Management's Discussion and Analysis of Financial Condition and Results of Operations

Ocean Energy, Inc. (the "Company," "OEI," or "Ocean") is an independent energy company engaged in the exploration, development and production of crude oil and natural gas. North American operations are focused in the shelf and deepwater areas of the Gulf of Mexico, the Rocky Mountains, Permian Basin, Arklatex, Anadarko, East Texas and the Gulf Coast regions. Internationally, Ocean holds a leading position among U.S. independents in West Africa with oil and gas activities in Equatorial Guinea, Angola and Côte d'Ivoire. The Company also conducts operations in Egypt, the Russian Republic of Tatarstan, Brazil, Pakistan and Indonesia.

The Company's accompanying Consolidated Financial Statements contain detailed information that should be referred to in conjunction with the following discussion.

Results of Operations

Ocean achieved its best ever annual financial performance in 2001. Growth in production volumes and higher commodity prices during the first half of the year contributed to net income of $274 million, or $1.53 per diluted share, an increase of 29% from 2000 net income of $213 million, or $1.22 per diluted share. In 2001, revenues from sales of natural gas and crude oil were $1.3 billion, an increase of $182 million, or 17%, over 2000.

Other accomplishments included a 10% year-over-year production increase. The Company's production averaged 149 MBOE per day for 2001 compared to 2000's rate of 135 MBOE per day. Ocean ended the year with a 387% reserve replacement rate and a finding and development cost of $5.52 per BOE.

Oil and Gas Operations
Amounts in Thousands

	YEAR ENDED DECEMBER 31,		
	2001	2000	1999
Oil and Gas Operations:			
Revenues:			
Natural gas	**$ 699,135**	$ 526,417	$ 343,788
Crude oil	**556,331**	547,137	413,777
	1,255,466	1,073,554	757,565
Operating expenses	**307,104**	256,882	239,028
Depreciation, depletion and amortization	**344,342**	304,976	309,699
Impairment of oil and gas properties	**-**	20,066	46,403
Operating profit	**604,020**	491,630	162,435
Corporate	**(37,045)**	(35,070)	(29,689)
Total Operating Profit	**$ 566,975**	$ 456,560	$ 132,746

Revenues

Ocean operates in highly competitive markets where energy prices fluctuate significantly. As oil and gas prices fluctuate, so do the Company's revenues, results of operations and cash flows. Natural gas prices, which were at record levels at the beginning of 2001, declined steadily throughout the year in response to the downturn in the economy, reduced weather-related demand and record gas storage levels. Crude oil prices also declined throughout 2001 as a result of the global economic downturn and decreases in demand that were only partially offset by OPEC's supply constraints.

Natural gas revenues increased $173 million, or 33%, to $699 million for the year ended December 31, 2001, from $526 million for the year ended December 31, 2000. This increase included

(l-r) John Campbell, Vice President – Exploitation, North American Onshore, and Scott Griffiths, Senior Vice President – Exploration and International New Ventures

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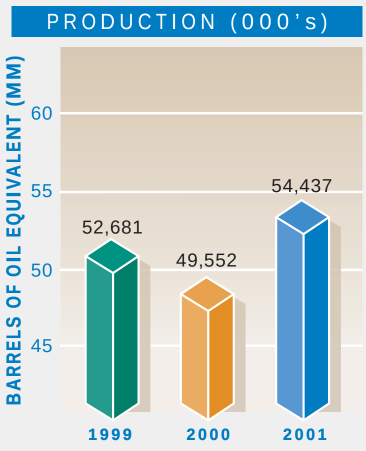
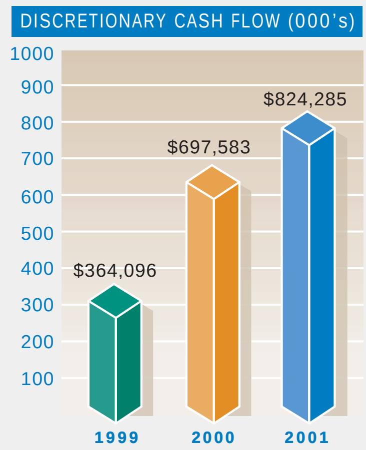
approximately $53 million related to an increase in the average realized price for natural gas, excluding the impact of financial derivatives. The average realized price for natural gas, excluding the impact of financial derivatives, rose 9% to $4.18 per Mcf for 2001 as compared to $3.85 for 2000. Although average realized gas prices were higher for 2001 than for 2000, the average realized price for natural gas, excluding the impact of financial derivatives, was $2.32 for the fourth quarter of 2001. Since most of Ocean's gas reserves and production are in the United States, future natural gas prices will be dependent primarily on the U.S. economic environment, weather patterns and other factors affecting demand, and drilling levels related to supply enhancements.

Natural gas revenues included an increase of $51 million due to an increase in production. Daily natural gas production for 2001 was 443 MMcf, an increase of 9% from 2000 volumes. The increase was due primarily to successful results from U.S. drilling activities and acquisitions of producing properties in Texas and Louisiana during 2001. As drilling expenditures were curtailed in the second half of the year in response to lower market prices for natural gas, gas production rates declined in this period.

Gas revenues were also positively impacted by the use of derivative financial instruments that reduced the Company's exposure to declining gas prices. Natural gas revenues for the year ended December 31, 2001, included a positive net year-over-year change of $69 million relating to the Company's use of derivative financial instruments. The effect of derivative financial instruments on natural gas revenues was $23 million for 2001 as compared to ($46) million for 2000.





Natural gas revenues increased $182 million, or 53%, to $526 million for the year ended December 31, 2000, from $344 million for the year ended December 31, 1999. This increase was due to higher average natural gas prices. The average realized price for natural gas, excluding the impact of financial derivatives, increased 74% to $3.85 per Mcf for 2000 as compared to $2.21 for 1999. Daily natural gas production for 2000 was 407 MMcf, a decrease of 4% from 1999 volumes due primarily to property sales. Natural gas revenues for 2000 included a reduction of $46 million due to the impact of the use of derivative financial instruments.

Total revenues from sales of crude oil remained relatively flat at $556 million for 2001 as compared to $547 million for 2000. Crude oil revenues for 2001 included a price decline of approximately $111 million due to reduced average realized prices for oil, excluding the impact of financial derivatives. Average realized crude oil prices decreased 16% to $21.48 for 2001 compared to $25.51 for 2000. The average realized price for crude oil, excluding the impact of financial derivatives, was $17.03 for the fourth quarter of 2001. Future crude oil prices will depend primarily on global economic conditions and the ability of OPEC to constrain production levels.

Crude oil revenues grew approximately $70 million due to an 11% year-over-year increase in crude oil production. Daily production averaged 75.3 MBbl for 2001 as compared to 67.6 MBbl for 2000. Higher production volumes were attributable to increased exploration and exploitation success from the Gulf of Mexico shelf properties and the Zafiro field in Equatorial Guinea.

(l-r) Earl Reynolds, Senior Vice President – International Operations, and William Flores, Jr., Senior Vice President – Drilling

Operating Data*

	YEAR ENDED DECEMBER 31,		
	2001	2000	1999
Net Daily Natural Gas Production (Mcf):			
Domestic	**416,265**	373,560	375,881
Côte d'Ivoire	**18,943**	23,365	30,273
Other International	**7,590**	9,641	16,246
Total	**442,798**	406,566	422,400
Average Natural Gas Prices ($ per Mcf):			
Domestic	**$ 4.26**	$ 3.95	$ 2.26
Côte d'Ivoire	**$ 2.47**	$ 2.28	$ 1.68
Other International	**$ 4.32**	$ 3.86	$ 1.89
Weighted Average	**$ 4.18**	$ 3.85	$ 2.21
Average Natural Gas Prices Including the Impact of Financial Derivatives ($ per Mcf)	**$ 4.33**	$ 3.54	$ 2.23
Net Daily Oil and NGL Production (Bbl):			
Domestic	**27,864**	27,254	37,076
Equatorial Guinea	**30,442**	22,798	20,062
Côte d'Ivoire	**3,194**	3,849	4,835
Egypt	**8,557**	8,820	8,217
Other International	**5,285**	4,906	3,743
Total	**75,342**	67,627	73,933
Average Oil and NGL Prices ($ per Bbl):			
Domestic	**$ 22.70**	$ 25.85	$ 17.06
Equatorial Guinea	**$ 21.17**	$ 26.06	$ 17.91
Côte d'Ivoire	**$ 22.00**	$ 24.15	$ 18.24
Egypt	**$ 22.18**	$ 26.61	$ 19.32
Other International	**$ 15.40**	$ 20.14	$ 12.32
Weighted Average	**$ 21.48**	$ 25.51	$ 17.38
Average Oil Prices Including the Impact of Financial Derivatives ($ per Bbl)	**$ 20.23**	$ 22.11	$ 15.33

* All price information excludes the impact of financial derivatives, unless otherwise stated.

Oil revenues for 2001 also included a positive net year-over-year change of $50 million relating to the Company's use of derivative financial instruments. The effect of derivative financial instruments on oil revenues was ($34) million for 2001 as compared to ($84) million for 2000.

Oil revenues increased $133 million, or 32%, to $547 million for the year ended December 31, 2000, from $414 million for 1999. This increase was the result of higher crude oil prices partially offset by lower oil production. The average realized price for oil, excluding the impact of financial derivatives, increased 47% to $25.51 during 2000 compared to $17.38 for 1999. Daily oil production decreased 9% to 67.6 MBbl in 2000 as compared to 73.9 MBbl for 1999 primarily due to property sales. Crude oil revenues for 2000 were reduced by $84 million because of the impact of financial derivatives.

Total production for 2001 was 54 MMBOE, a 10% increase over 2000. Average daily production for the full year was 443 MMcf of gas and 75.3 MBbl of oil, or 149 MBOE per day. The Company expects its production to increase during 2002 as a result of new production from the deepwater Nansen and Boomvang fields in the Gulf of Mexico and continued exploitation in the Zafiro field in Equatorial Guinea, net of anticipated declines in areas where the Company has reduced its budgeted capital expenditures, such as in the U.S. onshore and Gulf of Mexico shelf properties.

Total production for 2000 was 50 MMBOE as compared to 53 MMBOE for 1999 due to natural declines and property sales. Average daily production for the full year was 407 MMcf of gas and 67.6 MBbl of oil, or 135 MBOE per day.

Operating Expenses

Total operating expenses increased $50 million, or 19%, to $307 million for 2001 from $257 million for 2000. Lease operating expense increased $37 million due primarily to the 10% increase in production and increased workover expense. Total production and ad valorem taxes increased $11 million, or 26%, from $55 million for 2001 as compared to $44 million for 2000 primarily due to increased

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production, higher sales prices and an increase in the tax rate for the State of Louisiana.

Total operating expense per BOE increased 9% to $5.64 per BOE for the year ended December 31, 2001, compared to $5.18 for 2000, primarily due to a 15% increase in production and ad valorem taxes per BOE and additional workover expense.

Total operating expenses increased $18 million, or 8%, to $257 million for the year ended December 31, 2000, from $239 million for 1999. Operating expenses per BOE increased 14% to $5.18 per BOE for the year ended December 31, 2000, compared to $4.54 per BOE in 1999. Substantially all of the increase per BOE in 2000 was attributable to increases in production taxes resulting from higher realized oil and gas prices.

Depreciation, Depletion and Amortization Expense

Total depreciation, depletion and amortization ("DD&A") expense for oil and gas operations increased $39 million, or 13%, to $344 million for 2001 from $305 million for 2000 due primarily to increased production. DD&A expense per BOE related to oil and gas operations increased 3% to $6.33 per BOE for 2001 as compared to $6.15 per BOE for 2000 primarily due to the effects of property acquisitions, higher estimated future development costs and the geographic mix of production.

Total DD&A expense for oil and gas operations decreased $5 million to $305 million for the year ended December 31, 2000, from $310 million for 1999 primarily due to decreased production. DD&A expense per BOE related to oil and gas operations rose 5% to $6.15 per BOE for the year ended December 31, 2000, from $5.88 per BOE for 1999 primarily due to the effects of property sales, the geographic mix of production and increased estimates of future development costs.

Impairment of Oil and Gas Properties

During the fourth quarter of 2000, the Company recognized an impairment in the amount of $20 million related to the discontinuance of exploration activities in the Republic of Yemen. During 1999, the Company recorded impairments of oil and gas properties of $46 million related primarily to the sale of its Canadian subsidiary and to the discontinuance of exploration activities in Bangladesh and other international locations. The Company had no ceiling test limitations in 2001, 2000 or 1999.

(l-r) Bob Thompson, Vice President and Controller;
Bruce Busmire, Vice President – Investor Relations;
Peggy d'Hemecourt, Vice President – Human Resources

Corporate

Corporate expenditures comprise general and administrative expenses and DD&A expense for non-oil and gas assets.

General and Administrative Expenses

General and administrative expenses increased $2 million, or 7%, to $31 million for the year ended December 31, 2001, compared to $29 million for 2000. This increase was due primarily to increases in compensation costs and increased charitable contributions benefiting victims of a natural disaster in Houston and the September 11 attacks on New York City. On a per BOE basis, general and administrative expenses declined to $0.56 per BOE for 2001 from $0.58 per BOE for 2000.

General and administrative expenses increased $7 million, or 32%, to $29 million for the year ended December 31, 2000, compared to $22 million for 1999. This increase was due primarily to an increase in expense relating to compensation plans that are tied directly to the market price of the Company's common stock.

The Company capitalizes certain employee-related costs that are directly attributable to oil and gas operations. The Company capitalized costs of $58 million, $45 million and $41 million in 2001, 2000 and 1999, respectively.

DD&A

DD&A expense for non-oil and gas assets was approximately $6 million, $6 million and $8 million for the years 2001, 2000 and 1999, respectively.

Other

Interest Expense

Interest expense decreased $12 million, or 16%, to $63 million for the year ended December 31, 2001, from

$75 million in 2000. This decrease was primarily the result of lower average borrowing rates achieved on the Company's outstanding debt due to a refinancing of fixed-rate debt and to a lower average rate applicable to the Company's credit facility during 2001. In addition, interest rate swaps relating to the Company's 7 5/8% and 7 7/8% senior notes reduced interest expense by approximately $3 million in 2001.

Interest expense decreased $31 million, or 29%, to $75 million for the year ended December 31, 2000, from $106 million in 1999. This decrease was the result of the Company's debt reduction program undertaken in 1999 and the increase in the amount of interest capitalized during 2000 ($44 million in 2000 as opposed to $41 million in 1999) due to the increase in the level of capital expenditures.

The Company capitalized interest expense of $45 million, $44 million and $41 million in 2001, 2000 and 1999, respectively.

Merger and Integration Costs

Merger and integration costs of $3 million associated with the merger of Ocean and Seagull Energy Corporation were recorded in the first quarter of 2000 and related primarily to severance costs. Merger and integration costs of $50 million were recorded for the year ended December 31, 1999, and consisted primarily of severance costs, the write-off of certain costs relating to an information technology system and compensation expense related to the vesting of restricted stock.

Income Tax Expense (Benefit)

Income tax expense of $226 million relating to continuing operations was recognized for the year ended December 31, 2001, compared to expense of $165 million for the year ended December 31, 2000. Total income tax expense increased primarily due to higher revenues and operating profit recognized in 2001. The effective income tax rate was 45% for 2001 and 44% for 2000.

Income tax expense of $165 million was recognized for the year ended December 31, 2000, compared to a benefit of $0.1 million for the year ended December 31, 1999. The change in the income tax provision is primarily the result of three factors: (i) significant improvement in operating results; (ii) changes in the nature of deferred tax assets and liabilities due to the Seagull merger and subsequent asset sales; and (iii) the relative significance of international operating results and taxes to the Company's total results of operations.

Dividends

Quarterly stock dividends, which were first declared in December 2000, continued for each quarter of 2001. The Company declared cash dividends on common stock totaling approximately $27 million during 2001. The amount of future dividends for OEI common stock will be determined on a quarterly basis and will depend on earnings, financial condition, capital requirements and other factors.

Liquidity and Capital Resources

Liquidity

One of management's goals has been to reduce the Company's long-term debt levels, resulting in a lower debt to capitalization ratio and reduced interest expense. The Company has lowered its debt to total capitalization ratio significantly since 1999 and has maintained that lower ratio during 2001 even with increased capital spending. The Company's debt to total capitalization ratio was 47% at both December 31, 2001, and December 31, 2000, 58% at December 31, 1999, and 68% at the date of the Seagull merger. With cash flows attributable to asset sales, prepaid oil and gas sales, higher commodity prices and disciplined capital spending, the Company has reduced its long-term debt from a total of nearly $2 billion to $1.3 billion at December 31, 2001. The Company achieved investment grade status from Standard & Poor's and from Moody's Investor Services during 2000 and early 2001, respectively.

In addition, the Company has successfully taken advantage of favorable market conditions to repurchase some of its higher interest rate debt and replace it with lower rate debt, thereby achieving a lower average interest rate for its long-term debt.

Debt Issuances and Repurchases

During 2001, the Company publicly issued $350 million of 7 1/4% senior notes due 2011 pursuant to a shelf registration statement. The proceeds

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were used to repay amounts outstanding under the Company's credit facility and to retire existing higher interest rate debt by exercising call provisions for the Company's $8\frac{5}{8}$% senior subordinated notes due 2005, in the amount of $100 million, and $9\frac{3}{4}$% senior subordinated notes due 2006, in the amount of $1.8 million.

Also during 2001, the Company repurchased on the open market approximately $22 million of its $8\frac{3}{8}$% senior subordinated notes due July 2008 and $25 million of its $8\frac{7}{8}$% senior subordinated notes due July 2007. The repurchase of these notes was funded with available cash balances and borrowings under the Company's existing credit facility.

In connection with the repurchase and the exercise of call provisions, the Company recorded a total after-tax extraordinary loss of approximately $4 million, or ($0.02) per basic and diluted share. The extraordinary loss is net of a current tax benefit of approximately $2 million.

During 1999, the Company repurchased $150 million of its outstanding $10\frac{3}{8}$% senior subordinated notes due 2005 and $158 million of its outstanding $9\frac{3}{4}$% senior subordinated notes due 2006. The repurchase of these notes was funded with available cash balances and borrowings under the credit facility. In connection with this repurchase, the Company recorded an after-tax extraordinary loss of $23 million, or ($0.16) per basic and diluted share. The extraordinary item is net of a current tax benefit of approximately $13 million.

Credit Facility

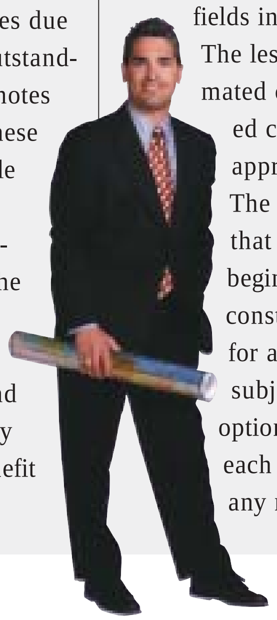
As of December 31, 2001, the Company's credit facility consisted of a $500 million revolving facility due in 2004. The credit facility bears interest, at the Company's option, at LIBOR or prime rates plus applicable margins ranging from zero to 1.7% or at a competitive bid. The average interest rate on the credit facility during 2001 was 5.2%. As of December 31, 2001, borrowings outstanding against the credit facility totaled $50 million. The Company also maintains letters of credit, which totaled $31 million at December 31, 2001. The Company's available borrowing capacity under the credit facility as of December 31, 2001, was $419 million.

Operating Leases

At December 31, 2001, the Company was a party to lease agreements ("Nansen and Boomvang Construction–Period Leases") in which the lessors agreed to construct and lease to the Company two spars that would be used in the development of the Nansen and Boomvang fields in the Gulf of Mexico. The lessors' share of the estimated construction and related costs for the two spars is approximately $170 million. The agreements provided that lease payments were to begin upon completion of construction and continue for a period of three years, subject to certain renewal options. Upon expiration of each lease term, including any renewals, the Company had the option to purchase the leased property for a specified price or to arrange for the sale of the lessors' interest in the spars to a third party. No rental expense was recorded pursuant to these leases for the year ended December 31, 2001, as the spars were still under construction at December 31, 2001.

The Nansen spar was completed and installed in January 2002. In accordance with the terms of the Nansen Construction–Period Lease, the Company arranged for the sale of the lessor's interest in the spar to a third-party purchaser. The Company has entered into a 20-year operating lease ("Nansen Operating Lease") with the purchaser. The Nansen Operating Lease contains various options whereby the Company may purchase the lessor's interest in the spar. Future cash payments under the Nansen Operating Lease will total $2 million, $7 million, $8 million, $11 million and $11 million for the years 2002, 2003, 2004, 2005 and 2006, respectively, and $194 million total for all years thereafter.

The Boomvang spar is scheduled for completion during the third quarter of 2002. The Company has arranged to replace the Boomvang Construction–Period Lease with a 20-year operating lease that is expected to have terms similar to the Nansen Operating Lease and rental payments of less than $1 million in 2002, approximately $3 million in 2003 and averaging approximately $4 million annually thereafter. The Boomvang Operating Lease is also expected to contain an option whereby



Mario Coll, Vice President – Operational Planning and Chief Information Officer the Company may purchase the lessor's interest in the spar. The estimated total construction cost for the lessor's share of the Boomvang spar is approximately $45 million.

Other Financing Transactions

During 2000, the Company entered into a market-sensitive prepaid natural gas sales contract to deliver approximately 53,500 MMBtu per day of natural gas for the period January 2002 through December 2003. In exchange for the natural gas to be provided, the Company received an advance payment of approximately $75 million. The contract has been amended to provide for delivery beginning in January 2003 at a rate of 53,500 MMBtu per day for 2003 and 55,600 MMBtu per day for 2004. To the extent that the Henry Hub price exceeds a stated amount per MMBtu for any delivery month ($2.50 for 2003 and $3.00 for 2004), the purchaser will make payments to the Company equal to the difference between the index price and the stated amount times the delivery quantity for that month.

In 1999, the Company entered into a prepaid crude oil sales contract to deliver approximately 5.6 MBbl per day of crude oil for the period February 2000 through May 2003. In exchange for the crude oil to be provided, the Company received an advance payment of approximately $100 million.

The obligations associated with the future delivery of the natural gas and crude oil have been recorded as deferred revenue. The contracts are amortized into revenue as scheduled deliveries of natural gas and crude oil are made.

Also during 2000, the Company conveyed certain Internal Revenue Code Section 29 Tax Credit-bearing properties to a trust for approximately $70 million, which was recorded in other noncurrent liabilities. The trust receives the operating cash flow from the properties until the investor recoups its investment plus a required after-tax rate of return. The transaction is determined to have an embedded derivative financial instrument as described in Note 12 to the Company's Consolidated Financial Statements.

At December 31, 2001, the Company had increased its estimated proved reserves to 601 MMBOE from 460 MMBOE at December 31, 2000. The increase was the result of a successful drilling program and strategic property acquisitions. The Company replaced 387% of its 2001 production at a finding and development cost of $5.52 per BOE. Excluding acquisitions, the Company experienced a 308% reserve replacement, and a finding and development cost of $5.11 per BOE. The Company's three-year average total finding and development cost including acquisitions is $5.08 per BOE.

Capital expenditures from oil and gas operations, excluding acquisitions, totaled $858 million in 2001, an increase of 52% over amounts spent in 2000. Oil and gas expenditures, excluding acquisitions, totaled $634 million for domestic operations and $224 million for international operations. During 2001, the Company completed a total of 315 gross wells (128 net wells), with an 87% success rate. Of that number, 40 were exploratory wells and 275 were development wells. The success rate for exploratory

Capital Expenditures and Acquisitions
Amounts in Thousands

	YEAR ENDED DECEMBER 31,		
	2001	2000	1999
Oil and Gas Operations:			
Leasehold acquisitions	**$ 93,468**	$ 62,350	$ 34,043
Exploration costs	**352,952**	202,860	148,033
Development costs	**411,624**	300,247	159,831
	858,044	565,457	341,907
Corporate	**18,902**	12,061	20,177
Total Continuing Operations	**876,946**	577,518	362,084
Discontinued Operations	**-**	-	6,942
Total Capital Expenditures	**$ 876,946**	$ 577,518	$ 369,026
Acquisitions	**$ 305,227**	$ 5,598	$ 991,409

James Painter, Senior Vice President – Gulf of Mexico and International Exploration

MD&A

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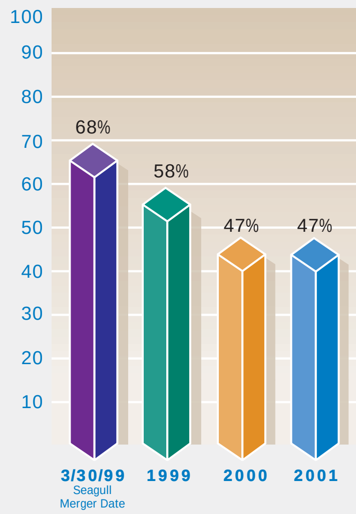
wells was 60%.

Acquisitions in 2001 totaled $305 million and included the purchase of all outstanding shares of stock of Texoil, Inc., an independent oil and gas company, for a cash purchase price of approximately $115 million plus assumed bank debt of $15 million. The Company also purchased oil and gas assets located primarily in East Texas and North Louisiana from Ensight Resources, L.L.C. for a purchase price of approximately $118 million. In addition, the Company recognized a deferred tax liability of approximately $50 million due to the excess of book over tax basis of the oil and gas properties acquired in the purchase of Texoil.

Standardized Measure of Discounted Future Net Cash Flows

The standardized measure of discounted future net cash flows before taxes for the Company's proved oil and gas reserves decreased to $3.4 billion at December 31, 2001, compared with $8.5 billion at the end of 2000. These amounts are calculated based on Securities and Exchange Commission ("SEC") criteria. The decrease was due to reduced price assumptions partially offset by reserve additions. Year-end calculations were made using weighted average year-end prices of $2.64 and $8.81 per Mcf for gas and $17.23 and $22.97 per Bbl for oil for 2001 and 2000, respectively. The Company's average realized prices, excluding the impact of financial derivatives, were $4.18 and $3.85 per Mcf for gas and $21.48 and $25.51 per Bbl for oil for 2001 and 2000, respectively. Significant changes can occur in these estimates based upon oil and gas prices in effect at year end. The above estimates should not be viewed as an estimate of fair market value. See Note 19 to the Company's Consolidated Financial Statements.

DEBT TO CAPITALIZATION RATIO (AT 12/31)



2002 Capital Expenditure Budget

The Company's capital expenditure budget for the year 2002 is approximately $650 million. The reduction from the prior year's expenditures reflects the Company's desire to manage expenditures in relation to expected cash flows from operations at a time when the Company is operating in an environment of economic recession and lower commodity prices.

Approximately $300 to $350 million of the 2002 capital expenditure budget will be spent in the Gulf of Mexico where the Company plans to grow its reserve base through the delineation of recent discoveries and additional deepwater exploration. Plans include development activities in five new deepwater fields and further development of the Nansen and Boomvang deepwater fields as well as Gulf of Mexico shelf properties.

Approximately $250 to $275 million of the 2002 capital expenditure budget is allocated to international operations with nearly half of the international budget to be spent in Equatorial Guinea on continued development of the Zafiro field. Additionally, the budget includes plans for development in Egypt and exploration activities in Angola.

Approximately $50 to $75 million of the 2002 capital expenditure budget is allocated to the Company's domestic onshore properties. The Company plans additional development in the Bear Paw field in Montana and in the Arklatex region.

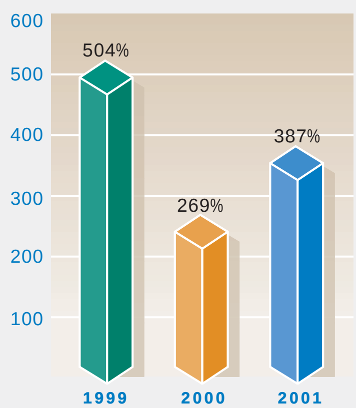
Actual capital spending may vary from the capital expenditure budget and is subject to change if market conditions shift or new opportunities are identified. The 2002 capital expenditure budget was developed using certain assumed price levels for the sales of natural gas and crude oil. Changes in commodity prices could impact the Company's cash flow from operations and funds available for reinvestment. For example, shortfalls in budgeted cash flows from operations could result in the reduction of the Company's capital spending program, increases in borrowing under the cred-

Steve Thorington, Senior Vice President – Finance and Corporate Development it facility or divestments of properties. The Company will evaluate its level of capital spending throughout the year based upon drilling results, commodity prices, cash flows from operations and property acquisitions. In general, the Company's strategy is to maintain capital spending, excluding acquisitions and/or divestments, at levels near discretionary cash flow (income from continuing operations before DD&A, impairments, deferred taxes and other non-cash operating activities).

The Company makes, and will continue to make, substantial capital expenditures for the acquisition, exploration, development and production of its oil and gas reserves. The Company has historically funded its expenditures from cash flow from operating activities, bank borrowings, sales of equity and debt securities, sales of non-strategic oil and gas properties, sales of partial interests in exploration concessions and project finance borrowings. The Company intends to finance capital expenditures for the year 2002 primarily with cash flow provided by operations.

The ability of the Company to satisfy its obligations and fund planned capital expenditures will be dependent upon its future performance. Such future performance is subject to many conditions that are beyond the Company's control, particularly oil and gas prices, and the Company's ability to obtain additional debt and equity financing, if necessary. In addition, where the Company is not the majority owner and/or operator of the venture, it may have limited control over the timing or amount of capital expenditures associated with the particular project. The Company currently expects that its cash flow from operations and availability under the credit facility will be adequate to execute its business plan for the year 2002. No assurance can be given that the Company will not experience liquidity problems from time to time or on a long-term basis. If the Company's cash flow from operations and availability under the credit facility are not sufficient to satisfy its cash requirements, there can be no assurance that additional debt or equity financing will be available to meet its requirements.

RESERVE REPLACEMENT (%)



Commodity Pricing

Changes in commodity prices significantly affect the Company's capital resources, liquidity and expected operating results. Price changes directly affect revenues and can indirectly impact expected production by changing the amount of funds available to reinvest in exploration and development activities. The prices the Company receives for its crude oil production are based on global market conditions. The prices the Company receives for its natural gas production are primarily driven by North American market forces. Oil and gas prices have fluctuated significantly in recent years in response to numerous economic, political and environmental factors. During the second half of 2001, prices declined due to a weakening commodity environment in the midst of a global recession. Prices are also affected by weather, factors of supply and demand, and commodity inventory levels. The Company expects that commodity prices will continue to fluctuate significantly in the future.

The Company has utilized and expects to continue to utilize derivative financial instruments with respect to a portion of its oil and gas production to achieve a more predictable cash flow by reducing its exposure to price fluctuations. Cash flow hedges are maintained at levels which management considers necessary to manage its cash flow in support of the 2002 capital expenditure budget. See Notes 2 and 13 to the Company's Consolidated Financial Statements.

Disclosures About Contractual Obligations and Commercial Commitments

The following table sets forth the Company's obligations and commitments to make future payments under its debt agreements, lease agreements, transportation agreements and other long-term obligations as of December 31, 2001:

Management's Discussion and Analysis of Financial Condition and Results of Operations

Contractual Obligations

Amounts in Thousands

	PAYMENTS DUE BY PERIOD				
	Total	Less than 1 Year	1-3 Years	4-5 Years	After 5 Years
Principal Payments on Long-Term Debt	$ 1,310,766	$ 1,132	$ 278,763	$ 177,139	$ 853,732
Interest Payments on Long-Term Debt	969,345	101,781	276,764	156,088	434,712
Operating Leases:					
Office space and equipment	34,000	9,000	21,000	4,000	-
Nansen Operating Lease (1)	233,000	2,000	26,000	22,000	183,000
Boomvang Construction-Period Lease	50,000	2,000	48,000	-	-
Future Minimum Transportation Payments	11,629	5,539	3,045	2,030	1,015
Total Contractual Cash Obligations	2,608,740	121,452	653,572	361,257	1,472,459
Other Long-Term Obligations:					
Deferred Revenue (2)	116,294	29,749	86,545	-	-
Conveyance of Section 29 properties (3)	52,342	13,750	31,066	7,526	-
Total Contractual Obligations	$ 2,777,376	$ 164,951	$ 771,183	$ 368,783	$ 1,472,459

(1) The Nansen Operating Lease became effective in January 2002.
(2) Represents amortization of forward sales as product is delivered.
(3) Represents estimates of proceeds from related trust properties as payments for obligation.

Other Commercial Commitments

Amounts in Thousands

	AMOUNT OF COMMITMENT EXPIRATION PER PERIOD				
	Total Amount Committed	Less than 1 Year	1-3 Years	4-5 Years	After 5 Years
Standby Letters of Credit	$ 31,148	$ 18,723	$ 12,425	$ -	$ -
Guarantees	5,926	809	2,690	1,618	809
Total Commercial Commitments	$ 37,074	$ 19,532	$ 15,115	$ 1,618	$ 809

Under the terms of certain joint venture agreements, international production sharing contracts or concession agreements, the Company has commitments to conduct seismic activity or to participate in other exploratory or development activities. Certain agreements are backed by letters of credit or parent company guarantees.

Under certain conditions relating to a change of control, the Company's long-term debt may be subject to a mandatory repurchase offer. In addition, under the terms of the Nansen Operating Lease, the Company would be required to provide a letter of credit or other comparable credit support up to a maximum amount of approximately $36 million if the Company's senior debt credit rating were to be downgraded below investment grade by both Moody's and Standard & Poor's. The amount required to be provided decreases as lease payments are made.

Critical Accounting Policies

Application of generally accepted accounting principles requires the use of estimates, judgments and assumptions that affect the reported amounts of assets and liabilities as of the date of the financial statements and revenues and expenses during the reporting period. In addition, alternatives can exist among various accounting methods. In such cases, the choice of accounting method can also have a significant impact on reported amounts.

The Company's estimates of its proved oil and gas reserve quantities, the application of the full cost method of accounting for the Company's exploration and production activities, the application of standards of accounting for derivative instruments and hedging activities, and the Company's accounting method used for revenue recognition require management to make numerous estimates and judgments.

Full Cost Method of Accounting for Oil and Gas Properties

The Company's exploration and production activities are accounted for using the full cost method. The Company believes that the full cost method is the most appropriate method to use to account for its oil and gas production activities. The Company is conducting significant exploration programs in the Gulf of Mexico and in certain international regions. The full cost method more appropriately treats the costs of entering these ventures as part of an overall investment in discovering and developing proved reserves, and allows for comparable analysis with our peers.

Under the full cost method, all acquisition, exploration and development costs, including certain related employee costs and a portion of interest expense, incurred for the purpose of finding oil and gas are capitalized. These capitalized costs are accumulated in pools on a country-by-country basis. Capitalized costs include the cost of drilling and equipping productive wells, dry hole costs, lease acquisition costs, delay rentals and costs related to such activities. Employee costs associated with production operations and general corporate activities are expensed in the period incurred. Transactions involving sales of reserves in place, unless significant, are recorded as adjustments to oil and gas properties.

Where proved reserves are established, capitalized costs are limited on a country-by-country basis to the sum of the present value of future net cash flows using current unescalated pricing discounted at 10%, related to estimated production of proved reserves and the lower of cost or estimated fair value of unproved properties, all net of expected income tax effects ("ceiling limitation"). To the extent the full cost pool exceeds the ceiling limitation, an impairment is made and additional depreciation, depletion and amortization expense is recorded. The Company did not have any writedowns related to full cost ceiling limitations in 2001, 2000 or 1999. Significant declines in prices, downward revisions in reserves or increases in finding and development costs could result in a ceiling test writedown. Leasehold costs, seismic costs and other costs incurred during the exploration phase are capitalized as unproved property costs. Upon evaluation, these costs are moved to the related full cost pool. Unproved properties whose acquisition costs are not individually significant are aggregated, and the portion of such costs estimated to be ultimately nonproductive, based on experience, is amortized to the full cost pool over an average holding period. Depreciation, depletion and amortization of oil and gas properties is computed on a country-by-country basis using a unit-of-production method based on estimated proved reserves. All costs associated with proved oil and gas properties, including an estimate of future development, restoration, dismantlement and abandonment costs associated therewith, are included in the computation base. The costs of investments in unproved properties and major development projects are excluded from this calculation until the project is evaluated and proved reserves are established or impaired.

In countries where the existence of proved reserves has not yet been determined, leasehold costs, seismic costs and other costs incurred during the exploration phase remain capitalized as unproved property costs until proved reserves have been established or until exploration activities cease. If exploration activities result in the establishment of a proved reserve base, amounts in the unproved property account are reclassified as proved properties and become subject to depreciation, depletion and amortization and the application of the ceiling test. If exploration efforts in a country are unsuccessful in establishing proved reserves and exploration activities cease, the amounts accumulated as unproved costs are charged against earnings as impairments.

Management's Discussion and Analysis of Financial Condition and Results of Operations

Reserves

Estimates of the Company's proved oil and gas reserves are prepared by the Company's engineers in accordance with guidelines established by the SEC. Those guidelines require that reserve estimates be prepared under existing economic and operating conditions with no provisions for increases in commodity prices except by contractual arrangement and assuming continuation of existing operating conditions. Estimation of oil and gas reserve quantities is inherently difficult and is subject to numerous uncertainties. Such uncertainties include the projection of future rates of production and the timing of development expenditures. The accuracy of the estimates depends on the quality of available geological and geophysical data and requires interpretation and judgment. Estimates may be revised either upward or downward by results of future drilling, testing or production. In addition, estimates of volumes considered to be commercially recoverable fluctuate with changes in commodity prices and operating costs. The Company's estimates of its reserves are expected to change as additional information becomes available. An independent petroleum engineering firm reviews at least 80% of the Company's year-end estimates of proved reserves. These reserve estimates have a significant effect on DD&A expense and on the ceiling limitation.

Capitalized Interest and Employee Costs

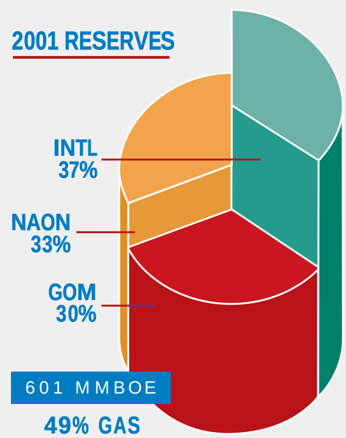
The Company capitalizes a portion of interest expense on borrowed funds and certain employee-related costs incurred for the purpose of finding and developing oil and gas reserves. This practice is in accordance with the full cost method, which requires that all costs associated with property acquisition, exploration and development activities be capitalized. The Company capitalizes interest cost in accordance with Statement of Financial Accounting Standards ("SFAS") No. 34, *Capitalization of Interest Cost*, and SFAS Interpretation No. 33, *Applying FASB Statement No. 34 to Oil and Gas Producing Operations Accounted for by the Full Cost Method*. Employee-related costs which are directly attributable to exploration and development are also capitalized, based on analysis of time spent on these activities. Amounts capitalized can be significant with increasing exploration and major development activities particularly in deepwater areas.

Revenue Recognition

The Company records revenues from the sales of crude oil and natural gas when delivery to the customer has occurred and title has transferred. This occurs when production has been delivered to a pipeline or a tanker lifting has occurred. The Company may have an interest with other producers in certain properties. In this case the Company uses the entitlements method to account for sales of production. Under the entitlements method the Company may receive more or less than its entitled share of production. If the Company receives more than its entitled share of production, the imbalance is treated as a liability. If the Company receives less than its entitled share, the imbalance is recorded as an asset.

Derivative Financial Instruments and Hedging Activities

The Company accounts for its investment in derivative financial instruments in accordance with SFAS



No. 133, *Accounting for Derivative Financial Instruments and Hedging Activities*, as amended. As a result, derivative financial instruments are marked to market quarterly. For derivative instruments designated as cash flow hedges, changes in fair value, to the extent the hedge is effective, are recognized in other comprehensive income until the hedged item is recognized in earnings. The Company does not enter into derivative or other financial instruments for trading purposes. The fair market values of the Company's derivative financial instruments are obtained from third-party counterparties.

Change in Accounting Method

Generally accepted accounting principles, effective January 1, 2001, establish standards of accounting for and disclosures of derivative instruments and hedging activities. See Note 2 to the Company's Consolidated Financial Statements for a discussion of the impact of SFAS No. 133 on the Company's financial position and results of operations as of the date of adoption.

Accounting Pronouncements

In 2001, the Financial Accounting Standards Board issued four new pronouncements:

Statement No. 141, Business Combinations

This statement requires that the purchase method of accounting be used to account for all business combinations and applies to all business combinations initiated after June 30, 2001. The statement also establishes specific criteria for the recognition of intangible assets separately from goodwill. The provisions of this statement would be applied if the Company were to enter into any future business combination. The statement has no impact on the Company's historical financial statements.

Statement No. 142, Goodwill and Other Intangible Assets

This statement requires that goodwill will no longer be amortized but tested for impairment at least annually. Other intangible assets are to be amortized over their useful lives and reviewed for impairment. An intangible asset with an indefinite useful life will not be amortized until its useful life becomes determinable. The effective date of this statement is January 1, 2002. The provisions of this statement would be applied if the Company were to enter into any future business combination pursuant to which goodwill or other intangible assets were recognized. The statement has no impact on the Company's historical financial statements.

Statement No. 143, Accounting for Asset Retirement Obligations

This statement ("SFAS No. 143") requires entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred and a corresponding increase in the carrying amount of the related long-lived asset. The Company will be required to adopt SFAS No. 143 effective January 1, 2003, using a cumulative effect approach to recognize transition amounts for asset retirement obligations, asset retirement costs and accumulated depreciation. The Company currently records estimated costs of dismantlement, removal, site reclamation and similar activities as part of its depreciation, depletion and amortization for oil and gas properties without recording a separate liability for such amounts. The Company has not yet completed its assessment of the impact of SFAS No. 143 on its financial condition and results of operations. It expects that adoption of the statement will result in increases in the capitalized costs of its oil and gas properties and in the recognition of additional liabilities related to asset retirement obligations.

Statement No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets

This statement ("SFAS No. 144") retains the fundamental provisions of SFAS No. 121, *Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed Of* ("SFAS No. 121"), for recognizing and measuring impairment losses while resolving significant implementation issues associated with SFAS No. 121. SFAS No. 144 also expands the basic provisions of APB Opinion No. 30, *Reporting the Results of Operations – Reporting the Effects of Disposal of a Segment of a Business, and Extraordinary, Unusual and Infrequently Occurring Events and Transactions,* regarding presentation of discontinued operations in the income statement. The scope for reporting a discontinued operation has been expanded to include a "component" of an entity. A component comprises operations and cash flows that can be clearly distinguished from the rest of the entity. It could be a segment, a reporting unit, a consolidated subsidiary or an asset group.

The Company adopted SFAS No.

144 as of January 1, 2002. Because the Company has elected the full cost method of accounting for oil and gas exploration and development activities, the impairment provisions of SFAS No. 144 do not apply to the Company's oil and gas assets. For the Company's non-oil and gas assets, the method of impairment assessment is largely unchanged from SFAS No. 121. The adoption of SFAS No. 144 had no impact on the Company's financial statements.

Environmental

Compliance with applicable environmental and safety regulations by the Company has not required any significant capital expenditures or materially affected its business or earnings. The Company believes it is in substantial compliance with environmental and safety regulations and foresees no material expenditures in the future; however, the Company is unable to predict the impact that compliance with future regulations may have on its capital expenditures, earnings and competitive position.

Forward-Looking Statements May Prove Inaccurate

This document contains "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934, and information that is based on management's belief and assumptions made by management based on currently available information. All statements other than statements of historical fact included in this document are forward-looking statements. When used in this document, words such as "anticipate," "believe," "estimate," "expect," "forecast," "intend," "project" and similar expressions serve to identify forward-looking statements. Although we believe that the expectations reflected in our forward-looking statements are reasonable, we can give no assurance that these expectations will prove correct. Our forward-looking statements are subject to risks, uncertainties and assumptions. Should one of these risks or uncertainties materialize, or should underlying assumptions prove incorrect, our actual results may vary materially from those expected. Among the key factors that may have a direct bearing on our results of operations and financial condition are:

- competitive practices in the oil and gas industry;
- geological, mechanical and economic risk inherent in the drilling and operation of exploratory and development wells;
- risk of non-cash writedown of unproved property costs in countries where proved reserves have not yet been established;
- risk of non-cash writedown of proved property costs due to declines in prices, downward revisions in reserves or significant increases in finding and development costs;
- volatility of energy commodity prices, generally, and fluctuations in the commodity prices for crude oil and natural gas that have not been properly hedged;
- general economic and capital markets conditions, including fluctuations in interest rates;
- the impact of current and future laws and governmental regulations, particularly environmental regulations, affecting the energy industry in general, and our oil and gas operations in particular;
- environmental liabilities that are not covered by insurance or indemnity;
- the political and economic climate in the foreign jurisdictions in which we conduct oil and gas operations, including potential adverse results of military or terrorist actions in those areas; and
- the effect on our results of operations and financial condition associated with implementing various accounting rules and regulations.

Defined Terms

Natural gas is stated herein in billion cubic feet ("Bcf"), million cubic feet ("MMcf") or thousand cubic feet ("Mcf"). Oil, condensate and natural gas liquids ("NGL") are stated in barrels ("Bbl") or thousand barrels ("MBbl"). Oil, condensate and NGL are converted to gas at a ratio of one barrel of liquids per six Mcf of gas. MMBOE, MBOE and BOE represent one million barrels, one thousand barrels and one barrel of oil equivalent, respectively, with six Mcf of gas converted to one barrel of liquid. MMBtu and BBtu are one million British Thermal Units and one billion British Thermal Units, respectively.

Selected Quarterly Financial Data

Summarized quarterly financial data is as follows:

Selected Quarterly Financial Data
Amounts in Thousands Except Per Share Data

	QUARTER ENDED			
	March 31	June 30	September 30	December 31
2001:				
Revenues	**$ 403,255**	**$ 355,842**	**$ 279,021**	**$ 217,348**
Operating Profit	**$ 240,095**	**$ 175,374**	**$ 100,143**	**$ 51,364**
Income Before Extraordinary Item	**$ 123,384**	**$ 84,007**	**$ 47,843**	**$ 22,523**
Earnings Per Share Before Extraordinary Item:				
Basic(1)	**$ 0.73**	**$ 0.49**	**$ 0.28**	**$ 0.13**
Diluted (1)	**$ 0.70**	**$ 0.47**	**$ 0.27**	**$ 0.13**
Net Income	**$ 123,384**	**$ 81,407**	**$ 47,843**	**$ 21,150**
Earnings Per Share:				
Basic(1)	**$ 0.73**	**$ 0.47**	**$ 0.28**	**$ 0.12**
Diluted (1)	**$ 0.70**	**$ 0.46**	**$ 0.27**	**$ 0.12**
2000:				
Revenues	$ 251,408	$ 241,873	$ 267,837	$ 312,436
Operating Profit (2)	$ 100,046	$ 99,637	$ 120,642	$ 136,235
Net Income (2)	$ 42,978	$ 45,493	$ 57,869	$ 66,864
Earnings Per Share:				
Basic (1)	$ 0.25	$ 0.27	$ 0.34	$ 0.39
Diluted (1)	$ 0.25	$ 0.26	$ 0.33	$ 0.38

(1) Quarterly earnings per common share may not total to the full year per share amount, as the weighted average number of shares outstanding for each quarter fluctuated as a result of the assumed exercise of stock options.

(2) Includes pre-tax impairment of oil and gas assets of $20 million in the fourth quarter of 2000 and merger and integration costs of $3 million in the first quarter of 2000.

Market Risk Disclosures

The Company experiences market risks in two major areas: commodity prices and interest rates. Because the U.S. dollar is the functional currency for all of the Company's existing foreign operations, with predominantly all transactions being denominated in U.S. dollars, the Company currently has limited risk from foreign currency translation.

Commodity Price Risk

The Company experiences market risk primarily in the area of commodity prices. The Company has utilized derivative financial instruments with respect to a portion of its 2002 oil and gas production to achieve a more predictable cash flow by reducing its exposure to price fluctuations. The Company does not enter into derivative or other financial instruments for trading purposes.

At December 31, 2001, the Company had in place collars covering portions of its 2002 oil and gas production. The gas collars, which are for the period January through December 2002, cover contracted volumes of 140 MMcf per day of natural gas with a weighted average floor price of $2.82 and a weighted average ceiling price of $4.07. Oil collars, which are also for the period January through December 2002, cover contracted volumes of 15 MBbl per day of oil with a floor price of $23.00 and a weighted average ceiling price of $28.03. A related trust has a swap agreement covering gas production through 2005. The quantities covered are 13,500 MMBtu per day at $4.12 for 2002, 11,100 MMBtu per day at $3.60 for 2003, 9,600 MMBtu per day at $3.41 for 2004 and 8,300 MMBtu per day at $3.28 for 2005. These instruments have been designated as cash flow hedges. See Notes 2 and 13 to the Company's Consolidated Financial Statements for a description of the Company's accounting policies for derivative financial instruments and for additional information regarding the derivative financial instruments to which the Company was a party at December 31, 2001.

The Company also had in place two crude oil basis swap contracts at December 31, 2001, to fix the sales price differential between WTI and

MD&A

Management's Discussion and Analysis of Financial Condition and Results of Operations

Brent. The contracts, which extend through May 2002 and relate to 20 MBbl per day, provide that the Company receive/pay a net settlement of WTI less Brent less $1.29. These instruments have not been designated as cash flow hedges.

To calculate the potential effect of the derivative financial instruments on future revenues, the Company applied the average NYMEX oil and gas strip prices as of the end of 2001 to the quantity of the oil and gas production covered by derivative financial instruments at December 31, 2001. The following table shows the estimated potential effects of the derivative financial instruments on revenues (in millions):

Instrument	Period Hedged	Estimated Increase in Revenues at Current Prices	Estimated Increase in Revenues with 10% Decrease in Prices	Estimated Increase in Revenues with 10% Increase in Prices
Oil collars	2002	$ 14	$ 25	$ 2
Gas collars	2002	$ 6	$ 16	$ 1
Gas swap of related trust	2002-2005	$ 9	$ 14	$ 4

Subsequent to December 31, 2001, the Company entered into crude oil collars for the period April through December 2002. The contracts cover 20 MBbl of crude oil per day with a weighted average floor price of $21.875 and a weighted average ceiling price of $26.275.

All derivative financial instruments outstanding at December 31, 2000, except for the gas swap of a related trust noted above, have expired. The effect of derivative financial instruments outstanding at December 31, 2000 was an $11 million decrease in revenues during 2001.

Interest Rate Risk

The Company has minimal exposure to risk resulting from changes in interest rates because substantially all debt obligations at December 31, 2001, were at fixed interest rates. At December 31, 2001, the Company had long-term debt outstanding of $1.3 billion. Of this amount, 96% is fixed rate debt. Approximately $50 million of debt outstanding at December 31, 2001, represents borrowings outstanding under the Company's credit facility and bears interest at floating rates, which averaged 5.2% for 2001.

The Company evaluated the potential effect that reasonably possible near-term changes in interest rates may have on the Company's credit facility. Utilizing the actual interest rate in effect and balance outstanding as of December 31, 2001, and assuming a 10% increase or decrease in interest rates and no change in the amount of debt outstanding, the potential effect on annual interest expense is approximately $250,000.

At December 31, 2001, the Company was party to interest rate swap agreements relating to its 7 5/8% senior notes due July 2005 and its 7 7/8% senior notes due August 2003. Under the terms of the agreements, the counterparties pay the Company a weighted average fixed annual rate of 7.74% on total notional amounts of $225 million, and the Company pays the counterparties a variable annual rate equal to the average six-month LIBOR rate plus a weighted average rate of 2.73%. The swap agreements remain in effect through the maturity dates of the respective notes.

Report of Management to Stockholders

The management of Ocean Energy, Inc. is responsible for the preparation and integrity of financial statements and related data in this Annual Report, whether audited or unaudited. The financial statements were prepared in conformity with generally accepted accounting principles and include certain estimates and judgments that management believes are reasonable under the circumstances.

Management is also responsible for and maintains a system of internal accounting controls that is designed to provide reasonable assurance that assets are safeguarded against loss or unauthorized use and that financial records are reliable for preparing financial statements, as well as to prevent and detect fraudulent financial reporting. The internal control system is supported by written policies and procedures and the employment of trained, qualified personnel. The Company has an internal audit function that reviews the adequacy of the internal accounting controls and compliance with them. Management has considered the recommendations of internal audit and KPMG LLP, independent certified public accountants, concerning the Company's system of internal controls and has responded appropriately to those recommendations.

KPMG LLP, independent certified public accountants, have audited the accompanying consolidated financial statements of Ocean Energy, Inc. as of December 31, 2001, and their report is included herein. Their audit was made in accordance with generally accepted auditing standards and included a review of the system of internal controls to the extent considered necessary to determine the audit procedures required to support their opinion on the consolidated financial statements.

The Board of Directors, through its Audit Committee composed exclusively of outside directors, meets periodically with representatives of management, internal audit and the independent auditors to ensure the existence of effective internal accounting controls and that financial information is reported accurately and timely with all appropriate disclosures included. The independent auditors and internal audit have full and free access to, and meet with, the Audit Committee, with and without management present.

James T. Hackett
Chairman of the Board,
President and Chief
Executive Officer

William L. Transier
Executive Vice President
and Chief Financial Officer

Robert L. Thompson
Vice President and
Controller

January 24, 2002

Independent Auditors' Report

The Board of Directors and Stockholders
Ocean Energy, Inc.:

We have audited the accompanying consolidated balance sheets of Ocean Energy, Inc. and subsidiaries as of December 31, 2001 and 2000, and the related consolidated statements of operations, stockholders' equity and cash flows for each of the years in the three-year period ended December 31, 2001. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Ocean Energy, Inc. and subsidiaries as of December 31, 2001 and 2000, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2001 in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the consolidated financial statements, effective January 1, 2001, the Company changed its method of accounting for derivative financial instruments.

KPMG LLP

KPMG LLP

Houston, Texas
January 24, 2002

Consolidated Statements of Operations

Amounts in Thousands Except Per Share Data

	YEAR ENDED DECEMBER 31,		
	2001	2000	1999
Revenues	**$ 1,255,466**	$ 1,073,554	$ 757,565
Costs of Operations:			
Operating expenses	**307,104**	256,882	239,028
Depreciation, depletion and amortization	**350,805**	311,383	317,487
Impairment of oil and gas properties	**-**	20,066	46,403
General and administrative	**30,582**	28,663	21,901
	688,491	616,994	624,819
Operating Profit	**566,975**	456,560	132,746
Other (Income) Expense:			
Interest expense	**62,707**	75,065	106,081
Merger and integration costs	**-**	3,273	49,603
Interest income and other	**309**	132	(1,314)
Income (Loss) Before Income Taxes	**503,959**	378,090	(21,624)
Income Tax Expense (Benefit)	**226,204**	164,887	(72)
Income (Loss) From Continuing Operations	**277,755**	213,203	(21,552)
Income From Discontinued Operations, Net of Income Taxes	**-**	-	1,127
Income (Loss) Before Extraordinary Loss	**277,755**	213,203	(20,425)
Extraordinary Loss, Net of Income Taxes	**3,973**	-	23,413
Net Income (Loss)	**273,782**	213,203	(43,838)
Preferred Stock Dividends	**3,250**	3,250	3,264
Net Income (Loss) Available to Common Stockholders	**$ 270,532**	$ 209,953	$ (47,102)
Basic Earnings (Loss) Per Common Share:			
Income (Loss) From Continuing Operations	**$ 1.61**	$ 1.26	$ (0.16)
Income From Discontinued Operations, Net of Income Taxes	**-**	-	0.01
Extraordinary Loss, Net of Income Taxes	**(0.02)**	-	(0.16)
Net Income (Loss) to Common Stockholders	**$ 1.59**	$ 1.26	$ (0.31)
Diluted Earnings (Loss) Per Common Share:			
Income (Loss) From Continuing Operations	**$ 1.55**	$ 1.22	$ (0.16)
Income From Discontinued Operations, Net of Income Taxes	**-**	-	0.01
Extraordinary Loss, Net of Income Taxes	**(0.02)**	-	(0.16)
Net Income (Loss)	**$ 1.53**	$ 1.22	$ (0.31)
Cash Dividends Declared Per Common Share	**$ 0.16**	$ 0.04	$ -
Weighted Average Number of Common Shares Outstanding:			
Basic	**170,178**	167,144	151,022
Diluted	**178,416**	174,749	151,022

See accompanying Notes to Consolidated Financial Statements.

Consolidated Balance Sheets

Amounts in Thousands Except Share Data

	DECEMBER 31, 2001	DECEMBER 31, 2000
ASSETS		
Current Assets:		
Cash and cash equivalents	**$ 20,006**	$ 23,039
Accounts receivable, net	**135,204**	222,478
Other current assets	**99,518**	79,037
Total Current Assets	**254,728**	324,554
Property, Plant and Equipment, at cost, full cost method for oil and gas properties:		
Proved oil and gas properties	**5,063,614**	4,106,791
Oil and gas properties excluded from amortization	**774,888**	573,412
Other	**172,701**	157,258
	6,011,203	4,837,461
Accumulated Depreciation, Depletion and Amortization	**(2,861,917)**	(2,469,511)
	3,149,286	2,367,950
Deferred Income Taxes	**-**	143,820
Other Assets	**65,164**	54,076
Total Assets	**$ 3,469,178**	$ 2,890,400
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities:		
Accounts and note payable	**$ 291,174**	$ 338,172
Accrued interest payable	**39,890**	39,839
Accrued liabilities	**44,230**	15,846
Total Current Liabilities	**375,294**	393,857
Long-Term Debt	**1,282,981**	1,032,564
Deferred Revenue	**116,294**	146,043
Deferred Income Taxes	**133,685**	45,761
Other Noncurrent Liabilities	**88,488**	119,487
Commitments and Contingencies	**-**	-
Stockholders' Equity:		
Preferred stock, $1.00 par value; authorized 10,000,000 shares; issued 50,000 shares	**50**	50
Common stock, $0.10 par value; authorized 520,000,000 shares and 230,000,000 shares, respectively; issued 174,936,240 and 170,069,114 shares, respectively	**17,494**	17,007
Additional paid-in capital	**1,579,899**	1,517,064
Accumulated deficit	**(100,832)**	(343,962)
Treasury stock, at cost; 2,641,640 and 2,754,566 shares, respectively	**(35,654)**	(35,354)
Deferred compensation and other	**(12,540)**	(2,117)
Accumulated other comprehensive income	**24,019**	-
Total Stockholders' Equity	**1,472,436**	1,152,688
Total Liabilities and Stockholders' Equity	**$ 3,469,178**	$ 2,890,400

See accompanying Notes to Consolidated Financial Statements.

Consolidated Statements of Cash Flows

Amounts in Thousands

	YEAR ENDED DECEMBER 31,		
	2001	2000	1999
OPERATING ACTIVITIES:			
Net income (loss)	**$ 273,782**	$ 213,203	$ (43,838)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	**350,805**	311,383	317,487
Impairment of oil and gas properties	**-**	20,066	46,403
Deferred income taxes	**179,146**	142,746	(48,123)
Extraordinary loss, net of taxes	**3,973**	-	23,413
Merger and integration costs	**-**	-	20,529
Other	**16,579**	6,912	20,277
Changes in operating assets and liabilities, net of acquisitions:			
Decrease (increase) in accounts receivable	**100,431**	(52,443)	475
Decrease (increase) in other current assets	**(2,880)**	(24,828)	18,446
Decrease in accounts payable	**(21,404)**	(272)	(51,731)
Amortization of deferred revenue	**(29,748)**	(27,269)	-
Increase (decrease) in accrued expenses and other	**(9,882)**	(3,792)	30,413
Net Cash Provided by Operating Activities	**860,802**	585,706	333,751
INVESTING ACTIVITIES:			
Capital expenditures of continuing operations	**(876,946)**	(577,518)	(362,084)
Acquisition costs, net of cash acquired	**(236,199)**	(5,598)	(33,169)
Proceeds from sales of property, plant and equipment	**63,791**	86,043	704,055
Other	**-**	(9,295)	(6,942)
Net Cash Provided by (Used in) Investing Activities	**(1,049,354)**	(506,368)	301,860
FINANCING ACTIVITIES:			
Proceeds from debt	**2,356,419**	1,552,865	1,543,601
Principal payments on debt	**(2,162,529)**	(1,805,744)	(2,186,852)
Proceeds from exercise of common stock options	**36,225**	21,355	2,813
Dividends paid	**(30,453)**	(3,250)	(3,264)
Purchase of treasury stock	**(6,671)**	(32,217)	(2,840)
Premiums paid on debt buy back	**(4,984)**	-	(28,837)
Increase in deferred revenue	**-**	74,947	100,000
Proceeds from conveyance of Section 29 credit properties	**-**	69,644	-
Other	**(2,488)**	1,212	(6,049)
Net Cash Provided by (Used in) Financing Activities	**185,519**	(121,188)	(581,428)
Increase (Decrease) in Cash and Cash Equivalents	**(3,033)**	(41,850)	54,183
Cash and Cash Equivalents at Beginning of Year	**23,039**	64,889	10,706
Cash and Cash Equivalents at End of Year	**$ 20,006**	$ 23,039	$ 64,889

See accompanying Notes to Consolidated Financial Statements.

Consolidated Statements of Stockholders' Equity

Financial Statements

Amounts in Thousands

	Preferred Stock	Common Stock	Additional Paid-In Capital	Accumulated Deficit
Balance, January 1, 2001	**$ 50**	**$ 17,007**	**$ 1,517,064**	**$ (343,962)**
Exercise of common stock options and employee stock purchases	**-**	**408**	**32,008**	**-**
Treasury stock purchase	**-**	**-**	**-**	**-**
Deferred compensation	**-**	**79**	**13,808**	**-**
Amortization of deferred compensation	**-**	**-**	**-**	**-**
Preferred stock dividends	**-**	**-**	**-**	**(3,250)**
Common stock dividends	**-**	**-**	**-**	**(27,402)**
Tax benefit from exercise of stock options	**-**	**-**	**15,049**	**-**
Funding of supplemental benefit plans trust	**-**	**-**	**1,582**	**-**
Transfer of supplemental benefit plans trust obligation	**-**	**-**	**-**	**-**
Other	**-**	**-**	**388**	**-**
Comprehensive income:				
Net income	**-**	**-**	**-**	**273,782**
Other comprehensive income (net of tax):				
Cumulative effect of accounting change for derivative financial instruments	**-**	**-**	**-**	**-**
Net effect of derivative financial instruments	**-**	**-**	**-**	**-**
Other	**-**	**-**	**-**	**-**
Balance, December 31, 2001	**$ 50**	**$ 17,494**	**$ 1,579,899**	**$ (100,832)**
Balance, January 1, 2000	$ 50	$ 16,699	$ 1,484,688	$ (547,216)
Exercise of common stock options	-	282	24,449	-
Treasury stock purchase	-	-	-	-
Deferred compensation	-	26	2,481	-
Amortization of deferred compensation	-	-	(25)	-
Preferred stock dividends	-	-	-	(3,250)
Common stock dividends declared	-	-	-	(6,699)
Other	-	-	5,471	-
Comprehensive income:				
Net income	-	-	-	213,203
Balance, December 31, 2000	$ 50	$ 17,007	$ 1,517,064	$ (343,962)
Balance, January 1, 1999	$ 1	$ 1,018	$ 892,339	$ (500,114)
Effect of Seagull Merger	49	15,621	588,088	-
Exercise of common stock options	-	60	3,303	-
Treasury stock purchase	-	-	-	-
Contribution to ESOP	-	-	(236)	-
Amortization of deferred compensation	-	-	-	-
Preferred stock dividends	-	-	-	(3,264)
Other	-	-	1,194	-
Comprehensive income (loss):				
Net loss	-	-	-	(43,838)
Other comprehensive income:				
Foreign currency translation adjustment:				
Income arising during the year	-	-	-	-
Reclassification adjustment	-	-	-	-
Net foreign currency translation adjustment	-	-	-	-
Balance, December 31, 1999	$ 50	$ 16,699	$ 1,484,688	$ (547,216)

See accompanying Notes to Consolidated Financial Statements.

Treasury Stock	Deferred Compensation and Other	Accumulated Other Comprehensive Income	Total Stockholders' Equity	Comprehensive Income (Loss)
$ (35,354)	**$ (2,117)**	**$ -**	**$ 1,152,688**	
-	**-**	**-**	**32,416**	
(6,671)	**-**	**-**	**(6,671)**	
-	**(13,887)**	**-**	**-**	
-	**3,380**	**-**	**3,380**	
-	**-**	**-**	**(3,250)**	
-	**-**	**-**	**(27,402)**	
-	**-**	**-**	**15,049**	
6,343	**(7,925)**	**-**	**-**	
-	**7,868**	**-**	**7,868**	
28	**141**	**-**	**557**	
-	**-**	**-**	**273,782**	**$ 273,782**
-	**-**	**(14,262)**	**(14,262)**	**(14,262)**
-	**-**	**38,701**	**38,701**	**38,701**
-	**-**	**(420)**	**(420)**	**(420)**
$ (35,654)	**$ (12,540)**	**$ 24,019**	**$ 1,472,436**	**$ 297,801**
$ (3,114)	$ (3,412)	$ -	$ 947,695	
-	-	-	24,731	
(32,217)	-	-	(32,217)	
-	(2,507)	-	-	
-	1,141	-	1,116	
-	-	-	(3,250)	
-	-	-	(6,699)	
(23)	2,661	-	8,109	
-	-	-	213,203	$ 213,203
$ (35,354)	$ (2,117)	$ -	$ 1,152,688	$ 213,203
$ -	$ (5,581)	$ (10,720)	$ 376,943	
(4,293)	(4,261)	-	595,204	
-	-	-	3,363	
(2,840)	-	-	(2,840)	
4,019	849	-	4,632	
-	5,581	-	5,581	
-	-	-	(3,264)	
-	-	-	1,194	
-	-	-	(43,838)	$ (43,838)
-	-	-	-	981
-	-	-	-	9,739
-	-	10,720	10,720	10,720
$ (3,114)	$ (3,412)	$ -	$ 947,695	$ (33,118)

1. Organization

Ocean Energy, Inc. (the "Company," "OEI," or "Ocean") is an independent energy company engaged in the exploration, development and production of crude oil and natural gas. North American operations are focused primarily in the shelf and deepwater areas of the Gulf of Mexico, the Rocky Mountains, the Permian Basin, Arklatex, Anadarko, East Texas and the Gulf Coast areas. Internationally, the Company conducts oil and gas activities in Equatorial Guinea, Côte d'Ivoire, Angola, Egypt, Tatarstan, Brazil, Pakistan and Indonesia. In May 2001, pursuant to a shareholder vote, the Company was reincorporated from the State of Texas to the State of Delaware.

On March 30, 1999, Ocean Energy, Inc. ("Old Ocean") was merged with and into Seagull Energy Corporation ("Seagull," the "Merger"). The resulting company was renamed Ocean Energy, Inc. The Merger was treated for accounting purposes as an acquisition of Seagull by Ocean with the assets and liabilities of Old Ocean being recorded based upon their historical costs, and the assets and liabilities of Seagull being recorded at their estimated fair market values. The financial results presented here include those of Old Ocean on a stand-alone basis for the first quarter of 1999 and of the combined company thereafter.

2. Summary of Significant Accounting Policies

General – The accompanying Consolidated Financial Statements of the Company have been prepared according to generally accepted accounting principles and pursuant to the rules and regulations of the Securities and Exchange Commission. These accounting principles require the use of estimates, judgments and assumptions that affect the reported amounts of assets and liabilities as of the date of the financial statements, and revenues and expenses during the reporting period. Actual results could differ from those estimates. Certain reclassifications of amounts previously reported have been made to conform to current year presentations.

Consolidation – The accompanying Consolidated Financial Statements include the accounts of Ocean Energy, Inc. and its majority-owned entities. All significant intercompany transactions have been eliminated.

Cash Equivalents – The Company considers all highly liquid investments with a maturity of three months or less when purchased to be cash equivalents.

Inventories – Materials and supplies and oil inventories are valued at the lower of average cost or market value (net realizable value).

Oil and Gas Properties – The Company's exploration and production activities are accounted for using the full cost method. Under this method, all acquisition, exploration and development costs, including certain related employee costs and a portion of interest expense, incurred for the purpose of finding oil and gas are capitalized. These capitalized costs are accumulated in pools on a country-by-country basis. Capitalized costs include the cost of drilling and equipping productive wells, dry hole costs, lease acquisition costs, delay rentals and costs related to such activities. Employee costs associated with production operations and general corporate activities are expensed in the period incurred. Transactions involving sales of reserves in place, unless significant, are recorded as adjustments to oil and gas properties.

Where proved reserves are established, capitalized costs are limited on a country-by-country basis to the sum of the present value of future net cash flows using current unescalated pricing discounted at 10%, related to estimated production of proved reserves and the lower of cost or estimated fair value of unproved properties, all net of expected income tax effects ("ceiling limitation"). To the extent the full cost pool exceeds the ceiling limitation, an impairment is made and additional depreciation, depletion and amortization ("DD&A") expense is recorded. Leasehold costs, seismic costs and other costs incurred during the exploration phase are capitalized as unproved property costs. Upon evaluation, these costs are moved to the related full cost pool. Unproved properties whose acquisition costs are not individually significant are aggregated, and the portion of such costs estimated to be ultimately nonproductive, based on experience, is amortized to the full cost pool over an average holding period. Depreciation, depletion and amortization of oil and gas properties is computed on a country-by-country basis using a unit-of-production method based on estimated proved reserves. All costs associated with proved oil and gas properties, including an estimate of future development, restoration, dismantlement and abandonment costs associated therewith, are included in the computation base. The costs of investments in unproved properties and major development projects are excluded from this calculation until the project is evaluated and proved reserves are established or impaired. The Company estimates oil and gas reserves annually. An independent petroleum engineering firm annually reviews at least 80% of the Company's estimates of proved reserves.

In countries where the existence of proved reserves has not yet been determined, leasehold costs, seismic costs and other costs incurred during the exploration phase remain capitalized as unproved property costs until proved reserves have been established or until exploration activities cease. If exploration activities result in the establishment of a proved reserve base, amounts in the unproved property account are reclassified as proved properties and become subject to depreciation, depletion and amortization and the application of the ceiling test. If exploration efforts in a country are unsuccessful in establishing proved reserves and exploration activities cease, the amounts accumulated as unproved costs are charged against earnings as impairments.

During the fourth quarter of 2000, the Company recognized an impairment in the amount of $13 million ($20 million, pre-tax) related to the discontinuance of exploration activities in the Republic of Yemen. The Company recognized impairments in the amount of $43 million ($46 million, pre-tax) for the year ended December 31, 1999, related primarily to the sale of the Canadian subsidiary ($23 million, pre-tax) and to the discontinuance of exploration activities in Bangladesh ($18 million, pre-tax) and other international locations ($5 million, pre-tax). The Company had no ceiling limitations in 2001, 2000 or 1999.

Interest cost capitalized as property, plant and equipment amounted to approximately $45 million, $44 million and $41 million in 2001, 2000 and 1999, respectively. The Company also capitalized certain employee costs related to exploratory and development activities in the amounts of $58 million, $45 million and $41 million in 2001, 2000 and 1999, respectively.

Other Property, Plant and Equipment – Other property, plant and equipment consists of oil and gas pipeline facilities, gas processing plant, and corporate-related assets and equipment with a net book value of $102 million and $100 million at December 31, 2001 and 2000, respectively. Depreciation of other property is computed principally using the straight-line method over their estimated useful lives, which vary from three to twenty years. The Company groups and evaluates other property, plant and equipment for impairment based on the ability to identify separate cash flows generated therefrom in accordance with Statement of Financial Standards ("SFAS") No. 121, *Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed of*. No impairment charges related to other property, plant and equipment were recorded during 2001, 2000 and 1999.

Maintenance, repairs and renewals are charged to operating expense except that renewals which extend the life of the asset are capitalized.

Environmental Liabilities – Environmental expenditures that relate to an existing condition caused by past operations, and that do not contribute to current or future revenue generation, are expensed. Liabilities are accrued when environmental assessments and/or clean-ups are probable, and the costs can be reasonably estimated.

Treasury Stock – The Company follows the weighted average cost method of accounting for treasury stock transactions.

Revenue Recognition – The Company records revenues from the sales of crude oil and natural gas when delivery to the customer has occurred and title has transferred. This occurs when production has been delivered to a pipeline or a tanker lifting has occurred. The Company may have an interest with other producers in certain properties. In this case, the Company uses the entitlements method to account for sales of production. Under the entitlements method, the Company may receive more or less than its entitled share of production. If the Company receives more than its entitled share of production, the imbalance is treated as a liability. If the Company receives less than its entitled share, the imbalance is recorded as an asset.

Derivative Instruments and Hedging Activities – From time to time, the Company has utilized and expects to continue to utilize derivative financial instruments to hedge cash flow from operations or to hedge the fair value of financial instruments.

The Company uses derivative financial instruments with respect to a portion of its oil and gas production to achieve a more predictable cash flow by reducing its exposure to price fluctuations. These transactions generally are swaps, collars or options, and are entered into with major financial institutions or commodities trading institutions. Derivative financial instruments are intended to reduce the Company's exposure to declines in the market prices of natural gas and crude oil that the Company produces and sells, and to manage cash flow in support of the Company's annual capital expenditure budget. Prior to January 1, 2001, gains and losses from derivative financial instruments were recognized in oil and gas revenues as the associated production occurred.

The Company may also utilize derivative financial instruments such as interest rate swap agreements. Prior to January 1, 2001, gains and losses from interest rate hedges were included in interest expense.

Effective January 1, 2001, the Company adopted SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended. This statement establishes accounting and reporting standards requiring that derivative instruments (including certain derivative instruments embedded in other contracts) be recorded at fair market value and included in the balance sheet as assets or liabilities.

Adoption of SFAS No. 133 at January 1, 2001, resulted in the recognition of $1 million of additional derivative assets, included in other current assets; $23 million of derivative liabilities, $11 million of which were included in current liabilities and $12 million of which were included in other noncurrent liabilities in the Company's Consolidated Balance Sheet; and $14 million, net of taxes, of deferred hedging losses, included in accumulated other comprehensive income as the effect of the change in accounting principle. The Company also recorded a deferred tax asset of $9 million upon adoption. Amounts were determined as of January 1, 2001, based on quoted market values, the Company's portfolio of derivative instruments and the Company's measurement of hedge effectiveness.

The accounting for changes in the fair value of a derivative instrument depends on the intended use of the derivative and the resulting designation, which is established at the inception of a derivative. SFAS No. 133 requires that a company formally document, at the inception of a hedge, the hedging relationship and the entity's risk management objective and strategy for undertaking the hedge, including identification of the hedging instrument, the hedged item or transaction, the nature of the risk being hedged, the method that will be used to assess effectiveness and the method that will be used to measure hedge ineffectiveness of derivative instruments that receive hedge accounting treatment.

For derivative instruments designated as cash flow hedges, changes in fair value, to the extent the hedge is effective, are recognized in other comprehensive income until the hedged item is recognized in earnings. Hedge effectiveness is assessed at least quarterly based on total changes in the derivative's fair value. Any ineffective portion of the derivative instrument's change in fair value is recognized immediately in revenues.

The Company may utilize derivative financial instruments which have not been designated as hedges under SFAS No. 133 even though they protect the Company from changes in commodity prices. These instruments are marked to market with the resulting changes in fair value recorded in oil and gas revenues.

The Company may also utilize derivative financial instruments such as interest rate swap agreements. Interest rate swap contracts are reflected at fair value on the Company's Consolidated Balance Sheets. If the transaction qualifies as a fair value hedge, the related portion of fixed-rate debt being hedged is reflected at an amount equal to the sum of its carrying value plus an adjustment representing the change in its fair value attributable to the interest rate risk being hedged. The gains or losses on the derivative financial instrument, as well as the offsetting gains or losses on the hedged item, are recognized currently in interest expense. Consequently, if gains or losses on the derivative financial instrument and the related hedged item do not completely offset, the difference is recognized currently in interest expense. The net effect of this accounting on the Company's operating results is that interest expense on the portion of fixed-rate debt being hedged is generally recorded based on variable interest rates.

Income Taxes – The Company uses the liability method of accounting for income taxes under which deferred tax assets and liabilities are recognized for the estimated future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities, and their respective tax bases. Deferred tax assets and liabilities are measured using enacted tax rates in effect for the year in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized as part of the provision for income taxes in the period that includes the enactment date.

Discontinued Operations – During 1999, the Company disposed of its Alaskan operations ("ENSTAR") acquired in the Seagull Merger. See Note 7. ENSTAR's net income, reflected as discontinued operations, was $1 million, net of income tax expense of $1 million, for the year ended December 31, 1999.

Foreign Currency Translation – The U.S. dollar is the functional currency for all of the Company's existing foreign operations, as predominantly all transactions in these operations are denominated in U.S. dollars.

Stock-Based Compensation – The Company accounts for stock-based compensation to employees or directors under the intrinsic value method. Under this method, the Company records no compensation expense for stock options granted when the exercise price of options granted is equal to or greater than the fair market value of the Company's common stock on the date of grant.

Concentrations of Market Risk – The future results of the Company's oil and gas operations will be affected by the market prices of oil and gas. The availability of a ready market for natural gas, oil and liquid products in the future will depend on numerous factors beyond the control of the Company, including weather, imports, marketing of competitive fuels, proximity and capacity of oil and gas pipelines and other transportation facilities, any oversupply or undersupply of gas, oil and liquid products, the regulatory environment, the economic environment, and other regional and political events, none of which can be predicted with certainty.

The Company operates in various phases of the oil and gas industry. The

Company's receivables include amounts due from purchasers of oil and gas production and amounts due from joint venture partners for their respective portions of operating expense and exploration and development costs. The Company believes that no single customer or joint venture partner exposes the Company to significant credit risk. While certain of these customers and joint venture partners are affected by periodic downturns in the economy in general or in their specific segment of the natural gas or oil industry, the Company believes that its level of credit-related losses due to such economic fluctuations has been and will continue to be immaterial to the Company's results of operations in the long term. Trade receivables are generally not collateralized. The Company analyzes customers' and joint venture partners' historical credit positions and payment history prior to extending credit.

During 2001, purchases by Duke Energy Trading & Marketing and affiliates ("DETM"), a wholly-owned subsidiary of Duke Energy Corp., and ExxonMobil Sales and Supply ("EMSS"), a wholly-owned subsidiary of ExxonMobil Corporation, accounted for 42% and 19%, respectively, of the Company's total oil and gas production revenues. During 2000, purchases by DETM and EMSS accounted for 44% and 20%, respectively, of the Company's total oil and gas production revenues. During 1999, purchases by DETM, EMSS, and Enron Corporation accounted for 11%, 18%, and 16%, respectively, of the Company's total oil and gas production revenues. DETM has an implied senior debt rating of A- from Standard & Poor's ("S&P") and Duke Energy Corporation's senior debt is rated A+ by S&P and A1 by Moody's. EMSS is not rated but ExxonMobil Corporation's senior debt is rated AAA by S&P and Aaa by Moody's.

The Company has a significant portion of its operations in various international areas. The Company's activities in these areas are subject to risks associated with international operations, including political and economic uncertainties, risks of cancellation or unilateral modification of agreements, operating restrictions, currency repatriation restrictions, expropriation, export restrictions, the imposition of new taxes and the increase of existing taxes, inflation, foreign exchange fluctuations and other risks arising out of international government sovereignty over areas in which the operations are conducted. The Company has endeavored to protect itself against political and commercial risks inherent in these operations. There is no certainty that the steps taken by the Company will provide adequate protection.

Concentrations of Credit Risk – Derivative financial instruments that hedge the price of oil and gas and interest rates are generally executed with major financial or commodities trading institutions which expose the Company to market and credit risks, and may at times be concentrated with certain counterparties or groups of counterparties. Although notional amounts are used to express the volume of these contracts, the amounts potentially subject to credit risk, in the event of non-performance by the counterparties, are substantially smaller. The credit worthiness of counterparties is subject to continuing review and full performance is anticipated. The Company's policy is to execute financial derivatives only with counterparties having a senior debt rating of A or higher.

Impact of Recently Issued Accounting Pronouncements – During 2001, the Financial Accounting Standards Board issued four new pronouncements:

Statement No. 141, *Business Combinations*, requires that the purchase method of accounting be used to account for all business combinations and applies to all business combinations initiated after June 30, 2001. The statement also establishes specific criteria for the recognition of intangible assets separately from goodwill. The provisions of this statement would be applied if the Company were to enter into any future business combination. The statement has no impact on the Company's historical financial statements.

Statement No. 142, *Goodwill and Other Intangible Assets*, requires that goodwill no longer be amortized but tested for impairment at least annually. Other intangible assets are to be amortized over their useful lives and reviewed for impairment. An intangible asset with an indefinite useful life will not be amortized until its useful life becomes determinable. The effective date of this statement is January 1, 2002. The provisions of this statement would be applied if the Company were to enter into any future business combination pursuant to which goodwill or other intangible assets were recognized. The statement has no impact on the Company's historical financial statements.

Statement No. 143, *Accounting for Asset Retirement Obligations* ("SFAS No. 143"), requires entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred and a corresponding increase in the carrying amount of the related long-lived asset. The Company will be required to adopt SFAS No. 143 effective January 1, 2003, using a cumulative effect approach to recognize transition amounts for asset retirement obligations, asset retirement costs and accumulated depreciation. The Company currently records estimated costs of dismantlement, removal, site reclamation and similar activities as part of its depreciation, depletion and amortization for oil and gas properties without recording a separate liability for such amounts. The Company has not yet completed its assessment of the impact of SFAS No. 143 on its financial condition and results of operations. It expects that adoption of the statement will result in increases in the capitalized costs of its oil and gas properties and in the recognition of additional liabilities related to asset retirement obligations.

Statement No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets* ("SFAS No. 144"), retains the fundamental provisions of SFAS No. 121, *Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed Of* ("SFAS No. 121"), for recognizing and measuring impairment losses while resolving significant implementation issues associated with SFAS No. 121. SFAS No. 144 also expands the basic provisions of APB Opinion No. 30, *Reporting the Results of Operations – Reporting the Effects of Disposal of a Segment of a Business, and Extraordinary, Unusual and Infrequently Occurring Events and Transactions*, regarding presentation of discontinued operations in the income statement. The scope for reporting a discontinued operation has been expanded to include a "component" of an entity. A component comprises operations and cash flows that can be clearly distinguished from the rest of the entity. It could be a segment, a reporting unit, a consolidated subsidiary or an asset group.

The Company adopted SFAS No. 144 as of January 1, 2002. Because the Company has elected the full cost method of accounting for oil and gas exploration and development activities, the impairment provisions of SFAS No. 144 do not apply to the Company's oil and gas assets, which are subject to the ceiling limitations. For the Company's non-oil and gas assets, the method of impairment assessment is largely unchanged from SFAS No. 121. The adoption of SFAS No. 144 had no impact on the Company's financial statements.

3. Income from Continuing Operations Per Share

The following table provides a reconciliation between basic and diluted income from continuing operations per share (stated in thousands except per share data):

	2001		2000	
	Basic	**Diluted**	Basic	Diluted
Income before extraordinary loss	**$ 277,755**	**$ 277,755**	$ 213,203	$ 213,203
Extraordinary loss, net of income taxes	**(3,973)**	**(3,973)**	-	-
Net income	**273,782**	**273,782**	213,203	213,203
Preferred stock dividends	**(3,250)**	**-**	(3,250)	-
Net income available to common stockholders	**$ 270,532**	**$ 273,782**	$ 209,953	$ 213,203
Weighted average common shares outstanding	**170,178**	**170,178**	167,144	167,144
Effect of dilutive securities:				
Stock options	**-**	**4,814**	-	4,217
Convertible preferred stock	**-**	**3,424**	-	3,388
Average common shares outstanding	**170,178**	**178,416**	167,144	174,749
Earnings per common share:				
Income before extraordinary loss	**$ 1.61**	**$ 1.55**	$ 1.26	$ 1.22
Extraordinary loss, net of income taxes	**(0.02)**	**(0.02)**	-	-
Net income	**$ 1.59**	**$ 1.53**	$ 1.26	$ 1.22

Income from continuing operations per share is computed by dividing income from continuing operations available to common stockholders by the weighted average number of common shares outstanding during the period. Diluted income from continuing operations per share is determined on the assumption that outstanding stock options have been converted using the average common stock price for the period and that convertible preferred stock has been converted at its stated conversion price.

Information for 1999 is not included in the table above because 1999 was a loss year. For purposes of computing income from continuing operations per share in a loss year, common stock equivalents are excluded from the computation of weighted average common shares outstanding because their effect is antidilutive. The preferred stock conversion is also excluded from the computation for the same year because of its antidilutive effect.

Weighted average options to purchase 4.3 million shares of common stock at $18.35 to $36.54 per share and 6.6 million shares of common stock at $13.46 to $36.54 per share were outstanding during 2001 and 2000, respectively, but were not included in the computation of diluted income from continuing operations per share because the options' exercise prices were greater than the average market price of the common shares. These options expire at various dates through 2011. Options to purchase 22.5 million shares of common stock were outstanding at December 31, 1999, but were not included in the computation of diluted loss from continuing operations per share because the effect of the assumed exercise of these stock options as of the beginning of the year would have an antidilutive effect. These options had exercise prices ranging from $2.11 to $36.54 and expire at various dates through 2009.

4. Operating Expenses

Components of operating expenses are as follows (in thousands):

	YEAR ENDED DECEMBER 31,		
	2001	2000	1999
Lease operating expense	**$ 226,350**	$ 189,035	$ 185,463
Production taxes	**47,350**	40,634	22,854
Transportation expenses	**25,211**	23,727	22,047
Ad valorem taxes	**8,193**	3,486	8,664
Operating expenses	**$ 307,104**	$ 256,882	$ 239,028

5. Supplemental Disclosures of Cash Flow Information

Supplemental disclosures of cash flow information are as follows (in thousands):

	YEAR ENDED DECEMBER 31,		
	2001	2000	1999
Cash paid during the year for:			
Interest	**$ 101,688**	$114,708	$ 135,556
Income taxes	**$ 22,966**	$ 38,244	$ 27,493

6. Other Current Assets

Other current assets include the following at December 31, 2001 and 2000 (in thousands):

	DECEMBER 31,	
	2001	2000
Prepaid drilling costs	**$ 38,887**	$ 31,026
Inventories	**24,107**	28,050
Oil and gas derivative financial instruments	**32,396**	17,995
Other	**4,128**	1,966
Other current assets	**$ 99,518**	$ 79,037

7. Acquisition and Disposition of Assets

2001 Acquisitions – During 2001, the Company acquired Texoil, Inc. ("Texoil") for a cash purchase price of approximately $115 million before assumed bank debt of $15 million. Texoil was an independent oil and gas company engaged in exploration, development and acquisition of oil and gas reserves in Texas and Louisiana. No goodwill was recorded in connection with the purchase of Texoil. The Company also acquired certain oil and gas assets from Ensight Resources, L.L.C. for a purchase price of approximately $118 million. The properties are located primarily in East Texas and North Louisiana. Pro forma results of operations assuming acquisitions occurred at the beginning of the period would not have been significantly different from actual results for 2001.

2001 Dispositions – The Company received approximately $64 million in proceeds from the sales of certain non-core properties during 2001.

2000 Dispositions – On March 31, 2000, the Company completed the sale of its East Bay Complex receiving net proceeds of approximately $78 million. The properties were located in the Mississippi Delta Region of the Gulf of Mexico. The Company had no other significant dispositions in 2000.

1999 Dispositions – During 1999, the Company disposed of ENSTAR for net proceeds of $287 million; domestic properties located in the Arkoma Basin and Gulf of Mexico for net proceeds of $231 million and $66 million, respectively; and its Canadian subsidiary for net proceeds of $68 million.

Proceeds from the dispositions were used primarily to repay amounts outstanding under the Company's existing credit facility.

8. Other Noncurrent Assets

Other noncurrent assets include the following at December 31, 2001 and 2000 (in thousands):

	DECEMBER 31,	
	2001	2000
Oil and gas imbalances (net of current portion of $3.5 million and $5 million in 2001 and 2000, respectively)	**$30,023**	$23,145
Deferred financing costs	**19,747**	22,009
Interest rate swap agreements	**3,869**	-
Assets held in supplemental benefit plans trust at fair market value	**3,668**	-
Other	**7,857**	8,922
Other noncurrent assets	**$65,164**	$54,076

9. Accrued Liabilities

Accrued liabilities include the following at December 31, 2001 and 2000 (in thousands):

	DECEMBER 31, 2001	2000
Income taxes payable	**$24,760**	$ -
Contribution to Ocean Retirement Savings Plan	**5,854**	3,383
Production and ad valorem taxes	**6,050**	3,983
Payroll and related employee benefits	**4,228**	2,844
Other	**3,338**	5,636
Accrued liabilities	**$44,230**	$15,846

10. Debt

Long-term debt consisted of the following at December 31, 2001 and 2000 (in thousands):

	DECEMBER 31, 2001	2000
Credit Facility (average interest rate of 5.2%) due March 2004	**$ 50,000**	$ -
Public Notes:		
7 7/8% Senior Notes, due August 2003	**100,000**	100,000
7 5/8% Senior Notes, due July 2005	**125,000**	125,000
7 1/4% Senior Notes, due October 2011	**350,000**	-
8 1/4% Senior Notes, due July 2018	**125,000**	125,000
7 1/2% Senior Notes, due September 2027	**150,000**	150,000
8 5/8% Senior Subordinated Notes, due August 2005	**-**	100,000
9 3/4% Senior Subordinated Notes, due October 2006	**-**	1,783
8 7/8% Senior Subordinated Notes, due July 2007	**174,875**	200,000
8 3/8% Senior Subordinated Notes, due July 2008	**227,600**	250,000
Other	**9,084**	9,199
	1,311,559	1,060,982
Less: Current maturities	**(1,132)**	(849)
Unamortized debt discount	**(27,446)**	(27,569)
Total long-term debt	**$ 1,282,981**	$ 1,032,564

Credit Facility – As of December 31, 2001, the Company's credit facility consisted of a $500 million revolving credit facility with a maturity date of March 30, 2004. The credit facility bears interest, at the Company's option, at LIBOR or prime rates plus applicable margins ranging from zero to 1.7% or at a competitive bid. As of December 31, 2001, borrowings outstanding against the credit facility totaled $50 million and letters of credit totaled $31 million, leaving $419 million of available credit.

Other Financing Activities – During 2001, the Company issued $350 million of 7 1/4% senior notes due 2011 pursuant to a shelf registration statement. The notes are redeemable at the Company's option, and upon certain changes in control, the notes would be subject to a mandatory repurchase offer. A portion of the proceeds was used to repay amounts outstanding under the Company's credit facility, and the remainder of the proceeds was used to retire existing higher interest rate debt by exercising call provisions for the Company's 8 5/8% senior subordinated notes due 2005 and 9 3/4% senior subordinated notes due 2006.

Also during 2001, the Company repurchased on the open market approximately $22 million of its 8 3/8% senior subordinated notes due July 2008 and $25 million of its 8 7/8% senior subordinated notes due July 2007. The repurchase of these notes was funded with available cash balances and borrowings under the Company's existing credit facility.

In connection with these early extinguishments of debt, the Company recorded a total after-tax extraordinary loss of approximately $4 million, or ($0.02) per diluted share. The extraordinary loss was net of a tax benefit of approximately $2 million.

During 1999, the Company repurchased the outstanding balance of its 10 3/8% senior subordinated notes, which totaled $150 million, and $158 million of its 9 3/4% senior subordinated notes. The repurchase of these notes was funded with available cash balances and borrowings under the credit facility. In connection with this repurchase, the Company recorded an after-tax extraordinary loss of $23 million, or ($0.16) per basic and diluted share. The extraordinary loss included a current tax benefit of approximately $13 million.

Public Notes – The Company's senior and senior subordinated notes are general unsecured obligations of the Company. Ocean Energy, Inc. (incorporated in Louisiana), a wholly owned subsidiary of the Company, has guaranteed the payment of principal, premium (if any), and interest. Other than intercompany arrangements and transactions, the consolidated financial statements of the subsidiary are equivalent in all material respects to those of the Company and therefore are not presented separately.

The Company's debt contains conditions and restrictive provisions including, among other things, restrictions on additional indebtedness by the Company and its subsidiaries, and entering into sale and leaseback transactions, the maintenance of certain financial ratios and restrictions on dividend payments or stock repurchases.

Under the most restrictive of these provisions, approximately $371 million was available for payment of cash dividends on common stock or to repurchase common stock as of December 31, 2001.

Annual Maturities – At December 31, 2001, the Company's aggregate annual maturities of long-term debt are $1 million, $101 million, $51 million, $126 million and $1 million for the years 2002, 2003, 2004, 2005 and 2006, respectively.

Deferred Financing Costs – Deferred financing costs represent financing costs incurred in connection with the execution of various debt facilities entered into or securities issued by the Company. These costs are capitalized as other noncurrent assets in the Company's Consolidated Balance Sheet and amortized to interest expense over the life of the related debt.

11. Deferred Revenue

During 2000, the Company entered into a market-sensitive prepaid natural gas sales contract to deliver approximately 53,500 MMBtu per day of natural gas for the period January 2002 through December 2003. In exchange for the natural gas to be provided, the Company received an advance payment of approximately $75 million. The contract was subsequently amended to provide for delivery of 53,500 MMBtu per day of natural gas for the period January 2003 through December 2003 and 55,600 MMBtu per day of natural gas for the period January 2004 through December 2004. To the extent that the index price, as defined, exceeds a stated amount per MMBtu for any delivery month ($2.50 for 2003 and $3.00 for 2004), the purchaser will make payments to the Company equal to the difference between the index price and the stated amount times the delivery quantity for that month.

In 1999, the Company entered into a prepaid crude oil sales contract to deliver approximately 5.6 MBbl per day of crude oil for the period February 2000 through May 2003. In exchange for the crude oil to be provided, the Company received an advance payment of approximately $100 million.

The obligations associated with the future delivery of the natural gas and crude oil have been recorded as deferred revenue. The amounts received are amortized into revenue as scheduled deliveries of natural gas and crude oil are made as follows:

	YEAR ENDED DECEMBER 31,		
	2002	2003	2004
Revenues (in thousands)	$ 29,749	$ 48,757	$ 37,788
Annual oil delivery (MBbl)	2,028	845	-
Annual gas delivery (BBtu)	-	19,260	20,016

12. Other Noncurrent Liabilities

Other noncurrent liabilities include the following at December 31, 2001 and 2000 (in thousands):

	DECEMBER 31,	
	2001	2000
Conveyance of Section 29 credit properties	**$ 44,750**	$ 68,611
Oil and gas imbalances (net of current portion of $2 million in 2001 and $2 million in 2000)	**15,581**	14,090
Supplemental benefit and directors deferred fee plans	**8,535**	14,908
Other	**19,622**	21,878
Other noncurrent liabilities	**$ 88,488**	$119,487

Conveyance of Section 29 Credit Properties – In September 2000, the Company conveyed certain Internal Revenue Code Section 29 Tax Credit-bearing properties to a trust for approximately $70 million, which was recorded in other noncurrent liabilities. The trust receives the operating cash flow from the properties until the investor recoups its investment plus a required after-tax rate of return. As part of the transaction, the trust was required to hedge 85% of its total estimated gas production through December 31, 2005. Although the Company is not a party to the financial instrument, under SFAS No. 133 this transaction is determined to have an embedded derivative financial instrument. The fair market value of that financial derivative at December 31, 2001, is $7.6 million and is offset against the amount included in other noncurrent liabilities.

Supplemental Benefit and Directors Deferred Fee Plans – Supplemental benefit and directors deferred fee plans represent the Company's obligation under its executive supplemental retirement plan ($4.8 million), the outside directors deferred fee plan ($1.6 million) and other supplemental benefit plans ($2.1 million).

13. Fair Value of Financial Instruments

The estimated fair value of financial instruments has been determined by the Company using available market information and valuation methodologies described below. Considerable judgment is required in interpreting market data to develop the estimates of fair value. The use of different market assumptions or valuation methodologies may have a material effect on the estimated fair value amounts. The estimated fair values of the Company's financial instruments are summarized as follows (in thousands):

	DECEMBER 31,			
	2001		2000	
	Carrying Amount	**Estimated Fair Value**	Carrying Amount	Estimated Fair Value
Long-term debt	**$ 1 ,284,113**	**$ 1,301,609**	$ 1,033,413	$ 1,051,580
Derivative financial instruments:				
Interest rate swaps	**3,869**	**3,869**	-	-
Oil and gas derivative financial instruments	**32,369**	**32,369**	17,995	7,839
Embedded derivative financial instrument	**7,592**	**7,592**	-	(12,375)

Debt – The fair value of public notes is estimated based on quoted market prices for the same or similar issues. The carrying amount of all other debt approximates fair value because these instruments bear interest at rates tied to current market rates or mature in one year.

Derivative Financial Instruments – As discussed in Note 2, the Company adopted SFAS No. 133 as of January 1, 2001. As a result, the Company's derivative financial instruments are recorded at fair market value on the Company's Consolidated Balance Sheet at December 31, 2001. The fair market values are the amounts the Company would expect to receive or pay to settle the instruments at the reporting date, taking into account the difference between market prices or index prices at year-end and the contract prices of the instruments. The fair market values were obtained from the third-party counterparties to the instruments.

Interest Rate Swaps – At December 31, 2001, the Company was party to interest rate swap agreements relating to its 7 5/8% senior notes due July 2005 and its 7 7/8% senior notes due August 2003. Under the terms of the agreements, the counterparties pay the Company a weighted average fixed annual rate of 7.74% on total notional amounts of $225 million, and the Company pays the counterparties a variable annual rate equal to the average six-month LIBOR rate plus a weighted average rate of 2.73%. The swap agreements remain in effect through the maturity dates of the respective notes. The swap agreements have been designated as fair value hedges pursuant to SFAS No. 133 and are included in other noncurrent assets in the Company's Consolidated Balance Sheet. Interest expense for 2001 was reduced by approximately $3 million as a result of the interest rate swaps.

Oil and Gas Derivative Financial Instruments – At December 31, 2001, the Company had in place collars covering portions of its 2002 oil and gas production. The gas collars, which are for the period January through December 2002, cover contracted volumes of 140 MMcf per day of natural gas with a weighted average floor price of $2.82 per Mcf and a weighted average ceiling price of $4.07 per Mcf. The oil collars, which are also for the period January through December 2002, cover contracted volumes of 15 MBbl per day of oil with a floor price of $23.00 per Bbl and a weighted average ceiling price of $28.03 per Bbl. The Company's oil and gas derivative financial instruments have been designated as cash flow hedges in accordance with SFAS No. 133 and are included in other current assets in the Company's Consolidated Balance Sheet. The carrying amount for oil and gas derivative financial instruments at December 31, 2000, represents premiums paid by the Company upon entering the contracts.

Subsequent to December 31, 2001, the Company entered into crude oil collars for the period April through December 2002. The contracts cover 20 MBbl of crude oil per day with a weighted average floor price of $21.875 and a weighted average ceiling price of $26.275.

The Company occasionally utilizes derivative financial instruments which have not been designated as cash flow hedges even though they protect the Company from changes in commodity prices. These instruments are marked to market quarterly with the resulting changes in fair value recorded in oil and gas revenues. As of December 31, 2001, the Company has in place two crude oil basis swap contracts to fix the sales price differential between WTI and Brent. The contracts, which extend through May 2002 and relate to 20 MBbl per day, provide that the Company receives/pays a net settlement of WTI less Brent less $1.29 per Bbl.

Embedded Derivative Financial Instrument – A related trust, to which the Company conveyed Section 29 tax credit-bearing properties, is required to hedge 85% of total estimated gas production from these properties through 2005. Through a swap agreement, the trust has hedged 13,500 MMBtu per day at $4.12 for 2002, 11,100 MMBtu per day at $3.60 for 2003, 9,600 MMBtu per day at $3.41 for 2004 and 8,300 MMBtu per day at $3.28 for 2005. The fair market value of the embedded derivative financial instrument is the amount the trust would expect to receive or pay to settle the instrument at the reporting date. The financial instrument has been designated as a cash flow hedge in accordance with SFAS No. 133. See Note 12.

The portion of the change in fair values of the Company's oil and gas derivative financial instruments and the embedded derivative financial instrument included in revenues comprises the following (in thousands):

	YEAR ENDED DECEMBER 31, 2001
Financial derivative settlements transferred from other comprehensive income	**$ (16,289)**
Net change in fair market value of put options	**4,120**
Ineffective portion of derivative financial instruments	**2,173**
Decrease in revenues from derivative financial instruments qualifying as cash flow hedges	**(9,996)**
Decrease in revenues from other oil and gas derivative financial instruments	**(1,120)**
Decrease in revenues from oil and gas derivative financial instruments	**$ (11,116)**

Approximately $23 million of net deferred gains included in accumulated other comprehensive income at December 31, 2001, will be reversed during the next 12 months as the forecasted transactions actually occur. All forecasted transactions currently being hedged are expected to occur by December 2005.

Prior to the adoption of SFAS No. 133, the impact of oil and gas derivative financial instruments and the embedded derivative financial instrument were recorded in revenues as the associated production occurred. During 2001, there were no gains or losses reclassified into earnings as a result of the discontinuance of hedge accounting treatment for any of the Company's derivative financial instruments.

The net effect of the Company's oil and gas derivative financial instruments and the embedded derivative financial instrument included as a component of other comprehensive income (loss), net of tax, is as follows (in thousands):

	YEAR ENDED DECEMBER 31, 2001
Cumulative effect of accounting change for oil and gas derivative financial instruments	**$ (14,262)**
Net change in fair market value of oil and gas derivative financial instruments	**40,104**
Financial derivative settlements taken to income	**(1,403)**
Net effect of oil and gas derivative financial instruments (increase in stockholders' equity)	**$ 24,439**

14. Stockholders' Equity

The following table reflects the activity in shares of the Company's common stock, preferred stock and treasury stock during the three years ended December 31, 2001:

	YEAR ENDED DECEMBER 31,		
	2001	2000	1999
Common Stock Outstanding:			
Shares at beginning of year	**170,069,114**	166,979,981	101,753,646
Shares issued in connection with Seagull Merger	**-**	-	64,629,732
Exercise of common stock options	**3,996,634**	2,820,008	596,603
Deferred compensation	**779,500**	269,125	-
Employee stock purchase plan	**90,992**	-	-
Shares at end of year	**174,936,240**	170,069,114	166,979,981
Preferred Stock Outstanding	**50,000**	50,000	50,000
Treasury Stock Outstanding:			
Shares at beginning of year	**2,754,566**	378,171	-
Shares assumed in connection with Seagull Merger	**-**	-	472,278
Purchase of shares	**361,278**	2,376,395	394,000
Transfer to supplemental benefit plans trust	**(472,000)**	-	-
Contribution of shares to employee plans	**(2,204)**	-	(488,107)
Shares at end of year	**2,641,640**	2,754,566	378,171

Preferred Stock – The Company is authorized to issue 10,000,000 shares of preferred stock, in one or more series. In 1998, the Company completed a private placement of 50,000 shares of Class C Convertible Preferred Stock for $38 million of oil and gas properties, and $12 million cash from one of its institutional investors and an affiliate of such investor. The preferred stock has a 6.5% cumulative dividend payable semiannually and ranks senior to the Company's common stock with respect to dividend distribution and distribution upon liquidation. Upon liquidation, the holders of the preferred shares are entitled to receive $1,000 per share, plus any accrued and unpaid dividends. The conversion price of the shares decreases based on the amount of dividends paid on common stock and was $14.84 at December 31, 2001.

Notes

Common Stock Dividends – At December 31, 2001, the Company had accrued dividends payable of $6.9 million ($0.04 per share) on the Company's outstanding common stock. Dividends of $27.4 million were charged to retained earnings during 2001. See Note 10 for discussion of restrictions on payment of cash dividends on common stock.

Treasury Stock – During 2001, the Company purchased 361,278 shares of its stock for approximately $6.7 million and contributed 472,000 shares to the supplemental benefit plans trust (see Note 15) and 2,204 shares to employee benefit plans. During 2000, the Company purchased approximately 2.4 million shares of its stock for $32 million. In December 1999, the Company purchased 394,000 shares of stock in the open market for $2.8 million and subsequently contributed 488,107 shares of treasury stock to its Employee Stock Ownership Plan. In connection with the Seagull Merger, the Company acquired 472,278 shares of treasury stock.

Preferred Share Purchase Rights – The Company has a Share Purchase Rights Plan to protect the Company's stockholders from coercive or unfair takeover tactics. Under this Plan, each outstanding share and each share of common stock subsequently issued has attached to it one Right, exercisable at $30.75, subject to certain adjustments. In the event a person or group acquires 10% or more of the outstanding common stock, or in the event the Company is acquired in a merger or other business combination, or 50% or more of the Company's consolidated assets or earning power is sold, each Right unless redeemed entitles the holder to purchase $30.75 worth of shares of common stock of the Company or of the acquiring company, as the case may be, for half of the then-current, per-share market prices.

The Rights, under certain circumstances, are redeemable at the option of OEI's Board of Directors at a price of $0.005 per Right, within 10 days (subject to extension) following the day on which the acquiring person or group exceeds the 10% threshold. If any person or group acquires 10% or more (but less than 50%) of the Company's outstanding common stock, the Board may, at its option, issue common stock in exchange for all or part of the outstanding and exercisable Rights (other than Rights owned by such person or group which would become null and void) at an exchange ratio of one share of common stock for each two shares of common stock for which each Right is then exercisable, subject to adjustment. The Rights expire on May 21, 2003, but may be extended by an action of the Board of Directors.

Accumulated Other Comprehensive Income – Components of accumulated other comprehensive income (loss) consisted of the following at December 31, 2001 (in thousands):

	DECEMBER 31, 2001
Net effect of oil and gas derivative financial instruments	**$ 24,439**
Minimum supplemental retirement plans liability adjustment and other	**(420)**
Accumulated other comprehensive income	**$ 24,019**

At December 31, 2001, the effect of derivative financial instruments is net of income tax expense of $15 million. The minimum supplemental retirement plans liability adjustment and other is net of deferred income tax benefit of $260,000.

15. Benefit Plans

Stock Option Plans – The Company currently has various stock option plans. The stock options generally become exercisable over a three-year period and expire 10 years after the date of grant. At December 31, 2001, approximately 4.6 million shares of common stock were available for grant. Information relating to stock options is summarized as follows:

	2001		2000		1999	
	Shares	**Weighted Average Exercise Price Per Share**	Shares	Weighted Average Exercise Price Per Share	Shares	Weighted Average Exercise Price Per Share
Balance outstanding - Beginning of year	**19,589,741**	**$ 12.45**	22,515,302	$ 12.88	12,667,983	$ 13.42
Seagull options assumed at merger date	**-**	**-**	-	-	5,414,601	$ 16.16
Granted	**3,069,200**	**$ 16.79**	3,085,950	$ 8.09	5,261,000	$ 7.23
Exercised	**(3,996,634)**	**$ 7.78**	(2,820,008)	$ 8.55	(596,603)	$ 5.64
Forfeited	**(1,223,441)**	**$ 19.22**	(3,191,503)	$ 14.73	(231,679)	$ 8.84
Balance outstanding - End of year	**17,438,866**	**$ 13.81**	19,589,741	$ 12.45	22,515,302	$ 12.88
Options exercisable - End of year	**11,561,734**	**$ 14.57**	14,239,266	$ 14.23	17,559,619	$ 14.45

The weighted average fair value of stock options granted during 2001, 2000 and 1999 was $7.99, $4.86 and $4.28 per share, respectively. The fair value of each option grant is estimated on the date of grant using the Black-Scholes options-pricing model with the following weighted average assumptions used for grants in 2001, 2000 and 1999:

	YEAR ENDED DECEMBER 31,		
	2001	2000	1999
Risk-free interest rate	**4.8%**	6.5%	5.2%
Expected life	**5 years**	5 years	5 years
Expected volatility	**53%**	65%	65%
Expected dividend yield	**1%**	0%	0%

Actual value realized, if any, is dependent on the future performance of Ocean common stock and overall stock market conditions. There is no assurance the value realized by an optionee will be at or near the value estimated by the Black-Scholes model.

Information relating to stock options outstanding at December 31, 2001 is summarized as follows:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number Outstanding at December 31, 2001	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price Per Share	Number Exercisable at December 31, 2001	Weighted Average Exercise Price Per Share
$ 3.65 –7.30	3,383,030	6.6	$ 6.57	2,364,999	$ 6.46
$ 7.31-10.96	4,499,077	6.8	$ 8.20	2,805,383	$ 8.59
$10.97-14.61	1,417,956	5.2	$ 12.25	1,312,285	$ 12.22
$14.62-18.26	3,757,150	8.0	$ 16.70	839,414	$ 16.86
$18.27-21.92	1,543,722	5.3	$ 19.71	1,401,722	$ 19.78
$21.93-25.57	2,143,181	5.4	$ 23.48	2,143,181	$ 23.48
$25.58-36.54	694,750	4.6	$ 30.08	694,750	$ 30.08
	17,438,866	6.5	$ 13.81	11,561,734	$ 14.57

The Company accounts for its stock-based compensation plans under Accounting Principles Board Opinion 25, *Accounting for Stock Issued to Employees*, and related interpretations. All outstanding options were issued at an exercise price equal to fair market value or greater of the Company's common stock as of the date of grant. Accordingly, for the years ended December 31, 2001, 2000 and 1999, no compensation expense relating to these options was recognized in the Company's results of operations.

Had compensation costs for the Company's stock option plans been determined based on the fair value at the grant dates in accordance with SFAS No. 123, *Accounting for Stock-Based Compensation*, the Company's net income (loss) and earnings (loss) per share would have been restated to the pro forma amounts (stated in thousands except per share data) indicated below:

	YEAR ENDED DECEMBER 31,		
	2001	2000	1999
Net income (loss):			
As reported	**$ 273,782**	$ 213,203	$ (43,838)
Pro forma	**$ 262,592**	$ 205,545	$ (71,019)
Net income (loss) per share:			
Basic:			
As reported	**$ 1.59**	$ 1.26	$ (0.31)
Pro forma	**$ 1.52**	$ 1.21	$ (0.49)
Diluted:			
As reported	**$ 1.53**	$ 1.22	$ (0.31)
Pro forma	**$ 1.47**	$ 1.18	$ (0.49)

Under SFAS No. 123, the acceleration of vesting of options due to the Seagull Merger resulted in the recognition of all remaining pro forma unamortized compensation expense relating to those options in the calculation of the 1999 pro forma amounts above.

Executive Supplemental Retirement Plan – The Executive Supplemental Retirement Plan ("the Plan") was established to provide supplemental retirement benefits to certain key employees. The Plan is a non-contributory defined benefit retirement plan, which provides for supplemental benefits based on the employee's years of service and compensation. The Company's policy generally is to fund the benefits as they become payable.

The following tables set forth the Plan's benefit obligation, Plan assets, reconciliation of funded status, amounts recognized in the Consolidated Balance Sheets and the actuarial assumptions used (in thousands):

	YEAR ENDED DECEMBER 31,	
	2001	2000
Change in benefit obligation:		
Benefit obligation at beginning of year	**$ 3,482**	$ 3,558
Service cost	**261**	147
Interest cost	**118**	65
Actuarial (gain) loss	**612**	(20)
Benefits paid	**(268)**	(268)
Benefit obligation at end of year	**4,205**	3,482
Change in Plan assets:		
Fair value of Plan assets at beginning of year	**-**	-
Employer contribution	**268**	268
Benefits paid	**(268)**	(268)
Fair value of Plan assets at end of year	**-**	-
Funded status	**(4,205)**	(3,482)
Unrecognized actuarial gain	**(14)**	(626)
Net amount recognized	**$ (4,219)**	$ (4,108)
Amounts recognized in the balance sheets consist of:		
Accrued benefit cost	**$ (4,219)**	$ (4,108)
Additional minimum liability	**(629)**	-
Deferred taxes	**240**	-
Accumulated other comprehensive loss	**389**	-
Net amount recognized	**$ (4,219)**	$ (4,108)

Net periodic benefit cost for the Plan includes the following components (in thousands):

	YEAR ENDED DECEMBER 31,		
	2001	2000	1999
Service cost	**$ 261**	$ 147	$ 182
Interest cost	**118**	65	61
Recognized actuarial gain	**-**	(30)	(16)
Net periodic benefit cost	**$ 379**	$ 182	$ 227

Weighted average assumptions include the following:

	YEAR ENDED DECEMBER 31,		
	2001	2000	1999
Discount rate	**7.25%**	7.5%	7.5%

Employee Stock Purchase Plan – During 2001, the Company established an Employee Stock Purchase Plan ("ESPP") that allows eligible employees to purchase common stock of the Company at a 15% discount from the lower of the stock price at the beginning of the offering period or at the end of the offering period. There are two offering periods annually, and employees may elect to make contributions to the ESPP in amounts from 1% to 15% of eligible compensation, subject to certain limits.

Deferred Compensation – During 2001, the Company awarded a total of 779,500 shares of common stock as deferred compensation with an average fair market value of $17.81 per share and a three-year vesting period to various Company employees. During 2000, the Company awarded a total of 269,125 shares of restricted common stock with an average fair market value of $9.31 per share and a three-year vesting period. The fair market value of the stock at the date of grant is included as a charge to equity and amortized to earnings as compensation expense over the vesting period.

Supplemental Benefit Plans Trust – During 2001, the Company established a trust ("the Trust") to assist the Company in funding its obligations under deferred compensation plans for certain employees and non-employee directors. Trust assets consist of investments in marketable securities and shares of Company common stock, and participants are invested either in the marketable securities and/or the shares of Company common stock in the deferred plans.

The Trust assets are included in the Company's Consolidated Balance Sheet. Investments in marketable securities of $3.7 million are classified as trading securities and reported at fair value, with unrealized gains and losses included in earnings in accordance with Statement of Financial Accounting Standards No. 115, *Accounting for Certain Investments in Debt and Equity Securities*. Obligations which are to be settled by Trust assets other than shares of Company common stock total $3.7 million at December 31, 2001, and are included in other noncurrent liabilities in the Company's Consolidated Balance Sheet.

For investments in Company stock, the Trust is funded with treasury stock as compensation is earned. The related compensation obligation will be settled by the delivery of a fixed number of shares of Company stock, and diversification is not permitted. As a result, when funding of shares of stock to the Trust occurs, the balance in the Company's treasury stock account is reduced by the average cost of the shares to the Company. The Trust records the shares at fair market value, and the difference is recorded to additional paid-in capital. The stock held by the Trust is included in stockholders' equity at December 31, 2001, and changes in the fair value are not recognized subsequent to funding. The related obligation totaled $7.9 million at December 31, 2001, and is also classified in stockholders' equity. The Trust held 472,000 shares of stock at December 31, 2001. These shares are included in the calculations of basic and diluted earnings per share as though they were outstanding.

The Trust assets and the related obligation were as follows at December 31, 2001 (in millions):

	DECEMBER 31, 2001
Assets Funded to Supplemental Benefit Plans Trust:	
Marketable securities and other	**$ 3.7**
Common stock	**7.9**
Total assets held in Trust	**$ 11.6**
Amount included in other noncurrent liabilities	**$ 3.7**
Amount included in stockholders' equity	**7.9**
Total supplemental benefit plans obligation	**$ 11.6**

Other Benefit Plans – The Company maintains the Ocean Retirement Savings Plan ("the ORS Plan"), a defined contribution plan created from the January 2001 merger of several previous 401(k) plans and an employee stock ownership plan. All regular employees are eligible to participate, and the Company matches a portion of employees' contributions. Company contributions, including additional optional annual contributions, to the ORS Plan and the previous plans were approximately $8 million, $8 million and $6 million in 2001, 2000 and 1999, respectively, and were included in operating and general and administrative expenses.

16. Income Taxes

The income (loss) before income taxes and the components of income tax expense (benefit) for each of the years ended December 31, 2001, 2000 and 1999 were as follows (in thousands):

	YEAR ENDED DECEMBER 31,		
	2001	2000	1999
Income (loss) before income taxes and extraordinary item:			
Domestic	**$ 297,402**	$ 159,058	$ (67,739)
Foreign	**206,557**	219,032	46,115
	$ 503,959	$ 378,090	$ (21,624)
Current income tax expense (benefit):			
Federal	**$ 1,710**	$ (685)	$ 21,577
Foreign	**42,333**	23,195	20,074
State	**900**	(633)	6,400
Total current	**44,943**	21,877	48,051
Deferred income tax expense (benefit):			
Federal	**140,239**	98,105	(38,179)
Foreign	**36,587**	42,364	(2,362)
State	**4,435**	2,541	(7,582)
Total deferred	**181,261**	143,010	(48,123)
Income tax expense (benefit)	**$ 226,204**	$ 164,887	$ (72)

Notes

The Company recognized tax benefits on the exercise of non-qualified stock options of $15 million in 2001, $5.6 million in 2000 and $1.2 million in 1999; recognized tax benefits on extraordinary items of $2 million in 2001 and $13 million in 1999; and incurred tax expense of $1 million on discontinued operations in 1999. In addition, the Company recognized a deferred tax liability of approximately $50 million due to the excess of book over tax basis of the oil and gas properties acquired in the purchase of Texoil.

As of December 31, 2001 and 2000, the Company and its subsidiaries had U.S. federal net operating loss (NOL) carryforwards of approximately $488 million and $354 million, respectively. These loss carryforward amounts will expire during the years 2006 through 2021. The Company has a statutory depletion carryforward of $7.7 million and an alternative minimum tax credit carryforward of $5.9 million at December 31, 2001.

For federal income tax purposes, certain limitations are imposed on an entity's ability to utilize its NOLs in future periods if a change of control, as defined for federal income tax purposes, has taken place. In general terms, the limitation on utilization of NOLs and other tax attributes during any one year is determined by the value of an acquired entity at the date of the change of control multiplied by the then-existing long-term, tax-exempt interest rate. The manner of determining an acquired entity's value has not yet been addressed by the Internal Revenue Service. The Company has determined that, for federal income tax purposes, a change of control occurred during 1999. However, the Company does not believe such limitations will significantly impact the Company's ability to utilize the NOLs.

Income tax expense (benefit) for each of the years ended December 31, 2001, 2000 and 1999 was different than the amount computed using the federal statutory rate (35%) for the following reasons (in thousands):

	YEAR ENDED DECEMBER 31,		
	2001	2000	1999
Amount computed using the statutory rate	**$ 176,386**	$ 132,332	$ (7,568)
Increase (reduction) in taxes resulting from:			
Net book deductions not available for tax due to differences in book/tax basis	**520**	539	283
Tax gain in excess of book gain	**-**	-	9,045
State and local income taxes, net of federal effect	**3,468**	1,240	(768)
Taxation of foreign operations, net of federal effect	**45,830**	30,510	7,309
Accrual to actual adjustments	**-**	-	(1,816)
Decrease in deferred tax asset valuation allowance	**-**	-	(6,570)
Other	**-**	266	13
Income tax expense (benefit)	**$ 226,204**	$ 164,887	$ (72)

The significant components of deferred income tax expense (benefit) attributable to income from continuing operations for the years ended December 31, 2001, 2000 and 1999 were as follows (in thousands):

	YEAR ENDED DECEMBER 31,		
	2001	2000	1999
Deferred tax expense (benefit) exclusive of the effects of other components listed below	**$ 181,261**	$ 143,010	$ (41,553)
Decrease in deferred tax asset valuation allowance	-	-	(6,570)
	$ 181,261	$ 143,010	$ (48,123)

The tax effects of temporary differences that gave rise to significant portions of the deferred tax liabilities and deferred tax assets as of December 31, 2001 and 2000 were as follows (in thousands):

	DECEMBER 31,	
	2001	2000
Deferred tax assets:		
Net operating loss carryforwards	**$ 170,636**	$ 123,897
Deferred revenue	**-**	25,455
Percentage depletion carryforwards	**2,688**	2,688
Alternative minimum tax credit carryforwards	**5,897**	4,187
Other	**16,948**	13,997
Deferred tax assets	**196,169**	170,224
Deferred tax liabilities:		
Property, plant and equipment, due to differences in depreciation, depletion and amortization	**(313,767)**	(71,131)
Components of other comprehensive income	**(14,878)**	-
Deferred tax liabilities	**(328,645)**	(71,131)
Net deferred tax assets (liabilities)	**(132,476)**	99,093
Less - reclassification to current deferred assets	**(1,209)**	(1,034)
Net noncurrent deferred tax assets (liabilities)	**$ (133,685)**	$ 98,059

17. Related Party Transactions

During 2001 and 2000, the Company purchased 300,000 shares and 750,000 shares, respectively, of its common stock from members of its Board of Directors, or related entities, for approximately $5.7 million and $11.5 million, respectively. These transactions were part of the Company's stock repurchase plan and were purchased at market prices on the day of the transaction. Such director purchase programs are no longer in place at the Company.

The Company pays an annual consulting fee of $425,000 from June 1, 1999 through May 31, 2002 to a member of the Company's Board of Directors as part of a contractual severance agreement in relinquishing his role as an officer of the predecessor company.

Effective January 1, 2000, the Company paid an annual salary of $100,000 to the Vice Chairman of the Board of Directors of the Company. Upon the Vice Chairman's resignation on January 23, 2001, the contract was terminated. In addition, severance benefits of $5.4 million paid to the former Vice Chairman have been included in merger and acquisition costs for the year ended December 31, 1999.

During 1999, the Company paid fees of $4.9 million to Merrill Lynch & Co., Inc. for financial advisory services related to the Seagull Merger. A member of the Company's Board of Directors also serves on the Board of Merrill Lynch & Co., Inc.

During 2001, the Company retained the law firm of Vinson & Elkins L.L.P. ("V&E") to perform various legal services for the Company. One of the members of the Board of Directors of the Company is retired managing partner of V&E. Fees paid to V&E totaled $0.9 million and $1.1 million for the years ended December 31, 2001 and 2000, respectively. V&E has been retained to perform similar services in 2002.

18. Commitments and Contingencies

Marketing Contract – Approximately 62% of the Company's monthly domestic gas production is being sold pursuant to a purchase and sale agreement with Duke Energy Trading and Marketing, L.L.C. The agreement is in effect through September 30, 2002.

Transportation Commitments – The Company has entered into various agreements for transportation of specified quantities of natural gas with estimated future minimum transportation expense payments required for years ending December 31, 2002 through 2006 of $5.5 million, $1 million, $1 million, $1 million and $1 million, respectively.

Lease Commitments – The Company leases certain office space and equipment under operating lease arrangements which require future minimum rental payments of $9 million in each of the years 2002 through 2004, $3 million in 2005 and 2006, and total less than $1 million for all subsequent years. Total rental expense under operating leases net of sub-lease income was approximately $7 million in 2001, $5 million in 2000 and $5 million in 1999.

At December 31, 2001, the Company was a party to lease agreements ("Nansen and Boomvang Construction-Period Leases") in which the lessors agreed to construct and lease to the Company two spars that would be used in the development of the Nansen and Boomvang fields in the Gulf of Mexico. The lessors' share of the estimated construction and related costs for the two spars is approximately $170 million. The agreements provided that lease payments were to begin upon completion of construction and continue for a period of three years, subject to certain renewal options. Upon expiration of each lease term, including any renewals, the Company had the option to purchase the leased property for a specified price or to arrange for the sale of the lessors' interest in the spars to a third party. No rental expense was recorded pursuant to these leases for the year ended December 31, 2001, as the spars were still under construction at December 31, 2001.

The Nansen spar was completed and installed in January 2002. In accordance with the terms of the Nansen Construction-Period Lease, the Company arranged for the sale of the lessor's interest in the spar to a third-party purchaser. The Company has entered into a 20-year operating lease ("Nansen Operating Lease") with the purchaser. The Nansen Operating Lease contains various options whereby the Company may purchase the lessor's interest in the spar. Future cash payments under the Nansen Operating Lease will total $2 million, $7 million, $8 million, $11 million and $11 million for the years 2002, 2003, 2004, 2005 and 2006, respectively, and $194 million total for all years thereafter.

The Boomvang spar is scheduled for completion during the third quarter of 2002. The Company has arranged to replace the Boomvang Construction-Period Lease with a 20-year operating lease ("Boomvang Operating Lease") that is expected to have terms similar to the Nansen Operating Lease and rental payments of less than $1 million in 2002, approximately $3 million in 2003 and averaging approximately $4 million annually thereafter. The Boomvang Operating Lease is also expected to contain an option whereby the Company may purchase the lessor's interest in the spar. The estimated total construction cost for the lessor's share of the Boomvang spar is approximately $45 million.

Other - The Company is a party to ongoing litigation in the normal course of business. Management regularly analyzes current information and, as necessary, provides accruals for probable liabilities on the eventual disposition of these matters. While the outcome of lawsuits or other proceedings against the Company cannot be predicted with certainty, management believes that the effect on its financial condition, results of operations and cash flows, if any, will not be material.

19. Supplemental Oil and Gas Information (Unaudited)

During 2001, the Company acquired oil and gas assets located primarily in Texas and Louisiana, and sold certain non-core properties. The Company sold its interest in East Bay during 2000, and sold its Canadian subsidiary and portions of its domestic assets in the Arkoma and Gulf of Mexico regions during 1999. See Note 7.

Capitalized Costs Relating to Oil and Gas Producing Activities

Amounts in Thousands

	Domestic	Equatorial Guinea	Côte d'Ivoire	Egypt	Other International	Total
December 31, 2001:						
Proved oil and gas properties	**$ 4,036,538**	**$ 596,849**	**$ 183,076**	**$ 171,118**	**$ 76,033**	**$ 5,063,614**
Oil and gas properties excluded from amortization	**510,489**	**66,927**	**-**	**24,276**	**173,196(1)**	**774,888**
Total capitalized costs	**4,547,027**	**663,776**	**183,076**	**195,394**	**249,229**	**5,838,502**
Accumulated depreciation, depletion and amortization	**(2,274,508)**	**(311,301)**	**(126,966)**	**(63,797)**	**(14,654)**	**(2,791,226)**
Net capitalized costs	**$ 2,272,519**	**$ 352,475**	**$ 56,110**	**$ 131,597**	**$ 234,575**	**$ 3,047,276**
December 31, 2000:						
Proved oil and gas properties	$ 3,235,958	$ 518,462	$ 179,341	$ 105,528	$ 67,502	$ 4,106,791
Oil and gas properties excluded from amortization	370,509	63,855	-	27,741	111,307	573,412
Total capitalized costs	3,606,467	582,317	179,341	133,269	178,809	4,680,203
Accumulated depreciation, depletion and amortization	(1,991,236)	(257,360)	(116,326)	(39,692)	(8,112)	(2,412,726)
Net capitalized costs	$ 1,615,231	$ 324,957	$ 63,015	$ 93,577	$ 170,697	$ 2,267,477

(1) Other International unproved properties are located in Angola ($84 million), Pakistan ($45 million), Brazil ($26 million) and other international locations ($18 million).

Notes

Costs Incurred in Oil and Gas Property Acquisition, Exploration and Development Activities

Amounts in Thousands

	Domestic	Equatorial Guinea	Côte d'Ivoire	Egypt	Other International	Total
Year Ended December 31, 2001:						
Acquisition costs:						
Proved	**$ 234,510**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 234,510**
Unproved	**126,120**	**5,299**	**-**	**1,782**	**30,984**	**164,185**
Exploration costs	**270,584**	**9,747**	**1,539**	**32,986**	**38,096**	**352,952**
Development costs	**307,060**	**64,613**	**1,764**	**26,760**	**11,427**	**411,624**
Total costs incurred	**$ 938,274**	**$ 79,659**	**$ 3,303**	**$ 61,528**	**$ 80,507**	**$ 1,163,271**
Year Ended December 31, 2000:						
Acquisition costs:						
Proved	$ 6,276	$ -	$ -	$ (727)	$ -	$ 5,549
Unproved	46,915	7,860	-	2,044	5,531	62,350
Exploration costs	148,703	5,595	1,510	6,132	40,920	202,860
Development costs	191,318	68,179	14,695	13,985	12,070	300,247
Total costs incurred	$ 393,212	$ 81,634	$ 16,205	$ 21,434	$ 58,521	$ 571,006
Year Ended December 31, 1999:						
Acquisition costs:						
Proved	$ 751,266	$ -	$ 15,660	$ 82,673	$ 50,717	$ 900,316
Unproved	116,319	181	-	25,855	9,900	152,255
Exploration costs	91,207	16,886	4,056	1,063	34,821	148,033
Development costs	52,321	97,873	2,591	3,717	3,329	159,831
Total costs incurred	$ 1,011,113	$ 114,940	$ 22,307	$ 113,308	$ 98,767	$ 1,360,435

Costs being excluded from amortization consist of the following at December 31, 2001 and are presented by the year incurred (in thousands):

		YEAR ENDED DECEMBER 31,			
	Total	2001	2000	1999	1998 and Prior
Unproved property costs	$ 500,625	$ 232,647	$ 62,350	$ 29,010	$ 176,618
Exploration costs	219,392	115,372	77,473	14,318	12,229
Development costs	54,871	-	11,599	29,077	14,195
	$ 774,888	$ 348,019	$ 151,422	$ 72,405	$ 203,042

Results of Operations for Oil and Gas Producing Activities

Amounts in Thousands

	Domestic	Equatorial Guinea	Côte d'Ivoire	Egypt	Other International	Total
Year Ended December 31, 2001:						
Revenues	**$ 881,460**	**$ 220,354**	**$ 42,722**	**$ 70,161**	**$ 40,769**	**$ 1,255,466**
Operating expenses[1]	**233,509**	**21,716**	**11,332**	**11,148**	**29,399**	**307,104**
DD&A[2]	**235,008**	**55,094**	**15,401**	**25,315**	**13,524**	**344,342**
Income tax expense [3]	**154,854**	**79,815**	**13,586**	**15,721**	**4,764**	**268,740**
Results of activities	**$ 258,089**	**$ 63,729**	**$ 2,403**	**$ 17,977**	**$ (6,918)**	**$ 335,280**
Year Ended December 31, 2000:						
Revenues	$ 711,012	$ 193,840	$ 47,729	$ 77,563	$ 43,410	$ 1,073,554
Operating expenses[1]	185,909	20,795	10,775	16,571	22,832	256,882
DD&A[2]	198,669	55,192	17,753	21,352	12,010	304,976
Impairment of oil and gas properties	-	-	-	-	20,066	20,066
Income tax expense[3]	122,413	61,799	9,616	14,913	3,167	211,908
Results of activities	$ 204,021	$ 56,054	$ 9,585	$ 24,727	$ (14,665)	$ 279,722
Year Ended December 31, 1999:						
Revenues	$ 489,612	$ 131,153	$ 50,799	$ 58,910	$ 27,091	$ 757,565
Operating expenses[1]	183,300	22,138	11,390	10,690	11,510	239,028
DD&A[2]	212,089	48,262	20,582	19,189	9,577	309,699
Impairment of oil and gas properties	-	-	-	-	46,403	46,403
Income tax expense (benefit)[3]	34,391	23,956	6,494	10,389	(12,032)	63,198
Results of activities	$ 59,832	$ 36,797	$ 12,333	$ 18,642	$ (28,367)	$ 99,237

(1) Operating expenses represent costs incurred to operate and maintain wells and related equipment and facilities. These costs include, among other things, repairs and maintenance, labor, materials, supplies, property taxes, insurance, severance taxes, transportation expense, and all overhead expenses directly related to oil and gas producing activities.

(2) DD&A represents depreciation, depletion and amortization.

(3) Income tax expense (benefit) is calculated by applying the statutory tax rate to operating profit, then adjusting for any applicable permanent tax differences or tax credits and allowances.

Notes

Reserve Quantity Information

	Domestic	Equatorial Guinea	Côte d'Ivoire	Egypt	Other International	Total
Proved Reserves (MBOE):						
January 1, 2001	**284,448**	**97,082**	**30,042**	**16,110**	**32,439**	**460,121**
Revisions of previous estimates	**582**	**27,887**	**2,034**	**2,074**	**4,862**	**37,439**
Extensions and discoveries	**101,738**	**9,000**	**-**	**16,394**	**3,300**	**130,432**
Purchases of reserves in place	**43,052**	**-**	**-**	**-**	**-**	**43,052**
Sales of reserves in place	**(15,774)**	**-**	**-**	**-**	**-**	**(15,774)**
Production	**(35,493)**	**(11,112)**	**(2,318)**	**(3,160)**	**(2,354)**	**(54,437)**
December 31, 2001	**378,553**	**122,857**	**29,758**	**31,418**	**38,247**	**600,833**
January 1, 2000	282,483	48,223	36,529	20,722	27,040	414,997
Revisions of previous estimates	(2,153)	48,008	(3,653)	(1,371)	4,073	44,904
Extensions and discoveries	74,353	9,195	-	23	3,674	87,245
Purchases of reserves in place	1,193	-	-	-	-	1,193
Sales of reserves in place	(38,666)	-	-	-	-	(38,666)
Production	(32,762)	(8,344)	(2,834)	(3,264)	(2,348)	(49,552)
December 31, 2000	284,448	97,082	30,042	16,110	32,439	460,121
January 1, 1999	194,106	41,048	34,394	-	22,401	291,949
Revisions of previous estimates	7,696	14,498	1,036	(33)	2,469	25,666
Extensions and discoveries	39,131	-	-	271	3,638	43,040
Purchases of reserves in place	141,850	-	4,705	25,700	24,481	196,736
Sales of reserves in place	(63,901)	-	-	(2,173)	(23,639)	(89,713)
Production	(36,399)	(7,323)	(3,606)	(3,043)	(2,310)	(52,681)
December 31, 1999	282,483	48,223	36,529	20,722	27,040	414,997
Proved Developed Reserves (MBOE):						
December 31, 2001	**258,067**	**32,394**	**12,358**	**12,247**	**28,769**	**343,835**
December 31, 2000	185,673	22,302	11,104	7,672	21,210	247,961
December 31, 1999	225,773	18,381	13,382	11,003	18,285	286,824
December 31, 1998	143,603	10,620	10,566	-	21,467	186,256
Proved Developed Oil Reserves (Mbbl):						
December 31, 2001	**73,679**	**32,394**	**3,497**	**12,129**	**20,950**	**142,649**
December 31, 2000	43,477	22,302	2,750	7,572	14,962	91,063
December 31, 1999	74,445	18,381	2,836	10,809	11,929	118,400
December 31, 1998	64,183	10,620	2,251	-	3,900	80,954
Proved Developed Gas Reserves (MMcf):						
December 31, 2001	**1,106,330**	**-**	**53,165**	**709**	**46,911**	**1,207,115**
December 31, 2000	853,176	-	50,121	608	37,487	941,392
December 31, 1999	907,968	-	63,273	1,167	38,134	1,010,542
December 31, 1998	476,522	-	49,891	-	105,401	631,814

The reserve volumes presented are estimates only and should not be construed as being exact quantities. These reserves may or may not be recovered and may increase or decrease as a result of future operations of the Company and changes in economic conditions.

Reserve Quantity Information

	Domestic	Equatorial Guinea	Côte d'Ivoire	Egypt	Other International	Total
Proved Oil Reserves (Mbbl):						
January 1, 2001	**80,682**	**97,082**	**4,238**	**16,008**	**23,635**	**221,645**
Revisions of previous estimates	**3,896**	**27,887**	**1,600**	**2,020**	**5,422**	**40,825**
Extensions and discoveries	**41,071**	**9,000**	**-**	**16,394**	**3,300**	**69,765**
Purchases of reserves in place	**12,463**	**-**	**-**	**-**	**-**	**12,463**
Sales of reserves in place	**(12,405)**	**-**	**-**	**-**	**-**	**(12,405)**
Production	**(10,170)**	**(11,112)**	**(1,166)**	**(3,123)**	**(1,929)**	**(27,500)**
December 31, 2001	**115,537**	**122,857**	**4,672**	**31,299**	**30,428**	**304,793**
January 1, 2000	89,808	48,223	7,039	20,492	18,237	183,799
Revisions of previous estimates	(330)	48,008	(1,392)	(1,279)	3,520	48,527
Extensions and discoveries	27,546	9,195	-	23	3,674	40,438
Purchases of reserves in place	406	-	-	-	-	406
Sales of reserves in place	(26,774)	-	-	-	-	(26,774)
Production	(9,974)	(8,344)	(1,409)	(3,228)	(1,796)	(24,751)
December 31, 2000	80,682	97,082	4,238	16,008	23,635	221,645
January 1, 1999	82,936	41,048	6,437	-	3,900	134,321
Revisions of previous estimates	10,234	14,498	1,358	33	2,276	28,399
Extensions and discoveries	7,682	-	-	271	3,638	11,591
Purchases of reserves in place	14,717	-	1,009	25,360	14,262	55,348
Sales of reserves in place	(12,229)	-	-	(2,173)	(4,473)	(18,875)
Production	(13,532)	(7,323)	(1,765)	(2,999)	(1,366)	(26,985)
December 31, 1999	89,808	48,223	7,039	20,492	18,237	183,799
Proved Gas Reserves (MMcf):						
January 1, 2001	**1,222,602**	**-**	**154,825**	**609**	**52,820**	**1,430,856**
Revisions of previous estimates	**(19,892)**	**-**	**2,602**	**331**	**(3,357)**	**(20,316)**
Extensions and discoveries	**364,000**	**-**	**-**	**-**	**-**	**364,000**
Purchases of reserves in place	**183,538**	**-**	**-**	**-**	**-**	**183,538**
Sales of reserves in place	**(20,216)**	**-**	**-**	**-**	**-**	**(20,216)**
Production	**(151,937)**	**-**	**(6,914)**	**(218)**	**(2,552)**	**(161,621)**
December 31, 2001	**1,578,095**	**-**	**150,513**	**722**	**46,911**	**1,776,241**
January 1, 2000	1,156,049	-	176,943	1,375	52,820	1,387,187
Revisions of previous estimates	(10,935)	-	(13,566)	(549)	3,312	(21,738)
Extensions and discoveries	280,840	-	-	-	-	280,840
Purchases of reserves in place	4,723	-	-	-	-	4,723
Sales of reserves in place	(71,353)	-	-	-	-	(71,353)
Production	(136,722)	-	(8,552)	(217)	(3,312)	(148,803)
December 31, 2000	1,222,602	-	154,825	609	52,820	1,430,856
January 1, 1999	667,019	-	167,743	-	111,004	945,766
Revisions of previous estimates	(15,236)	-	(1,927)	(400)	1,171	(16,392)
Extensions and discoveries	188,693	-	-	-	-	188,693
Purchases of reserves in place	762,799	-	22,177	2,039	61,311	848,326
Sales of reserves in place	(310,031)	-	-	-	(115,000)	(425,031)
Production	(137,195)	-	(11,050)	(264)	(5,666)	(154,175)
December 31, 1999	1,156,049	-	176,943	1,375	52,820	1,387,187

Notes

The Company's standardized measure of discounted future net cash flows as of December 31, 2001 and 2000, and changes therein for each of the years 2001, 2000 and 1999, are provided based on the present value of future net revenues from proved oil and gas reserves. The Company's estimates of proved oil and gas reserves are prepared by internal petroleum engineers in accordance with guidelines established by the Securities and Exchange Commission and are reviewed by an independent petroleum engineering firm. These estimates were computed by applying year-end prices for oil and gas to estimated future production of proved oil and gas reserves over the economic lives of the reserves and assuming continuation of existing operating conditions. Year-end 2001 and 2000 calculations were made using prices of $17.23 per Bbl and $22.97 per Bbl, respectively, for oil and $2.64 per Mcf and $8.81 per Mcf, respectively, for gas.

Because the disclosure requirements are standardized, significant changes can occur in these estimates based upon oil and gas prices in effect at year end. The following estimates should not be viewed as an estimate of fair market value. Income taxes are computed by applying the statutory income tax rate in the jurisdiction to the net cash inflows relating to proved oil and gas reserves less the tax bases of the properties involved and giving effect to appropriate net operating loss carryforwards, tax credits and allowances relating to such properties.

Standardized Measure of Discounted Future Net Cash Flows

Amounts in Thousands

	Domestic	Equatorial Guinea	Côte d'Ivoire	Egypt	Other International	Total
December 31, 2001:						
Future cash inflows	**$ 6,299,765**	**$ 2,150,338**	**$ 409,176**	**$ 557,149**	**$ 529,131**	**$ 9,945,559**
Future development costs	**(839,346)**	**(252,411)**	**(91,225)**	**(117,410)**	**(37,090)**	**(1,337,482)**
Future production costs	**(2,030,995)**	**(413,738)**	**(106,064)**	**(84,464)**	**(258,325)**	**(2,893,586)**
Future net cash flows before income taxes	**3,429,424**	**1,484,189**	**211,887**	**355,275**	**233,716**	**5,714,491**
10% annual discount	**(1,417,802)**	**(529,891)**	**(116,784)**	**(125,218)**	**(118,362)**	**(2,308,057)**
Discounted future net cash flows before income taxes	**2,011,622**	**954,298**	**95,103**	**230,057**	**115,354**	**3,406,434**
Discounted income taxes	**(257,220)**	**(256,611)**	**(31,928)**	**(50,236)**	**(41,551)**	**(637,546)**
Standardized measure of discounted future net cash flows	**$ 1,754,402**	**$ 697,687**	**$ 63,175**	**$ 179,821**	**$ 73,803**	**$ 2,768,888**
December 31, 2000:						
Future cash inflows	$ 13,982,861	$ 2,235,805	$ 517,314	$ 377,839	$ 580,997	$17,694,816
Future development costs	(485,669)	(314,856)	(88,594)	(47,251)	(32,509)	(968,879)
Future production costs	(1,884,571)	(182,127)	(107,897)	(65,870)	(204,873)	(2,445,338)
Future net cash flows before income taxes	11,612,621	1,738,822	320,823	264,718	343,615	14,280,599
10% annual discount	(4,736,565)	(655,452)	(162,360)	(68,098)	(169,756)	(5,792,231)
Discounted future net cash flows before income taxes	6,876,056	1,083,370	158,463	196,620	173,859	8,488,368
Discounted income taxes	(2,045,909)	(285,118)	(126,409)	(91,183)	(92,756)	(2,641,375)
Standardized measure of discounted future net cash flows	$ 4,830,147	$ 798,252	$ 32,054	$ 105,437	$ 81,103	$ 5,846,993

Principal Sources of Change in the Standardized Measure of Discounted Future Net Cash Flows

Amounts in Thousands

	YEAR ENDED DECEMBER 31,		
	2001	2000	1999
Beginning of Year	**$ 5,846,993**	$ 2,415,418	$ 903,823
Revisions of previous quantity estimates less related costs	**298,266**	568,080	312,017
Extensions and discoveries less related costs	**462,453**	1,960,883	200,617
Purchases of reserves in place	**234,510**	5,549	900,316
Sales of reserves in place	**(63,791)**	(86,043)	(417,231)
Net changes in future prices and production costs	**(6,076,392)**	3,775,961	1,191,165
Future development costs incurred during the period	**411,625**	300,247	159,831
Sales of oil and gas produced, net of production costs	**(948,361)**	(816,672)	(518,537)
Accretion of discount	**848,836**	295,185	91,708
Net changes in income taxes	**2,003,829**	(2,104,939)	(523,177)
Changes in estimated future development costs, production, timing and other	**(249,080)**	(466,676)	114,886
	(3,078,105)	3,431,575	1,511,595
End of Year	**$ 2,768,888**	$ 5,846,993	$ 2,415,418