NUEVO ENERGY CO
Form 10-K
April 01, 2002

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

FORM 10-K

(Mark One)
[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2001

OR

[_] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from to

Commission File Number 1-10537

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 [X] No [_]

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

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

The aggregate market value of the voting stock held by non-affiliates of the registrant at March 26, 2002, was approximately $259,987,138.

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

Common Stock, par value $.01 per share. Shares outstanding on March 26, 2002: 17,104,417.

DOCUMENTS INCORPORATED BY REFERENCE:

Portions of the registrant's annual proxy statement, to be filed within 120 days after December 31, 2001, are incorporated by reference into Part III.

NUEVO ENERGY COMPANY

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PART I

ITEM 1. BUSINESS

General

Nuevo Energy Company became a public company in July 1990 and is engaged in the acquisition, exploitation, development and production of and exploration for crude oil and natural gas. We have increased our proved oil and gas reserves through major acquisitions in the Republic of Congo in 1995 and in California in 1996 and also acquired proved reserves near or adjacent to our California assets followed by successful exploitation of our acquired properties.

We are the largest independent oil and gas exploration and production company in California. With approximately 93% of our reserves located in California at year-end 2001, we have a long reserve life and highly predictable well production profiles. Four fields in the San Joaquin Valley accounted for 73% of our California reserves and 92% of our California value in 2001. We also operate fields offshore California. This high asset concentration combined with a high proportion of operated properties enables us to control the timing of exploitation and development expenditures within commodity price cycles.

Our international assets are principally concentrated offshore the Republic of Congo and accounted for 7% of our reserves at year-end 2001. This non-operated property provides a stable production profile which has been enhanced by a recent infill development program.

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.

Strategy

Prior to late 2001, our strategy had been focused on our strengths: acquiring undervalued assets in familiar geographic areas and geologic plays, developing our assets cost-effectively through secondary and tertiary recovery methods, and pursuing logical field extensions of existing plays that fit our competencies.

In late 2001, the new management team was formed to redirect the focus of the Company. In order to generate greater profitability from the existing asset base, we determined that capital expenditures and costs would have to be reduced. A disciplined capital allocation process was implemented which resulted in a $70 - 80 million capital budget for 2002, versus $148 million in 2001. Management is committed to spending no more capital than our cash flow allows.

In order to reduce costs and gain greater operational control, in late 2001, we notified our California field operations and human resources outsourcing provider that the outsourcing agreements will be terminated effective March 15, 2002. Nuevo employees now staff the majority of these functions. We have also implemented cost reduction measures throughout our organization. At year-end 2001, an unsuccessful California exploration program was terminated and the technical staff was reduced. Overall, our general and administrative expenses, exploration expenses and lease operating expenses will be significantly reduced in 2002 versus 2001.

These initial steps will ensure that we generate higher returns from our existing asset base. However, our intermediate and longer-term objectives are to increase our growth in production and reserves while improving the profitability of our operations. This will be accomplished by reducing our financial leverage, acquiring higher margin properties and adding one or two additional core areas in North America.

Reserves

We invested $433.1 million during the three years ended December 31, 2001 and added 104.6 MMBOE, replacing 177% of our production at an average cost of $4.14 per BOE.

The following table details our estimated proved reserves at December 31, 2001:

	Net Proved Reserves		
	Oil(/1/) (MBbls)	Gas (MMcf)	MBOE
U.S. Properties			
California Fields			
Cymric	82,845	4,048	83,521
Brea Olinda	30,185	18,014	33,188
Midway-Sunset	26,185	--	26,185
Belridge	15,623	1,195	15,822
Santa Clara	10,621	18,754	13,747
Dos Cuadras	9,284	4,549	10,042
Point Pedernales	8,032	1,878	8,345
Buena Vista	2,656	27,431	7,228
Other	13,325	30,092	18,339
Total California Fields	198,756	105,961	216,417
Other U.S. Fields	257	5,402	1,157

Total U.S. Properties	199,013	111,363	217,574
Foreign Properties			
Yombo, Congo	15,571	--	15,571
Other	274	1,129	462
Total Foreign Properties	15,845	1,129	16,033
Total Properties	214,858	112,492	233,607

(/1/)Includes natural gas liquids

Domestic Operations

Our domestic operations are located primarily onshore and offshore California. We also have domestic operations in the onshore Gulf Coast region, Alabama and Louisiana. At December 31, 2001, our net U.S. proved reserves totaled approximately 217.6 MMBOE or 93% of our total proved reserve base. During 2001, domestic production was 16.7 MMBOE, or 90% of total production.

We continue to create value through domestic oil and gas development projects by initiating workovers, recompletions, development drilling, secondary and tertiary recovery operations and other production enhancement techniques to maximize current production and the ultimate recovery of reserves. Capital expenditures for domestic exploitation projects totaled $100.7 million in 2001 and are currently budgeted at approximately $65 -- 75 million in 2002. The main focus of our 2002 exploitation program will be directed to the continued successful development of Star Fee in the Cymric field.

The focus of our exploratory drilling was in California where we drilled 1 successful well and 8 dry holes in 2001. Capital expenditures for domestic exploration activity totaled $10.7 million in 2001. In late 2001, we made the decision to scale back our exploratory efforts and to discontinue all exploration activities in California.

California Onshore. Net proved reserves were approximately 176.7 MMBOE at December 31, 2001, and production was 11.1 MMBOE in 2001. Our main California onshore properties include interests in the Cymric, Midway-Sunset and Belridge fields in the Western San Joaquin Basin in Kern County, California, the Buena Vista Hills field in the Southern San Joaquin Basin in Kern County and the Brea Olinda field in the North San Joaquin Valley. We have onshore properties that 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. We operate and own a 100% working interest (79% net revenue) in our operated portion of the Buena Vista Hills field. Production from this field is from the Etchegoin Sands and the Antelope Shale. We also operate three fee properties in the Brea Olinda oil field in northern Orange County with a 100% working and net revenue interest. We have royalty interests in additional wells in the Brea Olinda field. Brea Olinda production is from multiple-pay zones in the Miocene and Pliocene sandstones at depths up to 6,500 feet.

California Offshore. Net proved reserves were approximately 39.7 MMBOE at December 31, 2001, and production was 5.2 MMBOE in 2001. Offshore California, we operate 12 platforms; 10 in federal waters and 2 in state waters and have interests in the Point Pedernales, Dos Cuadras and East Dos Cuadras, and Santa Clara fields. We own an 80% working interest (67% net revenue) in the Point Pedernales field We operate the Point Pedernales 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 operate the Santa Clara field with a 100% working interest (83% net revenue).

Other Domestic. We have properties located in the onshore Gulf Coast region, Alabama and Louisiana with a total proved reserve base of 1.2 MMBOE at December 31, 2001, and production of 0.4 MMBOE in 2001. These properties include our interests in the Giddings field in Grimes and Austin Counties, Texas; and in the North Frisco City field in Monroe County, Alabama. We own an interest in 12 producing wells in the Giddings field and have an average 46.9% working (35.2% net revenue) interest in these wells. We are the operator of the North Frisco City field and own approximately a 22% working (17% net revenue) interest in this field.

International Operations

At December 31, 2001, our estimated international net proved reserves totaled 16.0 MMBOE, or 7% of our total proved reserve base. During 2001, our international production was 1.9 MMBOE, or 10% of our total production.

Our international investments involve risks typically associated with investments in emerging markets such as an uncertain political, economic, legal and tax environment and possible 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 the Overseas Private Investment Corporation ("OPIC"). See "Risk Factors" for a discussion of the risks of our international investments.

Congo. Our international reserves and production consist of a 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, 2001 were 16.0 MMBbl, and production during 2001 totaled 1.9 MMBbls. In 2001 revenues relating to production from the Yombo field accounted for approximately 11% of our total oil and gas revenues. 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 had a 50% interest in the Masseko field which we have elected not to pursue due to economic conditions at this time. Should circumstances change in the future, we may pursue development of the field. As a result of the decision not to pursue this field, an impairment of $13.0 million was recorded in 2001.

During 2000 and 2001, a five well development program was implemented. This highly successful program increased our net production in the Congo from 5,000 BOPD in October 2000 to a peak production rate of 6,450 BOPD in August 2001. The individual wells produced at rates between 500 and 1,800 BOPD. The field is currently fully developed, due to the lack of slots for new wells. As additional slots become available, additional drilling activity is possible.

Ghana. As of June 17, 2001, we relinquished our 1.9 million-acre Accra-Keta Permit offshore the Republic of Ghana. 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. A total impairment of $1.0 million was recorded during the second and third quarters of 2001 in connection with this relinquishment.

Tunisia. In 2000, we acquired interests in two exploration permits in the Republic of Tunisia, subject to governmental approval, that added 1.3 million acres to our international portfolio. The first of these permits is the 171,000-acre (gross) Alyane Permit located offshore Tunisia in the Gulf of Gabes. We owned a 100% participating interest and were operator of the block. As a result of a shift in our international exploration strategy, we withdrew our request for formal government approval of the Convention and Joint Venture Agreement in January 2002 resulting in a relinquishment of our interest in Alyane.

In April 2000, we acquired a 10.42% participating interest from Bligh Tunisia Inc. in the 1.1 million gross acre Anaguid Permit located onshore southern Tunisia in the Ghadames Basin for approximately $1.5 million. This permit is operated by Anadarko Petroleum Company. In July 2001, we acquired an additional 12.08% participating interest from Coho Anaguid Inc., which is subject to governmental approval. The two interests total 22.5% participating interest. The partners anticipate drilling one exploration well on the Anaguid Permit by December 2002, subject to rig availability. Our anticipated costs under this commitment are approximately $0.7 million. In 2001, the partners completed the acquisition of 1,801 kilometers of new 2-D seismic data. We currently anticipate the drilling of a subsequent well in 2003, which might be required in connection with the acquisition of the interest from Coho Anaguid, Inc.

In addition to acquiring our interests in the Anaguid Permit, we have, effective April 1, 2000, increased our existing 17.5% participating interest in the 1,000,000 gross acre Fejaj Permit onshore Tunisia, by acquiring an additional interest from Bligh Tunisia Inc., giving us a 42.86% participating interest. We along with our partners plan to re-enter and deepen the Chott Fejaj #3-A well on the Fejaj Permit to test a sub-salt prospect in the fourth quarter of 2002. Our anticipated costs under this commitment are approximately $1.3 million. The current term of the Fejaj Permit has been extended due to a shortage of land rigs in Tunisia. The Chott Fejaj #3-A well was initially drilled to the top of salt in December 1998, when it was temporarily abandoned.

Canada. In May 2000, 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. The cyclic steaming potential of the acreage was evaluated in 2001, and was determined to be non-commercial. We have no current plans for the area.

Drilling Activities

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, 2001. Undeveloped acreage is considered to be those leased acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and gas, regardless of whether or not such acreage contains proved reserves. A gross acre in the following table 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 and percentages. 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	192,857	134,047
Undeveloped Acreage	2,433,283	836,884
Total	2,626,140	970,931

The following table sets forth our undeveloped acreage at December 31, 2001:

	Gross	Net
California(/1/)	250,486	123,351
Texas	10,880	2,806
Congo, West Africa:		
Marine 1 Permit	38,000	19,000
Tunisia, North Africa	2,100,000	676,071
Other	33,917	15,656
Total	2,433,283	836,884

(/1/Includes)COOGER acreage

Productive Wells

The following table sets forth our gross and net interests in productive oil and gas wells at December 31, 2001. Productive wells are producing wells and wells capable of production.

	Gross	Net

Oil Wells	2,601	1,967
Gas Wells	257	148
Total	2,858	2,115

Drilling Activity

Our drilling activities in 2001 were in the continental United States and offshore in state and federal waters, and offshore Congo.

At December 31, 2001, we had 2 gross (0.2 net) wells in progress. 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
1999	--	4	4	--	2.33	2.33
2000	11	2	13	11	1.45	12.45
2001	1	8	9	1	4.95	5.95

	Development Wells					
	Gross			Net		
	Productive	Dry Holes	Total	Productive	Dry Holes	Total
1999	44	1	45	40.21	0.33	40.54
2000	175	3	178	173.25	2.68	175.93
2001	101	1	102	95.98	1.00	96.98

In 2001, we drilled 35 wells in the Cymric field in central California, which contained 36% of our total estimated net proved equivalent reserves at December 31, 2001, and anticipate drilling approximately 36 wells in the Cymric field during 2002. In the Midway-Sunset field in central California, which contained 11% of the total estimated net proved equivalent reserves at December 31, 2001, we drilled 40 wells during 2000, and deferred the development in this field to 2002 where we plan to drill 10 Potter Sands and 2 Diatomite wells. In the Belridge field in central California, which contained 7% of the total estimated net proved equivalent reserves at December 31, 2001, we drilled 14 wells during 2001, and plan to drill approximately 11 wells in 2002.

In 1999, we initiated a waterflood project in the Yombo field offshore Congo to enhance production from existing Upper Sendji and Tchala zones. The development program continued during 2000 and 2001, drilling a total of 5 infill wells which increased our production approximately 30% from 2000 to 2001. Both pipelines originating from our platforms to the Conkouati (FPSO) were replaced in 2001. Plans for 2002 include two conversions to water injection and facility maintenance.

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 have attempted to purchase assets which, for any of a variety of reasons, are out of favor in the marketplace and are available for acquisition at attractive prices. We also seek to divest lower growth assets at times when those assets are valued highly by the marketplace.

In January 2001, we acquired producing properties previously held by Naftex ARM, LLC, in Kern County, California for approximately $28.5 million which is located southeast of our interest in the Cymric field.

In 2000, we sold our working interest in the Las Cienegas field in California for approximately $4.6 million. These assets were reclassified as assets held for sale during the third quarter of 1999, at which time we discontinued depleting and depreciating these assets. No impairment charge was recorded upon reclassification to assets held for sale.

In 1999, we sold our interests in 13 onshore fields and a gas processing plant located in Ventura County, California for approximately $29.6 million. The effective date of the sale was September 1, 1999. A portion of the proceeds, $4.5 million, was deposited in escrow to address possible remediation issues. The funds will remain in escrow until the Los Angeles Regional Water Quality Control Board approves completion of the remediation work. All or any portion of the funds not used in remediation shall be delivered to us. The remainder of the proceeds were used to retire bank debt.

In 1999, we acquired oil and gas properties located onshore and offshore California for $61.4 million from Texaco Inc. We used funds from a $100.0 million interest-bearing escrow account that provided "like-kind exchange" tax treatment for the purchase of domestic oil and gas producing properties. The escrow account was created with proceeds from our January 1999 sale of our East Texas natural gas assets. Following the Texaco transaction, the $41.0 million remaining in the escrow account, which included $2.4 million of interest income, was used to repay a portion of outstanding bank debt in early July 1999. The acquisition included interests in Cymric, East Coalinga, Dos Cuadras, Buena Vista Hills and other fields we operate.

In 1999, we completed the sale of our East Texas natural gas assets to an affiliate of Samson Resources Company for approximately $191.0 million. We realized an $80.2 million gain on the sale of these assets. A $5.2 million gain on settled hedge transactions was also realized in connection with the closing of this sale in 1999. The effective date of the sale was July 1, 1998. We reclassified these assets to assets held for sale and discontinued depleting these assets during the third quarter of 1998. Estimated net proved reserves associated with these properties totaled approximately 329.0 Bcf of natural gas equivalent at January 1, 1999.

Gas Plant and Other Facilities

At December 31, 2001, we owned interests in the following gas plant facilities:

Facility	State	Operator	Capacity MMCFD	2001 Throughput MMCFD	Ownership Interest
Stearns Gas Plant.......	California	Nuevo Energy Company	5	3.0	100%
HS&P Gas Plant..........	California	Nuevo Energy Company	13	2.1	80%

In December 1999, we sold the Santa Clara Valley Gas Plant, located east of Ventura, California, in connection with the sale of our interest in non-core properties onshore California.

Real Estate

In 1996, along with our acquisition of certain California upstream oil and gas properties from Union Oil Company of California, 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. As of December 31, 2001, the carrying amount of this land totaled $55.9 million. A majority of this real estate has associated oil and gas activity.

We may, from time to time, sell certain of our surface real estate assets. We sold 13.3 acres of our Brea Highland property in 2001 for $6.1 million and we expect to monetize a portion of our California real estate portfolio in 2002. Our Brea Highlands residential development project, now named "Tonner Hills", is currently going through the entitlement process in Orange County.

The agricultural land, primarily in Kings County, Fresno County and Kern County, has surface leases for grazing or farming use, which are compatible with the production of oil.

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 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. We have historically had a net long position in natural gas in California where we produce more natural gas than we consume in thermal crude production. As gas prices escalated in late 2000, we began to sell our California gas production to the market rather than use it as fuel gas consumed in less economic cyclic steaming operations to gas sales. In January and February 2001, we sold an average of 19 MMcfd, or 44% of our total daily gas production, which resulted in an increase in gas sales of 33%. As gas prices moderated later in 2001, we resumed using natural gas in our steam operations in August.

In California, we generate a total of 22.5 Megawatts ("MW") of power at various sites and consume approximately 77% in our operations. In 2000, two turbines came on-line at our Brea Olinda field using gas previously flared. 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 service, our facilities receive power under interruptible service contracts. Considering the fact that California has experienced shortages of electricity 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.

Production of California San Joaquin Valley heavy oil (defined herein as those fields which produce primarily 15(degrees) API quality crude oil or heavier through thermal operations) constituted 52% of our total 2001 crude output. In addition, properties which produce primarily other grades of relatively heavy oil (generally, 20(degrees) API or heavier, but produced through non-thermal operations) constituted 14% of our total 2001 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.

In February 2000, we entered into a 15-year contract, effective January 1, 2000, to sell all of our current and future California crude oil production to Tosco 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. 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. In doing so, the contract makes it substantially easier for us to hedge our realized prices. The Tosco contract permits, under certain circumstances, to separately market up to ten percent of our California crude production. We exercised this right and, effective January 1, 2001, began selling 5,000 BOPD of our San Joaquin Valley oil production to a third party under a one-year contract containing NYMEX pricing. A new contract was entered into with the same party for a one-year period on January 1, 2002.

Our Yombo field production in Marine 1 Permit offshore Congo produces a relatively heavy crude oil (16-20(degrees) API gravity) which is processed into a low-sulfur, No. 6 fuel oil product for sale to worldwide markets. Production from this property constituted 12% of our total 2001 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 Tosco Corporation accounted for 63%, 84% and 79% of 2001, 2000 and 1999 oil and gas revenues. Sales to Torch Energy Marketing accounted for 23%, 11% and 12% of 2001, 2000 and 1999 oil and gas revenues. Beginning in January 2002, our natural gas is being marketed by a new provider, Coral Energy. 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, control the amount of oil and gas produced by assigning allowable rates of production and control contamination of the environment. Pipelines and gas plants are also are subject to the jurisdiction of various Federal, state and local agencies.

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 or across 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 therefore pays royalties on 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.

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 all 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. 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.

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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 15 to the Notes to the Consolidated Financial Statements).

With respect to our offshore oil and gas operations in California, we have significant exit cost liabilities. These liabilities include costs for dismantlement, rehabilitation and abandonment. As of December 31, 2001, the net liability for these exit costs was approximately $113.1 million. We are not indemnified for any part of these exit costs. (See Note 15 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 these 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") and is considering the adoption of stricter disposal standards for nonhazardous wastes. Furthermore, 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.

Superfund. The federal Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), also known as the "Superfund" law, 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 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 the costs of such action. 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. We have not 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), 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 pollutants and of oil and Hazardous Substances. 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 "responsible parties" related to the prevention of oil spills and damages resulting from such spills in United States waters and adjoining shorelines. A "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 responsible party for oil removal costs 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, 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 in 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 OCS 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 California Coastal Commission.

Our management believes that we are in substantial compliance with current applicable environmental laws and regulations and that continued compliance with existing requirements 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, 2001, we had 95 full time employees, at which time we outsourced certain administrative and operational functions to third-party service providers. In late 2001, we terminated our California field operations and human resources outsource contracts and brought the professional and other positions in-house. At March 16, 2002, we had approximately 377 full time employees. (See Note 7 to the Notes to Consolidated Financial Statements).

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.

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 March 26, 2002, we had 17,102,417 shares of common stock outstanding. There were approximately 994 stockholders of record and approximately 2,789 additional beneficial owners as of March 22, 2002. 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 Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations-- Capital Resources and Liquidity and Note 12 to the Notes to Consolidated Financial Statements. The high and low recorded prices of our common stock during 2001 and 2000 are presented in the following table.

	Market Price	
	High	Low

2001		
First Quarter	$19.3500	$15.8750
Second Quarter	$21.5600	$15.2500
Third Quarter	$18.5000	$13.0000
Fourth Quarter	$16.0000	$11.1000
2000		
First Quarter	$26.0000	$15.5000
Second Quarter	$22.0600	$16.8125
Third Quarter	$20.2500	$14.3125
Fourth Quarter	$21.0000	$14.5000

Treasury Stock Repurchases

On February 12, 2001, our Board of Directors authorized the open market repurchase of an additional 1.0 million shares of common stock increasing the total amount authorized to 5.6 million shares of which 2.0 million are remaining. Repurchases may be made at times and at prices deemed appropriate by management and consistent with the authorization of our Board. During the first quarter of 2001, we repurchased 0.1 million shares at an average purchase price of $16.32 per share, including commissions. There were no shares repurchased during the second, third or fourth quarters of 2001. As of December 31, 2001, we had repurchased a total of 3.6 million shares since December 1997, at an average purchase price of $16.56 per share, including commissions.

Shareholder Rights Plan

In March 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.

On January 10, 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 stock by a person who, at the commencement of the offer, beneficially owns less than 5% of the outstanding common

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stock. A qualifying offer must remain open for at least 120 days, must be conditioned on the person commencing the qualifying offer acquiring at least 75% of the outstanding common stock and the per share consideration must exceed the greater of: (1) 135% of the highest closing price of the common stock during the one-year period prior to the commencement of the qualifying offer or (2) 150% of the average closing price of the common stock during the 20 day period prior to the commencement of the qualifying offer.

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. Stock acquired will be held in a benefit trust and will be restricted for a two-year period. The Plan was amended in 2001 to remove the discount on investments in our common stock and to provide additional investment alternatives. Target levels of ownership are based on multiples of base salary and are administered by the Compensation Committee of the Board of Directors. The Plan applies to certain highly compensated employees and all executives at a level of Vice-President and above.

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,				
	2001	2000	1999	1998	1997
	(In thousands, except per share data)				
Operating Results Data					
Revenues					
Oil and gas revenues.........	$368,560	$331,655	$242,274	$242,675	$331,973
Other........................	2,695	4,950	89,961	10,028	25,305
Total revenues.............	371,255	336,605	332,235	252,703	357,278
Costs and expenses					
Lease operating expense......	191,877	156,476	130,549	139,934	138,641
Exploration..................	22,058	9,774	14,017	16,562	11,082
General and administrative...	36,904	32,974	32,266	28,094	31,806
Depreciation, depletion and amortization................	76,154	67,370	80,652	85,036	102,158
Impairments..................	103,490	--	--	68,904	30,000
Interest expense.............	43,006	37,472	33,110	32,471	27,357
Dividends on TECONS..........	6,613	6,613	6,613	6,613	6,613
Cumulative effect of a change in accounting principle net of income tax benefit........	--	796	--	--	--
Extraordinary loss on early extinguishment of debt.......	--	--	--	--	3,024
Net income (loss)(/1/)........	(79,171)	11,635	31,442	(94,272)	(13,700)
Earnings (loss) per Common share--Basic.................	(4.73)	0.67	1.62	(4.77)	(0.69)
Earnings (loss) per Common share--Diluted...............	(4.73)	0.64	1.61	(4.77)	(0.69)

Financial Position Data

Total assets..................	$839,812	$848,024	$760,030	$817,685	804,286
Long-term debt, net of current maturities..................	450,444	409,727	340,750	419,150	305,940
Company-Obligated Mandatorily Redeemable Convertible Preferred Securities of Nuevo Financing I.................	115,000	115,000	115,000	115,000	115,000

(/1/No) common stock dividends have been declared since our formation. See Note 10 to the Notes to Consolidated Financial Statements concerning restrictions on the payment of common stock dividends.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

We began operations in 1990 as an independent oil and gas company and have grown through a series of acquisitions of oil and gas properties and the subsequent exploitation and development of these properties, and complemented these efforts with divestitures of non-core assets and an exploration program.

Results of Operations

Our results of operations are significantly affected by fluctuations in oil and gas prices. Success in acquiring oil and gas properties and our ability to maintain or increase production through exploitation activities has also significantly affected our operating results. The following table reflects our production and average prices for oil and natural gas:

	Year Ended December 31,		
	2001	2000	1999
Production			
Oil (MBbls)			
Domestic......................................	14,345	15,413	15,685
Foreign.......................................	1,882	1,843	1,835
Total.....................................	16,227	17,256	17,520
Natural gas (MMcf)			
Domestic......................................	12,751	15,215	17,620
Natural gas liquids (MBbls)			
Domestic......................................	189	178	207
Average sales price			
Oil ($/Bbl)			
Domestic......................................	$ 19.06	$ 21.73	$ 13.59
Foreign.......................................	20.94	22.19	16.69
Total--excluding hedges.......................	19.27	21.88	13.82
Total--hedge effect...........................	(3.13)	(7.13)	(2.61)
Total--net of hedge effect....................	$ 16.14	$ 14.75	$ 11.21
Natural gas ($/Mcf)			
Domestic/Total................................	$ 8.03	$ 4.78	$ 2.27

Average production cost per BOE			
Domestic	$ 10.67	$ 7.88	$ 6.07
Foreign	7.47	7.39	7.01
Total	10.35	7.84	6.15

Year Ended December 31, 2001 Compared to Year Ended December 31, 2000

We had a net loss of $79.2 million for 2001, or ($4.73) per diluted share as compared to net income of $11.6 million, or $0.64 per diluted share in 2000. In 2001, we had $131.7 million ($78.9 million after-tax) of non-recurring items. The largest component of the non-recurring items was a $103.5 million Statement of Financial Accounting Standards (SFAS) No. 121 impairment of the carrying value of our oil and gas properties. Other components of the non-recurring charge included costs associated with the termination of all outstanding derivative contracts with Enron Corp. and certain of its affiliates ("Enron"), restructuring charges related to the termination of two outsource contracts and the reorganization of our exploration and production operations and the write-off of certain domestic projects and project costs. Excluding these charges, the net loss for 2001 was $0.2 million, or ($0.01) per diluted share.

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The following table details our 2001 results of operations excluding the non-recurring charges discussed above:

	Year Ended December 31, 2001		
	Reported	Non-Recurring Items	Excluding Non-Recurring Items(/1/)
	(In thousands)		
Revenues	$ 371,255	$ (2,068)	$373,323
Costs and Expenses			
Lease operating expenses	191,877	1,666	190,211
Exploration costs	22,058	--	22,058
General and administrative expenses	36,904	3,799	33,105
Depreciation, depletion and amortization	76,154	--	76,154
Impairment of oil and gas properties	103,490	103,490	--
Restructuring charges	4,859	4,859	--
Loss on assets held for sale	3,494	3,494	--
Interest expense, net	43,006	263	42,743
Dividends on TECONS	6,613	--	6,613
Other expense	14,928	12,077	2,851
	503,383	129,648	373,735
Loss Before Income Taxes	(132,128)	(131,716)	(412)
Income Tax Benefit	52,957	52,792	165
Net Loss	$ (79,171)	$ (78,924)	$ (247)

(/1/The)above presentation should not be used as a substitute for amounts reported under generally accepted accounting principles. It is presented solely to improve the understanding of the impact of the charges.

Revenues

Oil and Gas Revenues. Oil and gas revenues increased 11% to $368.6 million in 2001 from $331.7 million in 2000 principally due to higher commodity prices and lower hedging losses during 2001, partially offset by lower production. The realized oil price in 2001 was $16.14 per Bbl, an increase of $1.39 per Bbl from 2000. Oil production averaged 44.5 MBbls per day, a decrease of 2.7 MBbls per day due to an eight-month curtailment of steaming operations in California as well as production shut-ins for facility repairs in 2001. Our hedging losses were $47.6 million in 2001 and $117.7 million in 2000. Natural gas production averaged 34.9 MMcf per day in 2001, declining 16% from 41.6 MMcf per day in 2000. The decline was due to lower domestic production onshore in the Gulf Coast and offshore California. The 2001 realized natural gas price was $8.03 per Mcf, which increased 68% from $4.78 per Mcf in 2000.

Gain on Sale of Assets. Our net gain from the sales of assets for 2001 was $0.9 million, primarily related to the gain from our sale of real estate in Brea, California of $1.1 million. The net gain on sale of assets for 2000 was $0.7 million primarily representing a $0.9 million gain on the sale of our working interest in the Las Cienagas field in California.

Interest and Other Income. Interest and other income for 2001 of $1.8 million includes $1.2 million of interest income on the overnight investment of excess cash and a gain on derivatives of $0.2 million. Interest and other income for 2000 of $4.3 million includes $1.9 million in interest income resulting from higher cash balances in 2000 plus $1.5 million for a partial reimbursement of previously expensed funds, resulting from a negotiated settlement of a legal claim, as well as several individually insignificant items

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Costs and Expenses Excluding Non-Recurring Items

Costs and Expenses. Lease operating expenses ("LOE") for 2001 totaled $190.2 million, as compared to $156.5 million for 2000. The 22% increase in LOE from 2000 to 2001 is primarily due to a 68% increase in gas prices in 2001 compared to 2000. We use gas as a feedstock to generate steam which is injected into reservoirs to facilitate the production of heavy California oil. Exploration costs, including geological and geophysical costs, dry hole costs and delay rentals, were $22.1 million in 2001, an increase of $12.3 million from 2000, primarily due to $11 million of dry hole costs associated with non-commercial wells drilled onshore California. Depreciation, depletion and amortization increased 13% in 2001 due to higher depletion rates which were primarily driven by a lower reserve base. General and administrative expense of $33.1 million in 2001 was comparable to 2000.

Interest Expense. Interest expense of $42.7 million in 2001 increased 14% compared to interest expense of $37.5 million in 2000. The increase is primarily due to the inclusion of a full year of interest for our 9 3/8% Senior Subordinated Notes issued in September 2000, offset by a decrease in the use of a line of credit and an increase of interest capitalized.

Dividends. Dividends on the TECONS were $6.6 million in 2001 and 2000. The TECONS pay dividends at a rate of 5.75% and were issued in December 1996. (See Note 11 to the Notes to Consolidated Financial Statements.)

Income Tax Benefit. We had an income tax benefit of $53.0 million in 2001 compared to an expense of $8.4 million in 2000. Our effective income tax rate was 40.1% in 2001 and 40.3% in 2000.

Non-Recurring Items

Impairments. During 2001, we recorded an impairment totaling $103.5 million on our Santa Clara, Huntington Beach, Pitas Point, Masseko and Point Pedernales fields and certain other oil and gas properties. SFAS No. 121 requires an impairment loss be recognized when the carrying value of an asset exceeds the sum of the undiscounted estimated future net cash flows. We recognized an impairment loss equal to the difference between the carrying amount and the fair value of the assets. The fair value of an oil and gas property equals the present value of expected future net cash flows from estimated proved reserves, utilizing a risk-adjusted rate of return. We had no impairments in 2000. (See Note 3 to the Notes to the Consolidated Financial Statements.)

Restructuring. We incurred $4.9 million of restructuring charges in 2001 related to the termination of two outsourcing contracts and the reorganization of our exploration and production operations. These costs included termination fees and severance. We had no such costs in 2000. (See Note 8 to the Notes to the Consolidated Financial Statements.)

Loss on Assets Held for Sale. 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 of $0.8 million. (See Note 4 to the Notes to the Consolidated Financial Statements.)

Other. We had other non-recurring income and expenses of $19.8 million in 2001 which were primarily related to the termination of hedging contracts with Enron, the reversal of a royalty refund claim, insurance costs related to business interruption and various consulting and legal costs. We had no such costs in 2000.

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Year Ended December 31, 2000 Compared to Year Ended December 31, 1999

Revenues

Oil and gas revenues for 2000 were 37% higher than 1999 oil and gas revenues primarily due to a 32% increase in average realized oil prices and a 111% increase in average realized gas prices from 1999 to 2000. Partially offsetting these increases in realized prices, our gas production decreased 14% from 1999 to 2000, and oil production decreased 2% from 1999 to 2000. The production decreases were primarily a result of asset sales.

Gain on Sale of Assets. The net gain on sale of assets for 2000 was $0.7 million, primarily representing a $0.9 million gain on the sale of our Las Cienegas field in California, partially offset by a $0.3 million net loss on the sale of several individually insignificant non-core assets. The net gain on sale of assets for 1999 was $85.3 million, which is comprised of an $80.2 million gain on the sale of our East Texas natural gas assets in January 1999, a $5.4 million gain on the sale of our interest in 13 onshore fields and a gas processing plant located in Ventura County, California, in December 1999, and a $0.3 million net loss on the sale of other non-core properties.

Interest and Other Income. Interest and other income for the year ended

December 31, 2000, of $4.3 million includes $1.9 million in interest income resulting from higher cash balances in 2000 plus $1.5 million for a partial reimbursement of previously expensed funds, resulting from a negotiated settlement of a legal claim (see Note 15 to the Notes to the Consolidated Financial Statements). Interest and other income for the year ended December 31, 1999, of $4.7 million includes $2.4 million associated with interest earned on the $100.0 million in proceeds from the sale of the East Texas natural gas properties funded into an escrow account to provide "like-kind exchange" tax treatment in the event we acquired domestic producing oil and gas properties in the first half of 1999. The escrow account was liquidated in June 1999, in connection with our June 1999 acquisition of certain California oil and gas properties from Texaco, Inc. and the repayment of a portion of bank debt. Also included in interest and other income in 1999 is $0.6 million related to the sale of an unconsolidated subsidiary.

Costs and Expenses

Costs and Expenses. LOE for 2000 totaled $156.5 million, as compared to $130.5 million for 1999. The 20% increase in LOE from 1999 to 2000 is primarily due to a $25.7 million increase in steam costs resulting from higher natural gas prices. Exploration costs, including geological and geophysical ("G&G") costs, dry hole costs and delay rentals, were $9.8 million and $14.0 million for the years ended December 31, 2000 and 1999. Exploration costs for the year ended 2000 included: $2.5 million of dry hole costs, $5.4 million of G&G costs, $0.1 million of delay rentals and $1.8 million of other exploration costs. Exploration costs for the year ended 1999 included: $8.1 million of dry hole costs ($7.2 million of which relates to onshore California), $3.6 million of G&G costs ($2.1 million of which relates to Ghana), $0.8 million of delay rentals and $1.5 million of other exploration costs. Depreciation, depletion and amortization decreased 16% in 2000 as compared to 1999. This decrease was driven by a lower depletion rate, which primarily resulted from a significant increase in reserve estimates attributable to higher commodity prices at year-end 2000 versus year-end 1999. General and administrative expenses increased only slightly in 2000 as compared to 1999.

Interest Expense. Interest expense of $37.5 million for year ended December 31, 2000, increased 13% as compared to interest expense in the same period in 1999. The increase is primarily attributable to an increase in outstanding borrowings under our credit facility during the year plus higher interest rates on those outstanding borrowings. On September 26, 2000, all borrowings outstanding under the credit facility were paid off with net proceeds received from our issuance of the 9 3/8% Notes (see Note 12 to the Notes to Consolidated Financial Statements). The increase is also due to higher interest rates as we exchanged our 8 7/8% Senior Subordinated Notes due 2008 for 9 1/2% Senior Subordinated Notes due 2008 in the third quarter of 1999.

Other Expense. Other expense of $5.1 million in 2000 includes: a $2.0 million settlement for a lawsuit (see Note 15 to the Notes to the Consolidated Financial Statements), $1.7 million for scientific information technology consulting, and $0.9 million in costs to evaluate potential business transactions. Other expense of $8.9 million in

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1999 includes: $3.1 million in third-party charges incurred in connection with the July 1999 exchange offer (see Note 12 to the Notes to Consolidated Financial Statements), $1.6 million relating to the fraud discussed below, $1.3 million for scientific information technology consulting, and other miscellaneous charges. In March 1999, we discovered that a non-officer employee had fraudulently authorized and diverted for personal use our company's funds totaling $5.9 million, $4.3 million in 1998 and the remainder in 1999, that were intended for international exploration.

Dividends. Dividends on the TECONS were $6.6 million in 2000 and 1999. The TECONS pay dividends at a rate of 5.75% and were issued in December 1996.

Income Tax Expense. Income tax expense of $8.4 million was recognized in 2000, compared to a benefit of $5.4 million in 1999. Our effective income tax rate was 40.3% and 20.5% in 2000 and 1999. At December 31, 1999, we determined that it was more likely than not that most of the deferred tax assets would be realized, based on commodity prices at year-end 1999, and the valuation allowance was decreased by $15.9 million.

Change in Accounting Principle.

In December 2000, the staff of the Securities and Exchange Commission announced that commodity inventories should be carried at the lower of cost or market rather than at market value. As a result, we changed our inventory valuation method to the lower of cost or market in the fourth quarter of 2000, retroactive to the beginning of the year. Accordingly, we recorded a non-cash, cumulative effect of a change in accounting principle to earnings, effective January 1, 2000, of $0.8 million (net of the related income tax benefit of $0.5 million) to value product inventory at the lower of cost or market. (See Note 2 to the Notes to the Consolidated Financial Statements.)

Capital Resources and Liquidity

We have grown and diversified our operations through a series of disciplined, low-cost acquisitions of oil and gas properties and the subsequent exploitation and development of these properties. We have historically funded our operations and acquisitions with operating cash flows, bank financing, private and public placements of debt and equity securities, property divestitures and joint ventures with industry participants.

Net cash provided by operating activities was $101.1 million, $93.7 million and $24.0 million in 2001, 2000 and 1999. We invested $145.4 million, $104.4 million and $125.9 million in oil and gas properties in 2001, 2000 and 1999. Additionally, we spent $8.6 million, $3.4 million and $10.2 million on gas plant and other facilities in 2001, 2000 and 1999. In January 2001, we acquired a producing property in California for $28.5 million.

In June 1999, we acquired working interests in oil and gas properties located onshore and offshore California for $61.4 million from Texaco Inc.("Texaco"). To purchase these assets, we used funds from a $100.0 million interest-bearing escrow account that was created with proceeds from our January 1999 sale of our East Texas natural gas assets. Following the Texaco transaction, the $41.0 million remaining in the escrow account, which included $2.4 million of interest income, was used to repay a portion of outstanding bank debt in early July 1999.

We believe our working capital, cash flow from operations and available financing sources are sufficient to meet our obligations as they become due and to finance our capital budget through 2002. Under our Credit Agreement which provides for secured revolving credit, we have a $225 million borrowing base with $102 million available at December 31, 2001 and had drawn $41.5 million under the agreement. In late December 2001 and early January 2002, we entered into interest rate swaps totaling $200 million; $150 million on our 9 3/8% notes and $50 million on our 9 1/2% Notes. (See Item 7A, Qualitative and Quantitative Disclosures About Market Risk).

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..............	$409,577	$ --	$ --	$ 2,367	$407,210
Operating leases............	9,978	1,521	3,086	3,011	2,360
Capital commitments.........	2,643	1,964	679	--	--
Total contractual cash obligations..............	$422,198	$ 3,485	$ 3,765	$ 5,378	$409,570

Long-term Debt

The following table details our long-term debt at December 31:

	2001
	(In thousands)
9 3/8% Senior Subordinated Notes due 2010....................	$150,000
9 1/2% Senior Subordinated Notes due 2008....................	257,210
9 1/2% Senior Subordinated Notes due 2006....................	2,367
Total long-term debt......................................	$409,577

9 3/8% Notes due 2010. In 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 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. Interest 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. We are not required to make mandatory redemption or sinking fund payments on these Notes. 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.

9 1/2% Notes due 2006. In 1996, we issued $160.0 million of 9 1/2% Notes and used the proceeds to pay for a portion of the purchase price of the Unocal Properties. Interest accrues at the rate of 9 1/2% per annum and is payable semi-annually in arrears on April 15 and October 15 and are redeemable, in whole or in part, at our option, on or after April 15, 2001, under certain conditions. These Notes have not been redeemed, in whole or in part, at December 31, 2001. We are not required to make mandatory redemption or sinking fund payments with respect to these Notes and they are unsecured general obligations, and are subordinated in right of payment to all existing and future senior indebtedness.

Operating Leases

We have operating leases in the normal course of business, which include those for office space and operating facilities and office and operating equipment, with varying terms from 2002 to 2009. At December 31, 2001, our total commitments under operating leases were approximately $10.0 million.

Minimum annual rental commitments at December 31, 2001, were as follows:

	Operating Leases (In thousands)
2002	$1,521
2003	1,503
2004	1,583
2005	1,604
2006	1,407
Thereafter	2,360
Total	$9,978

Capital Commitments

At December 31, 2001, we had capital commitments of $2.6 million primarily relating to our international oil and gas exploration and development activity. 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. Each of these commitments is discussed in further detail below:

Amount of Commitment
Expiration Per Period

	Total Amounts Committed	Less than 1 Year	1-3 Years	4-5 Years	After 5 Years
	(In thousands)				
Bank credit facility..............	$41,500	$ --	$ --	$41,500	$ --
Letters of credit.................	250	250	--	--	--
Total commercial commitments....	$41,750	$ 250	$ --	$41,500	$ --

Lines of Credit

Bank Credit Facility. Our Third Amended and Restated Credit Agreement, dated June 7, 2000, provides for secured revolving credit availability of up to $410.0 million from a bank group led by Bank of America, N.A., Bank One, N.A., and Bank of Montreal until its expiration on June 7, 2005.

The borrowing base is subject to a semi-annual borrowing base determination within 60 days following March 1 and August 15 of each year and establishes the maximum borrowings that may be outstanding under the credit facility. It is determined by a 60% vote of the 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 such excess over a defined period of time. We have a $225 million borrowing base under our Credit Facility with $102 million available at December 31, 2001 and had drawn $41.5 million under the agreement. Amounts outstanding under the credit facility bear interest at a rate equal to the London Interbank Offered Rate ("LIBOR") plus an amount which increases as the Indebtedness to Capitalization (as defined under the Credit Agreement) increases.

Letters of Credits

We had one letter of credit outstanding at December 31, 2001 in the amount of $0.3 million, which expires in February 2002.

Contingencies and Other Matters

Legal Proceedings

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. The cost of repair is expected to be partially covered by insurance. We may have exposure to costs that may not be recoverable from insurance, including those associated with the repair of undamaged equipment. Production was back on in January 2002.

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 and the cause of the failure is under investigation. 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 is 3,000 barrels of crude oil and 2.4 MMcf of natural gas, representing approximately 6% of our daily production. Crude oil production resumed in early July and full gas sales resumed by mid August. The cost of repair, less a $50,000 deductible, is expected to be covered by insurance. We may have exposure to costs that may not be recoverable from insurance.

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 successfully removed this lawsuit to the United States District Court for the Central District of California. The plaintiffs, who own certain interests in the Point Pedernales properties, have asserted numerous causes of action including breach of contract, fraud and conspiracy in connection with the plaintiff's allegation that:

- royalties have not been properly paid to them for production from the Point Pedernales field;
- payments have not been made to them related to production from the Pescado and Sacate fields, and;
- we have failed to recognize the plaintiff's interests in the Tranquillon Ridge project.

The plaintiffs have not specified damages. We intend to vigorously contest these claims.

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. The Company and ExxonMobil each own a 50% interest in the Sacate Field, offshore Santa Barbara County, California. We have alleged that by grossly inflating the fee that ExxonMobil insists we must pay to use an existing ExxonMobil platform and production infrastructure, ExxonMobil failed to submit a proposal for the development of the Sacate field consistent with the Unit Operating Agreement. We, therefore believe that we have been denied a reasonable opportunity to exercise our rights under the Unit Operating Agreement. We have alleged that ExxonMobil's actions breach the Unit Operating Agreement and the covenant of good faith and fair dealing. We are seeking damages and a declaratory judgment as to the payment that must be made to access ExxonMobil's platform and facilities.

We have been named as a defendant in certain other lawsuits incidental to our business. Management does not believe that the outcome of such litigation will have a material adverse impact on our operating results, financial condition or liquidity above the amounts we have reserved to cover any potential losses. However, these

actions and claims in the aggregate seek substantial damages against us and are subject to the inherent uncertainties in any litigation. We are defending ourselves vigorously in all such matters.

In March 1999, it was discovered that a non-officer employee had fraudulently authorized and diverted, for personal use, Company funds of $5.9 million; $1.6 million in 1999 and the remainder in 1998, that were intended for international exploration. The Board of Directors engaged a Certified Fraud Examiner to conduct an in-depth review of the fraudulent transactions. The investigation confirmed that only one employee was involved in the matter and that all misappropriated funds were identified. We have reviewed and, where appropriate, strengthened our internal control procedures. In August 2000, we recorded $1.5 million of other income for a partial reimbursement of these previously expensed funds, resulting from the negotiated settlement of a related legal claim.

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 Bbls 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 either have been or are expected to be covered by our insurance, less a deductible of $0.1 million. We incurred clean up and repair costs of $0.3 million, $ 0.3 million and $0.5 million during 2001, 2000 and 1999. As of December 31, 2001, we had received insurance reimbursements of $4.2 million, with a remaining insurance receivable of $0.5 million. For amounts not covered by insurance, including the $0.1 million deductible, we recorded lease operating expenses of $1.1 million in 2001 and $0.4 million during 1999. No such expenses were recorded in 2000. We also have exposure to costs that may not be recoverable from insurance, including certain fines, penalties, and damages and certain legal fees. Such costs are not quantifiable at this time, but are not expected to be material to our operating results, financial condition or liquidity.

Our international 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 the Overseas Private Investment Corporation ("OPIC"). The political risk insurance through OPIC covers up to $25.0 million relating to expropriation and political violence, which is the maximum coverage available through OPIC. We have no deductible for this insurance.

In connection with our February 1995 acquisitions of two subsidiaries (each a "Congo subsidiary") 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:

- a disposition by either us or CMS of our respective Congo subsidiary,
- either Congo subsidiary's sale of its interest in the Yombo field,
- the acquisition of us or CMS by another consolidated group or
- 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 $38.5 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 $56.2 million. We do not expect a triggering event to occur with respect to us or CMS and do not believe the agreement will have a material adverse effect upon us.

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 1996, the previous Congo government requested that the convention governing the Marine 1 Exploitation Permit be converted to a Production Sharing Agreement ("PSA"). Preliminary discussions were held with the government in early 1997. 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 would have no detrimental impact to us, otherwise, we will not agree to any such conversion. The new government established in the Congo in 1997 has recently begun discussions with us and our partner concerning the conversion to a PSA. Discussions with the new government are ongoing and, to date, no agreement has been reached concerning conversion to a PSA.

Contingent Payment and Price Sharing Agreements

In connection with the acquisition from Unocal in 1996 of the properties located in California, we are obligated to make a contingent payment for the years 1998 through 2004 if oil prices exceed thresholds set forth in the agreement with Unocal. Any contingent payment will be accounted for as a purchase price adjustment to oil and gas properties. The contingent payment will equal 50% of the difference between the actual average annual price received on a field-by-field basis (capped by a maximum price) and a minimum price, less ad valorem and production taxes, multiplied by the actual number of barrels of oil sold that are produced from the properties acquired from Unocal during the respective year. The minimum price of $17.75 per Bbl under the agreement (determined based on the near month delivery of WTI crude oil on the NYMEX) is escalated at 3% per year and the maximum price of $21.75 per Bbl on the NYMEX is escalated at 3% per year. Minimum and maximum prices are reduced to reflect the field level price by subtracting a fixed differential established for each field. The reduction was established at approximately the differential between actual sales prices and NYMEX prices in effect in 1995 ($4.34 per Bbl weighted average for all the properties acquired from Unocal). We accumulate credits to offset the contingent payment when prices are $.50 per Bbl or more below the minimum price. We paid $10.8 million to Unocal under this agreement on March 15, 2002.

In connection with the acquisition of the Congo properties in 1995, we entered into a price sharing agreement with the seller. There is no termination date associated with this agreement. Under the terms of the agreement, if the average price received for the oil production during the year is greater than the benchmark price established by the agreement, we are obligated to pay the seller 50% of the difference between the benchmark price and the actual price received, for all the barrels associated with this acquisition. The benchmark price was $15.78 per Bbl for 2001, $15.19 per Bbl for 2000 and $14.79 per Bbl for 1999. The benchmark price increases each year, based on the increase in the Consumer Price Index. For 2001, the effect of this agreement was that we only owned upside above $15.78 per Bbl on approximately 56% of our Congo production. We were obligated to pay the seller $3.4 million in 2001 and $5.4 million in 2000 under this price sharing agreement. This obligation was accounted for as a reduction in oil revenues. No payment was due in 1999.

We acquired a 12% working interest in the Point Pedernales oil field from Unocal in 1994 and the remainder of our 80.3 % working interest from Torch in 1996. We are entitled to all revenue proceeds up to $9.00 per Bbl, with the excess revenue over $9.00 per Bbl, if any, shared with the original owners from whom Torch acquired its interest. We own amounts below $9.00 per Bbl with the other working interest owners based on their respective ownership interests. For 2001, the effect of this agreement is that we were entitled to receive the pricing upside above $9.00 per Bbl on approximately 73% of the gross Point Pedernales production. As of December 31, 2001, we had $0.2 million accrued as our obligation under this agreement. As of December 31, 2000, we had $0.6 million accrued as our obligation under this agreement. As of December 31, 1999, we had $5.1 million accrued as our obligation under this agreement.

Critical Accounting Policies

Oil and Gas Properties

We use the successful efforts method to account for our investments in oil and gas properties. Under successful efforts, 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.

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 G&G expenses, exploratory dry holes and delay rentals, are charged to expense as incurred.

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 remaining proved developed reserves. Total estimated costs of $113.1 million (net of salvage value) for future dismantlement, abandonment and site remediation are included when calculating depreciation and depletion using the unit-of-production method. At December 31, 2001, we had recorded $74.2 million as a component of accumulated depreciation, depletion and amortization.

In accordance with SFAS No. 121, Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed of, 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. 121 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 present value of expected future net cash flows from proved reserves, utilizing a risk-adjusted rate of return. Due to low commodity prices in the fourth quarter of 2001, we estimated the expected undiscounted future net cash flows of our oil and gas properties and compared such undiscounted future net cash flows to the carrying amount of the oil and gas properties to determine if the carrying amount was recoverable. For some of our oil and gas properties, the carrying amount of the properties exceeded the estimated undiscounted future net cash flows; thus, we adjusted the carrying amount of the respective oil and gas properties to their fair value as determined by discounting their estimated future net cash flows. The factors used to determine fair value included, but were not limited to, estimates of proved reserves, future commodity prices, timing of future production, future capital expenditures and a discount rate commensurate with our internal rate of return on our oil and gas properties. As a result, we recognized a non-cash pre-tax charge of $103.5 million ($62.0 million after tax) related to the impairment of oil and gas properties in 2001.

Recognition of Crude Oil and Natural Gas Revenue

Crude oil and natural gas revenues are recognized when title 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. We did not have a material imbalance position in terms of units or value at December 31, 2001 or 2000. Approximately $ 58.1 million, $46.0 million and $20.4 million is included as oil and gas revenues and operating expenses related to gas production used in our steam injection projects in 2001, 2000 and 1999.

Derivative Financial Instruments

We adopted SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, effective January 1, 2001 which requires all derivative instruments to be carried on the balance sheet at fair value. In accordance with the transition provisions of SFAS No. 133, we recorded a cumulative effect transition adjustment of $(16.0) million, net of related tax benefit of $10.8 million, in other comprehensive income to recognize the fair value of our derivatives designated as cash-flow hedging instruments at the date of adoption.

Beginning on January 1, 2001, all of our derivative instruments are recognized on the balance sheet at their fair value. We currently use swaps and options to hedge our exposure to material changes in the future price of crude oil and interest rate swaps to hedge the fair value of our long-term debt.

On the date the derivative contract is entered into, we designate the derivative as either a hedge of fair value of a recognized asset or liability ("fair value" hedge), as a hedge of the variability of cash flows to be received ("cash-flow" hedge), or as a foreign currency cash flow 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 loss or gain on 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 earnings are affected by the variability of cash flows. At December 31, 2001, we had both cash-flow hedges and fair value hedges.

We formally document all relationships between hedging instruments and hedged items, as well as our 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, 2001, we had recorded $11.5 million, net of related taxes of $7.8 million, of cumulative hedging gains 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 $47.6 million, $117.7 million and $44.9 million in 2001, 2000 and 1999. The portion of our hedging transactions that were ineffective totaled $0.4 million in 2001 and was recorded in interest and other income.

Price Risk Management Activities

We use price risk management activities to manage non-trading market risks.

We use derivative financial instruments such as swaps and put options to hedge the impact of market price risk exposure on our crude oil and natural gas production and to mitigate our exposure to interest rate risk.

New Accounting Pronouncements

Accounting for Asset Retirement Obligations. In August 2001, the Financial Accounting Standards Board ("FASB") issued SFAS No. 143, Accounting for Asset Retirement Obligations. This Statement requires companies to record a liability relating to the retirement and removal of assets used in their business. The liability is discounted to its present value, and the related asset value is increased by the amount of the resulting liability. 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. The provisions of this Statement are effective for fiscal years beginning after June 15, 2002. We are currently evaluating the effects of this pronouncement.

Accounting for the Impairment or Disposal of Long-Lived Assets. In October 2001, the FASB issued SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets. This Statement requires that long-lived assets that are to be disposed of by sale be measured at the lower of historical net book value or fair value less cost to sell. The standard also expands 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 this Statement does not have a material impact on our financial condition or results of operations.

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 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. 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 "Hedging" below for discussion of 15-year crude oil contract).

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 decreases 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.

California Natural Gas and Electricity Markets

The price of natural gas and the threat of electrical disruptions are factors that create volatility in our California oil and gas operations. Because of the recent developments in these commodities, we have made significant changes in our natural gas disposition and electricity production in California. Regarding natural gas, we have historically had a net long position in California--producing more natural gas than consumed in thermal

crude production. Moreover, as gas prices escalated in late 2000, we began to exploit this gas position by diverting gas consumed in less economic cyclic steaming operations to gas sales. In January and February 2001, we sold an average of 19 MMcf per day, or 44% of our total daily gas production, which resulted in an increase in gas sales of 33%. As natural gas prices moderated later in 2001, we resumed the use of previously diverted natural gas in our steam operations.

In California, we generate a total of 22.5 Megawatts ("MW") of power at various sites. In 2000, two turbines came on-line at our Brea Olinda field using gas previously flared. 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 service, our facilities receive power under interruptible service contracts. Considering the fact that California has experienced shortages of electricity and some of our facilities receive interruptible service, we could experience periodic power interruptions. In addition, the State of California could change existing rules or impose new rules or regulations with respect to power that could impact our operating costs.

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.

Hedging

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. In addition, the index used to calculate the floating price in a hedge is frequently not the same as the prices actually received for the production hedged. The difference (referred to as basis differential) may be material, and may reduce the benefit or increase the detriment caused by a particular hedge. 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. Consequently, prior to 2000, hedging California heavy crude oil was particularly subject to the risks associated with volatile basis differentials. 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 Tosco 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. Therefore, the actual price received as a percentage of NYMEX will vary with our production mix. Based on our current production mix, the price we receive for our California oil production is expected to average approximately 72% of WTI. 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.

As a result of hedging transactions, oil and gas revenues were reduced by $47.6 million, $117.7 million and $44.9 million in 2001, 2000 and 1999.

Insurance

As a result of the September 11, 2001 terrorist attack, 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.

Risk Management 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 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. 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 price management activity.

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.

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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 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. Quantities covered by these hedges are based on West Texas Intermediate ("WTI") barrels. Our production is expected to average 73% of WTI, therefore, each WTI barrel effectively hedges 1.37 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, 2001, we had entered into the following cash flow hedges:

	WTI Barrels Per Day	Average Strike Price
Swaps		
First quarter 2002	12,500	$25.91
Second quarter 2002	2,000	23.50
Third quarter 2002	6,800	23.20
Fourth quarter 2002	5,000	23.90
Put Options		
Second quarter 2002	14,000	$22.00
Third quarter 2002	9,000	22.00
Fourth quarter 2002	9,000	22.00

At December 31, 2001, the fair market value of these hedge positions is

$19.6 million, net of the cost of the options of $3.8 million. A 10% increase in the underlying commodity prices would reduce this gain by $7.7 million.

Subsequent to December 31, 2001, we entered into the following swap agreements:

	WTI Barrels Per Day	Average Strike Price
Second quarter 2002	9,000	$24.31
Third quarter 2002	4,200	24.41
Fourth quarter 2002	6,000	24.01
First quarter 2003	6,000	23.36
Second quarter 2003	4,000	23.03
Third quarter 2003	4,000	23.07

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 primarily results from our long-term debt with both fixed and floating interest rates.

In late December 2001, we entered into two interest rate swap agreements with notional amounts totaling $150 million to hedge the fair value of our 9 1/2% Notes due 2008 and our 9 3/8% Notes due 2010. These swaps are designated as fair value hedges and are reflected as a reduction of long-term debt of $0.6 million as of December 31, 2001,with a correlating increase in long-term liabilities. Under the terms of the agreements for the 9 3/8% Notes, the counterparty pays us a weighted average fixed annual rate of 9 3/8% on total notional amounts 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 3.49%. Under the terms of the agreement for the 9 1/2% Notes, the counterparty pays us a weighted average fixed annual rate of 9 1/2% on total notional amounts of $50 million, and we pay the counterparty a variable annual rate equal to the six-month LIBOR rate plus a weighted average rate of 3.92%.

Subsequent to December 31, 2001, we entered into an interest rate swap agreement with a notional amount totaling $50 million to hedge the fair value of our 9 3/8% Notes. Under the terms of this agreement, the counterparty pays us a weighted average fixed annual rate of 9 3/8% on the notional amount of $50 million, and we pay the counterparty a variable annual rate equal to the three-month LIBOR rate plus a weighted average rate of 3.49%.

The following table presents principal amounts and the related average interest rates by year of maturity for our debt obligations at December 31, 2001:

	2002	2003	2004	2005	Thereafter	Total	Fair Value Liability
	(In thousands, except percentages)						

Long-term debt:							
Variable rate..........	$--	$--	$--	$41,500	$ --	$ 41,500	$ 41,500
Average interest rate..	--	--	--	3.71%	--	3.71%	
Fixed rate.............	$--	$--	$--	$ --	$409,577	$409,577	$394,512
Average interest rate..	--	--	--	--	9.41%	9.41%	

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO FINANCIAL STATEMENTS AND SCHEDULES

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

To the Stockholders and Board of Directors of
Nuevo Energy Company:

We have audited the accompanying consolidated balance sheet of Nuevo Energy Company (a Delaware corporation) and subsidiaries as of December 31, 2001, and the related consolidated statements of income, cash flows, stockholders' equity and comprehensive income and changes in accumulated other comprehensive income for the year then ended. 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 audit.

We conducted our audit in accordance with auditing standards generally accepted in the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. 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 audit provides 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, 2001, and the results of their operations and their cash flows for the year then ended in conformity with accounting principles generally accepted in the United States.

As discussed in Note 2 to the Consolidated Financial Statements, effective January 1, 2001, the Company changed its method of accounting for derivative instruments.

Our audit was made for the purpose of forming an opinion on the basic financial statements taken as a whole. The information included in Schedule II is presented for purposes of complying with the Securities and Exchange Commission's rules and is not a required part of the basic financial statements. This information has been subjected to the auditing procedures applied in our audit of the basic financial statements and, in our opinion, amounts pertaining to the year ended December 31, 2001 are fairly stated in all material respects in relation to the basic financial statements taken as a whole.

ARTHUR ANDERSEN LLP

Houston, Texas
February 8, 2002

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INDEPENDENT AUDITORS' REPORT

The Board of Directors
Nuevo Energy Company:

We have audited the accompanying consolidated balance sheet of Nuevo Energy Company and subsidiaries as of December 31, 2000, and the related consolidated statements of income, stockholders' equity, cash flows and comprehensive income and changes in accumulated other comprehensive income for each of the years in the two-year period ended December 31, 2000. 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, 2000, and the results of their operations and their cash flows for each of the years in the two-year period ended December 31, 2000, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the consolidated financial statements, effective January 1, 2000, the Company changed its method of accounting for its processed fuel oil and natural gas liquids inventories.

KPMG LLP

Houston, Texas
February 8, 2001

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NUEVO ENERGY COMPANY

CONSOLIDATED STATEMENTS OF INCOME

(In thousands, except per share data)

	Year Ended December 31,		
	2001	2000	1999
Revenues			
Oil and gas revenues	$ 368,560	$331,655	$242,274
Gain on sale of assets, net	882	657	85,294
Interest and other income	1,813	4,293	4,667
	371,255	336,605	332,235
Costs and Expenses			
Lease operating expenses	191,877	156,476	130,549
Exploration costs	22,058	9,774	14,017
General and administrative expenses	36,904	32,974	32,266
Depreciation, depletion and amortization	76,154	67,370	80,652
Impairment of oil and gas properties	103,490	--	--
Restructuring charges	4,859	--	--
Loss on assets held for sale	3,494	--	--
Interest expense, net	43,006	37,472	33,110
Dividends on TECONS	6,613	6,613	6,613
Other expense	14,928	5,103	8,945
	503,383	315,782	306,152
Income (loss) before income taxes and cumulative effect	(132,128)	20,823	26,083
Income tax (expense) benefit	52,957	(8,392)	5,359
Income (loss) before cumulative effect	(79,171)	12,431	31,442
Cumulative effect of a change in accounting			

principle, net of income tax benefit of $537...	--	(796)	--
Net income (loss).............................	$ (79,171)	$ 11,635	$ 31,442
Basic earnings (loss) per common share			
Income (loss) before cumulative effect........	$ (4.73)	$ 0.71	$ 1.62
Cumulative effect of a change in accounting principle, net of income tax benefit.........	--	(0.04)	--
Net income (loss)...........................	$ (4.73)	$ 0.67	$ 1.62
Weighted average Common shares outstanding-- Basic.......................................	16,735	17,447	19,353
Diluted earnings (loss) per common share			
Income (loss) before cumulative effect........	$ (4.73)	$ 0.68	$ 1.61
Cumulative effect of a change in accounting principle, net of income tax benefit.........	--	(0.04)	--
Net income (loss)...........................	$ (4.73)	$ 0.64	$ 1.61
Weighted average Common shares outstanding-- Diluted.....................................	16,735	17,941	19,507

See accompanying notes.

NUEVO ENERGY COMPANY

CONSOLIDATED BALANCE SHEETS

(In thousands, except share amounts)

	December 31,	
	2001	2000
ASSETS		
Current assets		
Cash and cash equivalents...........................	$ 7,110	$ 39,447
Accounts receivable, net of allowance of $1,280 in 2001 and $766 in 2000..............................	48,304	71,777
Inventory...	3,839	4,546
Assets held for sale................................	819	--
Assets from price risk management activities.........	19,610	--
Prepaid expenses and other..........................	2,050	2,726
Total current assets.............................	81,732	118,496
Property and equipment, at cost		
Land..	55,859	53,246
Oil and gas properties (successful efforts method)...	1,014,429	1,102,233
Gas plant facilities................................	8,723	12,020
Other facilities....................................	10,365	12,907

	1,089,376	1,180,406
Accumulated depreciation, depletion and amortization	(424,837)	(496,444)
Total property and equipment, net	664,539	683,962
Deferred tax assets, net	70,013	16,282
Other assets	23,528	29,284
Total assets	$ 839,812	$ 848,024

LIABILITIES AND STOCKHOLDERS' EQUITY

Current liabilities		
Accounts payable	$ 35,771	$ 25,895
Accrued interest	5,635	5,757
Accrued drilling costs	15,081	12,467
Accrued lease operating costs	23,244	30,037
Deferred income tax	7,783	--
Other accrued liabilities	11,610	17,668
Total current liabilities	99,124	91,824
Long-term debt (Note 12)	450,444	409,727
Other long-term liabilities	15,337	8,356
Company-Obligated Mandatorily Redeemable Convertible Preferred Securities of Nuevo Financing I	115,000	115,000
Commitments and contingencies (Note 15)		
Stockholders' equity		
Preferred stock, $1.00 par value, 10,000,000 shares authorized; 7% Cumulative Convertible Preferred Stock, none issued and outstanding at December 31, 2001 and 2000	--	--
Common stock, $0.01 par value, 50,000,000 shares authorized, 20,905,796 and 20,620,296 shares issued and 16,880,080 and 16,632,318 shares outstanding at December 31, 2001 and 2000	209	206
Additional paid-in capital	366,792	361,643
Treasury stock, at cost, 3,902,721 and 3,813,074 shares, at December 31, 2001 and 2000	(75,855)	(74,703)
Stock held by benefit trust, 122,995 and 174,904 shares, at December 31, 2001 and 2000	(2,919)	(3,646)
Deferred stock compensation	(902)	(602)
Accumulated other comprehensive income	11,534	--
Accumulated deficit	(138,952)	(59,781)
Total stockholders' equity	159,907	223,117
Total liabilities and stockholders' equity	$ 839,812	$ 848,024

See accompanying notes.

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NUEVO ENERGY COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In thousands)

	Year Ended December 31, 2001	2000	1999
Cash flows from operating activities			
Net income (loss)	$ (79,171)	$ 11,635	$ 31,442
Adjustments to reconcile net income (loss) to net cash provided by operating activities			
Cumulative effect of a change in accounting principle, net of income taxes	--	796	--
Depreciation, depletion and amortization	76,154	67,370	80,652
Dry hole costs	14,138	2,503	8,051
Amortization of debt financing costs	2,399	1,983	1,696
Impairment of oil and gas properties	103,490	--	--
Gain on sale of assets, net	(882)	(657)	(85,294)
Loss on assets held for sale	3,494	--	--
Deferred income taxes	(52,957)	8,763	(6,559)
Debt modification costs	--	--	3,064
Other	6,912	(31)	1,030
	73,577	92,362	34,082
Working capital changes, net of non-cash transactions			
Accounts receivable	23,043	(26,266)	(20,461)
Accounts payable	9,876	5,403	(4,527)
Accrued liabilities	(7,880)	25,490	17,901
Other	2,468	(3,287)	(2,971)
Net cash provided by operating activities	101,084	93,702	24,024
Cash flows from investing activities			
Additions to oil and gas properties	(145,418)	(104,420)	(125,919)
Acquisitions of oil and gas properties	(28,456)	--	--
Proceeds from sales of properties	6,145	3,083	234,312
Additions to gas plant and other facilities	(8,554)	(3,388)	(10,247)
Net cash provided by (used in) investing activities	(176,283)	(104,725)	98,146
Cash flows from financing activities			
Proceeds from borrowings	143,450	197,100	142,590
Debt issuance and modification costs	(97)	(5,186)	(8,053)
Payments of long-term debt	(102,100)	(128,873)	(223,392)
Proceeds from exercise of stock options	3,694	2,701	1,690
Purchase of treasury shares	(2,085)	(25,560)	(32,120)
Net cash provided by (used in) financing activities	42,862	40,182	(119,285)
Increase (decrease) in cash and cash equivalents	(32,337)	29,159	2,885
Cash and cash equivalents			
Beginning of year	39,447	10,288	7,403
End of year	$ 7,110	$ 39,447	$ 10,288

See accompanying notes.

NUEVO ENERGY COMPANY

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

(In thousands)

	Common Stock Shares	Common Stock Amount	Additional Paid-In Capital	Treasury Stock	Stock Held by Benefit Trust	Accumulated Other Comprehensive Income	Deferred Compensation	Ac
January 1, 1999...........	19,787	$203	$355,600	$(19,335)	$(1,732)	$ --	$ --	$
Exercise of stock options and related tax benefit........	129	1	1,810	--	--	--	--	
Stock acquired by benefit trust..........	--	--	--	1,850	(1,850)	--	--	
Issuance of warrants and other.........	--	--	120	--	--	--	--	
Withdrawal from benefit trust..	14	--	--	--	398	--	--	
Purchase of Treasury shares.........	(1,999)	--	--	(32,120)	--	--	--	
Deferred stock compensation...	--	--	325	--	--	--	(216)	
Net income......	--	--	--	--	--	--	--	
December 31, 1999...........	17,931	204	357,855	(49,605)	(3,184)		(216)	
Exercise of stock options and related tax benefit........	183	2	3,200	--	--	--	--	
Stock acquired by benefit trust..........	--	--	--	462	(462)	--	--	
Purchase of Treasury shares.........	(1,482)	--	--	(25,560)	--	--	--	
Deferred stock compensation...	--	--	588	--	--	--	(386)	
Net income......	--	--	--	--	--	--	--	

December 31, 2000	16,632	206	361,643	(74,703)	(3,646)		(602)	
Exercise of stock options and related tax benefit	287	3	4,463	--	--	--	--	
Stock acquired by benefit trust	--	--	--	933	(933)	--	--	
Purchase of Treasury shares	(128)	--	--	(2,085)	--	--	--	
Deferred stock compensation	--	--	686	--	--	--	(300)	
Withdrawal from benefit trust (Note 10)	89	--	--	--	1,660	--	--	
Other comprehensive income	--	--	--	--	--	11,534	--	
Net loss	--	--	--	--	--	--	--	
December 31, 2001	16,880	$209	$366,792	$(75,855)	$(2,919)	$11,534	$(902)	$

See accompanying notes.

NUEVO ENERGY COMPANY

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
AND CHANGES IN ACCUMULATED OTHER COMPREHENSIVE INCOME

(In thousands)

	Year Ended December 31, 2001	2000	1999
Comprehensive Income			
Net income (loss)	$(79,171)	$11,635	$31,442
Unrealized gains (losses) from cash flow hedging activity:			
Cumulative effect transition adjustment (net of tax benefit of $10,784)	(15,976)	--	--
Reclassification of initial cumulative effect transition adjustment at original value (net of taxes of $14,120)	20,917	--	--
Additional reclassification adjustments for changes in initial value to settlement date (net of taxes of $5,082)	7,529	--	--
Changes in fair value of derivative instruments during the period (net of tax benefit of $632)	(936)	--	--

Other comprehensive income	11,534	--	--
Comprehensive income	$(67,637)	$11,635	$31,442
Accumulated Other Comprehensive Income			
Beginning balances as of December 31, 2000, 1999 and 1998	$ --	$ --	$ --
Unrealized gains (losses) from cash flow hedging activity:			
Cumulative effect transition adjustment, net of tax benefit	(15,976)	--	--
Reclassification of initial cumulative effect transition adjustment at original value, net of taxes	20,917	--	--
Additional reclassification adjustments for changes in initial value to settlement date, net of taxes	7,529	--	--
Changes in fair value of derivative instruments during the period, net of tax benefit	(936)	--	--
Balance as of December 31,	$ 11,534	$ --	$ --

See accompanying notes.

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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 exploration for, and the acquisition, exploitation, development and production of crude oil and natural gas. Our principal oil and gas properties are located domestically onshore and offshore California and the onshore Gulf Coast region, and internationally offshore the Republic of Congo, West Africa.

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.

Oil and Gas Properties

We use the successful efforts method to account for our investments in oil and gas properties. Under successful efforts, 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.

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.

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 remaining proved developed reserves. Total estimated costs of $113.1 million (net of salvage value) for future dismantlement, abandonment and site remediation are included when calculating depreciation and depletion using the unit-of-production method. At December 31, 2001, we had recorded $74.2 million as a component of accumulated depreciation, depletion and amortization related to this future obligation.

In accordance with Statement of Financial Accounting Standards ("SFAS") No. 121, Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed of, 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. 121 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 present value of expected future net cash flows from proved reserves, utilizing a risk-adjusted

rate of return. Also, in accordance with SFAS No. 121, when we classify an asset as held for sale, if the carrying amount of the asset is less than their fair market value less our estimated costs to sell the asset, the difference is recognized as a loss in the period that we classify the asset as held for sale.

During 2001, we recorded an impairment totaling $103.5 million on our Santa Clara, Huntington Beach, Pitas Point, Masseko and Point Pedernales fields and certain other oil and gas properties. We recorded no impairments in 2000 or 1999. (See Note 3.)

During 2001 and 1999, 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 $2.5 million and $0.3 million of interest costs in 2001 and 1999. There were no interest costs capitalized in 2000.

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

Derivative Financial Instruments

We adopted SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, effective January 1, 2001. This statement requires all derivative instruments to be carried on the balance sheet at fair value. In accordance with the transition provisions of SFAS No. 133, we recorded a cumulative effect transition adjustment of $(16.0) million, net of related tax benefit of $10.8 million, in other comprehensive income to recognize the fair value of our derivatives designated as cash-flow hedging instruments at the date of adoption.

Beginning on January 1, 2001, all of our derivative instruments are recognized on the balance sheet at their fair value. We currently use swaps and put options to hedge our exposure to material changes in the future price of crude oil and interest rate swaps to hedge the fair value of our long-term debt.

On the date the derivative contract is entered into, 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 ("cash-flow" hedge), or as a foreign currency cash flow 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 earnings are affected by the variability of cash flows. At December 31, 2001, we had both cash-flow hedges and fair value hedges. (See Note 16.)

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, 2001, we had recorded $11.5 million, net of related taxes of $7.8 million, of cumulative hedging gains 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 $47.6 million, $117.7 million and $44.9 million in 2001, 2000 and 1999. The portion of our hedging transactions that were ineffective totaled $0.4 million in 2001 and was recorded in interest and other income.

Price Risk Management Activities

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

Comprehensive Income

Comprehensive income includes net income and all changes in other comprehensive income including 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, 2001, we had accrued approximately $5.1 million for future environmental expenditures.

Inventory

Our inventory is valued at the lower of cost or market. We had crude oil inventory in Congo of $0.8 million and $3.2 million at December 31, 2001 and 2000. Our materials and supplies inventory totaled $3.0 million and $1.3 million at December 31, 2001 and 2000.

Gas Plant and Other Facilities

Gas plant and other facilities include the costs to acquire certain gas plant and other facilities and to secure rights-of-way. Capitalized costs associated with gas plant and other facilities are amortized primarily over the estimated useful lives of the various components of the facilities utilizing the straight-line method. The estimated useful lives of such assets range from three to thirty years. We review these assets for impairment whenever events or changes in circumstances indicate that their carrying amounts may not be recoverable.

Recognition of Crude Oil and Natural Gas Revenue

Crude oil and natural gas revenue is recognized when title 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. We did not have a material imbalance position in terms of units or value at December 31, 2001 or 2000. Approximately $ 58.1 million, $46.0 million and $20.4 million in 2001, 2000 and 1999 is included as oil and gas revenues and operating expenses related to gas production used in our steam injection projects.

Stock-Based Compensation

We account for stock options under Accounting Principles Board Opinion (APB) No. 25, Accounting for Stock Issued to Employees. No compensation expense is recognized for such options. 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 and to present the pro forma disclosure required by SFAS No. 123.

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, net of amounts capitalized, for 2001, 2000 and 1999 was $38.3 million, $32.1 million and $33.5 million. Net amounts paid (refunded) in cash for income taxes for 2001, 2000 and 1999 were $0.4 million, $(0.5) million and $2.3 million.

Change in Accounting Principle

Prior to December 31, 2000, we recorded inventory relating to quantities of processed fuel oil and natural gas liquids in storage at current market pricing. Also, fuel oil in inventory was stated at year end market prices less transportation costs, and we recognized changes in the market value of inventory from one period to the next as oil revenues. In December 2000, the staff of the Securities and Exchange Commission announced that commodity inventories should be carried at the lower of cost or market rather than at market value. As a result, we changed our inventory valuation method to the lower of cost or market in the fourth quarter of 2000, retroactive to the beginning of the year and recorded a non-cash, cumulative effect of a change in accounting principle to earnings, effective January 1, 2000, of $0.8 million, net of related income tax benefit of $0.5 million, to value product inventory at the lower of cost or market. Quarterly results for 2000 were restated to reflect this change in accounting.

Had we valued our product inventory at the lower of cost or market prior to 2000, net income would have been $30.6 million for the year ended December 31, 1999.

Use of Estimates

In order to prepare these financial statements in conformity with accounting principles generally accepted in the United States, 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.

Functional Currency

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

New Accounting Pronouncements

Accounting for Asset Retirement Obligations. In August 2001, the Financial Accounting Standards Board ("FASB") issued SFAS No. 143, Accounting for Asset Retirement Obligations. This Statement requires companies to record a liability relating to the retirement and removal of assets used in their business. The liability is discounted to its present value, and the related asset value is increased by the amount of the resulting liability.

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. The provisions of this Statement are effective for fiscal years beginning after June 15, 2002. We are currently evaluating the effects of this pronouncement.

Accounting for the Impairment or Disposal of Long-Lived Assets. In October 2001, the FASB issued SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets. This Statement 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 do not expect that it will have a material impact on our financial condition or results of operations.

Reclassifications

Certain reclassifications of prior period amounts have been made to conform to the current presentation.

3. Impairments

In accordance with SFAS No. 121, we review oil and gas properties for impairment whenever events and circumstances indicate a decline in the recoverability of their carrying value. If the expected undiscounted future net cash flows of our oil and gas properties are lower than the carrying amount of the oil and gas properties, the carrying amount is reduced to the fair market value. For some of our oil and gas properties, due to persistently low commodity prices, the carrying amount of the properties exceeded the estimated undiscounted future net cash flows; thus, we adjusted the carrying amount of the respective oil and gas properties to their fair value as determined by discounting their estimated future net cash flows. The factors used to determine fair value included, but were not limited to, estimates of proved reserves, future commodity prices, timing of future production, future capital expenditures and a discount rate commensurate with our internal rate of return on our oil and gas properties. As a result, we recognized a non-cash pre-tax charge of $103.5 million ($62.0 million after tax) related to the impairment of oil and gas properties in the fourth quarter of 2001. There were no impairments in 2000 or 1999.

4. Assets Held for Sale

In 2001, we made the decision not to pursue our power plant project in Kern County, California due to the inability to secure the proper permits required. We transferred our remaining equipment to assets held for sale and recognized a $3.5 million loss in connection with writing down the equipment to their estimated fair value less our costs to sell the assets of $0.8 million.

5. Acquisitions

In July 2001, we entered into a definitive agreement with Coho Anaguid, Inc., Anadarko Tunisia Anaguid Company, and Pioneer Natural Resources Anaguid Ltd., to acquire a portion of Coho's interest in the Anaguid Permit, a 1.1 million-acre permit located onshore southern Tunisia in the Ghadames Basin. Our 10.42% working interest increased to 22.5%, subject to approval by the Tunisian government. The Anaguid Permit, operated by Anadarko, is on trend with the prolific Hassi Berkine and El Borma fields located to the west in Algeria and Tunisia. Under the current work commitment, a well is expected to be drilled in the Anaguid Permit during 2002.

In January 2001, we acquired approximately 2,900 acres of producing properties previously held by Naftex ARM, LLC, in Kern County, California for approximately $28.5 million. The newly acquired acreage is southeast of our interest in the Cymric field, of which more than half is natural gas. In addition, the acreage provides significant development potential.

In June 1999, we acquired working interests in oil and gas properties located onshore and offshore California for $61.4 million from Texaco Inc. The working interests in the acquired properties range from an additional 25% interest in properties already owned and operated by us to 100%. We used funds from a $100.0

million interest-bearing escrow account that provided "like-kind exchange" tax treatment for the purchase of domestic oil and gas producing properties. The escrow account was created with proceeds from our sale of East Texas natural gas assets (see discussion in Note 6). Following this acquisition, the $41.0 million remaining in the escrow account, including $2.4 million of interest income, was used to repay a portion of outstanding bank debt in early July 1999. The acquisition included interests in Cymric, East Coalinga, Dos Cuadras, Buena Vista Hills and other fields we operate.

6. Divestitures

In January 2002, we withdrew our request for formal government approval of the Convention and Joint Venture resulting in a relinquishment of our interest in the Alyane Permit located offshore Tunisia in the Gulf of Gabes.

As of June 17, 2001, we relinquished our 1.9 million-acre Accra-Keta Permit offshore the Republic of Ghana. 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. An impairment of $1.0 million was recorded during the second and third quarters of 2001 in connection with this relinquishment.

In May 2000, we sold our working interest in the Las Cienegas field in California for approximately $4.6 million. We reclassified these assets to assets held for sale during the third quarter of 1999, at which time we discontinued depletion and depreciation. No impairment charge was recorded upon reclassification to assets held for sale. In connection with this sale, we unwound hedges of 2,800 BOPD for the period from May 2000 through December 2000 and recorded an adjusted net gain on sale of approximately $0.9 million. We also sold certain non-core assets during 2000, recognizing a net loss of approximately $0.3 million.

On December 31, 1999, we completed the sale of our working interests, ranging from 8% to 100%, in 13 onshore fields and a gas processing plant located in Ventura County, California, to Vintage Petroleum, Inc. The effective date of the sale was September 1, 1999. We reclassified these properties to assets held for sale and discontinued depleting and depreciating these assets during the third quarter of 1999. Revenues less costs for the period September 1, 1999, through December 31, 1999, and other adjustments resulted in an adjusted sales price of $29.6 million at closing on December 31, 1999. Approximately $4.5 million of the proceeds was deposited in escrow to address possible remediation issues. The funds will remain in escrow until the Los Angeles Regional Water Quality Control Board approves completion of the remediation work. All or any portion of the funds not used in remediation shall be returned. As of December 31, 2001, the balance in the escrow account remained at $4.5 million. The remainder of the proceeds from the sale were used to repay a portion of our outstanding bank debt. We recorded a gain of $5.3 million on the sale of these properties.

On January 6, 1999, we completed the sale of our East Texas natural gas assets to an affiliate of Samson Resources Company for approximately $191.0 million. An escrow account of $100.0 million was funded with a portion of the proceeds as discussed in Note 5. The remainder of the proceeds were used to repay outstanding senior bank debt. We realized an $80.2 million adjusted pre-tax gain on the sale of the East Texas natural gas assets resulting in the realization of $14.6 million of our deferred tax asset. A $5.2 million gain on settled hedge transactions was realized in connection with the closing of this sale in 1999.

7. Outsourcing Services

Torch Energy Advisors Incorporated ("Torch"), through its affiliates is an outside service provider primarily in the business of providing management and advisory services relating to oil and gas assets.

Effective March 16, 2002, we will have the following outsourcing contracts in force:

- oil and gas administration: we pay a monthly base fee which is adjusted upward or downward to reflect the current number and type of properties for which services are provided

- crude oil marketing: we pay a base charge and a variable charge based on the volume of crude oil sold or marketed

Since 1999 Torch has provided the following services: oil and gas administration (accounting, information technology and land administration), human resources, corporate administration (legal, graphics, support, and corporate insurance), crude oil marketing, natural gas marketing, land leasing and field operations.

We have a Master Services Agreement with Torch, which contains the overall terms and conditions governing each individual service agreement. The crude oil marketing contract has one year remaining on its term while the oil and gas administration agreement runs through 2003, with a possible one-year extension. In late 2001, we terminated the California field operations and human resources contracts and did not renew the gas marketing contract. The termination required ninety days notice and is effective March 15, 2002. We have reduced both the staffing requirements and cost structure under the Torch agreements and brought certain professional and other positions in-house.

Under the Master Services Agreement, we paid outsourcing fees to Torch in the amount of $8.4 million, $13.7 million and $14.1 million in 2001, 2000 and 1999. Torch operated certain oil and gas interests that we own. Since 1999 we were charged, on the same basis as other third parties, for all customary expenses and cost reimbursements associated with these activities. Fees charged for field operations for the years ended December 31, 2001, 2000 and 1999, were $22.3 million, $21.8 million and $25.1 million. Upon the effective date of the termination of these outsourcing agreements, we assume direct responsibility for the California field operations.

A subsidiary of Torch marketed oil, natural gas and natural gas liquids from certain of our oil and gas properties and gas plants. In 2001, 2000 and 1999, the marketing fees were $1.9 million, $1.8 million and $1.2 million. Beginning in 2002, our natural gas is being marketed by a new provider, Coral Energy.

8. Restructuring Charges

Termination of Outsourcing Agreements.

We terminated two outsourcing agreements with the objective of exercising greater control over certain operating functions and lowering our costs. The terminated agreements were the California field operations and human resources effective March 15, 2002. We have retained a majority of the field employees currently working on our California properties while the human resources function was brought in-house. (See Note 7.)

Reorganization of Exploration and Production Operations.

We have reorganized our exploration and production operations in an effort to reflect a smaller, more focused exploitation program and eliminated our California exploration program. In connection with this reorganization, approximately 20 technical positions were eliminated.

The following table details the amounts related to our restructuring:

	2001 Restructuring Charges	Payments in 2001	Liability at December 31, 2001
	(In thousands)		
Severance and benefits................	$2,178	$ 503	$1,675
Contract termination..................	2,681	--	2,681
	$4,859	$ 503	$4,356

We expect that the balance of the restructuring liability will be paid during the first half of 2002.

9. Accounts Receivable

Our accounts receivable consisted of the following at December 31:

	2001	2000
	(In thousands)	
Oil and gas sales	$32,220	$61,018
Joint interest billings	9,348	7,754
Other	6,736	3,005
	$48,304	$71,777

10. 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 12, we and our restricted subsidiaries had $17.7 million available for the payment of dividends and share repurchases at December 31, 2001. We have not paid dividends on our Common Stock and do not anticipate the payment of cash dividends in the immediate future.

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 and 1999, weighted average shares held by the benefit trust of 145,000 and 64,000 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. In 2000 and 1999, we had 2.4 million and 2.5 million stock options 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 2001, 2000 or 1999 due to their anti-dilutive effect. The reconciliation is as follows:

	For the Year Ended December 31,					
	2001		2000		1999	
	Net Loss	Shares	Net Income	Shares	Net Income	Shares
	(In thousands)					

Earnings (loss) before cumulative effect per Common share--Basic.................	$(79,171)	16,735	$12,431	17,447	$31,442	19,353
Effect of dilutive securities:						
Stock options...............	--	--	--	335	--	154
Shares held by Benefit Trust......................	--	--	(152)	159	--	--
Earnings (loss) before cumulative effect per Common share--Diluted...............	$(79,171)	16,735	$12,279	17,941	$31,442	19,507

Treasury Stock Repurchases

On February 12, 2001, our Board of Directors authorized the open market repurchase of an additional 1.0 million shares of common stock increasing the amount authorized to repurchase to 5.6 million shares, of which

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2.0 million is remaining. Repurchases may be made at times and at prices deemed appropriate by management and consistent with the authorization of our Board. During the first quarter of 2001, we repurchased 0.1 million shares at an average purchase price of $16.32 per share, including commissions. There were no shares repurchased during the second, third or fourth quarters of 2001. As of December 31, 2001, we had repurchased a total of 3.6 million shares since December 1997, at an average purchase price of $16.56 per share, including commissions.

Shareholder Rights Plan

In March 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.

On January 10, 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 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.

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. Stock is held in a benefit trust and is restricted for a two-year period. The stock held in the benefit trust (122,995 shares, 174,904 shares and 75,904 shares at December 31, 2001, 2000 and 1999) is accounted for as a liability at market value, with any changes in market value charged or credited to general and administrative expense. We recorded a net benefit of $0.2 million and $0.1 million in 2001 and 2000 and an expense of $1.7 million in 1999 related to deferred compensation. The Plan was amended in 2001 to remove the discount on investments in our common stock and to provide additional investment alternatives. 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 can be settled in cash or Common Stock, at the option of the employee. In 2001 and 1999, 89,000 shares and 14,000 shares were withdrawn from the Plan at a fair market value of $1.7 million and $0.4 million. In 2000, there were no such withdrawals from the Plan. The Plan applies to certain highly compensated employees and all executives at a level of Vice-President and above.

Director Compensation

In May 1999, the Compensation Committee of our Board of Directors implemented changes to the compensation of our non-employee directors. Non-employee directors may elect to receive all or part of the 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. Each non-employee director also receives a semi-annual grant of 1,750 ten-year options to purchase our Common Stock at the market price of the stock on the date of the grant. Non-employee directors also receive a semi-annual grant of 1,250 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.

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 our Chief Financial Officer and our Senior Vice President to accept employment with us. In 2001, we recorded $0.1 million of general and administration expense related to 9,073 shares of common stock granted to our Chief Executive Officer in accordance with his employment agreement. The purpose of the Stock Incentive Plans is to provide our directors and key employees performance incentives and to provide a means of encouraging these individuals to own our stock.

The total maximum number of shares subject to options under the Stock Incentive Plans is 5,000,000 shares. Options are granted under the Stock Incentive Plans on the basis of the optionee'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 following table details a summary of activity in the stock option plans during the three years ended 2001:

	Option	Weighted-Average Exercise Price
Outstanding at January 1, 1999	2,676,363	$23.94
Granted	481,225	$16.02
Exercised	(128,909)	$14.16
Canceled	(411,500)	$25.52
Outstanding at December 31, 1999	2,617,179	$22.72
Granted	419,189	$15.69
Exercised	(182,925)	$13.40
Canceled	(80,525)	$34.18
Outstanding at December 31, 2000	2,772,918	$21.94
Granted	875,026	$15.51
Exercised	(285,000)	$12.93
Canceled	(104,525)	$33.88
Outstanding at December 31, 2001	3,258,419	$20.62

We had options exercisable of 2,728,494 (weighted average exercise price of $21.80), 2,361,979 (weighted average exercise price of $23.04) and 2,202,454 (weighted average exercise price of $24.00) at December 31, 2001, 2000 and 1999. Detail of stock options outstanding and options exercisable at December 31, 2001 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 $15.06........	854,263	8.27	$12.36	576,763	$12.51
$15.50 to $19.63........	1,453,956	7.28	$16.89	1,202,031	$16.81
$20.38 to $29.88........	407,700	5.14	$23.27	407,200	$23.27
$34.00 to $47.88........	542,500	5.69	$41.62	542,500	$41.62
Total.................	3,258,419			2,728,494	

The weighted-average fair value of options granted during 2001, 2000 and 1999 was $10.63, $10.87 and $11.38. 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 54.5%, 112% and 55.7% in 2001, 2000 and 1999; risk free interest of 4%, 5% and 6% in 2001, 2000 and 1999, and average expected option lives of three years in 2001 and 2000 and five years in 1999. Had compensation expense for stock-based compensation been determined based on the fair value at the date of grant, our net income, earnings available to common stockholders and earnings per share would have been reduced to the pro forma amounts indicated below.

		Year Ended December 31, 2001	2000	1999
		(In thousands, except share data)		
Net income (loss)....................	As reported	$(79,171)	$11,635	$31,442
	Pro forma	(83,177)	6,740	24,673
Earnings (loss) per Common share-- Basic..............................	As reported	(4.73)	0.67	1.62
	Pro forma	(4.97)	0.39	1.27
Earnings (loss) per Common share-- Diluted............................	As reported	(4.73)	0.64	1.61
	Pro forma	(4.97)	0.38	1.26

11. 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, (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 $115.0 million aggregate principal amount of 5.75% 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 TECON plus accrued and unpaid dividends on December 15, 2026.

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12. Long-Term Debt

Our long-term debt consisted of the following at December 31:

	2001	2000
	(In thousands)	
9 3/8% Senior Subordinated Notes due 2010	$150,000	$150,000
9 1/2% Senior Subordinated Notes due 2008	257,210	257,310
9 1/2% Senior Subordinated Notes due 2006	2,367	2,417
Bank credit facility (at 3.71% on December 31, 2001)	41,500	--
Total debt	451,077	409,727
Interest rate swaps	(633)	--
Long-term debt	$450,444	$409,727

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. If one of our subsidiaries guarantees other subordinated indebtedness of ours, the subsidiary must also guarantee these Notes. Currently, none of our subsidiaries guarantee subordinated indebtedness of ours. 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 these Notes for $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. These amendments streamlined our covenant structure and provided us with additional flexibility to pursue our operating strategy. 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. We also incurred a total of $3.1 million in third-party fees during the third and fourth quarters of 1999, which are included in other expense.

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. We are not required to make mandatory redemption or sinking fund payments on these Notes. The indenture contains covenants that, among other things, limit the Company's 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 9 1/2% Notes are not currently guaranteed by our subsidiaries but are required to be guaranteed by any subsidiary that guarantees pari passu or subordinated indebtedness. Currently, none of our subsidiaries guarantees our subordinated indebtedness. 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.

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9 1/2% Notes due 2006

In April 1996, we issued $160.0 million of 9 1/2% Notes due 2006 and used the proceeds to pay for a portion of the purchase price of the Unocal Properties. In August 1999, we exchanged $157.5 million of these notes for our 9 1/2% Notes due 2008. In October 1999, we purchased $0.1 million of the remaining Notes. No significant costs were incurred in connection with that early retirement. 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. These Notes had not been redeemed, in whole, or in part at December 31, 2001. We are not required to make mandatory redemption or sinking fund payments with respect to these Notes and they are unsecured general obligations, and are subordinated in right of payment to all existing and future senior indebtedness.

Interest Rate Swaps

In December 2001, we entered into two interest rate swap agreements with notional amounts totaling $150 million to hedge the fair value of our 9 1/2% Notes due 2008 and our 9 3/8% Notes due 2010. These swaps are designated as fair value hedges and are reflected as a reduction of long-term debt of $0.6 million as of December 31, 2001 with a corresponding increase in long-term liabilities. Under the terms of the agreements for the 9 3/8% Notes, the counterparty pays us a weighted average fixed annual rate of 9 3/8% on total notional amounts of $100 million, and we pay the counterparty a variable annual rate equal to the six-month London Interbank Offered Rate ("LIBOR") rate plus a weighted average rate of 3.49%. Under the terms of the agreement for the 9 1/2% Notes, the counterparty pays us a weighted average fixed annual rate of 9 1/2% on total notional amounts of $50 million, and we pay the counterparty a variable annual rate equal to the six-month LIBOR rate plus a weighted average rate of 3.92%.

Subsequent to December 31, 2001, we entered into an interest rate swap agreement with a notional amount totaling $50 million to hedge the fair value of our 9 3/8% Notes. Under the terms of this agreement, the counterparty pays us a weighted average fixed annual rate of 9 3/8% on the notional amount of $50 million, and we pay the counterparty a variable annual rate equal to the three-month LIBOR rate plus a weighted average rate of 3.49%

Bank Credit Facility

Our Third Amended and Restated Credit Agreement ("Credit Agreement"), dated June 7, 2000, provides for secured revolving credit availability of up to

$410.0 million 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.

The borrowing base is subject to a semi-annual borrowing base determination within 60 days following March 1 and August 15 of each year and establishes the maximum borrowings that may be outstanding under the credit facility. It is determined by a 60% vote of the 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 such excess over a defined period of time. We have a $225 million borrowing base under our Credit Facility with $102 million available at December 31, 2001 and had drawn $41.5 million under the agreement.

Amounts outstanding under the credit facility bear interest at a rate equal to LIBOR plus an amount which increases as the Indebtedness (as defined in the Credit Agreement) increases.

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, 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, 2001, we were in compliance with all covenants of the Credit Agreement.

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

2002	$ --
2003	--
2004	--
2005	41,500
2006	2,367
Thereafter	407,210
Total debt maturities	$451,077

Based upon the quoted market price, the fair value of the 9 3/8% Notes was estimated to be $146.8 million and 150.0 million at December 31, 2001 and 2000; the fair value of the 9 1/2% Notes due 2008 was estimated to be $245.6 million and $260.4 million at December 31, 2001 and 2000, and the fair value of the 9 1/2% Notes due 2006 was estimated to be $2.4 million and $2.5 million at December 31, 2001 and 2000. The carrying amount of the credit facility approximates the fair value of the debt at December 31, 2001.

13. Income Taxes

Income tax (expense) benefit is summarized as follows:

	Year Ended December 31,		
	2001	2000	1999
	(In thousands)		
Current			
Federal	$ --	$ 371	$(1,012)
State	--	--	(188)
	--	371	(1,200)
Deferred			
Federal	42,465	(7,102)	8,457
State	10,492	(1,661)	(1,898)
	52,957	(8,763)	6,559
Total income tax (expense) benefit	$52,957	$(8,392)	$ 5,359

For the year ended December 31, 2000, we recorded a tax benefit of $0.5 million related to the cumulative effect of a change in accounting principle (see Note 2). A deferred tax benefit related to the exercise of employee stock options of approximately $0.8 million and $0.5 million was allocated directly to additional paid-in capital in 2001 and 2000.

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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,		
	2001	2000	1999
Statutory federal income tax rate	(35.0)%	35.0%	35.0%
(Decrease) increase in tax rate resulting from:			
State income taxes, net of federal benefit	(5.2)	5.2	5.2
Decrease in valuation allowance	--	--	(60.8)
Nondeductible travel and entertainment and other	0.1	0.1	0.1
	(40.1)%	40.3 %	(20.5)%

During 1999, we determined that it would be more likely than not that the deferred tax assets would be realized. At such time, we reduced the valuation allowance by $15.9 million.

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:

	As of December 31,	
	2001	2000
	(In thousands)	
Net operating loss carryforwards	$57,568	$ 51,033
Alternative minimum tax credit carryforwards	1,704	1,704
Property and equipment	3,261	--
State income taxes	5,268	--
Total deferred income tax assets	67,801	52,737
Less: valuation allowance	(1,777)	(1,777)
Net deferred income tax assets	66,024	50,960
Property and equipment	--	(31,338)
Equity in foreign subsidiaries	(1,854)	(1,684)
State income taxes	(1,940)	(1,656)
Total deferred income tax liabilities	(3,794)	(34,678)
Net deferred income tax asset	$62,230	$ 16,282

At December 31, 2001, we had a net operating loss carryforward for regular tax purposes of approximately $164.5 million, which will begin expiring in 2018. Alternative minimum tax credit carryforwards of $1.7 million does 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. At December 31, 2001, we determined that it was more likely than not that most of the deferred tax assets would be realized.

14. Industry Segment Information

Our operations are concentrated primarily in two segments: exploration and production of oil and natural gas, and gas plant and other facilities. For segment reporting purposes, domestic producing areas have been aggregated as one reportable segment due to similarities in their operations as allowed by SFAS No. 131, Disclosures About Segments of an Enterprise and Related Information. Financial information by reportable segment is presented below:

As of and For the Year Ended December 31,		
2001	2000	1999
(In thousands)		

Sales to unaffiliated customers			
Oil and gas--Domestic	$ 332,646	$290,774	$211,647
Oil and gas--Foreign	35,914	40,881	30,627
Total sales	368,560	331,655	242,274
Gain on sale of assets, net	882	657	85,294
Interest and other income	1,813	4,293	4,667
Total revenues	$ 371,255	$336,605	$332,235
Operating profit (loss) before income taxes			
Oil and gas--Domestic (/1/)	$ (17,410)	$ 84,747	$ 97,948
Oil and gas--Foreign	(8,444)	14,899	5,208
	(25,854)	99,646	103,156
Unallocated corporate expenses	56,655	34,738	37,350
Interest expense	43,006	37,472	33,110
Dividends on TECONS	6,613	6,613	6,613
Operating profit (loss) before income taxes	$(132,128)	$ 20,823	$ 26,083
Identifiable assets			
Oil and gas--Domestic	$ 541,688	$613,658	$566,256
Oil and gas--Foreign	56,404	103,204	82,074
Gas plant and other facilities	7,395	11,455	12,297
	605,487	728,317	660,627
Corporate assets, investments and other	234,325	119,707	99,403
Total	$ 839,812	$848,024	$760,030
Capital expenditures (/2/)			
Oil and gas--Domestic	$ 164,028	$101,773	$106,071
Oil and gas--Foreign	24,935	11,694	24,570
Total oil and gas expenditures	188,963	113,467	130,641
Less: Geological & geophysical, delay rentals and other expenses	(15,089)	(9,047)	(4,722)
Additions to oil and gas properties per Statement of Cash Flows	$ 173,874	$104,420	$125,919
Gas plant and other facilities	$ 8,554	$ 3,388	$ 10,247
Depreciation, depletion and amortization			
Oil and gas--Domestic	$ 63,485	$ 57,819	$ 70,024
Oil and gas--Foreign	10,381	8,085	9,177
Gas plant and other facilities	512	512	666
Corporate	1,776	954	785
Total	$ 76,154	$ 67,370	$ 80,652

(/1/Includes) gain on sale of the East Texas natural gas asset of $80.2 million in 1999.

(/2/Includes) acquisitions of oil and gas properties.

Credit Risks due to Certain Concentrations

In 2001, 2000 and 1999, we had one customer that accounted for 63%, 84%, and 79% of oil and gas revenues. In 2001, 2000 and 1999, we had another customer that accounted for 23%, 11% and 12% of oil and gas revenues.

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 Tosco 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. Therefore, the actual price received as a percentage of NYMEX will vary with our production mix. Based on the current production mix, the price we receive for our California production is expected to average approximately 72% of West Texas Intermediate ("WTI"). 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. The Tosco contract permits us, under certain circumstances, to separately market up to ten percent of our California crude production. We exercised this right and, effective January 1, 2001, and January 1, 2002, began selling 5,000 BOPD of our San Joaquin Valley oil production to a third party under a one-year contract using NYMEX pricing.

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 Tosco are similarly uncollateralized.

15. Contingencies and Other Matters

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. The cost of repair is expected to be partially covered by insurance. We may have exposure to costs that may not be recoverable from insurance, including those associated with the repair of undamaged equipment. Production was back on in January 2002.

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 and the cause of the failure is under investigation. 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 is 3,000 barrels of crude oil and 2.4 MMcf of natural gas, representing approximately 6% of our daily production. Crude oil production resumed in early July and full gas sales resumed by mid August. The cost of repair, less a $50,000 deductible, is expected to be covered by insurance. We may have exposure to costs that may not be recoverable from insurance.

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 successfully removed this lawsuit to the United States District Court for the Central District of California. The plaintiffs, who own certain interests in the Point Pedernales properties, have asserted numerous causes of action including breach of contract, fraud and conspiracy in connection with the plaintiff's allegation that: (i) royalties have not been properly paid to them for production from the Point Pedernales field, (ii) payments have not been made to them related to production from the Sacate field, and (iii) we have failed to recognize the plaintiff's interests in the Tranquillon Ridge project. The plaintiffs have not specified damages. We intend to vigorously contest these claims.

We have been named as a defendant in certain other lawsuits incidental to our business. However, these actions and claims in the aggregate seek substantial 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 the matters discussed above. 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.

In March 1999, we discovered that a non-officer employee had fraudulently authorized and diverted for personal use Company funds totaling $5.9 million, $1.6 million in 1999 and the remainder in 1998, that were intended for international exploration. The Board of Directors engaged a Certified Fraud Examiner to conduct an in-depth review of the fraudulent transactions. The investigation confirmed that only one employee was involved in the matter and that all misappropriated funds were identified. We have reviewed and, where appropriate, strengthened our internal control procedures. In August 2000, we recorded $1.5 million of other income for a partial reimbursement of these previously expensed funds, resulting from the negotiated settlement of a related legal claim.

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 either have been or are expected to be covered by our insurance, less a deductible of $120,000. We incurred clean-up and repair costs of $0.3 million, $ 0.3 million and $0.5 million during 2001, 2000 and 1999. As of December 31, 2001, we had received insurance reimbursements of $4.2 million, with a remaining insurance receivable of $0.5 million. For amounts not covered by insurance, including the $0.1 million deductible, we recorded lease operating expenses of $1.1 million in 2001 and $0.4 million during 1999. No such expenses were recorded in 2000. We also have exposure to costs that may not be recoverable from insurance, including certain fines, penalties, and damages and certain legal fees. Such costs are not quantifiable at this time, but are not expected to be material to our operating results, financial condition or liquidity.

Our international 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 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 and political violence, which is the maximum coverage available through OPIC. We have no deductible for this insurance.

In connection with our February 1995 acquisitions of two subsidiaries (each a "Congo subsidiary") 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 us or CMS's Congo subsidiary 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 US income tax purposes. We and CMS have agreed 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 $38.5 million if a triggering event 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 $56.2 million. We do not expect a triggering event to occur with respect to us or CMS and do not believe the agreement will have a material adverse effect upon us.

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.

Our total estimated costs of future dismantlement, abandonment and site remediation is approximately $113.1 million (net of salvage value) which is included when calculating depreciation and depletion using the unit-of-production method. At December 31, 2001, we had recorded $74.2 million as a component of accumulated depreciation, depletion and amortization.

16. Financial Instruments

We have entered into commodity swaps, put options and interest rate swaps. The commodity swaps 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 these hedges are based on West Texas

Intermediate ("WTI") barrels. Our production is expected to average 73% of WTI, therefore, each WTI barrel hedges 1.37 barrels of our production.

Derivative Instruments Designated as Cash Flow Hedges

At December 31, 2001, we had entered into the following cash flow hedges:

	WTI Barrels Per Day	Average Strike Price
Swaps		
First quarter 2002	12,500	$25.91
Second quarter 2002	2,000	23.50
Third quarter 2002	6,800	23.20
Fourth quarter 2002	5,000	23.90
Put Options		
Second quarter 2002	14,000	$22.00
Third quarter 2002	9,000	22.00
Fourth quarter 2002	9,000	22.00

At December 31, 2001, the fair market value of these hedge positions is $19.6 million, net of the cost of the options of $3.8 million. All of these agreements expose us to counterparty credit risk to the extent that the counterparty is unable to meet its settlement commitments.

Derivative Instruments Designated as Fair Value Hedges

In late December 2001, we entered into two interest rate swap agreements with notional amounts totaling $150 million, to hedge the fair value of our 9 1/2% Notes due 2008 and our 9 3/8% Notes due 2010. These swaps are designated as fair value hedges and are reflected as a reduction of long-term debt of $0.6 million as of December 31, 2001, with a corresponding increase in long-term liabilities. Under the terms of the agreements for the 9 3/8% Notes, the counterparty pays us a weighted average fixed annual rate of 9 3/8% on total notional amounts 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 3.49%. Under the terms of the agreement for the 9 1/2% Notes, the counterparty pays us a weighted average fixed annual rate of 9 1/2% on total notional amounts of $50 million, and we pay the counterparty a variable annual rate equal to the six-month LIBOR rate plus a weighted average rate of 3.92%.

Subsequent to December 31, 2001, we entered into an interest rate swap agreement with a notional amount totaling $50 million to hedge the fair value of our 9 3/8% Notes. Under the terms of this agreement, the counterparty pays us a weighted average fixed annual rate of 9 3/8% on the notional amount of $50 million, and we pay the counterparty a variable annual rate equal to the three-month LIBOR rate plus a weighted average rate of 3.49%.

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, 2001 and 2000.

	December 31, 2001		December 31, 2000	
	Carrying Amount	Approximate Fair Value	Carrying Amount	Approximate Fair Value
	(In thousands)			
Other investments................	$ --	$ --	$ 78	$ 78
Derivative Instruments				
Option commodity contracts.....	9,490	9,490	5,595	11,088
Commodity price swaps..........	10,120	10,120	--	(32,253)
Interest rate swaps............	(633)	(633)	--	--
Long-term debt (see Note 12).....	450,444	436,012	409,727	412,823
TECONS...........................	115,000	68,770	115,000	60,950

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, 2001 and 2000.

Other--Enron Exposure and Call Spreads

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. At December 31, 2001, a deferred gain of $2.2 million remains in accumulated other comprehensive income related to the outstanding Enron options, which will be reclassified into earnings when the hedged production occurs, in the next 12 months.

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In 2001 and 2000, we entered into call spreads with the anticipation of using the proceeds to offset the Unocal Contingent payment. (See Note 17). 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 hedge instrument and is marked-to-market with changes in fair value recognized in earnings. At December 31, 2001, $1.1 million is reflected in long-term liabilities.

17. Contingent Payment and Price Sharing Agreements

In connection with the acquisition from Unocal in 1996 of the properties located in California, we are obligated to make a contingent payment for the years 1998 through 2004 if oil prices exceed thresholds set forth in the agreement with Unocal. Any contingent payment will be accounted for as a purchase price adjustment to oil and gas properties. The contingent payment will equal 50% of the difference between the actual average annual price received on a field-by-field basis (capped by a maximum price) and a minimum price, less ad valorem and production taxes, multiplied by the actual number of barrels of oil sold that are produced from the properties acquired from Unocal during the respective year. The minimum price of $17.75 per Bbl under the agreement (determined based on the near month delivery of WTI crude oil on the NYMEX) is escalated at 3% per year and the maximum price of $21.75 per Bbl on the NYMEX is escalated at 3% per year. Minimum and maximum prices are reduced to reflect the field level price by subtracting a fixed differential established for each field. The reduction was established at approximately the differential between actual sales prices and NYMEX prices in effect in 1995 ($4.34 per Bbl weighted average for all the properties acquired from Unocal). We accumulate credits to offset the contingent payment when prices are $.50 per Bbl or more below the minimum price. We paid $10.8 million to Unocal under this agreement on March 15, 2002.

In connection with the acquisition of the Congo properties in 1995, we entered into a price sharing agreement with the seller. There is no termination date associated with this agreement. Under the terms of the agreement, if the average price received for the oil production during the year is greater than the benchmark price established by the agreement, we are obligated to pay the seller 50% of the difference between the benchmark price and the actual price received, for all the barrels associated with this acquisition. The benchmark price was $15.78 per Bbl for 2001, $15.19 per Bbl for 2000 and $14.79 per Bbl for 1999. The benchmark price increases each year, based on the increase in the Consumer Price Index. For 2001, the effect of this agreement was that we only owned upside above $15.78 per Bbl on approximately 56% of our Congo production. We were obligated to pay the seller $3.4 million in 2001 and $5.4 million in 2000 under this price sharing agreement. This obligation was accounted for as a reduction in oil revenues. No payment was due in 1999.

We acquired a 12% working interest in the Point Pedernales oil field from Unocal in 1994 and the remainder of its 80.3 % working interest from Torch in 1996. We are entitled to all revenue proceeds up to $9.00 per Bbl, with the excess revenue over $9.00 per Bbl, if any, we share with the original owners from whom Torch acquired its interest. We own amounts below $9.00 per Bbl with the other working interest owners based on their respective ownership interests. For 2001, the effect of this agreement is we were entitled to receive the pricing upside above $9.00 per Bbl on approximately 73% of the gross Point Pedernales production. As of December 31, 2001, we had $0.2 million accrued as our obligation under this agreement. As of December 31, 2000, we had $0.6 million accrued as our obligation under this agreement. As of December 31, 1999, we had $5.1 million accrued as our obligation under this agreement.

18. 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, 2001, and for previous years, are based primarily on reserve reports prepared by the independent petroleum engineering firm of Ryder Scott Company. 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 NYMEX prices at year-end 2001, of $19.84 per Bbl and $2.57 per MMbtu, and are adjusted for the effects of contractual agreements with Unocal and Amoco in connection with the California and Congo property acquisitions (see Note 17).

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:

	Year Ended December 31,		
	2001	2000	1999
	(In thousands)		
Domestic			
Property acquisition			
Proved properties	$ 41,135	$ --	$ 62,300
Unproved properties (/1/)	6,131	4,892	520
Exploration	16,004	5,591	4,973
Development			
Proved reserves	95,005	79,857	35,372
Unproved reserves	5,716	11,433	2,906
	$163,991	$101,773	$106,071
Foreign			
Property acquisition			
Proved properties	$ --	$ --	$ --
Unproved properties (/1/)	47	479	424
Exploration	4,703	6,467	3,742

Development			
Proved reserves	20,222	4,406	20,404
Unproved reserves	--	342	--
	$ 24,972	$ 11,694	$ 24,570
Total			
Property acquisition			
Proved properties	$ 41,135	$ --	$ 62,300
Unproved properties (/1/)	6,178	5,371	944
Exploration	20,707	12,058	8,715
Development			
Proved reserves	115,227	84,263	55,776
Unproved reserves	5,716	11,775	2,906
	$188,963	$113,467	$130,641

(/1/Includes)capitalized interest directly related to development activities of $2.5 million and $0.3 million in 2001 and 1999.

Capitalized costs

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

	As of December 31,		
	2001	2000	1999
	(In thousands)		
Domestic			
Proved properties	$ 893,215	$ 986,889	$ 898,032
Unproved properties	27,117	25,341	21,755
Total capitalized costs	920,332	1,012,230	919,787
Accumulated depreciation, depletion and amortization	(378,644)	(461,225)	(403,727)
Net capitalized costs	$ 541,688	$ 551,005	$ 516,060
Foreign			
Proved properties	$ 91,437	$ 84,558	$ 80,374
Unproved properties	2,660	5,445	2,618
Total capitalized costs	94,097	90,003	82,992
Accumulated depreciation, depletion and amortization	(37,693)	(29,008)	(20,901)
Net capitalized costs	$ 56,404	$ 60,995	$ 62,091
Total			
Proved properties	$ 984,652	$1,071,447	$ 978,406
Unproved properties	29,777	30,786	24,373

Total capitalized costs	1,014,429	1,102,233	1,002,779
Accumulated depreciation, depletion and amortization	(416,337)	(490,233)	(424,628)
Net capitalized costs	$ 598,092	$ 612,000	$ 578,151

Results of operations for producing activities

	Year Ended December 31,		
	2001	2000	1999
	(In thousands)		
Domestic			
Revenues from oil and gas producing activities	$ 332,646	$ 290,774	$ 211,647
Production costs	(177,862)	(142,850)	(117,680)
Exploration costs	(16,170)	(5,503)	(10,643)
Depreciation, depletion and amortization	(63,485)	(57,819)	(70,024)
Provision for impairment of oil and gas properties	(89,466)	--	--
Income tax (provision) benefit	5,750	(34,096)	(2,727)
Results of operations from producing activities (excluding corporate overhead and interest costs)	$ (8,587)	$ 50,506	$ 10,573
Foreign			
Revenues from oil and gas producing activities	$ 35,914	$ 40,881	$ 30,627
Production costs	(14,015)	(13,626)	(12,869)
Exploration costs	(5,888)	(4,271)	(3,374)
Depreciation, depletion and amortization	(10,381)	(8,085)	(9,177)
Provision for impairment of oil and gas properties	(14,024)	--	--
Income tax (provision) benefit	3,366	(6,005)	(1,067)
Results of operations from producing activities (excluding corporate overhead and interest costs)	$ (5,028)	$ 8,894	$ 4,140
Total			
Revenues from oil and gas producing activities	$ 368,560	$ 331,655	$ 242,274
Production costs	(191,877)	(156,476)	(130,549)
Exploration costs	(22,058)	(9,774)	(14,017)
Depreciation, depletion and amortization	(73,866)	(65,904)	(79,201)
Provision for impairment of oil and gas properties	(103,490)	--	--
Income tax (provision) benefit	9,116	(40,101)	(3,794)
Results of operations from producing activities (excluding corporate overhead			

and interest costs)......................	$ (13,615)	$ 59,400	$ 14,713

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

	Year Ended December 31,					
	2001		2000		1999	
	Oil(/1/) (MBbl)	Gas (MMcf)	Oil(/1/) (MBbl)	Gas (MMcf)	Oil(/1/) (MBbl)	Gas (MMcf)
Domestic						
Proved reserves at beginning of year....	196,692	165,977	239,190	145,125	164,300	403,256
Revisions of previous estimates............	15,164	(55,422)	(40,340)	20,740	61,168	56,097
Extensions and discoveries..........	311	578	15,945	17,678	10,795	11,800
Production............	(14,536)	(12,750)	(15,591)	(15,215)	(15,892)	(17,620)
Sales of reserves in-place................	--	--	(2,512)	(2,351)	(10,270)	(335,927)
Purchase of reserves in-place............	1,383	12,980	--	--	29,089	27,519
Proved reserves at end of year.............	199,014	111,363	196,692	165,977	239,190	145,125
Proved developed reserves Beginning of year...	160,039	122,500	174,846	112,204	123,077	308,667
End of year.........	169,507	92,890	160,039	122,500	174,846	112,204
Foreign						
Proved reserves at beginning of year....	23,202	--	26,048	--	25,841	--
Revisions of previous estimates............	(5,478)	--	(1,003)	--	2,042	--
Extensions and discoveries..........	--	1,129	--	--	--	--
Production............	(1,880)	--	(1,843)	--	(1,835)	--
Sales of reserves in-place................	--	--	--	--	--	--
Purchase of reserves in-place............	--	--	--	--	--	--
Proved reserves at end of year.............	15,844	1,129	23,202	--	26,048	--
Proved developed reserves Beginning of year...	11,013	--	13,749	--	10,242	--

End of year	15,844	1,129	11,013	--	13,749	--
Total						
Proved reserves at beginning of year	219,894	165,977	265,238	145,125	190,141	403,256
Revisions of previous estimates	9,686	(55,422)	(41,343)	20,740	63,210	56,097
Extensions and discoveries	311	1,707	15,945	17,678	10,795	11,800
Production	(16,416)	(12,750)	(17,434)	(15,215)	(17,727)	(17,620)
Sales of reserves in-place	--	--	(2,512)	(2,351)	(10,270)	(335,927)
Purchase of reserves in-place	1,383	12,980	--	--	29,089	27,519
Proved reserves at end of year	214,858	112,492	219,894	165,977	265,238	145,125
Proved developed reserves						
Beginning of year	171,052	122,500	188,595	112,204	133,319	308,667
End of year	185,351	94,019	171,052	122,500	188,595	112,204

(/1/Includes)estimated NGL reserves.

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Discounted future net cash flows

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

	Year Ended December 31,		
	2001	2000	1999
	(In thousands)		
Domestic			
Future cash inflows	$ 3,182,420	$ 6,168,033	$ 4,823,952
Future production costs	(1,773,397)	(2,968,448)	(2,132,655)
Future development costs	(382,412)	(349,150)	(357,708)
Future net inflows before income tax	1,026,611	2,850,435	2,333,589
Future income taxes	(149,564)	(896,974)	(704,236)
Future net cash flows	877,047	1,953,461	1,629,353
10% discount factor	(366,050)	(803,899)	(739,181)
Standardized measure of discounted future net cash flows	$ 510,997	$ 1,149,562	$ 890,172
Foreign			
Future cash inflows	$ 248,569	$ 521,831	$ 469,327
Future production costs	(123,628)	(235,825)	(177,150)
Future development costs	(6,863)	(54,475)	(46,750)

Future net inflows before income tax..	118,078	231,531	245,427
Future income taxes..................	(25,237)	(70,452)	(66,971)
Future net cash flows................	92,841	161,079	178,456
10% discount factor..................	(24,152)	(55,752)	(61,455)
Standardized measure of discounted future net cash flows...............	$ 68,689	$ 105,327	$ 117,001
Total			
Future cash inflows..................	$ 3,430,989	$ 6,689,864	$ 5,293,279
Future production costs..............	(1,897,025)	(3,204,273)	(2,309,805)
Future development costs.............	(389,275)	(403,625)	(404,458)
Future net inflows before income tax..	1,144,689	3,081,966	2,579,016
Future income taxes..................	(174,801)	(967,426)	(771,207)
Future net cash flows................	969,888	2,114,540	1,807,809
10% discount factor..................	(390,202)	(859,651)	(800,636)
Standardized measure of discounted future net cash flows...............	$ 579,686	$ 1,254,889	$ 1,007,173

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* In addition to the information presented in the above table, we entered into swap and option arrangements on a portion of our future crude production as of December 31, 2001 (see Note 16). The effects of these hedges would increase the present value of future net cash flows discounted at a 10% rate ("PV-10") by approximately $17.8 million as of December 31, 2001.

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

	Year Ended December 31,		
	2001	2000	1999
Domestic			
Standardized measure--beginning of year..	$1,149,562	$ 890,172	$ 277,963
Sales, net of production costs...........	(154,785)	(147,924)	(94,384)
Purchases of reserves in-place...........	13,759	--	224,251
Net change in prices and production costs.................................	(904,288)	387,009	439,615
Extensions, discoveries and improved recovery, net of future production and development costs......................	2,750	181,885	59,873
Changes in estimated future development costs.................................	(61,735)	(8,806)	(12,375)
Development costs incurred...............	62,562	79,857	32,380
Revisions of quantity estimates..........	20,906	(233,132)	276,965
Accretion of discount....................	151,060	110,162	27,796
Net change in income taxes...............	211,477	(149,592)	(211,448)
Sales of reserves in-place...............	--	(9,242)	(151,348)
Changes in production rates and other....	19,729	49,173	20,884

Standardized measure--end of year........	$ 510,997	$1,149,562	$ 890,172
Foreign			
Standardized measure--beginning of year..	$ 105,327	$ 117,001	$ 21,970
Sales, net of production costs...........	(21,899)	(27,255)	(17,759)
Purchases of reserves in-place...........	--	--	--
Net change in prices and production costs..................................	(56,360)	19,595	59,641
Extensions, discoveries and improved recovery, net of future production and development costs......................	114	--	--
Changes in estimated future development costs..................................	16,455	(7,167)	12,711
Development costs incurred...............	16,100	4,406	7,175
Revisions of quantity estimates..........	(25,804)	(7,204)	8,479
Accretion of discount....................	13,861	14,300	2,197
Net change in income taxes...............	24,150	(7,284)	(26,001)
Sales reserves in-place..................	--	--	--
Changes in production rates and other....	(3,255)	(1,065)	48,588
Standardized measure--end of year........	$ 68,689	$ 105,327	$ 117,001
Total			
Standardized measure--beginning of year..	$1,254,889	$1,007,173	$ 299,933
Sales, net of production costs...........	(176,684)	(175,179)	(112,143)
Purchases of reserves in-place...........	13,759	--	224,251
Net change in prices and production costs..................................	(960,648)	406,604	499,256
Extensions, discoveries and improved recovery, net of future production and development costs......................	2,864	181,885	59,873
Changes in estimated future development costs..................................	(45,280)	(15,973)	336
Development costs incurred...............	78,662	84,263	39,555
Revisions of quantity estimates..........	(4,898)	(240,336)	285,444
Accretion of discount....................	164,921	124,462	29,993
Net change in income taxes...............	235,627	(156,876)	(237,449)
Sales of reserves in-place...............	--	(9,242)	(151,348)
Changes in production rates and other....	16,474	48,108	69,472
Standardized measure--end of year........	$ 579,686	$1,254,889	$1,007,173

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* In addition to the information presented in the above table, the Company had entered into swap and option arrangements on a portion of its future crude production as of December 31, 2001 (see Note 16). The effects of these hedges would increase the PV-10 by approximately $17.8 million as of December 31, 2001.

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19. Selected Quarterly Financial Data (Unaudited)

	Quarter Ended(/1/)			
	March 31, 2001	June 30, 2001	September 30, 2001	December 31, 2001

	(In thousands, except share data)			
Revenues	$117,522	$100,696	$83,146	$ 69,891
Operating earnings (loss)	28,505	16,109	7,843	(134,167)
Net income (loss)	9,603	2,659	(2,383)	(89,050)
Earnings (loss) per Common share--Basic	0.58	0.16	(0.14)	(5.28)
Earnings (loss) per Common share--Diluted	0.57	0.14	(0.14)	(5.28)

	Quarter Ended(/1/)(/2/)			
	March 31, 2000	June 30, 2000	September 30, 2000	December 31, 2000
	(In thousands, except share data)			
Revenues	$ 71,505	$ 72,171	$91,274	$ 101,655
Operating earnings	20,372	20,505	32,689	25,424
Net income	651	263	8,850	1,871
Earnings per Common share before cumulative effect--Basic	0.08	0.02	0.51	0.11
Earnings per Common share before cumulative effect--Diluted	0.08	0.00	0.49	0.10
Earnings per Common share--Basic	0.04	0.02	0.51	0.11
Earnings per Common share--Diluted	0.04	0.00	0.49	0.10

(/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/Results) for the 2000 quarters were revised due to a change in accounting for processed fuel oil and natural gas liquids inventories (see Note 2).

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SCHEDULE II

NUEVO ENERGY COMPANY

VALUATION AND QUALIFYING ACCOUNTS

Years Ended December 31, 2001, 2000 and 1999
(In thousands)

	Additions			
Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period

2001					
Allowance for doubtful accounts..............	$ 766	$1,314	$ --	$ 800	$1,280
Valuation allowance on deferred taxes........	1,777	--	--	--	1,777
Legal reserves.........	807	4,000	--	--	4,807
Environmental reserves..............	4,479	--	613	--	5,092
2000					
Allowance for doubtful accounts..............	--	--	766	--	766
Valuation allowance on deferred taxes........	1,777	--	--	--	1,777
Legal reserves.........	1,951	--	--	1,144	807
Environmental reserves..............	4,500	--	--	21	4,479
1999					
Valuation allowance on deferred taxes........	17,646	--	--	15,869	1,777
Legal reserves.........	1,515	236	200	--	1,951
Environmental reserves..............	--	--	4,500	--	4,500

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

On March 9, 2001, we notified KPMG LLP ("KPMG") that their engagement as our independent accountants would be terminated following the issuance of their report on our consolidated financial statements for the fiscal year ended December 31, 2000. On March 9, 2001, our Board of Directors, on the recommendation of the Audit Committee, appointed Arthur Andersen LLP as our independent accountants to audit our consolidated financial statements for the year ending December 31, 2001.

We and KPMG have not, in connection with the audit of our consolidated financial statements for each of the prior two years ended December 31, 2000 and December 31, 1999, or for any subsequent or interim period prior to and including March 9, 2001, had any disagreement on any matter of accounting principles or practice, financial statement disclosure, or auditing scope or procedure, which disagreement, if not resolved to KPMG's satisfaction, would have caused KPMG to make reference to the subject matter of the disagreement in connection with its reports.

The reports of KPMG on our financial statements for the past two fiscal years did not contain an adverse opinion or a disclaimer of opinion and were not qualified or modified as to uncertainty or audit scope.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

The information required by this item will be included in our definitive proxy statement, which will be filed not later than 120 days after December 31, 2001, and is incorporated herein by reference.

ITEM 11. EXECUTIVE COMPENSATION

The information required by this item will be included in our definitive proxy statement, which will be filed not later than 120 days after December 31, 2001, and is incorporated herein by reference.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The information required by this item will be included in our definitive proxy statement, which will be filed not later than 120 days after December 31, 2001, and is incorporated herein by reference.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

The information required by this item will be included in a definitive proxy statement, which will be filed not later than 120 days after December 31, 2001, and is incorporated herein by reference.

PART IV

ITEM 14. EXHIBITS, FINANCIAL STATEMENT SCHEDULES AND REPORTS ON FORM 8-K

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

1. Financial Statements.

Our consolidated financial statements are included in Part II, Item 8 of this report:

2. Financial statement schedules and supplementary information required to be submitted.

Schedules other than that listed above are omitted because they are not applicable.

(b) Reports on Form 8-K:

. We filed a Current Report on Form 8-K, dated November 9, 2001, reporting Item 9. Regulation FD Disclosure.

. We filed a Current Report on Form 8-K, dated January 22, 2002, reporting Item 9. Regulation FD Disclosure.

NUEVO ENERGY COMPANY

EXHIBIT LIST
December 31, 2001

Each exhibit identified below is filed as a part of this report. Exhibits not incorporated by reference to a prior filing are designated by and 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.

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

4.10 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).

4.11 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).

4.12 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).

4.13 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).

4.14 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 Employment Agreement with Douglas L. Foshee. (Exhibit 10.23 to our 1997 Form 10-K)

10.22 Employment Agreement with Robert M. King. (Exhibit 10.24 to our 1998 Form 10-K).

10.23 Employment Agreement with Dennis Hammond. (Exhibit 10.26 to our 1997 Form 10-K)

10.24 Employment Agreement with Michael P. Darden. (Exhibit 10.1 to our 1998 Third Quarter Form 10-Q).

10.25 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).

10.26 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).

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

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

10.29 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).

10.30 Employment Agreement with Phillip Gobe dated February 26, 2001. (Exhibit 10.30 to our 2000 Form 10-K).

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

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

10.33 2001 Stock Incentive Plan (Exhibit 99.1 to our Form S-8, filed on October 21, 2001).

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

+10.35 Janet F. Clark Stock Option Plan

+10.36 George B. Nilsen Stock Option Plan

+10.37 Resignation Agreement with Robert M. King November 30, 2001.

+10.38 Resignation Agreement with Dennis Hammond dated January 9, 2002.

+10.39 Resignation Agreement with Michael P. Darden dated January 11, 2002.

(21) Subsidiaries of the Registrant

(23) Consents of experts and counsel

*23.1 Consent of ARTHUR ANDERSEN LLP

*23.2 Consent of KPMG LLP

(99) Additional Exhibits
*99.1 Management's representation regarding Arthur Andersen LLP

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 14.

- 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, 2000, 1999 or 1998 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.

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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)

Date: April 1, 2002

/s/ James L. Payne
By: ______________________________
James L. Payne
Chairman, President and Chief Executive Officer

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	Date
/s/ James L. Payne *By: ______________________________ James L. Payne Chairman, President and Chief Executive Officer (Principal Executive Officer)	April 1, 2002
/s/ Janet f. Clark *By: ______________________________ Janet F. Clark Senior Vice President and Chief Financial Officer (Principal Financial and Accounting Officer)	April 1, 2002
/s/ Isaac Arnold, Jr. *By: ______________________________ Isaac Arnold, Jr. Director	April 1, 2002
/s/ David H. Batchelder *By: ______________________________ David H. Batchelder	April 1, 2002

Director

*By: /s/ Charles M. Elson Charles M. Elson Director	April 1, 2002
*By: /s/ Robert L. Gerry III Robert L. Gerry III Director	April 1, 2002
*By: /s/ James T. Jongebloed James T. Jongebloed Director	April 1, 2002
*By: /s/ Gary R. Peterson Gary R. Peterson Director	April 1, 2002
*By: /s/ David Ross David Ross Director	April 1, 2002
*By: /s/ Robert W. Shower Robert W. Shower Director	April 1, 2002