UNIT CORP
Form 10-K
February 28, 2008
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 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, 2007

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: 1-9260

UNIT CORPORATION

(Exact name of registrant as specified in its charter)

Delaware	**73-1283193**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**
7130 South Lewis, Suite 1000	
Tulsa, Oklahoma	**74136**
(Address of principal executive offices)	**(Zip Code)**

(Registrant s telephone number, including area code) (918) 493-7700

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 $.20 per share	NYSE

Rights to Purchase Series A Participating Cumulative Preferred Stock	NYSE

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Yes x No ¨

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act.

Yes ¨ No x

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes x No ¨

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of large accelerated filer , accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act.

Large accelerated filer x Accelerated filer ¨ Non-accelerated filer ¨ Smaller reporting company ¨

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes ¨ Nox

As of June 29, 2007, the aggregate market value of the voting and non-voting common equity (based on the closing price of the stock on the New York Stock Exchange on June 29, 2007) held by non-affiliates was approximately $2,097,585,734. Determination of stock ownership by non-affiliates was made solely for the purpose of this requirement, and the registrant is not bound by these determinations for any other purpose.

Indicate the number of shares outstanding of each of the issuer s classes of common stock, as of the latest practicable date.

Class	Outstanding at February 15, 2008
Common Stock, $0.20 par value per share	47,141,625 shares

DOCUMENTS INCORPORATED BY REFERENCE

Document	Parts Into Which Incorporated
Portions of the registrant s Definitive Proxy Statement (the Proxy Statement) with respect to its annual meeting of shareholders scheduled to be held on May 7, 2008.	Part III

Exhibit Index See Page 100

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UNIT CORPORATION

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DEFINITIONS

The following are explanations of some of the terms used in this report.

ARO Asset retirement obligations.

Bcf Billion cubic feet of natural gas.

Bcfe Billion cubic feet of natural gas equivalent. Determined using the ratio of one barrel of crude oil to six Mcf of natural gas.

Bbl Barrel, or 42 U.S. gallons liquid volume.

BOKF Bank of Oklahoma Financial Corporation.

Btu British thermal unit, used in terms of volumes. Btu is used to refer to the amount of natural gas required to raise the temperature of one pound of water by one degree Fahrenheit at one atmospheric pressure.

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

DD&A Depreciation, depletion and amortization.

FASB Financial and Accounting Standards Board.

Finding and development costs Costs associated with acquiring and developing proved natural gas and oil reserves which are capitalized under generally accepted accounting principles, including any capitalized general and administrative expenses.

Gross acres or gross wells The total acres or wells in which a working interest is owned.

IF Inside FERC (U.S. Federal Energy Regulatory Commission).

LIBOR London Interbank Offered Rate.

MBbls Thousand barrels of crude oil or other liquid hydrocarbons.

Mcf Thousand cubic feet of natural gas.

Mcfe Thousand cubic feet of natural gas equivalent. Determined using the ratio of one barrel of crude oil and/or NGLs to six Mcf of natural gas.

MMBbls Million barrels of crude oil or other liquid hydrocarbons.

MMBtu Million Btu s.

MMcf Million cubic feet of natural gas.

MMcfe Million cubic feet of natural gas equivalent. Determined using the ratio of one barrel of crude oil and/or NGLs to six Mcf of natural gas.

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DEFINITIONS (Continued)

Net acres or net wells The sum of the fractional working interests owned in gross acres or gross wells.

NGLs Natural gas liquids.

NGPL-TXOK Natural Gas Pipeline Co. of America/Texok zone.

NYMEX The New York Mercantile Exchange.

OPIS Oil Price Information Service.

PEPL Panhandle East Pipeline Co.

Producing property A natural gas and oil property with existing production.

Proved developed reserves Proved reserves that can be expected to be recovered from existing wells with existing equipment and operating methods. For additional information, see the SEC s definition in Rule 4-10(a)(3) of Regulation S-X.

Proved reserves The estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. For additional information, see the SEC s definition in Rule 4-10(a)(2)(i) through (iii) of Regulation S-X.

Proved undeveloped reserves Proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage are limited to those drilling units that offset productive units and that are reasonably certain of production when drilled. For additional information, see the SEC s definition in Rule 4-10(a)(4) of Regulation S-X.

SARs Stock appreciation rights.

Undeveloped acreage Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of natural gas and oil regardless of whether the acreage contains proved reserves.

Well spacing The regulation of the number and location of wells over an oil or gas reservoir, as a conservation measure. Well spacing is normally accomplished by order of the appropriate regulatory conservation commission.

Workovers Operations on a producing well to restore or increase production.

WTI West Texas Intermediate, the benchmark crude oil in the United States.

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UNIT CORPORATION

Annual Report

For The Year Ended December 31, 2007

PART I

Item 1. ***Business***

Unless otherwise indicated or required by the context, as used in this report, the terms corporation , company , Unit , us , our , we and its Unit Corporation and, as appropriate, Unit Corporation and/or one or more of its subsidiaries.

Our executive offices are at 7130 South Lewis, Suite 1000, Tulsa, Oklahoma 74136; our telephone number is (918) 493-7700. In addition to our executive offices, we have offices in Houston, Humble, Borger, Booker, Midland, Pampa and Weatherford, Texas; Casper, Wyoming; Oklahoma City, Panola and Woodward, Oklahoma; and Denver, Colorado.

Information regarding our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and any amendments to these reports, will be made available in print, free of charge, to any shareholder who request them, or at our internet website at www.unitcorp.com, as soon as reasonably practicable after we electronically file these reports with or furnish them to the Securities and Exchange Commission (SEC). Materials we file with the SEC may be read and copied at the SEC s Public Reference Room at 100 F. Street, N.E. Room 1580, N.W., Washington, D.C. 20549. Information on the operation of the Public Reference Room may be obtained by calling the SEC at 1-800-SEC-0330. The SEC also maintains an Internet website at *www.sec.gov* that contains reports, proxy and information statements, and other information regarding our company that we file electronically with the SEC.

In addition, we post on our Internet website, *www.unitcorp.com*, copies of the various corporate governance documents that we have adopted. We may from time to time provide important disclosures to investors by posting them in the investor relations section of our website, as allowed by SEC rules. Information regarding our corporate governance guidelines and code of ethics, and the charters of our Board's Audit, Compensation and Nomination and Governance Committees, are available free of charge on our website listed above or in print to any shareholder who request them.

GENERAL

We were founded in 1963 as a contract drilling company. Today, our operations are generally conducted through our three principal wholly owned subsidiaries:

Unit Drilling Company which drills onshore oil and natural gas wells for our own account and for others (land contract drilling),

Unit Petroleum Company which explores, develops, acquires and produces oil and natural gas properties for our own account (oil and natural gas exploration), and

Superior Pipeline Company, L.L.C. which buys, sells, gathers, processes and treats natural gas for our own account and for third parties (mid-stream).

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The following table provides certain information about us as of February 15, 2008:

Number of drilling rigs	129
Completed gross wells in which we own an interest	7,631
Number of natural gas treatment plants	4
Number of processing plants	8
Number of natural gas gathering systems	36
States in which our principal operations are located	Oklahoma, Texas, Louisiana, Wyoming, Utah, New Mexico, Colorado and Montana

At various times, and from time to time, each of these three principal subsidiaries may conduct operations through subsidiaries of their own.

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2007 HIGHLIGHTS

Unit Drilling Company

- Added nine drilling rigs through the acquisition of a privately owned drilling company in June 2007 and three drilling rigs were constructed during the year.
- Averaged an 80% utilization rate.

Unit Petroleum Company

- For the 24th consecutive year it replaced more than 150% of its annual production with new oil, NGLs and natural gas reserves by replacing approximately 171% of its 2007 oil, NGLs and natural gas production.
- Attained net proved oil, NGLs and natural gas reserves of 514.6 Bcfe, an 8% increase over its proved oil, NGLs and natural gas reserves at the end of 2006.

Superior Pipeline Company

- Completed the installation of three natural gas processing plants, increasing processing capacity by approximately 90% from 50 MMcf per day to 95 MMcf per day.
- Completed the construction of three new gathering systems, including one system with a 5 MMcf per day processing plant.
- Added an additional 78 miles of pipeline, which is an approximate 13% increase and connected an additional 56 new wells to its gathering systems.

FINANCIAL INFORMATION ABOUT SEGMENTS

See Note 14 of our Notes to Consolidated Financial Statements in Item 8 of this report for information with respect to each segment s revenues, profits or losses and total assets.

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LAND CONTRACT DRILLING

General. Our land contract drilling business is conducted through Unit Drilling Company and its two subsidiaries Unit Texas Drilling L.L.C. and Leonard Hudson Drilling Co., Inc. Through these companies we drill onshore natural gas and oil wells for our own account as well as for a wide range of other oil and natural gas companies. Our operations are mainly located in the Oklahoma and Texas areas of the Anadarko and Arkoma Basins, the North Texas Barnett Shale, the Texas and Louisiana Gulf Coast, East Texas and the Rocky Mountain regions of Wyoming, Colorado, Utah and Montana.

The table below identifies certain information concerning our land contract drilling operations:

	Year Ended December 31,		
	2007	**2006**	**2005**
Number of drilling rigs owned at end of period	129.0	117.0	112.0
Average number of drilling rigs owned during period	123.8	114.0	105.2
Average number of drilling rigs utilized	99.4	109.0	102.1
Utilization rate (1)	80%	96%	97%
Average revenue per day (2)	$ 17,291	$ 17,574	$ 12,401
Total footage drilled (feet in 1,000 s)	10,453	11,461	10,815
Number of wells drilled	996	1,033	980

(1) Utilization rate is determined by dividing the average number of drilling rigs used by the average number of drilling rigs owned during the period.

(2) Represents the total revenues from our contract drilling operations divided by the total number of days our drilling rigs were used during the period.

Description and Location of Our Drilling Rigs. A land drilling rig consists, in part, of engines, drawworks or hoists, derrick or mast, substructure, pumps to circulate the drilling fluid, blowout preventers and drill pipe. As a result of the normal wear and tear of operating 24 hours a day, several of the major components of a drilling rig, such as engines, mud pumps and drill pipe, must be replaced or rebuilt on a periodic basis. Other components, such as the substructure, mast and drawworks, can be used for extended periods of time with proper maintenance. We also own additional equipment used in the operation of our drilling rigs, including large air compressors, trucks and other support equipment.

The maximum depth capacities of our various drilling rigs range from 5,000 to 40,000 feet. In 2007, 124 of our 129 drilling rigs performed contract drilling services.

The following table shows certain information about our drilling rigs (including their distribution) as of February 8, 2008:

Region	**Contracted Rigs**	**Non-Contracted Rigs**	**Total Rigs**	**Average Rated Drilling Depth (ft)**
Anadarko Basin Oklahoma	22	4	26	17,900
Panhandle of Texas	37	2	39	14,263
Arkoma Basin	14	1	15	15,833
East Texas and Gulf Coast	11	6	17	18,235
North Texas Barnett Shale	4	3	7	11,714
Rocky Mountains	16	9	25	17,280
Totals	104	25	129	16,120

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At present, we do not have a shortage of drilling rig related equipment. However, at any given time, our ability to use all of our drilling rigs is dependent on a number of conditions, including the availability of qualified labor, drilling supplies and equipment as well as demand. Demand for our drilling rigs increased throughout 2005 and our utilization rate remained above 95% throughout the first three quarters of 2006. In the fourth quarter of 2006 and throughout 2007, demand for our drilling rigs declined to the point that as of December 2007 our utilization rate was approximately 80%. Despite this decrease in demand, we continue to experience certain difficulties in finding qualified labor to work on our drilling rigs. If demand for our drilling rigs increases above 80% and the industry rig count grows, we expect competition for qualified labor to continue which will result in higher operating costs.

The following table shows the average number of our drilling rigs working by quarter for the years indicated:

	2007	2006	2005
First quarter	96.8	108.6	99.3
Second quarter	97.9	110.3	100.3
Third quarter	100.3	110.6	102.6
Fourth quarter	102.7	106.7	106.2

Drilling Rig Fleet. The following table summarizes the changes to our drilling rig fleet during 2007. A more complete discussion of these changes follows the table:

Drilling rigs owned at December 31, 2006	117
Drilling rigs purchased during 2007	9
Drilling rigs constructed during 2007	3
Total drilling rigs owned at December 31, 2007	129

Acquisitions and Construction. In June 2007, we acquired a privately owned drilling company operating primarily in the Texas Panhandle. This acquisition included nine drilling rigs ranging from 800 to 1,000 horsepower. Eight of the nine drilling rigs were operational immediately after the purchase; the last drilling rig is being refurbished and is anticipated to become operational during March of 2008. During the first six months of 2007, we completed the construction of two 1,500 horsepower drilling rigs for approximately $19.4 million and placed one of them into each of our Rocky Mountain and Anadarko divisions. In the fourth quarter of 2007, we completed the construction of a third 1,500 horsepower drilling rig for an estimated $12.0 million which was also moved into our Rocky Mountain division. The addition of these drilling rigs brought our drilling rig fleet to 129 at December 31, 2007.

During 2007, we paid approximately $16.0 million for the purchase of major components to be used in the construction of two 1,500 horsepower drilling rigs. These two new drilling rigs are anticipated to be placed in service sometime during the second quarter of 2008.

Drilling Contracts. Our drilling contracts are generally obtained through competitive bidding on a well by well basis. Contract terms and payment rates vary depending on the type of contract used, the duration of the work, the equipment and services supplied and other matters. We pay certain operating expenses, including the wages of our drilling personnel, maintenance expenses and incidental drilling rig supplies and equipment. The contracts are usually subject to termination by the customer on short notice and on payment of a fee. Our contracts also contain provisions regarding indemnification against certain types of claims involving injury to persons, property and for acts of pollution. The specific terms of these indemnifications are subject to negotiation on a contract by contract basis.

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The type of contract used determines our compensation. Contracts are generally one of three types: daywork; footage; or turnkey. Additional compensation may be acquired for special risks and unusual conditions. Under a daywork contract, we provide the drilling rig with the required personnel and the operator supervises the drilling of the well. Our compensation is based on a negotiated rate to be paid for each day the drilling rig is used. Footage contracts usually require us to bear some of the drilling costs in addition to providing the drilling rig. We are paid on completion of the well at a negotiated rate for each foot drilled. Under turnkey contracts we drill the well to a specified depth for a set amount and provide most of the required equipment and services. We bear the risk of drilling the well to the contract depth and are paid when the contract provisions are completed.

Under turnkey contracts we may incur losses if we underestimate the costs to drill the well or if unforeseen events occur. To date, we have not experienced significant losses in performing turnkey contracts. In 2007, 2006 and 2005, we did not drill any turnkey wells. All of our work in 2007 was under daywork contracts to the exclusion of footage or turnkey contracts. Because market demand for our drilling rigs as well as the desires of our customers determine the types of contracts we use, we cannot predict when and if a part of our drilling will be conducted under footage or turnkey contracts.

Most of our current contracts are not long-term and generally provide for the drilling of one well. We do have some contracts that have terms ranging from one to two years. These longer term contracts may contain a fixed rate for the duration of the contract or provide for the periodic renegotiation of the rate within a specific range from the existing rate.

Customers. During 2007, Questar Corporation was our largest customer providing approximately 13% of our total contract drilling revenues. No other third party customer accounted for 10% or more of our contract drilling revenues. During 2007, 2006 and 2005, we drilled 77, 72 and 53 wells, respectively, for our exploration and production subsidiary. As required by the SEC, the profit received by our contract drilling subsidiary when we drill wells for our exploration and production subsidiary reduced the carrying value of our oil and natural gas properties by $22.7 million, $22.2 million and $8.6 million during 2007, 2006 and 2005, respectively, rather than being included in our operating profit.

Additional Information. Further information relating to our contract drilling operations can be found in Notes 2, 3 and 14 of the Notes to Consolidated Financial Statements in Item 8 of this report.

OIL AND NATURAL GAS EXPLORATION

General. In 1979, we began to develop our exploration and production operations to diversify our contract drilling revenues. Today, our wholly owned subsidiary, Unit Petroleum Company, conducts our exploration and production activities. Our producing oil and natural gas properties, undeveloped leaseholds and related assets are located mainly in Oklahoma, Texas, Louisiana and New Mexico and, to a lesser extent, in Arkansas, North Dakota, Colorado, Wyoming, Montana, Alabama, Kansas, Mississippi, Michigan and a small portion in Canada.

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The following table presents certain information regarding our oil and natural gas operations as of December 31, 2007:

Property/Area	Number of Gross Wells	Number of Net Wells	2007 Average Net Daily Production Natural Gas (Mcf)	Oil (Bbls)	NGL (Bbls)
Western division (consists principally of the Rocky Mountain region, New Mexico, Western and Southern Texas and the Gulf Coast region)	3,181	495.89	36,034	1,434	1,581
East division (consists principally of the Appalachian region, Arkansas, East Texas, Northern Louisiana and Eastern Oklahoma)	1,002	225.34	43,873	52	9
Central division (consists principally of Kansas, Western Oklahoma and the Texas Panhandle)	3,438	822.40	39,172	1,504	560
Total	7,621	1,543.63	119,079	2,990	2,150

When we are the operator of a property, we generally attempt to use a drilling rig owned by one of our subsidiaries.

Acquisitions. On October 13, 2006, we completed the acquisition of Brighton Energy, L.L.C., a privately owned oil and natural gas company. On February 1, 2008, Brighton Energy, L.L.C. was merged with and into Unit Petroleum Company.

Our oil and natural gas exploration segment did not make any significant acquisitions during 2007, however, on January 18, 2008, we purchased a 50% interest in a 6,800 gross-acre leasehold that we did not already own in our Segno area of operations located in Hardin County, Texas. Included in this purchase were five producing wells with 4.9 Bcfe of estimated proved reserves and current production of 2.8 MMcf of natural gas per day and 88.2 barrels of condensate. The purchase price was $16.8 million of which $15.8 million was allocated to the reserves of the wells and $1.0 million was allocated to the undeveloped leasehold. The production and reserves acquired in this purchase will be included in our 2008 results.

Well and Leasehold Data. The tables below identify certain information regarding our oil and natural gas exploratory and development drilling operations:

	Year Ended December 31, 2007 Gross	Net	2006 Gross	Net	2005 Gross	Net
Wells drilled:						
Exploratory:						
Oil	2	0.50			1	0.31
Natural gas	6	4.43	5	2.39	6	1.91
Dry	5	2.32	5	2.24	2	2.00
	13	7.25	10	4.63	9	4.22
Development:						
Oil	15	5.45	12	2.62	15	4.94
Natural gas	197	69.30	199	67.93	157	58.08
Dry	28	14.64	23	10.12	11	5.39
	240	89.39	234	80.67	183	68.41
Total	253	96.64	244	85.30	192	72.63

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	Year Ended December 31,					
	2007		2006		2005	
	Gross	Net	Gross	Net	Gross	Net
Oil and natural gas wells producing or capable of producing:						
Oil	2,612	392.99	2,784	492.90	2,746	428.93
Natural gas	4,855	1,077.38	4,659	1,007.83	3,719	830.00
Total	7,467	1,470.37	7,443	1,500.73	6,465	1,258.93

As of February 15, 2008, we have participated in starting 28 gross (12.82 net) wells during 2008.

Cost incurred for development drilling includes $52.7 million, $34.3 million and $31.9 million in 2007, 2006 and 2005, respectively, to develop booked proved undeveloped oil and natural gas reserves.

The following table summarizes our oil and natural gas leasehold acreage for each of the years indicated:

	Year Ended December 31,					
	2007		2006		2005	
	Gross	Net	Gross	Net	Gross	Net
Developed acreage	1,022,788	299,734	1,019,898	292,870	901,917	259,572
Undeveloped acreage	441,726	227,589(1)	371,314	182,742	345,663	174,763

(1) Approximately 73% of the net undeveloped acres are covered by leases that will expire in each of the years 2008 2010 unless drilling or production extends the terms of the leases.

The future estimated development costs necessary to develop our proved undeveloped oil and natural gas reserves in the United States for the years 2008, 2009 and 2010, as disclosed in our December 31, 2007 oil and natural gas reserve report, are $141.6 million, $61.0 million and $16.8 million, respectively.

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Price and Production Data. The following table identifies the average sales price, oil, NGLs and natural gas production volumes and average production cost per equivalent Mcf for our oil, NGLs and natural gas production for the years indicated:

	Year Ended December 31,		
	2007	**2006**	**2005**
Average sales price per barrel of oil produced:			
Price before hedging	$ 70.61	$ 63.39	$ 54.47
Effect of hedging			
Price including hedging	$ 70.61	$ 63.39	$ 54.47
Average sales price per barrel of NGLs produced:			
Price before hedging	$ 45.01	$ 36.08	$ 34.69
Effect of hedging	.02		
Price including hedging	$ 45.03	$ 36.08	$ 34.69
Average sales price per Mcf of natural gas produced:			
Price before hedging	$ 6.24	$ 6.17	$ 7.76
Effect of hedging	0.06		(0.12)
Price including hedging	$ 6.30	$ 6.17	$ 7.64
Oil production (MBbls)	1,091	1,012	847
NGL production (MBbls)	785	441	237
Natural gas production (MMcf)	43,464	44,169	34,058
Total production (MMcfe)	54,720	52,889	40,565
Average production cost per equivalent Mcf	$ 1.69	$ 1.34	$ 1.32

Oil, NGL and Natural Gas Reserves. The following table identifies our estimated proved developed and undeveloped oil, NGLs and natural gas reserves for the years indicated:

	Year Ended December 31,		
	2007	**2006**	**2005**
Oil (MBbls)	9,676	9,357	8,052
Natural gas liquids (MBbls)	6,149	2,226	1,819
Natural gas (MMcf)	419,616	406,400	352,841
Total proved reserves (MMcfe)	514,569	475,899	412,066

Contracts. Our oil production is sold at or near our wells under purchase contracts at prevailing prices in accordance with arrangements customary in the oil industry. Our natural gas production is sold to intrastate and interstate pipelines as well as to independent marketing firms under contracts with terms generally ranging from one month to a year. Few of these contracts contain provisions for readjustment of price, most of the contracts are market sensitive.

Customers. During 2007, Eagle Energy Partners I, L.P. accounted for approximately 12% of our oil and natural gas revenues, and no other third party customer accounted for 10% or more of our oil and natural gas revenues. During 2007, Superior Pipeline Company, L.L.C. (Superior) purchased $18.4 million of our natural gas production and natural gas liquids and provided gathering and transportation services of $4.7 million. Intercompany revenue from services and purchases of production between our mid-stream segment and our oil and natural gas segment has been eliminated in our consolidated financial statements. In 2006 and 2005, we eliminated intercompany revenues of $8.0 million and $6.8 million, respectively, of natural gas production and NGLs.

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Additional Information. Further information relating to our oil and natural gas operations is contained in Notes 2, 3, 14 and Supplemental Oil and Gas Disclosures of the Notes to Consolidated Financial Statements in Item 8 of this report.

MID-STREAM

General. Superior is a mid-stream company engaged primarily in the buying, selling, gathering, processing and treating of natural gas and operates four natural gas treatment plants, eight operating processing plants, 36 active gathering systems and 676 miles of pipeline. Superior operates in Oklahoma, Texas, Louisiana and Kansas.

The following table presents certain information regarding our mid-stream operations for the years indicated:

	Year Ended December 31,		
	2007	2006	2005
Gas gathered MMBtu/day	219,635	247,537	142,444
Gas processed MMBtu/day	50,350	31,833	30,613
Natural gas liquids sold gallons/day	129,421	66,902	61,665

Acquisitions. Our mid-stream segment did not have any significant acquisitions during 2007.

Contracts. Our mid-stream segment provides its customers with a full range of gathering, processing and treating services. These services are usually provided to each customer under long-term contracts (more than one year), but we do have some short-term contracts as well. Our natural gas processing agreements include the following types of contracts:

Fee-Based Contracts. These contracts provide for a set fee for gathering and transporting raw natural gas. Our mid-stream s revenue is a function of the volume of natural gas that is gathered or transported and is not directly dependent on the value of the natural gas. For the year ended December 31, 2007, 73% of our mid-stream segment s total volumes and 21% of operating margins (as defined below) were under fee-based contracts.

Percent of Proceeds Contracts (POP). These contracts provide for our mid-stream segment to retain a negotiated percentage of the sale proceeds from residue natural gas and NGL s it gathers and processes, with the remainder being remitted to the producer. In this arrangement, Superior and the producers are directly dependent on the volume of the commodity and its value; Superior owns a percentage of that commodity and is directly subject to fluctuations in its market value. For the year ended December 31, 2007, 14% of our mid-stream segment s total volumes and 26% of operating margins (as defined below) were under POP contracts.

Percent of Index Contracts (POI). Under these contracts our mid-stream s segment, as the processor, purchases raw well-head natural gas from the producer at a stipulated index price and, after processing the natural gas, sells the processed residual gas and the produced NGL s to third parties. Our mid-stream segment is subject to the economic risk (processing margin risk) that the aggregate proceeds from the sale of the processed natural gas and the NGL s could be less than the amount paid for the unprocessed natural gas. For the year ended December 31, 2007, 13% of our mid-stream segment s total volumes and 53% of operating margins (as defined below) were under POI contracts.

For the above contracts, operating margin is defined as total operating revenues less operating expenses and does not include depreciation and amortization, general and administrative expenses, interest expense or income taxes.

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Customers. During 2007, ONEOK and Murphy Energy Company accounted for approximately 82% and 10% of our mid-stream revenues, respectively. Gas sales to ONEOK accounted for approximately 63% of our mid-stream revenues and we believe there are other customers available to purchase this gas if necessary.

Additional Information. Further information relating to our mid-stream operations is contained in Notes 2, 3 and 14 of the Notes to Consolidated Financial Statements in Item 8 of this report.

VOLATILE NATURE OF OUR BUSINESS

The prevailing prices for natural gas, NGLs and oil significantly affect our revenues, operating results, cash flow and future rate of growth. Because natural gas makes up the biggest part of our oil, NGLs and natural gas reserves, as well as the focus of most of the contract drilling work we do for others, changes in natural gas prices have a larger impact on us than changes in oil and NGL prices. Historically, oil, NGLs and natural gas prices have been volatile, and we expect them to continue to be so. The following table shows the highest and lowest average monthly natural gas, oil and NGL prices we received by quarter, for our oil and gas segment, taking into account the effect of our hedging activity, for each of the periods indicated:

Quarter	Average Quarterly Natural Gas Price per Mcf High	Low	Average Quarterly Oil Price per Bbl High	Low	Average Quarterly NGL Price per Bbl High	Low
2007:						
First	$ 6.88	$ 5.80	$ 58.69	$ 50.79	$ 35.41	$ 31.54
Second	$ 7.02	$ 6.44	$ 65.23	$ 60.73	$ 40.07	$ 36.92
Third	$ 6.07	$ 5.21	$ 76.09	$ 69.88	$ 48.97	$ 41.32
Fourth	$ 6.45	$ 5.84	$ 91.96	$ 83.13	$ 54.94	$ 49.48
2006:						
First	$ 7.99	$ 6.13	$ 62.39	$ 57.58	$ 46.96	$ 35.41
Second	$ 6.06	$ 5.46	$ 69.67	$ 67.26	$ 33.48	$ 30.03
Third	$ 6.74	$ 5.55	$ 72.49	$ 61.56	$ 41.08	$ 38.30
Fourth	$ 6.72	$ 4.50	$ 58.23	$ 56.15	$ 36.25	$ 31.37
2005:						
First	$ 6.00	$ 5.39	$ 53.05	$ 44.88	$ 33.52	$ 29.95
Second	$ 6.95	$ 5.65	$ 53.85	$ 47.88	$ 30.45	$ 24.15
Third	$ 9.97	$ 6.95	$ 63.21	$ 56.71	$ 36.20	$ 30.03
Fourth	$ 10.35	$ 9.33	$ 62.17	$ 57.00	$ 52.96	$ 38.72

Prices for oil, NGLs and natural gas are subject to wide fluctuations in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty and a variety of additional factors that are beyond our control. These factors include:

- political conditions in oil producing regions, including the Middle East, Nigeria and Venezuela;
- the ability of the members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- demand for oil and natural gas from other developing nations including China and India;
- the price of foreign imports;

imports of liquefied natural gas;

actions of governmental authorities;

the domestic and foreign supply of oil and natural gas;

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- the level of consumer demand;
- United States storage levels of natural gas;
- the ability to transport natural gas or oil to key markets;
- weather conditions;
- domestic and foreign government regulations;
- the price, availability and acceptance of alternative fuels; and
- overall economic conditions.

These factors and the volatile nature of the energy markets make it impossible to predict the future prices of oil, NGLs and natural gas. You are encouraged to read the Risk Factors discussed in Item 1A of this report for additional risks that can impact our operations.

Our contract drilling operations are dependent on the level of demand in our operating markets. Both short-term and long-term trends in oil and natural gas prices affect demand. Because oil and natural gas prices are volatile, the level of demand for our services can also be volatile. Both demand for our drilling rigs and dayrates steadily increased over 2005 and the first three quarters of 2006, before declining late in the fourth quarter of 2006 and throughout 2007. In January 2005, the average dayrate for our drilling rigs was $9,994 per day with a 97% utilization rate. In December 2006, our average dayrate was $19,930 with an 88% utilization rate and in December 2007, our average dayrate was $17,945 with a 79% utilization rate. The decrease in utilization starting in the fourth quarter of 2006 was, in part, due to the decline in the price of natural gas as well as concerns regarding future demand for natural gas on the part of our customers. Since short-term and long-term trends in oil and natural gas prices affect the demand for our drilling rigs, the future demand for and the dayrates we will receive for our drilling services is uncertain.

Our mid-stream operations provide us greater flexibility in delivering our (and other parties) natural gas from the wellhead to major natural gas pipelines. Margins received for the delivery of this natural gas is dependent on the price for oil, natural gas and natural gas liquids and the demand for natural gas in our area of operations. If the price of natural gas liquids falls without a corresponding decrease in the cost of natural gas, it may become uneconomical to us to extract certain natural gas liquids. The volumes of natural gas processed are highly dependent on the volume and Btu content of the natural gas gathered.

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COMPETITION

All of our businesses are highly competitive and price sensitive. Competition in the land contract drilling business traditionally involves factors such as price, efficiency, condition of equipment, availability of labor and equipment, reputation and customer relations. Some of our land contract drilling competitors are substantially larger than we are and have greater resources than we do.

Our oil and natural gas operations likewise encounter strong competition from other oil and gas companies. Many of these competitors have greater financial, technical and other resources than we do and have more experience than we do in the exploration for and production of oil and natural gas.

Our mid-stream operations compete with purchasers and gatherers of all types and sizes, including those affiliated with various producers, other major pipeline companies, as well as independent gatherers for the right to purchase natural gas, build gathering systems in production fields and deliver the natural gas once the gathering systems are established. The principal elements of competition include the rates, terms and availability of services, reputation and the flexibility and reliability of service.

As discussed elsewhere in this report, throughout 2005, 2006 and 2007 all of our operations experienced strong competition for qualified labor. If demand for our services and products continue at the levels experienced during recent years, we anticipate this competition will also continue.

OIL AND NATURAL GAS PROGRAMS AND CONFLICTS OF INTEREST

Unit Petroleum Company serves as the general partner of 13 oil and gas limited partnerships. Three of these partnerships were formed for investment by third parties and ten (the employee partnerships) were formed to allow our employees and directors to participate with Unit Petroleum Company in its operations. The partnerships formed for use in connection with third party investments were formed in 1984 and 1986. One employee partnership has been formed each year beginning with 1984.

The employee partnerships formed in 1984 through 1999 have been consolidated into a single consolidating partnership. The employee partnerships each have a set annual percentage (ranging from 1% to 15%) of our interest in most of the oil and natural gas wells we drill or acquire for our own account during the year in which the partnership was formed. The total interest the participants have in our oil and natural gas wells by participating in these partnerships does not exceed one percent of our interest in the wells.

Under the terms of our partnership agreements, the general partner has broad discretionary authority to manage the business and operations of the partnership, including the authority to make decisions regarding the partnership s participation in a drilling location or a property acquisition, the partnership s expenditure of funds and the distribution of funds to partners. Because the business activities of the limited partners and the general partner are not the same, conflicts of interest will exist and it is not possible to entirely eliminate these conflicts. Additionally, conflicts of interest may arise when we are the operator of an oil and natural gas well and also provide contract drilling services. In these cases, the drilling operations are conducted under drilling contracts containing terms and conditions comparable to those contained in our drilling contracts with non-affiliated operators. We believe we fulfill our responsibility to each contracting party and comply fully with the terms of the agreements which regulate these conflicts.

These partnerships are further described in Notes 2 and 9 to the Consolidated Financial Statements in Item 8 of this report.

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EMPLOYEES

As of February 15, 2008, we had approximately 2,669 employees in our land contract drilling operations, 160 employees in our oil and natural gas exploration operations, 63 employees in our mid-stream operations and 102 in our general corporate area. None of our employees are members of a union or labor organization nor have our operations ever been interrupted by a strike or work stoppage. We consider relations with our employees to be satisfactory.

GOVERNMENTAL REGULATIONS

Our business depends on the demand for services from the oil and natural gas exploration and development industry, and therefore our business can be affected by political developments and changes in laws and regulations that control or curtail drilling for oil and natural gas for economic, environmental or other policy reasons.

Various state and federal regulations affect the production and sale of oil and natural gas. All states in which we conduct activities impose restrictions on the drilling, production, transportation and sale of oil and natural gas.

Under the Natural Gas Act of 1938, the Federal Energy Regulatory Commission (the FERC) regulates the interstate transportation and the sale in interstate commerce for resale of natural gas. The FERC s jurisdiction over interstate natural gas sales has been substantially modified by the Natural Gas Policy Act under which the FERC continued to regulate the maximum selling prices of certain categories of gas sold in first sales in interstate and intrastate commerce. Effective January 1, 1993, however, the Natural Gas Wellhead Decontrol Act (the Decontrol Act) deregulated natural gas prices for all first sales of natural gas. Because first sales include typical wellhead sales by producers, all natural gas produced from our natural gas properties is sold at market prices, subject to the terms of any private contracts which may be in effect. The FERC s jurisdiction over natural gas transportation is not affected by the Decontrol Act.

Our sales of natural gas will be affected by intrastate and interstate gas transportation regulation. Beginning in 1985, the FERC adopted regulatory changes that have significantly altered the transportation and marketing of natural gas. These changes are intended by the FERC to foster competition by, among other things, transforming the role of interstate pipeline companies from wholesale marketers of natural gas to the primary role of gas transporters. All natural gas marketing by the pipelines is required to divest to a marketing affiliate, which operates separately from the transporter and in direct competition with all other merchants. As a result of the various omnibus rulemaking proceedings in the late 1980s and the individual pipeline restructuring proceedings of the early to mid-1990s, the interstate pipelines must provide open and nondiscriminatory transportation and transportation-related services to all producers, natural gas marketing companies, local distribution companies, industrial end users and other customers seeking service. Through similar orders affecting intrastate pipelines that provide similar interstate services, the FERC expanded the impact of open access regulations to intrastate commerce.

FERC has pursued other policy initiatives that have affected natural gas marketing. Most notable are (1) the large-scale divestiture of interstate pipeline-owned gas gathering facilities to affiliated or non-affiliated companies; (2) further development of rules governing the relationship of the pipelines with their marketing affiliates; (3) the publication of standards relating to the use of electronic bulletin boards and electronic data exchange by the pipelines to make available transportation information on a timely basis and to enable transactions to occur on a purely electronic basis; (4) further review of the role of the secondary market for released pipeline capacity and its relationship to open access service in the primary market; and (5) development of policy and promulgation of orders pertaining to its authorization of market-based rates (rather than traditional cost-of-service based rates) for transportation or transportation-related services upon the pipeline s demonstration of lack of market control in the relevant service market. We do not know what effect the FERC s other activities will have on the access to markets, the fostering of competition and the cost of doing business.

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As a result of these changes, sellers and buyers of natural gas have gained direct access to the particular pipeline services they need and are better able to conduct business with a larger number of counter parties. We believe these changes generally have improved the access to markets for natural gas while, at the same time, substantially increasing competition in the natural gas marketplace. We cannot predict what new or different regulations the FERC and other regulatory agencies may adopt or what effect subsequent regulations may have on production and marketing of natural gas from our properties.

In the past, Congress has been very active in the area of natural gas regulation. However, as discussed above, the more recent trend has been in favor of deregulation and the promotion of competition in the natural gas industry. Thus, in addition to first sales deregulation, Congress also repealed incremental pricing requirements and natural gas use restraints previously applicable. There are other legislative proposals pending in the Federal and State legislatures which, if enacted, would significantly affect the petroleum industry. At the present time, it is impossible to predict what proposals, if any, might actually be enacted by Congress or the various state legislatures and what effect, if any, these proposals might have on the production and marketing of natural gas by us. Similarly, and despite the trend toward federal deregulation of the natural gas industry, whether or to what extent that trend will continue or what the ultimate effect will be on the production and marketing of natural gas by us cannot be predicted.

Our sales of oil and natural gas liquids are not regulated and are at market prices. The price received from the sale of these products will be affected by the cost of transporting the products to market. Much of that transportation is through interstate common carrier pipelines. Effective as of January 1, 1995, the FERC implemented regulations generally grandfathering all previously approved interstate transportation rates and establishing an indexing system for those rates by which adjustments are made annually based on the rate of inflation, subject to certain conditions and limitations. These regulations may tend to increase the cost of transporting oil and natural gas liquids by interstate pipeline, although the annual adjustments may result in decreased rates in a given year. These regulations have generally been approved on judicial review. Every five years, the FERC will examine the relationship between the annual change in the applicable index and the actual cost changes experienced by the oil pipeline industry. We are not able to predict with certainty what effect, if any, these relatively new federal regulations or the periodic review of the index by the FERC will have on us.

Federal, state, and local agencies have promulgated extensive rules and regulations applicable to our oil and natural gas exploration, production and related operations. Oklahoma, Texas and other states require permits for drilling operations, drilling bonds and the filing of reports concerning operations and impose other requirements relating to the exploration of oil and natural gas. 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, plugging and abandonment of such wells. The statutes and regulations of some states limit the rate at which oil and natural gas is produced from our properties. The federal and state regulatory burden on the oil and natural gas industry increases our cost of doing business and affects our profitability. Because these rules and regulations are amended or reinterpreted frequently, we are unable to predict the future cost or impact of complying with those laws.

Our operations are subject to stringent federal, state and local laws and regulations governing protection of the environment. These laws and regulations may require acquisition of permits before certain of our operations may be commenced and may restrict the types, quantities and concentrations of various substances that can be released into the environment. Planning and implementation of protective measures are required to prevent accidental discharges. Spills of oil, natural gas liquids, drilling fluids, and other substances may subject us to penalties and cleanup requirements. Handling, storage and disposal of both hazardous and non-hazardous wastes are subject to regulatory requirements.

The federal Clean Water Act, as amended by the Oil Pollution Act, the federal Clean Air Act, the federal Resource Conservation and Recovery Act, and their state counterparts, are the primary vehicles for imposition of such requirements and for civil, criminal and administrative penalties and other sanctions for violation of their

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requirements. In addition, the federal Comprehensive Environmental Response Compensation and Liability Act and similar state statutes impose strict liability, without regard to fault or the legality of the original conduct, on certain classes of persons who are considered responsible for the release of hazardous substances into the environment. Such liability, which may be imposed for the conduct of others and for conditions others have caused, includes the cost of remedial action as well as damages to natural resources.

Environmental laws and regulations are complex and subject to frequent change that may result in more stringent and costly requirements. Compliance with applicable requirements has not, to date, had a material affect on the cost of our operations, earnings or competitive position. However, compliance with amended, new or more stringent requirements, stricter interpretations of existing requirements, or the discovery of contamination may cause us to incur additional costs or subject us to liabilities that may have a material adverse effect on our results of operations and financial condition.

FINANCIAL INFORMATION ABOUT GEOGRAPHIC AREAS

Our revenues during the last three fiscal years, as well as information relating to long-lived assets attributable to our Canadian operations are immaterial. We have no other international operations.

Item 1A. *Risk Factors*

FORWARD-LOOKING STATEMENTS/CAUTIONARY STATEMENT AND RISK FACTORS

This report, including information included in, or incorporated by reference from future filings by us with the SEC, as well as information contained in written material, press releases and oral statements issued by or on our behalf, contain, or may contain, certain statements that are forward-looking statements within the meaning of federal securities laws. This report modifies and supersedes documents filed by us before this report. In addition, certain information that we file with the SEC in the future will automatically update and supersede information contained in this report. All statements, other than statements of historical facts, included or incorporated by reference in this report, which address activities, events or developments which we expect or anticipate will or may occur in the future, are forward-looking statements. The words believes, intends, expects, anticipates, projects, estimates, predicts and similar expressions are used to identify forward-looking statements.

These forward-looking statements include, among others, such things as:

- the amount and nature of our future capital expenditures;
- the amount of wells we plan to drill or rework;
- prices for oil, NGLs and natural gas;
- demand for oil and natural gas;
- our exploration prospects;
- the estimates of our proved oil, NGLs and natural gas reserves;
- oil, NGLs and natural gas reserve potential;

development and infill drilling potential;

our drilling prospects;

expansion and other development trends of the oil and natural gas industry;

our business strategy;

production of oil, NGLs and natural gas reserves;

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growth potential for our mid-stream operations;

gathering systems and processing plants we plan to construct or acquire;

volumes and prices for natural gas gathered and processed;

expansion and growth of our business and operations; and

demand for our drilling rigs and drilling rig rates.

These statements are based on certain assumptions and analyses made by us in light of our experience and our perception of historical trends, current conditions and expected future developments as well as other factors we believe are appropriate in the circumstances. However, whether actual results and developments will conform to our expectations and predictions is subject to a number of risks and uncertainties which could cause actual results to differ materially from our expectations, including:

the risk factors discussed in this report and in the documents we incorporate by reference;

general economic, market or business conditions;

the nature or lack of business opportunities that we pursue;

demand for our land drilling services;

changes in laws or regulations; and

other factors, most of which are beyond our control.

You should not place undue reliance on any of these forward-looking statements. Except as required by law, we disclaim any current intention to update forward-looking information and to release publicly the results of any future revisions we may make to forward-looking statements to reflect events or circumstances after the date of this report to reflect the occurrence of unanticipated events.

In order to help provide you with a more thorough understanding of the possible effects of some of these influences on any forward-looking statements made by us, the following discussion outlines some (but not all) of the factors that in the future could cause our 2008 consolidated results and beyond to differ materially from those that may be presented in any such forward-looking statement made by or on behalf of us.

Oil, NGLs and Natural Gas Prices. The prices we receive for our oil, NGLs and natural gas production have a direct impact on our revenues, profitability and cash flow as well as our ability to meet our projected financial and operational goals. The prices for natural gas and crude oil are heavily dependent on a number of factors beyond our control, including:

the demand for oil and/or natural gas;

- current weather conditions in the continental United States (which can greatly influence the demand for natural gas at any given time as well as the price we receive for such natural gas);

- the amount and timing of liquid natural gas imports; and

- the ability of current distribution systems in the United States to effectively meet the demand for oil and/or natural gas at any given time, particularly in times of peak demand which may result because of adverse weather conditions.

Oil prices are extremely sensitive to foreign influences based on political, social or economic underpinnings, any one of which could have an immediate and significant effect on the price and supply of oil. In addition, prices of natural gas, NGLs and oil are becoming more and more influenced by trading on the commodities markets which, at times, has tended to increase the volatility associated with these prices resulting, at times, in large differences in such prices even on a week-to-week and month-to-month basis. All of these factors, especially when coupled with the fact that much of our product prices are determined on a daily basis, can, and at times do, lead to wide fluctuations in the prices we receive.

Based on our 2007 production, a $0.10 per Mcf change in what we receive for our natural gas production would result in a corresponding $339,000 per month ($4.1 million annualized) change in our pre-tax operating cash flow. A $1.00 per barrel change in our oil price would have an $85,000 per month ($1.0 million annualized) change in our pre-tax operating cash flow and a $1.00 per barrel change in our NGLs price would have a $61,000 per month ($0.7 million annualized) change in our pre-tax operating cash flow. During 2007, substantially all of our natural gas, crude oil and NGLs volumes were sold at market responsive prices.

In order to reduce our exposure to short-term fluctuations in the price of oil, NGLs and natural gas, we sometimes enter into hedging arrangements such as swaps and collars. Our hedging arrangements apply to only a portion of our production and provide only partial price protection against declines in oil, NGLs and natural gas prices. These hedging arrangements may expose us to risk of financial loss and limit the benefit to us of future increases in prices. A more thorough discussion of our hedging arrangements is contained in the Management s Discussion and Analysis of Financial Condition and Results of Operation section of this report contained in Item 7.

Drilling Customer Demand. With the exception of the drilling we do for our own account, the demand for our drilling services depends entirely on the needs of third parties. Based on past history, these parties requirements are subject to a number of factors, independent of any subjective factors, that directly impact the demand for our drilling rigs. These factors include the availability of funds to carry out their drilling operations. For many of these parties, even if they have the funds available, their decision to spend those funds is often based on the then current prices for oil, NGLs and natural gas. Many of our customers budgets tend to be susceptible to the influences of current price fluctuations. Other factors that affect our ability to work our drilling rigs are: the weather which, under adverse circumstances, can delay or even cause the abandonment of a project by an operator; the competition faced by us in securing the award of a drilling contract in a given area; our experience and recognition in a new market area; and the availability of labor to operate our drilling rigs.

Uncertainty of Oil, NGLs and Natural Gas Reserves. There are many uncertainties inherent in estimating quantities of oil, NGLs and natural gas reserves and their values, including many factors beyond our control. The oil, NGLs and natural gas reserve information included in this report represents only an estimate of these reserves. Oil, NGLs and natural gas reservoir engineering is a subjective and an inexact process of estimating underground accumulations of oil, NGLs and natural gas that cannot be measured in an exact manner. Estimates of economically recoverable oil, NGLs and natural gas reserves depend on a number of variable factors, including historical production from the area compared with production from other producing areas, and assumptions concerning:

- reservoir size;
- the effects of regulations by governmental agencies;
- future oil, NGLs and natural gas prices;
- future operating costs;
- severance and excise taxes;
- development costs; and
- workover and remedial costs.

Some or all of these assumptions may vary considerably from actual results. For these reasons, estimates of the economically recoverable quantities of oil and natural gas attributable to any particular group of properties, classifications of those oil, NGLs and natural gas reserves based on risk of recovery, and estimates of the future

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net cash flows from oil, NGLs and natural gas reserves prepared by different engineers or by the same engineers but at different times may vary substantially. Accordingly, oil, NGLs and natural gas reserve estimates may be subject to periodic downward or upward adjustments. Actual production, revenues and expenditures with respect to our oil, NGLs and natural gas reserves will likely vary from estimates, and those variances may be material.

The information regarding discounted future net cash flows included in this report is not necessarily the current market value of the estimated oil, NGLs and natural gas reserves attributable to our properties. As required by the SEC, the estimated discounted future net cash flows from proved oil, NGLs and natural gas reserves are determined based on prices and costs as of the date of the estimate. Actual future prices and costs may be materially higher or lower. Actual future net cash flows are also affected, in part, by the following factors:

- the amount and timing of oil and natural gas production;
- supply and demand for oil and natural gas;
- increases or decreases in consumption; and
- changes in governmental regulations or taxation.

In addition, the 10% discount factor, required by the SEC for use in calculating discounted future net cash flows for reporting purposes, is not necessarily the most appropriate discount factor based on interest rates in effect from time to time and the risks associated with our operations or the oil and natural gas industry in general.

We periodically review the carrying value of our oil and natural gas properties under the full cost accounting rules of the SEC. Under these rules, capitalized costs of proved oil and natural gas properties may not exceed the present value of estimated future net revenues from proved reserves, discounted at 10%. Application of this ceiling test generally requires pricing future revenue at the unescalated prices in effect as of the end of each fiscal quarter and requires a write-down for accounting purposes if we exceed the ceiling, even if prices are depressed for only a short period of time. We may be required to write down the carrying value of our oil and natural gas properties when oil, NGLs and natural gas prices are depressed or unusually volatile. If a write-down is required, it would result in a charge to earnings but would not impact our cash flow from operating activities. Once incurred, a write-down of oil and natural gas properties is not reversible.

We are continually identifying and evaluating opportunities to acquire oil and natural gas properties, including acquisitions that would be significantly larger than those we have consummated to date. We cannot assure you that we will successfully consummate any acquisition, that we will be able to acquire producing oil and natural gas properties that contain economically recoverable reserves or that any acquisition will be profitably integrated into our operations.

Debt and Bank Borrowing. We have incurred and currently expect to continue to incur substantial working capital expenditures because of the growth in our operations. Historically, we have funded our working capital needs through a combination of internally generated cash flow and borrowings under our bank credit facility. We have also, from time to time, obtained funds through equity financing. We currently have, and will continue to have, a certain amount of indebtedness. At December 31, 2007, our outstanding long-term debt was $120.6 million.

Our level of debt, the cash flow needed to satisfy our debt and the covenants contained in our bank credit facility could:

- limit funds otherwise available for financing our capital expenditures, our drilling program or other activities or cause us to curtail these activities;
- limit our flexibility in planning for or reacting to changes in our business;

place us at a competitive disadvantage to those of our competitors that are less indebted than we are;

- make us more vulnerable during periods of low oil, NGLs and natural gas prices or in the event of a downturn in our business; and

- prevent us from obtaining additional financing on acceptable terms or limit amounts available under our existing or any future credit facilities.

Our ability to meet our debt obligations depends on our future performance. If the requirements of our indebtedness are not satisfied, a default could be deemed to occur and our lenders would be entitled to accelerate the payment of the outstanding indebtedness. If that were to occur, we would not have sufficient funds available and probably would not be able to obtain the financing required to meet our obligations.

The amount of our existing debt, as well as our future debt, is, to a large extent, a function of the costs associated with the projects we undertake at any given time and of our cash flow. Generally, our normal operating costs are those incurred as a result of the drilling of oil and natural gas wells, the acquisition of producing properties, the costs associated with the maintenance or expansion of our drilling rig fleet, and the operations of our natural gas buying, selling, gathering, processing and treating systems. To some extent, these costs, particularly the first two items, are discretionary and we maintain a degree of control regarding the timing or the need to actually incur them. However, in some cases, unforeseen circumstances may arise, such as in the case of an unanticipated opportunity to make a large acquisition or the need to replace a costly drilling rig component due to an unexpected loss, which could force us to incur increased debt above that which we had expected or forecasted. Likewise, if our cash flow should prove to be insufficient to cover our current cash requirements we would need to increase our debt either through bank borrowings or otherwise.

We entered into the following interest rate swaps to help manage our exposure to possible future interest rate increases. Under these transactions we have swapped the variable interest rate we would otherwise incur on a portion of our bank debt for a fixed interest rate. A more thorough discussion of our hedging or swap arrangements are contained in the Management s Discussion and Analysis of Financial Condition and Results of Operation section of this report contained in Item 7.

Term	Amount	Fixed Rate	Floating Rate
March 2005 January 2008	$ 50,000,000	3.99%	3 month LIBOR
December 2007 May 2012	$ 15,000,000	4.53%	3 month LIBOR
December 2007 May 2012	$ 15,000,000	4.16%	3 month LIBOR

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RISK FACTORS

There are many other factors that could adversely affect our business. The following discussion describes the material risks currently known to us. However, additional risks that we do not know about or that we currently view as immaterial may also impair our business or adversely affect the value of our securities. You should carefully consider the risks described below together with the other information contained in, or incorporated by reference into, this report.

Oil, NGLs and natural gas prices are volatile, and low prices have negatively affected our financial results and could do so in the future.

Our revenues, operating results, cash flow and future rate of growth depend substantially on prevailing prices for oil, NGLs and natural gas. Historically, oil, NGLs and natural gas prices and markets have been volatile, and they are likely to continue to be volatile in the future. Any decline in prices in the future would have a negative impact on our future financial results. Because our oil, NGLs and natural gas reserves are predominantly natural gas, significant changes in natural gas prices would have a particularly large impact on our financial results.

Prices for oil, NGLs and natural gas are subject to wide fluctuations in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty and a variety of additional factors that are beyond our control. These factors include:

- political conditions in oil producing regions, including the Middle East, Nigeria and Venezuela;
- the ability of the members of the Organization of Petroleum Exporting Countries to agree on prices and their ability to maintain production quotas;
- the price of foreign oil imports;
- imports of liquefied natural gas;
- actions of governmental authorities;
- the domestic and foreign supply of oil and natural gas;
- the level of consumer demand;
- U.S. storage levels of natural gas;
- weather conditions;
- domestic and foreign government regulations;
- the price, availability and acceptance of alternative fuels; and

overall economic conditions.

These factors and the volatile nature of the energy markets make it impossible to predict with any certainty the future prices of oil, NGLs and natural gas.

Our contract drilling operations depend on levels of activity in the oil and natural gas exploration and production industry.

Our contract drilling operations depend on the level of activity in oil and natural gas exploration and production in our operating markets. Both short-term and long-term trends in oil, NGLs and natural gas prices affect the level of that activity. Because oil, NGLs and natural gas prices are volatile, the level of exploration and production activity can also be volatile. Any decrease from current oil, NGLs and natural gas prices would depress the level of exploration and production activity. This, in turn, would likely result in a decline in the

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demand for our drilling services and would have an adverse effect on our contract drilling revenues, cash flows and profitability. As a result, the future demand for our drilling services is uncertain.

The industries in which we operate are highly competitive, and many of our competitors have greater resources than we do.

The drilling industry in which we operate is generally very competitive. Most drilling contracts are awarded on the basis of competitive bids, which may result in intense price competition. Many of our competitors in the contract drilling industry have greater financial and human resources than we do. These resources may enable them to better withstand periods of low drilling rig utilization, to compete more effectively on the basis of price and technology, to build new drilling rigs or acquire existing drilling rigs and to provide drilling rigs more quickly than we do in periods of high drilling rig utilization.

The oil and natural gas industry is also highly competitive. We compete in the areas of property acquisitions and oil and natural gas exploration, development, production and marketing with major oil companies, other independent oil and natural gas concerns and individual producers and operators. In addition, we must compete with major and independent oil and natural gas concerns in recruiting and retaining qualified employees. Many of our competitors in the oil and natural gas industry have substantially greater resources than we do.

Shortages of experienced personnel for our contract drilling operations could limit our ability to meet the demand for our services.

During periods of increasing demand for contract drilling services, the industry may experience shortages of qualified drilling rig personnel. During these periods, our ability to attract and retain sufficient qualified personnel to market and operate our drilling rigs is adversely affected which negatively impacts both our operations and profitability. Operationally, it is more difficult to hire qualified personnel, which adversely affects our ability to mobilize inactive drilling rigs in response to the increased demand for our contract drilling services. Additionally, wage rates for drilling personnel are likely to increase, resulting in greater operating costs.

Shortages of drill pipe, replacement parts and other related drilling rig equipment adversely affect our operating results.

During periods of increased demand for drilling services, the industry has experienced shortages of drill pipe, replacement parts and other related drilling rig equipment. These shortages can cause the price of these items to increase significantly and require that orders for the items be placed well in advance of expected use. These price increases and delays in delivery may require us to increase capital and repairs expenditures in our contract drilling segment. Severe shortages could impair our ability to operate our drilling rigs.

Continued growth through acquisitions is not assured.

Over the past several years, we have increased each of our segments, in part, through mergers and acquisitions. The land drilling industry, the exploration and development industry, as well as the gas gathering and processing industry, have experienced significant consolidation over the past several years, and there can be no assurance that acquisition opportunities will continue to be available. Additionally, we are likely to continue to face intense competition from other companies for available acquisition opportunities.

There can be no assurance that we will:

- be able to identify suitable acquisition opportunities;
- have sufficient capital resources to complete additional acquisitions;
- successfully integrate acquired operations and assets;

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- effectively manage the growth and increased size;
- maintain the crews and market share to operate any future drilling rigs we may acquire; or
- successfully improve our financial condition, results of operations, business or prospects in any material manner as a result of any completed acquisition.

We may incur substantial indebtedness to finance future acquisitions and also may issue equity securities or convertible securities in connection with any acquisitions. Debt service requirements could represent a significant burden on our results of operations and financial condition and the issuance of additional equity would be dilutive to existing shareholders. Also, continued growth could strain our management, operations, employees and other resources.

Successful acquisitions, particularly those of oil and natural gas companies or of oil and natural gas properties require an assessment of a number of factors, many of which are beyond our control. These factors include recoverable reserves, exploration potential, future oil, NGLs and natural gas prices, operating costs and potential environmental and other liabilities. Such assessments are inexact and their accuracy is inherently uncertain.

Our operations have significant capital requirements, and our indebtedness could have important consequences to you.

We have experienced and expect to continue to experience substantial working capital needs because of the growth in all of our operations. On February 15, 2008, our outstanding long-term debt was $144.8 million. Our level of indebtedness, the cash flow needed to satisfy our indebtedness and the covenants governing our indebtedness could:

- limit funds available for financing capital expenditures, our drilling program or other activities or cause us to curtail these activities;
- limit our flexibility in planning for, or reacting to changes in, our business;
- place us at a competitive disadvantage to some of our competitors that are less leveraged than we are;
- make us more vulnerable during periods of low oil, NGLs and natural gas prices or in the event of a downturn in our business; and
- prevent us from obtaining additional financing on acceptable terms or limit amounts available under our existing or any future credit facilities.

Our ability to meet our debt service and other contractual and contingent obligations will depend on our future performance. In addition, lower oil, NGLs and natural gas prices could result in future reductions in the amount available for borrowing under our credit facility, reducing our liquidity and even triggering mandatory loan repayments.

Our future performance depends on our ability to find or acquire additional oil, NGLs and natural gas reserves that are economically recoverable.

In general, production from oil and natural gas properties declines as reserves are depleted, with the rate of decline depending on reservoir characteristics. Unless we successfully replace the reserves that we produce, our reserves will decline, resulting eventually in a decrease in oil and natural gas production and lower revenues and cash flow from operations. Historically, we have succeeded in increasing reserves after taking production into account through exploration and development. We have conducted these activities on our existing oil and natural gas properties as well as on newly acquired properties. We may not be able to continue to replace reserves from these activities at acceptable costs. Lower prices of oil and natural gas may further limit the kinds of reserves that can economically be developed. Lower prices also decrease our cash flow and may cause us to decrease capital expenditures.

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We are continually identifying and evaluating opportunities to acquire oil and natural gas properties, including acquisitions that would be significantly larger than those consummated to date by us. We cannot assure you that we will successfully consummate any acquisition, that we will be able to acquire producing oil and natural gas properties that contain economically recoverable reserves or that any acquisition will be profitably integrated into our operations.

The competition for producing oil and natural gas properties is intense. This competition could mean that to acquire properties we will have to pay higher prices and accept greater ownership risks than we have in the past.

Our exploration and production operations involve a high degree of business and financial risk which could adversely affect us.

Exploration and development involve numerous risks that may result in dry holes, the failure to produce oil and natural gas in commercial quantities and the inability to fully produce discovered reserves. The cost of drilling, completing and operating wells is substantial and uncertain. Numerous factors beyond our control may cause the curtailment, delay or cancellation of drilling operations, including:

- unexpected drilling conditions;
- pressure or irregularities in formations;
- equipment failures or accidents;
- adverse weather conditions;
- compliance with governmental requirements; and
- shortages or delays in the availability of drilling rigs or delivery crews and the delivery of equipment.

Exploratory drilling is a speculative activity. Although we may disclose our overall drilling success rate, those rates may decline. Although we may discuss drilling prospects that we have identified or budgeted for, we may ultimately not lease or drill these prospects within the expected time frame, or at all. Lack of drilling success will have an adverse effect on our future results of operations and financial condition.

Our mid-stream operations involve numerous risks, both financial and operational. The cost of developing gathering systems and processing plants is substantial and our ability to recoup these costs is uncertain. Our operations may be curtailed, delayed or cancelled as a result of many things beyond our control, including:

- unexpected changes in the deliverability of natural gas reserves from the wells connected to the gathering systems;
- availability of competing pipelines in the area;
- equipment failures or accidents;
- adverse weather conditions;

- compliance with governmental requirements;
- delays in the development of other producing properties within the gathering system s area of operation; and
- demand for natural gas and its constituents.

Many of the wells from which we gather and process natural gas are operated by other parties. As a result, we have little control over the operations of those wells which can act to increase our risk. Operators of those wells may act in ways that are not in our best interests.

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Competition for experienced technical personnel may negatively impact our operations or financial results.

Our continued drilling success and the success of other activities integral to our operations will depend, in part, on our ability to attract and retain experienced explorationists, engineers and other professionals. Competition for these professionals is extremely intense. We are likely to continue to experience increased costs to attract and retain these professionals.

Our hedging arrangements might limit the benefit of increases in oil, NGLs and natural gas prices.

In order to reduce our exposure to short-term fluctuations in the price of oil, NGLs and natural gas, we sometimes enter into hedging arrangements. Our hedging arrangements apply to only a portion of our production and provide only partial price protection against declines in oil, NGLs and natural gas prices. These hedging arrangements may expose us to risk of financial loss and limit the benefit to us of increases in prices.

Estimates of our reserves are uncertain and may prove to be inaccurate.

There are numerous uncertainties inherent in estimating quantities of proved reserves and their values, including many factors beyond our control. The reserve data represents only estimates. Reservoir engineering is a subjective and inexact process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner. Estimates of economically recoverable oil, NGLs and natural gas reserves depend on a number of variable factors, including historical production from the area compared with production from other producing areas, and assumptions concerning:

- the effects of regulations by governmental agencies;
- future oil, NGLs and natural gas prices;
- future operating costs;
- severance and excise taxes;
- development costs; and
- workover and remedial costs.

Some or all of these assumptions may vary considerably from actual results. For these reasons, estimates of the economically recoverable quantities of oil and natural gas attributable to any particular group of properties, classifications of those reserves based on risk of recovery, and estimates of the future net cash flows from reserves prepared by different engineers or by the same engineers but at different times may vary substantially. Accordingly, reserve estimates may be subject to downward or upward adjustment. Actual production, revenues and expenditures with respect to our reserves will likely vary from estimates, and those variances may be material.

The information regarding discounted future net cash flows should not be considered as the current market value of the estimated oil, NGLs and natural gas reserves attributable to our properties. As required by the SEC, the estimated discounted future net cash flows from proved reserves are based on prices and costs as of the date of the estimate, while actual future prices and costs may be materially higher or lower. Actual future net cash flows also will be affected by the following factors:

- the amount and timing of actual production;

supply and demand for oil and natural gas;

increases or decreases in consumption; and

changes in governmental regulations or taxation.

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In addition, the 10% per year discount factor, which is required by the SEC to be used in calculating discounted future net cash flows for reporting purposes, is not necessarily the most appropriate discount factor based on interest rates in effect from time to time and risks associated with our operations or the oil and natural gas industry in general.

If oil, NGLs and natural gas prices decrease or are unusually volatile, we may be required to take write-downs of our oil and natural gas properties, the carrying value of our drilling rigs or our natural gas gathering and processing systems.

We periodically review the carrying value of our oil and natural gas properties under the full cost accounting rules of the SEC. Under these rules, capitalized costs of proved oil and natural gas properties may not exceed the present value of estimated future net revenues from proved reserves, discounted at 10% per year. Application of the ceiling test generally requires pricing future revenue at the unescalated prices in effect as of the end of each fiscal quarter and requires a write-down for accounting purposes if the ceiling is exceeded, even if prices were depressed for only a short period of time. We may be required to write down the carrying value of our oil and natural gas properties when oil, NGLs and natural gas prices are depressed or unusually volatile. If a write-down is required, it would result in a charge to earnings, but would not impact cash flow from operating activities. Once incurred, a write-down of oil and natural gas properties is not reversible at a later date.

Our drilling equipment, transportation equipment, gas gathering and processing systems and other property and equipment are carried at cost. We are required to periodically test to see if these values have been impaired whenever events or changes in circumstances suggest the carrying amount may not be recoverable. If any of these assets are determined to be impaired, the loss is measured as the amount by which the carrying amount of the asset exceeds its fair value. An estimate of fair value is based on the best information available, including prices for similar assets. Changes in these estimates could cause us to reduce the carrying value of property and equipment. Once these values have been reduced, they are not reversible.

Our operations present inherent risks of loss that, if not insured or indemnified against, could adversely affect our results of operations.

Our drilling operations are subject to many hazards inherent in the drilling industry, including blowouts, cratering, explosions, fires, loss of well control, loss of hole, damaged or lost drilling equipment and damage or loss from inclement weather. Our exploration and production and mid-stream operations are subject to these and similar risks. Any of these events could result in personal injury or death, damage to or destruction of equipment and facilities, suspension of operations, environmental damage and damage to the property of others. Generally, drilling contracts provide for the division of responsibilities between a drilling company and its customer, and we seek to obtain indemnification from our drilling customers by contract for some of these risks. To the extent that we are unable to transfer these risks to drilling customers by contract or indemnification agreements, we seek protection from some of these risks through insurance. However, some risks are not covered by insurance and we cannot assure you that the insurance we do have or the indemnification agreements we have entered into will adequately protect us against liability from all of the consequences of the hazards described above. The occurrence of an event not fully insured or indemnified against, or the failure of a customer to meet its indemnification obligations, could result in substantial losses. In addition, we cannot assure you that insurance will be available to cover any or all of these risks. Even if available, the insurance might not be adequate to cover all of our losses, or we might decide against obtaining that insurance because of high premiums or other costs.

In addition, we are not the operator of many of our wells. As a result, our operating risks for those wells and our ability to influence the operations for those wells are less subject to our control. Operators of those wells may act in ways that are not in our best interests.

Governmental regulations could adversely affect our business.

Our business is subject to federal, state and local laws and regulations on taxation, the exploration for and development, production and marketing of oil and natural gas and safety matters. Many laws and regulations

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require drilling permits and govern the spacing of wells, rates of production, prevention of waste, unitization and pooling of properties and other matters. These laws and regulations have increased the costs of planning, designing, drilling, installing, operating and abandoning our oil and natural gas wells and other facilities. In addition, these laws and regulations, and any others that are passed by the jurisdictions where we have production, could limit the total number of wells drilled or the allowable production from successful wells, which could limit our revenues.

We are also subject to complex environmental laws and regulations adopted by the various jurisdictions where we own or operate. We could incur liability to governments or third parties for discharges of oil, natural gas or other pollutants into the air, soil or water, including responsibility for remedial costs. We could potentially discharge these materials into the environment in any number of ways including the following:

- from a well or drilling equipment at a drill site;
- from gathering systems, pipelines, transportation facilities and storage tanks;
- damage to oil and natural gas wells resulting from accidents during normal operations; and
- blowouts, cratering and explosions.

Because the requirements imposed by laws and regulations are frequently changed, we cannot assure you that laws and regulations enacted in the future, including changes to existing laws and regulations, will not adversely affect our business. In addition, because we acquire interests in properties that have been operated in the past by others, we may be liable for environmental damage caused by the former operators, which liability could be material.

Any future implementation of price controls on oil, NGLs and natural gas would affect our operations.

Certain groups have asserted efforts to have the United States Congress impose some form of price controls on either natural gas, oil or both. There is no way at this time to know what result these efforts will have nor, if implemented, their effect on our operations. However, it is possible that these efforts, if successful, would serve to limit the amount that we might be able to get for our future oil and natural gas production. Any future limits on the price of oil, NGLs and natural gas could also result in adversely affecting the demand for our drilling services.

Our shareholders' rights plan and provisions of Delaware law and our by-laws and charter could discourage change in control transactions and prevent shareholders from receiving a premium on their investment.

Our by-laws and charter provide for a classified board of directors with staggered terms and authorizes the board of directors to set the terms of preferred stock. In addition, our charter and Delaware law contain provisions that impose restrictions on business combinations with interested parties. We have also adopted a shareholders' rights plan. Because of our shareholders' rights plan and these provisions of our by-laws, charter and Delaware law, persons considering unsolicited tender offers or other unilateral takeover proposals may be more likely to negotiate with our board of directors rather than pursue non-negotiated takeover attempts. As a result, these provisions may make it more difficult for our shareholders to benefit from transactions that are opposed by an incumbent board of directors.

New technologies may cause our current exploration and drilling methods to become obsolete, resulting in an adverse effect on our production.

Our industry is subject to rapid and significant advancements in technology, including the introduction of new products and services using new technologies. As competitors use or develop new technologies, we may be placed at a competitive disadvantage, and competitive pressures may force us to implement new technologies at a

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substantial cost. In addition, competitors may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before we can. We cannot be certain that we will be able to implement technologies on a timely basis or at a cost that is acceptable to us. One or more of the technologies that we currently use or that we may implement in the future may become obsolete, and we may be adversely affected.

The results of our operations depend on our ability to transport oil and gas production to key markets.

The marketability of our oil and natural gas production depends in part on the availability, proximity and capacity of pipeline systems. The unavailability of or lack of available capacity on these systems and facilities could result in the shut-in of producing wells or the delay or discontinuance of development plans for properties. Federal and state regulation of oil and natural gas production and transportation, tax and energy policies, changes in supply and demand, pipeline pressures, damage to or destruction of pipelines and general economic conditions could adversely affect our ability to produce, gather and transport oil and natural gas.

The loss of one or a number of our larger customers could have a material adverse effect on our financial condition and results of operations.

During 2007, our largest customer, Questar Corporation accounted for approximately 13% of our contract drilling revenues. No other third party customer accounted for 10% or more of our contract drilling revenues. Any of our customers may choose not to use our services and the loss of one or a number of our larger customers could have a material adverse effect on our financial condition and results of operations. As of February 15, 2008, our oil and natural gas segment was using 14 of our drilling rigs.

Our mid-stream segment depends on certain natural gas producers for a significant portion of its supply of natural gas and NGLs. The loss of any of these producers could result in a decline in our volumes and revenues.

We rely on certain natural gas producers for a significant portion of our natural gas and NGL supply. While some of these producers are subject to long-term contracts, we may be unable to negotiate extensions or replacements of these contracts on favorable terms, if at all. The loss of all or even a portion of the natural gas volumes supplied by these producers, as a result of competition or otherwise, could have a material adverse effect on our mid-stream segment unless we were able to acquire comparable volumes from other sources.

Item 1B. *Unresolved Staff Comments*

None.

Item 2. *Properties*

The information called for by this item was consolidated with and disclosed in connection with Item 1 above.

Item 3. *Legal Proceedings*

We are a party to various legal proceedings arising in the ordinary course of our business, none of which, in our opinion, will result in judgments which would have a material adverse effect on our financial position, operating results or cash flows.

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

No matters were submitted to our security holders during the fourth quarter of 2007.

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PART II

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

Our common stock trades on the New York Stock Exchange under the symbol UNT. The following table identifies the high and low sales prices per share of our common stock for the periods indicated:

	2007		2006	
Quarter	**High**	**Low**	**High**	**Low**
First	$ 52.12	$ 44.27	$ 61.88	$ 48.76
Second	$ 65.65	$ 50.45	$ 64.83	$ 50.74
Third	$ 63.00	$ 45.60	$ 60.13	$ 43.56
Fourth	$ 50.41	$ 43.30	$ 52.93	$ 41.38

On February 15, 2008, the closing sale price of our common stock, as reported by the NYSE, was $52.36 per share. On that date, there were approximately 1,325 holders of record of our common stock.

We have never declared any cash dividends on our common stock and currently have no plans to declare any dividends on our common stock in the foreseeable future. Any future determination by our board of directors to pay dividends on our common stock will be made only after considering our financial condition, results of operations, capital requirements and other relevant factors. Additionally, our bank credit facility prohibits the payment of cash dividends on our common stock under certain circumstances. For further information regarding our bank credit facility's impact on our ability to pay dividends see Our Credit Facility under Item 7 of this report.

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

The following table shows selected consolidated financial data. The data should be read in conjunction with Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations, for a review of 2007, 2006 and 2005 activity.

	As of and for the Year Ended December 31,				
	2007	**2006**	**2005**	**2004**	**2003**
	(In thousands except per share amounts)				
Revenues	$ 1,158,754	$ 1,162,385	$ 885,608	$ 519,203	$ 301,377
Income before cumulative effect of change in accounting principle	$ 266,258	$ 312,177	$ 212,442	$ 90,275	$ 48,864
Net income	$ 266,258	$ 312,177	$ 212,442	$ 90,275	$ 50,189
Income before cumulative effect of change in accounting principle per common share:					
Basic	$ 5.74	$ 6.75	$ 4.62	$ 1.97	$ 1.12
Diluted	$ 5.71	$ 6.72	$ 4.60	$ 1.97	$ 1.12
Net income per common share:					
Basic	$ 5.74	$ 6.75	$ 4.62	$ 1.97	$ 1.15
Diluted	$ 5.71	$ 6.72	$ 4.60	$ 1.97	$ 1.15
Total assets	$ 2,199,819	$ 1,874,096	$ 1,456,195	$ 1,023,136	$ 712,925
Long-term debt	$ 120,600	$ 174,300	$ 145,000	$ 95,500	$ 400
Other long-term liabilities	$ 59,115	$ 55,741	$ 41,981	$ 37,725	$ 17,893
Cash dividends per common share	$	$	$	$	$

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Item 7. ***Management s Discussion and Analysis of Financial Condition and Results of Operations***
Please read the following discussion of our financial condition and results of operations in conjunction with the consolidated financial statements and related notes included in Item 8 of this annual report.

General

We were founded in 1963 as a contract drilling company. Today, we operate, manage and analyze our results of operations through our three principal business segments:

Contract Drilling carried out by our subsidiary Unit Drilling Company and its subsidiaries. This segment contracts to drill onshore oil and natural gas wells for our own account and for others.

Oil and Natural Gas carried out by our subsidiary Unit Petroleum Company. This segment explores, develops, acquires and produces oil and natural gas properties for our own account.

Gas Gathering and Processing (Mid-Stream) carried out by our subsidiary Superior Pipeline Company, L.L.C. This segment buys, sells, gathers, processes and treats natural gas for our own account and for third parties.

Executive Summary

Our drilling segment added 12 drilling rigs in 2007 and averaged an 80% utilization rate. Our oil and natural gas segment attained its longstanding objective of replacing at least 150% of the year s production with new reserves by replacing 171% of its 2007 oil, NGLs and natural gas production. We met our production replacement objective for the 24th consecutive year by participating in the completion of 253 new wells with an 87% success rate. We recently completed an acquisition, in January 2008, involving our Segno area which is one of our key development areas. We plan to begin drilling operations on a new well in the acreage block in early 2008. Superior Pipeline continued to grow by adding three processing plants and 78 additional miles of pipeline in 2007.

Recent Events Oil and Natural Gas

Segno Acquisition. On January 18, 2008, we purchased a 50% interest in a 6,800 gross-acre leasehold that we did not already own in our Segno area of operations located in Hardin County, Texas. Included in the purchase were five producing wells with 4.9 Bcfe of estimated proved reserves and current production of 2.8 MMcf of natural gas per day and 88.2 barrels of condensate. The purchase price was $16.8 million which consisted of $15.8 million allocated to the reserves of the wells and $1.0 million allocated to the undeveloped leasehold. The production and reserves acquired in this purchase will be included in our 2008 results.

Outlook for 2008

Our plan for 2008 is to continue our growth. Objectives of this plan include:

Adding two new 1,500 horsepower, diesel electric drilling rigs to our drilling rig fleet.

Replacing at least 150% of our 2008 production with new oil, NGLs and natural gas reserves.

Participating in the drilling of approximately 280 wells.

- Expanding our presence in the mid-stream business.

Potential risks and/or obstacles that could prevent us from achieving these objectives are many, some of which are noted elsewhere in this report and include:

- We are not successful in replacing the oil, NGLs and natural gas reserves that we produce;
- Lower than expected levels of cash flow from our operations;
- Decreased drilling rig rates and rig utilization;
- General economic and industry downturn.

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Critical Accounting Policies and Estimates

Summary

In this section, we identify those critical accounting policies we follow in preparing our financial statements and related disclosures. Many of these policies require us to make difficult, subjective and complex judgments in the course of making estimates of matters that are inherently imprecise. Some accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. We evaluate our estimates and assumptions on a regular basis. We base our estimates on historical experience and various other assumptions that we believe are reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates and assumptions used in preparation of our financial statements. In the following discussion we will attempt to explain the nature of these estimates, assumptions and judgments, as well as the likelihood that materially different amounts would be reported in our financial statements under different conditions or using different assumptions.

The following table lists the critical accounting policies, estimates and assumptions that can have a significant impact on the application of these accounting policies, and the financial statement accounts affected by these estimates and assumptions.

Accounting Policies	Estimates or Assumptions	Accounts Affected
Full cost method of accounting for oil, NGLs and natural gas properties	Oil, NGLs and natural gas reserves, estimates and related present value of future net revenues Valuation of unproved properties Estimates of future development costs	Oil and natural gas properties Accumulated DD&A Provision for DD&A Impairment of proved and unproved properties Long-term debt and interest expense
Accounting for ARO for oil, NGLs and natural gas properties	Cost estimates related to the plugging and abandonment of wells Timing of cost incurred	Oil and natural gas properties Accumulated DD&A Provision for DD&A Current and non-current liabilities Operating expense
Accounting for impairment of long-lived assets	Forecast of undiscounted estimated future net operating cash flows	Drilling property and equipment Accumulated depreciation Provision for depreciation Impairment of drilling property and equipment
Turnkey and footage drilling contracts	Estimates of costs to complete turnkey and footage contracts	Revenue and operating expense Current assets and liabilities
Accounting for value of stock compensation awards	Estimates of stock volatility Estimates of expected life of awards granted Estimates of rates of forfeitures	Oil and natural gas properties Shareholder s equity Operating expenses
Accounting for derivative instruments and hedging	Derivatives measured at fair value	Current and non-current assets and liabilities

Derivatives measured for effectiveness	Other comprehensive income as a component of equity

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Significant Estimates and Assumptions

Full Cost Method of Accounting for Oil, NGLs and Natural Gas Properties. The determination and valuation of our oil, NGLs and natural gas reserves is a very subjective process. It entails estimating underground accumulations of oil, NGLs and natural gas that cannot be measured in an exact manner. The degree of accuracy of these estimates depends on a number of factors, including, the quality and availability of geological and engineering data, the precision of the interpretations of that data, and individual judgments based on experience and training. Each year, we hire an independent petroleum engineering firm to audit our internal evaluation of our oil, NGLs and natural gas reserves. The wells or locations for which estimates of reserves were audited were reserves that comprised the top 83% of the total proved discounted future net income based on the unescalated pricing policy of the SEC as taken from reserve and income projections prepared by us as of December 31, 2007.

As a general rule, the degree of accuracy of oil, NGLs and natural gas reserve estimates varies with the reserve classification and the related accumulation of available data, as shown in the following table:

Type of Reserves	Nature of Available Data	Degree of Accuracy
Proved undeveloped	Data from offsetting wells, seismic data	Less accurate
Proved developed non-producing	Logs, core samples, well tests, pressure data	More accurate
Proved developed producing	Production history, pressure data over time	Most accurate

Assumptions as to future oil, NGLs and natural gas prices and operating and capital costs also play a significant role in estimating oil, NGLs and natural gas reserves and the estimated present value of the cash flows to be received from the future production of those reserves. Volumes of recoverable reserves are influenced by the assumed prices and costs due to what is known as the economic limit (that point in the future when the projected costs and expenses of producing recoverable oil, NGLs and natural gas reserves is greater than the projected revenues from the oil, NGLs and natural gas reserves). But more significantly, the estimated present value of the future cash flows from our oil, NGLs and natural gas reserves is extremely sensitive to prices and costs, and may vary materially based on different assumptions. SEC financial accounting and reporting standards require that the pricing we use be tied to the price we received for our oil, NGLs and natural gas on the last day of the reporting period. This requirement can result in significant changes from period to period given the volatile nature of oil, NGLs and natural gas prices. For example, based on our year end 2007 oil, NGLs and natural gas reserves, a $1.00 decline in the price used to calculate our economically recoverable oil and NGLs reserves will reduce our estimated oil reserves by 48,000 barrels and estimated NGL reserves by 6,000 barrels and a $0.10 decline in the price of natural gas used to calculate our natural gas reserves will reduce our estimated economically recoverable natural gas reserves by 586,000 Mcf. Estimated future cash flows discounted at 10% before income taxes would change by $29.5 million.

We compute our provision for DD&A on a units-of-production method. Each quarter, we use the following formulas to compute the provision for DD&A for our producing properties:

DD&A Rate = Unamortized Cost / Beginning of Period Reserves

Provision for DD&A = DD&A Rate x Current Period Production

Oil, NGLs and natural gas reserve estimates have a significant impact on our DD&A rate. If reserve estimates for a property or group of properties are revised downward in the future, the DD&A rate will increase as a result of the revision. Alternatively, if reserve estimates are revised upward, the DD&A rate will decrease. Based on our 2007 production level of 54,720,000 equivalent Mcf, a 5% decline in the amount of our 2007 oil, NGLs and natural gas reserves would increase our DD&A rate by $0.13 per Mcfe and would decrease pre-tax income by $7.1 million annually. A 5% increase in the amount of our 2007 oil, NGLs and natural gas reserves would decrease our DD&A rate by $0.11 per Mcfe and would increase pre-tax income by $6.0 million annually.

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We account for our oil and natural gas exploration and development activities using the full cost method of accounting. Under this method, all costs incurred in the acquisition, exploration and development of oil and natural gas properties are capitalized. At the end of each quarter, the net capitalized costs of our oil and natural gas properties are limited to the lower of unamortized cost or a ceiling. The ceiling is defined as the sum of the present value (using a 10% discount rate) of the estimated future net revenues from our proved reserves, based on period-end oil, NGLs and natural gas prices adjusted for any hedging, plus the lower of cost or estimated fair value of unproved properties not included in the costs being amortized, less related income taxes. If the net capitalized costs of our oil and natural gas properties exceed the ceiling, we are required to write-down the excess amount. A ceiling test write-down is a non-cash charge to earnings. If required, it reduces earnings and impacts shareholders equity in the period of occurrence and results in lower depreciation, depletion and amortization expense in future periods. Once incurred, a write-down cannot be reversed.

The risk that we will be required to write-down the carrying value of our oil and natural gas properties increases when oil, NGLs and natural gas prices are depressed or if we have large downward revisions in our estimated proved oil, NGLs and natural gas reserves. Application of these rules during periods of relatively low oil or natural gas prices, even if temporary, increases the chance of a ceiling test write-down. Based on oil, NGL and natural gas prices on December 31, 2007 ($95.98 per barrel for oil, $66.89 per barrel of NGLs and $6.22 per Mcf for natural gas), the unamortized cost of our oil and natural gas properties did not exceed the ceiling of our proved oil, NGL and natural gas reserves. Natural gas and oil prices remain volatile and any significant declines below prices used in the reserve evaluation could result in a ceiling test write-down in the future.

We use the sales method for recording natural gas sales. This method allows for the recognition of revenue, which may be more or less than our share of pro-rata production from certain wells. Our policy is to expense our pro-rata share of lease operating costs from all wells as incurred. The expenses relating to the wells in which we have an imbalance are not material.

Accounting for ARO for Oil, NGLs and Natural Gas Properties. We record the fair value of liabilities associated with the retirement of assets having a long life. In our case, when the reserves in each of our oil or gas wells deplete or otherwise become uneconomical, we are required to incur costs to plug and abandon the wells. These costs under Financial Accounting Standards No. 143 (FAS 143), Accounting for Asset Retirement Obligations, are recorded in the period in which the liability is incurred (at the time the wells are drilled or acquired). We do not have any assets restricted for the purpose of settling these plugging liabilities. Our engineering staff uses historical experience to determine the estimated plugging costs taking into account the type of well (either oil or natural gas), the depth of the well and physical location of the well to determine the estimated plugging costs.

Accounting for Impairment of Long-Lived Assets. Drilling equipment, transportation equipment, gas gathering and processing systems and other property and equipment are carried at cost. Renewals and enhancements are capitalized while repairs and maintenance are expensed. Realization of the carrying value of property and equipment is reviewed for possible impairment whenever events or changes in circumstances suggest that these carrying amounts may not be recoverable. Assets are determined to be impaired if a forecast of undiscounted estimated future net operating cash flows directly related to the asset, including disposal value if any, is less than the carrying amount of the asset. If any asset is determined to be impaired, the loss is measured as the amount by which the carrying amount of the asset exceeds its fair value. The estimate of fair value is based on the best information available, including prices for similar assets. Changes in these estimates could cause us to reduce the carrying value of property and equipment. An estimate of the impact to our earnings if other assumptions had been used is not practicable because of the significant number of assumptions that would be involved in the estimates.

Goodwill represents the excess of the cost of acquisitions over the fair value of the net assets acquired. An annual impairment test is performed in the fourth quarter to determine whether the fair value has decreased and additionally when events indicate an impairment may have occurred. Goodwill is all related to our drilling segment, and accordingly, the impairment test is generally based on the estimated future net cash flows of our drilling segment.

Turnkey and Footage Drilling Contracts. In our contract drilling operations, because we do not bear the risk of completion of a well being drilled under a daywork contract, we recognize revenues and expense generated under daywork contracts as the services are performed. Under footage and turnkey contracts we bear the risk of completion of the well, so revenues and expenses are recognized when the well is substantially completed. Substantial completion is determined when the well bore reaches the depth specified in the contract. The entire amount of a loss, if any, is recorded when the loss can be reasonably determined, however, any profit is recorded only at the time the well is finished. The costs of drilling contracts uncompleted at the end of the reporting period (which includes expenses incurred to date on footage or turnkey contracts) are included in other current assets. In 2007 and 2006, we did not drill any wells under turnkey or footage contracts.

Accounting for Value of Stock Compensation Awards. Effective January 1, 2006, we adopted SFAS No. 123 (revised 2004), Share-Based Payment, (SFAS 123(R)) to account for stock-based compensation. Under this method, compensation cost is measured at the grant date based on the fair value of an award and is recognized over the service period, which is usually the vesting period. We elected to use the modified prospective method for adoption, which requires compensation expense to be recorded for all unvested stock options and other equity-based compensation beginning in the first quarter of adoption. The determination of the fair value of an award requires significant estimates and subjective judgments regarding, among other things, the appropriate option pricing model, the expected life of the award and performance vesting criteria assumptions. As there are inherent uncertainties related to these factors and our judgment in applying them to the fair value determinations, there is risk that the recorded stock compensation may not accurately reflect the amount ultimately earned by the employee. For years prior to 2006, we accounted for our stock-based compensation in accordance with the intrinsic value method. Under this method, we recognized compensation cost as the excess, if any, of the quoted market price of our stock at the grant date over the amount an employee must pay to acquire the stock.

Accounting for Derivative Instruments and Hedging. We utilize derivative contracts to hedge against the variability in cash flows associated with the forecasted sale of our future natural gas, NGLs and oil production. We have hedged a portion of our anticipated oil, NGLs and natural gas production for the next 12-24 months. In the case of acquisitions, we may hedge acquired production for a longer period. We do not use derivative instruments for trading purposes. Under accounting rules, we may elect to designate those derivatives that qualify for hedge accounting as cash flow hedges against the price that we will receive for our future oil, NGLs and natural gas production. To the extent that changes in the fair values of the cash flow hedges offset changes in the expected cash flows from our forecasted production, such amounts are not included in our consolidated results of operations. Instead, they are recorded directly to stockholders equity until the hedged oil, NGLs or natural gas quantities are produced and sold. To the extent that changes in the fair values of the derivative exceed the changes in the expected cash flows from the forecasted production, the changes are recorded in income in the period in which they occur.

Mid-Stream Contracts. We recognize revenue from the gathering and processing of natural gas and NGLs in the period the service is provided based on contractual terms.

New Accounting Standards

Fair Value Measurements. In September 2006, the FASB issued Statement No. 157 (FAS 157), Fair Value Measurements, which establishes a framework for measuring fair value and requires additional disclosures about fair value measurements. Beginning January 1, 2008, we partially applied FAS 157 as allowed by FASB Staff Position (FSP) 157-2, which delayed the effective date of FAS 157 for nonfinancial assets and liabilities. As of January 1, 2008, we have applied the provisions of FAS 157 to our financial instruments and the impact was not material. Under FSP 157-2, we will be required to apply FAS 157 to our nonfinancial assets and liabilities beginning January 1, 2009. We are currently reviewing the applicability of FAS 157 to our nonfinancial assets and liabilities as well as the potential impact on our consolidated financial statements.

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The Fair Value Option for Financial Assets and Financial Liabilities. In February 2007, the FASB issued Statement No. 159 (FAS 159), The Fair Value Option for Financial Assets and Financial Liabilities Including an amendment of FASB Statement No. 115, which permits entities to choose to measure many financial instruments and certain other items at fair value at specified election dates. A business entity is required to report unrealized gains and losses on items for which the fair value option has been elected in earnings at each subsequent reporting date. This statement is expected to expand the use of fair value measurement. FAS 159 is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years, and is applicable beginning in the first quarter of 2008. We do not believe the impact of FAS 159 will have a material effect on our consolidated financial statements.

Business Combinations. In December 2007, the FASB issued Statement No. 141R (FAS 141R), Business Combinations, which will require most identifiable assets, liabilities, noncontrolling interest (previously referred to as minority interests) and goodwill acquired in a business combination to be recorded at full fair value. FAS 141R is effective for our year beginning January 1, 2009, and will be applied prospectively. We are currently reviewing the applicability of FAS 141R to our operations and its potential impact on our consolidated financial statements.

Noncontrolling Interests. In December 2007, the FASB issued Statement No. 160 (FAS 160), Noncontrolling Interest in Consolidated Financial Statements an amendment to ARB No. 51, which requires noncontrolling interests (previously referred to as minority interests) to be reported as a component of equity. FAS 160 is effective for our year beginning January 1, 2009, and will require retroactive adoption of the presentation and disclosure requirements for existing minority interests. We are currently reviewing the applicability of FAS 160 to our operations and its potential impact on our consolidated financial statements.

Financial Condition and Liquidity

Summary. Our financial condition and liquidity depends on the cash flow from our operations and borrowings under our bank credit facility. Our cash flow is influenced mainly by:

- the demand for and the dayrates we receive for our drilling rigs;
- the quantity of natural gas, oil and NGLs we produce;
- the prices we receive for our natural gas production and, to a lesser extent, the prices we receive for our oil and NGL production; and
- the margins we obtain from our natural gas gathering and processing contracts.

The following is a summary of certain financial information as of December 31, and for the years ended December 31:

	2007	2006	2005
	(In thousands except percentages)		
Working capital	$ 40,611	$ 71,998	$ 51,173
Long-term debt	$ 120,600	$ 174,300	$ 145,000
Shareholders equity	$ 1,434,817	$ 1,158,036	$ 836,962
Ratio of long-term debt to total capitalization	7.8%	13.1%	14.8%
Net income	$ 266,258	$ 312,177	$ 212,442
Net cash provided by operating activities	$ 577,571	$ 506,702	$ 317,771
Net cash used in investing activities	$ (512,333)	$ (540,723)	$ (384,996)
Net cash provided by (used in) financing activities	$ (64,751)	$ 33,663	$ 67,507

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The following table summarizes certain operating information for the years ended December 31:

	2007	2006	2005
Contract Drilling:			
Average number of our drilling rigs in use during the period	99.4	109.0	102.1
Total number of drilling rigs owned at the end of the period	129	117	112
Average dayrate	$ 18,663	$ 18,767	$ 12,431
Oil and Natural Gas:			
Oil production (MBbls)	1,091	1,012	847
Natural gas liquids production (MBbls)	785	441	237
Natural gas production (MMcf)	43,464	44,169	34,058
Average oil price per barrel received	$ 70.61	$ 63.39	$ 54.47
Average NGL price per barrel received	$ 45.03	$ 36.08	$ 34.69
Average NGL price per barrel received excluding hedges	$ 45.01	$ 36.08	$ 34.69
Average natural gas price per mcf received	$ 6.30	$ 6.17	$ 7.64
Average natural gas price per mcf received excluding hedges	$ 6.24	$ 6.17	$ 7.76
Mid-Stream:			
Gas gathered MMBtu/day	219,635	247,537	142,444
Gas processed MMBtu/day	50,350	31,833	30,613
Gas liquids sold gallons/day	129,421	66,902	61,665
Number of natural gas gathering systems	36	37	36
Number of processing plants	8	6	5

At December 31, 2007, we had unrestricted cash totaling $1.1 million and we had borrowed $120.6 million of the $275.0 million we had elected to have available under our bank credit facility.

Working Capital. Our working capital balance fluctuates primarily as a result of the timing of our accounts receivable and accounts payable. We had working capital of $40.6 million as of December 31, 2007. This compares to working capital of $72.0 million at the end of 2006 and $51.2 million at the end of 2005.

Contract Drilling. Our drilling work is subject to many factors that influence the number of drilling rigs we have working as well as the costs and revenues associated with that work. These factors include the demand for drilling rigs, competition from other drilling contractors, the prevailing prices for natural gas and oil, availability and cost of labor to run our drilling rigs and our ability to supply the equipment needed.

Although rig utilization declined in the fourth quarter of 2006 and continued to slowly decline throughout 2007, we do not anticipate declines in labor cost per hour due to the competition within the industry to keep qualified employees and attract individuals with the skills required to meet the future requirements of the drilling industry. To help keep qualified labor, we previously implemented longevity pay incentives and in the second quarter of 2006 provided pay increases in some of our operating districts. To date, these efforts have allowed us to meet our labor requirements. However, if current demand for drilling rigs strengthens above the 2007 levels of 80%, shortages of experienced personnel may limit our ability to operate our drilling rigs.

Most of our drilling rig fleet is used to drill natural gas wells so changes in natural gas prices have a disproportionate influence on the demand for our drilling rigs as well as the prices we can charge for our contract drilling services. In 2007, our average dayrate was $18,663 per day compared to $18,767 per day in 2006 and $12,431 per day in 2005. The average number of our drilling rigs used in 2007 was 99.4 drilling rigs (80%) compared with 109.0 drilling rigs (96%) in 2006 and 102.1 drilling rigs (97%) for 2005. Based on the average utilization of our drilling rigs during 2007, a $100 per day change in dayrates has a $9,940 per day ($3.6 million annualized) change in our pre-tax operating cash flow. Industry demand for our drilling rigs remained strong throughout the first nine months of 2006 before declining in the fourth quarter of 2006 and into 2007. The reduction in demand for drilling rigs was primarily the result of the evaluation of the economics of drilling prospects by the operators using our contract drilling services after natural gas prices declined significantly in the last half of the third quarter of 2006 combined with high levels of natural gas storage throughout the majority of the winter season and again this summer. We expect that utilization and dayrates for our drilling rigs will continue to depend mainly on the price of natural gas, the levels of natural gas storage and the availability of drilling rigs to meet the demands of the industry.

Our contract drilling subsidiaries provide drilling services for our exploration and production subsidiary. The contracts for these services contain the same terms and rates as the contracts we use with unrelated third parties for comparable type projects. During 2007, 2006 and 2005, we drilled 77, 72 and 53 wells, respectively, for our exploration and production subsidiary. The profit associated with these wells received by our contract drilling segment of $22.7 million, $22.2 million and $8.6 million during 2007, 2006 and 2005, respectively, was used to reduce the carrying value of our oil and natural gas properties rather than being included in our operating profit.

Impact of Prices for Our Oil, NGLs and Natural Gas. Natural gas comprises 82% of our oil, NGLs and natural gas reserves. Any significant change in natural gas prices has a material affect on our revenues, cash flow and the value of our oil, liquids and natural gas reserves. Generally, prices and demand for domestic natural gas are influenced by weather conditions, supply imbalances and by world wide oil price levels. Domestic oil prices are primarily influenced by world oil market developments. All of these factors are beyond our control and we can not predict nor measure their future influence on the prices we will receive.

Based on our production in 2007, a $0.10 per Mcf change in what we are paid for our natural gas production would result in a corresponding $339,000 per month ($4.1 million annualized) change in our pre-tax operating cash flow. Our 2007 average natural gas price was $6.30 compared to an average natural gas price of $6.17 for 2006 and $7.64 for 2005. A $1.00 per barrel change in our oil price would have an $85,000 per month ($1.0 million annualized) change in our pre-tax operating cash flow and a $1.00 per barrel change in our NGL prices would have a $61,000 per month ($0.7 million annualized) change in our pre-tax operating cash flow based on our production in 2007. Our 2007 average oil price per barrel was $70.61 compared with an average oil price of $63.39 in 2006 and $54.47 in 2005 and our 2007 average NGL price per barrel was $45.03 compared with an average liquids price of $36.08 in 2006 and $34.69 in 2005.

Because natural gas prices have such a significant affect on the value of our oil, NGLs and natural gas reserves, declines in these prices can result in a decline in the carrying value of our oil and natural gas properties. Price declines can also adversely affect the semi-annual determination of the amount available for us to borrow under our bank credit facility since that determination is based mainly on the value of our oil, NGLs and natural gas reserves. Such a reduction could limit our ability to carry out our planned capital projects.

Most of our natural gas production is sold to third parties under month-to-month contracts.

Mid-Stream Operations. Our mid-stream operations are conducted through Superior Pipeline Company, L.L.C. Superior is a mid-stream company engaged primarily in the buying and selling, gathering, processing and treating of natural gas and operates four natural gas treatment plants, eight processing plants, 36 gathering systems and 676 miles of pipeline. Superior operates in Oklahoma, Texas, Louisiana and Kansas and has been in business since 1996. This subsidiary enhances our ability to gather and market not only our own natural gas but also that owned by third parties and gives us additional capacity to construct or acquire existing natural gas gathering and processing facilities. During 2007, 2006 and 2005 Superior purchased $18.4 million, $8.0 million and $6.8 million, respectively of our natural gas production and natural gas liquids and provided gathering and transportation services of $4.7 million, $5.3 million and $2.4 million, respectively. Intercompany revenue from services and purchases of production between this business segment and our oil and natural gas exploration operations has been eliminated in our consolidated condensed financial statements.

Superior gathered 219,635 MMBtu per day in 2007 compared to 247,537 MMBtu per day in 2006 and 142,444 MMBtu per day in 2005, processed 50,350 MMBtu per day in 2007 compared to 31,833 MMBtu per day

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in 2006 and 30,613 MMBtu per day in 2005 and sold NGLs of 129,421 gallons per day in 2007 compared to 66,902 gallons per day in 2006 and 61,665 gallons per day in 2005. Gas gathering volumes per day in 2007 decreased 11% compared to 2006 primarily due to a decline in our Southeast Oklahoma gathering system due to natural production declines associated with the connected wells and decreased new well connections. Volumes processed increased due to the addition of three natural gas processing plants in 2007 and also resulted in increased NGL volumes.

Our Credit Facility. On December 31, 2007, we had a $275.0 million revolving credit facility. On May 24, 2007, we entered into a First Amended and Restated Senior Credit Agreement (Credit Facility) which amended and restated the credit facility entered into between us and our lenders on January 30, 2004. The Credit Facility is a revolving credit facility maturing on May 24, 2012 and has a maximum credit amount of $400.0 million. Borrowings under the Credit Facility are limited to a commitment amount elected by us. Currently we have elected to have an aggregate commitment amount of $275.0 million. We are charged a commitment fee of 0.25 to 0.375 of 1% on the amount available but not borrowed with the rate varying based on the amount borrowed as a percentage of our total borrowing base amount. We incurred origination, agency and syndication fees of $737,500 at the inception of the Credit Facility. These fees are being amortized over the life of the agreement. The average interest rate for 2007 was 6.0%. At December 31, 2007 and February 15, 2008, our borrowings were $120.6 million and $144.8 million, respectively.

The borrowing base under the Credit Facility is subject to re-determination on April 1 and October 1 of each year. Each redetermination is based primarily on a percentage of the discounted future value of our oil, NGLs and natural gas reserves, as determined by the lenders, and, to a lesser extent, the loan value the lenders reasonably attribute to the cash flow (as defined in the Credit Facility) of our mid-stream operations. The company or the lenders may request a one time special redetermination of the borrowing base between each scheduled redetermination date. In addition, we may request a redetermination following the consummation of an acquisition meeting the requirements defined in the Credit Facility. The lender s aggregate commitment is limited to the lesser of the amount of the value of the borrowing base or $400.0 million. The current borrowing base is $425.0 million.

At our election, any part of the outstanding debt may be fixed at LIBOR for a 30, 60, 90 or 180 day term. During any LIBOR funding period the outstanding principal balance of the note to which such LIBOR option applies may be repaid on three days prior notice to the administrative agent and subject to the payment of any applicable funding indemnification amounts. Interest on the LIBOR is computed at the LIBOR base applicable for the interest period plus 1.00% to 1.75% depending on the level of debt as a percentage of the borrowing base and payable at the end of each term, or every 90 days, whichever is less. Borrowings not under the LIBOR bear interest at the BOKF National Prime Rate payable at the end of each month and the principal borrowed may be paid anytime in part or in whole without premium or penalty. At December 31, 2007, all of the $120.6 million we had borrowed was subject to LIBOR.

The Credit Facility includes prohibitions against:

- the payment of dividends (other than stock dividends) during any fiscal year in excess of 25% of our consolidated net income for the preceding fiscal year,
- the incurrence of additional debt with certain very limited exceptions and
- the creation or existence of mortgages or liens, other than those in the ordinary course of business, on any of our property, except in favor of our lenders.

The Credit Facility also requires that we have at the end of each quarter:

- a consolidated net worth of at least $900.0 million,
- a current ratio (as defined in the Credit Facility) of not less than 1 to 1 and

a leverage ratio of long-term debt to consolidated EBITDA (as defined in the Credit Facility) for the most recently ended rolling four fiscal quarters of no greater than 3.50 to 1.0.

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On December 31, 2007, we were in compliance with the covenants contained in the Credit Facility.

We entered into the following interest rate swaps to help manage our exposure to possible future interest rate increases:

Term	Amount	Fixed Rate	Floating Rate
March 2005 January 2008	$ 50,000,000	3.99%	3 month LIBOR
December 2007 May 2012	$ 15,000,000	4.53%	3 month LIBOR
December 2007 May 2012	$ 15,000,000	4.16%	3 month LIBOR

Capital Requirements

Drilling Acquisitions and Capital Expenditures. In January 2006, we acquired a 1,000 horsepower drilling rig for approximately $3.9 million. This newly acquired drilling rig was modified at one of our drilling yards for an additional $1.7 million and became operational in April 2006. In May we began moving a 1,500 horsepower drilling rig to our Rocky Mountain division following completion of its construction in the first quarter of 2006 for approximately $10.2 million. In the second quarter of 2006, we also completed the purchase of two new 1,500 horsepower drilling rigs for a total of $15.2 million of which $4.6 million was paid before the second quarter of 2006 and the balance of $10.6 million was paid at delivery of the drilling rigs. An additional $3.0 million of modifications were made to the drilling rigs before the drilling rigs were placed into service. The first drilling rig was placed into service in May 2006 and the second drilling rig was placed into service in June 2006. At the end of August 2006 we completed the construction of another 1,500 horsepower rig for approximately $9.5 million which was moved into our Rocky Mountain division. In the last half of 2006 we completed construction of a 750 horsepower rig for approximately $4.5 million.

During 2006, we purchased major components to be used in the construction of two new 1,500 horsepower drilling rigs. The first rig was placed into service in our Rocky Mountain division at the end of March 2007 and the second rig was placed into service in the second quarter of 2007. The combined capitalized cost of both drilling rigs was $19.4 million. On June 5, 2007, we completed the acquisition of a privately owned drilling company operating primarily in the Texas Panhandle. The acquired company owned nine drilling rigs, a fleet of 11 trucks, and an office, shop and equipment yard. The drilling rigs range from 800 horsepower to 1,000 horsepower with depth capacities rated from 10,000 to 15,000 feet. Eight of the nine drilling rigs were operating under contracts on the acquisition date. The remaining drilling rig is being refurbished and anticipated to be placed in service during March of 2008. Results of operations for the acquired company have been included in our statements of income beginning June 5, 2007. Total consideration paid for this acquisition was $38.5 million.

For our contract drilling operations, during 2007, we recorded $220.4 million in capital expenditures including the effect of a $19.4 million deferred tax liability and $5.3 million in goodwill associated with our second quarter 2007 acquisition. For 2008, we anticipate capital expenditures to be approximately $119.0 million excluding acquisitions. We are constructing two new 1,500 horsepower, diesel electric drilling rigs. We anticipate placing these drilling rigs into service in our Rocky Mountain division during the second quarter of 2008.

We currently do not have a shortage of drill pipe and drilling equipment. At December 31, 2007, we had commitments to purchase approximately $26.5 million of drill pipe and drill collars in 2008. We also had committed to purchase $1.5 million of additional rig components with 20% or $0.3 million paid through December 31, 2007.

Oil and Natural Gas Acquisitions and Capital Expenditures. Most of our capital expenditures are discretionary and directed toward future growth. Our decision to increase our oil, NGLs and natural gas reserves through acquisitions or through drilling depends on the prevailing or expected market conditions, potential return on investment, future drilling potential and opportunities to obtain financing under the circumstances involved,

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all of which provide us with a large degree of flexibility in deciding when and if to incur these costs. We completed drilling 253 gross wells (96.64 net wells) in 2007 compared to 244 gross wells (85.30 net wells) in 2006 and 192 gross wells (72.63 net wells) in 2005. Our 2007 total capital expenditures for oil and natural gas exploration, excluding an $0.8 million decrease in the plugging liability in 2007, totaled $308.1 million. Currently we plan to participate in drilling an estimated 280 gross wells in 2008 and estimate our total capital expenditures for oil and natural gas exploration to be approximately $360.0 million, excluding acquisitions. Whether we are able to drill the full number of wells we are planning on drilling is dependent on a number of factors, many of which are beyond our control and include the availability of drilling rigs, prices for oil, NGLs and natural gas, the cost to drill wells, the weather and the efforts of outside industry partners.

On May 16, 2006, we closed the acquisition of certain oil and natural gas properties from a group of private entities for approximately $32.4 million in cash. Proved oil, NGLs and natural gas reserves involved in this acquisition consisted of approximately 14.2 Bcfe. The effective date of this acquisition was April 1, 2006 and results from this acquisition were included in the statement of income beginning May 1, 2006.

On October 13, 2006, we completed the acquisition of Brighton Energy, L.L.C., a privately owned oil and natural gas company for approximately $67.0 million in cash. Included in this acquisition was all of Brighton s oil and natural gas assets (excluding Atoka and Coal counties in Oklahoma) and included approximately 23.1 Bcfe of proved reserves. The majority of the acquired reserves are located in the Anadarko Basin of Oklahoma and the onshore Gulf Coast basins of Texas and Louisiana, with additional reserves in Arkansas, Kansas, Montana, North Dakota and Wyoming. This acquisition had an effective date of August 1, 2006 and results of operations from this acquisition are included in the statement of income beginning October 1, 2006 with the results for the period from August 1, 2006 through September 30, 2006 included as an adjustment to the purchase price.

On January 18, 2008, we purchased a 50% interest in a 6,800 gross-acre leasehold that we did not already own in our Segno area of operations located in Hardin County, Texas. Included in the purchase were five producing wells with 4.9 Bcfe of estimated proved reserves and current production of 2.8 MMcf of natural gas per day and 88.2 barrels of condensate. The purchase price was $16.8 million which consisted of $15.8 million allocated to the reserves of the wells and $1.0 million allocated to the undeveloped leasehold. The production and reserves acquired in this purchase will be included in our 2008 results.

Mid-Stream Acquisitions and Capital Expenditures. In September 2006, we closed the acquisition of Berkshire Energy, LLC, a private company for an adjusted purchase price of $21.7 million. The principal tangible assets of the acquired company consisted of a natural gas processing plant, a natural gas gathering system with 15 miles of pipeline, three field compressors and two plant compressors. This purchase had an effective date of July 31, 2006. The financial results of this acquisition are included in the company's statement of income from September 1, 2006 forward with the results for the period of August 1, 2006 through August 31, 2006 included as an adjustment to the purchase price.

During 2007, the mid-stream segment incurred $34.2 million in capital expenditures as compared to $42.9 million in 2006 and $21.8 million in 2005, including acquisitions. For 2008, we have budgeted capital expenditures of approximately $32.0 million. Our plan is to grow this segment through the construction of new facilities or acquisitions.

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Contractual Commitments. At December 31, 2007, we had the following contractual obligations:

	Payments Due by Period				
	Total	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years
	(In thousands)				
Bank debt (1)	$ 150,178	$ 6,662	$ 13,495	$ 130,021	$
Retirement agreements (2)	723	643	80		
Operating leases (3)	4,187	1,799	2,137	251	
Drill pipe, drilling components and equipment purchases (4)	27,724	27,724			
Total contractual obligations	$ 182,812	$ 36,828	$ 15,712	$ 130,272	$

(1) See previous discussion in MD&A regarding our bank credit facility. This obligation is presented in accordance with the terms of the credit facility and includes interest calculated using our year end interest rate of 4.8% which includes the effect of the interest rate swaps.

(2) In the second quarter of 2001, we recorded $1.3 million in additional employee benefit expenses for the present value of a separation agreement made in connection with the retirement of King Kirchner from his position as Chief Executive Officer. The liability associated with this expense, including accrued interest, is paid in monthly payments of $25,000 which started in July 2003 and continues through June 2009. In the first quarter of 2004, we acquired a liability for the present value of a separation agreement between PetroCorp Incorporated and one of its previous officers. The liability associated with this last agreement is paid in quarterly payments of $12,500 through December 31, 2007. In the first quarter of 2005, we recorded $0.7 million in additional employee benefit expense for the present value of a separation agreement made in connection with the retirement of John Nikkel from his position as Chief Executive Officer. The liability associated with this expense, including accrued interest, is paid in monthly payments of $31,250 which started in November 2006 and continuing through October 2008. These liabilities, as presented above, are undiscounted.

(3) We lease office space in Tulsa and Woodward, Oklahoma; Houston and Midland, Texas; and Denver, Colorado under the terms of operating leases expiring through January 31, 2012. Additionally, we have several equipment leases and lease space on short-term commitments to stack excess drilling rig equipment and production inventory.

(4) We have committed to purchase approximately $26.5 million of drill pipe and drill collars in 2008. We have also committed to purchase $1.5 million of drilling rig components with 20% or $0.3 million paid through December 31, 2007.

At December 31, 2007, we also had the following commitments and contingencies that could create, increase or accelerate our liabilities:

		Estimated Amount of Commitment Expiration Per Period			
Other Commitments	Total Accrued	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years
		(In thousands)			
Deferred compensation plan (1)	$ 2,987	Unknown	Unknown	Unknown	Unknown
Separation benefit plans (2)	$ 4,945	$ 61	Unknown	Unknown	Unknown
Derivative liabilities interest rate swaps	$ 249	$ 56			$ 193
Plugging liability (3)	$ 33,191	$ 672	$ 6,550	$ 2,254	$ 23,715
Gas balancing liability (4)	$ 3,364	Unknown	Unknown	Unknown	Unknown
Repurchase obligations (5)	$	Unknown	Unknown	Unknown	Unknown
Workers compensation liability (6)	$ 22,469	$ 7,380	$ 4,809	$ 1,458	$ 8,822

(1) We provide a salary deferral plan which allows participants to defer the recognition of salary for income tax purposes until actual distribution of benefits, which occurs at either termination of employment, death or certain defined unforeseeable emergency hardships. We recognize payroll expense and record a liability, included in other long-term liabilities in our Consolidated Balance Sheet, at the time of deferral.

(2) Effective January 1, 1997, we adopted a separation benefit plan (Separation Plan). The Separation Plan allows eligible employees whose employment with us is involuntarily terminated or, in the case of an employee who has completed 20 years of service, voluntarily or involuntarily terminated, to receive benefits equivalent to four weeks salary for every whole year of service completed with the company up to a maximum of 104 weeks. To receive payments the recipient must waive any claims against us in exchange for receiving the separation benefits. On October 28, 1997, we adopted a Separation Benefit Plan for Senior Management (Senior Plan). The Senior Plan provides certain officers and key executives of the company with benefits generally equivalent to the Separation Plan. The Compensation Committee of the Board of Directors has absolute discretion in the selection of the individuals covered in this plan. On May 5, 2004 we also adopted the Special Separation Benefit Plan (Special Plan). This plan is identical to the Separation Benefit Plan with the exception that the benefits under the plan vest on the earliest of a participant s reaching the age of 65 or serving 20 years with the company. At December 31, 2007, there were 31 eligible employees to participate in the plan.

(3) When a well is drilled or acquired, under Financial Accounting Standards No. 143 (FAS 143), Accounting for Asset Retirement Obligations, we have recorded the fair value of liabilities associated with the retirement of long-lived assets (mainly plugging and abandonment costs for our depleted wells).

(4) We have recorded a liability for those properties we believe do not have sufficient oil, NGLs and natural gas reserves to allow the under-produced owners to recover their under-production from future production volumes.

(5) We formed The Unit 1984 Oil and Gas Limited Partnership and the 1986 Energy Income Limited Partnership along with private limited partnerships (the Partnerships) with certain qualified employees, officers and directors from 1984 through 2007, with a subsidiary of ours serving as general partner. The Partnerships were formed for the purpose of conducting oil and natural gas acquisition, drilling and development operations and serving as co-general partner with us in any additional limited partnerships formed during that year. The Partnerships participated on a proportionate basis with us in most drilling operations and most producing property acquisitions commenced by us for our own account during the period from the formation of the Partnership through December 31 of that year. These partnership agreements require, on the election of a limited partner, that we repurchase the limited partner s interest at amounts to be determined by appraisal in the future. Such repurchases in any one year are limited to 20% of the units outstanding. We made repurchases of $7,000 and $4,000 in 2006 and 2005, respectively and had no repurchases in 2007.

(6) We have recorded a liability for future estimated payments related to workers compensation claims primarily associated with our contract drilling segment.

Hedging Activities. Periodically we hedge interest rates and the prices to be received for a portion of our future natural gas, oil and NGL production. We do so in an attempt to reduce the impact and uncertainty that price variations have on our cash flow.

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Interest Rate Swaps. We enter into interest rate swaps to help manage our exposure to possible future interest rate increases. As of December 31, 2007, we had three interest rate swaps which were cash flow hedges. There was no material amount of ineffectiveness. The fair value of these swaps was recognized on the December 31, 2007 balance sheet as current and non-current derivative assets and liabilities and presented in the table below:

Term	Amount	Fixed Rate	Floating Rate	Fair Value Asset (Liability)
		($ in thousands)		
March 2005 January 2008	$ 50,000	3.99%	3 month LIBOR	$ 96
December 2007 May 2012	$ 15,000	4.53%	3 month LIBOR	(240)
December 2007 May 2012	$ 15,000	4.16%	3 month LIBOR	(9)
				$ (153)

As a result of these interest rate swaps, interest expense decreased by $0.7 million and $0.5 million in 2007 and 2006, respectively, and increased by $0.2 million in 2005. A loss of $0.1 million, net of tax, is reflected in accumulated other comprehensive income (loss) as of December 31, 2007.

Commodity Hedges. We use hedging to reduce price volatility and manage price risks. Our decision on the quantity and price at which we choose to hedge certain of our products is based in part on our view of current and future market conditions. In 2007, in our oil and gas segment, approximately 22% of our natural gas production and 3% of our NGL production, was subject to derivative contracts and in our mid-stream segment, approximately 28% of our NGL production and 6% of our natural gas processing, was subject to derivative contracts. In 2006, none of our oil and gas segment s production was subject to derivative contracts as compared to 2005 when approximately 32% of its oil production and 13% of its natural gas production was subject to derivative contracts.

For 2008, in an attempt to better manage our cash flows, we have increased the amount of our hedged production. As of February 15, 2008, in our oil and gas segment approximately 77% of our current daily oil production is hedged for January through December 2008, 40% of our current daily natural gas production is hedged for January through December 2008, and 75% of our current monthly NGL production is hedged January through April 2008. In our mid-stream segment, approximately 32% of our anticipated monthly NGL processing along with the associated natural gas purchases is hedged for January through April 2008, 20% of our anticipated monthly ethane and 35% of our anticipated monthly propane volumes along with the associated natural gas purchases is hedged for May through July 2008, and 11% of our anticipated monthly propane volumes along with the associated natural gas purchases is hedged for August through December 2008.

For 2009, as of February 15, 2008, in our oil and gas segment approximately 16% of our current daily natural gas production is hedged for the period January through December 2009.

While the use of hedging arrangements limits the downside risk of adverse price movements, it also may limit our future revenues from favorable price movements.

The use of hedging transactions also involves the risk that the counterparties will be unable to meet the financial terms of the transactions. At December 31, 2007, Bank of Montreal, Bank of Oklahoma, N.A., and Bank of America, N.A. were the counterparties with respect to all of our commodity hedging transactions.

Currently all of our commodity hedges are cash flow hedges and there is no material amount of ineffectiveness. At December 31, 2007, we recorded the fair value of our commodity hedges on our balance sheet as derivative assets of $2.0 million and derivative liabilities of $0.1 million. At December 31, 2006, we had derivative assets of $1.4 million and no derivative liabilities.

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We recognize the effective portion of changes in fair value as accumulated other comprehensive income (loss), and reclassify the sales to revenue and the purchases to expense as the underlying transactions are settled. As of December 31, 2007, we had a gain of $2.1 million, net of tax, from our oil and natural gas segment derivatives and a loss of $0.8 million, net of tax, from our mid-stream segment derivatives in accumulated other comprehensive income (loss). At December 31, 2007 all of our commodity instruments were short-term and will be settled into earnings within twelve months. Realized earnings from our commodity derivative settlements included in revenues and expense were as follows at December 31:

	2007	2006	2005
		(In thousands)	
Increases (decreases) in:			
Oil and natural gas revenue	$ 2,589	$	$ (4,081)
Gas gathering and processing revenue	(2,078)		
Gas gathering and processing expense	1,694		
Impact on pre-tax earnings	$ (1,183)	$	$ (4,081)

At December 31, 2007, the following cash flow hedges were outstanding:

Oil and Natural Gas Segment:

Term	Sell/ Purchase	Commodity	Hedged Volume	Average Fixed Price	Market
Jan 08 Apr 08	Sell	Liquids swap (1)	388,000 Gal/mo	$1.235	OPIS Conway
Jan 08 Apr 08	Sell	Liquids swap (1)	500,000 Gal/mo	$1.164	OPIS Mont Belvieu
Jan 08 Dec 08	Sell	Crude oil swap	1,000 Bbl/day	$91.32	WTI NYMEX
Jan 08 Dec 08	Sell	Crude oil collar	1,000 Bbl/day	$85.00 put & $98.75 call	WTI NYMEX
Jan 08 Dec 08	Sell	Natural gas swap	10,000 MMBtu/day	$7.615	IF Centerpoint East
Jan 08 Dec 08	Sell	Natural gas collar	10,000 MMBtu/day	$7.00 put & $8.40 call	IF Centerpoint East
Jan 08 Dec 08	Sell	Natural gas collar	10,000 MMBtu/day	$7.20 put & $8.80 call	IF CP Tenn (Zone 0)

(1) Types of liquids include ethane and propane.

Mid-Stream Segment:

Term	Sell/ Purchase	Commodity	Hedged Volume	Average Fixed Price	Market
Jan 08 Apr 08	Sell	Liquids swap (1)	1,836,000 Gal/mo	$1.424	OPIS Conway
Jan 08 Apr 08	Purchase	Naturalgas swap	171,000 MMBtu/mo	$6.673	IF PEPL
May 08 Jul 08	Sell	Liquids swap (2)	1,038,000 Gal/mo	$1.109	OPIS Conway
May 08 Jul 08	Purchase	Natural gas swap	85,000 MMBtu/mo	$6.415	IF PEPL

(1) Types of liquids include natural gasoline, ethane, propane, isobutane and natural butane.

(2) Types of liquids include ethane and propane.

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Subsequent to December 31, 2007, we entered into the following cash flow hedges:

Oil and Natural Gas Segment:

Term	Sell / Purchase	Commodity	Hedged Volume	Average Fixed Price	Market
Jan 08 Apr 08	Sell	Liquids swap (1)	194,000 Gal/mo	$1.288	OPIS Conway
Jan 08 Apr 08	Sell	Liquids swap (1)	250,000 Gal/mo	$1.239	OPIS Mont Belvieu
Jan 08 Dec 08	Sell	Crude oil collar	500 Bbl/day	$90.00 put & $102.50 call	WTI NYMEX
Feb 08 Dec 08	Sell	Natural gas swap	10,000 MMBtu/day	$7.433	IF Centerpoint East
Feb 08 Dec 08	Sell	Natural gas collar	10,000 MMBtu/day	$7.50 put & $8.70 call	NGPL TXOK
Jan 09 Dec 09	Sell	Natural gas swap	10,000 MMBtu/day	$7.77	IF Centerpoint East
Jan 09 Dec 09	Sell	Natural gas swap	10,000 MMBtu/day	$8.28	IF CP Tenn (Zone 0)

(1) Types of liquids include ethane and propane.

Mid-Stream Segment:

Term	Sell/ Purchase	Commodity	Hedged Volume	Average Fixed Price	Market
Aug 08 Dec 08	Sell	Propane	188,000 Gal/mo	$1.434	OPIS Conway
Aug 08 Dec 08	Purchase	Natural gas swap	17,000 MMBtu/mo	$6.908	IF PEPL

Stock and Incentive Compensation. During 2007, we granted awards covering 616,907 shares of restricted stock. These awards included specific one time retention awards as well as awards which were part of our annual compensation determinations. We also granted awards covering 101,236 shares of stock appreciation rights to certain of our executive officers in 2007. In 2006, 44,665 shares of SARs was granted and in 2005, 38,190 shares of restricted stock was granted. During 2007, we recognized compensation expense of $4.6 million for all of our restricted stock and SARs grants. The 2007 restricted stock awards and SARs had an estimated fair value as of the grant date of $26.3 million. Compensation expense will be recognized over the three year vesting periods, and during 2007, we recognized $2.1 million in additional compensation expense and capitalized $0.5 million for these awards granted. In total for 2007, we recognized stock compensation expense for restricted stock awards, stock options and SARs of $4.8 million and capitalized stock compensation cost for oil and natural gas properties of $1.2 million.

Self-Insurance. We are self-insured for certain losses relating to workers compensation, general liability, property damage, control of well and employee medical benefits. In addition, our insurance policies contain deductibles or retentions per occurrence that range from $0.25 million for Oklahoma workers' compensation, as well as claims under our occupation benefits plan to $1.0 million for general liability and drilling rig physical damage. We have purchased stop-loss coverage in order to limit, to the extent feasible, our per occurrence and aggregate exposure to certain types of claims. However, there is no assurance that the insurance coverage we have will adequately protect us against liability from all potential consequences. If our insurance coverage becomes more expensive, we may choose to decrease our limits and increase our deductibles rather than pay higher premiums. We have elected to use an ERISA governed occupational injury benefit plan to cover the field and support staff for drilling operations in the State of Texas in lieu of covering them under Texas workers compensation.

Oil and Natural Gas Limited Partnerships and Other Entity Relationships. We are the general partner of 13 oil and natural gas partnerships which were formed privately or publicly. Each partnership s revenues and costs are shared under formulas set out in that partnership's agreement. The partnerships repay us for contract drilling, well supervision and general and administrative expense. Related party transactions for contract drilling and well supervision fees are the related party s share of such costs. These costs are billed on the same basis as billings to unrelated third parties for similar services. General and administrative reimbursements consist of direct general and administrative expense incurred on the related party s behalf as well as indirect expenses assigned to the related parties. Allocations are based on the related party s level of activity and are considered by us to be reasonable. During 2007, 2006 and 2005, the total we received for all of these fees was $1.6 million, $1.3 million and $1.0 million, respectively. We expect that these fees for 2008 will be comparable to those in 2007. Our proportionate share of assets, liabilities and net income relating to the oil and natural gas partnerships is included in our consolidated financial statements.

Effects of Inflation

The effect of inflation in the oil and natural gas industry is primarily driven by the prices for oil and natural gas. Increases in these prices increase the demand for our contract drilling rigs and services. This increase in demand in turn affects the dayrates we can obtain for our contract drilling services. Before 1999, the effect of inflation on our operations was minimal due to low inflation rates, relatively low natural gas and oil prices and moderate demand for our contract drilling services. Over the last six years natural gas and oil prices have been more volatile, and during periods of higher demand for our drilling rigs we have experienced increases in labor costs as well as the costs of services to support our drilling rigs. During this same period, when oil, NGLs and natural gas prices did decline, labor rates did not come back down to the levels existing before the increases. If natural gas prices increase substantially for a long period, shortages in support equipment (such as drill pipe, third party services and qualified labor) will result in additional increases in our material and labor costs. Increases in dayrates for drilling rigs also increase the cost of our oil and natural gas properties. With an overall increase in drilling activity throughout the industry, costs for goods and services related to both our oil and natural gas exploration segment, and our mid-stream segment have been increasing. These conditions may limit our ability to realize increases in our operating profits. How inflation will affect us in the future will depend on additional increases, if any, realized in our drilling rig rates, the prices we receive for our oil, NGLs and natural gas and the rates we receive for gathering and processing natural gas.

Off-Balance Sheet Arrangements

We do not currently utilize any off-balance sheet arrangements with unconsolidated entities to enhance liquidity and capital resource positions, or for any other purpose. However, as is customary in the oil and gas industry, we have various contractual commitments.

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Results of Operations

2007 versus 2006

Provided below is a comparison of selected operating and financial data between the years of 2007 and 2006:

	2007	2006	Percent Change
Total revenue	$ 1,158,754,000	$ 1,162,385,000	%
Net income	$ 266,258,000	$ 312,177,000	(15)%
Contract Drilling:			
Revenue	$ 627,642,000	$ 699,396,000	(10)%
Operating costs excluding depreciation	$ 304,780,000	$ 313,882,000	(3)%
Percentage of revenue from daywork contracts	100%	100%	%
Average number of drilling rigs in use	99.4	109.0	(9)%
Average dayrate on daywork contracts	$ 18,663	$ 18,767	(1)%
Depreciation	$ 56,804,000	$ 51,959,000	9%
Oil and Natural Gas:			
Revenue	$ 391,480,000	$ 357,599,000	9%
Operating costs excluding depreciation, depletion and amortization	$ 97,109,000	$ 81,120,000	20%
Average natural gas price (Mcf)	$ 6.30	$ 6.17	2%
Average oil price (Bbl)	$ 70.61	$ 63.39	11%
Average natural gas liquids price (Bbl)	$ 45.03	$ 36.08	25%
Natural gas production (Mcf)	43,464,000	44,169,000	(2)%
Oil production (Bbl)	1,091,000	1,012,000	8%
NGL production (Bbl)	785,000	441,000	78%
Depreciation, depletion and amortization rate (Mcfe)	$ 2.32	$ 2.04	14%
Depreciation, depletion and amortization	$ 127,417,000	$ 108,124,000	18%
Mid-Stream Operations:			
Revenue	$ 138,595,000	$ 101,863,000	36%
Operating costs excluding depreciation and amortization	$ 119,776,000	$ 88,834,000	35%
Depreciation and amortization	$ 11,059,000	$ 6,247,000	77%
Gas gathered MMBtu/day	219,635	247,537	(11)%
Gas processed MMBtu/day	50,350	31,833	58%
Gas liquids sold Gallons/day	129,421	66,902	93%
General and administrative expense	$ 22,036,000	$ 18,690,000	18%
Interest expense	$ 6,362,000	$ 5,273,000	21%
Income tax expense	$ 147,153,000	$ 176,079,000	(16)%
Average interest rate	6.0%	5.9%	2%
Average long-term debt outstanding	$ 170,141,000	$ 135,617,000	25%

Contract Drilling:

Industry demand for our drilling rigs remained strong throughout the first nine months of 2006 before declining in the fourth quarter of 2006. Our utilization rate for 2007 was 80% as our utilization fluctuated slightly above or below the 80% level throughout the last six months of 2007. The reduction in demand for drilling rigs, which started in the fourth quarter of 2006, was primarily the result of the evaluation of the economics of drilling prospects by the operators using our contract drilling services after natural gas prices declined significantly in the last half of the third quarter of 2006. High levels of natural gas storage throughout the majority of the 2006 winter season and again during the summer of 2007 also contributed to reduced demand for drilling rigs. Drilling revenues decreased $71.8 million or 10% in 2007 versus 2006. Average rig utilization declined from 109.0 drilling rigs in 2006 to 99.4 in 2007. The decline in rig utilization decreased drilling revenues by $61.5 million while decreases in revenue per day between the comparative periods decreased revenue by $10.3 million. Our average dayrate in 2007 was 1% lower than in 2006. Our average dayrate in January 2007 was $19,713 and declined steadily throughout the year, averaging $17,945 in December 2007. We anticipate average dayrates to continue to decline through early 2008, with our utilization rate remaining at approximately 80%.

Drilling operating costs decreased $9.1 million or 3% between 2007 and 2006. Operating cost decreased as a result of 9.6 fewer drilling rigs operating between the comparative years and reductions in workers compensation cost. Operating cost increased $509 per day in 2007 when compared with 2006 with $178 per day of the increase resulting from increases in direct drilling cost and $48 per day resulting from $1.8 million of bad debt expense. The remainder of the increase resulted from additional yard, truck and auto expense associated with the acquisition of additional facilities and equipment from our June 2007 rig acquisition and from increases in daily cost for rig maintenance and compensation expense to retain qualified drilling staff. With continued competition for qualified labor and utilization continuing around 80%, we expect our drilling rig expense per day to remain steady or increase slightly in 2008. Contract drilling depreciation increased $4.8 million or 9% as the total number of drilling rigs owned increased between the comparative periods.

Oil and Natural Gas:

Oil and natural gas revenues increased $33.9 million or 9% in 2007 as compared to 2006 due to an increase in equivalent production volumes of 3% and an increase in average oil, NGL and natural gas prices. Average oil prices between the comparative years increased 11% to $70.61 per barrel, NGL prices increased 25% to $45.03 per barrel and natural gas prices increased 2% to $6.30 per Mcf. In 2007, oil production increased 8% and NGL production increased 78% while natural gas production decreased by 2%. Natural gas production increases were limited in the first quarter of 2007 due to adverse weather which slowed the timing for completion of certain wells and pipeline construction delays which prevented the connection of wells that had recently been drilled and completed. Increased oil and NGL production came primarily from our ongoing development drilling activity and from acquisitions completed in 2006. With the continuation of our internal drilling program and our previous acquisitions, our total production for 2008 compared to 2007 is anticipated to increase 8% to 11%. Actual increases in revenues, however, will also be driven by commodity prices received for our production.

Oil and natural gas operating costs increased $16.0 million or 20% in 2007 as compared to 2006. An increase in the average cost per equivalent Mcf produced represented 81% of the increase in operating costs with the remaining 19% of the increase attributable to the increase in volumes produced from both development drilling and producing property acquisitions. Increases in general and administrative expenses directly related to oil and natural gas production, lease operating expenses and gross production taxes contributed to the majority of the operating cost increase. General and administrative expenses increased as labor costs increased primarily due to a 21% increase in the average number of employees working in the exploration and production area. Total depreciation, depletion and amortization (DD&A) increased $19.3 million or 18%. Higher production volumes accounted for 19% of the increase while increases in our DD&A rate represented 81% of the increase. The increase in our DD&A rate in 2007 compared to 2006 resulted primarily from a 10% increase in the cost of Mcf equivalents added to our reserves in 2007 compared to 2006. Increases in natural gas and oil prices over the last two years have also caused increased sales prices for producing property acquisitions and even with the increased sales prices; we continue to see strong competition for producing property acquisitions.

Mid-Stream:

Our mid-stream revenues were $36.7 million or 36% higher in 2007 as compared to 2006 due to the higher NGL volumes sold and processed volumes combined with higher NGL and natural gas prices. The average price for NGLs sold increased 24% and the average price for natural gas sold increased 2%. Gas processing volumes per day increased 58% between the comparative years and NGLs sold per day increased 93% between the comparative years. An 11% decrease in gathering volumes per day partially offset the increase in revenue from natural gas liquids and processing sales. The significant increase in volumes processed per day is primarily attributable to the acquisition of a processing plant in September of 2006 and the installation of three processing plants in 2007 combined to a lesser extent with volumes added from new wells connected to existing systems throughout 2007. NGLs sold volumes per day increased due to recent upgrades to several of our processing facilities. Gas gathering volumes decreased primarily from a decline in volumes gathered from our Southeast Oklahoma gathering system due to natural declines of production in the formation and decreased well connections. NGL sales were reduced $2.1 million due to the impact of NGL hedges.

Operating costs increased $30.9 million or 35% in 2007 compared to 2006 due to a 33% increase in natural gas volumes purchased and a 5% increase in prices paid for natural gas purchased, a 54% increase in field direct operating cost due to the additions to our natural gas gathering and processing systems and the volume of natural gas processed and a 51% increase in general and administrative expenses. The total number of employees working in our mid-stream segment increased by 29%. Depreciation and amortization increased $4.8 million, or 77%, primarily attributable to the additional depreciation and amortization associated with tangible and intangible assets acquired between the comparative periods. Operating costs increased $1.7 million in 2007 over 2006 due to the impact of natural gas purchase hedges.

Other:

General and administrative expense increased $3.3 million or 18% in 2007 compared to 2006. The increase was primarily attributable to increased stock based compensation costs and increased payroll expenses due to a 16% increase in the number of employees added and to a lesser extent an increase in insurance cost.

Total interest expense increased $1.1 million or 21% between the comparative periods. Average debt outstanding was 25% higher in 2007 as compared to 2006 primarily due to the acquisition of producing properties in the last four months of 2006 and the acquisition of a drilling company in the second quarter of 2007. Average debt outstanding accounted for approximately 90% of the interest expense increase, with the remaining 10% resulting from an increase in average interest rates on our bank debt. Interest expense was reduced $0.7 million in 2007 and $0.5 million in 2006 from settlements on our interest rate swap. Associated with our increased level of undeveloped inventory of oil and natural gas properties, the construction of additional drilling rigs and the construction of gas gathering systems, we capitalized $4.6 million of interest in 2007 compared to $3.5 million in 2006.

Income tax expense decreased $28.9 million or 16% due primarily to the decrease in income before income taxes. Our effective tax rate for 2007 was 35.6% versus 36.1% in 2006 with the change due primarily to the increase in manufacturing tax deduction for 2007. The portion of our taxes reflected as current income tax expense for 2007 was $66.6 million or 45% of total income tax expense in 2007 as compared with $112.8 million or 64% of total income tax expense in 2006. The reduction in the percentage of tax expense recognized as current is the result of increased intangible drilling costs to be deducted in the current year. Income taxes paid in 2007 were $73.4 million.

In January 2006, one of our drilling rigs was destroyed by a fire. No personnel were injured although the drilling rig was a total loss. Insurance proceeds for the loss exceeded our net book value and provided a gain of approximately $1.0 million which is recorded in other revenues.

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2006 versus 2005

Provided below is a comparison of selected operating and financial data between the years of 2006 and 2005:

	2006	2005	Percent Change
Total revenue	$ 1,162,385,000	$ 885,608,000	31%
Net income	$ 312,177,000	$ 212,442,000	47%
Contract Drilling:			
Revenue	$ 699,396,000	$ 462,141,000	51%
Operating costs excluding depreciation	$ 313,882,000	$ 266,472,000	18%
Percentage of revenue from daywork contracts	100%	100%	%
Average number of drilling rigs in use	109.0	102.1	7%
Average dayrate on daywork contracts	$ 18,767	$ 12,431	51%
Depreciation	$ 51,959,000	$ 42,876,000	21%
Oil and Natural Gas:			
Revenue	$ 357,599,000	$ 318,208,000	12%
Operating costs excluding depreciation, depletion and amortization	$ 81,120,000	$ 60,779,000	33%
Average natural gas price (Mcf)	$ 6.17	$ 7.64	(19)%
Average oil price (Bbl)	$ 63.39	$ 54.47	16%
Average natural gas liquids price (Bbl)	$ 36.08	$ 34.69	4%
Natural gas production (Mcf)	44,169,000	34,058,000	30%
Oil production (Bbl)	1,012,000	847,000	19%
NGL production (Bbl)	441,000	237,000	86%
Depreciation, depletion and amortization rate (Mcfe)	$ 2.04	$ 1.65	24%
Depreciation, depletion and amortization	$ 108,124,000	$ 67,282,000	61%
Mid-Stream Operations:			
Revenue	$ 101,863,000	$ 100,464,000	1%
Operating costs excluding depreciation and amortization	$ 88,834,000	$ 92,467,000	(4)%
Depreciation and amortization	$ 6,247,000	$ 3,279,000	91%
Gas gathered MMBtu/day	247,537	142,444	74%
Gas processed MMBtu/day	31,833	30,613	4%
Gas liquids sold Gallons/day	66,902	61,665	8%
General and administrative expense	$ 18,690,000	$ 14,343,000	30%
Interest expense	$ 5,273,000	$ 3,437,000	53%
Income tax expense	$ 176,079,000	$ 122,231,000	44%
Average interest rate	5.9%	4.8%	23%
Average long-term debt outstanding	$ 135,617,000	$ 107,161,000	27%

Contract Drilling:

Industry demand for our drilling rigs increased throughout 2005 and remained strong during the first three quarters of 2006 before beginning to soften in the last half of the fourth quarter. Drilling revenues increased $237.3 million or 51% in 2006 versus 2005. During 2005, we added 12 drilling rigs from acquisition and construction and during 2006 we added six drilling rigs primarily through construction and we lost one rig to fire in January 2006. The 17 net additional drilling rigs added during the two years helped increase our 2006 drilling revenues by approximately 27%. The increase in utilization from these additional drilling rigs and the increase in utilization of our previously owned drilling rigs represented 13% of the increase in our drilling revenues while increases in dayrates and mobilization fees accounted for the remaining 87% of the increase. Our average dayrate in 2006 was 51% higher than in 2005.

Drilling operating costs increased $47.4 million or 18% over 2005. Thirty-eight percent of this increase resulted from the net 17 drilling rigs placed in service during 2005 and 2006 and increased utilization of our previously owned drilling rigs, while increases in operating cost per day accounted for the remaining 62% of the increase. Operating cost per day increased $736 in 2006 when compared with 2005. A majority of the increase was attributable to costs directly associated with the drilling of wells with increases in labor cost the primary reason for the increase. Demand for drilling rigs softened in the fourth quarter of 2006 as operators reevaluated their drilling programs in response to the declines in natural gas prices late in the third quarter of 2006. We did not drill any turnkey or footage wells in 2006 and we had one footage well in 2005. Contract drilling depreciation increased $9.1 million or 21%. The addition of the 17 net drilling rigs placed in service during 2005 and 2006 increased depreciation $4.1 million or 10% with the remainder of the increase attributable to the increase in utilization of previously owned drilling rigs.

Oil and Natural Gas:

Our 2006 oil and natural gas revenues increased $39.4 million or 12% as compared to 2005. A 30% increase in equivalent oil, NGL and natural gas volumes along with increased oil and NGL prices accounted for the increase while a decrease in natural gas prices partially offset the increase. Average oil prices between the comparative years increased 16% to $63.39 per barrel and NGL prices increased 4% to $36.08 per barrel while natural gas prices declined 19% to $6.17 per Mcf. In 2006, natural gas production increased 30% while oil production increased 19% and NGL production increased 86%. The increase in oil, NGL and natural gas production came primarily from our ongoing development drilling activity, the two acquisitions completed in 2005 and from the two acquisitions completed in 2006.

Oil and natural gas operating costs increased $20.3 million or 33% in 2006 as compared to 2005. An increase in the average cost per equivalent Mcf produced represented 20% of the increase with the remaining 80% attributable to the increase in volumes produced from both development drilling and producing property acquisitions. Lease operating expenses represented 74% of the increase, gross production taxes 12%, general and administrative cost directly related to oil and natural gas production 12%, and accretion in plugging liability 2%. Lease operating expenses per Mcfe increased 18% between the comparative years. Workover expenses represented 4% of the increase of lease operating expenses while the remaining 96% was primarily due to increases in the cost of goods and services and the 242 net wells added from acquisitions and drilling in 2006. Gross production taxes increased due to the increase in natural gas and oil volumes produced and the increase in oil prices between the comparative years partially offset by decreases in natural gas prices. General and administrative cost increased primarily from a 14% increase in the number of our employees. Total DD&A on our oil and natural gas properties increased $40.8 million or 61%. Higher production volumes contributed to 50% of the increase and increases in the DD&A rate represented the other 50% of the increase. The increase in the DD&A rate in 2006 as compared to 2005, resulted from an 18% higher overall finding cost per equivalent Mcf.

Mid-Stream:

Our mid-stream revenues were $1.4 million higher in 2006 versus 2005 due to the higher volumes transported offset by lower natural gas prices on volumes sold. Gas gathering volumes per day in 2006 were 74% higher as compared to 2005 while gas processing volumes per day increased 4%. The significant increase in volumes gathered per day is primarily attributable to one natural gas gathering system that gathered 141,645 MMBtu and 68,297 MMBtu per day during 2006 and 2005, respectively. One of our largest gathering systems changed pipeline outlets between the comparative periods and the new outlet accepted the delivered natural gas unprocessed, which offset most of the increase we had in processed natural gas between the years. Operating costs decreased 4% in 2006 compared with 2005 due a 19% decrease in prices paid for natural gas purchased. The decrease in natural gas purchases was partially offset by an 87% increase in field direct operating cost due to the growth in our natural gas gathering systems and the volume of natural gas transported. The 91% increase in depreciation and amortization in our mid-stream segment came from the additional depreciation associated with tangible assets acquired during the comparative periods and the $0.9 million amortization of intangible assets associated with the acquisition of Berkshire Energy, LLC.

Other:

General and administrative expense in 2006 increased $4.3 million or 30%. The increase was primarily from increases in the number of employees associated with the growth of the company and $1.7 million of additional expense incurred after the implementation of Financial Accounting Standards (FAS) No. 123(R) Share-Based Payment which requires the recognition of expense related to the value of stock options and restricted stock granted over their vesting period.

Total interest expense increased 53% between the comparative years. Our average debt outstanding was higher in 2006 as compared to 2005 because of the capital expenditures made in the fourth quarter of 2005 and throughout 2006. The increase in interest rates accounted for 54% of the interest expense increase while the increase in average debt outstanding accounted for approximately 46% of the increase. Settlements of our interest rate swap partially offset the increase in our bank interest rate. Associated with our increased level of development of our oil and natural gas properties and the construction of additional drilling rigs and natural gas gathering systems, we capitalized $3.5 million of interest in 2006 compared to $2.2 million in 2005.

Our 2006 income tax expense increased $53.9 million or 44% over 2005 due primarily to our increase in income before income taxes. Our effective tax rate for 2006 was 36.1% versus 36.5% in 2005. The decrease in the effective tax rate resulted primarily from decreased state tax expense associated with increased operations in states with lower income tax rates. As a result of the increase in our pre-tax income and the prior use of our net operating loss carryforwards, the portion of our taxes reflected as current income tax expense increased in 2006 when compared with 2005. Current income tax expense for 2006 and 2005 was $112.8 million and $64.6 million, respectively.

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

Our operations are exposed to market risks primarily as a result of changes in the prices for natural gas and oil and interest rates.

Commodity Price Risk. Our major market risk exposure is in the prices we receive for our oil, NGLs and natural gas production. The prices we receive are primarily driven by the prevailing worldwide price for crude oil and market prices applicable to our natural gas production. Historically, these prices have fluctuated and we expect these prices to continue to fluctuate. The price of oil, NGLs and natural gas also affects both the demand for our drilling rigs and the amount we can charge for the use of our drilling rigs. Based on our 2007 production, a $0.10 per Mcf change in what we are paid for our natural gas production would result in a corresponding $339,000 per month ($4.1 million annualized) change in our pre-tax cash flow. A $1.00 per barrel change in our oil price would have an $85,000 per month ($1.0 million annualized) change in our pre-tax operating cash flow and a $1.00 per barrel change in our NGLs prices would have a $61,000 per month ($0.7 million annualized) change in our pre-tax cash flow.

In an effort to try and reduce the impact of price fluctuations, over the past several years we have periodically used hedging strategies to hedge the price we will receive for a portion of our future oil, NGLs and natural gas production. A detailed explanation of those transactions has been included under Hedging Activities in the financial condition portion of Management s Discussion and Analysis of Financial Condition and Results of Operations included above.

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In an effort to try and reduce the impact of price fluctuations received for natural gas liquids, we entered into a series of natural gas liquid sales and natural gas purchase swaps to effectively lock in the fractionation spread we receive on a portion of our liquids processed and sold. A detailed explanation of those transactions has been included under Hedging Activities in the financial condition portion of Management s Discussion and Analysis of Financial Condition and Results of Operations included above.

Interest Rate Risk. Our interest rate exposure relates to our long-term debt, all of which bears interest at variable rates based on the BOKF National Prime Rate or the LIBOR Rate. At our election, borrowings under our revolving credit facility may be fixed at the LIBOR Rate for periods of up to 180 days. In February 2005, we entered into an interest rate swap for $50.0 million of our outstanding debt to help manage our exposure to any future interest rate volatility. In October 2007 and again in November 2007 we entered into additional interest rate swaps of $15.0 million each. A detailed explanation of these transactions has been included under Hedging Activities in the financial condition portion of Management s Discussion and Analysis of Financial Condition and Results of Operations included above. Based on our average outstanding long-term debt subject to the floating rate in 2007, a 1% change in the floating rate would affect our annual pre-tax cash flow by approximately $0.9 million.

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

Index to Financial Statements

Unit Corporation and Subsidiaries

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Management s Report on Internal Control over Financial Reporting

Management of the company is responsible for establishing and maintaining adequate internal control over financial reporting. Internal control over financial reporting is defined in Rules 13a-15(f) or 15d-15(f) promulgated under the Securities Exchange Act of 1934 as a process designed by, or under the supervision of, the company s principal executive and principal financial officers and effected by the company s board of directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles and includes those policies and procedures that:

- Pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of the assets of the company;

- Provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and

- Provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the company s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate. Internal control over financial reporting cannot provide absolute assurance of achieving financial reporting objectives because of its inherent limitations. Internal control over financial reporting is a process that involves human diligence and compliance and is subject to lapses in judgment and breakdowns resulting from human failures. Internal control over financial reporting also can be circumvented by collusion or improper management override. Because of such limitations, there is a risk that material misstatements may not be prevented or detected on a timely basis by internal control over financial reporting. However, these inherent limitations are known features of the financial reporting process. Therefore, it is possible to design into the process safeguards to reduce, though not eliminate, this risk.

The company s management assessed the effectiveness of the company s internal control over financial reporting as of December 31, 2007. In making this assessment, the company s management used the criteria set forth in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on their assessment, the company's management concluded that, as of December 31, 2007, the company s internal control over financial reporting was effective based on those criteria.

The effectiveness of the company's internal control over financial reporting as of December 31, 2007, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

Report of Independent Registered Public Accounting Firm

To Board of Directors and Shareholders of

Unit Corporation:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, changes in shareholders' equity, and cash flows present fairly, in all material respects, the financial position of Unit Corporation and its subsidiaries at December 31, 2007 and 2006, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2007, in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the accompanying index appearing under item 15(a)(2), presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company's internal control over financial reporting based on our integrated 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 audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included 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. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company s internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

PricewaterhouseCoopers LLP

Tulsa, Oklahoma

February 28, 2008

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UNIT CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	As of December 31, 2007	2006
	(In thousands except share amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,076	$ 589
Restricted cash	19	18
Accounts receivable (less allowance for doubtful accounts of $3,350 and $1,600)	159,455	200,415
Materials and supplies	13,558	18,901
Prepaid expenses and other	22,907	13,017
Total current assets	197,015	232,940
Property and equipment:		
Drilling equipment	987,184	781,190
Oil and natural gas properties, on the full cost method:		
Proved properties	1,624,478	1,330,010
Undeveloped leasehold not being amortized	64,722	53,687
Gas gathering and processing equipment	119,515	85,339
Transportation equipment	23,240	20,749
Other	19,974	17,082
	2,839,113	2,288,057
Less accumulated depreciation, depletion, amortization and impairment	927,759	735,394
Net property and equipment	1,911,354	1,552,663
Goodwill	62,808	57,524
Other intangible assets, net	13,798	17,087
Other assets	14,844	13,882
Total assets	$ 2,199,819	$ 1,874,096
LIABILITIES AND SHAREHOLDERS EQUITY		
Current liabilities:		
Accounts payable	$ 100,258	$ 92,125
Accrued liabilities	40,508	52,166
Income taxes payable		2,956
Contract advances	6,825	5,061
Current portion of other long-term liabilities (Note 5)	8,813	8,634
Total current liabilities	156,404	160,942
Long-term debt (Note 5)	120,600	174,300
Other long-term liabilities (Note 5)	59,115	55,741

Deferred income taxes (Note 7)	428,883	325,077
Commitments and contingencies (Note 13)		
Shareholders equity:		
Preferred stock, $1.00 par value, 5,000,000 shares authorized, none issued		
Common stock, $.20 par value, 175,000,000 shares authorized, 47,035,089 and 46,283,990 shares issued, respectively	9,280	9,257
Capital in excess of par value	344,512	333,833
Accumulated other comprehensive income (net of tax of $662 and $789, respectively)	1,160	1,339
Retained earnings	1,079,865	813,607
Total shareholders equity	1,434,817	1,158,036
Total liabilities and shareholders equity	$ 2,199,819	$ 1,874,096

The accompanying notes are an integral part of the consolidated financial statements.

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UNIT CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME

	Year Ended December 31, 2007	2006	2005
	(In thousands except per share amounts)		
Revenues:			
Contract drilling	$ 627,642	$ 699,396	$ 462,141
Oil and natural gas	391,480	357,599	318,208
Gas gathering and processing	138,595	101,863	100,464
Other	1,037	3,527	4,795
Total revenues	1,158,754	1,162,385	885,608
Expenses:			
Contract drilling:			
Operating costs	304,780	313,882	266,472
Depreciation	56,804	51,959	42,876
Oil and natural gas:			
Operating costs	97,109	81,120	60,779
Depreciation, depletion and amortization	127,417	108,124	67,282
Gas gathering and processing:			
Operating costs	119,776	88,834	92,467
Depreciation and amortization	11,059	6,247	3,279
General and administrative	22,036	18,690	14,343
Interest	6,362	5,273	3,437
Total expenses	745,343	674,129	550,935
Income before income taxes	413,411	488,256	334,673
Income tax expense:			
Current	66,642	112,812	64,565
Deferred	80,511	63,267	57,666
Total income taxes	147,153	176,079	122,231
Net income	$ 266,258	$ 312,177	$ 212,442
Net income per common share:			
Basic	$ 5.74	$ 6.75	$ 4.62
Diluted	$ 5.71	$ 6.72	$ 4.60

The accompanying notes are an integral part of the consolidated financial statements.

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UNIT CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS EQUITY

Year Ended December 31, 2005, 2006 and 2007

	Common Stock	Capital In Excess of Par Value	Accumulated Other Comprehensive Income	Unearned Compensation - Restricted Stock	Retained Earnings	Total
	(In thousands except share and per share amounts)					
Balances, January 1, 2005	$ 9,149	$ 310,132	$	$	$ 288,988	$ 608,269
Comprehensive income:						
Net Income					212,442	212,442
Other comprehensive income (net of tax of $1,610 and $1,899):						
Change in value of cash flow derivative instruments used as cash flow hedges			(3,072)			(3,072)
Adjustment reclassification derivative settlements			3,557			3,557
Total comprehensive income						212,927
Activity in employee compensation plans (186,710 shares)	38	5,954		(2,226)		3,766
Issuance of 246,053 shares of common stock for acquisition	49	11,951				12,000
Balances, December 31, 2005	9,236	328,037	485	(2,226)	501,430	836,962
Comprehensive income:						
Net Income					312,177	312,177
Other comprehensive income (net of tax of $202 and $701):						
Change in value of cash flow derivative instruments used as cash flow hedges			1,188			1,188
Adjustment reclassification derivative settlements			(334)			(334)
Total comprehensive income						313,031
Activity in employee compensation plans (105,217 shares)	21	5,796		2,226		8,043
Balances, December 31, 2006	9,257	333,833	1,339		813,607	1,158,036
Comprehensive income:						
Net Income					266,258	266,258
Other comprehensive income (net of tax of $268 and $191):						
Change in value of cash flow derivative instruments used as cash flow hedges			(438)			(438)
Adjustment reclassification derivative settlements			259			259
Total comprehensive income						266,079
Activity in employee compensation plans (728,228 shares)	23	10,679				10,702
Balances, December 31, 2007	$ 9,280	$ 344,512	$ 1,160	$	$ 1,079,865	$ 1,434,817

The accompanying notes are an integral part of the consolidated financial statements.

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UNIT CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31, 2007	2006	2005
	(In thousands)		
OPERATING ACTIVITIES:			
Net income	$ 266,258	$ 312,177	$ 212,442
Adjustments to reconcile net income to net cash provided (used) by operating activities:			
Depreciation, depletion and amortization	196,111	167,066	114,294
Gain on disposition of assets	(185)	(1,275)	(2,655)
Deferred tax expense	80,511	63,267	57,666
Employee stock compensation plans	9,254	6,785	3,488
Bad debt expense	1,750		
Plugging liability accretion	1,704	1,492	953
Other, net	(92)	30	
Changes in operating assets and liabilities increasing (decreasing) cash:			
Accounts receivable	39,042	7,233	(106,585)
Materials and supplies	5,343	(4,793)	(1,054)
Prepaid expenses and other	(6,926)	(2,128)	(954)
Accounts payable	(7,296)	(32,577)	15,897
Accrued liabilities	(9,667)	(10,012)	21,056
Contract advances	1,764	(563)	3,223
Net cash provided by operating activities	577,571	506,702	317,771
INVESTING ACTIVITIES:			
Capital expenditures	(478,950)	(423,428)	(254,450)
Producing property and other acquisitions	(38,500)	(122,915)	(136,413)
Proceeds from disposition of property and equipment	5,309	6,796	8,722
Acquisition of other assets	(192)	(1,176)	(2,855)
Net cash used in investing activities	(512,333)	(540,723)	(384,996)
FINANCING ACTIVITIES:			
Borrowings under line of credit	175,800	287,300	268,200
Payments under line of credit	(229,500)	(258,000)	(218,700)
Net payments on notes payable and other long-term debt			273
Proceeds from exercise of stock options	692	803	1,201
Tax benefit from stock options	267	532	
Book overdrafts (Note 2)	(12,010)	3,028	16,533
Net cash provided by (used in) financing activities	(64,751)	33,663	67,507
Net increase (decrease) in cash and cash equivalents	487	(358)	282
Cash and cash equivalents, beginning of year	589	947	665
Cash and cash equivalents, end of year	$ 1,076	$ 589	$ 947
Supplemental disclosure of cash flow information:			
Cash paid during the year for:			
Interest paid (net of capitalized)	$ 7,135	$ 5,678	$ 2,586
Income taxes	$ 73,417	$ 125,144	$ 47,276

See Note 3 for non-cash financing and investing activities.

The accompanying notes are an integral part of the consolidated financial statements.

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UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 ORGANIZATION

Unless the context clearly indicates otherwise, references in this report to Unit , company , we , our us or like terms refer to Unit Corporation a its subsidiaries.

We are primarily engaged in the land contract drilling of natural gas and oil wells, the exploration, development, acquisition and production of oil and natural gas properties and the buying, selling, gathering, processing and treating of natural gas. Our operations are located principally in the United States and are organized in the following three reporting segments: (1) Contract Drilling, (2) Oil and Natural Gas and (3) Mid-Stream.

Contract Drilling. Carried out by our subsidiary, Unit Drilling Company and its subsidiaries, we contract to drill onshore oil and natural gas wells for our own account and for others. Our current contract drilling operations are conducted in the natural gas producing provinces of the Oklahoma and Texas areas of the Anadarko and Arkoma Basins, the Texas Gulf Coast, the North Texas Barnett Shale and the Rocky Mountain regions. We provide land contract drilling services for a wide range of customers.

Oil and Natural Gas. Carried out by our subsidiary, Unit Petroleum Company, we explore, develop, acquire and produce oil and natural gas properties for our own account. Our primary exploration and production operations are conducted in the Anadarko and Arkoma Basins and in the Texas Gulf Coast area with additional properties in the Permian Basin. The majority of our contract drilling and exploration and production activities are oriented toward drilling for and producing natural gas.

Mid-Stream. Through our subsidiary, Superior Pipeline Company, L.L.C., we buy, sell, gather, process and treat natural gas for our own account and for third parties. Mid-Stream operations are performed in Oklahoma, Texas, Louisiana and Kansas.

NOTE 2 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Principles of Consolidation. The consolidated financial statements include the accounts of Unit Corporation and its subsidiaries. Our investment in limited partnerships is accounted for on the proportionate consolidation method, whereby our share of the partnerships assets, liabilities, revenues and expenses are included in the appropriate classification in the accompanying consolidated financial statements.

Certain amounts in the accompanying consolidated financial statements for prior periods have been reclassified to conform to current year presentation.

Accounting Estimates. he preparation of financial statements in conformity with generally accepted accounting principles (GAAP) requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Drilling Contracts. We recognize revenues and expenses generated from daywork drilling contracts as the services are performed, since we do not bear the risk of completion of the well. Under footage and turnkey contracts, we bear the risk of completion of the well; therefore, revenues and expenses are recognized when the well is substantially completed. Under this method, substantial completion is determined when the well bore reaches the negotiated depth as stated in the contract. The entire amount of a loss, if any, is recorded when the loss is determinable. The costs of uncompleted drilling contracts include expenses incurred to date on footage or turnkey contracts, which are still in process at the end of the period, and are included in other

UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

current assets. Typically, all three types of contracts are for this drilling of one well which can take from 20 to 90 days. At December 31, 2007, 26 of our daywork contracts were multi-well and had durations which ranged from 6 months to two years. These longer term contracts may contain a fixed rate for the duration of the contract or provide for the periodic renegotiation of the rate within a specific range from the existing rate.

Cash Equivalents and Book Overdrafts. We include as cash equivalents all investments with maturities at date of purchase of three months or less which are readily convertible into known amounts of cash. Book overdrafts are checks that have been issued before the end of the period, but not presented to our bank for payment before the end of the period. At December 31, 2007 and 2006, book overdrafts of $15.6 million and $27.7 million were included in accounts payable.

Accounts Receivable. Accounts receivable are carried on a gross basis, with no discounting, less an allowance for doubtful accounts. No allowance for doubtful accounts is recognized at the time the revenue which generates the accounts receivable is recognized. We estimate the allowance for doubtful accounts based on existing economic conditions, the financial condition of our customers, and the amount and age of past due accounts. Receivables are considered past due if full payment is not received by the contractual due date. Past due accounts are generally written off against the allowance for doubtful accounts only after all collection attempts have been unsuccessful.

Financial Instruments and Concentrations of Credit Risk. Financial instruments, which potentially subject us to concentrations of credit risk, consist primarily of trade receivables with a variety of oil and natural gas companies. We do not generally require collateral related to receivables. Our credit risk is considered to be limited due to the large number of customers comprising our customer base. During 2007, Questar Corporation was our largest drilling customer and accounted for approximately 13% of our total contract drilling revenues, Eagle Energy Partners I, L.P. accounted for approximately 12% of our oil and natural gas revenues and ONEOK and Murphy Oil USA, Inc. accounted for approximately 82% and 10% of our mid-stream revenues, respectively. During 2006, Chesapeake Operating, Inc. was our largest drilling customer and accounted for approximately 10% of our total contract drilling revenues. During 2006, Eagle Energy Partners I, L.P., ONEOK and ConocoPhillips Company accounted for approximately 17%, 16% and 10% of our oil and natural gas revenues, respectively. During 2006, ONEOK accounted for approximately 77% of our mid-stream revenues. For 2005, Eagle Energy Partners I, L.P. accounted for approximately 31% of our oil and natural gas revenues and ONEOK and Duke Energy Corporation accounted for approximately 54% and 36% of our mid-stream revenues, respectively. We had a concentration of cash of $14.4 million and $4.3 million at December 31, 2007 and 2006, respectively with one bank.

Property and Equipment. Drilling equipment, natural gas gathering and processing equipment, transportation equipment and other property and equipment are carried at cost. Renewals and improvements are capitalized while repairs and maintenance are expensed. Depreciation of drilling equipment is recorded using the units-of-production method based on estimated useful lives starting at 15 years, including a minimum provision of 20% of the active rate when the equipment is idle. We use the composite method of depreciation for drill pipe and collars and calculate the depreciation by footage actually drilled compared to total estimated remaining footage. Depreciation of other property and equipment is computed using the straight-line method over the estimated useful lives of the assets ranging from 3 to 15 years.

Realization of the carrying value of property and equipment is reviewed for possible impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. Assets are determined to be impaired if a forecast of undiscounted estimated future net operating cash flows directly related to the asset including disposal value if any, is less than the carrying amount of the asset. If any asset is determined to be impaired, the loss is measured as the amount by which the carrying amount of the asset exceeds

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UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

its fair value. An estimate of fair value is based on the best information available, including prices for similar assets. Changes in such estimates could cause us to reduce the carrying value of property and equipment.

When property and equipment components are disposed of, the cost and the related accumulated depreciation are removed from the accounts and any resulting gain or loss is generally reflected in operations. For dispositions of drill pipe and drill collars, an average cost for the appropriate feet of drill pipe and drill collars is removed from the asset account and charged to accumulated depreciation and proceeds, if any, are credited to accumulated depreciation.

We record an asset and a liability equal to the present value of the expected future asset retirement obligation (ARO) associated with our oil and gas properties. The ARO asset is depreciated in a manner consistent with the depreciation of the underlying physical asset. We measure changes in the liability due to passage of time by applying an interest method of allocation. This amount is recognized as an increase in the carrying amount of the liability and as a corresponding accretion expense.

Goodwill. Goodwill represents the excess of the cost of acquisitions over the fair value of the net assets acquired. Goodwill is not amortized, but an impairment test is performed at least annually to determine whether the fair value has decreased. Goodwill is all related to our contract drilling segment. In 2005, the carrying amount of goodwill increased by $9.1 million resulting from the $1.1 million of goodwill acquired in the acquisition of a subsidiary of Strata Drilling, L.L.C., $7.6 million for the 2005 earn-out as provided for in the purchase agreement relating to the SerDrilco Incorporated acquisition and a $0.4 million adjustment to the Sauer Drilling Company purchase price. In 2006, the carrying amount of goodwill increased by $17.9 million from additional goodwill recorded for the final earn-out due under the SerDrilco Incorporated acquisition. In 2007, we added goodwill of $5.3 million as a result of the acquisition which closed on June 5, 2007. All of these acquisitions are more fully discussed in Note 3. Goodwill of $9.2 million is deductible for tax purposes.

Intangible Assets. Intangible assets are capitalized and amortized over the estimated period benefited. Such amounts are reviewed for possible impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. Amortization of $3.3 million and $0.9 million was recorded in 2007 and 2006, respectively. Amortization of $4.4 million, $3.8 million, $2.6 million, $1.2 million and $1.2 million is expected to be recorded in 2008, 2009, 2010, 2011 and 2012, respectively.

Oil and Natural Gas Operations. We account for our oil and natural gas exploration and development activities on the full cost method of accounting prescribed by the SEC. Accordingly, all productive and non-productive costs incurred in connection with the acquisition, exploration and development of oil, NGLs and natural gas reserves are capitalized and amortized on a composite units-of-production method based on proved oil and natural gas reserves. All costs associated with acquisition, exploration and development of oil, NGLs and natural gas reserves, including directly related overhead costs and related asset retirement costs, are capitalized. Directly related overhead costs of $13.1 million, $10.2 million and $7.0 million were capitalized in 2007, 2006 and 2005, respectively. Independent petroleum engineers annually audit Unit s determination of its oil, NGLs and natural gas reserves. The average composite rates used for depreciation, depletion and amortization (DD&A) were $2.32, $2.04 and $1.65 per Mcfe in 2007, 2006 and 2005, respectively. The calculation of DD&A includes estimated future expenditures to be incurred in developing proved reserves and estimated dismantlement and abandonment costs, net of estimated salvage values. Our unproved properties totaling $64.7 million are excluded from the DD&A calculation. In the event the unamortized cost of oil and natural gas properties being amortized exceeds the full cost ceiling, as defined by the SEC, the excess is charged to expense in the period during which such excess occurs. The full cost ceiling is based principally on the estimated future discounted net cash flows from our oil and natural gas properties. As discussed in Supplemental Information, these estimates are imprecise.

UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

No gains or losses are recognized on the sale, conveyance or other disposition of oil and natural gas properties unless a significant reserve amount is involved.

Revenue from the sale of oil and natural gas is recognized when title passes, net of royalties.

Our contract drilling segment provides drilling services for our exploration and production segment. The contracts for these services are issued under the same conditions and rates as the contracts entered into with unrelated third parties. During 2007, the contract drilling segment drilled 77 wells for our exploration and production segment. As required by the SEC, the profit received by the contract drilling segment of $22.7 million, $22.2 million and $8.6 million during 2007, 2006 and 2005, respectively, was used to reduce the carrying value of our oil and natural gas properties rather than being included in its operating profit.

Gas Gathering and Processing Revenue. Our gathering and processing segment recognizes revenue from the gathering and processing of natural gas and NGLs in the period the service is provided based on contractual terms.

Self Insurance. We are self-insured for certain losses relating to workers compensation, general liability, property damage, control of well and employee medical benefits. In addition, our insurance policies contain deductibles or retentions per occurrence that range from $0.25 million for Oklahoma workers' compensation, as well as claims under our occupation benefit plans, to $1.0 million for general liability and drilling rig physical damage. We have purchased stop-loss coverage in order to limit, to the extent feasible, per occurrence and aggregate exposure to certain types of claims. However, there is no assurance that the insurance coverage we have will adequately protect it against liability from all potential consequences. If insurance coverage becomes more expensive, we may choose to decrease our limits and increase our deductibles rather than pay higher premiums. Following the acquisition of SerDrilco Incorporated and the creation of Unit Texas Drilling, L.L.C., we have elected to use an ERISA governed occupational injury benefit plan to cover the field and support staff for drilling operations in the State of Texas in lieu of covering them under Texas workers compensation.

Treasury Stock. We did not own any treasury stock at December 31, 2007, 2006 and 2005.

Hedging Activities. On January 1, 2001, we adopted Statement of Financial Accounting Standard No. 133 (subsequently amended by Financial Accounting Standard No. s 137, 138 and 149), Accounting for Derivative Instruments and Hedging Activities (FAS 133). This statement requires all derivatives to be recognized on the balance sheet and measured at fair value. If a derivative is designated as a cash flow hedge, we are required to measure the effectiveness of the hedge, or the degree that the gain (loss) for the hedging instrument offsets the loss (gain) on the hedged item, at each reporting period. The effective portion of the gain (loss) on the derivative instrument is recognized in other comprehensive income as a component of equity and subsequently reclassified into earnings when the forecasted transaction affects earnings. The ineffective portion of a derivative s change in fair value is required to be recognized in earnings immediately. Derivatives that do not qualify for hedge treatment under FAS 133 must be recorded at fair value with gains (losses) recognized in earnings in the period of change.

We document our risk management strategy and hedge effectiveness at the inception of and during the term of each hedge.

Limited Partnerships. Unit Petroleum Company, is a general partner in 13 oil and natural gas limited partnerships sold privately and publicly. Some of our officers, directors and employees own the interests in most of these partnerships. We share in each partnership s revenues and costs in accordance with formulas set out in each of the limited partnership agreement. The partnerships also reimburse us for certain administrative costs incurred on behalf of the partnerships.

UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Income Taxes. Measurement of current and deferred income tax liabilities and assets is based on provisions of enacted tax law; the effects of future changes in tax laws or rates are not included in the measurement. Valuation allowances are established where necessary to reduce deferred tax assets to the amount expected to be realized. Income tax expense is the tax payable for the year and the change during that year in deferred tax assets and liabilities.

In June 2006, the Financial Accounting Standards Board (FASB) issued FASB Interpretation No. 48 (FIN 48), Accounting for Uncertainty in Income Taxes, an Interpretation of FASB Statement No. 109. FIN 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise s financial statements in accordance with FAS No. 109, Accounting for Income Taxes and prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a return. Guidance is also provided on de-recognition, classification, interest and penalties, accounting in interim periods, disclosure and transition. We adopted the provisions of FIN 48 effective January 1, 2007. We have no unrecognized tax benefits and the adoption of FIN 48 had no effect on our results of operations or financial condition and we do not expect any significant changes in unrecognized tax benefits in the next twelve months. In the third quarter of 2007, the Internal Revenue Service completed its review of our 2004 federal tax return and no adjustments to the return were assessed.

Natural Gas Balancing. We use the sales method for recording natural gas sales. This method allows for recognition of revenue, which may be more or less than its share of pro-rata production from certain wells. We estimate our December 31, 2007 balancing position to be approximately 3.7 Bcf on under-produced properties and approximately 3.6 Bcf on over-produced properties. We have recorded a receivable of $0.8 million on certain wells where we estimate that insufficient reserves are available for us to recover the under-production from future production volumes. We have also recorded a liability of $3.4 million on certain properties where we believe there are insufficient reserves available to allow the under-produced owners to recover their under-production from future production volumes. Our policy is to expense the pro-rata share of lease operating costs from all wells as incurred. Such expenses relating to the balancing position on wells in which we have imbalances are not material.

Employee and Director Stock Based Compensation. Before January 1, 2006, we accounted for our stock-based compensation plans under the recognition and measurement principles of APB 25, Accounting for Stock Issued to Employees, and related Interpretations. Under APB 25, no stock-based employee compensation cost related to stock options was reflected in net income, since all options granted under the plans had an exercise price equal to the market value of the underlying common stock on the date of grant.

On January 1, 2006, we adopted Statement of Financial Accounting Standards No. 123 (revised 2004), *Share-Based Payment*, (FAS 123(R)) to account for stock-based employee compensation. Among other items, FAS 123(R) eliminates the use of APB Opinion No. 25 and the intrinsic value method of accounting for equity compensation and requires companies to recognize the cost of employee services received in exchange for awards of equity instruments based on the grant date fair value of those awards in their financial statements. We elected to use the modified prospective method for adoption, which requires compensation expense to be recorded for all unvested stock options and other equity-based compensation beginning in the first quarter of adoption. Financial statements for prior periods have not been restated. On adoption of FAS 123(R), we elected to use the short-cut method to calculate the historical pool of windfall tax benefits in accordance with Financial Accounting Staff Position No. FAS 123(R)-3, Transition Election to Accounting for the Tax Effects of Share-Based Payment Awards , issued on November 10, 2005. For all unvested options outstanding as of January 1, 2006, the previously measured but unrecognized compensation expense, based on the fair value at the original grant date, will be recognized in the financial statements over the remaining vesting period. For equity-based compensation awards granted or modified after December 31, 2005, compensation expense, based on the fair

UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

value on the date of grant or modification, will be recognized in the financial statements over the vesting period. To the extent compensation cost relates to employees directly involved in oil and natural gas acquisition, exploration and development activities, these amounts are capitalized to oil and natural gas properties. Amounts not capitalized to oil and natural gas properties are recognized in general and administrative expense and operating costs of our business segments. We utilize the Black-Scholes option pricing model to measure the fair value of stock options and stock appreciation rights. The value of restricted stock grants is based on the closing stock price on the date of the grant.

Any unearned compensation recorded under APB 25 related to stock-based compensation awards is required to be eliminated against the appropriate equity accounts. As a result, with the adoption of FAS 123(R) we eliminated $2.2 million of unearned compensation cost associated with grants of restricted stock and reduced additional paid-in capital by the same amount on the condensed consolidated balance sheet. FAS 123(R) requires cash inflows resulting from tax deductions in excess of compensation expense recognized for stock-based compensation to be classified as financing cash inflows in our statements of cash flows. Accordingly, for the years ended December 31, 2007 and 2006, we recorded $0.3 million and $0.5 million, respectively, of tax benefits from stock based compensation as provided by financing activities.

The following table illustrates the effect on net income and earnings per share if we had applied the fair value recognition provisions of FAS 123(R) to stock-based employee compensation before January 1, 2006. Compensation expense included in reported net income before January 1, 2006 is our matching 401(k) contribution.

	2005 (In thousands except per share amounts)
Net income, as reported	$ 212,442
Add stock-based employee compensation expense included in reported net income, net of tax	1,923
Less total stock-based employee compensation expense determined under fair value based method for all awards	(3,989)
Pro forma net income	$ 210,376
Basic earnings per share:	
As reported	$ 4.62
Pro forma	$ 4.58
Diluted earnings per share:	
As reported	$ 4.60
Pro forma	$ 4.55

In 2007 and 2006, we recognized stock compensation expense for restricted stock awards, stock options and stock settled stock appreciation rights (SARs) of $4.8 million and $3.1 million, respectively, and capitalized stock compensation cost for oil and natural gas properties of $1.2 million and $0.7 million, respectively. The tax benefit related to this stock based compensation was $2.1 million and $0.9 million, respectively. The remaining unrecognized compensation cost related to unvested awards at December 31, 2007 is approximately $27.3 million with $6.4 million of this amount anticipated to be capitalized. The weighted average period of time over which this cost will be recognized is 1.2 years.

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UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Impact of Financial Accounting Pronouncements. In September 2006, the FASB issued Statement No. 157 (FAS 157), Fair Value Measurements, which establishes a framework for measuring fair value and requires additional disclosures about fair value measurements. Beginning January 1, 2008, we partially applied FAS 157 as allowed by FASB Staff Position (FSP) 157-2, which delayed the effective date of FAS 157 for nonfinancial assets and liabilities. As of January 1, 2008, we have applied the provisions of FAS 157 to our financial instruments and the impact was not material. Under FSP 157-2, we will be required to apply FAS 157 to our nonfinancial assets and liabilities beginning January 1, 2009. We are currently reviewing the applicability of FAS 157 to our nonfinancial assets and liabilities as well as the potential impact on our consolidated financial statements.

In February 2007, the FASB issued Statement No. 159 (FAS 159), The Fair Value Option for Financial Assets and Financial Liabilities Including an amendment of FASB Statement No. 115, which permits entities to choose to measure many financial instruments and certain other items at fair value at specified election dates. A business entity is required to report unrealized gains and losses on items for which the fair value option has been elected in earnings at each subsequent reporting date. This statement is expected to expand the use of fair value measurement. FAS 159 is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years, and is applicable beginning in the first quarter of 2008. We do not believe the impact of FAS 159 will have a material effect on our consolidated financial statements.

In December 2007, the FASB issued Statement No. 141R (FAS 141R), Business Combinations, which will require most identifiable assets, liabilities, noncontrolling interest (previously referred to as minority interests) and goodwill acquired in a business combination to be recorded at full fair value. FAS 141R is effective for our year beginning January 1, 2009, and will be applied prospectively. We are currently reviewing the applicability of FAS 141R to our operations and its potential impact on our consolidated financial statements.

In December 2007, the FASB issued Statement No. 160 (FAS 160), Noncontrolling Interest in Consolidated Financial Statements an amendment to ARB No. 51, which requires noncontrolling interests (previously referred to as minority interests) to be reported as a component of equity. FAS 160 is effective for our year beginning January 1, 2009, and will require retroactive adoption of the presentation and disclosure requirements for existing minority interests. We are currently reviewing the applicability of FAS 160 to our operations and its potential impact on our consolidated financial statements.

UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NOTE 3 ACQUISITIONS

On June 5, 2007, our subsidiary, Unit Drilling Company, closed the purchase of a privately owned drilling company operating primarily in the Texas Panhandle. This acquisition included nine drilling rigs, drill pipe and collars, a fleet of 11 trucks, an office, shop, equipment yard and personnel. The drilling rigs range from 800 horsepower to 1,000 horsepower with depth capacities rated from 10,000 to 15,000 feet. Eight of the acquired drilling rigs were operational at the time of purchase and the remaining drilling rig is being refurbished and is anticipated to become operational in March of 2008. The financial results of this acquisition are included in our statement of income from June 5, 2007 forward. The total consideration paid in this acquisition was allocated as follows (in thousands):

Drilling rigs	$ 39,326
Spare drilling equipment	1,613
Drill pipe and collars	7,784
Trucks	1,551
Other vehicles	190
Yard and office	846
Goodwill	5,285
Deferred income taxes	(18,095)
Total consideration	$ 38,500

On October 13, 2006, we completed the acquisition of Brighton Energy, L.L.C., (Brighton) a privately owned oil and natural gas company for approximately $67.0 million. This acquisition involved all of Brighton s oil and natural gas assets (excluding Atoka and Coal counties in Oklahoma). The majority of the acquired reserves are located in the Anadarko Basin of Oklahoma and the onshore Gulf Coast basins of Texas and Louisiana, with additional reserves in Arkansas, Kansas, Montana, North Dakota and Wyoming. This acquisition had an effective date of August 1, 2006 and was included in our statement of income starting in October 2006 with the results for the period from August 1, 2006 through September 30, 2006 included as an adjustment to the purchase price. The $67.0 million paid in this acquisition increased our basis in oil and natural gas properties by $65.4 with the remaining $1.6 million reflecting working capital.

In September 2006, our mid-stream segment closed the acquisition of Berkshire Energy, LLC., a private company for an adjusted purchase price of $21.7 million. The principal assets of the acquired company consist of a natural gas processing plant, a natural gas gathering system with 15 miles of pipeline, three field compressors, two plant compressors and associated customer contracts and relationships. As part of the acquisition, Superior acquired long-term contracts for the gathering and processing of natural gas that will flow through this gathering system, the value of which is reported as an amortizable intangible asset. The capitalized value of these contracts and associated customer relationship will be amortized over an estimated life of 7 years. The purchase had an effective date of July 31, 2006. The financial results of the acquisition were included in the our statement of income from September 1, 2006 forward with the results for the period from August 1, 2006 through August 31, 2006 included as an adjustment to the purchase price. The $21.7 million acquisition price for Berkshire Energy, LLC was allocated as follows (in thousands):

Working capital	$ 337
Processing plant and gathering system	3,422
Amortizable intangible assets	17,957
Total consideration	$ 21,716

UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

On May 16, 2006, we announced we had closed the acquisition of certain oil and natural gas properties from a group of private entities for approximately $32.4 million in cash. This acquisition had an effective date of April 1, 2006. The $32.4 million paid in this acquisition increased our basis in oil and natural gas properties.

The amounts paid for all of the acquisitions discussed above were determined through arms-length negotiations between the parties and have been accounted for using the purchase accounting method.

NOTE 4 EARNINGS PER SHARE

The following data shows the amounts used in computing earnings per share.

	Income (Numerator)	Weighted Shares (Denominator)	Per-Share Amount
	(In thousands except per share amounts)		
For the year ended December 31, 2007:			
Basic earnings per common share	$ 266,258	46,366	$ 5.74
Effect of dilutive stock options, restricted stock and SARs		287	(0.03)
Diluted earnings per common share	$ 266,258	46,653	$ 5.71
For the year ended December 31, 2006:			
Basic earnings per common share	$ 312,177	46,228	$ 6.75
Effect of dilutive stock options, restricted stock and SARs		223	(0.03)
Diluted earnings per common share	$ 312,177	46,451	$ 6.72
For the year ended December 31, 2005:			
Basic earnings per common share	$ 212,442	45,940	$ 4.62
Effect of dilutive stock options and restricted stock		249	(0.02)
Diluted earnings per common share	$ 212,442	46,189	$ 4.60

The following options and their average exercise prices were not included in the computation of diluted earnings per share because the option exercise prices were greater than the average market price of our common stock for the years ended December 31:

	2007	2006	2005
Options and SARs	105,655	33,000	
Average exercise price	$ 56.33	$ 61.40	$

NOTE 5 LONG-TERM DEBT AND OTHER LONG-TERM LIABILITIES

Long-Term Debt

Long-term debt consisted of the following as of December 31:

	2007	2006
	(In thousands)	
Revolving credit facility, with interest at December 31, 2007 and 2006 of 6.0% and 6.4%, respectively	$ 120,600	$ 174,300
Less current portion		
Total long-term debt	$ 120,600	$ 174,300

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UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

On May 24, 2007, we entered into a First Amended and Restated Senior Credit Agreement (Credit Facility) with a maximum credit amount of $400.0 million maturing on May 24, 2012. Borrowings under the Credit Facility are limited to a commitment amount elected by us. As of December 31, 2007, the commitment amount was $275.0 million. We are charged a commitment fee of 0.25 to 0.375 of 1% on the amount available but not borrowed with the rate varying based on the amount borrowed as a percentage of the total borrowing base amount. We incurred origination, agency and syndication fees of $737,500 at the inception of the Credit Facility. These fees are being amortized over the life of the agreement. The average interest rate for 2007 was 6.0%. At December 31, 2007 and February 15, 2008, borrowings were $120.6 million and $144.8 million, respectively.

The borrowing base under the Credit Facility is subject to redetermination by the lenders on April 1 and October 1 of each year. The current value of the borrowing base is $425.0 million. Each redetermination is based primarily on a percentage of the discounted future value of our oil, NGLs and natural gas reserves, as determined by the lenders, and, to a lesser extent, the loan value the lenders reasonably attribute to the cash flow (as defined in the Credit Facility) of our mid-stream operations. The company or the lenders may request a one time special redetermination of the borrowing base between each scheduled redetermination date. In addition, we may request a redetermination following the consummation of an acquisition meeting the requirements defined in the Credit Facility. The lender s aggregate commitment is limited to the lesser of the amount of the value of the borrowing base or $400.0 million.

At our election, any part of the outstanding debt may be fixed at LIBOR for a 30, 60, 90 or 180 day term. During any LIBOR funding period the outstanding principal balance of the note to which LIBOR options apply may be repaid on three days prior notice to the administrative agent and subject to the payment of any applicable funding indemnification amounts. Interest on the LIBOR is computed at the LIBOR base applicable for the interest period plus 1.00% to 1.75% depending on the level of debt as a percentage of the borrowing base and payable at the end of each term, or every 90 days, whichever is less. Borrowings not under LIBOR bear interest at the BOK Financial Corporation (BOKF) National Prime Rate payable at the end of each month and the principal borrowed may be paid anytime in part or in whole without premium or penalty. At December 31, 2007, all of the $120.6 million of the company's borrowings was subject to LIBOR.

The Credit Facility includes prohibitions against:

- the payment of dividends (other than stock dividends) during any fiscal year in excess of 25% of the company s consolidated net income for the preceding fiscal year;
- the incurrence of additional debt with certain limited exceptions; and
- the creation or existence of mortgages or liens, other than those in the ordinary course of business, on any of the company s property, except in favor of the company s lenders.

The Credit Facility also requires that we have at the end of each quarter:

- consolidated net worth of at least $900 million;
- a current ratio (as defined in the Credit Facility) of not less than 1 to 1; and

a leverage ratio of long-term debt to consolidated EBITDA (as defined in the Credit Facility) for the most recently ended rolling four fiscal quarters of no greater than 3.50 to 1.0.

On December 31, 2007, we were in compliance with the covenants of the Credit Facility.

UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Other Long-Term Liabilities

Other long-term liabilities consisted of the following as of December 31:

	2007	2006
	(In thousands)	
Plugging liability	$ 33,191	$ 33,692
Workers compensation	22,469	22,157
Separation benefit plans	4,945	3,516
Deferred compensation plan	2,987	2,544
Gas balancing liability	3,364	1,080
Retirement agreements	723	1,386
Derivative liabilities interest rate swaps	249	
	67,928	64,375
Less current portion	8,813	8,634
Total other long-term liabilities	$ 59,115	$ 55,741

Estimated annual principle payments under the terms of long-term debt and other long-term liabilities from 2008 through 2012 are $8.8 million, $9.3 million, $2.1 million, $2.5 million and $121.8 million, respectively. Based on the borrowing rates currently available to us for debt with similar terms and maturities, long-term debt at December 31, 2007 approximates its fair value.

NOTE 6. ASSET RETIREMENT OBLIGATIONS

Under Financial Accounting Standards No. 143 (FAS 143), Accounting for Asset Retirement Obligations, we are required to record the fair value of liabilities associated with the retirement of long-lived assets. We own oil and natural gas properties which require cash to plug and abandon the wells when the oil, NGLs and natural gas reserves in the wells are depleted or the wells are no longer able to produce. These expenditures under FAS 143 are recorded in the period in which the liability is incurred (at the time the wells are drilled or acquired). We do not have any assets restricted for the purpose of settling these plugging liabilities.

The following table shows the activity for our retirement obligation for plugging liability for the years ending December 31:

	2007	2006
	(In thousands)	
Plugging liability, January 1:	$ 33,692	$ 22,015
Accretion of discount	1,704	1,490
Liability incurred	2,043	4,383
Liability settled	(1,448)	(270)
Revision of estimates	(2,800)	6,074
Plugging liability, December 31:	33,191	33,692
Less current portion	672	760
Total long-term plugging liability	$ 32,519	$ 32,932

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UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NOTE 7 INCOME TAXES

A reconciliation of income tax expense, computed by applying the federal statutory rate to pre-tax income to our effective income tax expense is as follows:

	2007	2006	2005
		(In thousands)	
Income tax expense computed by applying the statutory rate	$ 144,694	$ 170,890	$ 117,136
State income tax, net of federal benefit	6,155	8,949	8,231
Domestic production activities deduction	(3,682)	(3,067)	(2,100)
Statutory depletion and other	(14)	(693)	(1,036)
Income tax expense	$ 147,153	$ 176,079	$ 122,231

Deferred tax assets and liabilities are comprised of the following at December 31:

	2007	2006
	(In thousands)	
Deferred tax assets:		
Allowance for losses and nondeductible accruals	$ 28,029	$ 23,593
Net operating loss carryforward	2,593	2,957
	30,622	26,550
Deferred tax liability:		
Depreciation, depletion and amortization	(450,670)	(345,746)
Net deferred tax liability	(420,048)	(319,196)
Current deferred tax asset	8,835	5,881
Non-current deferred tax liability	$ (428,883)	$ (325,077)

Realization of the deferred tax assets are dependent on generating sufficient future taxable income. Although realization is not assured, management believes it is more likely than not that the deferred tax asset will be realized. The amount of the deferred tax asset considered realizable, however, could be reduced in the near-term if estimates of future taxable income are reduced. At December 31, 2007, we have net operating loss carryforwards of approximately $6.9 million which expire from 2009 to 2021.

NOTE 8 EMPLOYEE BENEFIT PLANS

Under our 401(k) Employee Thrift Plan, employees who meet specified service requirements may contribute a percentage of their total compensation, up to a specified maximum, to the plan. We may match each employee s contribution, up to a specified maximum, in full or on a partial basis. We made discretionary contributions under the plan of 83,277, 46,941 and 51,938 shares of common stock and recognized expense of $4.8 million, $3.7 million and $3.0 million in 2007, 2006 and 2005, respectively.

We provide a salary deferral plan (Deferral Plan) which allows participants to defer the recognition of salary for income tax purposes until actual distribution of benefits which occurs at either termination of employment, death or certain defined unforeseeable emergency hardships. Funds set aside in a trust to satisfy our obligation under the Deferral Plan at December 31, 2007, 2006 and 2005 totaled $3.0 million, $2.5 million and $2.6 million, respectively. We recognized payroll expense and recorded a liability at the time of deferral.

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UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Effective January 1, 1997, we adopted a separation benefit plan (Separation Plan). The Separation Plan allows eligible employees whose employment is involuntarily terminated or, in the case of an employee who has completed 20 years of service, voluntarily or involuntarily terminated, to receive benefits equivalent to four weeks salary for every whole year of service completed up to a maximum of 104 weeks. To receive payments, the recipient must waive any claims against us in exchange for receiving the separation benefits. On October 28, 1997, we adopted a Separation Benefit Plan for Senior Management (Senior Plan). The Senior Plan provides certain officers and key executives of Unit with benefits generally equivalent to the Separation Plan. The Compensation Committee of the Board of Directors has absolute discretion in the selection of the individuals covered in this plan. We recognized expense of $1.5 million, $1.1 million and $0.7 million in 2007, 2006 and 2005, respectively, for benefits associated with anticipated payments from both separation plans.

We have entered into key employee change of control contracts with five of our current executive officers. These severance contracts have an initial three-year term that is automatically extended for one year on each anniversary, unless a notice not to extend is given by us. If a change of control of the company, as defined in the contracts, occurs during the term of the severance contract, then the contract becomes operative for a fixed three-year period. The severance contracts generally provide that the executive s terms and conditions for employment (including position, work location, compensation and benefits) will not be adversely changed during the three-year period after a change of control. If the executive s employment is terminated (other than for cause, death or disability), the executive terminates for good reason during such three-year period, or the executive terminates employment for any reason during the 30-day period following the first anniversary of the change of control, and on certain terminations prior to a change of control or in connection with or in anticipation of a change of control, the executive is generally entitled to receive, in addition to certain other benefits, any earned but unpaid compensation; up to 2.9 times the executive s base salary plus annual bonus (based on historic annual bonus); and the company matching contributions that would have been made had the executive continued to participate in the company s 401(k) plan for up to an additional three years.

The severance contract provides that the executive is entitled to receive a payment in an amount sufficient to make the executive whole for any excise tax on excess parachute payments imposed under Section 4999 of the Code. As a condition to receipt of these severance benefits, the executive must remain in the employ of the company prior to change of control and render services commensurate with his position.

NOTE 9 TRANSACTIONS WITH RELATED PARTIES

Unit Petroleum Company serves as the general partner of 13 oil and gas limited partnerships. Three were formed for investment by third parties and ten (the employee partnerships) were formed to allow employees of Unit and its subsidiaries and directors of Unit to participate in Unit Petroleum s oil and gas exploration and production operations. The partnerships for the third party investments were formed in 1984 and 1986. An additional third party partnership, the 1979 Oil and Gas Limited Partnership was dissolved on July 1, 2003. Employee partnerships have been formed for each year beginning with 1984. Interests in the employee partnerships were offered to the employees of Unit and its subsidiaries whose annual base compensation was at least a specified amount ($36,000 for 2007, 2006 and 2005) and to the directors of Unit.

The employee partnerships formed in 1984 through 1990 were consolidated into a single consolidating partnership in 1993 and the employee partnerships formed in 1991 through 1999 were also consolidated into the consolidating partnership in 2002. The consolidation of the 1991 through the 1999 employee partnerships at the end of last year was done by the general partners under the authority contained in the respective partnership agreements and did not involve any vote, consent or approval by the limited partners. The employee partnerships have each had a set percentage (ranging from 1% to 15%) of our interest in most of the oil and natural gas wells

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UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

we drill or acquire for our own account during the particular year for which the partnership was formed. The total interest the employees have in our oil and natural gas wells by participating in these partnerships does not exceed one percent.

Amounts received in the years ended December 31, from both public and private Partnerships for which Unit is a general partner are as follows:

	2007	2006	2005
		(In thousands)	
Contract drilling	$ 729	$ 617	$ 399
Well supervision and other fees	$ 377	$ 297	$ 382
General and administrative Expense reimbursement	$ 444	$ 337	$ 263

Related party transactions for contract drilling and well supervision fees are the related party s share of such costs. These costs are billed to related parties on the same basis as billings to unrelated parties for such services. General and administrative reimbursements are both direct general and administrative expense incurred on the related party s behalf and indirect expenses allocated to the related parties. Such allocations are based on the related party s level of activity and are considered by management to be reasonable.

NOTE 10 SHAREHOLDER RIGHTS PLAN

We maintain a Shareholder Rights Plan (the Plan) designed to deter coercive or unfair takeover tactics, to prevent a person or group from gaining control of us without offering fair value to all our shareholders and to deter other abusive takeover tactics, which are not in the best interest of shareholders.

Under the terms of the Plan, each share of common stock is accompanied by one right, which given certain acquisition and business combination criteria, entitles the shareholder to purchase from us one one-hundredth of a newly issued share of Series A Participating Cumulative Preferred Stock at a price subject to adjustment by us or to purchase from an acquiring company certain shares of its common stock or the surviving company s common stock at 50% of its value.

The rights become exercisable 10 days after we learn that an acquiring person (as defined in the Plan) has acquired 15% or more of the outstanding common stock of Unit or 10 business days after the commencement of a tender offer, which would result in a person owning 15% or more of our shares. We can redeem the rights for $0.01 per right at any date before the earlier of (i) the close of business on the 10th day following the time we learn that a person has become an acquiring person or (ii) May 19, 2015 (the Expiration Date). The rights will expire on the Expiration Date, unless redeemed earlier by Unit.

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UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NOTE 11 STOCK-BASED COMPENSATION

The following table estimates the fair value of each option and SARs granted under all of our plans during the twelve month periods ending December 31, using the Black-Scholes model applying the estimated values presented in the table:

	2007	2006	2005
Options granted	28,000	33,000	58,500
Stock appreciation rights	101,236	44,665	
Estimated fair value (in millions)	$ 2.9	$ 2.1	$ 1.3
Estimate of stock volatility	0.33 to 0.44	0.38 to 0.46	0.51 to 0.55
Estimated dividend yield	0%	0%	0%
Risk free interest rate	3.75 to 5.00%	4.76 to 5.00%	4.35 to 4.42%
Expected life range based on prior experience (in years)	5 to 8	5 to 8	6 to 10
Forfeiture rate	0 to 11%	0 to 5%	0 to 20%

Expected volatilities are based on the historical volatility of our stock. We use historical data to estimate option exercise and employee termination rates within the model and aggregate groups of employees that have similar historical exercise behavior for valuation purposes. To date, we have not paid dividends on our stock. The risk free interest rate is computed from the United States Treasury Strips rate using the term over which it is anticipated the grant will be exercised.

At our annual meeting on May 3, 2006, our shareholders approved the Unit Corporation Stock and Incentive Compensation Plan. This plan allows for the issuance of 2.5 million shares of common stock with 2.0 million shares being the maximum number of shares that can be issued as "incentive stock options." Awards under this plan may be granted in any one or a combination of the following:

- incentive stock options under Section 422 of the Internal Revenue Code;
- non-qualified stock options;
- performance shares;
- performance units;
- restricted stock;
- restricted stock units;
- stock appreciation rights;

- cash based awards; and

- other stock-based awards.

This plan also contains various limits as to the amount of awards that can be given to an employee in any fiscal year. All awards are generally subject to the minimum vesting periods, as determined by our Compensation Committee and included in the award agreement.

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UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Activity pertaining to restricted stock awards granted under the Unit Corporation Stock and Incentive Compensation Plan is as follows:

	Number of Shares	Weighted Average Grant Date Price
Nonvested at January 1, 2006		$
Granted	23,381	51.76
Vested		
Forfeited		
Nonvested at December 31, 2006	23,381	51.76
Granted	616,907	46.95
Vested	(4,234)	51.76
Forfeited		
Nonvested at December 31, 2007	636,054	$ 47.09

The restricted stock awards vest in periods ranging from one to three years. The fair value of the restricted stock granted in 2007 and 2006 at the grant date was $26.3 million and $1.2 million, respectively. The aggregate intrinsic value of the 4,234 shares of restricted stock on their 2007 vesting date was $0.2 million. The aggregate intrinsic value of the 636,054 shares outstanding subject to vesting at December 31, 2007 was $29.4 million with a weighted average remaining life of 2.2 years.

Activity pertaining to SARs granted under the Unit Corporation Stock and Incentive Compensation Plan is as follows:

	Number of Shares	Weighted Average Grant Date Price
Outstanding at January 1, 2006		$
Granted	44,665	51.76
Exercised		
Forfeited		
Outstanding at December 31, 2006	44,665	51.76
Granted	101,236	44.31
Exercised		
Forfeited		
Outstanding at December 31, 2007	145,901	$ 46.59

The SARs granted in 2007 and 2006 vest in thirds annually with the first vesting period on January 5, 2009 for the 2007 grant and January 1, 2008 for the 2006 grant. The SARs expire after 10 years from the date of the grant. No shares vested in 2007 or 2006. Fair value of SARs at grant date in 2007 and 2006 was $2.3 million and $1.3 million, respectively. The aggregate intrinsic value of the 145,901 shares outstanding subject to vesting at December 31, 2007 was zero with a weighted average remaining contractual term of 9.7 years.

In December 1984, our Board of Directors approved the adoption of an Employee Stock Bonus Plan. Under this plan 330,950 shares of common stock were reserved for issuance. On May 3, 1995, our shareholders approved and amended the plan to increase by 250,000 shares the aggregate number of shares of common stock that could be issued under the plan. Under the terms of the plan, awards were granted to employees in either cash or stock or a combination thereof, and are payable in a lump sum or in installments subject to certain restrictions. On December 13, 2005, 38,190 shares (in the form of restricted stock awards) were granted under

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UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

the plan one half of which was distributed on January 1, 2007 and the other half was distributed on January 1, 2008. No shares vested in 2006. As a result of the approval of the adoption of the Unit Corporation Stock and Incentive Compensation Plan at our shareholders annual meeting on May 3, 2006, no further grants will be made under this plan.

Activity pertaining to restricted stock awards granted under the Employee Stock Bonus Plan is as follows:

	Number of Shares	Weighted Average Grant Date Price
Nonvested at January 1, 2005		$
Granted	38,190	58.30
Vested		
Forfeited		
Nonvested at December 31, 2005	38,190	58.30
Granted		
Vested		
Forfeited	(738)	58.30
Nonvested at December 31, 2006	37,452	58.30
Granted		
Vested	(18,749)	58.30
Forfeited	(329)	58.30
Nonvested at December 31, 2007	18,374	$ 58.30

The fair value of the restricted stock granted in 2005 at the grant date was $2.0 million. The grant date fair value of the 18,749 shares vesting in 2007 was $1.0 million. The aggregate intrinsic value of the 18,749 shares of restricted stock on their 2007 vesting date was $0.9 million. The aggregate intrinsic value of the 18,374 shares outstanding subject to vesting at December 31, 2007 was $0.8 million with a weighted average remaining contractual term ending January 1, 2008.

We also have a Stock Option Plan, which provided for the granting of options for up to 2,700,000 shares of common stock to officers and employees. The option plan permitted the issuance of qualified or nonqualified stock options. Options granted typically become exercisable at the rate of 20% per year one year after being granted and expire after 10 years from the original grant date. The exercise price for options granted under this plan is the fair market value of the common stock on the date of the grant. As a result of the approval of the adoption of the Unit Corporation Stock and Incentive Compensation Plan, no further awards will be made under this plan.

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UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Activity pertaining to the Stock Option Plan is as follows:

	Number of Shares	Weighted Average Exercise Price
Outstanding at January 1, 2005	553,750	$ 22.11
Granted	34,000	37.16
Exercised	(91,237)	16.08
Cancelled	(61,800)	25.03
Outstanding at December 31, 2005	434,713	24.14
Granted	5,000	55.83
Exercised	(57,563)	15.61
Cancelled	(800)	37.83
Outstanding at December 31, 2006	381,350	25.81
Granted		
Exercised	(25,850)	23.31
Cancelled	(1,000)	37.83
Outstanding at December 31, 2007	354,500	$ 25.96

The fair value of the stock options granted at the grant date under the Stock Option Plan in 2006 and 2005 was $0.1 million and $0.7 million, respectively. The total grant date fair value of the 68,470, 67,670 and 79,870 shares vesting in 2007, 2006 and 2005 was $1.0 million, $1.4 million and $1.5 million, respectively. The intrinsic value of options exercised in 2007 was $0.8 million. Total cash received from the options exercised in 2007 was $0.6 million.

		Outstanding Options at December 31, 2007	
Exercise Prices	Number of Shares	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price
$3.75	34,000	1.0 years	$ 3.75
$16.69 $19.04	95,800	4.4 years	$ 18.37
$21.50 $26.28	84,460	5.9 years	$ 22.93
$34.75 $37.83	135,240	7.0 years	$ 37.71
$53.90 $60.32	5,000	8.3 years	$ 55.83

The aggregate intrinsic value of the 354,500 shares outstanding subject to options at December 31, 2007 was $7.2 million with a weighted average remaining contractual term of 5.5 years.

	Exercisable Options At December 31, 2007	
Exercise Prices	Number of Shares	Weighted Average Exercise Price

$3.75		34,000	$	3.75
$16.69	$19.04	95,800	$	18.37
$21.50	$22.95	64,290	$	22.86
$34.83	$37.83	72,040	$	37.79
$53.90	$60.32	1,000	$	55.83

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UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Options for 267,130, 224,910 and 214,803 shares were exercisable with weighted average exercise prices of $22.97, $21.34 and $17.68 at December 31, 2007, 2006 and 2005, respectively. The aggregate intrinsic value of shares exercisable at December 31, 2007 was $6.2 million with a weighted average remaining contractual term of 5.0 years.

In February and May 1992, our Board of Directors and shareholders, respectively, approved the Unit Corporation Non-Employee Directors Stock Option Plan. Under the plan, on the first business day following each annual meeting of shareholders, each person who was then a member of our Board of Directors and who was not then an employee of the company or any of its subsidiaries was granted an option to purchase 2,500 shares of common stock. In February and May 2000, our Board of Directors and shareholders, respectively, approved the Unit Corporation 2000 Non-Employee Directors Stock Option Plan, which replaced the prior plan. Under the new plan an aggregate of 300,000 shares of common stock may be issued on exercise of the stock options. Commencing with the year 2000 annual meeting, the amount granted increased to 3,500 shares of common stock. The option price for each stock option is the fair market value of the common stock on the date the stock options are granted. The term of each option is 10 years and cannot be increased and no stock options may be exercised during the first six months of its term except in case of death.

Activity pertaining to the Directors Plan is as follows:

	Number of Shares	Weighted Average Exercise Price
Outstanding at January 1, 2005	94,000	$ 20.27
Granted	24,500	39.50
Exercised	(19,000)	17.99
Cancelled	(3,500)	39.50
Outstanding at December 31, 2005	96,000	24.93
Granted	28,000	62.40
Exercised	(3,500)	20.10
Outstanding at December 31, 2006	120,500	33.78
Granted	28,000	57.63
Exercised	(6,000)	14.81
Outstanding at December 31, 2007	142,500	$ 39.26

The fair value of the stock options granted at the grant date under the Stock Option Plan in 2007, 2006 and 2005 was $0.6 million, $0.7 million and $0.6 million, respectively. The total grant date fair value of the 28,000, 28,000 and 24,500 shares vesting in 2007, 2006 and 2005 was $0.6 million, $0.7 million and $0.6 million, respectively. The intrinsic value of options exercised in 2007 was $0.2 million. Total cash received from options exercised in 2007 was $0.1 million.

	Outstanding and Exercisable Options at December 31, 2007		
Exercise Prices	Number of Shares	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price
$6.90	2,500	1.3 years	$ 6.90

$12.19	$17.54	14,000	3.1 years	$ 16.20
$20.10	$20.46	28,000	4.8 years	$ 20.28
$28.23	$39.50	42,000	6.8 years	$ 33.87
$57.63	$62.40	56,000	8.8 years	$ 60.02

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UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Options for 142,500, 120,500 and 96,000 shares were exercisable with weighted average exercise prices of $39.26, $33.78 and $24.93 at December 31, 2007, 2006 and 2005, respectively. The aggregate intrinsic value of the shares outstanding subject to options at December 31, 2007 was $1.8 million with a weighted average remaining contractual term of 6.8 years.

NOTE 12. DERIVATIVES

Interest Rate Swaps

We have entered into interest rate swaps to help manage our exposure to possible future interest rate increases. As of December 31, 2007, we had three interest rate swaps which were cash flow hedges. There was no material amount of ineffectiveness. The fair value of these swaps was recognized on the December 31, 2007 balance sheet as current and non-current derivative assets and liabilities and is presented in the table below:

Term	Amount	Fixed Rate	Floating Rate	Fair Value Asset (Liability)
		($ in thousands)		
March 2005 January 2008	$ 50,000	3.99%	3 month LIBOR	$ 96
December 2007 May 2012	$ 15,000	4.53%	3 month LIBOR	(240)
December 2007 May 2012	$ 15,000	4.16%	3 month LIBOR	(9)
				$ (153)

As a result of these interest rate swaps, interest expense decreased by $0.7 million and $0.5 million in 2007 and 2006, respectively, and increased by $0.2 million in 2005. A loss of $0.1 million, net of tax, is reflected in accumulated other comprehensive income (loss) as of December 31, 2007.

Commodity Hedges

We have entered into various types of derivative instruments covering a portion of our projected natural gas, oil and NGL production or processing, as applicable, to reduce our exposure to market price volatility as discussed more fully below and elsewhere in this report. As of December 31, 2007, our derivative instruments were comprised of swaps and collars.

Swaps. We receive or pay a fixed price for the hedged commodity and pay or receive a floating market price to the counterparty. The fixed-price payment and the floating-price payment are netted, resulting in a net amount due to or paid from the counterparty.

Collars. A collar contains a fixed floor price (put) and a ceiling price (call). If the market price exceeds the call strike price or falls below the put strike price, we receive the fixed price and pay the market price. If the market price is between the call and the put strike price, no payments are due from either party.

Fractionation Spreads. In our mid-stream segment, when we enter into both NGL sales swaps and natural gas purchase swaps, we attempt to lock in our fractionation spread for natural gas processed. The fractionation spread is the difference in the value received for the NGLs recovered from natural gas in comparison to the amount received for the equivalent MMBtu s of natural gas if unprocessed.

Currently all of our commodity hedges are cash flow hedges and there is no material amount of ineffectiveness. At December 31, 2007, we recorded the fair value of our commodity hedges on our balance sheet as derivative assets of $2.0 million and derivative liabilities of $0.1 million. At December 31, 2006, we had derivative assets of $1.4 million and no derivative liabilities.

UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

We recognize the effective portion of changes in fair value as accumulated other comprehensive income (loss), and reclassify the sales to revenue and the purchases to expense as the underlying transactions are settled. As of December 31, 2007, we had a gain of $2.1 million, net of tax, from our oil and natural gas segment derivatives and a loss of $0.8 million, net of tax, from our mid-stream segment derivatives in accumulated other comprehensive income (loss). At December 31, 2007 all of our commodity instruments were short-term and will be settled into earnings within twelve months. Realized earnings from our commodity derivative settlements included in revenues and expenses were as follows at December 31:

	2007	2006	2005
		(In thousands)	
Increases (decreases) in:			
Oil and natural gas revenue	$ 2,589	$	$ (4,081)
Gas gathering and processing revenue	(2,078)		
Gas gathering and processing expense	1,694		
Impact on pre-tax earnings	$ (1,183)	$	$ (4,081)

At December 31, 2007, the following cash flow hedges were outstanding:

Oil and Natural Gas Segment:

Term	Sell/ Purchase	Commodity	Hedged Volume	Average Fixed Price	Market
Jan 08 Apr 08	Sell	Liquids swap (1)	388,000 Gal/mo	$1.235	OPIS Conway
Jan 08 Apr 08	Sell	Liquids swap (1)	500,000 Gal/mo	$1.164	OPIS Mont Belvieu
Jan 08 Dec 08	Sell	Crude oil swap	1,000 Bbl/day	$91.32	WTI NYMEX
Jan 08 Dec 08	Sell	Crude oil collar	1,000 Bbl/day	$85.00 put & $98.75 call	WTI NYMEX
Jan 08 Dec 08	Sell	Natural gas swap	10,000 MMBtu/day	$7.615	IF Centerpoint East
Jan 08 Dec 08	Sell	Natural gas collar	10,000 MMBtu/day	$7.00 put & $8.40 call	IF Centerpoint East
Jan 08 Dec 08	Sell	Natural gas collar	10,000 MMBtu/day	$7.20 put & $8.80 call	IF CP Tenn (Zone 0)

(1) Types of liquids include ethane and propane.

Mid-Stream Segment:

Term	Sell/ Purchase	Commodity	Hedged Volume	Average Fixed Price	Market
Jan 08 Apr 08	Sell	Liquids swap (1)	1,836,000 Gal/mo	$ 1.424	OPIS Conway
Jan 08 Apr 08	Purchase	Natural gas swap	171,000 MMBtu/mo	$ 6.673	IF PEPL
May 08 Jul 08	Sell	Liquids swap (2)	1,038,000 Gal/mo	$ 1.109	OPIS Conway
May 08 Jul 08	Purchase	Natural gas swap	85,000 MMBtu/mo	$ 6.415	IF PEPL

(1) Types of liquids include natural gasoline, ethane, propane, isobutane and natural butane.

(2) Types of liquids include ethane and propane.

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UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Subsequent to December 31, 2007, we entered into the following cash flow hedges:

Oil and Natural Gas Segment:

Term	Sell/ Purchase	Commodity	Hedged Volume	Average Fixed Price	Market
Jan 08 Apr 08	Sell	Liquids swap (1)	194,000 Gal/mo	$1.288	OPIS Conway
Jan 08 Apr 08	Sell	Liquids swap (1)	250,000 Gal/mo	$1.239	OPIS Mont Belvieu
Jan 08 Dec 08	Sell	Crude oil collar	500 Bbl/day	$90.00 put & $102.50 call	WTI NYMEX
Feb 08 Dec 08	Sell	Natural gas swap	10,000 MMBtu/day	$7.43	IF Centerpoint East
Feb 08 Dec 08	Sell	Natural gas collar	10,000 MMBtu/day	$7.50 put & $8.70 call	NGPL TXOK
Jan 09 Dec 09	Sell	Natural gas swap	10,000 MMBtu/day	$7.77	IF Centerpoint East
Jan 09 Dec 09	Sell	Natural gas swap	10,000 MMBtu/day	$8.28	IF CP Tenn (Zone 0)

(1) Types of liquids include ethane and propane.

Mid-Stream Segment:

Term	Sell/ Purchase	Commodity	Hedged Volume	Average Fixed Price	Market
Aug 08 Dec 08	Sell	Propane	188,000 Gal/mo	$ 1.434	OPIS Conway
Aug 08 Dec 08	Purchase	Natural gas swap	17,000 MMBtu/mo	$ 6.908	IF PEPL

NOTE 13 COMMITMENTS AND CONTINGENCIES

We lease office space in Tulsa and Woodward, Oklahoma; Houston and Midland, Texas; and Denver, Colorado under the terms of operating leases expiring through January, 2012. Additionally, we have several equipment leases and lease space on short-term commitments to stack excess drilling rig equipment and production inventory. Future minimum rental payments under the terms of the leases are approximately $1.8 million, $1.8 million and $0.4 million in 2008, 2009 and 2010, respectively. Total rent expense incurred was $1.7 million, $1.3 million and $1.1 million in 2007, 2006 and 2005, respectively.

The Unit 1984 Oil and Gas Limited Partnership and the 1986 Energy Income Limited Partnership agreements along with the employee oil and gas limited partnerships require, on the election of a limited partner, that we repurchase the limited partner s interest at amounts to be determined by appraisal in the future. These repurchases in any one year are limited to 20% of the units outstanding. We made repurchases of $7,000 and $4,000 in 2006 and 2005, respectively, and had no repurchases in 2007.

We manage our exposure to environmental liabilities on properties to be acquired by identifying existing problems and assessing the potential liability. We also conduct periodic reviews, on a company-wide basis, to identify changes in our environmental risk profile. These reviews evaluate whether there is a probable liability, its amount, and the likelihood that the liability will be incurred. The amount of any potential liability is determined by considering, among other matters, incremental direct costs of any likely remediation and the proportionate cost of employees who are expected to devote a significant amount of time directly to any possible remediation effort. As it relates to evaluations of purchased properties, depending on the extent of an identified environmental problem, we may exclude a property from the acquisition, require the seller to remediate the property to our satisfaction, or agree to assume liability for the remediation of the property.

We have not historically experienced any environmental liability while being a contract driller since the greatest portion of risk is borne by the operator. Any liabilities we have incurred have been small and have been resolved while the drilling rig is on the location and the cost has been included in the direct cost of drilling the well.

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UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

We have committed to purchase approximately $26.5 million of drill pipe and drill collars in 2008. We have also committed to purchase $1.5 million of drilling rig components with 20% or $0.3 million paid through December 31, 2007.

We are subject to various legal proceedings arising in the ordinary course of our various businesses none of which, in our opinion, will result in judgments which would have a material adverse effect on our financial position, operating results or cash flows.

NOTE 14 INDUSTRY SEGMENT INFORMATION

We have three business segments: contract drilling, oil and natural gas exploration and mid-stream operations, representing our three main business units offering different products and services. The contract drilling segment is engaged in the land contract drilling of oil and natural gas wells, the oil and natural gas exploration segment is engaged in the development, acquisition and production of oil and natural gas properties and the mid-stream segment is engaged in the buying, selling, gathering, processing and treating of natural gas.

The accounting policies of the segments are the same as those described in the Summary of Significant Accounting Policies (Note 2). We evaluate the performance of our business segments based on operating income, which is defined as operating revenues less operating expenses and depreciation, depletion and amortization. We also have some natural gas production in Canada, which is not significant.

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UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	2007	2006 (In thousands)	2005
Revenues:			
Contract drilling	$ 673,517	$ 741,176	$ 483,501
Elimination of inter-segment revenue	45,875	41,780	21,360
Contract drilling net of inter-segment revenue	627,642	699,396	462,141
Oil and natural gas exploration	391,480	357,599	318,208
Gas gathering and processing	161,679	115,146	109,652
Elimination of inter-segment revenue	23,084	13,283	9,188
Gas gathering and processing net of inter-segment revenue	138,595	101,863	100,464
Other	1,037	3,527	4,795
Total revenues	$ 1,158,754	$ 1,162,385	$ 885,608
Operating income (1):			
Contract drilling	$ 266,058	$ 333,555	$ 152,793
Oil and natural gas exploration	166,954	168,355	190,147
Gas gathering and processing	7,760	6,782	4,718
Total operating income	440,772	508,692	347,658
General and administrative expense	(22,036)	(18,690)	(14,343)
Interest expense	(6,362)	(5,273)	(3,437)
Other income (expense) net	1,037	3,527	4,795
Income before income taxes	$ 413,411	$ 488,256	$ 334,673
Identifiable assets (2):			
Contract drilling	$ 879,784	$ 755,290	$ 593,328
Oil and natural gas exploration	1,148,633	979,362	752,538
Gas gathering and processing	148,865	123,500	97,486
Total identifiable assets	2,177,282	1,858,152	1,443,352
Corporate assets	22,537	15,944	12,843
Total assets	$ 2,199,819	$ 1,874,096	$ 1,456,195
Capital expenditures:			
Contract drilling	$ 220,424(3)	$ 170,485(4)	$ 142,242(5)
Oil and natural gas exploration	307,337	350,156(6)	274,597
Gas gathering and processing	34,176	42,942(7)	21,796
Other	2,190	2,566	1,753
Total capital expenditures	$ 564,127	$ 566,149	$ 440,388

Depreciation, depletion and amortization:			
Contract drilling	$ 56,804	$ 51,959	$ 42,876
Oil and natural gas exploration	127,417	108,124	67,282
Gas gathering and processing	11,059	6,247	3,279
Other	831	736	857
Total depreciation, depletion and amortization	$ 196,111	$ 167,066	$ 114,294

(1) Operating income is total operating revenues less operating expenses, depreciation, depletion and amortization and does not include non-operating revenues, general corporate expenses, interest expense or income taxes.

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UNIT CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(2) Identifiable assets are those used in Unit s operations in each industry segment. Corporate assets are principally cash and cash equivalents, short-term investments, corporate leasehold improvements, furniture and equipment.

(3) Includes $5.3 million of goodwill from the acquisition in June 2007.

(4) Includes $17.9 million of goodwill from the third and final year of the SerDrilco earn-out agreement.

(5) Includes $1.1 million for goodwill acquired in the Strata Drilling, L.L.C. and $7.6 million for goodwill from the second year of the SerDrilco earn-out agreement.

(6) Includes $10.2 million for capitalized cost relating to plugging liability recorded in 2006.

(7) Includes $18.0 million for capitalized intangibles.

NOTE 15 SELECTED QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial information for 2007 and 2006 is as follows:

	Three Months Ended			
	March 31	**June 30**	**September 30**	**December 31**
	(In thousands except per share amounts)			
2007:				
Revenues	$ 277,271	$ 286,640	$ 286,335	$ 308,508
Gross profit (1)	$ 106,829	$ 108,916	$ 106,509	$ 118,518
Net income	$ 64,482	$ 65,566	$ 64,061	$ 72,149
Net income per common share:				
Basic	$ 1.39	$ 1.41	$ 1.38	$ 1.56
Diluted (2)	$ 1.39	$ 1.41	$ 1.37	$ 1.55
2006:				
Revenues	$ 282,808	$ 280,349	$ 299,894	$ 299,334
Gross profit (1)	$ 122,649	$ 123,642	$ 134,369	$ 128,032
Net income	$ 74,913	$ 74,817	$ 81,265	$ 81,182
Net income per common share:				

Basic (2)	$	1.62	$	1.62	$	1.76	$	1.76
Diluted	$	1.61	$	1.61	$	1.75	$	1.75

(1) Gross profit excludes other revenues, general and administrative expense and interest expense.

(2) Due to the effect of rounding the basic earnings per share for the year's four quarters does not equal annual earnings per share.

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UNIT CORPORATION AND SUBSIDIARIES

SUPPLEMENTAL OIL AND GAS DISCLOSURES

Our oil and gas operations are substantially located in the United States. We do have operations in Canada that are insignificant. The capitalized costs at year end and costs incurred during the year were as follows:

	2007	2006 (In thousands)	2005
Capitalized costs:			
Proved properties	$ 1,624,478	$ 1,330,010	$ 995,119
Unproved properties	64,722	53,687	38,421
	1,689,200	1,383,697	1,033,540
Accumulated depreciation, depletion, amortization and impairment	(589,029)	(462,310)	(354,706)
Net capitalized costs	$ 1,100,171	$ 921,387	$ 678,834
Cost incurred:			
Unproved properties acquired	$ 33,398	$ 29,262	$ 23,814
Proved properties acquired	1,820	92,278	106,921
Exploration	37,673	26,008	16,862
Development	235,203	192,421	125,073
Asset retirement obligation	(757)	10,187	1,927
Total costs incurred	$ 307,337	$ 350,156	$ 274,597

The following table shows a summary of the oil and natural gas property costs not being amortized at December 31, 2007, by the year in which such costs were incurred:

	2007	2006	2005 (In thousands)	2004 and Prior	Total
Undeveloped Leasehold Acquired	$ 31,220	$ 15,889	$ 14,968	$ 2,645	$ 64,722

Unproved properties not subject to amortization relates to properties which are not individually significant and consist primarily of lease acquisition costs. The evaluation process associated with these properties has not been completed and therefore, the company is unable to estimate when these costs will be included in the amortization calculation.

The results of operations for producing activities are provided below.

	2007	2006 (In thousands)	2005
Revenues	$ 386,231	$ 352,460	$ 314,543
Production costs	(84,382)	(70,869)	(53,449)
Depreciation, depletion and amortization	(126,719)	(107,604)	(66,910)
	175,130	173,987	194,184

Income tax expense	(62,337)	(62,816)	(70,929)
Results of operations for producing activities (excluding corporate overhead and financing costs)	$ 112,793	$ 111,171	$ 123,255

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UNIT CORPORATION AND SUBSIDIARIES

SUPPLEMENTAL OIL AND GAS DISCLOSURES (Continued)

Estimated quantities of proved developed oil, liquids and natural gas reserves and changes in net quantities of proved developed and undeveloped oil, liquids and natural gas reserves were as follows (unaudited):

	Oil Bbls	Liquids Bbls (In thousands)	Natural Gas Mcf
2007:			
Proved developed and undeveloped reserves:			
Beginning of year	9,357	2,226	406,400
Revision of previous estimates (1)	(111)	2,830	(16,382)
Extensions, discoveries and other additions	1,521	1,878	72,642
Purchases of minerals in place			420
Production	(1,091)	(785)	(43,464)
End of Year	9,676	6,149	419,616
Proved developed reserves:			
Beginning of year	7,465	2,042	307,734
End of year	7,770	5,133	326,071
2006:			
Proved developed and undeveloped reserves:			
Beginning of year	8,052	1,819	352,841
Revision of previous estimates	(20)	179	(2,779)
Extensions, discoveries and other additions	1,240	638	71,453
Purchases of minerals in place	1,119	31	29,067
Sales of minerals in place	(22)		(12)
Production	(1,012)	(441)	(44,170)
End of Year	9,357	2,226	406,400
Proved developed reserves:			
Beginning of year	6,763	1,691	269,379
End of year	7,465	2,042	307,734
2005:			
Proved developed and undeveloped reserves:			
Beginning of year	7,487	1,074	295,406
Revision of previous estimates	(245)	462	(2,072)
Extensions, discoveries and other additions	584	521	50,941
Purchases of minerals in place	1,072		43,056
Sales of minerals in place			(432)
Production	(846)	(238)	(34,058)
End of Year	8,052	1,819	352,841
Proved developed reserves:			
Beginning of year	5,956	1,074	223,611
End of year	6,763	1,691	269,379

(1) As a result of processing more natural gas liquids out of our natural gas, revisions of previous estimates reflect an increase in NGLs derived from natural gas.

Oil, NGLs and natural gas reserves cannot be measured exactly. Estimates of oil, NGLs and natural gas reserves require extensive judgments of reservoir engineering data and are generally less precise than other

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UNIT CORPORATION AND SUBSIDIARIES

SUPPLEMENTAL OIL AND GAS DISCLOSURES (Continued)

estimates made in connection with financial disclosures. We use Ryder Scott Company, independent petroleum consultants, to audit our reserves as prepared by our reservoir engineers. The wells or locations for which estimates of reserves were audited were reserves that comprised the top 83% of the total proved discounted future net income based on the unescalated pricing policy of the SEC as taken from reserve and income projections prepared by us as of December 31, 2007.

Proved oil and gas reserves, as defined in SEC Rule 4-10(a), are the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based on future conditions.

Reservoirs are considered proved if economic productibility is supported by either actual production or conclusive formation test. The area of a reservoir considered proved includes:

- that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any; and
- the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.

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

Estimates of proved reserves do not include the following:

- oil that may become available from known reservoirs but is classified separately as indicated additional reserves ;
- crude oil, natural gas, and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors;
- crude oil, natural gas, and natural gas liquids, that may occur in undrilled prospects; and
- crude oil, natural gas, and natural gas liquids, that may be recovered from oil shales, coal, gilsonite and other such sources.

Proved developed oil, NGLs and natural gas reserves are 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 should be included as 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 undeveloped oil, NGLs and natural gas reserves are 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

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UNIT CORPORATION AND SUBSIDIARIES

SUPPLEMENTAL OIL AND GAS DISCLOSURES (Continued)

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.

Estimates of oil, NGLs and natural gas reserves require extensive judgments of reservoir engineering data as previously explained. Assigning monetary values to such estimates does not reduce the subjectivity and changing nature of such reserve estimates. Indeed the uncertainties inherent in the disclosure are compounded by applying additional estimates of the rates and timing of production and the costs that will be incurred in developing and producing the reserves. The information set forth in this report is, therefore, subjective and, since judgments are involved, may not be comparable to estimates submitted by other oil and natural gas producers. In addition, since prices and costs do not remain static and no price or cost escalations or de-escalations have been considered, the results are not necessarily indicative of the estimated fair market value of estimated proved reserves, nor of estimated future cash flows.

The standardized measure of discounted future net cash flows (SMOG) was calculated using year-end prices and costs, and year-end statutory tax rates, adjusted for permanent differences that relate to existing proved oil, NGLs and natural gas reserves. SMOG as of December 31 is as follows (unaudited):

	2007	2006	2005
		(In thousands)	
Future cash flows	$ 3,890,789	$ 2,749,673	$ 3,223,210
Future production costs	(1,007,681)	(763,677)	(753,933)
Future development costs	(234,415)	(218,749)	(142,259)
Future income tax expenses	(880,560)	(538,720)	(792,052)
Future net cash flows	1,768,133	1,228,527	1,534,966
10% annual discount for estimated timing of cash flows	(777,802)	(543,632)	(671,283)
Standardized measure of discounted future net cash flows relating to proved oil, NGLs and natural gas reserves	$ 990,331	$ 684,895	$ 863,683

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UNIT CORPORATION AND SUBSIDIARIES

SUPPLEMENTAL OIL AND GAS DISCLOSURES (Continued)

The principal sources of changes in the standardized measure of discounted future net cash flows were as follows (unaudited):

	2007	2006	2005
		(In thousands)	
Sales and transfers of oil and natural gas produced, net of production costs	$ (301,847)	$ (281,591)	$ (261,094)
Net changes in prices and production costs	344,497	(408,186)	357,793
Revisions in quantity estimates and changes in production timing	(155)	(4,190)	(2,821)
Extensions, discoveries and improved recovery, less related costs	311,529	197,897	218,923
Changes in estimated future development costs	19,971	(10,875)	(14,281)
Previously estimated cost incurred during the period	49,333	30,112	21,330
Purchases of minerals in place	1,540	65,531	128,187
Sales of minerals in place		(399)	(640)
Accretion of discount	98,412	131,290	78,706
Net change in income taxes	(192,045)	149,990	(183,764)
Other net	(25,799)	(48,367)	(268)
Net change	305,436	(178,788)	342,071
Beginning of year	684,895	863,683	521,612
End of year	$ 990,331	$ 684,895	$ 863,683

Our SMOG and changes to it were determined in accordance with Statement of Financial Accounting Standards No. 69. Certain information concerning the assumptions used in computing SMOG and their inherent limitations are discussed below. We believe this information is essential for a proper understanding and assessment of the data presented.

The assumptions used to compute SMOG do not necessarily reflect our expectations of actual revenues to be derived from those reserves nor their present worth. Assigning monetary values to the reserve quantity estimation process does not reduce the subjective and ever-changing nature of reserve estimates. Additional subjectivity occurs when determining present values because the rate of producing the reserves must be estimated. In addition to difficulty inherent in predicting the future, variations from the expected production rate could result from factors outside of our control, such as unintentional delays in development, environmental concerns or changes in prices or regulatory controls. Also, the reserve valuation assumes that all reserves will be disposed of by production. However, other factors such as the sale of reserves in place could affect the amount of cash eventually realized.

Future cash flows are computed by applying year-end spot prices of $95.98 per barrel for oil, $66.89 per barrel for NGLs and $6.22 per Mcf for natural gas relating to proved reserves and to the year-end quantities of those reserves. Future price changes are considered only to the extent provided by contractual arrangements in existence at year-end.

Future production and development costs are computed by estimating the expenditures to be incurred in developing and producing the proved oil, NGLs and natural gas reserves at the end of the year, based on continuation of existing economic conditions.

Future income tax expenses are computed by applying the appropriate year-end statutory tax rates to the future pretax net cash flows relating to proved oil, NGLs and natural gas reserves less the tax basis of our properties. The future income tax expenses also give effect to permanent differences and tax credits and allowances relating to our proved oil, NGLs and natural gas reserves.

Care should be exercised in the use and interpretation of the above data. As production occurs over the next several years, the results shown may be significantly different as changes in production performance, petroleum prices and costs are likely to occur.

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

None.

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

(a) **Evaluation of Disclosure Controls and Procedures**

The company maintains disclosure controls and procedures, as that term is defined in Rule 13a-15(e) and Rule 15d-15(e) under the Securities Exchange Act of 1934 (the Exchange Act), that are designed to ensure that information required to be disclosed in reports the company files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms, and that such information is collected and communicated to management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. In designing and evaluating its disclosure controls and procedures, our management recognized that no matter how well conceived and operated, disclosure controls and procedures can provide only reasonable, not absolute, assurance that the objectives of the disclosure controls and procedures are met. Our disclosure controls and procedures have been designed to meet, and our management believes that they meet, reasonable assurance standards. Based on their evaluation as of the end of the period covered by this Annual Report on Form 10-K, our Chief Executive Officer and Chief Financial Officer have concluded that, subject to the limitations noted above, the company s disclosure controls and procedures were effective.

(b) **Management s Report on Internal Control Over Financial Reporting**

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as that is defined in Exchange Act Rule 13a-15(f). Our management, including our Chief Executive Officer and Chief Financial Officer, conducted an evaluation of the effectiveness of our internal control over financial reporting based on the *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the results of this evaluation, our management concluded that our internal control over financial reporting was effective as of December 31, 2007.

The effectiveness of the company s internal control over financial reporting as of December 31, 2007, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

(c) **Changes in Internal Control Over Financial Reporting**

During the last quarter, there were no changes in our internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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

None.

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PART III

Item 10. ***Directors, Executive Officers and Corporate Governance***

In accordance with Instruction G(3) of Form 10-K, the information required by this item is incorporated in this report by reference to the Proxy Statement, except for the information regarding our executive officers which is presented below. The Proxy Statement will be filed before our annual shareholders meeting scheduled to be held on May 7, 2008.

Our Code of Ethics and Business Conduct applies to all directors, officers and employees, including our Chief Executive Officer, our Chief Financial Officer and our Controller. You can find our Code of Ethics and Business Conduct on our internet website, www.unitcorp.com. We will post any amendments to the Code of Ethics and Business Conduct, and any waivers that are required to be disclosed by the rules of either the SEC or the NYSE, on our internet website.

Because our common stock is listed on the NYSE, our Chief Executive Officer was required to make, and he has made, an annual certification to the NYSE stating that he was not aware of any violation of our corporate governance listing standards of the NYSE. Our Chief Executive Officer made his annual certification to that effect to the NYSE as of May 3, 2007. In addition, we have filed, as exhibits to this Annual Report on Form 10-K, the certifications of our Chief Executive Officer and Chief Financial Officer required under Section 302 of the Sarbanes-Oxley Act of 2002 to be filed with the SEC regarding the quality of our public disclosure.

Executive Officers

The table below and accompanying text sets forth certain information as of February 15, 2008 concerning each of our executive officers as well as certain officers of our subsidiaries. There were no arrangements or understandings between any of the officers and any other person(s) under which the officers were elected.

NAME	AGE	POSITION HELD
Larry D. Pinkston	53	Chief Executive Officer since April 1, 2005, Director since January 15, 2004, President since August 1, 2003, Chief Operating Officer since February 24, 2004, Vice President and Chief Financial Officer from May 1989 to February 24, 2004
Mark E. Schell	50	Senior Vice President since December 2002, General Counsel and Corporate Secretary since January 1987
David T. Merrill	47	Chief Financial Officer and Treasurer since February 24, 2004, Vice President of Finance from August 2003 to February 24, 2004
Brad J. Guidry	52	Senior Vice President, Unit Petroleum Company since March 1, 2005
John Cromling	60	Executive Vice President, Unit Drilling Company since April 15, 2005
Robert Parks	53	A Manager and President, Superior Pipeline Company, L.L.C. since June 1996
Richard E. Heck	47	Vice President, Safety, Health and Environment since January 2008

Mr. Pinkston joined the company in December, 1981. He had served as Corporate Budget Director and Assistant Controller before being appointed Controller in February, 1985. In December, 1986 he was elected Treasurer of the company and was elected to the position of Vice President and Chief Financial Officer in May, 1989. In August, 2003, he was elected to the position of President. He was elected a director of the company by the Board in January, 2004. In February, 2004, in addition to his position as President, he was elected to the office of Chief Operating Officer. In April 2005, he also began serving as Chief Executive Officer. Mr. Pinkston holds the offices of President, Chief Executive Officer and Chief Operating Officer. He holds a Bachelor of Science Degree in Accounting from East Central University of Oklahoma.

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Mr. Schell joined the company in January 1987, as its Secretary and General Counsel. In December 2002, he was elected to the additional position as Senior Vice President. From 1979 until joining the company, Mr. Schell was Counsel, Vice President and a member of the Board of Directors of C&S Exploration, Inc. He received a Bachelor of Science degree in Political Science from Arizona State University and his Juris Doctorate degree from the University of Tulsa Law School. He is a member of the Oklahoma and American Bar Association as well as being a member of the American Corporate Counsel. He also serves as a director of the Oklahoma Independent Producers Association.

Mr. Merrill joined the company in August 2003 and served as its Vice President of Finance until February 2004 when he was elected to the position of Chief Financial Officer and Treasurer. From May 1999 through August 2003, Mr. Merrill served as Senior Vice President, Finance with TV Guide Networks, Inc. From July 1996 through May 1999 he was a Senior Manager with Deloitte & Touche LLP. From July 1994 through July 1996 he was Director of Financial Reporting and Special Projects for MAPCO, Inc. He began his career as an auditor with Deloitte, Haskins & Sells in 1983. Mr. Merrill received a Bachelor of Business Administration Degree in Accounting from the University of Oklahoma and is a Certified Public Accountant.

Mr. Guidry joined Unit Petroleum Company in August 1988 as a Staff Geologist. In 1991, he was promoted to Geologic Manager overseeing the Geologic Operations of the company. In January 2003, he was promoted to Vice President of the West division. In March 2005, Mr. Guidry was promoted to Senior Vice President of Exploration for Unit Petroleum Company. From 1979 to 1988, he was employed as a Division Geologist for Reading and Bates Petroleum Co. From 1978 to 1979, he worked with ANR Resources in Houston. He began his career as an open hole well logging engineer with Dresser Atlas Oilfield Services. Mr. Guidry graduated from Louisiana State University with a Bachelor of Science degree in Geology.

Mr. Cromling joined Unit Drilling Company in 1997 as a Vice-President and Division Manager. In April 2005, he was promoted to the position of Executive Vice-President of Drilling for Unit Drilling Company. In 1980, he formed Cromling Drilling Company which managed and operated drilling rigs until 1987. From 1987 to 1997, Cromling Drilling Company provided engineering consulting services and generated and drilled oil and natural gas prospects. Prior to this, he was employed by Big Chief Drilling for 11 years and served as Vice-President. Mr. Cromling graduated from the University of Oklahoma with a degree in Petroleum Engineering.

Mr. Parks founded Superior Pipeline Company, L.L.C. in 1996. When Superior was acquired by the company in July 2004, he continued with Superior as one of its managers and as its President. From April 1992 through April 1996 Mr. Parks served as Vice-President Gathering and Processing for Cimarron Gas Companies. From December 1986 through March 1992, he served as Vice-President Business Development for American Central Gas Companies. Mr. Parks began his career as an engineer with Cities Service Company in 1978. He received a Bachelor of Science degree in Chemical Engineering from Rice University and his M.B.A. from the University of Texas at Austin.

Mr. Heck joined Unit Drilling Company in March 2005 as Director of Safety, Health and Environment. In January 2008, he was promoted to the position of Vice President, Safety, Health and Environment for Unit Corporation. From 2001 through 2003 Mr. Heck was a Senior Safety and Loss Prevention Manager with the Williams Companies. From 1998 to 2001 he served as Director of Safety, Health and Environment for MAPCO's Thermogas Company. Mr. Heck worked with Union Oil Company of California from 1984 to 1998. He started his career with Union Oil as a drilling engineer prior to serving in various safety, health and environmental positions. Mr. Heck graduated from the New Mexico Institute of Mining and Technology with a Bachelor of Science Degree in Petroleum Engineering.

Item 11. ***Executive Compensation***

In accordance with Instruction G(3) of Form 10-K, the information required by this Item is incorporated into this report by reference to the Proxy Statement (see Item 10 above).

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

The following table provides information for all equity compensation plans as of the fiscal year ended December 31, 2007, under which our equity securities were authorized for issuance:

Plan Category	Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights (a)	Weighted Average Exercise Price of Outstanding Options, Warrants and Rights (b)	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column (a)) (c)
Equity compensation plans approved by security holders (1)	409,630(2)	$ 28.64	1,745,468(3)
Equity compensation plans not approved by security holders			
Total	409,630	$ 28.64	1,745,468

(1) Shares awarded under all above plans may be newly issued, from our treasury or acquired in the open market.

(2) This number includes the following:

267,130 stock options outstanding under the company's Amended and Restated Stock Option Plan.

142,500 stock options outstanding under the Non-Employee Directors' Stock Option Plan.

(3) This number reflects 31,500 shares available for issuance under the Non-Employee Directors' Stock Option Plan and 1,713,968 shares available for issuance under the Unit Corporation Stock and Incentive Compensation Plan. No more than 2,000,000 of the shares available under the Unit Corporation Stock and Incentive Compensation Plan may be issued as incentive stock options and all of the shares available under this plan may be issued as restricted stock. In addition, shares related to grants that are forfeited, terminated, cancelled, expire unexercised, or settled in such manner that all or some of the shares are not issued to a participant shall immediately become available for issuance.

In accordance with Instruction G(3) of Form 10-K, the information required by this Item is incorporated into this report by reference to the Proxy Statement (see Item 10 above).

Item 13. ***Certain Relationships and Related Transactions, and Director Independence***

In accordance with Instruction G(3) of Form 10-K, the information required by this Item is incorporated into this report by reference to the Proxy Statement (see Item 10 above).

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

In accordance with Instruction G(3) of Form 10-K, the information required by this Item is incorporated into this report by reference to the Proxy Statement (see Item 10 above).

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PART IV

Item 15. ***Exhibits, Financial Statement Schedules***
(a) Financial Statements, Schedules and Exhibits:

1. ***Financial Statements:***
Included in Part II of this report:

Report of Independent Registered Public Accounting Firm
Consolidated Balance Sheets as of December 31, 2007 and 2006
Consolidated Statements of Income for the years ended December 31, 2007, 2006 and 2005
Consolidated Statements of Changes in Shareholders Equity for the years ended December 31, 2005, 2006 and 2007
Consolidated Statements of Cash Flows for the years ended December 31, 2007, 2006 and 2005
Notes to Consolidated Financial Statements

2. ***Financial Statement Schedules:***
Included in Part IV of this report for the years ended December 31, 2007, 2006 and 2005:

Schedule II Valuation and Qualifying Accounts and Reserves

Other schedules are omitted because of the absence of conditions under which they are required or because the required information is included in the consolidated financial statements or notes thereto.

3. ***Exhibits:***
The exhibit numbers in the following list correspond to the numbers assigned such exhibits in the Exhibit Table of Item 601 of Regulation S-K.

3.1	Restated Certificate of Incorporation of Unit Corporation (filed as Exhibit 3.1 to Form S-3 (file No. 333-83551), which is incorporated herein by reference).
3.1.2	Certificate of Amendment of Amended and Restated Certificate of Incorporation of the Company (filed as Exhibit 3.1 to Unit's Form 8-K, dated May 9, 2006 which incorporated herein by reference).
3.2	By-Laws of Unit Corporation as amended and restated through June 19, 2007 (filed as Exhibit 3.2 to Unit s Form 8-K, dated June 21, 2007 which is incorporated herein by reference).
4.2.1	Form of Common Stock Certificate (filed as Exhibit 4.1 on Form S-3 as S.E.C. File No. 333-83551, which is incorporated herein by reference).
4.2.2	Rights Agreement as amended and restated on May 18, 2005 (filed as Exhibit 4.1 to Unit s Form 8-K dated May 18, 2005, which is incorporated herein by reference).
4.3	Indenture (filed as Exhibit 4.3 to Unit s Form S-3 filed with the S.E.C. File No. 333-104165, which is incorporated herein by reference).
10.1.1	

	Third Amended and Restated Security Agreement effective November 1, 2005 (filed as Exhibit 10.2 to Unit s Form 8-K dated November 4, 2005, which is incorporated herein by reference).
10.1.2*	Form of Unit Corporation Restricted Stock Bonus Agreement (filed as Exhibit 10.1 to Unit s Form 8-K dated December 13, 2005, which is incorporated herein by reference).
10.1.3*	Unit Corporation Stock and Incentive Compensation Plan (incorporated herein by reference to Appendix A to the Company's Proxy Statement for its 2006 Annual Meeting filed on March 29, 2006).

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10.1.4	Consulting Agreement with John G. Nikkel dated April 9, 2007 (filed as Exhibit 10.1 to Unit s Form 8-K dated April 10, 2007, which is incorporated herein by reference).
10.1.5	First Amended and Restated Senior Credit Agreement dated May 24, 2007 (filed as Exhibit 10.1 to Unit s Form 8-K dated May 25, 2007, which is incorporated herein by reference).
10.2.1	Unit 1979 Oil and Gas Program Agreement of Limited Partnership (filed as Exhibit I to Unit Drilling and Exploration Company s Registration Statement on Form S-1 as S.E.C. File No. 2-66347, which is incorporated herein by reference).
10.2.2	Unit 1984 Oil and Gas Program Agreement of Limited Partnership (filed as an Exhibit 3.1 to Unit 1984 Oil and Gas Program s Registration Statement Form S-1 as S.E.C. File No. 2-92582, which is incorporated herein by reference).
10.2.3*	Unit Drilling and Exploration Employee Bonus Plan (filed as Exhibit 10.16 to Unit s Registration Statement on Form S-4 as S.E.C. File No. 33-7848, which is incorporated herein by reference).
10.2.4*	Unit s Amended and Restated Stock Option Plan (filed as an Exhibit to Unit s Registration Statement on Form S-8 as S.E.C. File No s. 33-19652, 33-44103, 33-64323 and 333-39584 which is incorporated herein by reference).
10.2.5*	Unit Corporation Non-Employee Directors Stock Option Plan (filed as an Exhibit to Form S-8 as S.E.C. File No. 33-49724, which is incorporated herein by reference).
10.2.6*	Unit Corporation Employees Thrift Plan (filed as an Exhibit to Form S-8 as S.E.C. File No. 33-53542, which is incorporated herein by reference).
10.2.7	Unit Consolidated Employee Oil and Gas Limited Partnership Agreement (filed as an Exhibit to Unit s Annual Report under cover of Form 10-K for the year ended December 31, 1993, which is incorporated herein by reference).
10.2.8*	Unit Corporation Salary Deferral Plan (filed as an Exhibit to Unit s Annual Report under cover of Form 10-K for the year ended December 31, 1993, which is incorporated herein by reference).
10.2.9*	Separation Agreement, dated May 11, 2001, between the Registrant and Mr. Kirchner (filed as Exhibit 99.4 to Unit s Form 8-K dated May 18, 2001, which is incorporated herein by reference).
10.2.10*	Consulting Agreement, dated December 16, 2004, between John G. Nikkel and the Registrant (filed as Exhibit 10.4 to Unit s Form 8-K dated December 20, 2004).
10.2.11*	Unit Corporation Separation Benefit Plan for Senior Management as amended (filed as an Exhibit 10.1 to Unit s Form 8-K dated December 20, 2004).
10.2.12*	Unit Corporation Special Separation Benefit Plan as amended (filed as Exhibit 10.3 to Unit s Form 8-K dated December 20, 2004).
10.2.13*	Consulting Agreement Renewal dated April 12, 2006, between John G. Nikkel and the Registrant (filed as Exhibit 99.1 to Unit's Form 8-K dated April 18, 2006).
10.2.14	Unit 2000 Employee Oil and Gas Limited Partnership Agreement of Limited Partnership (filed as an Exhibit to Unit s Annual Report under the cover of Form 10-K for the year ended December 31, 1999).
10.2.15*	Unit Corporation 2000 Non-Employee Directors Stock Option Plan (filed as an Exhibit to Form S-8 as S.E.C. File No. 333-38166, which is incorporated herein by reference).
10.2.16	Unit 2001 Employee Oil and Gas Limited Partnership Agreement of Limited Partnership (filed as an Exhibit to Unit s Annual Report under the cover of Form 10-K for the year ended December 31, 2000).

10.2.17	Unit 2002 Employee Oil and Gas Limited Partnership Agreement of Limited Partnership (filed as an Exhibit to Unit s Annual Report under cover of Form 10-K for the year ended December 31, 2001).
10.2.18	Unit 2003 Employee Oil and Gas Limited Partnership Agreement of Limited Partnership (filed as an Exhibit to Unit s Annual Report under cover of Form 10-K for the year ended December 31, 2002).
10.2.19	Unit 2004 Employee Oil and Gas Limited Partnership Agreement of Limited Partnership (filed as an Exhibit to Unit s Annual Report under cover of Form 10-K for the year ended December 31, 2003).
10.2.20	Unit 2005 Employee Oil and Gas Limited Partnership Agreement of Limited Partnership (filed as an Exhibit to Unit s Annual Report under cover of Form 10-K for the year ended December 31, 2004).
10.2.21*	Form of Indemnification Agreement entered into between the Company and its executive officers and directors (filed as Exhibit 10.1 to Unit s Form 8-K dated February 22, 2005, which is incorporated herein by reference).
10.2.22	Unit 2006 Employee Oil and Gas Limited Partnership Agreement of Limited Partnership (filed as an Exhibit to Unit's Annual Report under cover of Form 10-K for the year ended December 31, 2005).
10.2.23	Unit 2007 Employee Oil and Gas Limited Partnership Agreement of Limited Partnership (filed as an Exhibit to Unit s Annual Report under cover of Form 10-K for the year ended December 31, 2006).
10.2.24	Separation Benefit Plan as amended August 21, 2007 (filed as an Exhibit to Unit's Form 10-Q for the quarter ended September 30, 2007).
10.2.25	Unit 2008 Employee Oil and Gas Limited Partnership Agreement of Limited Partnership (filed herein).
21	Subsidiaries of the Registrant (filed herein).
23.1	Consent of Independent Registered Public Accounting Firm, PricewaterhouseCoopers LLP (filed herein).
23.2	Consent of Ryder Scott Company, L.P. (filed herein).
31.1	Certification of Chief Executive Officer under Rule 13a - 14(a) of the Exchange Act (filed herein).
31.2	Certification of Chief Financial Officer under Rule 13a - 14(a) of the Exchange Act (filed herein).
32	Certification of Chief Executive Officer and Chief Financial Officer under Rule 13a-14(a) of the Exchange Act and 18 U.S.C. Section 1350, as adopted under Section 906 of the Sarbanes-Oxley Act of 2002 (filed herein).

* Indicates a management contract or compensatory plan identified under the requirements of Item 15 of Form 10-K.

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Schedule II

UNIT CORPORATION AND SUBSIDIARIES

VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

Allowance for Doubtful Accounts:

Description	Balance at Beginning of Period	Additions Charged to Costs & Expenses	Deductions & Net Write-Offs	Balance at End of Period
		(In thousands)		
Year ended December 31, 2007	$ 1,600	$ 1,750	$	$ 3,350
Year ended December 31, 2006	$ 1,612	$	$ 12	$ 1,600
Year ended December 31, 2005	$ 1,661	$	$ 49	$ 1,612

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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.

UNIT CORPORATION

Date: February 28, 2008

By: /s/ Larry D. Pinkston
LARRY D. PINKSTON
President and Chief Executive Officer

(Principal Executive 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 the 28th day of February, 2008.

Name	Title
/s/ John G. Nikkel **John G. Nikkel**	Chairman of the Board and Director
/s/ Larry D. Pinkston **Larry D. Pinkston**	President and Chief Executive Officer, Chief Operating Officer and Director (Principal Executive Officer)
/s/ David T. Merrill **David T. Merrill**	Chief Financial Officer and Treasurer (Principal Financial Officer)
/s/ Stanley W. Belitz **Stanley W. Belitz**	Controller (Principal Accounting Officer)
/s/ J. Michael Adcock **J. Michael Adcock**	Director
/s/ Gary Christopher **Gary Christopher**	Director
/s/ Don Cook **Don Cook**	Director
/s/ King P. Kirchner **King P. Kirchner**	Director
/s/ William B. Morgan **William B. Morgan**	Director

/s/ ROBERT SULLIVAN, JR.	Director
Robert Sullivan, Jr.	
/s/ JOHN H. WILLIAMS	Director
John H. Williams	

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EXHIBIT INDEX

Exhibit No.	Description
10.2.25	Unit 2008 Employee Oil and Gas Limited Partnership Agreement of Limited Partnership.
21	Subsidiaries of the Registrant.
23.1	Consent of Independent Registered Public Accounting Firm, PricewaterhouseCoopers LLP.
23.2	Consent of Ryder Scott Company, L.P.
31.1	Certification of Chief Executive Officer under Rule 13a 14(a) of the Exchange Act.
31.2	Certification of Chief Financial Officer under Rule 13a 14(a) of the Exchange Act.
32	Certification of Chief Executive Officer and Chief Financial Officer under Rule 13a-14(a) of the Exchange Act and 18 U.S.C. Section 1350, as adopted under Section 906 of the Sarbanes-Oxley Act of 2002.