bank One, NA (Syndication Agent), Bank of Montreal (Documentation Agent) and certain lenders (Exhibit 10.1 to our 2000 Second Quarter Form 10-Q).

10.2 1990 Stock Option Plan, as amended (Exhibit 10.8 to our Form S-1 dated July 13, 1992).

10.3 1993 Stock Incentive Plan, as amended (Exhibit 4.2 to our Form S-8 (No. 333-21063) filed on February 4, 1997.)

10.4 1999 Stock Incentive Plan (Exhibit 99.1 to our Form S-8 (No. 333-87899) filed on September 28, 1999).

10.5 Nuevo Energy Company Deferred Compensation Plan (Exhibit 99 to our Form S-8 (No. 333-51217) filed on April 28, 1998).

10.6 Stock Purchase Agreement, dated as of June 30, 1994, among Amoco Production Company (APC), Walter International Inc. (Walter), Walter Congo Holdings, Inc. (Walter Holdings), Walter International Congo, Inc. (before the merger Walter Congo and after the merger Old Walter Congo), Nuevo, Nuevo Holding and The Nuevo Congo Company (before the merger, Nuevo Congo and after the merger, Old Nuevo Congo). (Exhibit 2.1 to Form 8-K dated March 10, 1995).

10.7 Amendment to Stock Purchase Agreement dated as of September 19, 1994, among APC, Walter Congo, Nuevo Congo, Walter Holdings, Nuevo Holding, Walter and Nuevo. (Exhibit 2.2 to Form 8-K dated March 10, 1995).

10.8 Second Amendment to Stock Purchase Agreement dated as of October 15, 1994, among APC, Walter Congo, Nuevo Congo, Walter Holdings, Nuevo Holding, Walter and Nuevo. (Exhibit 2.3 to Form 8-K dated March 10, 1995).

Table of Contents

10.9 Third Amendment to Stock Purchase Agreement dated as of December 2, 1994, among APC, Walter Congo, Nuevo Congo, Walter Holdings, Nuevo Holding, Walter and Nuevo. (Exhibit 2.4 to Form 8-K dated March 10, 1995.)

10.10 Fourth Amendment to Stock Purchase Agreement dated as of February 23, 1995, among APC, Walter Congo, Nuevo Congo, Walter Holdings, Nuevo Holding, Walter and Nuevo. (Exhibit 2.5 to Form 8-K dated March 10, 1995).

10.11 Tax Agreement dated as of February 23, 1995, executed by APC, Amoco Congo Exploration Company (ACEC), Amoco Congo Production Company (ACPC), Walter, Walter Holdings, Walter Congo, Nuevo, Nuevo Holding and Nuevo Congo. (Exhibit 2.6 to Form 8-K dated March 10, 1995).

10.12 Agreement and Plan of Merger executed by Nuevo Congo, Nuevo Holding and APC dated February 24, 1995. (Exhibit 2.7 to Form 8-K dated March 10, 1995).

10.13 Finance Agreement dated as of December 28, 1994, among Nuevo Holding, Nuevo Congo and The Overseas Private Investment Corporation (OPIC). (Exhibit 2.8 to Form 8-K dated March 10, 1995).

10.14 Subordination Agreement dated December 28, 1994, among Nuevo Congo, Nuevo Holding, Walter Congo, Walter Holdings and APC. (Exhibit 2.9 to Form 8-K dated March 10, 1995).

10.15 Guaranty covering the obligations of Nuevo Congo and Walter Congo under the Stock Purchase Agreement dated February 24, 1995, executed by Walter and Nuevo. (Exhibit 2.10 to Form 8-K dated March 10, 1995).

10.16 Inter-Purchaser Agreement dated as of December 28, 1994, among Walter, Old Walter Congo, Walter Holdings, Nuevo, Old Nuevo Congo and Nuevo Holding. (Exhibit 2.11 to Form 8-K dated March 10, 1995).

10.17 Latent ORRI Contract dated February 25, 1995, among Walter, Walter Holdings, Walter Congo, Nuevo, Nuevo Holding and Nuevo Congo. (Exhibit 2.12 to Form 8-K dated March 10, 1995).

10.18 Latent Working Interest Contract dated February 25, 1995, among Walter, Walter Holdings, Walter Congo, Nuevo, Nuevo Holding and Nuevo Congo. (Exhibit 2.13 to Form 8-K dated March 10, 1995).

10.19 Asset Purchase Agreement dated as of February 16, 1996 between Nuevo Energy Company, the Purchaser, and Union Oil Company of California as Seller. (Exhibit 2.1 to Form S-3 (No. 333-1504).

10.20 Asset Purchase Agreement dated as of April 4, 1997, by and among Torch California Company and Express Acquisition Company, as Sellers, and Nuevo Energy Company, as Purchaser. (Exhibit 2.2 to Form S-3 (No. 333-1504)).

10.21 Purchase and Sale Agreement dated October 16, 1998 between Nuevo Energy Company (Seller) and Samson Lone Star Limited Partnership (Buyer). (Exhibit 10.28 to our 1998 Form 10-K).

10.22 Master Services Agreement among the Company and Torch Energy Advisors Incorporated, Torch Operating Company, Torch Energy Marketing, Inc., and Novistar, Inc. dated January 1, 1999. (Exhibit 10.29 to our 1998 Form 10-K).

10.23 Employment Agreement with Bruce Murchison dated June 1, 1999. (Exhibit 10.27 to our 1999 Third Quarter Form 10-Q).

10.24 Employment Agreement with John P. McGinnis dated July 15, 1999. (Exhibit 10.28 to our 1999 Third Quarter Form 10-Q).

10.25 Crude Oil Purchase Agreement dated February 4, 2000 between Nuevo Energy Company and Tosco Corporation. (Exhibit 10.1 to Form 8-K dated March 23, 2000).

10.26 Severance Protection Agreement dated March 25, 2001. (Exhibit 10.31 to our 2000 Form 10-K).

Table of Contents

10.27 Amendment to 1999 Stock Incentive Plan (Exhibit 99.1 to our Form S-8, filed on October 21, 2001).

10.28 2001 Stock Incentive Plan (Exhibit 99.1 to our Form S-8, filed on October 21, 2001).

10.29 Employment Agreement with James L. Payne dated October 15, 2001. (Exhibit 10.1 to our 2001 Third Quarter Form 10-Q).

10.30 Janet F. Clark Stock Option Plan (Exhibit 10.35 to our 2001 Form 10-K).

10.31 George B. Nilsen Stock Option Plan (Exhibit 10.36 to our 2001 Form 10-K).

10.32 Registration Rights Agreement dated September 18, 2002 by and among Nuevo Energy Company, Yorktown Energy Partners III, L.P., Yorktown Energy IV, L.P., Yorktown Partners LLC, SAFIC S.A., Charles de Mestral, J. Ross Craft, Montana Oil and Gas, Ltd., David A. Badley, James S. Scott, Glenn Reed, Doug Allison and Mohamed Yaich (Exhibit 10.1 to our Form 8-K dated September 19, 2002).

10.33 Amendment to the 2001 Stock Incentive Plan (Exhibit 99.1 to our Form S-8 dated November 1, 2002).

10.34 First Amendment to Employment Agreement with James L. Payne dated September 11, 2002.

10.35 Key Executive Terminated Without Cause Agreement.

*10.36 Purchase and Sale Agreement, dated February 28, 2003, between Nuevo Energy Company and BlackSand Partners, L.P.

*10.37 Purchase and Sale Agreement, dated December 30, 2003, between Nuevo Energy Company and Tonner Hills SSP, LLC and Tonner Hills 680 LLC.

*12.1 Computation of Earnings to Fixed Charges and Ratio of Earnings to Combined Fixed Charges and Preferred Stock Dividends

*21 Subsidiaries of the Registrant

(23) Consents of experts and counsel

*23.1 Consent of KPMG LLP

*23.2 Consent of Ryder Scott Company L.P.

(31) Certifications pursuant to Section 302 of the Sarbanes-Oxley Act of 2002

*31.1 Certification of Chief Executive Officer of Nuevo Energy Company pursuant to Section 302 of the Sarbanes-Oxley Act of 2002

*31.2 Certification of Chief Financial Officer of Nuevo Energy Company pursuant to Section 302 of the Sarbanes-Oxley Act of 2002

(32) Certifications pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

*32.1 Certification of Chief Executive Officer of Nuevo Energy Company pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

*32.2 Certification of Chief Financial Officer of Nuevo Energy Company pursuant to Section 906 of the Sarbanes-Oxley Act of 2002