UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, DC 20549

Form 10-K

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

For the fiscal year ended December 31, 2004

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission File Number 1-32414

W&T OFFSHORE, INC.
(Exact name of registrant as specified in its charter)

Texas **(State of incorporation)**	**72-1121985** **(IRS Employer Identification Number)**
Eight Greenway Plaza, Suite 1330 **Houston, Texas** **(Address of principal executive offices)**	**77046** **(Zip Code)**

(713) 626-8525
(Registrant's telephone number, including area code)

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

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, par value $0.00001	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports) and (2) has been subject to such filing requirements for the past 90 days. Yes ☐ No ☑

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

Indicate by check mark whether the registrant is an accelerated filer. Yes☐ No ☑

The aggregate market value of the registrant's common stock held by non-affiliates was approximately $310,027,000 based on the closing sale price of $20.42 per share as reported by the New York Stock Exchange on March 29, 2005.

The number of shares of the registrant's common stock outstanding on March 30, 2005 was 65,969,024.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's Proxy Statement relating to the Annual Meeting of Shareholders to be held May 26, 2005 are incorporated by reference into Part III of this Form 10-K.

[Table of Contents](#)

W&T OFFSHORE, INC.

TABLE OF CONTENTS

Forward-Looking Statements

This Annual Report on Form 10-K contains forward-looking statements within the meaning of the Private Litigation Securities Reform Act of 1995 that involve risks, uncertainties and assumptions. If the risks or uncertainties materialize or the assumptions prove incorrect, our results may differ materially from those expressed or implied by such forward-looking statements and assumptions. All statements other than statements of historical fact are statements that could be deemed forward-looking statements, such as those statements that address activities, events or developments that we expect, believe or anticipate will or may occur in the future. These statements are based on certain assumptions and analyses made by us in light of our experience and perception of historical trends, current conditions, expected future developments and other factors we believe are appropriate in the circumstances. Certain factors that may affect our financial condition and results of operations are discussed in "Factors That Could Affect Future Results" in Item 7A of this Annual Report and may be discussed from time to time in our reports filed with the Securities and Exchange Commission subsequent to this report. We assume no obligation, nor do we intend, to update these forward-looking statements.

PART I

Items 1. and 2. ***Business and Properties***

Unless the context requires otherwise, references in this Annual Report to “W&T,” “we,” “us” and “our” refer to W&T Offshore, Inc. and its consolidated subsidiaries. We are an independent oil and natural gas acquisition, exploitation and exploration company. We are focused primarily in the Gulf of Mexico area, where we have developed significant technical expertise and where the high production rates associated with hydrocarbon deposits have historically provided us the best opportunity to achieve a rapid payback on our invested capital. We have leveraged our historic experience to focus on higher impact capital projects in the Gulf of Mexico, including the deepwater (water depths in excess of 500 feet) and the deep shelf (well depths in excess of 15,000 feet).

Based on a reserve report prepared by Netherland, Sewell & Associates, Inc., our independent petroleum consultants, our proved reserves at December 31, 2004 were 467.5 Bcfe. We calculate that our proved reserves had a PV-10 of $1.5 billion and a standardized measure of after-tax discounted cash flows of $974.8 million as of December 31, 2004. Of those reserves, 62% were proved developed reserves and 49% were natural gas reserves.

We grow our reserves through drilling programs and acquisitions. Some of our acquisitions are made through the exercise of preferential rights in properties in which we already own an interest. During 2004, we exercised preferential rights to purchase on five such properties. The costs of exercising our preferential rights totaled $32.5 million and added approximately 19.2 Bcfe of proved reserves. We have focused on acquiring properties where we can develop an inventory of drilling prospects that enable us to continue to add reserves post-acquisition. During 2003 and 2002, we made significant acquisitions from ConocoPhillips and Burlington Resources, Inc., respectively. During 2004, we did not complete any significant acquisition. In spite of the extremely competitive nature of the current acquisition landscape, our acquisition team is working diligently to find properties that fit our historical profile and will add strategic and financial value to the Company.

For the year ended December 31, 2004, capital expenditures of $284.8 million included $90.7 million for development activities, $150.4 million for exploration and $43.7 million for other capital items including acquisitions. These expenditures do not include any amount of allocated general and administrative expenses or interest. Our capital expenditures for the year ended December 31, 2004 were primarily financed by net cash flow provided by operating activities. We participated in the drilling of 32 exploratory wells and seven development wells of which 26 were on the conventional shelf and land, four were deep shelf wells and nine were in the deepwater. All of the development wells were successful. Of the 32 exploration wells, 21 were successful and five of the successful wells are in the deepwater. We operate a total of 16 of the 21 successful exploratory wells, including four wells that we operate in the deepwater. During the three-year period ended December 31, 2004, we drilled 52 exploratory wells, of which 37 were successful (which we define as completed or planned for completion).

During 2005, we expect to spend $266 million on capital projects and $42 million on plug and abandonments, major maintenance and expense workovers. During 2005, we anticipate drilling 30 exploratory wells and five or more development wells.

We have become more active in bidding for Gulf of Mexico leases on the outer continental shelf (“OCS”) at lease sales conducted by the U.S. government through the Minerals Management Service (“MMS”). At the March 2004 OCS lease sale, the MMS awarded us leases for a 100% working interest in seven OCS blocks located in the central Gulf of Mexico, three of which are in the deepwater. At the August 2004 OCS lease sale, the MMS has awarded us leases for a 100% working interest in six OCS blocks located in the western Gulf of Mexico, four of which are in the deepwater. We were high bidder on nine of the 15 bids that we submitted at the March 2005 OCS lease sale. High bids are subject to MMS evaluation, which will occur within 90 days of the sale.

Business Strategy

We plan to continue to acquire and exploit reserves on the OCS of the Gulf of Mexico, the area of our historical success, or in other areas outside of the Gulf of Mexico that are compatible with our technical expertise and could yield rates of return comparable to those we have historically achieved. We believe attractive acquisition opportunities will continue to arise in the Gulf of Mexico as the major integrated oil companies and other large independent oil and gas exploration and production companies continue to divest properties to focus on larger and more capital-intensive projects that better match their long-term strategic goals.

We believe our opportunities for deepwater exploration have been enhanced by technological advances in recent years that enable the connection of subsea wells to existing infrastructure over longer distances, eliminating the requirement for new, dedicated production facilities, the installation of which requires long lead times and large capital investments. We also believe asset divestitures and resource constraints of major integrated oil companies and other large upstream companies may allow us to acquire attractive deepwater prospects at favorable prices with a significant portion of the up-front development expenses, such as infrastructure and seismic, already invested.

We believe a significant portion of our acreage has exploration potential below currently producing zones, including deep shelf reserves. We consider deep shelf targets to be hydrocarbon-bearing horizons located in shallow water areas of the Gulf of Mexico at subsurface depths greater than 15,000 feet. Although the cost to drill deep shelf wells can be significantly higher than shallower wells, the reserve targets are typically larger and the use of existing infrastructure and recent royalty suspension incentives from the MMS should partially offset higher drilling costs.

We believe our conservative financial approach has contributed to our success and has positioned us to capitalize on new opportunities as they develop. We have typically relied solely on net cash provided by operating activities and traditional commercial bank credit facilities to fund our growth. We have historically limited annual capital spending for exploration, exploitation and development activities to net cash provided by operating activities and typically used our bank credit facility for acquisitions and to balance working capital fluctuations.

In the future, as we further expand our operations into the higher impact deepwater and deep shelf areas of the Gulf of Mexico, our capital spending may exceed net cash provided by operating activities, in which event we may issue debt or equity securities to fund such future expenditures.

Proved Reserves

Of our 467.5 Bcfe of proved reserves at December 31, 2004, 62% were proved developed and 49% were natural gas. Our estimates of proved reserves were based on a reserve report prepared by Netherland, Sewell & Associates, Inc., our independent petroleum consultants, and the reserve amounts are consistent with filings we make with federal agencies.

Table of Contents

Our proved reserves as of December 31, 2004 are summarized in the table below.

	As of December 31, 2004				
Classification of Reserves (1)	**Oil (MMBbls)**	**Gas (Bcf)**	**Total (Bcfe)**	**% of Total Proved**	**PV-10 (In millions)**
Proved developed producing	8.3	96.2	145.8	31%	$ 562.1
Proved developed non-producing	12.1	72.1	144.4	31%	444.1
Total proved developed	20.3	168.3	290.2	62%	1,006.2
Proved undeveloped	19.7	59.3	177.3	38%	464.0
Total proved	40.0	227.6	467.5	100%	$ 1,470.2

(1) Totals may not add due to rounding.

Production

During 2004, our net production averaged approximately 225 MMcfe per day with approximately 4 MMcfe per day temporarily shut in as a result of Hurricane Ivan. See "*Factors That Affect Future Results"—Our business involves many uncertainties and operating risks that can prevent us from realizing profits and can cause substantial losses* beginning at page 33 for a further discussion of the effect of Hurricane Ivan on our business.

Properties

The majority of our fields are in the Gulf of Mexico. These fields are found in water depths ranging from less than ten feet up to 4,200 feet. The reservoirs in our fields are generally characterized as having high porosity and permeability, which typically result in high production rates. The following table describes our ten largest fields as of December 31, 2004. At December 31, 2004, these fields accounted for approximately 60% of our PV-10 value, or $942.5 million (before plug and abandonment cost), and had proved reserves totaling 281 Bcfe.

				2004 Average Daily Equivalent Sales Rate (MMcfe/d)	
Field Name	**Field Category**	**Operator**	**Percent Natural Gas of Net Reserves**	**Gross**	**Net**
East Cameron 321	Shelf	Marathon	35%	11.8	7.4
Green Canyon 19	Deepwater	ExxonMobil	16%	25.6	3.2
High Island 111	Shelf	W&T	91%	19.0	10.1
High Island 177	Shelf	W&T	82%	35.0	30.1
Main Pass 69	Shelf/Deepshelf	W&T	66%	0.3	0.2
Mississippi Canyon 718	Deepwater	Mariner	57%	2.4	0.9
Mobile 823	Shelf	ExxonMobil	100%	78.7	8.2
Ship Shoal 349	Shelf	W&T	17%	16.0	7.5
South Timbalier 228	Shelf	W&T	13%	2.0	1.6
West Delta 30	Shelf	W&T and Anglo-Suisse (1)	6%	8.8	4.3

(1) W&T operates all downhole operations.

The following table describes our successful exploratory wells that were drilled in 2004, and their estimated cost as of December 31, 2004 (dollars in millions).

Block	Working Interest	Estimated Cost Gross	Estimated Cost Net	Water Depth (feet)	Date Objective Drilled/Tested
Deepwater:					
Ewing Bank 977 #1	60%	$ 3.0	$ 2.4	550	1st Quarter
Ewing Bank 949 #2/2st	97%	11.9	5.3	865	1st Quarter
Green Canyon 178	60%	4.5	3.6	1,404	2nd Quarter
Green Canyon 646 #1	60%	2.6	1.6	4,230	1st Quarter
Mississippi Canyon 674 #3	49%	20.4	10.0	2,778	4th Quarter
Deep Shelf:					
Main Pass 69 #5	98%	16.6	16.3	35	3rd Quarter
Vermilion 84 #1	73%	9.1	6.6	50	4th Quarter
Conventional Shelf:					
Ship Shoal 358 A-4	24%	6.0	1.5	419	3rd Quarter
South Marsh Island 28 A-4st3	100%	1.3	1.3	91	4th Quarter
South Marsh Island 28 A-5	100%	2.0	2.0	91	4th Quarter
South Marsh Island 281 I-2st	18%	3.1	0.6	44	2nd Quarter
South Timbalier 229 A-4	100%	6.3	6.3	230	1st Quarter
South Timbalier 229 A-5	100%	5.9	5.9	230	2nd Quarter
South Timbalier 229 A-6	100%	3.1	3.1	230	3rd Quarter
South Timbalier 299 #1	25%	2.5	0.6	317	3rd Quarter
South Timbalier 299 #2	25%	4.4	1.1	317	4th Quarter
South Timbalier 299 #3	25%	1.3	0.3	317	3rd Quarter
South Timbalier 299 #4	100%	3.3	3.3	317	4th Quarter
Vermilion 115 #1	100%	1.9	1.9	60	2nd Quarter
Land:					
Wharton County #1	25%	4.5	1.4		2nd Quarter
Wharton County #2	25%	6.3	2.1		2nd Quarter
		$120.0	$77.2		

Acreage

The following table summarizes gross and net developed and undeveloped acreage at December 31, 2004. Net acreage is our percentage ownership of gross acreage. Deepwater refers to acreage in over 500 feet of water.

	Developed Acreage		Undeveloped Acreage		Total Acreage	
	Gross	Net	Gross	Net	Gross	Net
Shelf	680,268	332,415	110,825	62,508	791,093	394,923
Deepwater	72,966	41,172	63,360	63,314	136,326	104,486
	753,234	373,587	174,185	125,822	927,419	499,409

Approximately 81% of our total gross acreage is held-by-production, which permits us to maintain all of our exploration, exploitation and development rights (including deep rights below currently producing zones) to the leased area as long as production continues. We have the right to propose future exploration and development projects, including deep exploration projects, on approximately the same amount of our acreage as is held-by-production.

Table of Contents

Production History

The following table presents the historical information about our produced oil and natural gas volumes.

	Year Ended December 31,		
	2004	2003	2002
Net sales:			
Natural gas (Bcf)	53.3	52.8	39.4
Oil (MMBbls)	4.8	4.4	2.5
Total natural gas and oil (Bcfe)	82.4	79.0	54.2

Productive Wells

The following table presents our ownership at December 31, 2004 of our productive oil and natural gas wells. A net well is our percentage working interest of a gross well.

	Oil Wells		Gas Wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
Operated	58	42.2	78	52.6	136	94.8
Non-operated	118	34.9	120	28.0	238	62.9
	176	77.1	198	80.6	374	157.7

Drilling Activity

Development and Exploration Drilling

The following table sets forth the results of our total drilling activities for the last three years.

	Year Ended December 31,		
	2004	2003	2002
Gross Wells:			
Productive	28	16	9
Non-productive	11	3	2
	39	19	11
Net Wells:			
Productive	18.0	6.6	4.0
Non-productive	7.7	0.9	1.1
	25.7	7.5	5.1

Exploration Drilling

The following table sets forth information relating to our exploration drilling over the past three fiscal years.

	Year Ended December 31,		
	2004	2003	2002
Gross Wells:			
Productive	21	10	6
Non-productive	11	2	2
	32	12	8
Net Wells:			
Productive	13.7	4.2	2.9
Non-productive	7.7	0.7	1.1
	21.4	4.9	4.0

Current Drilling Activity

We were in the process of drilling 4 gross (2.5 net) exploration wells as of March 29, 2005.

Oil and Natural Gas Marketing and Delivery Commitments

We sell our oil and natural gas through various marketing companies. We are not dependent upon, or confined to, any one purchaser or small group of purchasers. However, we currently sell over 10% of our production to each of the following companies: BP Amoco, Shell Trading and ConocoPhillips. Due to the nature of oil and natural gas markets and because oil and natural gas are commodities and there are numerous purchasers in the Gulf of Mexico, we do not believe the loss of a single purchaser or a few purchasers would materially affect our ability to sell our production.

Employees

As of December 31, 2004, we employed 133 people. We are not a party to any collective bargaining agreements, and we have not experienced any strikes or work stoppages. We consider our relations with our employees to be good.

Competition

The oil and natural gas industry is highly competitive. Our oil and natural gas business competes for the acquisition of oil and natural gas properties, primarily on the basis of the price to be paid for such properties, with numerous entities, including major oil companies, other independent oil and natural gas concerns and individual producers and operators. Many of these competitors are large, well established companies and have financial and other resources substantially greater than ours, which give them an advantage over us in evaluating and obtaining properties and prospects. Our ability to acquire additional oil and natural gas properties and to discover reserves in the future will depend upon our ability to evaluate and select suitable properties and consummate transactions in a highly competitive environment. For a more thorough discussion of how competition could impact our ability to complete successfully our business strategy. See "*Factors That Could Affect Future Results—Competition for oil and natural gas properties is intense; some of our competitors have larger financial, technical and personnel resources that give them an advantage in evaluating and obtaining properties and prospects"* beginning at page 32.

Regulation

General. Various aspects of our oil and natural gas operations are subject to extensive and continually changing regulation, as legislation affecting the oil and natural gas industry is under constant review for amendment or expansion. Numerous departments and agencies, both federal and state, are authorized by statute to issue, and have issued, rules and regulations binding upon the oil and natural gas industry and its individual members. The Federal Energy Regulatory Commission ("FERC") regulates the transportation and sale for resale of natural gas in interstate commerce pursuant to the Natural Gas Act of 1938 ("NGA") and the Natural Gas Policy Act of 1978 ("NGPA"). In 1989, however, Congress enacted the Natural Gas Wellhead Decontrol Act, which removed all remaining price and nonprice controls affecting wellhead sales of natural gas, effective January 1, 1993. While sales by producers of natural gas and all sales of crude oil, condensate and natural gas liquids can currently be made at uncontrolled market prices, Congress could reenact price controls in the future.

Regulation and transportation of natural gas. Our sales of natural gas are affected by the availability, terms and cost of transportation. The price and terms for access to pipeline transportation are subject to extensive regulation. In recent years, the FERC has undertaken various initiatives to increase competition within the natural gas industry. As a result of initiatives like FERC Order No. 636, issued in April 1992, the interstate natural gas transportation and marketing system has been substantially restructured to remove various barriers and practices that historically limited non-pipeline natural gas sellers, including producers, from effectively competing with interstate pipelines for sales to local distribution companies and large industrial and commercial customers. The most significant provisions of Order No. 636 require that interstate pipelines provide firm and interruptible transportation service on an open access basis that is equal for all natural gas supplies. In many instances, the results of Order No. 636 and related initiatives have been to substantially reduce or eliminate the interstate pipelines' traditional role as wholesalers of natural gas in favor of providing only storage and transportation services.

Similarly, the Texas Railroad Commission has been changing its regulations governing transportation and gathering services provided by intrastate pipelines and gatherers. While the changes by these federal and state regulators affect us only indirectly, they are intended to further enhance competition in natural gas markets. We cannot predict what further action the FERC or state regulators will take on these matters; however, we do not believe that we will be affected by any action taken materially differently than other natural gas producers with which we compete.

The Outer Continental Shelf Lands Act ("OCSLA"), which FERC implements as to transportation and pipeline issues, requires that all pipelines operating on or across the OCS provide open access, non-discriminatory transportation service. One of FERC's principal goals in carrying out OCSLA's mandate is to increase transparency in the market to provide producers and shippers on the OCS with greater assurance of open access service on pipelines located on the OCS and non-discriminatory rates and conditions of service on such pipelines.

Although the FERC has historically imposed light-handed regulation on offshore facilities that meet its traditional test of gathering status, it has the authority to exercise jurisdiction under the OCSLA over gathering facilities, if necessary, to permit non-discriminatory access to service. In an effort to heighten its oversight of the OCS, the FERC recently attempted to promulgate reporting requirements for all OCS "service providers," including gatherers, but the regulations were struck down as ultra vires by a federal district court, which decision was affirmed by the U.S. Court of Appeals in October 2003. The FERC withdrew its regulations in March 2004. Subsequently, in April 2004, the MMS initiated an inquiry into whether it should amend its regulations to assure that pipelines provide open and non-discriminatory access over OCS pipeline facilities. For those facilities transporting natural gas across the OCS that are not considered to be gathering facilities, the rates, terms and conditions applicable to this transportation are generally regulated by the FERC under the NGA and NGPA, as well as the OCSLA.

Additional proposals and proceedings that might affect the natural gas industry are pending before Congress, the FERC, state commissions and the courts. The natural gas industry historically has been very heavily regulated; therefore, there is no assurance that the less stringent regulatory approach recently pursued by the FERC and Congress will continue.

Federal leases. A substantial portion of our operations is located on federal oil and natural gas leases, which are administered by the MMS pursuant to the OCSLA. These leases are issued through competitive bidding and contain relatively standardized terms. These leases require compliance with detailed MMS regulations and orders that are subject to interpretation and change by the MMS.

For offshore operations, lessees must obtain MMS approval for exploration, development and production plans prior to the commencement of such operations. In addition to permits required from other agencies such as the Coast Guard, the Army Corps of Engineers and the Environmental Protection Agency, lessees must obtain a permit from the MMS prior to the commencement of drilling. The MMS has promulgated regulations requiring offshore production facilities located on the OCS to meet stringent engineering and construction specifications. The MMS also has regulations restricting the flaring or venting of natural gas, and has proposed to amend such regulations to prohibit the flaring of liquid hydrocarbons and oil without prior authorization. Similarly, the MMS has promulgated other regulations governing the plug and abandonment of wells located offshore and the installation and removal of all production facilities.

To cover the various obligations of lessees on the OCS, the MMS generally requires that lessees have substantial net worth or post bonds or other acceptable assurances that such obligations will be satisfied. The cost of these bonds or assurances can be substantial, and there is no assurance that they can be obtained in all cases. We are currently exempt from supplemental bonding requirements by the MMS. Under some circumstances, the MMS may require any of our operations on federal leases to be suspended or terminated. Any such suspension or termination could materially adversely affect our financial condition and results of operations.

The MMS also administers the collection of royalties under the terms of the OCSLA and the oil and natural gas leases issued thereunder. The amount of royalties due is based upon the terms of the oil and natural gas leases as well as the regulations promulgated by the MMS. The MMS regulations governing the calculation of royalties and the valuation of crude oil produced from federal leases currently rely on arm’s-length sales prices and spot market prices as indicators of value. On August 20, 2003, the MMS issued a proposed rule that would change certain components of its valuation procedures for the calculation of royalties owed for crude oil sales. The proposed changes include changing the valuation basis for transactions not at arm’s-length from spot to the New York Mercantile Exchange prices adjusted for locality and quality differentials, and clarifying the treatment of transactions under a joint operating agreement. Final comments on the proposed rule were due on November 10, 2003. We cannot predict whether this proposed rule will take effect as written, nor can we predict whether the proposed rule, if it takes effect, will be challenged in federal court and whether it will withstand such a challenge. We believe this rule, as proposed, will not have a material impact on our financial condition, liquidity or results of operations.

Oil and natural gas liquids transportation rates. Sales of crude oil, condensate and natural gas liquids by us are not currently regulated and are made at market prices. In a number of instances, however, the ability to transport and sell such products is dependent on pipelines whose rates, terms and conditions of service are subject to FERC jurisdiction under the Interstate Commerce Act. In other instances, the ability to transport and sell such products is dependent on pipelines whose rates, terms and conditions of service are subject to regulation by state regulatory bodies under state statutes.

The regulation of pipelines that transport crude oil, condensate and natural gas liquids is generally more light-handed than the FERC’s regulation of natural gas pipelines under the Natural Gas Act. Regulated pipelines that transport crude oil, condensate and natural gas liquids are subject to common carrier obligations that generally ensure non-discriminatory access. With respect to interstate pipeline transportation subject to regulation of the FERC under the Interstate Commerce Act, rates generally must be cost-based, although market-based rates or negotiated settlement rates are permitted in certain circumstances. Pursuant to FERC Order No. 561, issued in October 1993, the FERC implemented regulations generally grandfathering all previously unchallenged interstate pipeline rates and made these rates subject to an indexing methodology. Under this indexing methodology, pipeline rates are subject to changes in the Producer Price Index for Finished Goods, minus one percent. A pipeline can seek to increase its rates above index levels provided that the pipeline can establish that there is a substantial divergence between the actual costs experienced by the pipeline and the rate resulting from application of the index. A pipeline can seek to charge a market-based rate if it establishes that it lacks significant market power. In addition, a pipeline can establish rates pursuant to settlement if agreed upon by all current shippers. A pipeline can seek to establish initial rates for new services through a cost-of-service proceeding, a market-based rate proceeding, or through an agreement between the pipeline and at least one shipper not affiliated with the pipeline. As provided for in Order No. 561, in July 2000, the FERC issued a Notice of Inquiry seeking comment on whether to retain or to change the existing oil rate-indexing method. In December 2000, the FERC issued an order concluding that the rate index reasonably estimated the actual cost changes in the pipeline industry and should be continued for another five-year period, subject to review in July 2005. In February 2003, on remand of its December 2000 order from the D.C. Circuit, the FERC changed the rate indexing methodology to the Producer Price Index for Finished Goods, but without the subtraction of 1% as had been done previously. The FERC made the change prospective only, but did allow oil pipelines to recalculate their maximum ceiling rates as though the new rate indexing methodology had been in effect since July 1, 2001. A challenge to FERC’s remand order was denied by the D.C. Circuit in April 2004.

With respect to intrastate crude oil, condensate and natural gas liquids pipelines subject to the jurisdiction of state agencies, such state regulation is generally less rigorous than the regulation of interstate pipelines. State agencies have generally not investigated or challenged existing or proposed rates in the absence of shipper complaints or protests. Complaints or protests have been infrequent and are usually resolved informally.

We do not believe that the regulatory decisions or activities relating to interstate or intrastate crude oil, condensate or natural gas liquids pipelines will affect us in a way that materially differs from the way it affects other crude oil, condensate and natural gas liquids producers or marketers.

Environmental regulations. We are subject to stringent federal, state and local laws. These laws, among other things, govern the issuance of permits to conduct exploration, drilling and production operations, the amounts and types of materials that may be released into the environment, the discharge and disposition of waste materials, the remediation of contaminated sites and the reclamation and abandonment of wells, sites and facilities. Numerous governmental departments issue rules and regulations to implement and enforce such laws, which are often difficult and costly to comply with and which carry substantial civil and even criminal penalties for failure to comply. Some laws, rules and regulations relating to protection of the environment may, in certain circumstances, impose strict liability for environmental contamination, rendering a person liable for environmental damages and cleanup cost without regard to negligence or fault on the part of such person. Other laws, rules and regulations may restrict the rate of oil and natural gas production below the rate that would otherwise exist or even prohibit exploration and production activities in sensitive areas. In addition, state laws often require various forms of remedial action to prevent pollution, such as closure of inactive pits and plugging of abandoned wells. The regulatory burden on the oil and natural gas industry increases our cost of doing business and consequently affects our profitability. These costs are considered a normal, recurring cost of our on-going operations. Our domestic competitors are generally subject to the same laws and regulations.

We believe that we are in substantial compliance with current applicable environmental laws and regulations and that continued compliance with existing requirements will not have a material adverse impact on our operations. However, environmental laws and regulations have been subject to frequent changes over the years, and the imposition of more stringent requirements could have a material adverse effect upon our capital expenditures, earnings or competitive position, including the suspension or cessation of operations in affected areas. As such, there can be no assurance that material cost and liabilities will not be incurred in the future.

The Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA") imposes liability, without regard to fault, on certain classes of persons that are considered to be responsible for the release of a "hazardous substance" into the environment. These persons include the current or former owner or operator of the disposal site or sites where the release occurred and companies that disposed or arranged for the disposal of hazardous substances. Under CERCLA, such persons may be subject to joint and several liability for the cost of investigating and cleaning up hazardous substances that have been released into the environment, for damages to natural resources and for the cost of certain health studies. In addition, companies that incur liability frequently also confront third party claims because it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment from a polluted site.

The Federal Solid Waste Disposal Act, as amended by the Resource Conservation and Recovery Act of 1976 ("RCRA"), regulates the generation, transportation, storage, treatment and disposal of hazardous wastes and can require cleanup of hazardous waste disposal sites. RCRA currently excludes drilling fluids, produced waters and other wastes associated with the exploration, development or production of oil and natural gas from regulation as "hazardous waste." Disposal of such non-hazardous oil and natural gas exploration, development and production wastes usually are regulated by state law. Other wastes handled at exploration and production sites or used in the course of providing well services may not fall within this exclusion. Moreover, stricter standards for waste handling and disposal may be imposed on the oil and natural gas industry in the future. From time to time, legislation is proposed in Congress that would revoke or alter the current exclusion of exploration, development and production wastes from the RCRA definition of “hazardous wastes,” thereby potentially subjecting such wastes to more stringent handling, disposal and cleanup requirements. If such legislation were enacted, it could have a significant impact on our operating cost, as well as the oil and natural gas industry in general. The impact of future revisions to environmental laws and regulations cannot be predicted.

Our operations are also subject to the Clean Air Act (“CAA”) and comparable state and local requirements. Amendments to the CAA were adopted in 1990 and contain provisions that may result in the gradual imposition of certain pollution control requirements with respect to air emissions from our operations. We may be required to incur certain capital expenditures in the future for air pollution control equipment in connection with obtaining and maintaining operating permits and approvals for air emissions. However, we believe our operations will not be materially adversely affected by any such requirements, and the requirements are not expected to be any more burdensome to us than to other similarly situated companies involved in oil and natural gas exploration and production activities.

The Federal Water Pollution Control Act of 1972, as amended (the “Clean Water Act”), imposes restrictions and controls on the discharge of produced waters and other wastes into navigable waters. Permits must be obtained to discharge pollutants into state and federal waters and to conduct construction activities in waters and wetlands. Certain state regulations and the general permits issued under the Federal National Pollutant Discharge Elimination System program prohibit the discharge of produced waters and sand, drilling fluids, drill cuttings and certain other substances related to the oil and natural gas industry into certain coastal and offshore waters, unless otherwise authorized. Further, the EPA has adopted regulations requiring certain oil and natural gas exploration and production facilities to obtain permits for storm water discharges. Cost may be associated with the treatment of wastewater or developing and implementing storm water pollution prevention plans. The Clean Water Act and comparable state statutes provide for civil, criminal and administrative penalties for unauthorized discharges for oil and other pollutants and impose liability on parties responsible for those discharges for the cost of cleaning up any environmental damage caused by the release and for natural resource damages resulting from the release. We believe that our operations comply in all material respects with the requirements of the Clean Water Act and state statutes enacted to control water pollution.

In November 2003, the EPA’s general wastewater permit for the western portion of the Gulf of Mexico expired. Recently, the EPA re-issued a new wastewater permit to become effective in November 2004. In the interim time period since the expiration of the permit, only those operations that were previously covered by the general permit at the time of its termination were allowed to continue discharging wastewater under an administrative extension of the permit. The EPA did not allow new operators to submit applications for coverage under the old permit.

In 2004, we transferred some properties and their corresponding discharge permits from our subsidiaries to the parent company. This permit transfer process involved canceling the existing permit of the subsidiary and applying for new coverage by the parent simultaneously. The EPA acted on the cancellation, but did not act on the application, citing the expiration of the general permit. We were informed by the EPA of this action several months later. We immediately ceased discharges under the affected permit and requested coverage under an EPA proposed alternative. Accordingly, we requested coverage under an Administrative Compliance Order until such time as the general permit is re-issued.

The EPA has advised that it will consider this Administrative Compliance Order to be diligent prosecution and that operators who apply for and comply with the Administrative Compliance Order, and the terms and conditions of the 1998 general permit, will be considered by the EPA to have only minor paperwork violations, in accordance with the 1995 Clean Water Act Settlement Policy.

Underground injection is the subsurface placement of fluid through a well, such as the reinjection of brine produced and separated from oil and natural gas production. The Safe Drinking Water Act of 1974, as amended, establishes a regulatory framework for underground injection, with the main goal being the protection of usable aquifers. The primary objective of injection well operating requirements is to ensure the mechanical integrity of the injection apparatus and to prevent migration of fluids from the injection zone into underground sources of drinking water. Hazardous-waste injection well operations are strictly controlled and certain wastes, absent an exemption, cannot be injected into underground injection control wells. In Louisiana and Texas, no underground injection may take place except as authorized by permit or rule. We currently own and operate various underground injection wells. Failure to abide by our permits could subject us to civil and/or criminal enforcement. We believe that we are in compliance in all material respects with the requirements of applicable state underground injection control programs and our permits.

Executive Order 13158, issued on May 26, 2000, directs federal agencies to safeguard existing Marine Protected Areas ("MPAs") in the United States and establish new MPAs. The order requires federal agencies to avoid harm to MPAs to the extent permitted by law and to the maximum extent practicable. It also directs the EPA to propose new regulations under the Clean Water Act to ensure appropriate levels of protection for the marine environment. This order has the potential to adversely affect our operations by restricting areas in which we may carry out future development and exploration projects and/or causing us to incur increased operating expenses.

Federal Lease Stipulations address the reduction of potential taking of protected marine species (sea turtles, marine mammals, Gulf sturgeon and other listed marine species). MMS permit approvals will be conditioned on collection and removal of debris resulting from activities related to exploration, development and production of offshore leases. MMS has issued Notices to Lessees and Operators ("NTL") 2003-G06 advising of requirements for posting of signs in prominent places on all vessels and structures.

Certain flora and fauna that have officially been classified as "threatened" or "endangered" are protected by the Endangered Species Act. This law prohibits any activities that could "take" a protected plant or animal or reduce or degrade its habitat area. If endangered species are located in an area we wish to develop, the work could be prohibited or delayed or expensive mitigation might be required.

Because our oil and natural gas operations include a production platform in the Gulf of Mexico located in a National Marine Sanctuary, we are also subject to additional federal regulation, including by the National Oceanic and Atmospheric Administration ("NOAA"). Unique regulations related to operations in the sanctuary include prohibition of drilling activities within certain protected areas, restrictions on the types of water and other substances that may be discharged, required depths of discharge in connection with drilling and production activities and limitations on mooring of vessels. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, incurrence of investigatory or remedial obligations or the imposition of injunctive relief.

Other statutes that provide protection to animal and plant species and which may apply to our operations include, but are not necessarily limited to, the National Environmental Policy Act, the Coastal Zone Management Act, the Oil Pollution Act, the Emergency Planning and Community Right-to-Know Act, the Marine Mammal Protection Act, the Marine Protection, Research and Sanctuaries Act, the Fish and Wildlife Coordination Act, the Fishery Conservation and Management Act, the Migratory Bird Treaty Act and the National Historic Preservation Act. These laws and regulations may require the acquisition of a permit or other authorization before construction or drilling commences and may limit or prohibit construction, drilling and other activities on certain lands lying within wilderness or wetlands and other protected areas and impose substantial liabilities for pollution resulting from our operations. The permits required for our various operations are subject to revocation, modification and renewal by issuing authorities.

We maintain insurance against "sudden and accidental" occurrences, which may cover some, but not all, of the risks described above. Most significantly, the insurance we maintain will not cover the risks described above which occur over a sustained period of time. Further, there can be no assurance that such insurance will continue to be available to cover all such cost or that such insurance will be available at a cost that would justify its purchase. The occurrence of a significant event not fully insured or indemnified against could have a material adverse effect on our financial condition and results of operations.

Regulation of oil and natural gas exploration and production. Our exploration and production operations are subject to various types of regulation at the federal, state and local levels. Such regulations include requiring permits and drilling bonds for the drilling of wells, regulating the location of wells, the method of drilling and casing wells and the surface use and restoration of properties upon which wells are drilled. Many states also have statutes or regulations addressing conservation matters, including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum rates of production from oil and natural gas wells and the regulation of spacing, plug and abandonment of such wells. Some state statutes limit the rate at which oil and natural gas can be produced from our properties.

State regulation. Most states regulate the production and sale of oil and natural gas, including requirements for obtaining drilling permits, the method of developing new fields, the spacing and operation of wells and the prevention of waste of oil and gas resources. The rate of production may be regulated and the maximum daily production allowable from both oil and gas wells may be established on a market demand or conservation basis or both.

Item 3. *Legal Proceedings*

From time to time, we are party to litigation or other legal and administrative proceedings that we consider to be a part of the ordinary course of our business. Currently, we are not involved in any legal proceedings nor are we party to any pending or threatened claims that could, individually or in the aggregate, reasonably be expected to have a material adverse effect on our financial condition, cash flow or results of operations.

Item 4. *Submission of Matters to a Vote of Security Holders*

Not applicable.

Item 4A. *Executive Officers of the Registrant*

The following table lists our executive officers:

Name	Age	Position
Tracy W. Krohn	50	Founder, Chairman, Chief Executive Officer, President, Treasurer and Director
Jerome F. Freel	92	Founder, Secretary, Director and Chairman Emeritus
W. Reid Lea	46	Vice President of Finance, Chief Financial Officer and Assistant Secretary
Jeffrey M. Durrant	50	Vice President of Exploration/Geoscience
Joseph P. Slattery	52	Vice President of Operations

Tracy W. Krohn has served as Chief Executive Officer and President since he founded the Company in 1983, as Chairman since 2004 and as Treasurer since 1997. Mr. Krohn's mother is married to Jerome F. Freel.

Jerome F. Freel has served as a director since our founding in 1983 and Secretary of the Company since 1984. Mr. Freel is married to Mr. Krohn's mother.

W. Reid Lea joined the Company as Vice President of Finance in 1999 and he has been the Chief Financial Officer since 2000. He is also our Assistant Secretary.

Jeffrey M. Durrant has been a member of our management team since 1997, initially as Geological Manager until 1999, then Exploration Manager until 2001 and, since 2001, Vice President of Exploration.

Joseph P. Slattery joined the Company in November 2002 as our Vice President of Operations. For more than eight years prior thereto, he was a major shareholder and president of Crescent Drilling & Production, Inc., a private consulting engineering firm specializing in total project management and field operations.

PART II

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

On January 28, 2005, certain shareholders of our common stock sold 12,655,263 shares pursuant to a registration statement that we filed with the Securities and Exchange Commission ("SEC") at an initial public offering price of $19.00 per share. Our common stock is listed and principally traded on the New York Stock Exchange under the symbol "WTI". From January 28, 2005 through March 24, 2005, the high and low closing sale prices per share of our common stock were $22.05 and $18.19, respectively. As of March 14, 2005, there were 56 registered holders of our common stock and approximately 3,400 beneficial shareholders. On March 24, 2005, the last reported closing sale price of our common stock on the New York Stock Exchange Composite Tape was $21.36 per share.

Dividends

Under the second amended and restated credit facility that we entered into on March 15, 2005, we are allowed to pay annual dividends of up to $30 million if we meet certain financial tests and are not in default. *See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources"* beginning at page 23 for more information regarding our credit facility.

The following table shows the frequency and amounts of all cash dividends distributed to shareholders during the two most recent fiscal years (in thousands, except per share data).

Payment Date	Aggregate Dividends on Common Stock	Dividend per Share of Common Stock	Aggregate Dividends on Series A Preferred Stock	Dividend per Share of Series A Preferred Stock
April 3, 2003	$ 10,000	$ 0.20		
May 27, 2003	2,000	0.04		
November 5, 2003	11,961	0.23	$ 3,039	$ 1.52
November 28, 2003	11,163	0.21	2,837	1.42
June 10, 2004	1,183	0.02	300	0.15
September 15, 2004	1,183	0.02	300	0.15
November 15, 2004	1,183	0.02	300	0.15

On March 28, 2005, the Company's board of directors declared a cash dividend of $0.02 per share of common stock, payable on May 2, 2005 to shareholders of record on April 15, 2005.

Additional Information. Since our initial public offering in January 2005, we are now required to file Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and other items with the Securities and Exchange Commission ("SEC"). Our reports filed with the SEC will be available free of charge to the general public through our website at *www.wtoffshore.com.* These reports will be accessible on our website as soon as reasonably practicable after being filed with the SEC. Requests for copies of this Annual Report and our other filings can also be obtained by contacting: Investor Relations, W&T Offshore, Inc., Eight Greenway Plaza, Suite 1330, Houston, Texas 77046 or by calling (713) 297-8024. These reports are also available at the SEC's public reference room at 450 Fifth Street, NW, Washington, DC 20549. The public may obtain information on the operation of the public reference room by calling the SEC at 1-800-SEC-0330. The SEC also maintains a website at *www.sec.gov* that contains reports, proxy and informational statements and other information regarding issuers that file electronically with the SEC.

Table of Contents

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

SELECTED HISTORICAL FINANCIAL INFORMATION

The selected historical financial information set forth below should be read in conjunction with "*Management's Discussion and Analysis of Financial Condition and Results of Operations*" and with our consolidated financial statements and notes to those financial statements included elsewhere in this report. The consolidated statement of income information for the years ended December 31, 2004, 2003, 2002, 2001 and 2000 and the consolidated balance sheet information as of December 31, 2004, 2003, 2002, 2001 and 2000 were derived from our audited financial statements. Share and per share information in this annual report gives effect to a 6.669173211-for-one split of our common stock effective November 30, 2004.

	Year Ended December 31,				
	2004	2003 (1)	2002 (1)	2001	2000
	(Dollars in thousands, except per share data)				
Consolidated Statement of Income Information:					
Revenues:					
Oil and gas	$ 508,195	$ 421,435	$ 189,892	$ 169,054	$ 102,285
Other	520	1,152	1,443	534	1,762
Total revenues	508,715	422,587	191,335	169,588	104,047
Operating costs and expenses:					
Lease operating	73,475	65,947	26,454	22,099	12,622
Gathering, transportation and production taxes	14,099	10,213	3,672	5,048	2,850
Depreciation, depletion and amortization	155,640	136,249	89,941	65,293	29,775
Asset retirement obligation accretion (2)	9,168	7,443	—	—	—
General and administrative (3)(4)	25,001	22,912	10,060	9,677	6,398
Total operating costs and expenses	277,383	242,764	130,127	102,117	51,645
Impairment of subsidiary assets (5)	—	—	3,750	—	—
Income from operations	231,332	179,823	57,458	67,471	52,402
Interest expense, net	(1,842)	(2,229)	(3,001)	(3,902)	(4,198)
Income before income taxes	229,490	177,594	54,457	63,569	48,204
Income taxes (6)	80,008	61,156	52,408	—	—
Cumulative effect of change in accounting principle (net of taxes of $77) (2)	—	144	—	—	—
Net income	149,482	116,582	2,049	63,569	48,204
Less preferred stock dividends	900	5,876	—	—	—
Net income applicable to common shareholders	$ 148,582	$ 110,706	$ 2,049	$ 63,569	$ 48,204
Net income per common and common equivalent share (7):					
Basic earnings per share	$ 2.82	$ 2.14	$ —	$ —	$ —
Diluted earnings per share	2.27	1.79	—	—	—
Common stock dividends	3,550	35,124	—	—	—
Cash dividends per common share	0.07	0.67	—	—	—
Subchapter S corporation tax distributions	—	—	13,883	14,001	2,494
Consolidated Cash Flow Information:					
Net cash provided by operating activities	$ 377,275	$ 263,155	$ 147,809	$ 123,884	$ 96,824
Capital expenditures	284,847	203,400	116,759	126,399	129,725
Other Financial Information (Unaudited):					
EBITDA (8)	$ 396,140	$ 323,659	$ 147,399	$ 132,764	$ 82,177

	December 31,				
	2004	2003	2002	2001	2000
	(Dollars in thousands)				
Consolidated Balance Sheet Information:					
Total assets	$ 760,784	$ 546,729	$ 341,194	$ 282,483	$ 214,170
Long-term debt	35,000	67,000	99,600	82,400	67,000
Shareholders' equity	359,878	214,455	133,330	164,182	114,613

Table of Contents

(1) In December 2003, we acquired working interests in 13 oil and gas fields located in the Gulf of Mexico from ConocoPhillips and in December 2002, we acquired working interests in 53 oil and gas fields located in the Gulf of Mexico from Burlington Resources.

(2) Effective January 1, 2003, we adopted Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations*. The cumulative effect of the change in accounting principle is $221 thousand ($144 thousand net of income taxes). See Note 2 to our consolidated financial statements.

(3) The amount for 2004 includes approximately $6.7 million resulting from expenses associated with our initial public offering and from an employee bonus granted by our board of directors to all employees of record on December 31, 2004 (other than the Chief Executive Officer and the Corporate Secretary) in amounts equal to their 2004 salaries. The bonus will be paid in two installments, on June 1, 2005 and January 3, 2006 solely to individuals who are still in our employ on those dates. The amount for 2004 also includes approximately $0.6 million of compensation expense resulting from an incentive compensation grant to certain key employees (other than the Chief Executive Officer and the Corporate Secretary), of which $0.4 million was restricted common stock and $0.2 million was cash.

(4) The amount for 2003 includes $9.3 million of compensation expense resulting from an incentive compensation grant to certain key employees (other than the Chief Executive Officer and the Corporate Secretary), of which approximately $5.5 million was restricted common stock and approximately $3.8 million was cash.

(5) This impairment is related to the sale of a subsidiary to two of our shareholders. See Notes 4 and 15 to our consolidated financial statements.

(6) On December 3, 2002, we revoked our election under Subchapter S of the Internal Revenue Code and began paying income tax at the corporate level. Current and deferred tax liabilities recorded in 2002 reflected the cumulative effect of certain tax liabilities, as more fully described in Note 9 to our consolidated financial statements.

(7) Net income per share information has not been presented for the 2000 through 2002 because we were an S corporation during the majority of that period of time. The results for those years would not be comparable to the presentation for 2004 and 2003.

(8) We define EBITDA as net income plus income tax expense, net interest expense, depreciation, depletion, amortization and accretion. Although not prescribed under GAAP, we believe the presentation of EBITDA is relevant and useful because it helps our investors understand our operating performance and makes it easier to compare our results with those of other companies that have different financing, capital or tax structures. EBITDA should not be considered in isolation from or as a substitute for net income, as an indication of operating performance or cash flows from operating activities or as a measure of liquidity. EBITDA, as we calculate it, may not be comparable to EBITDA measures reported by other companies. In addition, EBITDA does not represent funds available for discretionary use. The following table presents a reconciliation of our consolidated net income to consolidated EBITDA.

	Year Ended December 31,				
	2004	2003	2002	2001	2000
	(Dollars in thousands)				
Net income	$ 149,482	$ 116,582	$ 2,049	$ 63,569	$ 48,204
Income taxes	80,008	61,156	52,408	—	—
Net interest expense	1,842	2,229	3,001	3,902	4,198
Depreciation, depletion, amortization and accretion	164,808	143,692	89,941	65,293	29,775
EBITDA	$ 396,140	$ 323,659	$ 147,399	$ 132,764	$ 82,177

Table of Contents

HISTORICAL RESERVE AND OPERATING INFORMATION

The following table presents summary information regarding our estimated net proved oil and natural gas reserves as of December 31, 2004, 2003, 2002, 2001 and 2000 and our historical operating data for the years ended December 31, 2004, 2003, 2002, 2001, 2000. All calculations of estimated net proved reserves have been made in accordance with the rules and regulations of the SEC and, except as otherwise indicated, give no effect to federal or state income taxes. For additional information regarding our reserves, please read the section of this report entitled "*Items 1. and 2. Business and Properties*" beginning at page 1. The selected historical operating data set forth below should be read in conjunction with "*Management's Discussion and Analysis of Financial Condition and Results of Operations*" and with our consolidated financial statements and the notes to those consolidated financial statements included elsewhere in this report.

	December 31,				
	2004	2003	2002	2001	2000
Reserve Data:					
Estimated net proved reserves (1):					
Natural gas (Bcf)	227.6	231.1	219.0	154.7	103.4
Oil (MMBbls)	40.0	35.6	23.1	15.2	17.3
Total natural gas and oil (Bcfe)	467.5	444.7	357.5	245.7	207.4
Proved developed producing (Bcfe)	145.8	135.5	108.1	69.2	79.7
Proved developed non-producing (Bcfe)	144.4	160.1	121.1	103.7	69.4
Total proved developed (Bcfe)	290.1	295.6	229.2	173.0	149.1
Proved undeveloped (Bcfe)	177.3	149.1	128.3	72.7	58.3
Proved developed reserves as a percentage of proved reserves	62.1%	66.5%	64.1%	70.4%	71.9%
Reserve additions (Bcfe):					
Acquisitions	19.2	124.1	128.3	2.1	64.9
Extensions, discoveries and other additions	65.2	48.6	24.2	93.0	22.2
Revisions	20.9	(6.5)	15.0	(12.9)	(9.4)
Total net reserve additions	105.3	166.2	167.5	82.2	77.7

	Year Ended December 31,				
	2004	2003	2002	2001	2000
Operating Data:					
Net sales:					
Natural gas (MMcf)	53,348	52,807	39,368	28,412	12,368
Oil (MBbls)	4,847	4,373	2,465	2,314	1,893
Total natural gas and oil (MMcfe) (1)	82,432	79,045	54,158	42,296	23,726
Average daily equivalent sales (MMcfe/d)	225.2	216.6	148.5	115.9	64.9
Average realized sales price (2):					
Natural gas ($/Mcf)	$ 6.18	$ 5.60	$ 3.34	$ 4.11	$ 4.02
Oil ($/Bbl)	36.77	28.74	23.57	22.66	27.79
Average per Mcfe data ($/Mcfe):					
Lease operating expenses	$ 0.89	$ 0.83	$ 0.49	$ 0.52	$ 0.53
Gathering, transportation costs and production taxes	0.17	0.13	0.07	0.12	0.12
Depreciation, depletion, amortization and accretion (3)	2.00	1.82	1.66	1.54	1.26
General and administrative (4)(5)	0.30	0.29	0.19	0.23	0.27
Net cash provided by operating activities	4.58	3.33	2.73	2.93	4.08
EBITDA (6)	4.81	4.09	2.72	3.14	3.46

(1) One billion cubic feet equivalent (Bcfe), one million cubic feet equivalent (MMcfe) and one thousand cubic feet equivalent (Mcfe) are determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids (totals may not add due to rounding).

(2) Average realized sales prices do not include any effects of hedging, because we did not engage in any financial hedge transactions during the periods presented.

(3) Accretion expense is only included in the data presented for 2004 and 2003, subsequent to our adoption of Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations*, on January 1, 2003.

(4) The amount for 2004 includes approximately $6.7 million ($0.08 per Mcfe) resulting from expenses associated with our initial public offering and from an employee bonus granted by our board of directors to all employees of record on December 31, 2004 (other than the Chief Executive Officer and the Corporate Secretary) in amounts equal to their 2004 salaries. The bonus will be paid in two installments, on June 1, 2005 and January 3, 2006 solely to individuals who are still in our employ on those dates. The amount for 2004 also includes approximately $0.6 million of compensation expense resulting from an incentive compensation grant to certain key employees (other than the Chief Executive Officer and the Corporate Secretary), of which $0.4 million was restricted common stock and $0.2 million was cash.

(5) The amount for 2003 includes $9.3 million ($0.11 per Mcfe) of compensation expense resulting from an incentive compensation grant to certain key employees (other than the Chief Executive Officer and the Corporate Secretary), of which approximately $5.5 million was restricted common stock and approximately $3.8 million was cash.

(6) We define EBITDA as net income plus income tax expense, net interest expense, depreciation, depletion, amortization and accretion. See Note 8 to the first table in *Selected Historical Financial Information* for reconciliation of EBITDA to net income. Although not prescribed under generally accepted accounting principles, we believe the presentation of EBITDA is relevant and useful because it helps our investors understand our operating performance and makes it easier to compare our results with those of other companies that have different financing, capital or tax structures. EBITDA should not be considered in isolation from or as a substitute for net income, as an indication of operating performance or cash flows from operating activities or as a measure of liquidity. EBITDA, as we calculate it, may not be comparable to EBITDA measures reported by other companies. In addition, EBITDA does not represent funds available for discretionary use.

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

The following discussion and analysis should be read in conjunction with our accompanying consolidated financial statements and the notes to those financial statements included elsewhere in this annual report. The following discussion includes forward-looking statements that reflect our plans, estimates and beliefs. Our actual results could differ materially from those discussed in these forward-looking statements. Factors that could cause or contribute to such differences include, but are not limited to, those discussed below and elsewhere in this annual report.

Overview

We are engaged in oil and natural gas acquisition, exploitation and exploration activities, primarily in the Gulf of Mexico. We own working interests in approximately 108 fields in federal and state waters and we operated wells accounting for approximately 63% of our average daily production in the month of December 2004. We have interests in leases covering approximately 927,000 acres spanning across the outer continental shelf off the coast of Louisiana, Texas, Mississippi and Alabama. We own interests in approximately 250 offshore structures, of which 105 are platforms in the fields that we operate. We maintain these platforms and use them to separate oil and natural gas derived from nearby wells. In recent years, we have acquired interests in acreage and wells in the deepwater (more than 500 feet of water) off the outer continental shelf.

In managing our business, we are concerned primarily with maximizing return on shareholders' equity. To accomplish this primary goal, we focus on profitably increasing production and reserves. We do not seek to increase production and reserves solely for the sake of recording growth. Rather, we acquire reserves or explore for new reserves where we believe we can achieve a rate of return on shareholders' equity over any five-year period comparable to our historic average. Our ability to control our costs over the past five years has contributed to the growth in our shareholders' equity. Certain risks are inherent in the oil and natural gas industry and our business, any one of which if it occurs, can negatively impact our ability to achieve historic rates of return on shareholders' equity.

We grow our reserves through drilling programs and acquisitions. Some of our acquisitions are made through the exercise of preferential rights in properties in which we already own an interest. During 2004, we exercised preferential rights to purchase on five such properties. The costs of exercising our preferential rights totaled $32.5 million and added approximately 19.2 Bcfe of proved reserves. We have focused on acquiring properties where we can develop an inventory of drilling prospects that enable us to continue to add reserves post-acquisition. During 2003 and 2002, we made significant acquisitions from ConocoPhillips and Burlington Resources, Inc., respectively. During 2004, we did not complete any significant acquisition. In spite of the extremely competitive nature of the current acquisition landscape, our acquisition team is working diligently to find properties that fit our historical profile and will add strategic and financial value to the Company.

During 2002, we completed our largest acquisition to date from Burlington Resources with working interests in 53 offshore fields. During 2003, we acquired working interests in 13 offshore fields from ConocoPhillips. Both of these acquisitions were consummated in the month of December, so they did not have a material effect on our operations or consolidated income statement in the year completed.

Our exploration efforts are balanced between discovering new reserves associated with acquisitions and discoveries on acreage already under lease. Historically, we have financed our exploratory drilling with net cash provided by operating activities. The investment associated with drilling a well and future development of a project principally depends upon the water depth of the well or project, the depth of the well or wells, the complexity of the geological formations involved and whether the well or project can be connected to existing infrastructure or will require additional investment in infrastructure. Deepwater and deep shelf drilling projects can be substantially more capital intensive than those on the conventional shelf. When projects are extremely capital intensive and involve substantial risk, we generally seek joint venture participants to share the risk.

We generally sell our oil and natural gas at the current market price at the wellhead, or we transport it to "pooling points" where it is sold. We are required to pay gathering and transportation cost with respect to all of our products. We market our products several different ways depending upon a number of factors, including the availability of purchasers for the product at the wellhead, the availability and cost of pipelines near the well or related production platforms, market prices, pipeline constraints and operational flexibility. During 2004, we sold an average of approximately 146 MMcf of natural gas per day and approximately 13,000 Bbls of oil per day. Our revenues in 2004 benefited from a general rise in oil and natural gas prices over the year. Over the past three years, we have not engaged in any commodity or financial hedging transactions, and we presently have no hedges in place.

Our operating costs involve the expense of operating our wells, platforms and other infrastructure in the Gulf of Mexico and transporting our products to the point of sale. Our operating costs are generally comprised of several components, including direct operating costs, repair and maintenance costs, transportation costs, production taxes, certain workover costs and ad valorem taxes. Our operating costs are driven in part by the type of commodity produced, the level of workover activity and the geographical location of the properties.

In recent years, we began to acquire and build platforms near the outer edge of the continental shelf and we began operating wells in the deepwater of the Gulf of Mexico. As we expand our deepwater operations, our operating costs may increase. While each field can present operating problems that can add to the costs of operating a field, the production cost of a field is generally directly proportional to the number of platforms built in the field to handle production. As technologies have improved, it has become possible to produce oil and natural gas from a larger acreage area using a single platform, which may reduce the operating cost structure associated with recently developed fields.

Applicable environmental regulations require us to remove our platforms after production has ceased, to plug and abandon all wells and to remediate any environmental damage our operations may have caused. The costs associated with our plug and abandonment liabilities generally increase as we drill wells in the deeper parts of the continental shelf and the deepwater. We generally do not pre-fund our estimated abandonment liabilities, which we estimated to be $142.4 million discounted at 8% at December 31, 2004, because we operate under an exemption from certain bonding requirements under MMS rules.

Results of Operations

The following table sets forth selected operating data for the periods indicated (all values are net to our interest):

	Year Ended December 31,		
	2004	**2003**	**2002**
Operating Data:			
Net sales:			
Natural gas (Bcf)	53.3	52.8	39.4
Oil (MMBbls)	4.8	4.4	2.5
Total natural gas and oil (Bcfe) (1)	82.4	79.0	54.2
Average daily equivalent sales (MMcfe/d)	225.2	216.6	148.5
Average realized sales price (2):			
Natural gas ($/Mcf)	$ 6.18	$ 5.60	$ 3.34
Oil ($/Bbl)	36.77	28.74	23.57
Average per Mcfe data ($/Mcfe):			
Lease operating expenses	$ 0.89	$ 0.83	$ 0.49
Gathering, transportation cost and production taxes	0.17	0.13	0.07
Depreciation, depletion, amortization and accretion (3)	2.00	1.82	1.66
General and administrative (4)(5)	0.30	0.29	0.19
Net cash provided by operating activities	4.58	3.33	2.73
EBITDA (6)	4.81	4.09	2.72

(1) One billion cubic feet equivalent (Bcfe), one million cubic feet equivalent (MMcfe) and one thousand cubic feet equivalent (Mcfe) are determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids (totals may not add due to rounding).

(2) Average realized sales prices do not include any effects of hedging, because we did not engage in any financial hedge transactions during the periods presented.

(3) Accretion expense is only included in the data presented for 2004 and 2003, subsequent to our adoption of Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations*, on January 1, 2003.

(4) The amount for 2004 includes approximately $6.7 million ($0.08 per Mcfe) resulting from expenses associated with our initial public offering and from an employee bonus granted by our board of directors to all employees of record on December 31, 2004 (other than the Chief Executive Officer and the Corporate Secretary) in amounts equal to their 2004 salaries. The bonus will be paid in two installments, on June 1, 2005 and January 3, 2006 solely to individuals who are still in our employ on those dates. The amount for 2004 also includes approximately $0.6 million of compensation expense resulting from an incentive compensation grant to certain key employees (other than the Chief Executive Officer and the Corporate Secretary), of which $0.4 million was restricted common stock and $0.2 million was cash.

(5) The amount for 2003 includes $9.3 million ($0.11 per Mcfe) of compensation expense resulting from an incentive compensation grant to certain key employees (other than the Chief Executive Officer and the Corporate Secretary), of which approximately $5.5 million was restricted common stock and approximately $3.8 million was cash.

(6) We define EBITDA as net income plus income tax expense, net interest expense, depreciation, depletion, amortization and accretion. See Note 8 to the first table in *Selected Historical Financial Information* for reconciliation of EBITDA to net income. Although not prescribed under generally accepted accounting principles, we believe the presentation of EBITDA is relevant and useful because it helps our investors understand our operating performance and makes it easier to compare our results with those of other companies that have different financing, capital or tax structures. EBITDA should not be considered in isolation from or as a substitute for net income, as an indication of operating performance or cash flows from operating activities or as a measure of liquidity. EBITDA, as we calculate it, may not be comparable to EBITDA measures reported by other companies. In addition, EBITDA does not represent funds available for discretionary use.

Year Ended December 31, 2004 Compared to Year Ended December 31, 2003

Oil and natural gas revenues. Oil and natural gas revenues increased $86.8 million to $508.2 million for the year ended December 31, 2004. Natural gas revenues increased $34.2 million and oil revenues increased $52.6 million. The natural gas revenue increase was caused by a 0.5 Bcf sales volume increase and a 10% increase in the average realized natural gas price from $5.60 per Mcf for the year ended December 31, 2003 to $6.18 per Mcf for the same period in 2004. The oil revenue increase was caused by a sales volume increase of 474 MBbls for the year ended December 31, 2004 and a 28% increase in the average realized price, from $28.74 per barrel in 2003 to $36.77 per barrel in 2004. The volume increase for oil and natural gas was primarily attributable to our transaction with ConocoPhillips in December 2003. Sales volumes for all products were negatively impacted for the year ended December 31, 2004 by the curtailment of production due to Hurricane Ivan, which reduced average daily equivalent sales for the three months ended December 31, 2004 by approximately 2%.

Lease operating expenses. Our lease operating expenses increased from $65.9 million in 2003 to $73.5 million in the same period of 2004. The increase is attributable in part to properties we acquired during December 2003. On a per Mcfe basis, lease operating expenses increased 7%, from $0.83 per Mcfe in 2003 to $0.89 per Mcfe in 2004 primarily due to higher operating costs associated with existing properties. Approximately $1.6 million of the increase relates to an employee bonus granted by our board of directors to all employees of record on December 31, 2004 (other than the Chief Executive Officer and Corporate Secretary) in amounts equal to their 2004 salaries.

Gathering and transportation cost and production taxes. Gathering and transportation cost and production taxes increased from $10.2 million in 2003 to $14.1 million in 2004, due primarily to an increase in the volume of our production during 2004 and increased transportation costs. Production taxes did not materially change during the year ended December 31, 2004 as compared to 2003. Most of our production, including production resulting from recent acquisitions, is from federal waters, where there are no production taxes.

Depreciation, depletion, amortization and accretion. Depreciation, depletion, amortization and accretion ("DD&A") increased from $143.7 million in 2003 to $164.8 million in 2004. On a per Mcfe basis, DD&A was $2.00 for the year ended December 31, 2004, compared to $1.82 for the same period in 2003. The increase in DD&A was a result of higher production volumes, combined with a higher depletion rate, an increase in our total depletable costs due to our drilling activities and the lack of additions to our oil and natural gas reserves in quantities sufficient to offset reserves added through acquisitions in the prior year.

General and administrative expenses. General and administrative expenses ("G&A") increased from $22.9 million for the year ended December 31, 2003 to $25.0 million in the same period of 2004. Approximately $1.5 million of the increase relates to expenses associated with our initial public offering. During December 2004, our board of directors granted an employee bonus to all employees of record on December 31, 2004 (other than the Chief Executive Officer and the Corporate Secretary) in amounts equal to their 2004 salaries. The bonus will be paid in two installments, on June 1, 2005 and January 3, 2006 solely to individuals who are still in our employ on those dates. Approximately $5.2 million of expenses related to this bonus are included in G&A for the year ended December 31, 2004. In 2003, the Company granted incentive compensation awards of $9.3 million to certain key employees (other than the Chief Executive Officer and the Corporate Secretary).

Interest expense. Interest expense decreased from $2.5 million for the year ended December 31, 2003 to $2.1 million in the same period of 2004 due primarily to lower average borrowings during 2004 offset by increased fees related to the unused portion of our credit facility.

Income tax expense. Income tax expense increased from $61.2 million in 2003 to $80.0 million in 2004 primarily due to increased taxable income. Our effective tax rate for the years ended December 31, 2004 and 2003 was 35% and 34%, respectively.

Net income. Net income for the year ended December 31, 2004 increased $32.9 million to $149.5 million. The primary reasons for this increase were as follows:

- higher volumes of crude oil and natural gas sold in 2004, as compared to the same period in 2003;
- higher oil prices in 2004 of $36.77 per barrel, as compared to $28.74 per barrel in the same period in 2003; and
- higher natural gas prices in 2004 of $6.18 per Mcf, as compared to $5.60 per Mcf in the same period in 2003.

Offsetting these favorable factors were increases in lease operating expenses, transportation costs, DD&A, G&A and income taxes.

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

Oil and natural gas revenue. Oil and natural gas revenues increased approximately $231.5 million to $421.4 million in 2003. Natural gas revenues increased $164.1 million and oil revenues increased $67.4 million. The natural gas revenue increase was caused by a 68% increase in the average realized natural gas price from $3.34 per Mcf in 2002 to $5.60 per Mcf in 2003, combined with a 13.4 Bcf volume increase in natural gas sales in 2003. The oil revenue increase was caused by a sales volume increase of 1.9 million barrels in 2003 and a 22% increase in the average realized price, from $23.57 per barrel in 2002 to $28.74 per barrel in 2003. The volume increase for oil and natural gas was primarily attributable to our transaction with Burlington Resources in December 2002.

Lease operating expenses. Our lease operating expenses increased from $26.5 million in 2002 to $65.9 million in 2003. The increase resulted from acquisitions during December 2002 and in 2003 that increased the number of properties we had under lease. On a per Mcfe basis, lease operating expenses increased 69%, from $0.49 per Mcfe during 2002 to $0.83 per Mcfe during 2003. This increase was due to the fact that the properties we acquired from Burlington Resources had historically higher operating costs than our existing properties in part because they consisted of multi-platform fields.

Gathering, transportation cost and production taxes. Gathering, transportation cost and production taxes increased from $3.7 million in 2002 to $10.2 million in 2003, due in part to an increase in the volume of our production during 2003. Other factors that contributed to the increase in gathering and transportation cost during 2003 were market conditions in 2003 and, in particular, certain pipeline constraints requiring additional processing levels on natural gas production, along with a higher cost gas gathering agreement that we acquired as a result of the transaction with Burlington Resources. Production taxes did not materially change in 2003. Most of our production, including production resulting from recent acquisitions, is from federal waters, where there are no production taxes.

Depreciation, depletion, amortization and accretion. DD&A increased from $89.9 million in 2002 to $143.7 million in 2003. The increase in DD&A was a result of higher production volumes, combined with a higher depletion rate and a substantial increase in our total properties as a result of the transactions with Burlington Resources in December 2002 and ConocoPhillips in December 2003. Included in DD&A in 2003 is $7.4 million related to the accretion of discount on our asset retirement obligations. Effective January 1, 2003, we adopted the provisions of Statement of Financial Accounting Standards ("SFAS") No. 143, *Accounting for Asset Retirement Obligations.*

General and administrative expenses. G&A, increased from $10.1 million in 2002 to $22.9 million in 2003. This increase was related primarily to a grant by the Company of incentive compensation awards to certain key employees (other than the Chief Executive Officer and the Corporate Secretary) in 2003. The cost of these grants was approximately $9.3 million, which had the effect of increasing our G&A for 2003 by $0.11 per Mcfe over what it otherwise would have been. The incentive compensation grants were comprised of approximately $5.5 million of restricted common stock and $3.8 million of cash. In addition, there were increases in compensation expense associated with increased personnel required to administer our growth, more active acquisition and exploitation programs and general cost inflation. While we use the full-cost method of accounting that requires us to capitalize some of the costs of exploration, we expensed approximately $1.8 million in 2002 and $1.9 million in 2003 of geological and geophysical costs incurred in our exploration activities, which we included as G&A.

Interest expense. Interest expense decreased to $2.5 million in 2003, compared to $3.1 million in 2002. The decrease was due to lower average debt levels in 2003 and a decline in overall interest rates. During 2003, we applied available excess cash flow to reduce our outstanding debt by $32.6 million.

Income tax expense. The amount of our income tax expense increased from $52.4 million in 2002 to $61.2 million in 2003. Income tax expenses in 2003 reflected our first full year as a corporate taxpayer after our December 2002 revocation of our election under subchapter S of the Internal Revenue Code. The $52.4 million of tax expense reflected in 2002 includes deferred taxes we were required to recognize upon our revocation of S-corporation status and is not reflective of the single year's expense. Our effective tax rate for 2003, the first full year in which we were taxed as a corporation, was 34%.

Cumulative effect of change in accounting principle. Upon our adoption of SFAS No. 143 effective January 1, 2003, we recorded an increase in net property, plant and equipment of $95.0 million, recognition of an initial asset retirement obligation of $101.7 million and a cumulative effect of adoption that increased net income and shareholders' equity by $0.1 million, net of income tax.

Net income. Net income increased from $2.0 million in 2002 to $116.6 million in 2003. The primary reasons for this increase were:

- the effect of a revocation of our election in 2002 under subchapter S of the Internal Revenue Code which required a $52.4 million provision for deferred taxes;
- the favorable effects on operating income contributed in 2003 by the properties we acquired in December 2002;
- higher crude oil and natural gas prices in 2003, as compared to 2002; and
- higher volumes of crude oil and natural gas sold in 2003, as compared to 2002.

These favorable factors were offset, in part, by higher lease operating, tax and G&A costs due to our growth.

Liquidity and Capital Resources

Cash flow and working capital. Net cash flow provided by operating activities for the year ended December 31, 2004 was $377.3 million, compared to $263.2 million for the comparable period in 2003. Net cash flow used in investing activities totaled $279.9 million and $204.4 million during 2004 and 2003, respectively, which primarily represents our investment in oil and gas properties. Net cash flow used in financing activities totaled $36.4 million and $73.7 million for the years ended December 31, 2004 and 2003, respectively. In total, cash and cash equivalents increased from $4.0 million as of December 31, 2003 to $65.0 million as of December 31, 2004.

Increases in our operating cash flows from 2002 through 2004 reflect increases in the volume of production from year to year, as well as an increase in the average prices we received for our oil and gas production over the three-year period. Average daily equivalent sales grew 46% from 2002 to 2003, and 4% from 2003 to 2004. Average realized prices on sales of a barrel of crude oil were $23.57 in 2002, $28.74 in 2003 and $36.77 in 2004. Average realized prices on sales of natural gas were $3.34 per Mcf in 2002, $5.60 per Mcf in 2003 and $6.18 per Mcf in 2004. We have been able to substantially fund our investing and financing activities with our operating cash flow in recent years.

The level of our investment in oil and gas properties changes from time to time, depending on numerous factors, including the price of oil and gas, acquisition opportunities and the results of our exploration and development activities. During 2004, our oil and gas investments totaled $282.5 million in oil and gas properties, including drilling 21.4 net exploration wells and 4.3 net development wells. During 2003, we invested $201.3 million in oil and gas properties, including a significant acquisition of a subsidiary of ConocoPhillips, numerous acquisitions of other interests and drilling 4.8 net exploration wells and 2.7 net development wells. During 2002, our oil and gas investments totaled $115.8 million in oil and gas properties, including a significant acquisition of subsidiaries of Burlington Resources in December 2002. Our drilling activity declined somewhat in 2002, with only 4.0 net exploratory wells and 1.1 net development wells drilled. The wells we have been drilling over the past three years have tended to be deeper and to involve more technological challenges than our past drilling projects, and have thus been more expensive to drill.

In each of the years ended December 31, 2004, 2003 and 2002, we borrowed under our credit agreement to finance investments and acquisitions, but consistent with our conservative financial approach, we repaid these borrowings as soon as possible. Payments under our credit agreement totaled $244.1 million in 2004, $285.8 million in 2003 and $147.0 million in 2002.

We had working capital deficits at December 31, 2004 and 2003 of $10.5 million and $29.1 million, respectively. Our credit agreement enables us to consider our available borrowings as current assets to calculate our working capital compliance ratio; therefore, we were in compliance with our credit agreement at December 31, 2004 and 2003. Working capital deficits are not unusual at the end of a period, and are usually the result of accounts payable related to exploration and development costs. We believe that our working capital balance should be viewed in conjunction with our cash provided by operations and the availability of borrowings under our bank credit facility when measuring liquidity. At December 31, 2004, $190.0 million was available for borrowing under our bank credit facility. Thus, working capital deficits have not had a material adverse effect on our ability to conduct our operations or acquire properties. As examples, in 2003 we financed a significant acquisition, the ConocoPhillips transaction, increasing our oil and gas assets approximately $44.1 million, while our debt decreased by $32.6 million. Additionally, the borrowing base under our credit facility grew from $180 million at December 31, 2002 to $230 million at December 31, 2004. Our undrawn borrowing capacity increased $109.6 million over the same period due to decreased borrowings and the increase in the size of the facility.

We intend to fund our future exploration and exploitation expenditures from net cash flow provided by operating activities and borrowings under our revolving credit facility. Our future net cash flow provided by operating activities will depend on our ability to maintain and increase production through our exploitation and exploratory drilling program and through acquisitions, as well as the prices of oil and natural gas. If our net cash from operating activities should decrease (whether as a result of a decrease in the price of oil and gas, lower production volumes or higher expenses), then we would not be able to fund the same levels of exploration and exploitation activities from operating cash as we have done in the past. We typically borrow under our bank credit facility for working capital needs in addition to funding acquisitions. We believe that our projected cash flows from operations and available capacity under our revolving credit facility will be sufficient to meet our cash requirements for the foreseeable future. However, we may require additional debt or equity financing depending upon our ability to finance future acquisitions or exploration, exploitation and development activity.

Credit facility. On March 15, 2005, we entered into a new $300 million secured revolving credit facility with an initial borrowing base of $230 million, which is subject to redetermination on March 1 and September 1 of each year. Security for the credit facility is 80% of the value of our oil and gas properties, as determined by our lenders. As of March 29, 2005, we had no long-term debt outstanding under the credit facility and had $5.0 million of letters of credit outstanding, with $225 million of undrawn capacity. As of December 31, 2004, we had $35 million in long-term debt outstanding under the credit facility and had $5.0 million of letters of credit outstanding, with $190.0 million of undrawn capacity. The indebtedness outstanding at December 31, 2004 was repaid in January 2005. If the borrowing base of the credit facility is determined to be lower than the then outstanding amount of loans and letters of credit, we must pay the difference in three monthly installments or provide additional collateral satisfactory to the lenders. The maturity date of the credit facility has been extended to March 15, 2009, when the entire amount outstanding, if any, will be due. Interest accrues either (1) at the higher of the Prime Rate or the Federal Funds Rate plus 0.50% plus a margin which varies from 0.0% to 0.625% depending upon the ratio of the amounts outstanding to the borrowing base or (2) to the extent any loan outstanding is designated as a Eurodollar loan, at the London Interbank Offered Rate, plus a margin that varies from 1.25% to 1.875%, depending upon the ratio of the amounts outstanding to the borrowing base.

The second amended and restated credit agreement has covenants that restrict the payment of cash dividends (increased to $30 million per year from $10 million per year in the previous facility), borrowings, sales of assets, loans to others, investments, merger activity, hedging contracts, liens and certain other transactions without the prior consent of the lenders and requires us to maintain a ratio of current assets (which is a term defined in the credit facility agreement to include the undrawn capacity of our borrowing base) to current liabilities of one-to-one and a ratio of EBITDA to interest expense of five-to-one, as well as a minimum tangible net worth, which minimum varies with our cumulative net income and the amount of proceeds we receive from issuing stock. The credit agreement requires us to maintain a lien in favor of the lenders on properties representing at least 80% of the total value of our oil and gas properties. In addition, we have granted a security interest in other collateral including 100% of our ownership interests in our subsidiaries. Our operating subsidiaries have also guaranteed our obligations under the credit agreement and granted liens on approximately 80% of the value of their property. Restrictions in our credit facility substantially prohibit us from borrowing any amounts except those drawn on our credit facility, and from borrowing any amounts on the credit facility during an event of default. Prior consent of the lenders is required to sell assets with a value in excess of $30 million. From time to time, we have requested and received permission from our lenders to sell assets. We were in compliance with our covenants under the credit agreement on December 31, 2004 and March 15, 2005, the effective date of the amended credit agreement.

Capital expenditures. For the year ended December 31, 2004, capital expenditures of $284.8 million included $90.7 million for development activities, $150.4 million for exploration and $43.7 million for other capital items including acquisitions. These expenditures do not include any amount of allocated general and administrative expenses or interest. Our capital expenditures for the year ended December 31, 2004 were primarily financed by net cash flow provided by operating activities. We participated in the drilling of 32 exploratory wells and seven development wells of which 26 were on the conventional shelf and land, four were deep shelf wells and nine were in the deepwater. All of the development wells were successful. Of the 32 exploration wells, 21 were successful and five of the successful wells are in the deepwater. We operate a total of 16 of the 21 successful exploratory wells, including four wells that we operate in the deepwater.

Of the drilling, completion and facilities expenditures budgeted for 2004, we spent approximately $98 million in the deepwater, approximately $44 million on the deep shelf and approximately $99 million on conventional shelf and onshore projects. Additionally, we spent approximately $12 million on expensed workovers or major maintenance projects and approximately $25 million for other related expenses and capital items, which include plug and abandonment expenses and seismic costs.

During 2005, we expect to spend $266 million on capital projects and $42 million on plug and abandonments, major maintenance and expense workovers. During 2005, we anticipate drilling 30 exploratory wells and five or more development wells.

Periodically, we sell oil and gas properties that we identify as non-core, which we define as either having limited exploration or exploitation potential or which are not expected to yield our historic return on equity when abandonment costs are considered. We are preparing to market approximately 12 non-core fields with proved reserves of approximately 8.7 Bcfe, or approximately 1.9% of our total proved reserves. Our independent petroleum consultants estimate that the net daily average production for 2005 from these properties will be approximately 4.3 MMcfe. We intend to offer these properties individually and as a package in an effort to maximize the realized sale price. We cannot predict if or when the fields will be sold.

Contractual Obligations. The following table summarizes our obligations and commitments as of December 31, 2004 to make future payments under certain contracts, aggregated by category of contractual obligation, for specified time periods:

	Payments Due by Period at December 31, 2004				
	Total	Less Than One Year	One to Three Years	Three to Five Years	More Than Five Years
	(Dollars in millions)				
Contractual Obligations:					
Long-term debt (1)	$ 35.0	$ —	$ 35.0	$ —	$ —
Operating leases	3.4	0.9	1.7	0.8	—
Letters of credit	5.0	5.0	—	—	—
Asset retirement obligations	142.4	27.5	19.9	21.5	73.5
Other liabilities	2.4	—	2.4	—	—
	$188.2	$ 33.4	$ 59.0	$ 22.3	$ 73.5

(1) As of December 31, 2004, we had $35 million of long-term debt outstanding under our credit facility. In January 2005, this amount was repaid in full.

Inflation and Seasonality

Inflation. While we have benefited from a general rise in the price of both oil and natural gas, the prices for drilling rigs, drilling services, offshore transportation services and steel have impacted our lease operating expenses and our capital spending in 2004 and we expect the prices of such goods and services will increase substantially in 2005. As we focus our exploratory efforts on deepwater and deep shelf targets, the drilling equipment that we need is more difficult to locate and more expensive. For example, the daily rate charged for a drilling rig capable of drilling in 600 feet of water has increased substantially from the daily rate charged in 2003, and we expect daily rates to continue to rise in 2005.

Seasonality. Our operating revenues and expenses are generally not affected by seasonal changes. In years prior to 2004, we experienced some seasonal decline in prices, usually in autumn, when natural gas storage facilities near fill capacity. These seasonal declines in prices are usually temporary, and we did not experience a noticeable decline in price for this reason in 2004. Our operations are affected by seasonal changes in weather.

Periodic storms in the Gulf of Mexico, particularly in the winter months, sometimes impede our ability to safely load, unload and transport personnel and equipment, although weather conditions infrequently have a direct impact on the rate of oil and natural gas production. Accordingly, although our results of operations are not generally subject to seasonal fluctuations, we are generally not able to install production platforms in the winter months; thus, we are not able to realize revenues from those platforms until we are able to install them.

Off-Balance Sheet Arrangements

We have outstanding letters of credit in the face amount of $5 million that we have posted to secure a portion of our areawide operators' bonding obligations required by the MMS.

Critical Accounting Policies

This discussion of financial condition and results of operations is based upon the information reported in our consolidated financial statements, which have been prepared in accordance with generally accepted accounting principles in the United States, or GAAP. The preparation of our financial statements requires us to make assumptions and estimates that affect the reported amounts of assets, liabilities, revenues and expenses, as well as the disclosure of contingent assets and liabilities at the date of our financial statements. We base our assumptions and estimates on historical experience and other sources that we believe to be reasonable at the time. Actual results may vary from our estimates. Our significant accounting policies are detailed in Note 1 to our consolidated financial statements. We have outlined below certain of these policies as being of particular importance to the portrayal of our financial position and results of operations and which require the application of significant judgment or estimates by our management.

Revenue recognition. Oil and gas revenues are recognized when production is sold to a purchaser at a fixed or determinable price, when delivery has occurred and title has transferred, and if the collection of the revenue is probable. The Company uses the sales method of accounting for its oil and gas revenues; therefore, no accruals are made for imbalances between production and allocated sales. Historically, these differences have not been material. Under this method of accounting, revenue is recorded based upon the Company's physical deliveries to its customers, which can be different from the Company's net working interest in field production. These differences create imbalances that are recognized as a liability only when the estimated remaining reserves will not be sufficient to enable the under-produced party to recoup its entitled share through production. As of December 31, 2004, 2003 and 2002, deliveries of natural gas in excess of the Company's working interest and under-deliveries were not significant.

Full-cost accounting. We account for our investments in oil and natural gas properties using the full-cost method of accounting. Under this method, virtually all acquisition, exploration, development and estimated abandonment cost incurred for the purpose of acquiring or finding oil and natural gas are capitalized. Under the full-cost method, however, we are permitted to charge to expense certain employee cost and G&A related to these activities and, in particular, most of our geological and geophysical cost. Total capitalized geological and geophysical costs on our balance sheet were approximately $22 million and $16 million at December 31, 2004 and 2003, respectively. We expensed approximately $2.5 million and $1.9 million in geological and geophysical administrative cost during 2004 and 2003, respectively. Under the full-cost method, sales of oil and natural gas properties are accounted for as adjustments to the net full-cost pool with no gain or loss recognized, unless an adjustment would significantly alter the relationship between capitalized cost and the value of proved reserves. We amortize our investment in oil and natural gas properties through DD&A, using the units of production method.

Our financial position and results of operations could have been significantly different had we used the successful-efforts method of accounting for our oil and natural gas investments. GAAP allows successful-efforts accounting as an alternative method to full-cost accounting. The primary difference between the two methods is in the treatment of exploration cost and in the resulting computation of DD&A. Under the full-cost method, which we follow, some exploratory costs are capitalized, while under successful-efforts, the cost associated with unsuccessful exploration activities and all geological and geophysical costs are expensed. In following the full-cost method, we calculate DD&A based on a single pool for all of our oil and natural gas properties, while the successful-efforts method utilizes cost centers represented by individual properties, fields or reserves. Typically, the application of the full-cost method of accounting for oil and natural gas properties results in higher capitalized cost and higher DD&A rates, compared to similar companies applying the successful efforts method of accounting.

Oil and natural gas reserve quantities. Reserve quantities and the related estimates of future net cash flows affect our periodic calculations of depletion and impairment of our oil and natural gas properties. Proved oil and natural gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future periods from known reservoirs under existing economic and operating conditions. Reserve quantities and future cash flows included in this report are prepared in accordance with guidelines established by the SEC and the Financial Accounting Standards Board, or FASB. The accuracy of our reserve estimates is a function of:

- the quality and quantity of available data and the engineering and geological interpretation of that data;
- our estimates regarding the amount and timing of future operating cost, severance taxes, development cost and workover cost, all of which may in fact vary considerably from actual results;
- the accuracy of various mandated economic assumptions (such as the future prices of oil and natural gas; and
- the judgments of the persons preparing the estimates.

Our proved reserve information as of December 31, 2004 included in this annual report is based on estimates prepared by Netherland, Sewell & Associates, Inc., independent petroleum consultants. Because these estimates depend on many assumptions, any or all of which may differ substantially from actual results, reserve estimates may be different from the quantities of oil and natural gas that are ultimately recovered. We make changes to depletion rates and impairment calculations in the same period that changes to the reserve estimates are made. Unless otherwise indicated, we deduct plug and abandonment expenses in our calculation of PV-10 reserve estimates. Approximately 69% of our reserves at December 31, 2004 were classified as either proved undeveloped or proved developed non-producing reserves. Most of our proved developed non-producing reserves are "behind pipe" and will be produced after depletion of another horizon in the same well. Approximately 66% of these proved undeveloped reserves have been booked within one year of the most recent reserve report and approximately 93% of these proved undeveloped reserves have been booked within two years of December 31, 2004. Of the remaining 7%, consisting of reserves booked more than two years ago, all are operated wells that are either scheduled to be developed within the next three years or are waiting on a proved developed producing well to deplete in order to use the wellbore to develop the target reserves.

We estimate the capital costs required to develop all of our proved undeveloped reserves will be $230.9 million (not including plug and abandonment costs). We plan to develop approximately 83% of our existing proved undeveloped reserves during the next three years at an estimated cost of $185.9 million. The remaining 17% are waiting on either proved producing wells to deplete in order to use the wellbore or production results from a planned well in order to develop the target reserves. However, we are not the sole working interest owner in 80% of our leases, so we are not in a position to guarantee the precise timing or costs of developing our reserves.

Reporting of oil and gas production and reserves. We produce natural gas liquids as part of the processing of our natural gas. The extraction of natural gas liquids in the processing of natural gas reduces the volume of natural gas available for sale. In our December 31, 2004 reserve report prepared by our independent petroleum consultants, natural gas liquids represented approximately 3.8% of our total oil and gas revenues. Natural gas liquids are products sold by the gallon. Therefore, in reporting reserve and production amounts of natural gas liquids, we include this production in the oil category. Prices for natural gas liquids in 2004 were approximately 25% lower on average than prices for equivalent volumes of oil, and average prices have been 24% lower over the life of the reserves. We report our average oil prices realized after taking into account the effect of the lower prices received for sales of natural gas liquids. We report all production information related to natural gas net of the effect of any reduction in natural gas volumes resulting from the processing of natural gas liquids.

Impairment of oil and natural gas properties. Under the full-cost method of accounting, we are required periodically to compare the present value of estimated future net cash flows from our proved reserves (based on period-end commodity prices and excluding abandonment liabilities), net of tax, to the net capitalized cost of proved oil and natural gas properties, including estimated capitalized net abandonment cost, net of deferred taxes. This comparison is referred to as the full-cost “ceiling test.” If the net capitalized cost of oil and natural gas properties in place exceed the estimated discounted future net cash flows from proved reserves, we are required to write down the value of our oil and natural gas properties to the value of the discounted net cash flows, and recognize an impairment charge. Any such write-downs are not recoverable or reversible in future periods.

Asset retirement obligations. We have significant obligations to remove our equipment and restore land or seabed at the end of oil and natural gas production operations. These obligations are primarily associated with plugging and abandoning wells and removing and disposing of offshore oil and natural gas platforms. Estimating the future restoration and removal cost is difficult and requires us to make estimates and judgments because most of the removal obligations are many years in the future and contracts and regulations often have vague descriptions of what constitutes removal. Asset removal technologies and cost are constantly changing, as are regulatory, political, environmental, safety and public relations considerations. Prior to 2003, under the full-cost method of accounting, the estimated undiscounted cost of our abandonment obligations, net of the value of salvage, were included as a component of our depletion base and expensed over the production life of the oil and natural gas properties. With the implementation of Statement of Financial Accounting Standards (SFAS) No. 143, *Accounting for Asset Retirement Obligations,* we are now required to record a separate liability for the discounted present value of our asset retirement obligations, with an offsetting increase to the related oil and natural gas properties on our balance sheet. Upon adoption of SFAS No. 143 on January 1, 2003, we recorded an increase in net property and equipment of $95.0 million and recognized an initial asset retirement obligation of $101.7 million and a cumulative effect of adoption that increased net income and shareholders’ equity by $0.1 million, net of income tax.

Inherent in the present value calculation are numerous assumptions and judgments, including the ultimate settlement amounts, inflation factors, credit adjusted discount rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the present value of our existing abandonment liability, we will make corresponding adjustments to our oil and natural gas property balance. In addition, increases in the discounted abandonment liability resulting from the passage of time will be reflected as accretion expense in our consolidated statement of income.

SFAS No. 143 requires a cumulative adjustment to reflect the impact of implementing the statement had the rule been in effect since inception. Therefore, in 2003 we calculated the cumulative accretion expense on our abandonment liability and the cumulative depletion expense on our corresponding property balance. We compared the sum of these cumulative expenses to the depletion expense we originally recorded. Because the historically recorded depletion expense was higher than the cumulative expense calculated under SFAS No. 143, the difference resulted in a small gain that we recorded as a cumulative effect of a change in accounting principle on January 1, 2003.

In addition, the calculation of our standardized measure under SFAS No. 69 requires that we include estimated future cash flows related to the settlement of asset retirement obligations. Accordingly, we utilize the same estimate of our plugging and abandonment liability when calculating our standardized measure and PV-10 (discounted at 10%) as we do for purposes of calculating our asset retirement obligation under SFAS No. 143 (discounted at our credit-adjusted risk-free rate).

Income Taxes. We provide for income taxes in accordance with SFAS No. 109, *Accounting for Income Taxes*. SFAS No. 109 requires the use of the liability method of computing deferred income taxes, whereby deferred income taxes are recognized for the future tax consequences of the differences between the tax basis of assets and liabilities and the carrying amount in our financial statements required by GAAP. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. Because our tax returns are filed after the financial statements are prepared, estimates are required in valuing tax assets and liabilities. We record adjustments to reflect the actual tax amounts paid in the period we file our tax returns.

Stock-based compensation. In October 1995, the FASB issued SFAS No. 123, *Accounting for Stock-Based Compensation*. The standard encourages, but does not require, companies to record compensation cost for stock-based employee compensation plans at fair value. We have elected to account for stock-based compensation using the intrinsic value method prescribed in Accounting Principles Board Opinion No. 25, *Accounting for Stock Issued to Employees*, and related interpretations. Accordingly, compensation cost for stock issued is measured as the excess, if any, of the fair value of our common stock at the date of the grant over the amount an employee must pay to acquire the common stock.

New Accounting Policies and Pronouncements

In September 2004, the SEC issued Staff Accounting Bulletin ("SAB") No. 106, which expressed the Staff's views regarding the application of SFAS No. 143 by oil and gas companies following the full cost accounting method. SAB No. 106 indicates that estimated dismantlement and abandonment costs that will be incurred as a result of future development activities on proved reserves are to be included in the estimated future cash flows in the full cost ceiling limitation. SAB No. 106 also indicates that these estimated costs are to be included in the costs to be amortized. We expect to begin applying SAB No. 106 in the first quarter of 2005, when it becomes effective for us. The application of SAB 106 is not anticipated to have a material impact on our consolidated financial statements.

In May 2003, the FASB issued SFAS No. 150, "Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity," to classify certain financial instruments as liabilities in statements of financial position. The financial instruments covered by SFAS No. 150 are mandatorily redeemable shares, which the issuing company is obligated to buy back in exchange for cash or other assets, put options and forward purchase contracts, instruments that do or may require the issuer to buy back some of its shares in exchange for cash or other assets and obligations that can be settled with shares, the monetary value of which is fixed, tied solely or predominantly to a variable such as a market index or varies inversely with the value of the issuers' shares. Most of the guidance in SFAS No. 150 is effective for all financial instruments entered into or modified after May 31, 2003 and otherwise is effective at the beginning of the first interim period beginning after June 15, 2003. We adopted the statement during 2003. The statement had no impact on our classification of our Series A preferred stock.

In December 2004, the FASB issued FASB Staff Position ("FSP") FAS 109-1, *Application of FASB Statement No. 109, Accounting for Income Taxes, to the Tax Deduction on Qualified Production Activities Provided by the American Jobs Creation Act of 2004*. FSP FAS 109-1 provided guidance on the application of SFAS No. 109, *Accounting for Income Taxes*, to the tax deduction on "qualified production activities." This deduction is available beginning in 2005 and therefore, has no effect on our current year's consolidated financial statements.

In December 2004, the FASB issued SFAS No. 123 (revised 2004) ("SFAS No. 123(R)"), *Share-Based Payment,* that requires compensation costs related to share-based transactions be recognized in the financial statements. The amount of compensation costs will be measured based on the grant-date fair value of the equity or liability instruments issued. Compensation cost will be recognized over the period that an employee provides service in exchange for the award. SFAS No. 123(R) replaces SFAS No. 123, *Accounting for Stock-Based Compensation,* and supercedes APB No. 25, *Accounting for Stock Issued to Employers.* SFAS No. 123(R) allows public companies to adopt its requirements using one of the following methods.

1. The "modified prospective" method in which compensation cost is recognized beginning with the effective date (a) based on the requirements of SFAS No. 123(R) for all share-based payments granted after the effective date and (b) based on the requirements of SFAS No. 123 for all awards granted to employees prior to the effective date of SFAS 123(R) that remain unvested on the effective date.
2. The "modified retrospective" method which includes the requirements of the modified prospective method described above, but also permits entities to restate based on the amounts previously recognized under SFAS No. 123 for purposes of pro forma disclosures either (a) all prior periods presented or (b) prior interim periods of the year of adoption.

SFAS No. 123(R) is effective for us in the first quarterly period after June 15, 2005. We are in the process of determining how the new method of valuing stock-based compensation as prescribed by SFAS No. 123(R) will be applied to valuing stock-based awards and the impact the recognition of compensation expense related to such awards will have on our financial statements; however, since our previous share-based payments have been recorded at fair value, we do not expect the adoption of SFAS No. 123(R) will have an impact on our consolidated financial statements.

For a more complete discussion of our accounting policies and procedures, see our notes to consolidated financial statements beginning at page 47.

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

Factors That Could Affect Future Results

Because of the following factors, as well as other variables affecting our operating results, past financial performance may not be a reliable indicator of future performance and historical trends should not be used to anticipate results or trends in future periods.

A substantial or extended decline in oil and natural gas prices may adversely affect our business, financial condition, cash flow, liquidity or results of operations and our ability to meet our capital expenditure obligations and financial commitments and to implement our business strategy.

The price we receive for our oil and natural gas production heavily influences our revenue, profitability, access to capital and future rate of growth. Oil and natural gas are commodities, and, therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the markets for oil and natural gas have been volatile. These markets will likely continue to be volatile in the future. The prices we receive for our production and the levels of our production depend on numerous factors beyond our control. These factors include the following:

- changes in global supply and demand for oil and natural gas;

- the actions of the Organization of Petroleum Exporting Countries;
- the price and quantity of imports of foreign oil and natural gas;
- political conditions and events, including embargoes, affecting oil producing activity;
- the level of global oil and natural gas exploration and production activity;
- the level of global oil and natural gas inventories;
- weather conditions;
- technological advances affecting energy consumption; and
- the price and availability of alternative fuels.

Lower oil and natural gas prices may not only decrease our revenues on a per unit basis but may also reduce the amount of oil and natural gas that we can produce economically. A substantial or extended decline in oil or natural gas prices may materially and adversely affect our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures.

Approximately 69% of our total proved reserves are undeveloped or non-producing, and there can be no assurance that those reserves will ultimately be developed or produced.

Approximately 38% of our total proved reserves are undeveloped and approximately 31% are developed non-producing. While we have a development plan for exploiting and producing all of our proved reserves, there can be no assurance that those reserves will ultimately be developed or produced. We are not the operator with respect to 24% of our proved undeveloped and proved non-producing reserves, so we may not be in a position to control the timing of all development activities. Furthermore, there can be no assurance that all of our undeveloped and non-producing reserves will ultimately be produced at the time periods we have planned, at the costs we have budgeted, or at all.

Relatively short production periods for our properties subject us to high reserve replacement needs and require significant capital expenditures to replace our reserves at a faster rate than companies whose reserves have longer production periods. Our failure to replace those reserves would result in decreasing reserves and production over time.

Unless we conduct successful development, exploitation and exploration activities or acquire properties containing proved reserves, our proved reserves will decline as those reserves are produced. Producing oil and natural gas reserves are generally characterized by declining production rates that vary depending upon reservoir characteristics and other factors. High production rates generally result in recovery of a relatively higher percentage of reserves from properties during the initial few years of production. The vast majority of our current operations are in the Gulf of Mexico. Production from reservoirs in the Gulf of Mexico generally declines more rapidly than from reservoirs in many other producing regions of the United States. Our independent petroleum consultants estimate that, on average, 50% of our total proved reserves are depleted within 3.4 years. Absent additional acquisitions or discoveries, our net well completions, as evaluated by our independent petroleum consultants, would be reduced from 139 to 51 in the next five years, even though we plan to drill additional development wells and to perform workovers. As a result, our need to replace reserves from new investments is relatively greater than that of producers who recover lower percentages of their reserves over a similar time period, such as those producers who have a portion of their reserves outside the Gulf of Mexico in areas where the rate of reserve production is lower. We may not be able to develop, exploit, find or acquire additional reserves to sustain our current production levels or to grow. There can be no assurance that we will be able to grow production at rates we experienced over the past five years. Absent a significant acquisition, we do not expect production to grow substantially in 2005, as the successful wells we are drilling under our current drilling program, including wells in the deep shelf and deepwater, may not produce until 2007.

Our future oil and natural gas reserves and production, and therefore our cash flow and income, are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves.

Competition for oil and natural gas properties and prospects is intense; some of our competitors have larger financial, technical and personnel resources that give them an advantage in evaluating and obtaining properties and prospects.

We operate in a highly competitive environment for reviewing prospects, acquiring properties, marketing oil and natural gas and securing trained personnel. Many of our competitors possess and employ financial resources that allow them to obtain substantially greater technical and personnel resources than we have. We actively compete with other companies in our industry when acquiring new leases or oil and gas properties. For example, new leases acquired from the MMS are acquired through a "sealed bid" process and are generally awarded to the highest bidder. These additional resources can be particularly important in reviewing prospects and purchasing properties. Our competitors may be able to evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. Our competitors may also be able to pay more for productive oil and natural gas properties and exploratory prospects than we are able or willing to pay. On the acquisition opportunities made available to us, we compete with other companies in our industry for properties operated by third parties through a private bidding process, direct negotiations or some combination thereof. Our ability to acquire additional prospects and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. If we are unable to compete successfully in these areas in the future, our future revenues and growth may be diminished or restricted. The availability of properties for acquisition depends largely on the divesting practices of other oil and natural gas companies, commodity prices, general economic conditions and other factors we cannot control or influence.

We plan to conduct exploration, exploitation and production operations on the deep shelf and in the deepwater of the Gulf of Mexico, which presents unique operating risks.

The deep shelf and the deepwater of the Gulf of Mexico are areas that have had limited historical drilling activity due, in part, to their geological complexity, depth and higher cost. There are additional risks associated with deep shelf and deepwater drilling that could result in substantial cost overruns and/or result in uneconomic projects or wells. Deeper targets are more difficult to detect with traditional seismic processing. Moreover, drilling costs and the risk of mechanical failure are significantly higher because of the additional depth and adverse conditions such as high temperature and pressure. For example, deepwater wells require specific kinds of rigs with significantly higher day rates than those rigs used in shallow water, and those rigs have limited availability. Deepwater wells have greater mechanical risks because the wellhead equipment is installed on the sea floor. Deepwater development costs can be significantly higher than shelf development costs because deepwater drilling requires bigger installation equipment; sophisticated sea floor production handling equipment; expensive, state-of-the-art platforms and/or investment in infrastructure. Deep shelf development can also be more expensive than conventional shelf projects as deep shelf development requires more actual drilling days and higher drilling and services costs due to extreme pressure and temperatures associated with greater drilling depths. For example, the cost to drill and complete our conventional wells on the shelf have generally been in the range of $5 million to $15 million (gross). The cost of drilling deep shelf or deepwater wells can be much higher. One such example, in which we were not the operator, required a second well to be drilled, as the first well encountered significant well control issues and was abandoned. The approximate cost to complete and drill the original objective was $65 million. Accordingly, we cannot assure you that our oil and natural gas exploration activities, in the deep shelf, the deepwater and elsewhere, will be commercially successful.

We are not the operator on the properties representing 24% of our proved developed non-producing and proved undeveloped reserves, including many of our deepwater and deep shelf reserves, and therefore we may not be in a position to control the timing of development efforts, the associated costs, or the rate of production of the reserves.

As we carry out our drilling program in the deepwater and the deep shelf, we will not serve as operator of all planned wells. As a result, we may have limited ability to exercise influence over the operations of some non-operated properties or their associated costs. Our dependence on the operator and other working interest owners for these projects, and our limited ability to influence operations and associated costs could prevent the realization of our targeted returns on capital in drilling or acquisition activities. Approximately 26% of our proved undeveloped reserves and 22% of our proved developed non-producing reserves are on properties operated by others. The success and timing of development and exploitation activities on properties operated by others depend upon a number of factors that will be largely outside of our control, including:

- the timing and amount of capital expenditures;
- the availability of suitable offshore drilling rigs, drilling equipment, support vessels, production and transportation infrastructure and qualified operating personnel;
- the operator’s expertise and financial resources;
- approval of other participants in drilling wells;
- selection of technology; and
- the rate of production of the reserves.

Our business involves many uncertainties and operating risks that can prevent us from realizing profits and can cause substantial losses.

Our development activities may be unsuccessful for many reasons, including weather (such as hurricanes and tropical storms in the Gulf of Mexico), cost overruns, equipment shortages and mechanical difficulties. Moreover, the successful drilling of a natural gas or oil well does not ensure we will realize a profit on our investment. A variety of factors, both geological and market-related, can cause a well to become uneconomical or only marginally economical. In addition to their costs, unsuccessful wells can hurt our efforts to replace reserves.

Our business involves a variety of operating risks, including:

- fires;
- explosions;
- blow-outs and surface cratering;
- uncontrollable flows of natural gas, oil and formation water;
- natural disasters, such as hurricanes and other adverse weather conditions;
- pipe, cement, subsea well or pipeline failures;
- casing collapses;
- mechanical difficulties, such as lost or stuck oil field drilling and service tools;
- abnormally pressured formations; and
- environmental hazards, such as natural gas leaks, oil spills, pipeline ruptures and discharges of toxic gases.

If we experience any of these problems, well bores, platforms, gathering systems and processing facilities could be affected, which could adversely affect our ability to conduct operations. We could also incur substantial losses as a result of:

- injury or loss of life;
- severe damage to and destruction of property, natural resources and equipment;
- pollution and other environmental damage;
- clean-up responsibilities;
- regulatory investigation and penalties;
- suspension of our operations; and
- repairs to resume operations.

Offshore operations are also subject to a variety of operating risks peculiar to the marine environment, such as capsizing, collisions and damage or loss from hurricanes or other adverse weather conditions. These conditions can cause substantial damage to facilities and interrupt production. As a result, we could incur substantial liabilities that could reduce or eliminate the funds available for exploration, exploitation and acquisitions or result in loss of equipment and properties. During the three-year period ended December 31, 2004, we spent approximately $1.1 million to remediate hurricane damage that was not covered by insurance. Approximately $1.0 million of hurricane damage relates to Hurricane Ivan in 2004. We temporarily shut in 99 gross operated wells during Hurricane Ivan in September 2004. As a result of the shut in we were forced to defer company-wide production of an average of approximately 35 MMcfe per day during September 2004 and an average of approximately 5 MMcfe per day, 4 MMcfe per day and 3 MMcfe per day during the months of October, November and December 2004, respectively.

The geographic concentration of our properties in the Gulf of Mexico subjects us to an increased risk of loss of revenue or curtailment of production from factors affecting the Gulf of Mexico.

The geographic concentration of our properties along the Texas and Louisiana Gulf Coast and adjacent waters on and beyond the outer continental shelf means that some or all of our properties could be affected by the same event should the Gulf of Mexico experience:

- severe weather;
- delays or decreases in production, the availability of equipment, facilities or services;
- delays or decreases in the availability of capacity to transport, gather or process production; or
- changes in the regulatory environment.

Because all our properties could experience the same condition at the same time, these conditions could have a relatively greater impact on our results of operations than they might have on other operators who have properties over a wider geographic area.

Substantial acquisitions and exploitation activities could require significant external capital and could change our risk and property profile.

In order to finance acquisitions of properties and our exploitation activities, we may need to alter or increase our capitalization substantially through the issuance of debt or equity securities, the sale of production payments or other means. These changes in capitalization may significantly affect our financial risk profile. For instance, to finance the acquisition of a subsidiary of ConocoPhillips, we borrowed approximately $36.8 million under our credit facility, which has been repaid. Additionally, significant acquisitions or other transactions can change the character of our operations and business, as we experienced with the acquisition of the Burlington subsidiaries, which had the effect of increasing our average lease operating expenses per Mcfe from $0.49 in 2002 to $0.83 in 2003. The character of the new properties may be substantially different in operating or geological characteristics or geographic location than our existing properties. Furthermore, we may not be able to obtain external funding for any such acquisitions or other transactions or to obtain external funding on terms acceptable to us.

Properties that we buy may not produce as projected and we may be unable to identify liabilities associated with acquired properties or obtain protection from the sellers of properties we purchase.

Our business strategy includes a continuing acquisition program. Our acquisition of oil and natural gas properties requires assessments of many factors that are inherently inexact and may be inaccurate, including the following:

- acceptable prices for available properties;
- amounts of recoverable reserves;
- estimates of future oil and natural gas prices;
- estimates of future exploratory, development and operating costs;
- our estimates of the costs and timing of plug and abandonment; and
- our estimates of potential environmental and other liabilities.

Our assessment of the acquired properties will not reveal all existing or potential problems, nor will it permit us to become familiar enough with the properties to fully assess their capabilities and deficiencies. In the course of our due diligence, we have not historically inspected every well, platform or pipeline. Even if we had inspected each of these, our inspections may not have revealed structural and environmental problems, such as pipeline corrosion or groundwater contamination. We may not be able to obtain contractual indemnities from the seller for liabilities that it created. We may be required to assume the risk of the physical condition of the properties in addition to the risk that the properties may not perform in accordance with our expectations.

If oil and natural gas prices decrease, we may be required to write-down the carrying values and/or the estimates of total reserves of our oil and natural gas properties.

Accounting rules applicable to us require that we review periodically the carrying value of our oil and natural gas properties for possible impairment. Based on specific market factors and circumstances at the time of prospective impairment reviews and the continuing evaluation of development plans, production data, economics and other factors, we may be required to write down the carrying value of our oil and natural gas properties. In 1998, we recorded an impairment charge of approximately $1.4 million due to lower commodity prices and the results of our year-end ceiling test. (See "*Management's Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Policies—Impairment of oil and natural gas properties*" on page 28 for a discussion of the ceiling test.) A write-down constitutes a noncash charge to earnings. We may incur noncash charges in the future, which could have a material adverse effect on our results of operations in the period taken. We may also reduce our estimates of the reserves that may be economically recovered, which could have the effect of reducing the total value of our reserves.

Our reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in our reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

The process of estimating oil and natural gas reserves is complex. It requires interpretations of available technical data and many assumptions, including assumptions relating to economic factors. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and the calculation of the present value of reserves shown in this report. Please read "*Business and Properties*" beginning at page 1 and for information about our estimated oil and natural gas reserves.

In order to prepare the reserve estimates included in this report, our independent petroleum consultants projected production rates and timing of development expenditures. Our independent petroleum consultants also analyzed available geological, geophysical, production and engineering data. The extent, quality and reliability of this data can vary and may not be in our control. The process also requires economic assumptions about matters such as oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. Therefore, estimates of oil and natural gas reserves are inherently imprecise.

Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves will most likely vary from our estimates. Any significant variance could materially affect the estimated quantities and present value of our reserves. In addition, our independent petroleum consultant may adjust estimates of proved reserves to reflect production history, drilling results, prevailing oil and natural gas prices and other factors, many of which are beyond our control.

You should not assume that the present value of future net revenues from our proved reserves is the current market value of our estimated oil and natural gas reserves. In accordance with SEC requirements, we base the estimated discounted future net cash flows from our proved reserves on prices and costs on the date of the estimate. Actual future prices and costs may differ materially from those used in the present value estimate. For example, if natural gas prices decline by $0.10 per Mcf, then the PV-10 value of our proved reserves as of December 31, 2004 would decrease from $1,470.2 million to $1,453.8 million. If oil prices decline by $1.00 per barrel, then the PV-10 value of our proved reserves as of December 31, 2004 would decrease from $1,470.2 million to $1,443.5 million.

Prospects that we decide to drill may not yield oil or natural gas in commercially viable quantities or quantities sufficient to meet our targeted rate of return.

A prospect is a property in which we own an interest or have operating rights and have what our geoscientists believe, based on available seismic and geological information, to be indications of oil or natural gas. Our prospects are in various stages of evaluation, ranging from a prospect that is ready to be drilled to a prospect that will require substantial additional seismic data processing and interpretation. There is no way to predict in advance of drilling and testing whether any particular prospect will yield oil or natural gas in sufficient quantities to recover drilling or completion cost or to be economically viable. The use of seismic data and other technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether oil or natural gas will be present or, if present, whether oil or natural gas will be present in commercial quantities. We cannot assure you that the analysis we perform using data from other wells, more fully explored prospects and/or producing fields will be useful in predicting the characteristics and potential reserves associated with our drilling prospects. As we focus our drilling efforts on deepwater and deep shelf targets, our drilling activities will likely become more expensive. In addition, the geological complexity of deepwater and deep shelf formations may make it more difficult for us to sustain our historical rates of drilling success. As a result, there can be no assurance that we will find commercially viable quantities of oil and natural gas, and therefore, there can be no assurance that we will achieve our targeted rate of return or have a positive rate of return on investment.

Market conditions or operational impediments may hinder our access to oil and natural gas markets or delay our production.

Market conditions or the unavailability of satisfactory oil and natural gas transportation arrangements may hinder our access to oil and natural gas markets or delay our production. The availability of a ready market for our oil and natural gas production depends on a number of factors, including the demand for and supply of oil and natural gas and the proximity of reserves to pipelines and terminal facilities. Our ability to market our production depends in substantial part on the availability and capacity of gathering systems, pipelines and processing facilities, in some cases owned and operated by third parties. Our failure to obtain such services on acceptable terms could materially harm our business. We may be required to shut in wells for a lack of a market or because of inadequacy or unavailability of pipelines or gathering system capacity. If that were to occur, then we would be unable to realize revenue from those wells until arrangements were made to deliver our production to market. We have, in the past, been required to shut in wells when hurricanes have caused or threatened damage to pipelines and gathering stations. In September 2004, 99 gross operated wells were temporarily shut in as a result of Hurricane Ivan.

We have been informed by the operator of a major offshore pipeline that the pipeline will be shut-in for approximately six weeks beginning June 1, 2005 for repairs mandated by the U.S. Department of Transportation. This would result in the deferral, but not the loss, of approximately 1.1 Bcfe of production, which will impact the second and third quarters of 2005.

In some cases, our wells are tied back to platforms owned by parties who do not have an economic interest in the well, and we cannot be assured that such parties will continue to process our oil and natural gas.

In some cases, our wells are tied back to platforms owned by parties with no economic interests in our wells. Currently, a portion of our oil and natural gas is processed for sale on these platforms, and no other processing facilities would be available without significant investment by us. In 2003, we had to shut in a well when the third-party host platform was shut down by its owner. Currently, two of our wells, accounting for 32.9 Bcfe (or 7.0%) of our total proved reserves, are tied back or are planned to be tied back to separate, third-party host platforms. There can be no assurance that either owner of such platforms will continue to operate the platform. If either platform ceases to operate its processing equipment, we may be required to shut in one or both of the associated wells.

We are subject to numerous laws and regulations that can adversely affect the cost, manner or feasibility of doing business.

Our operations and facilities are subject to extensive federal, state and local laws and regulations relating to the exploration for, and the development, production and transportation of, oil and natural gas, and operating safety. Future laws or regulations, any adverse change in the interpretation of existing laws and regulations or our failure to comply with existing legal requirements may harm our business, results of operations and financial condition. We may be required to make large and unanticipated capital expenditures to comply with governmental regulations, such as:

- land use restrictions;
- lease permit restrictions;
- drilling bonds and other financial responsibility requirements, such as plug and abandonment bonds;
- spacing of wells;
- unitization and pooling of properties;
- safety precautions;
- operational reporting; and
- taxation.

Under these laws and regulations, we could be liable for:

- personal injuries;
- property and natural resource damages;
- well reclamation cost; and
- governmental sanctions, such as fines and penalties.

Our operations could be significantly delayed or curtailed and our cost of operations could significantly increase as a result of regulatory requirements or restrictions. We are unable to predict the ultimate cost of compliance with these requirements or their effect on our operations. See "*Properties—Regulation"* beginning at page 6 for a more detailed description of our regulatory risks.

Our operations may incur substantial liabilities to comply with the environmental laws and regulations.

Our oil and natural gas operations are subject to stringent federal, state and local laws and regulations relating to the release or disposal of materials into the environment or otherwise relating to environmental protection. These laws and regulations:

- require the acquisition of a permit before drilling commences;
- restrict the types, quantities and concentration of substances that can be released into the environment in connection with drilling and production activities;
- limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas; and
- impose substantial liabilities for pollution resulting from our operations.

Failure to comply with these laws and regulations may result in:

- the assessment of administrative, civil and criminal penalties;
- incurrence of investigatory or remedial obligations; and
- the imposition of injunctive relief.

We have, in the past, been subject to investigation with respect to allegations that we did not comply with applicable rules and regulations. Resolution of these matters has required considerable management time and expense.

Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent or costly waste handling, storage, transport, disposal or cleanup requirements could require us to make significant expenditures to reach and maintain compliance and may otherwise have a material adverse effect on our industry in general and on our own results of operations, competitive position or financial condition. Under these environmental laws and regulations, we could be held strictly liable for the removal or remediation of previously released materials or property contamination regardless of whether we were responsible for the release or contamination or if our operations met previous standards in the industry at the time they were performed. Our permits require that we report any incidents that cause or could cause environmental damages. For instance, during March 2005, we reported an oil spill of six barrels. See *"Properties—Regulation"* beginning at page 6 for a more detailed description of our environmental risks.

We operate a production platform in a National Marine Sanctuary.

Our oil and natural gas operation includes a production platform located in a National Marine Sanctuary in the Gulf of Mexico that is subject to special federal laws and regulations. Unique regulations related to operations in the Sanctuary include, among other things, prohibition of drilling activities within certain protected areas, restrictions on substances that may be discharged, depths of discharge in connection with drilling and production activities and limitations on mooring of vessels. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, incurrence of investigatory or remedial obligations or the imposition of injunctive relief, including cessation of production from wells associated with this platform. During December 2004, our average net production from wells associated with this platform was approximately 11 MMcfe per day. If we are required to curtail or cease production from this platform, it could adversely affect our cash flows, results of operations and asset value.

The loss of senior management could adversely affect us.

To a large extent, we depend on the services of our senior management. The loss of the services of any of our senior management, including Tracy W. Krohn, our Chairman, Chief Executive Officer, President and Treasurer; W. Reid Lea, our Vice President of Finance, Chief Financial Officer and Assistant Secretary; Jeffrey M. Durrant, our Vice President of Exploration/Geoscience; or Joseph P. Slattery, our Vice President of Operations, could have a negative impact on our operations. We do not maintain or plan to obtain any insurance against the loss of any of these individuals. Please read "*Executive Officers of the Registrant*" beginning at page 12 for more information regarding the members of our management team.

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

Shortages or the high cost of drilling rigs, equipment, supplies or personnel could delay or adversely affect our exploitation and exploration operations, which could have a material adverse effect on our business, financial condition or results of operations. If the unavailability or high cost of rigs, equipment, supplies or personnel were particularly severe in Texas, Louisiana and the Gulf of Mexico, we could be materially and adversely affected because our operations and properties are concentrated in those areas. We must currently schedule rigs as much as four to nine months in advance.

Counterparty credit risk may negatively impact the conversion of our accounts receivables to cash.

Substantially all of our accounts receivable result from oil and natural gas sales or joint interest billings to third parties in the energy industry. This concentration of customers and joint interest owners may impact our overall credit risk in that these entities may be similarly affected by any adverse changes in economic and other conditions. Recent market conditions resulting in downgrades to credit ratings of energy merchants have affected the liquidity of several of our purchasers. During the third quarter of 2002, we discontinued selling to several energy merchants who received downgrades to their credit ratings, or we required payment on delivery of our oil and natural gas sales. We continue to sell oil and natural gas to companies we believe are reasonable credit risks. In some cases, we have required purchasers to post letters of credit to secure their performance under the purchase contracts. Based on the current demand for oil and natural gas, we do not expect that termination of sales to previous purchasers would have a material adverse effect on our ability to sell our production at favorable market prices.

Our insurance coverage may not be sufficient or may not be available to cover some liabilities or losses that we may incur.

The occurrence of a significant accident or other event not fully covered or not covered by our insurance could have a material adverse impact on our operations and financial condition. Our insurance does not protect us against all operational risks. We do not carry business interruption insurance. Accordingly, we will not be covered for financial losses incurred as a direct result of temporarily shutting in 99 gross operated wells during Hurricane Ivan in September 2004. For some risks, we may not obtain insurance if we believe the cost of available insurance is excessive relative to the risks presented. Because we use third party drilling contractors to drill our wells, we may not realize the full benefit of workmen's compensation laws in dealing with their employees. In addition, pollution and environmental risks generally are not fully insurable.

We are controlled by Tracy W. Krohn as long as he owns a majority of our outstanding common stock, and you will be unable to affect the outcome of shareholder voting during that time. This control may adversely affect the value of our common stock and inhibit potential changes of control.

Tracy W. Krohn controls approximately 40,752,007 shares of our common stock, representing approximately 61.8% of our voting interests. As a result, Mr. Krohn has the ability to control the outcome of all matters requiring shareholder approval, and nonaffiliated shareholders by themselves, will not be able to affect the outcome of any shareholder vote. As a result, Mr. Krohn, subject to any fiduciary duty owed to our minority shareholders under Texas law, is able to control all matters affecting us, including:

- the composition of our board of directors and, through it, any determination with respect to our business direction and policies, including the appointment and removal of officers;
- the determination of incentive compensation, which may affect our ability to retain key employees;
- any determinations with respect to mergers or other business combinations;
- our acquisition or disposition of assets;
- our financing decisions and our capital raising activities;
- our payment of dividends on our common stock;
- amendments to our articles of incorporation or bylaws; and
- determinations with respect to our tax returns.

Mr. Krohn is generally not prohibited from selling a controlling interest in us to a third party. In addition, his concentrated control could discourage others from initiating any potential merger, takeover or other change of control transaction that might be beneficial to our business. As a result, the market price of our common stock could be adversely affected.

In addition, because Mr. Krohn owns a majority of our common stock, we are a “controlled company” within the meaning of the rules of the New York Stock Exchange. As such, we are not required to comply with certain corporate governance rules of the New York Stock Exchange that would otherwise apply to us as a listed company on that exchange. These rules are generally intended to increase the likelihood that boards will make decisions in the best interests of shareholders. Specifically, we are not required to have a majority of independent directors on our board of directors and we are not required to have nominating and corporate governance and compensation committees composed of independent directors. Should the interests of Mr. Krohn differ from those of other shareholders, the other shareholders will not be afforded the protections of having a majority of directors on the board who are independent from our principal shareholder.

Commodity price risk. Our revenues, profitability and future rate of growth substantially depend upon market prices of oil and natural gas, which fluctuate widely. Oil and natural gas price decline and volatility could adversely affect our revenues, net cash flow provided by operating activities and profitability. For example, assuming a 10% decline in realized oil and natural gas prices, our 2004 income before income taxes would have declined by approximately 22%. If costs and expenses of operating our properties had increased by 10% in 2004, our income before income taxes would have declined by approximately 4%.

Interest rate risk. Interest rate risk is assessed by calculating the change in interest expense that would result from a hypothetical 100 basis point change in the interest rate on our weighted average borrowings under our credit facility for the year ended December 31, 2004. Interest rate changes will impact future results of operations and cash flows. Assuming the same average borrowings, a 100 basis point increase in interest rates would have increased our 2004 interest expense by approximately $0.3 million.

Hedging. We have not entered into a hedging transaction since approximately 1996. We may consider a hedge on a portion of our future oil or natural gas production in the future. Our revolving credit agreement permits, but does not require, hedging transactions on terms that we consider to be favorable. If we make a significant acquisition of oil and natural gas properties, then we may consider hedging if it enhances our ability to finance the acquisition or if we determine that it is necessary to meet our financial objectives.

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

W&T OFFSHORE, INC. AND SUBSIDIARIES
IN DEX TO FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
W&T Offshore, Inc. and Subsidiaries

We have audited the accompanying consolidated balance sheets of W&T Offshore, Inc. and Subsidiaries as of December 31, 2004 and 2003, and the related consolidated statements of income, changes in shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2004. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. We were not engaged to perform an audit of the Company's internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of W&T Offshore, Inc. and Subsidiaries as of December 31, 2004 and 2003, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2004, in conformity with U.S. generally accepted accounting principles.

As discussed in Note 2 to the consolidated financial statements, effective January 1, 2003, the Company adopted Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations*.

/s/ ERNST & YOUNG LLP

New Orleans, Louisiana
March 29, 2005

[Table of Contents](#)

W&T OFFSHORE, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31, 2004	December 31, 2003
	(In thousands, except share data)	
Assets		
Current assets:		
Cash and cash equivalents	$ 64,975	$ 4,016
Receivables:		
Oil and gas sales	40,427	39,107
Joint interest	22,165	24,184
Income taxes	9,122	—
Total receivables	71,714	63,291
Royalty deposits	5,166	5,614
Prepaid expenses and other assets	4,127	1,302
Total current assets	145,982	74,223
Property and equipment—at cost:		
Oil and gas properties and equipment—full cost method of accounting	1,140,740	842,846
Furniture, fixtures and other	6,627	5,222
Total property and equipment	1,147,367	848,068
Less accumulated depreciation, depletion and amortization	543,154	388,446
Net property and equipment	604,213	459,622
Deferred financing costs, less accumulated amortization of $940 and $479 in 2004 and 2003, respectively	517	958
Restricted deposits for asset retirement obligations	10,072	11,926
Total assets	$ 760,784	$ 546,729
Liabilities and Shareholders' Equity		
Current liabilities:		
Accounts payable	$ 107,220	$ 57,213
Undistributed oil and gas proceeds	13,286	11,500
Asset retirement obligations	27,489	17,552
Accrued liabilities	8,452	765
Income taxes	—	16,288
Total current liabilities	156,447	103,318
Long-term debt	35,000	67,000
Asset retirement obligations, less current portion	114,937	110,052
Deferred income taxes	92,093	51,904
Other liabilities	2,429	—
Commitments and contingencies		
Shareholders' equity:		
Series A preferred stock, $0.00001 par value; 2,000,000 shares authorized, issued and outstanding at December 31, 2004 and 2003	45,435	45,435
Common stock, $0.00001 par value; authorized 118,330,000 shares, issued and outstanding 52,611,674 and 52,516,556 shares at December 31, 2004 and 2003, respectively	—	—
Additional paid-in capital	6,478	6,087
Retained earnings	307,965	162,933
Total shareholders' equity	359,878	214,455
Total liabilities and shareholders' equity	$ 760,784	$ 546,729

See accompanying notes.

Table of Contents

W&T OFFSHORE, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME

	Year Ended December 31,		
	2004	2003	2002
	(In thousands, except per share data)		
Revenues:			
Oil and gas revenues	$ 508,195	$ 421,435	$ 189,892
Other	520	1,152	1,443
Total revenues	508,715	422,587	191,335
Operating costs and expenses:			
Lease operating	73,475	65,947	26,454
Production taxes	375	303	307
Gathering and transportation	13,724	9,910	3,365
Depreciation, depletion and amortization	155,640	136,249	89,941
Asset retirement obligation accretion	9,168	7,443	—
General and administrative	25,001	22,912	10,060
Total costs and expenses	277,383	242,764	130,127
Impairment of subsidiary assets	—	—	3,750
Operating income	231,332	179,823	57,458
Other income (expense):			
Interest and dividend income	276	279	49
Interest expense	(2,118)	(2,508)	(3,050)
Total other expense	(1,842)	(2,229)	(3,001)
Income before income taxes	229,490	177,594	54,457
Income taxes	80,008	61,156	52,408
Income before cumulative effect of change in accounting principle	149,482	116,438	2,049
Cumulative effect of change in accounting principle (net of tax of $77)	—	144	—
Net income	149,482	116,582	2,049
Less preferred stock dividends	900	5,876	—
Net income applicable to common and common equivalent shares	$ 148,582	$ 110,706	$ 2,049
Basic net income per common share:			
Income before cumulative effect of change in accounting principle	$ 2.82	$ 2.14	
Cumulative effect of change in accounting principle	—	—	
Net income	$ 2.82	$ 2.14	
Diluted net income per common share:			
Income before cumulative effect of change in accounting principle	$ 2.27	$ 1.79	
Cumulative effect of change in accounting principle	—	—	
Net income	$ 2.27	$ 1.79	

See accompanying notes.

W&T OFFSHORE, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF CHANGES IN SHAREHOLDERS' EQUITY

	Preferred		Common		Additional Paid-In Capital	Retained Earnings	Treasury Stock		Total Shareholders' Equity
	Shares	Value	Shares	Value			Shares	Value	
	(In thousands, except per share data)								
Balances at January 1, 2002	—	$ —	75,727	$ —	$ 2,135	$ 162,047	—	$ —	$ 164,182
Income tax distributions to shareholders	—	—	—	—	—	(13,883)	—	—	(13,883)
Net income	—	—	—	—	—	2,049	—	—	2,049
Treasury stock repurchase	—	—	—	—	—	—	5,823	(14,997)	(14,997)
Retirement of treasury stock	—	—	(5,823)	—	(2,135)	(12,862)	(5,823)	14,997	—
Conversion of common stock to preferred stock	2,000	50,000	(19,414)	—	—	(50,000)	—	—	—
Equity offering costs	—	(4,565)	206	—	544	—	—	—	(4,021)
Balances at December 31, 2002	2,000	45,435	50,696	—	544	87,351	—	—	133,330
Cash dividends:									
Common stock ($0.67 per share)	—	—	—	—	—	(35,124)	—	—	(35,124)
Preferred stock ($2.94 per share)	—	—	—	—	—	(5,876)	—	—	(5,876)
Issuance of restricted stock	—	—	1,821	—	5,543	—	—	—	5,543
Net income	—	—	—	—	—	116,582	—	—	116,582
Balances at December 31, 2003	2,000	45,435	52,517	—	6,087	162,933	—	—	214,455
Cash dividends:									
Common stock ($0.07 per share)	—	—	—	—	—	(3,550)	—	—	(3,550)
Preferred stock ($0.45 per share)	—	—	—	—	—	(900)	—	—	(900)
Issuance of restricted stock	—	—	95	—	391	—	—	—	391
Net income	—	—	—	—	—	149,482	—	—	149,482
Balances at December 31, 2004	2,000	$ 45,435	52,612	$ —	$ 6,478	$ 307,965	—	$ —	$ 359,878

See accompanying notes.

Table of Contents

W&T OFFSHORE, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2004	2003	2002
		(In thousands)	
Operating activities:			
Net income	$ 149,482	$ 116,582	$ 2,049
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion, amortization and accretion	164,808	143,692	89,941
Impairment of subsidiary assets	—	—	3,750
Amortization of debt issuance costs	461	442	583
Issuance of restricted stock awards	391	5,543	—
Gain on the sale of equipment	—	(182)	—
Cumulative effect of change in accounting principle, net of tax	—	(144)	—
Deferred income taxes	40,189	1,660	50,166
Changes in operating assets and liabilities:			
Oil and gas receivables	(1,320)	(16,090)	(19,454)
Joint interest receivables and other	2,019	(3,998)	302
Income taxes	(25,410)	14,046	2,242
Prepaid expenses, royalty deposits and other assets	(2,397)	(3,012)	(1,724)
Asset retirement obligations	(12,857)	(9,181)	—
Accounts payable and accrued liabilities	59,481	13,797	19,954
Other liabilities	2,428	—	—
Net cash provided by operating activities	377,275	263,155	147,809
Investing activities:			
Investment in oil and gas property and equipment	(282,510)	(201,318)	(115,835)
Proceeds from sales of oil and gas property and equipment	3,127	173	4,145
Purchases of furniture, fixtures and other	(2,337)	(2,082)	(924)
Proceeds from the sale of subsidiary	—	1,000	—
Change in restricted deposits	1,854	(2,175)	(9)
Net cash used in investing activities	(279,866)	(204,402)	(112,623)
Financing activities:			
Borrowings of long-term debt	212,100	253,200	164,200
Repayments of borrowings of long-term debt	(244,100)	(285,800)	(147,000)
Dividends / distributions to shareholders	(4,450)	(41,000)	(13,883)
Treasury stock repurchase	—	—	(14,997)
Equity offering costs	—	—	(4,021)
Debt issuance costs	—	(91)	(1,310)
Net cash used in financing activities	(36,450)	(73,691)	(17,011)
Increase (decrease) in cash and cash equivalents	60,959	(14,938)	18,175
Cash and cash equivalents, beginning of period	4,016	18,954	779
Cash and cash equivalents, end of period	$ 64,975	$ 4,016	$ 18,954

See accompanying notes.

W&T OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Significant Accounting Policies

Operations

W&T Offshore, Inc. and Subsidiaries (the "Company") is an independent oil and natural gas acquisition, exploitation, and exploration company focused primarily in the Gulf of Mexico.

Basis of Presentation

Our consolidated financial statements include the accounts of W&T Offshore, Inc., and its wholly owned subsidiaries. For the periods prior to January 1, 2003, the financial statements also included a 99% ownership interest in W&T Offshore, LLC. We sold our interest in W&T Offshore, LLC effective January 2, 2003 (see Notes 4 and 15). All significant intercompany transactions and amounts have been eliminated for all years presented.

Use of Estimates and Market Risk

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, disclosure of contingent assets and liabilities at the date of the financial statements, the reported amounts of revenues and expenses. Actual results could differ from those estimates.

Our future financial condition and results of operations will depend upon prices received for our oil and natural gas production and the costs of finding, acquiring, developing and producing reserves. Prices for oil and natural gas are subject to fluctuations in response to changes in supply, market uncertainty and a variety of other factors beyond our control. These factors include worldwide political instability (especially in the Middle East), the foreign supply of oil and natural gas, the price of foreign imports, the level of consumer demand and the price and availability of alternative fuels.

Cash Equivalents

We consider all highly liquid investments purchased with original or remaining maturities of three months or less at the date of purchase to be cash equivalents.

Revenue Recognition

Oil and gas revenues are recognized when production is sold to a purchaser at a fixed or determinable price, when delivery has occurred and title has transferred and if the collection of the revenue is probable. We use the sales method of accounting for our oil and gas revenues. Under this method of accounting, revenue is recorded based upon our physical deliveries to our customers, which can be different from our net revenue ownership interest in field production. These differences create imbalances that are recognized as a liability only when the estimated remaining reserves will not be sufficient to enable the under-produced party to recoup our entitled share through production. As of December 31, 2004 and 2003, deliveries of natural gas in excess of our revenue interest and under-deliveries were not significant.

Concentration of Credit Risk

Our customers are primarily large integrated oil and natural gas companies. Our production is sold utilizing month-to-month contracts that are based on prevailing prices. Substantially all of the contracts are collateralized by letters of credit or other financial guarantees. We historically have not had any significant problems collecting our receivables, except in rare circumstances; therefore, we do not maintain an allowance for doubtful accounts.

W&T OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

The following table identifies customers from whom we derived 10% or more of our total oil and gas revenues:

Customer	Year Ended December 31, 2004	2003	2002
BP Amoco (includes sales to Tractebel—contract purchased by BP Amoco)	22%	13%	**
Shell Trading (US company)	21%	18%	14%
ConocoPhillips.	20%	46%	23%
Duke Energy Trading and Marketing LLC	**	**	22%
Reliant Services, Inc.	—%	—%	17%

** less than 10%

We believe that the loss of any of the customers above would not result in a material adverse effect on our ability to market future oil and gas production.

Oil and Gas Properties and Equipment

We use the full cost method of accounting for oil and gas properties. Under this method, all costs associated with the acquisition, exploration, development and abandonment of oil and gas reserves, including directly related overhead costs, incurred for the purpose of exploring for and developing oil and natural gas are capitalized. Acquisition costs include costs incurred to purchase, lease or otherwise acquire property. Exploration costs include costs of drilling exploratory wells and geological and geophysical costs. Development costs include the cost of drilling development wells and costs of completions, platforms, facilities and pipelines. Costs associated with production, including certain geological and geophysical costs, and general and administrative costs are expensed in the period incurred.

Sales of proved and unproved oil and gas properties, whether or not being amortized currently, are accounted for as adjustments of capitalized costs, with no gain or loss recognized, unless such adjustments would significantly alter the relationship between capitalized costs and proved reserves of oil and gas.

Amortization of capitalized oil and gas properties is calculated using the unit-of-production method based on production and estimates of proved reserve quantities. In addition to costs associated with evaluated properties, the amortization base includes estimated future development costs. Such costs include land acquisition costs, geological and geophysical expenses, carrying charges on nonproducing properties, costs of drilling both productive and nonproductive wells, and overhead charges directly related to acquisition, exploration and development activities.

We capitalize interest on expenditures made in connection with exploration and development projects that are not subject to current amortization. Interest is capitalized only for the period that exploration and development activities are in progress. Since we have not excluded any expenditures related to our oil and gas properties from amortization, we did not capitalize any interest during the years ended December 31, 2004, 2003 or 2002.

Under the full cost method of accounting, we are required to periodically perform a “ceiling test,” which compares the present value of estimated future net cash flows from proved reserves (based on period-end commodity prices and excluding cash flows related to estimated abandonment costs), net of related tax effect, to the net capitalized costs of proved oil and gas properties, including estimated capitalized abandonment costs, net of related deferred taxes. If the net capitalized costs of proved oil and gas properties exceed the estimated discounted future net cash flows from proved reserves, we are required to write-down the value of our oil and gas properties to the value of the discounted cash flows. We did not have a ceiling test impairment during the years ended December 31, 2004, 2003 or 2002.

Furniture, fixtures and non-oil and gas property and equipment are depreciated using the straight-line method based on the estimated useful life of the respective assets. Repairs and maintenance costs are expensed in the period incurred.

Fair Value of Financial Instruments

We include fair value information in the notes to consolidated financial statements when the fair value of our financial instruments is different from the book value. We believe that the book value of our cash and cash equivalents, receivables, accounts payable, accrued liabilities and long-term debt materially approximates fair value due to the short-term nature and the terms of these instruments.

Income Taxes

We use the liability method of accounting for income taxes in accordance with Statement of Financial Accounting Standards ("SFAS") No. 109, *Accounting for Income Taxes*. Under this method, deferred tax assets and liabilities are determined by applying tax regulations in effect at the end of a reporting period to the cumulative temporary differences between the tax bases of assets and liabilities and their reported amounts in the financial statements. Prior to December 3, 2002, our shareholders had elected S Corporation status under the Internal Revenue Code (the "Code") and certain comparable state tax laws. As a result, our taxable income for federal and state jurisdictions was reported on the tax returns of our shareholders.

Deferred Financing Costs

Costs incurred in connection with the issuance of long-term debt are capitalized and amortized to interest expense over the scheduled maturity of the debt utilizing the interest method.

Stock-Based Compensation

SFAS No. 123, *Accounting for Stock-Based Compensation*, encourages but does not require, companies to record compensation costs for stock-based employee compensation plans at fair value. We have chosen to account for stock-based compensation using the intrinsic value method prescribed in Accounting Principles Board Opinion No. 25, *Accounting For Stock Issued to Employees* ("APB No. 25"), and related interpretations. Accordingly, compensation cost for stock issued is measured as the excess, if any, of the fair value of our common stock at the date of the grant over the amount an employee must pay to acquire the common stock.

Earnings Per Share

Basic earnings per share of common stock was calculated by dividing the income before cumulative effect of a change in accounting principle, cumulative effect of change in accounting principle and net income applicable to common stock by the weighted-average number of common shares outstanding during the periods presented. For purposes of basic earnings per share computations, net income applicable to common stock has been adjusted to reflect the effect of preferred stock dividends.

Recent Accounting Developments

In September 2004, the Securities and Exchange Commission issued Staff Accounting Bulletin ("SAB") No. 106, which expressed the Staff's views regarding the application of SFAS No. 143 by oil and gas companies following the full cost accounting method. SAB No. 106 indicates that estimated dismantlement and abandonment costs that will be incurred as a result of future development activities on proved reserves are to be included in the estimated future cash flows in the full cost ceiling limitation. SAB No. 106 also indicates that these estimated costs are to be included in the costs to be amortized. We expect to begin applying SAB No. 106 in the first quarter of 2005, when it becomes effective for us. The application of SAB 106 is not anticipated to have a material impact on our consolidated financial statements.

In December 2004, the FASB issued FASB Staff Position ("FSP") FAS 109-1, *Application of FASB Statement No. 109, Accounting for Income Taxes, to the Tax Deduction on Qualified Production Activities Provided by the American Jobs Creation Act of 2004*. FSP FAS 109-1 provided guidance on the application of SFAS No. 109, *Accounting for Income Taxes*, to the tax deduction on "qualified production activities." This deduction is available beginning in 2005 and therefore, has no effect on our current year's consolidated financial statements.

In December 2004, the FASB issued SFAS No. 123 (revised 2004) ("SFAS No. 123(R)"), *Share-Based Payment,* that requires compensation costs related to share-based transactions be recognized in the financial statements. The amount of compensation costs will be measured based on the grant-date fair value of the equity or liability instruments issued. Compensation cost will be recognized over the period that an employee provides service in exchange for the award. SFAS No. 123(R) replaces SFAS No. 123, *Accounting for Stock-Based Compensation,* and supercedes APB No. 25, *Accounting for Stock Issued to Employers.* SFAS No. 123(R) allows public companies to adopt its requirements using one of the following methods.

1. The "modified prospective" method in which compensation cost is recognized beginning with the effective date (a) based on the requirements of SFAS No. 123(R) for all share-based payments granted after the effective date and (b) based on the requirements of SFAS No. 123 for all awards granted to employees prior to the effective date of SFAS 123(R) that remain unvested on the effective date.
2. The "modified retrospective" method which includes the requirements of the modified prospective method described above, but also permits entities to restate based on the amounts previously recognized under SFAS No. 123 for purposes of pro forma disclosures either (a) all prior periods presented or (b) prior interim periods of the year of adoption.

SFAS No. 123(R) is effective for us in the first quarterly period after June 15, 2005. We are in the process of determining how the new method of valuing stock-based compensation as prescribed by SFAS No. 123(R) will be applied to valuing stock-based awards and the impact the recognition of compensation expense related to such awards will have on our financial statements; however, since our previous share-based payments have been recorded at fair value, we do not expect the adoption of SFAS No. 123(R) will have an impact on our consolidated financial statements.

2. Asset Retirement Obligations

In June 2001, the FASB issued SFAS No. 143, *Accounting for Asset Retirement Obligations*. SFAS No. 143 requires that an asset retirement obligation ("ARO") associated with the retirement of a tangible long-lived asset be recognized as a liability in the period in which a legal obligation is incurred and becomes determinable, with an offsetting increase in the carrying amount of the associated asset. The cost of the tangible asset, including the initially recognized ARO, is depleted such that the cost of the ARO is recognized over the useful life of the asset. The ARO is recorded at fair value, and accretion expense is recognized over time as the discounted liability is accreted to our expected settlement value. The fair value of the ARO is measured using expected future cash outflows discounted at our credit-adjusted risk-free interest rate.

We adopted SFAS No. 143 on January 1, 2003, which resulted in an increase to net oil and gas properties of $95.0 million and additional liabilities related to asset retirement obligations of $101.7 million. These amounts reflect our ARO had the provisions of SFAS No. 143 been applied since inception and resulted in a noncash cumulative effect increase to earnings of approximately $0.2 million ($0.1 million net of tax). In accordance with the provisions of SFAS No. 143, we record an abandonment liability associated with our oil and gas wells and platforms when those assets are placed in service, rather than our past practice of accruing the expected undiscounted abandonment costs on a unit-of-production basis over the productive life of the associated full-cost pool. Under SFAS No. 143, depletion expense is reduced since a discounted ARO is depleted in the property balance rather than the undiscounted value previously depleted under the old rules. The lower depletion expense under SFAS No. 143 is offset, however, by accretion expense, which is recognized over time as the discounted liability is accreted to our expected settlement value.

The following table is a reconciliation of the asset retirement obligation liability since adoption (in millions):

	2004	2003
Asset retirement obligation, beginning of period	$127.6	$ —
Initial obligation upon adoption of SFAS No. 143	—	101.7
Liabilities settled	(12.9)	(9.1)
Accretion expense	9.2	7.4
Liabilities incurred, net of sales	14.7	27.3
Revision in estimated cash flows	3.8	0.3
Asset retirement obligation, end of period	$142.4	$127.6

The following table presents the pro forma effects of the retroactive application of this change in accounting principle as if the principle had been adopted on January 1, 2002 (in thousands):

	Year Ended December 31, 2002	
	As Reported	Pro Forma
		(Unaudited)
Net income	$ 2,049	$ 3,144
Asset retirement obligation	—	101,700

3. Restricted Deposits

Restricted deposits as of December 31, 2004 and 2003 consisted of funds escrowed for the future plug and abandonment of certain oil and gas properties. In connection with the Burlington Acquisition (as defined in Note 5), we received approximately $9.6 million in escrowed funds attributable to the future plug and abandonment of two oil and gas fields. We are currently not obligated to contribute additional amounts to further fund these escrowed accounts.

In connection with the ConocoPhillips Acquisition in 2003 as discussed in Note 5, we provided the U.S. Minerals Management Service with a $1.8 million U.S. Treasury note in satisfaction of the mandatory area-wide operator bonding requirements.

4. Sale of Subsidiary

On January 2, 2003, we sold our 99% ownership interest in W&T Offshore, LLC to our two largest common shareholders for $1 million in cash (see Note 15). The sales price was determined by management to approximate fair value. In connection with this sale, we reduced our carrying value to $1 million as of December 31, 2002 by recording an impairment expense of $3.8 million ($2.4 million net of tax). The results of operations of W&T Offshore, LLC represented less than 2% of total revenue and less than 4% of pretax net income during the year ended December 31, 2002.

5. Significant Acquisitions

In December 2003, we acquired substantially all of ConocoPhillips' Gulf of Mexico shelf assets ("ConocoPhillips Acquisition"). In December 2002, we acquired substantially all of Burlington Resources Inc's Gulf of Mexico shelf assets ("Burlington Acquisition"). These acquisitions were accounted for as purchases in accordance with SFAS No. 141, *Business Combinations*. The results of operations from these acquisitions have been included in the accompanying statements of income since their respective closing dates.

The following unaudited pro forma information shows the effect on our consolidated results of operations as if the ConocoPhillips Acquisition and Burlington Acquisition occurred on January 1, 2003 and 2002, respectively. The pro forma information includes only significant acquisitions and numerous assumptions, and is not necessarily indicative of future results of operations (in thousands).

	Year Ended December 31,			
	2003		2002	
	Audited	Pro Forma (Unaudited)	Audited	Pro Forma (Unaudited)
Oil and gas revenues	$ 421,435	$ 502,140	$ 189,892	$ 294,636
Income before income taxes and cumulative effect of a change in accounting principle	$ 177,594	$ 234,287	$ 54,457	$ 96,083
Net income before income taxes	$ 177,738	$ 234,431	$ 54,457	$ 96,083
Net income	$ 116,582	$ 153,432	$ 2,049	$ 43,675

The 2002 pro forma net income assumes that we were a federal taxpayer effective December 3, 2002 at a rate of 35%.

6. Equity Structure and Transactions

At December 31, 2001, our capital structure consisted of 100,000 authorized shares of common stock, of which 3,900 shares were issued and outstanding. In late 2002, we repurchased and retired 300 shares of common stock and purchased a less than 1% interest in W&T Offshore, LLC from a shareholder for $15 million in cash. In a transaction with a third party, the same shareholder sold his remaining 1,000 shares of our common stock for $50 million.

Contemporaneously, we executed an Exchange Agreement with the third-party purchaser pursuant to which the purchaser tendered the 1,000 shares of common stock in exchange for two million shares of our Series A Preferred Stock ("Preferred Stock"), having a face amount of $50 million.

Upon the completion of the Exchange Agreement, we were recapitalized and declared a 2,911.48115-for-one stock dividend on our remaining 2,600 outstanding shares of common stock. The recapitalization resulted in 20 million shares of capital stock, of which 18 million were designated as common stock, with a par value per share of $0.00001, and two million shares designated as preferred stock, with a par value per share of $0.00001.

We incurred approximately $4.5 million in offering costs related to the above transactions. The costs consisted of $4.0 million in cash payments to brokers and the issuance to a broker of 31,685 shares of common stock valued at $0.5 million.

A special dividend in the aggregate amount of $12 million was authorized for holders of record immediately preceding the issuance of the Preferred Stock on December 3, 2002 (see Note 7). The special dividend was paid during the second quarter of 2003.

On October 26, 2004, the board of directors declared a 6.669173211-for-1 split of our common stock, which was payable on November 30, 2004 in the form of a dividend to shareholders of record on November 15, 2004. The total authorized number of shares of common stock was increased to 118.33 million. Shares of our Preferred Stock were not split; however, any conversion of Preferred Stock to common stock will be adjusted to reflect the common stock split. For all periods presented, the share and per share data reflected in the consolidated financial statements have been adjusted to give effect to the common stock split.

On January 28, 2005, certain shareholders of our common stock sold 12,655,263 shares pursuant to a registration statement that we filed with the Securities and Exchange Commission at an initial public offering price of $19.00 per share. Our common stock is listed and principally traded on the New York Stock Exchange under the symbol "WTI".

7. Preferred Stock

The Preferred Stock is convertible at the option of the holder, at any time, into common stock on the basis of one share of common stock for each share of Preferred Stock, subject to certain adjustments. The Preferred Stock would be converted into common stock upon the effectiveness of an initial public offering of the common stock at our election. The Preferred Stock has a redemption price equal to the greater of $50 million or $25 per share. The holders of the Preferred Stock are entitled to vote, together with the common stock, on any matter as to which the common stock is entitled to vote, including the election of directors.

The Preferred Stock is redeemable at the option of the holder at any time upon the earlier of (1) the occurrence of a breach event as defined in our articles of incorporation, or (2) the death or disability of the Chief Executive Officer, at a redemption price equal to the greater of the liquidation preference of $25 per share ($50 million in the aggregate) or our per share fair market value. We and the holders of the Preferred Stock have the option to initiate the sale of the Company as a means of financing a redemption. The Preferred Stock has no stated dividend rate. Except for a special dividend payable to holders of the common stock in accordance with our amended and restated articles of incorporation, the holders of the Preferred Stock share equally on a per share basis with common stock holders if a dividend is declared on common stock.

In connection with our initial public offering in January 2005, all outstanding shares of Preferred Stock were converted into a total of 13,338,350 shares of our common stock.

8. Long-Term Debt

Our long-term debt facility consists of a $230 million revolving line of credit as amended December 12, 2003. At December 31, 2004, the Borrowing Base amount was $230 million, the outstanding loan balance on the revolving line of credit was $35 million, excluding $5 million of outstanding letters of credit, and the available line of credit was $190 million. The interest rate at December 31, 2004 relating to these loans was 2.97%. On March 15, 2005, we entered into a new $300 million secured revolving credit facility with an initial borrowing base of $230 million, which is subject to redetermination on March 1 and September 1 of each year. The new revolving line of credit matures on March 15, 2009 and is secured by substantially all of our oil and gas properties. Interest accrues either (1) at the higher of the Prime Rate or the Federal Funds Rate plus 0.50% plus a margin which varies from 0.0% to 0.625% depending upon the ratio of the amounts outstanding to the borrowing base or (2) to the extent any loan outstanding is designated as a Eurodollar loan, at the London Interbank Offered

Rate, plus a margin that varies from 1.25% to 1.875%, depending upon the ratio of the amounts outstanding to the borrowing base.

We are subject to various financial covenants, including a minimum tangible net worth ratio, a minimum current ratio and a minimum interest coverage ratio. We were in compliance with these covenants on December 31, 2004.

9. Income Taxes

From the time of our formation through December 2, 2002, we elected to be treated for federal and state income tax purposes as an S Corporation. As a result, our earnings were taxed at the shareholder level rather than at the corporate level. On December 2, 2002, we revoked our S Corporation election and, accordingly, became subject to federal and state income taxes. The recognition of deferred income tax due to the change in tax status decreased net income by $52.4 million for the year ended December 31, 2002.

Deferred income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes. Significant components of our deferred tax assets and liabilities were as follows (in thousands):

	December 31,	
	2004	2003
Deferred tax liabilities:		
Oil and gas properties and equipment	$ 93,516	$ 49,880
Change in accounting method	962	2,024
Total deferred tax liabilities	94,478	51,904
Deferred tax assets—accruals	2,385	—
Net deferred tax liabilities	$ 92,093	$ 51,904

Significant components of income tax expense were as follows (in thousands):

	Year Ended December 31,		
	2004	2003	2002
Current	$ 39,819	$ 59,418	$ 2,242
Deferred	40,189	1,738	(2,203)
Effect of tax status change	—	—	52,369
	$ 80,008	$ 61,156	$ 52,408

The reconciliation of income taxes computed at the U.S. federal statutory tax rate to our income tax expense, excluding the effect of the tax status change, is as follows (in thousands):

	Year Ended December 31,					
	2004		2003		2002	
Income before income taxes	$229,490		$177,594		$ 54,457	
Less Subchapter S income	—		—		(54,400)	
	$229,490		$177,594		$ 57	
Income tax expense at the federal statutory rate	$ 80,322	35.0%	$ 62,158	35.0%	$ 20	35.0%
State income taxes, net of federal tax benefit	—	0.0%	—	0.0%	1	2.0%
Permanent and other	(314)	0.0%	(1,002)	(0.6)%	17	29.5%
	$ 80,008	35.0%	$ 61,156	34.4%	$ 38	66.5%

10. Commitments

We have several operating lease agreements for office space, which terminate in January 2009. Minimum future lease payments due under noncancelable operating leases with terms in excess of one year as of December 31, 2004 are as follows (in thousands): $866–2005, $866–2006, $866–2007, $790–2008, $7–2009, $0–Thereafter.

Total rent expense was approximately $0.9 million, $0.6 million and $0.5 million during the years ended December 31, 2004, 2003 and 2002, respectively.

11. Contingent Liabilities

We are subject to claims and complaints, which may arise in the ordinary course of business. It is the opinion of management that the outcome of these matters will not have a material adverse effect on our financial position or results of operations.

12. Employee Benefit Plan

We maintain a defined contribution benefit plan in compliance with Section 401(k) of the Internal Revenue Code (the “401(k) Plan”), which covers those employees who meet the 401(k) Plan’s eligibility requirements. We match employee contributions up to a maximum of 25% of the first 5% of the participant’s compensation, subject to Code limitations. We may also elect to make additional contributions in an amount determined by our board of directors. For 2004, we increased the Company matching contributions to 100% of each participant’s contribution up to a maximum of 5% of the participant’s compensation, subject to Code limitations. Our expenses relating to the 401(k) Plan were approximately $0.5 million, $0.1 million and $0.1 million for the years ended December 31, 2004, 2003 and 2002, respectively.

13. Long-Term Incentive Compensation Plan

In 2003, we implemented a long-term incentive compensation plan, the purpose of which is to reward certain key employees for exceptional performance. In 2004, we replaced this plan with a new long-term incentive compensation plan (the “Plan”). The key metrics for determining awards, which may be in the form of stock options, stock appreciation rights, restricted stock or performance shares, are return on equity, lease operating cost containment, general and administrative cost containment, reserve replacement and growth, reserve replacement cost and increased production. The cumulative award under the plans to date has been approximately 2.8% of the outstanding common shares on a fully diluted basis. The Plan may be terminated by executive management or the board of directors at any time without incurring additional obligations for grants. During 2004 and 2003, we issued 95,118 and 1,820,594 shares, respectively, of restricted common stock to key employees pursuant to the terms of the plans. All of these shares were outstanding as of December 31, 2004. In accordance with APB No. 25, compensation cost related to the stock awards was $0.4 million and $5.5 million for the years ended December 31, 2004 and 2003, respectively. These amounts are included in general and administrative expenses. As of December 31, 2004, there are 1,667,293 shares of common stock available for award under the Plan. (See Note 1—*Recent Accounting Developments*).

W&T OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

14. Earnings Per Share

The following table presents the reconciliation of the numerator and denominator for calculating earnings per share in accordance with the disclosure requirements of Statement of Financial Accounting Standards No. 128 as follows (in thousands, except per share amounts):

	Year Ended December 31,	
	2004	2003
Net income applicable to common and common equivalent shares	$ 148,582	$ 110,706
Add Preferred Stock dividends	900	5,876
Adjusted net income applicable to common and common equivalent shares	$ 149,482	$ 116,582
Weighted average number of shares outstanding	52,604	51,699
Add shares assumed issued upon conversion of the Preferred Stock	13,338	13,338
Adjusted weighted average number of shares outstanding	65,942	65,037
Net income applicable to common and common equivalent shares:		
Basic earnings per share	$ 2.82	$ 2.14
Diluted earnings per share	$ 2.27	$ 1.79

Earnings per share information has not been presented for 2002 because we were an S corporation during most of 2002. Accordingly, the results in 2002 would not be comparable to the current presentation.

15. Related Party Transactions

The grandson of our Corporate Secretary is employed by an insurance agency that writes certain insurance coverage for the Company. Personal commissions earned by the grandson for writing such coverage totaled approximately $47,000 in 2004. Business was awarded to this insurance agency as low bidder in a competitive bidding process in which the Company received at least one other quote.

Effective January 1, 2003 we sold our 99% ownership interest in W&T Offshore, LLC ("W&T LLC") to our two largest common shareholders, who are also officers and directors (see Note 4). We continued to provide management services, including land, geological, accounting, engineering and administrative services for W&T LLC for which we received no compensation in 2003. We executed a management agreement with W&T LLC under which we received approximately $0.1 million for providing management services to W&T LLC during 2004. These fees are recorded as a direct reduction of general and administrative expenses.

We utilize the services of an employment placement firm owned by the wife of the Chief Executive Officer. We incurred approximately $0.4 million, $0.3 million and $0.1 million in fees paid to this firm during the years ended December 31, 2004, 2003 and 2002, respectively.

During 2003, we purchased oilfield goods, services and equipment from a drilling and production company, which was majority-owned by one of our executives. During the year ended December 31, 2003, we incurred expenses of approximately $2.2 million with this company. The executive sold his interest in the drilling and production company effective December 31, 2003.

During 2004, we paid approximately $0.9 million to Adams and Reese LLP for legal services. Virginia Boulet, who serves as special counsel to Adams and Reese LLP, was appointed to our board of directors on March 25, 2005.

Table of Contents

16. Supplemental Cash flow Information and Noncash Financing Activities

The following information reflects our supplemental cash flow and noncash financing activities (in thousands):

	Year Ended December 31,		
	2004	2003	2002
Cash flow information:			
Cash paid for interest expense	$ 1,692	$ 2,111	$ 2,522
Cash paid for income taxes	65,229	45,450	—
Noncash financing activities:			
Issuance of common stock in lieu of cash for equity offering costs	—	—	544
Assumption of plug and abandonment liabilities in exchange for restricted deposits	—	—	9,627

17. Oil and Gas Properties and Equipment

Net capitalized costs related to our oil and natural gas producing activities are as follows (in millions):

	December 31,		
	2004	2003	2002
Net capitalized cost:			
Proved oil and natural gas properties	$ 949.2	$ 712.9	$ 521.4
Unproved oil and natural gas properties	58.9	16.2	2.7
Capitalized asset retirement obligations	132.7	113.7	—
Accumulated depreciation, depletion and amortization	(541.1)	(386.3)	(262.3)
	$ 599.7	$ 456.5	$ 261.8

	Year Ended December 31,		
	2004	2003	2002
Costs incurred:			
Proved property acquisitions	$ 33.5	$ 69.1	$ 56.6
Development	90.7	65.1	31.0
Exploration	150.4	54.5	26.1
Unproved property acquisitions	7.9	13.4	0.7
Asset retirement obligations	18.5	27.6	—
	$ 301.0	$ 229.7	$ 114.4

	Year Ended December 31,		
	2004	2003	2002
Depreciation, depletion, amortization and accretion per Mcfe	$ 2.00	$ 1.82	$ 1.66

W&T OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

18. Selected Quarterly Financial Data—UNAUDITED

Unaudited quarterly financial data for the years ended December 31, 2004 and 2003 are as follows (in thousands, except per share amounts):

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
Year Ended December 31, 2004				
Revenues	$ 123,267	$ 126,059	$ 120,534	$ 138,855
Operating income	59,124	53,950	58,920	59,338
Net income	38,043	34,710	38,053	38,676
Net income per common share: (1)				
Basic	0.72	0.65	0.72	0.73
Diluted	0.58	0.53	0.58	0.59
Year Ended December 31, 2003				
Revenues	$ 117,111	$ 104,152	$ 101,980	$ 99,344
Operating income	66,535	35,352	39,858	38,078
Income before cumulative effect of change in accounting principle	42,800	22,697	25,610	25,331
Net income	42,944	22,697	25,610	25,331
Net income per common share: (1)				
Basic	0.84	0.44	0.49	0.37
Diluted	0.67	0.35	0.39	0.37

(1) The sum of the individual quarterly earnings per share may not agree with year-to-date earnings per share because each quarterly calculation is based on the income for that quarter and the weighted average number of shares outstanding during that quarter.

19. Oil and Gas Reserve Information—UNAUDITED

Our net proved oil and gas reserves at December 31, 2004, 2003, and 2002 have been estimated by independent petroleum consultants in accordance with guidelines established by the Securities and Exchange Commission ("SEC"). Accordingly, the following reserve estimates are based upon existing economic and operating conditions at the respective dates.

There are numerous uncertainties in estimating quantities of proved reserves and in providing the future rates of production and timing of development expenditures. The following reserve data represent estimates only and are inherently imprecise and may be subject to substantial revisions as additional information such as reservoir performance, additional drilling, technological advancements and other factors become available.

W&T OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

The following table sets forth our estimated quantities of net proved and proved developed oil (including condensate) and natural gas reserves, all of which are located onshore and offshore in the continental United States:

	Oil (MBbls)	Natural Gas (MMcf)
Proved reserves as of January 1, 2002	15,156	154,718
Revisions of previous estimates	51	14,669
Extensions, discoveries and other additions	2,670	8,164
Purchase of producing properties	7,670	82,295
Sales of reserves	—	(1,439)
Production	(2,465)	(39,368)
Proved reserves as of December 31, 2002	23,082	219,039
Revisions of previous estimates (1)	1,780	(17,226)
Extensions, discoveries and other additions	3,687	26,470
Purchase of producing properties	11,426	55,585
Sales of reserves	—	—
Production	(4,373)	(52,807)
Proved reserves as of December 31, 2003	35,602	231,061
Revisions of previous estimates	2,351	6,770
Extensions, discoveries and other additions	4,582	37,732
Purchase of producing properties	2,294	5,464
Sales of reserves	(1)	(106)
Production	(4,847)	(53,348)
Proved reserves as of December 31, 2004	39,981	227,573
Year-end proved developed reserves:		
2004	20,311	168,260
2003	19,718	177,263
2002	11,333	161,188

(1) Approximately 48% of the 17,226 downward revision in 2003 was made when the owner of a production platform on which the production from our well was being processed decided to shut down the platform.

The following tables present the standardized measure of future net cash flows related to our proved oil and gas reserves together with changes therein, as defined by the FASB, including a reduction for estimated plug and abandonment costs that are also reflected as a liability on the balance sheet at December 31, 2004 and 2003 in accordance with SFAS No. 143. As required by the SEC, we determined estimated future net cash flows using period-end market prices for oil and gas without considering hedge contracts in place at the end of the period. Average year-end prices related to proved reserves of natural gas were $6.31, $6.07 and $4.85 per Mcf and for oil were $39.05, $29.00 and $28.69 per barrel at December 31, 2004, 2003 and 2002. Future production and development costs are based on current costs with no escalations. Estimated future cash flows net of future income taxes have been discounted to their present values based on a 10% annual discount rate.

W&T OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

The standardized measure of discounted future net cash flows does not purport, nor should it be interpreted, to present the fair market value of our oil and gas reserves. These estimates reflect proved reserves only and ignore, among other things, changes in prices and costs, revenues that could result from probable reserves which could become proved reserves in 2005 or later years and the risks inherent in reserve estimates. The standardized measure of discounted future net cash flows relating to our proved oil and gas reserves is as follows (in thousands):

	Year Ended December 31,		
	2004	2003	2002
Standardized Measure of Discounted Future Net Cash Flows			
Future cash inflows	$ 2,998,214	$ 2,435,234	$ 1,725,666
Future costs:			
Production	(467,784)	(425,275)	(302,070)
Development	(277,905)	(246,853)	(170,143)
Dismantlement and abandonment	(204,626)	(180,924)	(139,570)
Future net cash flows before income taxes	2,047,899	1,582,182	1,113,883
Future income taxes	(646,418)	(503,283)	(354,079)
Future net cash inflows before 10% discount	1,401,481	1,078,899	759,804
10% annual discount factor	(426,693)	(317,960)	(210,153)
	$ 974,788	$ 760,939	$ 549,651

	Year Ended December 31,		
	2004	2003	2002
Changes in Standardized Measure			
Standardized measure, beginning of year	$ 760,939	$ 549,651	$ 217,841
Sales and transfers of oil and gas produced, net of production costs	(421,142)	(346,244)	(161,209)
Net changes in price, net of future production costs	256,315	151,242	304,538
Extensions and discoveries, net of future production and development costs	257,206	59,882	36,593
Changes in estimated future development costs (including plug and abandonment costs)	(76,704)	(27,030)	(24,878)
Development costs incurred during the period (including plug and abandonment costs)	103,653	73,569	32,172
Revisions of quantity estimates	78,371	35,875	72,024
Accretion of discount	100,580	80,580	30,692
Net change in income taxes	(94,649)	(98,816)	(167,066)
Purchases of reserves in-place	58,152	285,781	214,770
Sales of reserves in-place	(524)	—	(1,368)
Changes in production rates due to timing and other	(47,409)	(3,551)	(4,458)
Net increase in standardized measure	213,849	211,288	331,810
Standardized measure, end of year	$ 974,788	$ 760,939	$ 549,651

20. Subsequent Event—UNAUDITED

On March 28, 2005, the Company's board of directors declared a cash dividend of $0.02 per share of common stock, payable on May 2, 2005 to shareholders of record on April 15, 2005.

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

None

Item 9A. ***Controls and Procedures***

We performed an evaluation, under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures as of the end of the period covered by this report. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer have each concluded that as of December 31, 2004 our disclosure controls and procedures are effective to ensure that information we are required to disclose in reports filed or submitted under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's rules and forms.

There have been no changes in our internal control over financial reporting that occurred during the quarterly period ended December 31, 2004 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. ***Other Information***

None

PART III

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

The information required by this item is incorporated by reference from our definitive proxy statement to be filed with the SEC within 120 days after the end of our fiscal year covered by this Form 10-K and to the information set forth in Item 4A of this report.

Item 11. ***Executive Compensation***

The information required by this item is incorporated by reference from our definitive proxy statement to be filed with the SEC within 120 days after the end of our fiscal year covered by this Form 10-K.

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

The information required by this item is incorporated by reference from our definitive proxy statement to be filed with the SEC within 120 days after the end of our fiscal year covered by this Form 10-K.

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

The information required by this item is incorporated by reference from our definitive proxy statement to be filed with the SEC within 120 days after the end of our fiscal year covered by this Form 10-K.

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

The information required by this item is incorporated by reference from our definitive proxy statement to be filed with the SEC within 120 days after the end of our fiscal year covered by this Form 10-K.

Table of Contents

PART IV

Item 15. ***Exhibits and Financial Statement Schedules***

(a) Documents filed as a part of this report

1. Financial Statements:

All other schedules are omitted because they are not applicable, not required or the required information is included in the consolidated financial statements or related notes.

2. Exhibits:

Exhibit Number	Description
3.1	Amended and Restated Articles of Incorporation of W&T Offshore, Inc. (Incorporated by reference to Exhibit 3.1 of the Company's Registration Statement on Form S-1 (File No. 333-115103))
3.2	Amended and Restated Bylaws of W&T Offshore, Inc. (Incorporated by reference to Exhibit 3.2 of the Company's Registration Statement on Form S-1 (File No. 333-115103))
4.1	Specimen Common Stock Certificate. (Incorporated by reference to Exhibit 4.1 of the Company's Registration Statement on Form S-1 (File No. 333-115103))
10.1	Credit Agreement, dated March 15, 2005, by and between W&T Offshore, Inc., a Texas Corporation, and Toronto Dominion (Texas), LLC, TD Securities (USA), LLC, JP Morgan Chase Bank, N.A. and Fortis Capital Corp., Harris Nesbitt Financing, Inc. and Bank of Scotland, Natexis Banques Populaires, and certain additional financial institutions. (Incorporated by reference from the Company's Current Report filed on Form 8-K, dated March 16, 2005)
10.2	Form of Indemnification and Hold Harmless Agreement between W&T Offshore, Inc. and each of its directors and W. Reid Lea. (Incorporated by reference to Exhibit 10.8 of the Company's Registration Statement on Form S-1 (File No. 333-115103))
10.3	Employment Agreement dated April 21, 2004, by and between Tracy W. Krohn and W&T Offshore, Inc. (Incorporated by reference to Exhibit 10.9 of the Company's Registration Statement on Form S-1 (File No. 333-115103))
10.4	2004 Directors Compensation Plan of W&T Offshore, Inc. (Incorporated by reference to Exhibit 10.11 of the Company's Registration Statement on Form S-1 (File No. 333-115103))
10.5	W&T Offshore, Inc. Long-Term Incentive Compensation Plan (2003). (Incorporated by reference to Exhibit 10.13 of the Company's Registration Statement on Form S-1 (File No. 333-115103))

Exhibit Number	Description
10.6	Exchange Agreement dated November 25, 2002, by and among W&T Offshore, Inc., and ING Furman Selz Investors III L.P., ING Barings U.S. Leveraged Equity Plan LLC, ING Barings Global Leveraged Equity Plan Ltd. and Jefferies & Company, Inc. (Incorporated by reference to Exhibit 10.12 of the Company's Registration Statement on Form S-1 (File No. 333-115103))
14	W&T Offshore, Inc. Code of Business Conduct and Ethics (as amended). (Incorporated by reference to Exhibit 14.1 of the Company's Form 8-A, dated March 23, 2005)
21*	Subsidiaries of the Registrant.
23.1*	Consent of Netherland, Sewell & Associates, Inc., Independent Petroleum Engineers and Geologists.
31.1*	Rule 13a-14(a)/15d-14(a) Certification of Chief Executive Officer.
31.2*	Rule 13a-14(a)/15d-14(a) Certification of Chief Financial Officer.
32.1*	Certification of Chief Executive Officer and Chief Financial Officer of W&T Offshore, Inc. pursuant to 18 U.S.C. § 1350.

* Filed or furnished herewith.

GLOSSARY OF OIL AND NATURAL GAS TERMS

The following are abbreviations and definitions of terms commonly used in the oil and natural gas industry that are used in this prospectus.

Acquisitions. Refers to acquisitions, mergers or exercise of preferential rights of purchase.

Bbl. One stock tank barrel or 42 U.S. gallons liquid volume.

Bcf. Billion cubic feet.

Bcfe. One billion cubic feet equivalent, determined using a ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

Deep shelf well. A well drilled on the outer continental shelf to subsurface depths greater than 15,000 feet.

Deepwater. Water depths below 500 feet in the Gulf of Mexico.

Development well. A well drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

Dry hole or well. A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production would exceed production expenses and taxes.

Exploitation. A drilling or other project which may target proven or unproven reserves (such as probable or possible reserves), but which generally has a lower risk than that associated with exploration projects.

Exploratory well. A well drilled to find and produce oil or natural gas reserves not classified as proved, to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir or to extend a known reservoir.

Field. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.

Gross acres or gross wells. The total acres or wells, as the case may be, in which a working interest is owned.

MBbls. One thousand barrels of crude oil or other liquid hydrocarbons.

Mcf. One thousand cubic feet.

Mcfe. One thousand cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil or other hydrocarbon.

MMBbls. One million barrels of crude oil or other liquid hydrocarbons.

MMcf. One million cubic feet.

MMcfe. One million cubic feet equivalent, determined using a ratio of 6 Mcf of natural gas to 1 Bbl of crude oil condensate or natural gas liquids.

Net acres or net wells. The sum of the fractional working interests owned in gross acres or gross wells, as the case may be.

Oil. Crude oil, condensate and natural gas liquids.

Productive well. A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceeds production expenses and taxes.

Proved developed reserves. Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery are included in "proved developed reserves" only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

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

Proved undeveloped drilling location. A site on which a development well can be drilled consistent with spacing rules for purposes of recovering proved undeveloped reserves.

Proved undeveloped reserves. Proved oil and gas reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Under no circumstances should estimates for proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.

PV-10 value. The present value of estimated future net revenues to be generated from the production of proved reserves, determined in accordance with the rules and regulations of the SEC (using prices and costs in effect as of the date of estimation) without giving effect to non-property related expenses such as general and administrative expenses, debt service and future income tax expenses or to depreciation, depletion and amortization and discounted using an annual discount rate of 10%.

Recompletion. The completion for production of an existing wellbore in another formation from that which the well has been previously completed.

Reservoir. A porous and permeable underground formation containing a natural accumulation of producible oil and/or natural gas that is confined by impermeable rock or water barriers and is individual and separate from other reserves.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on March 30, 2005.

W&T OFFSHORE, INC.

By: /S/ W. REID LEA
W. Reid Lea
Chief Financial Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on March 30, 2005.

/S/ TRACY W. KROHN **Tracy W. Krohn**	Chairman, Chief Executive Officer, President and Treasurer and Director (Principal Executive Officer)
/S/ W. REID LEA **W. Reid Lea**	Chief Financial Officer (Principal Financial Officer)
/S/ WILLIAM W. TALAFUSE **William W. Talafuse**	Vice President of Accounting and Chief Accounting Officer (Principal Accounting Officer)
/S/ VIRGINIA BOULET **Virginia Boulet**	Director
/S/ JEROME F. FREEL **Jerome F. Freel**	Secretary and Director
/S/ STUART B. KATZ **Stuart B. Katz**	Director
/S/ JAMES L. LUIKART **James L. Luikart**	Director

Exhibit 21

SUBSIDIARIES OF W&T OFFSHORE, INC.

The subsidiaries of W&T Offshore, Inc. are listed below.

Name	State of Organization
Offshore Energy I LLC	Delaware
Offshore Energy II LLC	Delaware
Offshore Energy III LLC	Delaware
Gulf of Mexico Oil and Gas Properties LLC	Delaware
W&T Holdings, L.L.C.*	Louisiana

* W&T Offshore, Inc. has commenced the process of dissolving this subsidiary.

Exhibit 23.1

NETHERLAND, SEWELL & ASSOCIATES, INC.

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

As independent petroleum engineers and geologists, we consent to the references to our firm in the W&T Offshore, Inc. Annual Report on Form 10-K for the year ended December 31, 2004 and to the incorporation by reference in this Form 10-K to our estimates of reserves and value of reserves, and to the use of our reports on reserves and the incorporation of the reports on reserves for the years ended 2004, 2003, and 2002 included in the W&T Offshore, Inc. Annual Report on Form 10-K made on or about March 30, 2005.

NETHERLAND, SEWELL & ASSOCIATES, INC.

By: /S/ FREDERIC D. SEWELL

Frederic D. Sewell
Chairman and Chief Executive Officer

Dallas, Texas
March 30, 2005

Exhibit 31.1

CERTIFICATION PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Tracy W. Krohn, certify that:

1. I have reviewed this annual report on Form 10-K of W&T Offshore, Inc.;
2. Based on my knowledge, this report does not contain any untrue statement of material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:
   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   b) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   c) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 30, 2005

/s/ TRACY W. KROHN

Tracy W. Krohn
Chief Executive Officer, President and Treasurer

Exhibit 31.2

CERTIFICATION PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, W. Reid Lea, certify that:

1. I have reviewed this annual report on Form 10-K of W&T Offshore, Inc.;
2. Based on my knowledge, this report does not contain any untrue statement of material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:
   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   b) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   c) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 30, 2005

/s/ W. REID LEA

W. Reid Lea
Chief Financial Officer

Exhibit 32.1

CERTIFICATION OF CHIEF EXECUTIVE OFFICER AND CHIEF FINANCIAL OFFICER

Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, each of the undersigned officers of W&T Offshore, Inc. (the "Company"), hereby certifies, to the best of his knowledge, that the Company's Annual Report on Form 10-K for the year ended December 31, 2004 fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and that information contained in such Annual Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: March 30, 2005

/s/ TRACY W. KROHN

Tracy W. Krohn
Chief Executive Officer

Date: March 30, 2005

/s/ W. REID LEA

W. Reid Lea
Chief Financial Officer