NUEVO ENERGY CO
Form 10-K405/A
February 16, 2001

1

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

FORM 10-K/A

(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, 1999

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 registere
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 [X].

The aggregate market value of the voting stock held by non-affiliates of the registrant at March 22, 2000, was approximately $350,119,028.

As of March 22, 2000, the number of outstanding shares of the registrant's common stock was 17,560,829.

Documents Incorporated by Reference:

Portions of the registrant's annual proxy statement, to be filed within 120 days after December 31, 1999, are incorporated by reference into Part III.

NUEVO ENERGY COMPANY

ANNUAL REPORT ON FORM 10-K
FOR THE FISCAL YEAR ENDED DECEMBER 31, 1999

TABLE OF CONTENTS

NUEVO ENERGY COMPANY

PART I

This document includes "forward looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended (the "Securities Act"), and Section 21E of the Securities Exchange Act of 1934 ("Exchange Act"). All statements other than statements of historical facts included in this document, including without limitation, statements under "Management's Discussion and Analysis of Financial Condition and Results of Operations" regarding the Company's financial position, estimated quantities and net present values of reserves, business strategy, plans and objectives of management of the Company for future operations and covenant compliance, are forward looking statements. The Company 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 the Company's expectations ("Cautionary Statements") are set forth throughout this document. All subsequent written and oral forward looking statements attributable to the Company or persons acting on its behalf are expressly qualified by the Cautionary Statements.

ITEM 1. BUSINESS

General

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 Predecessor Partnerships. Such Plan of Consolidation provided for the exchange of the net assets of the Predecessor Partnerships for common stock of Nuevo ("Common Stock"). The Common Stock began trading on the New York Stock Exchange on July 10, 1990, under the symbol "NEV." All references to the "Company" include Nuevo and its majority and wholly-owned subsidiaries, unless otherwise indicated or the context indicates otherwise.

Nuevo, headquartered in Houston, Texas, is primarily engaged in the exploration for, and the acquisition, exploitation, development and production of crude oil and natural gas. The Company's strategy to differentiate itself from its numerous peer group competitors and to generate long term shareholder value consists of: (i) a management philosophy that frames all important decisions in terms of anticipated impact on per share (rather than absolute) growth of reserves, production, cash flow and net asset value; (ii) a contrarian investment and financing orientation, in which the Company seeks to purchase assets during periods of industry weakness and sell assets during periods of industry strength; (iii) the outsourcing of non-strategic functions; and (iv) the alignment of employee compensation structures with shareholder objectives. Nuevo is also committed to an exemplary corporate governance structure, which reinforces management's overarching view that Nuevo should be a conduit for shareholders to achieve superior long term capital gains. All of Nuevo's directors, other than the chief executive officer, are independent directors. Nuevo's directors and executive officers have each made substantial equity investments in Nuevo, in order to align the Company's directors and executive officers interests with that of stockholders.

The Company accumulates oil and gas reserves through the drilling of exploratory wells on acreage owned by or leased to the Company, or through the purchase of reserves from others. The Company maximizes production from these reserves through the drilling of developmental wells and through other exploitative techniques. The Company also owns and operates gas plants and other facilities, which are ancillary to the primary business of producing oil and natural gas. The Company also owns certain surface real estate parcels in California that are candidates for sale and/or development in future years.

Oil and Gas Activities

Since its inception in 1990, Nuevo has expanded its operations through a series of disciplined, low-cost acquisitions of oil and gas properties and the subsequent exploitation and development of these properties. The Company has complemented these efforts with strategic divestitures and an opportunistic exploration program, which provides exposure to high potential prospects. The Company's primary strengths are its track record of rapid reserve growth on a per share basis, achieved at extremely low cost relative to industry averages; its large inventory of exploitation projects in its core areas of operation which the Company believes will support future growth in

reserves and production per share; its demonstrated ability to significantly reduce operating costs on acquired properties from levels experienced by prior operators; its ability to identify and acquire, at attractive prices, long-lived producing properties which have significant potential for further exploration, exploitation and development; a capital structure supportive of a growing investment program and future acquisitions; and a price risk management policy designed to protect the Company's ability to generate self-sustaining cash flow and to meet the interest coverage tests under the Company's bond indentures. During the five years ended December 31, 1999, the Company invested $595.4 million in seven acquisitions that added estimated net proved reserves of 214.6 million barrels ("MMBBLS") of oil and 171.1 billion cubic feet ("BCF") of natural gas and replaced 501% of its production at an average cost of $2.72 per barrel of oil equivalent ("BOE"). As a result, the Company's estimated net proved equivalent reserves have increased by approximately 258% since 1995.

Domestic Operations

As of December 31, 1999, the Company's estimated net U.S. proved reserves totaled 263.4 million barrels of oil equivalent ("MMBOE") or 91% of Nuevo's total proved reserve base. During 1999, the Company's domestic production was 18.9 MMBOE, or 91% of total production.

West: The majority of the Company's domestic properties are located in the state of California, where the Company operates from an office in Bakersfield. The Company's properties in California are categorized by district as either Bakersfield, Pacific Onshore or Pacific Offshore.

Nuevo's Bakersfield district operations encompass an estimated net proved reserve base of 135.4 MMBOE as of December 31, 1999, and produced 8.5 MMBOE in 1999. Bakersfield district properties include the Company's interests in the Cymric, Midway-Sunset and Belridge oil fields in the Western San Joaquin Basin in Kern County, California, and in the Coalinga gas field in the North San Joaquin Valley. The Company's Bakersfield properties utilize thermal operations to maximize current production and the ultimate recovery of reserves. The Company owns a 100% working interest (88% net revenue) in its properties in the Cymric field and the entire working interest and an average net revenue interest of approximately 98% in its properties in the Midway-Sunset field. Production is from two zones in the Cymric field, the Tulare formation 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. The productive zones of the Belridge field above 2,000 feet in which the Company owns royalty interest are operated by another independent energy company. The remaining deeper zones of the Belridge field are operated and owned by the

Company in fee with 100% working and net revenue interests. The Coalinga gas field is operated by Nuevo and the Company owns an average 61% working interest (52% net revenue). Production is from the Gatchell formation.

Nuevo's Pacific Onshore district operations encompass an estimated net proved reserve base of 50.8 MMBOE as of December 31, 1999, and produced 2.5 MMBOE in 1999. Pacific Onshore district properties include the Company's interest in the Brea Olinda oil field in northern Orange County. The Company operates three fee properties in the Brea Olinda field with a 100% working and net revenue interest. The Company also has 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.

Nuevo's Pacific Offshore district operations encompass an estimated net proved reserve base of 74.9 MMBOE as of December 31, 1999, and resulted in production of 6.9 MMBOE in 1999. Pacific Offshore district properties include the Company's interests in the Point Pedernales, Dos Cuadras, Huntington Beach, Santa Clara and Belmont oil fields in federal OCS leases, offshore Santa Barbara and Ventura Counties and Long Beach. The Company acquired a 12% working interest (10% net revenue) in the Point Pedernales field in July 1994 and an additional 68% working interest (57% net revenue) in the field as part of the acquisition of the California properties in 1996. The Point Pedernales field is operated by the Company, and 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 fields are located offshore five and one-half miles from Santa Barbara in the Santa Barbara Channel. The Company operates three platforms with a 50% working interest (42% net revenue) and another platform with a 67.5% working interest (56% net revenue).

East: The Company also has properties located in the onshore Gulf Coast region, which are operated from the Company's headquarters in Houston. Nuevo's Houston district operations encompass an estimated net proved reserve base of 2.3 MMBOE as of December 31, 1999, and produced 1.0 MMBOE in 1999. Houston district properties include the Company's interests in the Giddings gas fields in Grimes and Austin Counties, Texas; and in the North Frisco City oil field in Monroe County, Alabama. The Company owns an interest in 12 producing wells in the Giddings field and has an average 46.9% working (35.2% net revenue) interest in these wells. The North Frisco City field is Company-operated. Nuevo owns approximately a 22% working (17% net revenue) interest.

General: The Company continues to create value through domestic oil and gas development projects. The Company initiates workovers, recompletions, development drilling, secondary and tertiary recovery operations and other production enhancement techniques to maximize current production and the ultimate recovery of reserves. The Company has identified in excess of 1,250 domestic exploitation projects on existing properties, at a West Texas Intermediate ("WTI") crude price of $18.50 per barrel of oil ("BBL"). Capital expenditures for domestic exploitation projects totaled $38.3 million in 1999 and are budgeted at approximately $105.0 million in 2000, if the crude oil forward strip remains above $20.00 per BBL. Examples of current or planned projects include the continuation of horizontal drilling in the Bakersfield district and infill drilling in the recently acquired acreage in the Cymric field to further exploit the Diatomite formation.

The Company also has a program targeting exploration opportunities in California. The Company seeks to reduce the risks normally associated with exploration through the use of advanced technologies, such as 3-D seismic surveys and computer aided exploration ("CAEX") techniques, and by participating with experienced industry partners. The Company's exploration program resulted in four dry wells in 1999.

Capital expenditures for domestic exploration activity totaled $3.9 million in 1999 and are budgeted at approximately $11.0 million in 2000.

International Operations

As of December 31, 1999, the Company's estimated international net proved reserves totaled 26.0 MMBOE, or 9% of Nuevo's total proved reserve base. During 1999, the Company's international production was 1.8 MMBOE, or 9% of Nuevo's total production.

Congo: The Company's international reserves and production consist of a 50% working interest (37.5% average net revenue) in the Yombo and Masseko oil fields located in the Marine I Permit offshore the Republic of Congo in West Africa ("Congo"). Estimated net proved reserves of the Yombo and Masseko oil fields as of December 31, 1999 were 26.0 MMBOE, and production during 1999 totaled 1.8 MMBOE, all from the Yombo field. In 1999, revenues relating to production from the Yombo field accounted for approximately 13% of the total oil and gas revenues for the Company. The properties are located 27 miles offshore in approximately 370 feet of water. The Company also owns 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"). The Company's production is converted on the FPSO to No. 6 fuel oil with less than 0.3% sulfur content.

The Company's most significant international discovery in 1997 was the Masseko M-4 well drilled on the Marine I Permit approximately six miles to the northwest of the Yombo field. The Company drilled an exploration well to evaluate the Lower Sendji and sub-salt sections underlying the Masseko structure, as well as to further delineate the Upper Sendji and Tchala zones, which were discovered but not developed by a previous operator. This well tested at rates over 3,000 gross barrels per day from a newly discovered middle Sendji section. Platform design and development plans are being formulated for Masseko. Other potential exploration features are being evaluated for possible future drilling. Additionally, the Company initiated a waterflood project in the Yombo field to enhance production from existing Upper Sendji and Tchala zones. Plans for 2000 include performing a study to evaluate waterflood performance and to convert up to three wells to water injectors.

Ghana: In February 2000, the Company relinquished its concession for petroleum rights covering approximately 1.7 million acres in the East Cape Three Points concession offshore the Republic of Ghana in West Africa ("Ghana"). In September 1998, the Company plugged and abandoned its first well in Ghana on the East Cape

Three Points concession due to the lack of commercial quantities of hydrocarbons. Dry hole costs and geological and geophysical costs for this well (net to the Company) were $7.3 million and $1.6 million, respectively, in 1998.

In October 1997, Nuevo Ghana, Inc., ("Nuevo Ghana"), signed a petroleum agreement with Ghana and the Ghana National Petroleum Corporation, ("GNPC") for petroleum rights covering 2.7 million acres offshore Ghana in the Accra-Keta prospect area. The Company is the operator of this prospect with a 100% working interest. The exploration program for this acreage involves reprocessing existing seismic data, shooting additional seismic and drilling an exploration well during the first phase of the agreement. The Company completed a 3-D seismic survey across this concession in March 2000. The results are currently being reviewed in-house, and based upon the results, the Company plans to drill its first exploratory well on the concession in late 2000.

Tunisia: In December 1998, the Company temporarily abandoned the Chott Fejaj #3 well in Tunisia, North Africa. Based on the Company's evaluation of the initial test results on this well, the Company expensed the $1.8 million of costs incurred as dry hole costs in 1998. The Company has acquired additional regional seismic data across its Chott-Fejaj concession. This data was acquired to better evaluate the sub-salt potential beneath the #3 well, which the Company plans to deepen in late 2000. The Company owns a 17.5% working interest in the well.

General: Capital expenditures for 1999 international exploration and development activity totaled $2.3 million and $20.4 million, respectively. The Company's 2000 international exploration budget of approximately $8.0 million includes seismic evaluation, data acquisition and the drilling of two wells. International development plans for 2000 include the continuation of the Company's waterflood program in the Congo and are budgeted at approximately $2.0 million.

The Company's 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 its foreign operations, the Company 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. The Company attempts to conduct its business and financial affairs so as to protect against political and economic risks applicable to operations in the various countries where it operates, but there can be no assurance that the Company will be successful in so protecting itself. A portion of the Company's investment in the Congo is insured through political risk insurance provided by the Overseas Private Investment Corporation ("OPIC"). See "Risk Factors".

Gas Plant and Other Facilities

The Company has owned and operated gas plants and other facilities, most of which have been ancillary to the primary business of producing oil and natural gas.

As of December 31, 1999, the Company owned two gas plants in California that are strategic assets for the Company's oil and gas activities in California. The Stearns Gas Plant is located in the Brea Olinda field and was processing 3.2 MMCFD at December 31, 1999. The HS&P Gas Plant is used to process gas production from the Point Pedernales field. At December 31, 1999, the HS&P Gas Plant was processing 2.6 MMCFD.

In December 1999, the Company sold the Santa Clara Valley Gas Plant, which is located east of Ventura, California, in connection with the Company's sale of its interest in the non-core properties onshore California.

In addition to the gas plants that process Company production, Nuevo has owned certain non-core gas gathering, pipeline and storage assets. In December 1997, the Company announced its intention to dispose of these non-core assets during 1998. The decision was made to dispose of these assets as they did not directly contribute to the Company's core oil and gas operations. Such assets included: the Company's 48.5% interest in the Richfield Gas Storage facility, which was sold in February 1998 for proceeds of $2.1 million, an 80%

interest in Bright Star Gathering, Inc., which was sold in July 1998 for proceeds of $1.7 million, and the Illini pipeline, which was sold in November 1999 for proceeds of $10.0 million. An agreement to sell the Illini Pipeline was reached in April 1998; however, the approval of the sale was not received from the Illinois Commerce Commission until November 1999. No gains or losses were recognized in connection with these sales. The Company recorded a non-cash, pre-tax

charge to fourth quarter 1997 earnings of $23.9 million, reflecting the estimated loss on the disposition of these assets. A positive revision to this charge was made in the fourth quarter of 1998 in the amount of $3.7 million to reflect the estimated current fair value of the Illini pipeline. The Company's results of operations included the operating results from these assets through the disposition date, as applicable. Such amounts were not significant relative to total revenues and net operating results for the Company. These assets were not depreciated subsequent to 1997. The Company retained its remaining two California gas plants, as these plants are strategic assets for the Company's oil and gas activities in California.

On May 2, 1997, the Company sold its 95% interest in the NuStar Joint Venture, which owned an interest in the Benedum natural gas processing plant, and an interest in certain related assets and natural gas gathering systems located in West Texas. The Company recognized a $2.3 million gain on this sale, which was effective January 1, 1997.

Real Estate

In April 1996, along with its acquisition of certain California upstream oil and gas properties from Union Oil Company of California ("Unocal") (see "Acquisitions and Divestitures of Oil and Gas Properties"), the Company acquired tracts of land in Orange and Santa Barbara Counties in California, two office buildings, one in Ventura County and one in Santa Barbara County, and nearly 16,000 acres of agricultural property in the central valley of California. As of December 31, 1999, there was $51.0 million allocated to land. The office buildings are included in other facilities at December 31, 1999.

Consistent with Nuevo's proactive asset management strategy, the Company plans to sell certain of its surface real estate assets in late 2000 or 2001. With land values rising in California, the Company expects to monetize a significant portion of its California real estate portfolio.

The surface fee in Orange County lies within the sphere of influence of the city of Brea, which is in north Orange County and includes three fee parcels, the Stearns Fee, the Stearns Columbia Fee and Naranjal "B" Fee. These are contiguous parcels with gross residential development potential of approximately 230 acres. Nuevo is working toward entitlement of this property, which is expected to be complete in the second half of 2000. The Company will evaluate its options at that time, including the potential sale. Plans are being formulated in relation to the tract of land in Santa Barbara 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.

Acquisitions and Divestitures of Oil and Gas Properties

Consistent with its contrarian acquisition and divestiture strategy, Nuevo has, from time to time, been an active participant in the market for oil and gas properties. The Company attempts to purchase high growth assets which, for any of a variety of reasons, are out of favor in the marketplace and hence available for acquisition at attractive prices. From time to time, the Company also seeks to divest itself of lower growth assets at times when those assets are valued highly by the marketplace. Examples of this contrarian strategy are listed below:

On December 31, 1999, the Company completed the sale of its interests in 13 onshore fields and a gas processing plant located in Ventura County, California for an adjusted sales price of $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 the Company. The remainder of the proceeds from the sale were used to repay a portion of the Company's outstanding bank debt.

In June 1999, the Company acquired oil and gas properties located onshore and offshore California for $61.4 million from Texaco, Inc. To purchase these assets, the Company 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 the Company's January 1999 sale of its 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 acquired properties had estimated net proved reserves at June 30, 1999, of 33.7 million barrels of oil equivalent ("BOE") and are either additional interests in the Company's existing properties or are located near its existing properties. The acquisition included interests in Cymric, East Coalinga, Dos Cuadras, Buena Vista Hills and other fields the Company operates.

On January 6, 1999, the Company completed the sale of its East Texas natural gas assets to an affiliate of Samson Resources Company for an adjusted sales price of approximately $191.0 million (see Note 4 to the Notes to Consolidated Financial Statements). The Company realized an $80.2 million adjusted pre-tax 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. The Company 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.

In April 1998, the Company acquired an additional working interest in the Marine I Permit in the Congo for $7.8 million. This acquisition increased the Company's net working interest in the Congo from 43.75% to 50.0%.

In July 1996, the Company completed the acquisition of certain East Texas oil and gas properties, which added 31.2 BCF to the Company's reserve base, for a net purchase price of $9.3 million in cash. The package consisted of interests in 11 fields. In December 1996, the holders of the preferential rights on these properties exercised such rights for a cash payment of $8.0 million, acquiring properties constituting approximately half of the estimated proved reserves related to this acquisition.

In June 1996, the Company sold 177 producing wells and the majority of its acreage in the Giddings field and East Texas Austin Chalk holdings for $27.3 million, representing estimated net proved reserves of 4.2 MMBOE as of December 31, 1995. The Company retained ownership of seven wells and surrounding acreage in the Turkey Creek prospect area of the Austin Chalk trend located in Grimes County, Texas.

In April 1996, the Company acquired certain upstream oil and gas properties located onshore and offshore California ("Unocal Properties") from Unocal and certain California oil properties ("Point Pedernales Properties" and, together with the Unocal Properties, the "California Properties") from Torch and certain of its wholly-owned subsidiaries for a combined net purchase price of $525.9 million, plus a contingent payment based on future realized oil prices. The California Properties consisted of 26 fields with approximately 2,400 active wells, and estimated net proved reserves as of December 31, 1999 of 249.3 MMBOE. During 1999, the California Properties constituted 86% of the Company's total oil and natural gas production on a barrel of oil equivalent basis. Since acquiring the California Properties, the Company has spent approximately $255.0 million to complete over 470 exploitation and development projects.

Subsidiaries

The Company's domestic oil and gas operations are organized under Nuevo Energy Company. The Company's oil and gas operations in the Congo are organized under The Nuevo Congo Company and Nuevo Congo Ltd., both wholly-owned subsidiaries of Nuevo. From time to time, the Company may set up a new wholly-owned subsidiary for its international oil and gas operations. As of December 31, 1999, the Company did not have any significant operating activities under any other subsidiary.

Industry Segment Information

For industry segment data (including foreign operations), see Note 13 to the Notes to Consolidated Financial Statements.

Markets

The markets for hydrocarbons continue to be quite volatile. The Company's financial condition, operating results, future growth and the carrying value of its oil and gas properties are substantially dependent on prevailing prices of oil and gas. The Company's ability to maintain or increase its 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 the control of the Company. 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 or gas would have an adverse effect on the Company's carrying value of its proved reserves, borrowing capacity, the Company's ability to obtain additional capital, and its revenues, profitability and cash flows from operations. (See Note 17 to the Notes to Consolidated Financial Statements.)

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 40% of the Company's total 1999 output.

In addition, properties which produce primarily other grades of relatively heavy oil (generally, 19 degrees API or heavier but produced through non-thermal operations) constituted 17% of the Company's total 1999 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, the Company entered into a 15-year contract, effective January 1, 2000, to sell all of its 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 Nuevo produces in California. While the contract does not reduce the Company's exposure to price volatility, it does effectively eliminate the basis differential risk between the NYMEX price and the field price of the Company's California oil production. In doing so, the contract makes it substantially easier for the Company to hedge its realized prices.

The Company's Yombo Field production in its Marine I Permit offshore the 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 9% of the Company's total 1999 output. 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 79%, 60% and 62% of 1999, 1998 and 1997 oil and gas revenues, respectively. Also in 1999 and 1998, sales to Torch Energy Marketing accounted for 12% and 10% of total 1999 and 1998 oil and gas revenues, respectively. The loss of any single significant customer or contract could have a material adverse short-term effect on the Company; however, management of the Company does not believe that the loss of any single significant customer or contract would materially affect its 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 the Company's 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 the Company may conduct operations. State and Federal regulations generally are 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 also are subject to the jurisdiction of various Federal, state and local agencies.

The Company's 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, as well as under Section 311 of the Natural Gas Policy Act. 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.

The Company's 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. In this connection, 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 the Company conducts 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.

The Company's 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 Company operations on federal leases to be suspended or terminated. Any such suspension or termination could materially and adversely affect the Company's financial condition and operations. On March 15, 2000, the MMS issued a final rule effective June 1, 2000 which 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 the Company sells its production in the spot market and therefore pays royalties on production from federal leases, it is not anticipated that this final rule will have any substantial impact on the Company.

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. The Company owns interest in numerous federal onshore oil and gas leases. It is possible that holders of equity interests in the Company may be citizens of foreign countries, which at some time in the future might be determined to be non-reciprocal under the Mineral Act.

The Company's pipelines used to gather and transport its 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 the Company 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. The Company believes its 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. The Company's 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 regulating the release of materials in the environment or otherwise relating to the protection of the environment will not have a material effect upon the operations, capital expenditures, earnings or the competitive position of the Company.

Activities of the Company 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"), the Department of Transportation and FERC. 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.

With respect to the Company's offshore oil and gas operations in California, the Company has significant exit cost liabilities. These liabilities include costs for dismantlement, rehabilitation and abandonment. As of December 31, 1999, the Company's net liability for these exit costs were approximately $99 million. The Company is not indemnified for any part of these exit costs.

Waste Disposal. The Company currently owns or leases, and has in the past owned or leased, numerous properties that have been used for production of oil and gas for many years. Although the Company has 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 owned or leased by the Company. In addition, many of these properties have been operated by third parties over whom the Company 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 more strict. Under these new laws, the Company could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators) or property contamination (including groundwater contamination) or to perform remedial plugging operations to prevent future contamination.

The Company may generate wastes, including hazardous wastes that are subject to the Federal Resource Conservation and Recovery Act and comparable state statutes. The EPA has limited the disposal options for certain hazardous wastes and is considering the adoption of stricter disposal standards for nonhazadous wastes. Furthermore, certain wastes generated by the Company's 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, without regard to fault or the legality of the original conduct, on certain classes of persons with respect to the release of a "hazardous substance" into the environment. These persons include the current owner and operator of a facility and persons that disposed of or arranged for the disposal of the hazardous substances found at 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 responsible classes of persons the costs of such action. In the course of its operations, the Company may have generated and may generate wastes that fall within CERCLA's definition of "hazardous substances". The Company may also be an owner of facilities on which "hazardous substances" have been released by previous owners or operators. The Company may be responsible under CERCLA for all or part of the costs to clean up facilities at which such wastes have been released. Neither the Company nor, to its knowledge, its Predecessor Partnerships has been named a potentially responsible person under CERCLA nor does the Company know of any prior owners or operators of its properties that are named as potentially responsible parties related to their ownership or operation of such property.

Air Emissions. The operations of the Company are subject to local, state and Federal regulations for the control of emissions of air pollution. 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 the Company to forego construction, modification or operation of certain air emission sources, although the Company believes that in the latter cases it would have enough permitted or permittable capacity to continue its operations without a material adverse effect on any particular producing field.

Oil Pollution Act. The Oil Pollution Act of 1990 ("OPA") and regulations thereunder impose certain duties and liabilities on "responsible parties" related to the prevention of oil spills and damages resulting from such spills in United States waters. A "responsible party" includes the owner or operator of a facility or vessel, or the lessee or permittee of the area in which a facility covered by OPA is located. OPA assigns joint and several liability 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.

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. The Company believes that it currently has established adequate proof of financial responsibility for its offshore facilities.

Management believes that the Company is 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 the Company.

Competition

The Company operates 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 the Company for the minimum projected return on investment and the availability of alternate fuel sources are factors that affect the Company's ability to compete in the marketplace. The Company's competitors include major integrated oil companies and a substantial number of independent energy companies, many of which possess greater financial and other resources than the Company. The Company competes with these competitors to acquire producing properties, exploration leases, licenses, concessions and marketing agreements.

Personnel

At December 31, 1999, the Company employed 62 full time employees who represent the executive officers and key operating, exploration, financial and accounting management. The Company outsources certain administrative and operational functions to Torch and its subsidiaries, which maintains a large technical, operating, accounting and administrative staff to provide services to Nuevo and its other clients. (See Note 6 to the Notes to Consolidated Financial Statements). The combined personnel of Torch and the Company consisted of 982 employees at December 31, 1999.

ITEM 2. PROPERTIES

Reserves, Productive Wells, Acreage and Production

The Company holds interests in oil and gas wells located in the United States and West Africa. The Company's principal developed properties are located in California, Texas, Louisiana, Alabama, and offshore Congo, West Africa; undeveloped acreage is located primarily in California, Texas, Congo, Ghana and Tunisia. Estimated proved oil and gas reserves at December 31, 1999 increased approximately 12% since December 31, 1998, primarily as a result of higher oil prices. (See Note 17 to the Notes to Consolidated Financial Statements). The Company has not filed any different oil or gas reserve information with any foreign government or other Federal authority or agency.

The following table sets forth certain information, as of December 31, 1999, which relates to the Company's principal oil and gas properties:

		Net Proved Reserves (SEC) December 31, 1999			1999
	Gross Wells	Oil* (Mbbls)	Gas (Mmcf)	MBOE	Oil* (Mbbls)
U.S. PROPERTIES					
California Fields					
Cymric	574	75,285	2,260	75,662	3,798
Midway-Sunset	483	37,537	--	37,537	2,590
Brea Olinda	217	33,275	21,924	36,929	783
Belridge	342	12,336	683	12,450	676
Santa Clara	26	20,572	37,565	26,833	840
Dos Cuadras	98	13,336	8,407	14,737	660
Point Pedernales	12	13,682	4,584	14,446	2,202
Huntington Beach	17	6,533	507	6,617	663
Other	632	26,040	58,890	35,855	3,205

Total California Fields	2,401	238,596	134,820	261,066	15,417
Other U.S. Fields					
North Frisco City, Alabama	6	401	1,132	590	230
Giddings, Texas	13	8	2,724	462	6
Other	27	185	6,449	1,259	239
Total U.S. Properties	2,447	239,190	145,125	263,377	15,892
FOREIGN PROPERTIES					
Yombo, Congo	24	18,017	--	18,017	1,835
Masseko, Congo	--	8,031	--	8,031	--
Total Foreign Properties	24	26,048	--	26,048	1,835
Unocal contingent payment	--	--	--	--	--
Hedge effect	--	--	--	--	--
TOTAL PROPERTIES	2,471	265,238	145,125	289,425	17,727

----

* includes natural gas liquids
** pre-tax

NUEVO ENERGY COMPANY

The summary of SEC reserves, which is presented on the previous page, is computed based on realized prices at December 31, 1999, held constant over time (see Note 17 to the Notes to Consolidated Financial Statements). Oil prices at December 31, 1999, were unusually high. Management believes that the following reserve information, which reflects fluctuating commodity pricing based on market information available at year-end, is more consistent with management's belief that the current oil and gas prices will revert to long-term historical averages. The following table sets forth this alternative reserve information (based on NYMEX prices of $22.40 per barrel of oil in 2000 and $20.00 per barrel thereafter, and $2.50 per Mcf of gas held constant), as of December 31, 1999. Because the prices used in the following table are lower than the year-end prices Nuevo received for its production, the following does not represent information attributable to "proved reserves" as defined by the SEC.

	Estimated Market Case December 31, 1999			
	Oil* (Mbbls)	Gas (Mmcf)	MBOE	PV-10**
U.S. PROPERTIES				
California Fields				

Cymric..................	72,265	2,247	72,640	$ 247,633
Midway-Sunset...........	35,656	--	35,656	114,632
Brea Olinda.............	33,118	21,866	36,762	78,504
Santa Clara.............	19,454	35,212	25,323	52,853
Belridge................	12,259	661	12,369	50,541
Dos Cuadras	12,058	7,522	13,312	34,388
Point Pedernales.........	13,636	4,597	14,402	27,533
Huntington Beach.........	5,915	457	5,991	20,702
Other...................	22,753	60,677	32,865	90,823
Total California Fields..............	227,114	133,239	249,320	717,609
Other U.S. Fields				
North Frisco City, Alabama................	401	1,132	590	5,054
Giddings, Texas..........	8	2,737	464	4,134
Other...................	176	6,471	1,255	8,295
Total U.S. Properties..	227,699	143,579	251,629	735,092
FOREIGN PROPERTIES				
Yombo, Congo............	18,589	--	18,589	111,808
Masseko, Congo...........	8,057	--	8,057	9,777
Total Foreign Properties...........	26,646	--	26,646	121,585
Hedge effect....................	--	--	--	(35,179)
TOTAL PROPERTIES	254,345	143,579	278,275	$ 821,498

* includes natural gas liquids
** pre-tax

Acreage

The following table sets forth the acres of developed and undeveloped oil and gas properties in which the Company held an interest as of December 31, 1999. 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 a working interest is owned directly by the Company. The number of net acres is the sum of the fractional ownership of working interests owned directly by the Company in the gross acres expressed as a whole number and percentages thereof. A "net acre" is deemed to exist when the sum of fractional ownership of working interests in gross acres equals one.

	Gross	Net
Developed Acreage	184,877	115,790
Undeveloped Acreage	5,710,074	4,301,168
Total	5,894,951	4,416,958

The following table sets forth the Company's undeveloped acreage as of December 31, 1999:

	Gross	Net
California	232,455	111,381
Texas	37,955	14,144
Congo, West Africa:		
Marine 1 Permit	38,000	19,000
Ghana, West Africa:		
East Cape Three Points	1,700,000*	1,275,000*
Accra-Keta	2,700,000	2,700,000
Tunisia, North Africa	976,540	170,895
Other	25,124	10,748
Total	5,710,074	4,301,168

* Relinquished in February 2000

Productive Wells

The following table sets forth the Company's gross and net interests in productive oil and gas wells as of December 31, 1999. Productive wells are producing wells and wells capable of production.

	Gross	Net
Oil Wells	2,361	1,743
Gas Wells	110	66
Total	2,471	1,809

Production

The Company's principal production volumes for the year ended December 31, 1999, were from California and the Congo.

Data relating to production volumes, average sales prices, average unit production costs and oil and gas reserve information appears in Note 17 to the

Notes to Consolidated Financial Statements.

Drilling Activity and Present Activities

During the three year period ended December 31, 1999, the Company's principal drilling activities occurred in the continental United States and offshore in state and Federal waters, and offshore the Congo in West Africa.

The Company believes that its demonstrated ability to reduce operating costs to levels well below those of the larger oil and gas companies from which acquisitions have been made allows it to compete successfully in an industry characterized by fluctuating commodity prices.

Between the date of the California Properties acquisition, April 9, 1996, and the end of 1999, the Company drilled 248 wells in the Cymric field in central California, which contained 26% of the Company's total estimated net proved equivalent reserves at December 31, 1999, and anticipates drilling approximately 120 wells during 2000. In the Midway-Sunset field in central California, which contained 13% of the total estimated net proved equivalent

reserves at December 31, 1999, the Company drilled 10 wells during 1999, and plans to drill approximately 45 wells in 2000.

In 1997, the Company drilled an exploration well to evaluate the Lower Sendji and subsalt sections underlying the Masseko structure located several miles to the west of the Yombo field in the Congo, as well as to further delineate the Upper Sendji and Tchala zones, which were discovered but not developed by the previous operator. This well tested at rates over 3,000 gross barrels per day from a newly discovered middle Sendji section. Platform design and development plans are being formulated for Masseko. Other potential exploration features are being evaluated for possible future drilling. Additionally, the Company initiated a waterflood project in the Yombo field to enhance production from existing Upper Sendji and Tchala zones. Plans for 2000 include performing a study to evaluate waterflood performance and to convert up to three wells to water injectors.

The Company's most significant discoveries in 1998 were: (i) four successful wells at Four Isle Dome in Louisiana, which helped increase net production from 0.6 MMCFPD and 35 BOPD at the beginning of 1998 to 7.9 MMCFPD and 170 BOPD at the end of 1998; (ii) two successful wells at Weeks Island, Louisiana, which each resulted in completions producing in excess of 700 BOPD; and (iii) successful extension to the south and east at the Monument Junction reservoir in the Cymric Field in California. In 1997, the Company's exploration program resulted in nine successful wells out of 14 drilled. Discoveries in 1997 included: the Masseko structure offshore Congo, the Monument Junction reservoir in Cymric field, California and Tranquillon Ridge, offshore California.

The Company had nine gross (nine net) wells in progress at December 31, 1999. The following table sets forth the results of drilling activity by the Company, net to its interest, for the last three calendar years. Gross wells, as it applies to wells in the following tables, refers to the number of wells in which a working interest is owned directly by the Company. The number of net wells is the sum of the fractional ownership of working interests owned directly by the Company in gross wells expressed as whole numbers and percentages thereof.

	Exploratory Wells					
	Gross			Net		
	Productive	Dry Holes	Total	Productive	Dry Holes	To
1997	9	5	14	6.63	2.33	8
1998	8	6	14	4.09	3.58	7
1999	--	4	4	--	2.33	2

	Development Wells					
	Gross			Net		
	Productive	Dry Holes	Total	Productive	Dry Holes	To
1997	236	1	237	217.52	1.00	21
1998	155	--	155	134.43	--	13
1999	44	1	45	40.21	0.33	4

Exit Cost Liabilities

With respect to the Company's offshore oil and gas operations in California, the Company has significant exit cost liabilities. These liabilities include costs for dismantlement, rehabilitation and abandonment. As of December 31, 1999, the Company's net liability for these exit costs were approximately $99 million. The Company is not indemnified for any part of these exit costs.

Gas Plant, Pipelines and Other Facilities

As of December 31, 1999, the Company owned interests in the following gas plant facilities:

Facility	State	Operator	Capacity MMCFD	1999 Throughput MMCFD	O I
Stearns Gas Plant	California	Nuevo Energy Company	5	3.2	
HS&P Gas Plant	California	Nuevo Energy Company	13	3.7	

In December 1999, the Company sold the Santa Clara Valley Gas Plant, which is located east of Ventura, California, in connection with the Company's sale of its interest in the non-core properties onshore California.

In December 1997, the Company announced its intention to dispose of the remainder of its non-core gas gathering, pipeline and storage assets during 1998. Such assets included: the Company's 48.5% interest in the Richfield Gas Storage facility, which was sold in February 1998 for proceeds of $2.1 million; an 80% interest in Bright Star Gathering, Inc., which was sold in July 1998 for proceeds of $1.7 million; and the Illini pipeline, which was sold in November 1999 for proceeds of $10.0 million. An agreement to sell the Illini Pipeline was reached in April 1998; however, the approval of the sale was not received from the Illinois Commerce Commission until November 1999. No gains or losses were recognized in connection with these sales. in the Company recorded a non-cash, pre-tax charge to fourth quarter 1997 earnings of $23.9 million, reflecting the estimated loss on the disposition of these assets. A positive revision to this charge was made in the fourth quarter of 1998 in the amount of $3.7 million to reflect the current estimated fair value of the Illini pipeline. The Company's results of operations included operating results from these assets through the disposition date, as applicable; however, these assets were not depreciated subsequent to 1997. The Company retained its remaining two California gas plants, as these plants are strategic assets for the Company's oil and gas activities in California.

On May 2, 1997, Nuevo Liquids, a wholly-owned subsidiary of the Company, sold its 95% interest in the NuStar Joint Venture, which held the Company's investment in the Benedum Plant System, for proceeds of $25.0 million. The Company recognized a pre-tax gain of $2.3 million on this sale. The effective date of this sale was January 1, 1997.

Risk Factors

Recently Low Oil Prices

The Company's financial condition, operating results, future growth and the carrying value of its oil and gas properties are substantially dependent on prevailing oil and gas prices. The Company's ability to maintain or increase its borrowing capacity and to obtain additional capital on attractive terms is also substantially dependent upon oil and gas prices. Beginning in late 1997 and continuing through early 1999, oil prices were very low compared with prices received for oil historically. Oil prices improved significantly during 1999, however, these low prices adversely affected the Company's revenues and operating cash flows during 1998 and early 1999. Any substantial or extended decline in future oil prices would have a material adverse effect on the Company in the future.

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 the control of the Company. 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 Company's carrying value of its proved reserves, borrowing capacity, the Company's ability to obtain additional capital, and its 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 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 the Company's production is California heavy oil. The market price for California heavy oil differs substantially from the established market indices for oil and gas, due principally 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 for 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

The Company's future performance depends upon its ability to find, develop and acquire additional oil and gas reserves that are economically recoverable. Without successful exploration, exploitation or acquisition activities, the Company's reserves and revenues will decline. No assurances can be given that the Company 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 the Company's exploitation and development activities will result in any increases in reserves. The Company's 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

The Company makes, and will continue to make, substantial capital expenditures for the exploitation, exploration, acquisition and production of oil and gas reserves. Historically, the Company has financed these expenditures primarily with cash generated by operations, proceeds from bank borrowings and the proceeds of debt and equity issuances. The Company believes that it will have sufficient cash provided by operating activities and borrowings under its bank credit facility to fund planned capital expenditures. If revenues or the Company's borrowing base decreases as a result of lower oil and gas prices, operating difficulties or declines in reserves, the Company 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 of the Company will depend upon its ability to develop, produce and sell its 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

Nuevo's 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 to the Company 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. Moreover, 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. The Company's 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. The Company 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 the Company's financial condition and results of operations. The Company maintains insurance coverage for its operations, including limited coverage for sudden environmental damages, but does not believe that insurance coverage for environmental damages that occur over time is available at a reasonable cost. Moreover, the Company does not believe that insurance coverage for the full potential liability that could be caused by sudden environmental damages is available at a reasonable cost. Accordingly, the Company may be subject to liability or may lose substantial portions of its properties in the event of certain environmental damages.

Foreign Investments

The Company's 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. The Company attempts to conduct its business and financial affairs so as to protect against political and economic risks applicable to operations in the various countries where it operates, but there can be no assurance the Company will be successful in protecting against such risks.

The Company's 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, the Company 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.

The Company's private ownership of oil and gas reserves under oil and gas leases in the United States differs distinctly from its ownership of foreign oil and gas properties. In the foreign countries in which the Company does 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

During 1999, the Company formalized its policies regarding the management of oil price risk to ensure the Company's ability to optimally manage its portfolio of investment opportunities. In a typical swap transaction, the Company 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, the Company is required to pay the counterparty the difference. The Company would be required to pay the counterparty the difference between such prices regardless of whether the Company's 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, the Company entered into a 15-year contract, effective January 1, 2000, to sell substantially all of its 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 Nuevo produces in California. Therefore, the actual price received as a percentage of NYMEX will vary with the Company's production mix. Based on the Company's current production mix, the price received by Nuevo for its California production is expected to average at approximately 72% of WTI. While the contract does not reduce the Company's exposure to price volatility, it does effectively eliminate the basis differential risk between the NYMEX price and the field price of the Company's California oil production, thereby facilitating Nuevo's ability to hedge its realized prices.

As a result of hedging transactions, oil and gas revenues were reduced by $44.9 million in 1999, increased by $0.6 million in 1998 and reduced by $6.0 million in 1997. For 2000, the Company has entered into swap contracts on 16,500 barrels of oil per day ("BOPD"), at an average West Texas Intermediate ("WTI") price of $17.94 per barrel. The Company has also entered into cost-less collars on an additional 16,500 BOPD, with a floor of $16.00 per barrel and ceiling of $21.21 per barrel. This production is hedged based on a fixed NYMEX price for each type of crude oil that the Company produces in California. As a result of the TOSCO contract, (see Note 13 to the Notes to Consolidated Financial Statements), which fixes the price of the Company's California production at approximately 72% of the NYMEX price effective January 1, 2000, these hedge transactions have the effect on a price basis of hedging substantially all of the Company's current production for the year 2000. Also for the year 2000, the Company has entered into basis swaps on 3,000 BOPD of its production in the Congo, hedging the basis differential between No. 6 fuel oil and WTI at an average differential of $1.88 per barrel. See Item 7a. "Quantitative and Qualitative Disclosures About Market Risk".

Hedge Policy

The Board of Directors adopted a Commodity Hedging Policy which is implemented by management and is periodically assessed by the Governance Committee of the Board. The Company's policy is designed to meet the following goals, during periods with abnormally low commodity prices: (i) assure the Company can generate sufficient operating cash flow to replace reserves that are produced and (ii) to assure compliance with restrictive debt covenants that would otherwise limit the Company's ability to incur additional debt. It is also the Company's policy that significant capital investments whose rates of return are sensitive to future oil and gas prices be protected from exposure to extreme price volatility.

The Company's hedging 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, the Company will hedge so much of its production as is necessary to meet its policy goals for that period. Variations from this approach require Board approval. The Company prohibits hedging activity that is speculative or otherwise increases the Company's risk. The Company recognizes the risks inherent in price management. In order to minimize such risk, the Company has instituted a set of controls addressing approval authority, trading limits and other control procedures. All hedging activity is the responsibility of the Chief Financial Officer. In addition, Internal Audit, which independently reports to the Audit Committee, reviews the Company's price management activity. Competition/Markets for Production

The Company operates 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 standards established by the Company for the minimum projected return on investment, the availability of alternate fuel

sources and the intermediate transportation of gas are factors which affect the Company's ability to compete in the marketplace. The Company's competitors include major integrated oil companies and a substantial number of independent energy companies, many of which possess greater financial and other resources than the Company.

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

Environmental and Other Regulation

The Company's operations are subject to numerous laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. These laws and regulations require the acquisition of a permit before drilling commences, restrict the types, quantities and concentration of various substances that can be released into the environment in connection with drilling and production activities, limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas, and impose substantial liabilities for pollution which might result from the Company's operations. Moreover, the recent trend toward stricter standards in environmental legislation and regulation is likely to continue. For instance, legislation has been proposed in Congress from time to time that would reclassify certain oil and gas exploration and production wastes as "hazardous wastes" which would make the reclassified wastes subject to much more stringent handling, disposal and cleanup requirements. If such legislation were to be enacted, it could have a significant impact on the operating costs of the Company, as well as the oil and gas industry in general. Initiatives to further regulate the disposal of oil and gas wastes are also pending in certain states, and these various initiatives could have a similar impact on the Company. The Company could incur substantial costs to comply with environmental laws and regulations.

The OPA imposes a variety of regulations on "responsible parties" related to the prevention of oil spills. The implementation of new, or the modification of existing, environmental laws or regulations, including regulations promulgated pursuant to the OPA, could have a material adverse impact on the Company.

ITEM 3. LEGAL PROCEEDINGS

The Company has been named as a defendant in the lawsuit Gloria Garcia Lopez and Husband, Hector S. Lopez, Individually, and as successors to Galo Land & Cattle Company v. Mobil Producing Texas & New Mexico, et al. currently pending in the 79th Judicial District Court of Brooks County, Texas (the "Lopez Case"). The plaintiffs, based on pleadings and deposition testimony, allege: i) underpayment of royalties and claim damages, on a gross basis against all working interest owners, of $56.5 million, including interest for the period from 1985 to date; ii) that their production was improperly commingled with gas produced from an adjoining lease, resulting in damages, including interest, of $40.8 million, on a gross basis; (iii) failure to develop, claiming damages and interest of $106.3 million (gross) for interest in the alleged failure to develop; and iv) numerous other claims, including claims for drainage, breach of the implied covenant to reasonably develop the lease, conversion, fraud, emotional distress, lease termination and exemplary damages, that may result in unspecified damages. Nuevo's working interest in these properties is 20%. The Company, along with the other defendants in this case, denies these allegations and is vigorously contesting these claims. Management does not believe that the outcome of this matter will have a material adverse impact on the Company's operating results, financial condition or liquidity.

The Company has been named as defendant in certain other lawsuits incidental to its business. Management does not believe that the outcome of such litigation will have a material adverse impact on the Company's operating results or financial condition. However, these actions and claims in the aggregate seek substantial damages against the Company and are subject to the inherent uncertainties in any litigation. The Company is defending itself vigorously in all such matters.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

There were no matters submitted to a vote of security holders during the fourth quarter of 1999.

NUEVO ENERGY COMPANY

PART II

ITEM 5. MARKET FOR THE REGISTRANT'S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

The principal market on which the Company's Common Stock is traded is the New York Stock Exchange (Symbol: NEV). On March 22, 2000, Nuevo had 17,560,829 shares of common stock outstanding and had reserved 1,936,830 shares of common stock for issuance upon conversion of the TECONS and 2,524,829 shares for issuance pursuant to employee stock options. There were approximately 1,160 stockholders of record and approximately 4,936 additional beneficial owners as of March 22, 2000. The Company has not paid dividends on its Common Stock and does not anticipate the payment of cash dividends in the immediate future as it contemplates the use of cash flows for expansion of its operations. In addition, certain restrictions contained in the Company's financing arrangements restrict the payment of dividends (See Management's Discussion and Analysis of Financial Condition and Results of Operations - Capital Resources and Liquidity and Note 10 to the Notes to Consolidated Financial Statements). The high and low recorded prices of the Company's Common Stock during 1999 and 1998 are presented in the following table:

	Market Price	
	High	Low
Quarter Ended:		
March 31, 1999.....................	$ 16.38	$ 6.13
June 30, 1999......................	$ 18.19	$ 11.63
September 30, 1999.................	$ 18.13	$ 13.50
December 31, 1999..................	$ 19.50	$ 13.63
March 31, 1998.....................	$ 40.56	$ 30.19
June 30, 1998......................	$ 37.81	$ 30.25

September 30, 1998..................	$ 32.75	$ 15.50
December 31, 1998...................	$ 23.50	$ 9.94

Treasury Stock Repurchases

Since December 1997, the Board of Directors of the Company authorized the open market repurchase of up to 3,616,600 shares of outstanding Common Stock at times and at prices deemed appropriate by management. As of December 31, 1999, the Company had repurchased 1,999,100 shares of its Common Stock in open market transactions at an average purchase price, including commissions, of $16.50 per share. As of March 22, 2000, the Company had repurchased 2,610,600 shares at an average purchase price of $16.75 per share, including commissions.

In March 1997, the Board of Directors authorized the open market repurchase of up to 1,000,000 shares of outstanding Common Stock during 1997, at times and prices deemed attractive by management. During April 1997, the Company repurchased 500,000 shares of Common Stock in open market transactions, at an average purchase price of $38.94 per share, plus 42,491 shares acquired from the cancellation of warrants issued during 1996.

Put Options

In May 1997, the Company sold put options on its Common Stock to a third party. The options gave the purchaser the right to sell to the Company 500,000 shares of its Common Stock at prices ranging from $40.26 to $41.04 per share through December 31, 1997. The contract gave the Company the choice of net cash, net shares, or physical settlement. Any repurchased shares would have been treated as Treasury Stock. The Company generated $1.6 million in option premium from these transactions, which is reflected in additional paid-in capital on the balance sheet. As of December 31, 1997, 400,000 of these options had expired with the Company's share prices

above the strike price, and 100,000 of these options were settled on December 31, 1997, for a nominal amount of net cash.

Shareholder Rights Plan

In March 1997, the Company adopted a Shareholder Rights Plan to protect the Company's 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 the prior consent of the Company, or the Company is acquired in a merger or other business combination, or 50% or more of its 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. The Company 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 the Board of Directors of the Company.

On January 10, 2000, the Company amended the Shareholder Rights Plan to provide that if the Company receives and consummates 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

During July 1997, the Board of Directors of the Company adopted a plan to encourage senior executives to personally invest in the shares of the Company, 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 Common Stock of the Company at a discount to market prices or make other investments at the employee's discretion. Stock acquired at a discount will be held in a benefit trust and restricted for a two-year period, and the Plan does not permit investment in a diversified equity portfolio until and unless targeted levels of Common Stock ownership in the Company are achieved and maintained. 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 all executives at a level of Vice-President and above.

ITEM 6. SELECTED FINANCIAL DATA

The following selected financial data with respect to the Company should be read in conjunction with the consolidated financial statements and supplementary information included in Item 8 (amounts in thousands, except per share data).

	As of and for the Years ended December 31			
	1999	1998	1997(4)	1996(4)
Oil and gas revenues..............	$ 239,306	$ 240,010	$ 331,973	$ 279,8
Gas plant revenues................	2,968	2,665	14,826	34,8
Pipeline and other revenues.......	4	2,700	5,772	6,7
Gain on sale of assets, net.......	85,294	5,768	1,372	6,0
Interest and other income.........	4,663	1,560	3,335	1,6
Total revenues..............	332,235	252,703	357,278	329,0
Total costs and expenses before extraordinary item (including income taxes and minority interest)(3)................	300,793	346,975	367,954	294,7
Extraordinary loss on early extinguishment of debt.......	--	--	3,024	

Net income (loss)(1)(5)...........	$ 31,442	$ (94,272)	$ (13,700)	$ 34,2
Net income (loss) attributable to Common stockholders..........	$ 31,442	$ (94,272)	$ (13,700)	$ 33,3
Earnings (loss) per Common Share - Basic(2)....................	$ 1.62	$ (4.76)	$ (0.69)	$ 1.
Earnings (loss) per Common share - Diluted(2)..................	$ 1.61	$ (4.76)	$ (0.69)	$ 1.
Total Assets......................	$ 760,030	$ 817,685	$ 804,286	$ 817,6
Long-term debt, net of current maturities..................	$ 340,750	$ 419,150	$ 305,940	$ 287,0
Company-obligated Mandatorily Redeemable Convertible Preferred Securities of Nuevo Financing I.................	$ 115,000	$ 115,000	$ 115,000	$ 115,0

(1) No Common Stock dividends have been declared since the formation of the Company. See Note 10 to the Notes to Consolidated Financial Statements concerning restrictions on the payment of Common Stock dividends.

(2) Retroactively restated to reflect the adoption of Statement of Financial Accounting Standards (SFAS) No. 128, "Earnings per Share". (See Note 2 to the Notes to Consolidated Financial Statements).

(3) Results for the years ended 1998 and 1997 include impairments of oil and gas properties of $68.9 million and $30.0 million, respectively, and (revision to) provision for impairment on assets held for sale of ($3.7) million and $23.9 million, respectively.

(4) Retroactively restated to reflect the Company's January 1, 1998 conversion from the full cost method to the successful efforts method of accounting for its investments in oil and gas properties. (See Note 2 to the Notes to Consolidated Financial Statements).

(5) The year ended December 31, 1996, includes activity of the California Properties from the date of acquisition (April 9, 1996).

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

Overview

Nuevo, headquartered in Houston, Texas, is primarily engaged in the exploration for, and the acquisition, exploitation, development and production of crude oil and natural gas. The Company's strategy to differentiate itself from its numerous peer group competitors and to generate long term shareholder value consists of: (i) a unique management philosophy that frames all important decisions in terms of anticipated impact on per share (rather than absolute) growth of reserves, production, cash flow and net asset value; (ii) a contrarian investment and financing orientation; (iii) the outsourcing of non-strategic functions; (iv) the alignment of employee compensation structures with shareholder objectives; and (v) a commitment to an exemplary governance structure which reinforces the overarching view of Nuevo as a conduit for shareholders to achieve superior long term capital gains.

Nuevo is an independent energy company. Since its inception in 1990, Nuevo has expanded its operations through a series of disciplined, low-cost acquisitions of oil and gas properties and the subsequent exploitation and development of these properties. The Company has complemented these efforts with strategic divestitures and an opportunistic exploration program, which provides exposure to high-potential prospects. The Company's primary strengths are its track record of rapid reserve growth on a per share basis, achieved at extremely low cost relative to industry averages; its large inventory of exploitation projects in its core areas of operation, which the Company believes will support future growth in reserves and production per share; its demonstrated ability to significantly reduce operating costs from levels experienced by prior operators; its ability to identify and acquire, at attractive prices, long-lived producing properties, which have significant potential for further exploration, exploitation and development; a capital structure supportive of a growing investment program and future acquisitions; and a price risk management policy designed to protect the Company's ability to generate self-sustaining cash flow and to meet the interest coverage tests under the Company's bond indentures.

The Company's results of operations have been significantly affected by fluctuations in oil and gas prices. The Company's success in acquiring oil and gas properties and its ability to maintain or increase production through its exploitation activities have also significantly affected the Company's results. The following table reflects the Company's oil and gas production and its average oil and gas prices (inclusive of crude oil and natural gas price swaps), by oil and gas segment and in total, for the periods presented:

	Year Ended December 31,		
	1999	1998	1997
PRODUCTION:			
Oil (MBBLS):			
East	413	838	878
West	15,272	16,284	14,694
Foreign	1,835	1,461	1,555
Total	17,520	18,583	17,127
Natural gas (MMCF):			
East	3,224	18,816	20,831
West	14,396	13,705	14,794
Total	17,620	32,521	35,625
Natural gas liquids (MBBLS):			
East	62	67	76
West	145	156	206
Total	207	223	282

	Year Ended December 31,		
	1999	1998	1997
AVERAGE SALES PRICE:			
Oil (per barrel):			
East	$ 15.25	$ 12.63	$ 18.95
West	$ 10.44	$ 8.98	$ 14.73
Foreign	$ 16.69	$ 10.82	$ 14.66
Total - exclusive of hedges	$ 13.82	$ 9.26	$ 14.94
Total - hedge effect	$ (2.61)	$ (0.01)	$ (0.08)
Total - net of hedge effect	$ 11.21	$ 9.25	$ 14.86
Natural gas (per MCF):			
East	$ 2.00	$ 1.80	$ 2.08
West	$ 2.33	$ 2.21	$ 2.06
Total - exclusive of hedges	$ 2.27	$ 1.98	$ 2.19
Total - hedge effect	$ --	$ 0.02	$ (0.13)
Total - net of hedge effect	$ 2.27	$ 2.00	$ 2.06
AVERAGE UNIT PRODUCTION COST PER EQUIVALENT BARREL (6 MCF EQUAL 1 BARREL):			
East	$ 2.45	$ 2.88	$ 2.71
West	$ 6.28	$ 5.94	$ 5.53
Foreign	$ 7.01	$ 8.14	$ 7.70
Total	$ 6.15	$ 5.56	$ 5.14

Effective January 1, 1998, the Company elected to convert from the full cost method to the successful efforts method of accounting for its investments in oil and gas properties. The Company believes that the successful efforts method of accounting is preferable, as it will provide a fair presentation of the Company's development activities in its core California business and the drilling success of its selective exploration activities, and reflect an impairment in the carrying value of its oil and gas properties only when there has been a permanent decline in their fair value. Accordingly, all prior year financial statements have been restated to conform to successful efforts accounting. The effect, after tax, of the change in accounting method as of December 31, 1997, was a reduction to retained earnings of $64.1 million, primarily attributable to a decrease in net property and equipment and the deferred tax liability of $99.2 million and $38.0 million, respectively. The change in accounting method resulted in a decrease in net income of $32.5 million ($1.64 per share - basic and diluted) during 1997.

Under the successful efforts method of accounting, 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. An impairment of unproved leasehold costs of $8.1 million was recognized as of December 31, 1998. No such impairment was recognized for the years ended December 31, 1999 or 1997. Exploration costs, including geological and geophysical expenses, exploratory dry holes and delay rentals, are charged to expense as incurred.

Costs of productive wells, development dry holes and productive leases are capitalized and depleted on a unit-of-production basis over the life of the remaining proved reserves. Capitalized drilling costs are depleted on a unit-of-production basis over the life of the remaining proved developed reserves. Estimated costs (net of salvage

value) of dismantlement, abandonment and site remediation are computed by the Company's independent reserve engineers and are included when calculating depreciation and depletion using the unit-of-production method.

The Company reviews proved oil and gas properties on a depletable unit basis whenever events or circumstances indicate that the carrying value of those assets may not be recoverable. For each depletable unit determined to be impaired, an impairment loss equal to the difference between the carrying value and the fair value of the depletable unit is recognized. Fair value, on a depletable unit basis, is estimated to be the value of the undiscounted expected future net revenues computed by application of estimated future oil and gas prices, production and expenses, as determined by management, to estimated future production of oil and gas reserves over the economic life of the reserves. If the carrying value exceeds the undiscounted future net revenues, an impairment is recognized equal to the difference between the carrying value and the discounted estimated future net revenues of that depletable unit. The Company considers all proved reserves and commodity pricing based on market information available at year-end in its estimate of future net revenues. During 1998, the Company recorded a fair value impairment totaling $60.8 million on its East Coalinga, Las Cienegas, Beta, Point Pedernales and South Mountain fields and certain other insignificant oil and gas properties due to the significant, sustained decline in domestic oil prices during the year from an average Company realized price of $14.86 per barrel for 1997 to an average realized price of $9.25 per barrel in 1998. During 1997, the Company recorded a fair value impairment totaling $30.0 million on its Brea Olinda field and certain other insignificant oil and gas properties due to decreases in the fair value of the depletable units attributable to a decline in domestic oil prices. No such impairment was recognized during 1999.

Interest costs associated with non-producing leases and exploration and development projects are capitalized only for the period that activities are in progress to bring these projects to their intended use. The capitalization rates are based on the Company's weighted average cost of funds used to finance expenditures.

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

Financing Activities

The Company had $341.5 million in outstanding indebtedness at December 31, 1999, which is scheduled to mature as follows (amounts in thousands):

2000	$ 750
2001	--
2002	--
2003	81,000
2004	--
Thereafter	259,750
	$ 341,500

In July 1999, the Company authorized a new issuance of $260.0 million of 9 1/2% senior subordinated notes due June 1, 2008 ("9 1/2% Notes"). The Company offered to exchange the new notes for its outstanding $160.0 million of 9 1/2% senior subordinated notes due 2006 ("Old 9 1/2% Notes") and $100.0 million of 8 7/8% senior subordinated notes due 2008 ("8 7/8% Notes"). In August 1999, the Company received tenders to exchange $157.46 million of its Old 9 1/2% Notes and $99.85 million of the 8 7/8% Notes. In connection with the exchange offers, the Company solicited consents to proposed amendments to the indentures under which the old notes were issued. These amendments streamline the Company's covenant structure and provide the Company with additional flexibility to pursue its operating strategy. The exchange was accounted for as a debt modification. As such, the consideration that the Company paid to the holders of the Old 9 1/2% Notes who tendered in the exchange offer (equal to 3% of the outstanding principal amount of the Old 9 1/2% Notes exchanged) was accounted for as deferred financing costs. Also in connection with this exchange offer, the Company 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 the 9 1/2% Notes accrues at the rate of 9 1/2% per annum and is payable semi-annually in arrears on June 1 and December 1. The 9 1/2% Notes are redeemable, in whole or in part, at the option of the Company, on or after June 1, 2003, under certain conditions. The Company is not required to make mandatory redemption or sinking fund payments with respect to the 9 1/2% 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 of 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 Nuevo's subsidiaries but are required to be guaranteed by any subsidiary that guarantees indebtedness ranking equal as to right of payment to the 9 1/2% Notes or subordinated indebtedness. The 9 1/2% Notes are unsecured general obligations of the Company, and are subordinated in right of payment to all existing and future senior indebtedness of the Company. In the event of a defined change in control, the Company will be required to make an offer to repurchase all outstanding 9 1/2% Notes at 101% of the principal amount thereof, plus accrued and unpaid interest to the date of redemption.

In June 1998, the Company issued $100.0 million, 8 7/8% Notes. In August 1999, most of the 8 7/8% Notes, except for $150,000, were exchanged for 9 1/2% Notes. The remaining $150,000 were retired in December 1999. No significant costs were incurred in connection with this early retirement of debt.

Nuevo's Amended and Restated Credit Agreement, (the "Agreement"), dated June 30, 1999, provides for secured revolving credit availability of up to $400.0 million (subject to a semi-annual borrowing base determination) from a bank group led by Bank of America, N.A. and Morgan Guaranty Trust Company of New York, until its expiration on April 1, 2003.

The borrowing base determination establishes the maximum borrowings that may be outstanding under the credit facility, and is determined by a two-thirds vote of the banks (three-fourths in the event of an increase in the borrowing base), each of which bases its judgement on (i) the present value of the Company's oil and gas reserves based on its own assumptions regarding future prices, production, costs, risk factors and discount rates, and (ii) on projected cash flow coverage ratios calculated under varying scenarios. If amounts outstanding under the credit facility exceed the b