CALCULATION OF REGISTRATION FEE

Title of each Class of Securities to be Offered	Maximum Aggregate Offering Price	Amount of Registration Fee (1)
6.625% Senior Subordinated Notes due 2021	$250,000,000	$29,025.00
Guarantees of 6.625% Senior Subordinated Notes due 2021	(2)	(2)

(1) Calculated in accordance with Rule 457(r) of the Securities Act of 1933, as amended.

(2) In accordance with Rule 457(n), no separate fee is payable with respect to guarantees of the senior subordinated notes being registered.

Table of Contents

Filed pursuant to Rule 424(b)(2)
SEC File No. 333-173884

PROSPECTUS SUPPLEMENT
(To prospectus dated May 3, 2011)

$250,000,000

Unit Corporation

6 5/8% Senior Subordinated Notes due 2021

The Senior Subordinated Notes

- Maturity: The notes will mature on May 15, 2021.

- Interest Payments: The notes will pay interest semi-annually in cash in arrears on May 15 and November 15 of each year, beginning on November 15, 2011.

- Guarantees: All of our existing and future domestic restricted subsidiaries.

- Ranking: The notes and the guarantees will be our general unsecured senior subordinated obligations and will be effectively subordinated to all of our existing and future senior debt. In addition, the notes will be structurally subordinated to all of the liabilities of our subsidiaries that are not guaranteeing the notes.

- Optional Redemption: On and after May 15, 2016, we may redeem all or a part of the notes at the redemption prices specified under "Description of the Notes —Optional redemption," plus accrued and unpaid interest on the notes, if any, to the applicable redemption date. Before May 15, 2014, we may redeem up to 35% of the original principal amount of the notes with the net cash proceeds from certain equity offerings. In addition, at any time before May 15, 2016, we may redeem all or part of the notes at a redemption price equal to 100% of the principal amount thereof plus a "make whole" premium specified in this prospectus supplement plus accrued and unpaid interest, if any, to the redemption date.

- Form: The notes will be issued only in registered form in minimum denominations of $2,000 and integral multiples of $1,000 in excess thereof.

Investing in the notes involves risks that are described in the "Risk Factors" section beginning on page S-15 of this prospectus supplement.

	Per Note	Total
Public offering price (1)	100.0%	$250,000,000
Underwriting discount	2.0%	$ 5,000,000
Proceeds, before expenses, to us (1)	98.0%	$245,000,000

(1) Plus accrued interest, if any, from May 18, 2011.

The notes will not be listed on any securities exchange. Currently there is no public market for the notes.

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or determined if this prospectus supplement or the accompanying prospectus is truthful or complete. Any representation to the contrary is a criminal offense.

The notes will be ready for delivery in book-entry form only through the facilities of The Depository Trust Company for the accounts of its participants, including Euroclear Bank S.A./N.V., as operator of the Euroclear System, and Clearstream Banking, *société anonyme*, on or about May 18, 2011.

Joint Book-Running Managers

BMO Capital Markets

BofA Merrill Lynch

Co-Managers

BBVA	**Credit Agricole CIB**	**BNP PARIBAS**
Comerica Securities	**BOSC, Inc.**	**BB&T Capital Markets**

The date of this prospectus supplement is May 11, 2011.

Table of Contents

TABLE OF CONTENTS

We have not authorized anyone to provide any information other than that contained or incorporated by reference in this prospectus supplement, the accompanying prospectus or in any free writing prospectus prepared by or on behalf of us or to which we have referred you. We take no responsibility for, and can provide no assurance as to the reliability of, any other information that others may give you. Further, you should not assume that the information contained in or incorporated by reference in this prospectus supplement or the accompanying prospectus is accurate as of any date other than the dates of this prospectus supplement or the accompanying prospectus or that any information we have incorporated by reference is accurate as of any date other than the date of the document incorporated by reference.

We expect that delivery of the notes will be made to investors on or about May 18, 2011, which will be the fifth business day following the date of this prospectus supplement (such settlement being referred to as "T+5"). Under Rule 15(c)6-1 under the Securities Exchange Act of 1934, trades in the secondary market are required to settle in three business days, unless the parties to any such trade expressly agree otherwise. Accordingly, purchasers who wish to trade notes before the delivery of the notes will be required to specify an alternate settlement arrangement at the time of any trade to prevent a failed settlement. Purchasers of the notes who wish to trade the notes before their date of delivery should consult their advisors.

FORWARD-LOOKING STATEMENTS

This prospectus supplement, the accompanying prospectus and the documents incorporated by reference herein or therein may include "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended (the "Securities Act"), and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). All statements, other than statements of historical facts, included or incorporated by reference in this prospectus supplement and the accompanying prospectus, 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 and how we expect to fund our 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 and drilling prospects;
- the estimates of our proved oil, NGLs and natural gas reserves;
- oil, NGLs and natural gas reserve potential;
- development and infill drilling potential;
- expansion and other development trends of the oil and natural gas industry;
- our business strategy;
- production of oil, NGLs and natural gas;
- 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;
- demand for our drilling rigs and drilling rig rates;
- our belief that the final outcome of our legal proceedings will not materially affect our financial results; and
-

our ability to timely secure third party services used in completing our wells.

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 our actual results to differ materially from our expectations, including:

- the risk factors discussed in this prospectus supplement and in the documents we incorporate by reference;
- general economic, market or business conditions;
- the availability of and nature or lack of business opportunities that we pursue;
- demand for our land drilling services;
- changes in laws or regulations;
- decreases or increases in commodity prices; 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 prospectus supplement to reflect the occurrence of unanticipated events.

Table of Contents

SUMMARY

This summary highlights information about us and the notes. This summary is not complete and may not contain all of the information that you should consider before investing in the notes. For a more complete understanding of our company, we encourage you to read the full text of this prospectus supplement, the accompanying prospectus and the information incorporated by reference. Unless otherwise indicated or required by the context, the terms "corporation", "company", "Unit", "us", "our", "we" and "its" refer to Unit Corporation and, as appropriate, Unit Corporation and/or one or more of its subsidiaries. For the definition of certain industry terms and acronyms, please see the Glossary.

Company Overview

Unit Corporation is an integrated energy company with operations predominantly focused on the Mid-Continent region of the United States. While founded in 1963 as a domestic land contract drilling company, today we are also engaged in the domestic exploration, development and production of crude oil and natural gas and midstream services businesses. Our operations are generally conducted through our three principal wholly owned subsidiaries: Unit Petroleum Company (our oil and natural gas segment), Unit Drilling Company (our contract drilling segment), and Superior Pipeline Company, L.L.C. (our midstream segment). We believe that this integrated approach is distinctive for a company our size and provides us with operational flexibility, an advantageous cost structure and an understanding of industry dynamics and trends.

Our operations are focused on emerging liquids-rich plays like the Granite Wash in Texas, Segno field in Texas, Bakken shale of North Dakota and Montana, and Marmaton play in Oklahoma. Unit Petroleum Company maintains a strong position with 104 million barrels of oil equivalent ("MMBoe") of proved reserves across 1,824,545 gross acres (695,242 net acres, approximately 49% of which were developed) as of December 31, 2010. Unit Drilling Company, through its fleet of 122 drilling rigs, drills onshore oil and natural gas wells for Unit Petroleum Company as well as for a wide range of other independent exploration and production companies. Superior Pipeline Company, L.L.C. provides gathering, processing and transmission services with over 860 miles of pipeline to move our gas and that of independent third parties.

Recently, the majority of our operating income has come from our oil and natural gas segment. In 2010, 70% of our operating income was generated from that segment, compared to 74% in 2009 excluding a $281.2 million non-cash ceiling test impairment of our natural gas and oil properties in 2009.

Presented below is our operating income by segment and as a percentage of total operating income during the three months ended March 31, 2011 and 2010 and the years 2010, 2009 and 2008, excluding a non-cash ceiling test write down of our oil and natural gas properties of $282.0 million in 2008 and $281.2 million in 2009.

	Operating Income					Percentage of Total				
	Three Months Ended March 31, (unaudited)		Year Ended December 31,			Three Months Ended March 31,		Year Ended December 31,		
(in thousands, except percentages)	2011	2010	2010	2009	2008	2011	2010	2010	2009	2008
Unit Petroleum Company (Oil and Natural Gas)	$38,789	$48,683	$176,649	$155,464	$278,209	53%	82%	70%	74%	52%
Unit Drilling Company (Contract Drilling)	27,847	6,168	59,601	50,909	239,979	38%	10%	23%	24%	45%
Superior Pipeline Company, L.L.C. (Midstream)	6,936	4,468	16,985	4,616	16,442	9%	8%	7%	2%	3%

We refer you to "Reconciliation of non-GAAP Operating Income to GAAP Income (Loss) Before Income Taxes" appearing later in this Summary for a table that reconciles non-GAAP operating income to GAAP income (loss) before income taxes.

Unit Petroleum Company (Oil and Natural Gas)

Our current operations are principally focused in the Anadarko Basin, a liquids-rich area located in Oklahoma, where we have approximately 57 MMBoe of proved reserves (55% of our total estimated proved reserves). These areas are renowned as having long-lived reserves, high drilling success rates, multiple pay horizons, high liquids and oil concentrations, and established production histories. Within this region we are actively exploiting the Granite Wash formation in Roberts and Hemphill counties, Texas and the Marmaton in Beaver County, Oklahoma. We are also active in our Segno field (a Wilcox formation) located in Polk, Tyler and Hardin counties, Texas and the Bakken shale of North Dakota and Montana.

We began to develop our oil and natural gas operations in 1979 as a means of diversifying our contract operations. As of December 31, 2010, we have an interest in 7,836 gross producing wells (approximately 1,641 net wells) and have accumulated approximately 1,824,545 gross acres (695,242 net acres, approximately 49% of which were developed). As of March 31, 2011, we operate more than 76% of our proved developed oil and gas reserves, which enables us to more effectively control our operations. Our proved reserves have grown an average of 10% annually since 2001 to 104 MMBoe as of December 31, 2010. Moreover, over the last 27 years, we have consistently grown our proved reserves, replacing on average 218% of our annual production during that period. We have achieved this growth through development drilling and targeted acquisitions.

The following table summarizes our net leasehold acreage, percentage of undeveloped net acreage, our estimated proved reserves, percentage of the proved reserves that is developed and our 2010 average net daily production. Our proved reserves are estimates as of December 31, 2010, based on a report prepared by Ryder Scott Company, L.P. ("Ryder Scott"), our independent reserve engineers in accordance with the rules of the Securities and Exchange Commission (the "SEC") regarding oil and natural gas reserve reporting currently in effect.

Our Divisions/Area	Net Acreage	% Undev. Net Acreage	Proved Reserves (MBoe)	% Proved Reserves Dev.	2010 Average Net Daily Production Gas (Mcf)	Oil (Bbls)	NGL (Bbls)
West division (consists principally of the Rocky Mountain region, New Mexico, Western and Southern Texas and the Gulf Coast region)	255,300	63%	24,027	86%	29,989	1,997	1,717
East division (consists principally of the Appalachian region, Arkansas, East Texas, Northern Louisiana and Eastern Oklahoma)	133,741	54%	22,655	90%	38,436	37	12
Central division (consists principally of Kansas, Western Oklahoma and the Texas Panhandle)	306,201	40%	57,010	73%	43,235	2,133	2,515
Total (or average)	695,242	51%	103,692	80%	111,660	4,167	4,244

Unit Drilling Company (Contract Drilling)

Our contract drilling business is conducted through Unit Drilling Company and its subsidiary, Unit Texas Drilling, L.L.C. These companies drill onshore oil and natural gas wells for Unit Petroleum Company as well as for a wide range of other independent oil and natural gas exploration and production companies. We are the fifth largest domestic land drilling contractor in the United States with a fleet of 122 drilling rigs, based on the Land Rig News Letter (March 31, 2011 publication date). The horsepower rating of the drilling rigs in our fleet ranges from 400 to 4,000 with 71% of our fleet in the range of 750 to 2,000, which experiences higher customer demand. As of March 31, 2011, approximately 62% of our drilling rigs are under contract. In addition to our drilling rigs, we provide the drilling crews and most of the ancillary equipment needed to operate our drilling rigs including top drives, skidding systems, large air compressors, trucks and other support equipment.

Our operations are conducted mainly in Oklahoma, Texas, Louisiana, Wyoming, Colorado, Utah, Montana and North Dakota. We continue to look for opportunities to expand our geographic areas of operation by either acquiring drilling rigs in other regions or by moving our drilling rigs into those regions. For example, as of March 31, 2011, we have nine drilling rigs working in the Bakken Shale play in North Dakota and Montana, an increase of seven drilling rigs from January 1, 2010. In addition, by the end of third quarter 2011, we plan to have moved an additional four new drilling rigs into that play. Within the regions in which we operate, our customers have increasingly become focused on horizontal drilling for oil and gas reserves. These reserves are typically found in deep geological formations. Our drilling rig fleet is capable of achieving depths ranging between 5,000 to 40,000 feet, which are required to develop these reserves. Currently, 70% of our drilling rig fleet is capable of horizontal drilling with 67 drilling rigs equipped with integrated top drives to better improve the directional and horizontal drilling effectiveness.

We continue to enhance and refurbish our drilling rig fleet to better meet the needs of our customers. In 2010, we began constructing five new 1,500 horsepower, diesel-electric drilling rigs. One of these new drilling rigs has been completed and was delivered and placed in service in the Bakken shale in March 2011. The remaining four drilling rigs are expected to be completed later in 2011. Each of these five new drilling rigs will initially be dedicated to a two-year drilling contract. Upon completion of the additional four drilling rigs, we will have 126 drilling rigs in our fleet. In addition, in 2010 we refurbished and upgraded 30 of our existing drilling rigs to meet the demand for horizontal drilling. For 2011, we intend to allocate approximately 42% of our contract drilling capital expenditure budget to continue refurbishment within our drilling rig fleet.

The following table shows certain information about our drilling rigs (including their distribution) as of March 31, 2011:

	Contracted Drilling Rigs	Non-Contracted Drilling Rigs	Total Drilling Rigs	Average Rated Drilling Depth (ft)
Anadarko Basin Oklahoma	27	9	36	17,472
Panhandle of Texas	15	17	32	14,344
Arkoma Basin	3	4	7	13,286
East Texas, Louisiana, Gulf Coast and South Texas	13	3	16	18,063
North Texas Barnett Shale	1	4	5	11,000
Rocky Mountains	16	10	26	18,423
Totals	75	47	122	16,426

We maintain long-standing customer relationships with numerous large independent oil and gas companies through both short and long term contracts. While a number of our contracts are on a well-to-well basis, as of March 31, 2011, 41 of our drilling rigs are under term contracts, ranging from six months to two years, and the three new drilling rigs expected to be delivered later in 2011 will also be placed in service under contracts with two year terms. We plan to continue seeking long-term commitments for the use of our drilling rigs.

Contract terms and payment rates vary depending on the type of contract, the duration of the work, the equipment and services supplied and other matters. Our contracts are generally one of three types: daywork; footage; or turnkey. Under a daywork contract, we provide the drilling rig with the required personnel and the operator of the well supervises the drilling of the well. We are paid on a negotiated rate paid for each day the drilling rig is used. Footage contracts are paid on completion of the well at a negotiated rate for each foot drilled. We drilled four wells under a footage contract in 2010. Under turnkey contracts we drill the well to a specified depth for a set amount and provide most of the required equipment and services. With the exception of the footage contracts noted above, all of our work during the last three years was under daywork contracts.

Superior Pipeline Company (Midstream)

Our midstream operations are conducted through Superior Pipeline Company, L.L.C. and its subsidiaries. Through these companies, we are engaged in the buying, selling, gathering, processing and treating of natural gas as well as producing, transporting and selling NGLs and condensate. Our operations consist of a mix of fee-based and commodity-based services.

Our operations are conducted in Oklahoma, Texas, Kansas, Pennsylvania and West Virginia. As of March 31, 2011, we owned and operated three natural gas treatment plants, 10 operating processing plants, and 34 active gathering systems with 867 miles of pipeline. Our 34 gathering systems are located in several active natural gas producing areas in Oklahoma, Texas and Kansas. We continue to look for opportunities to expand our midstream operations into high growth natural gas regions within the United States. In the first quarter of 2011, we began construction of a 16 mile pipeline in Preston County, West Virginia. That system will have a capacity of approximately 220 MMcf per day and is planned to be operational by mid-2011.

The following table presents certain information regarding our midstream segment for the periods indicated.

	Three Months Ended March 31,		Year Ended December 31,		
	2011	2010	2010	2009	2008
Gas gathered—MMBtu/day	185,730	180,117	183,867	183,989	197,367
Gas processed—MMBtu/day	86,445	76,513	82,175	75,908	67,796
NGLs sold—gallons/day	328,333	253,707	271,360	243,492	195,837

Our midstream services are usually provided to each customer under term contracts lasting more than one year. These customer agreements include the following types of contracts: fee based, percent of proceeds (“POP”) and percent of index (“POI”). Fee based contracts provide for a set fee for gathering and transporting raw natural gas. POP contracts allow us to retain a negotiated percentage of the sale proceeds from residue natural gas and natural gas liquids we gather and process, with the remainder being remitted to the producer. Under POI contracts, we purchase raw well-head natural gas from the producer at a stipulated index price; and, after processing the natural gas, we sell the processed residual gas and the produced natural gas liquids to third parties.

Presented below is the percentage of our total volume and operating margin in our midstream segment generated by the different types of contract agreement during the years 2010, 2009 and 2008.

	Total Volumes			Operating Margins		
	2010	2009	2008	2010	2009	2008
Fee Based Contracts	51%	59%	66%	15%	22%	20%
Percent of Proceeds (“POP”)	33%	23%	18%	38%	30%	33%
Percent of Index (“POI”)	16%	18%	16%	47%	48%	47%

Business Strengths

Integrated Business Approach Reduces Costs, Enhances Returns and Maintains Operating Flexibility. We believe our integrated business model provides us with operational flexibility, an advantageous cost structure and a better understanding of industry dynamics and trends.

Geographically Concentrated, Quality Oil & Natural Gas Asset Base. In our key operating areas, our properties are concentrated in locations that enable us to establish economies of scale within our three segments. Today, our producing properties generate a significant amount of cash flow due to their liquids rich nature.

Proven Track Record of Consistently Adding Reserves. Over the past 27 years, we have consistently grown our proved reserves replacing on average 218% of our annual production. We believe our inventory of our existing properties should allow us to continue to grow our proved reserves and production for the next several years.

Leading Service Provider in High Growth Basins. Our drilling fleet and midstream operations are focused on liquids rich basins. We believe those services and the diversity of our drilling fleet provide us a competitive advantage relative to many of our peers.

Longstanding and Diversified Customer Base. We maintain long-term customer relationships with numerous large independent oil and gas companies. We believe our strong relationships enhance the stability of our cash flows from our drilling and midstream segments.

Business Strategy

Our main business objective is to enhance our shareholders' value through sustainable, capital-efficient growth while maintaining a strong credit profile and financial flexibility. Our plan to carry out that objective is set forth in more detail below.

Increase Our Exposure to Oil and Liquids Basins. In late 2008, we decided to increase our liquids-rich production. As a result, we increased our liquids production from 25% of our overall production in 2008 to 31% of our overall production in 2010. In the current commodity price environment, we intend to continue to allocate capital towards higher rate of return oil and liquids production.

Manage Drilling Fleet to Maximize Utilization Rates and Dayrate Margins. We manage our drilling rig fleet through a combination of term contracts, geographic diversification and refurbishments and new builds to increase the use of our drilling rigs, meet customer demand and improve our margins.

Expand Midstream Operations by Focusing on High Growth Areas. Our midstream operations are focused on liquids-rich and growth basins in the United States, such as the Granite Wash and the Marcellus shale. In the first quarter of 2011, we began a pipeline construction project in the Marcellus shale. We intend to continue to expand our position within these regions to increase throughput and cash flow.

Maintain a Strong Balance Sheet and Liquidity Access. We intend to maintain a conservative approach to our financial position in order to preserve our operational flexibility and financial stability. As of March 31, 2011, on a pro forma basis after giving effect to this offering and the application of the proceeds described herein, we would have an unfunded borrowing base credit facility and approximately $60 million of cash. We believe that our conservative financial position provides us with strategic advantages to implement our planned development and extension of our asset base.

Pursue Selective Acquisition Opportunities in Existing Basins. We continue to evaluate potential acquisition and joint venture opportunities. Although we believe our multi-year inventory of drilling prospects, geographically diverse drilling rig fleet and midstream expansion opportunities provide us with the ability to grow our operations, we intend to continue to seek select acquisition opportunities primarily in and around our core areas of operation.

Recent Events

2011 Capital Budget. In February 2011, we announced our 2011 capital budget of approximately $605 million. Of that amount, $415 million is budgeted for our oil and natural gas segment, which includes $357 million for drilling and completion activities, a 12% increase over estimated 2010 capital expenditures, $143 million for our contract drilling segment, a 20% increase over estimated 2010 capital expenditures, and $47 million for our midstream segment, a 58% increase over estimated 2010 capital expenditures.

Borrowing Base Redetermination. As of April 1, 2011, the borrowing base under our credit facility was redetermined to be $600 million (which will be reduced by approximately $54 million on the closing of the sale of the notes). Our credit facility has a maximum credit amount of $400 million. Our borrowings are limited to the commitment amount that we elect, subject to that maximum amount. As of March 31, 2011, our elected commitment amount was $325 million.

Midstream Agreement. We recently signed a contract to build a 12-mile pipeline system and compressor station in Tioga and Potter Counties, Pennsylvania. This system will deliver gas to Dominion Transmission pipeline and is scheduled to be completed in the fourth quarter of this year.

Our Offices

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 or yards in Beaver, Elk City, Oklahoma City, Oklahoma; Canadian, Houston and Humble, Texas; Englewood and Denver, Colorado; Pinedale, Wyoming; and Pittsburgh, Pennsylvania.

The Offering

The following summary is provided solely for your convenience. This is a brief summary of certain terms of the notes, the guarantees and the related indenture and is not intended to be complete. Certain of the terms and conditions described below are subject to important limitations and exceptions. You should read the full text and more specific details contained elsewhere in this prospectus supplement. For a more complete description of the terms of the notes, the guarantees and the related indenture, including the definitions of certain terms used in this summary, see "Description of the Notes."

Issuer	Unit Corporation
Notes Offered	\$250,000,000 aggregate principal amount of 6 5/8% senior subordinated notes due May 15, 2021 .
Maturity Date	May 15, 2021.
Interest Payment Dates	May 15 and November 15, commencing November 15, 2011.
Guarantees	Each of our existing and future domestic restricted subsidiaries will jointly and severally, fully and unconditionally, guarantee, on a senior subordinated basis, our obligations under the notes and all obligations under the indenture.
Ranking	The notes and guarantees will be our and our subsidiary guarantors' general unsecured, senior subordinated obligations. The notes and the subsidiary guarantees will rank: • subordinated in right of payment to all of our and any subsidiary guarantors' existing and future senior indebtedness, • equally in right of payment with all of our and any subsidiary guarantors' existing and future senior subordinated indebtedness; • senior in right of payment to all of our and any subsidiary guarantors' existing and future subordinated obligations; and • structurally subordinated to the liabilities of our non-guarantor subsidiaries. As of March 31, 2011, after giving effect to this offering and assuming that we had applied the net proceeds we receive from the offering in the manner described under "Use of proceeds," we would have an unfunded borrowing base credit facility and we would have had no senior subordinated indebtedness other than the notes.
Optional Redemption	On and after May 15, 2016, we may redeem all or, from time to time, a part of the notes at the redemption prices described in this prospectus supplement plus accrued and unpaid interest on the notes, if any, to the applicable redemption date.

Table of Contents

	Before May 15, 2014, we may on any one or more occasions redeem up to 35% of the original principal amount of the notes with the net cash proceeds of one or more equity offerings at a redemption price of 106.625% of the principal amount, plus accrued and unpaid interest, if any, to the redemption date, provided that at least 65% of the original principal amount of the notes remains outstanding after each such redemption. In addition, at any time before May 15, 2016, we may redeem the notes, in whole or in part, at a redemption price equal to 100% of the principal amount thereof plus a "make whole" premium specified in this prospectus supplement plus accrued and unpaid interest, if any, to the redemption date. See "Description of the Notes—Optional redemption."
Change of control	If a change of control occurs, subject to certain conditions, we must offer to repurchase from each holder all or any part of such holder's notes at a purchase price in cash equal to 101% of the principal amount of the notes plus accrued and unpaid interest, if any, to the date of purchase. See "Description of the Notes—Change of control."
Certain Covenants	We will issue the notes under an indenture with the Trustee. The indenture will, among other things, limit our ability and the ability of our subsidiary guarantors to, under certain circumstances: • incur additional debt; • pay dividends or make distributions on our capital stock or repurchase, redeem or retire our capital stock or subordinated debt; • make investments; • create liens on our property or assets; • create restrictions on the ability of our restricted subsidiaries to pay dividends or make any loans or other payments to us; • engage in transactions with our affiliates; • transfer or sell assets and subsidiary stock; • consolidate, merge or transfer all or substantially all of our assets and the assets of our subsidiaries; and • engage in any business other than the oil and gas business. These covenants are subject to important exceptions and qualifications, which are described under the caption "Description of the Notes—Certain covenants."

Book-Entry Form	The notes will be issued in book-entry form and will be represented by permanent global certificates deposited with, or on behalf of, The Depository Trust Company ("DTC") and registered in the name of a nominee of DTC. Beneficial interests in any of the notes will be shown on, and transfers will be effected only through, records maintained by DTC or its nominee and any such interest may not be exchanged for certificated securities, except in limited circumstances.
Absence of an established market for the notes	The notes will be new securities and there is currently no established market for the notes. Accordingly, we cannot assure you as to the development or liquidity of any market for the notes. The underwriters have advised us that they currently intend to make a market in the notes. However, they are not obligated to do so, and they may discontinue any market making with respect to the notes without notice. We do not intend to apply for a listing of the notes on any securities exchange or any automated dealer quotation system.
Use of proceeds	We will use the net proceeds of this offering (i) to pay down loan amounts outstanding under our unsecured credit facility, which had approximately $185.0 million outstanding as of March 31, 2011, and (ii) for general working capital purposes. See "Use of Proceeds."
Conflicts of Interest	More than 5% of the net proceeds of the offering will be used to repay borrowings we have received from both Bank of America, N.A., an affiliate of Merrill Lynch, Pierce, Fenner & Smith Incorporated, and BMO Capital Markets Financing, Inc., an affiliate of BMO Capital Markets Corp. Because Merrill Lynch, Pierce, Fenner & Smith Incorporated and BMO Capital Markets Corp. are participating underwriters in this offering, a "conflict of interest" is deemed to exist under the applicable provisions of Rule 5121 of the Financial Industry Regulatory Authority, Inc., or FINRA. Accordingly, this offering will be made in compliance with the applicable provisions of Rule 5121, which require that a "qualified independent underwriter," as defined by the FINRA rules, participate in the preparation of the registration statement and the prospectus and exercise the usual standards of due diligence in respect thereto. BB&T Capital Markets, a division of Scott & Stringfellow, LLC, is serving in that capacity. We have agreed to indemnify BB&T Capital Markets, a division of Scott & Stringfellow, LLC, against certain liabilities incurred in connection with acting as qualified independent underwriter for the offering, including liabilities under the Securities Act. In addition, in accordance with Rule 5121, neither Merrill Lynch, Pierce, Fenner & Smith Incorporated nor BMO Capital Markets Corp. will make sales to discretionary accounts without the prior written consent of the customer.
Trustee	The trustee under the indenture is Wilmington Trust FSB.

You should refer to the section entitled "Risk Factors" beginning on page S-15 for an explanation of certain risks of investing in the notes.

[Table of Contents](#)

Summary Historical Consolidated Financial Data

The following table presents our summary historical consolidated financial data for the periods and as of the dates indicated. The summary statement of operations data for the three years ended December 31, 2010, and the summary balance sheet data as of December 31, 2010, 2009 and 2008 are derived from our audited consolidated financial statements. The summary statement of operations data for the three months ended March 31, 2011 and 2010, and the summary balance sheet data as of March 31, 2011 and 2010 are derived from our unaudited condensed consolidated financial statements included in our Quarterly Reports on Form 10-Q for the quarters ended March 31, 2011 and 2010, respectively. The summary financial data presented below are qualified in their entirety by reference to, and should be read in conjunction with, "Management's Discussion and Analysis of Financial Condition and Results of Operations" and our financial statements and related notes included in this prospectus supplement.

	Three Months Ended March 31,		Year Ended December 31,		
(In thousands)	2011	2010	2010	2009	2008
	(unaudited)				
Statement of operations data:					
Revenues:					
Contract drilling	$ 97,988	$ 60,854	$316,384	$236,315	$ 622,727
Oil and natural gas	109,834	99,053	400,807	357,879	553,998
Gas gathering and processing	39,764	41,135	154,516	108,628	181,730
Other	(181)	5,508	10,138	7,076	(362)
Total revenues	247,405	206,550	881,845	709,898	1,358,093
Expenses:					
Contract drilling:					
Operating costs	52,844	40,900	186,813	140,080	312,907
Depreciation	17,297	13,786	69,970	45,326	69,841
Oil and natural gas:					
Operating costs	30,781	25,034	105,365	87,734	116,239
Depreciation, depletion and amortization	40,268	25,336	118,793	114,681	159,550
Impairment of oil and natural gas properties (1)	—	—	—	281,241	281,966
Gas gathering and processing:					
Operating costs	29,055	32,726	122,146	87,908	150,466
Depreciation and amortization	3,773	3,941	15,385	16,104	14,822
General and administrative	6,892	6,279	26,152	24,011	25,419
Interest, net	54	—	—	539	1,304

Total expenses	180,964	148,002	644,624	797,624	1,132,514
Income (loss) before income taxes	66,441	58,548	237,221	(87,726)	225,579
Income tax expense (benefit):					
Current	—	2,240	(9,935)	(223)	40,877
Deferred	25,414	20,155	100,672	(32,003)	41,077
Total income taxes	25,414	22,395	90,737	(32,226)	81,954
Net income (loss)	$ 41,027	$ 36,153	$146,484	$ (55,500)	$ 143,625

(1) In December 2008, we incurred a non-cash ceiling test write down of our oil and natural gas properties of $282.0 million pre-tax ($175.5 million net of tax) due to low commodity prices at year-end. In March 2009, we incurred a non-cash ceiling test write down of our oil and natural gas properties of $281.2 million pre-tax ($175.1 million net of tax) due to low commodity prices at quarter-end. There was no impact on our compliance with the covenants contained in our credit facility for either of these write downs.

Table of Contents

(In thousands)	Three months ended March 31, 2011	2010	As of December 31, 2010	2009	2008
	(unaudited)				
Balance sheet data:					
Cash and cash equivalents	$ 1, 236	$ 1,039	$ 1,359	$ 1,140	$ 584
Other current assets	187,779	169,682	186,821	126,955	286,001
Total current assets	189,015	170,721	188,180	128,095	286,585
Property and equipment:					
Drilling equipment	1,313,374	1,224,646	1,273,861	1,217,361	1,172,655
Oil and natural gas properties, on the full cost method:					
Proved properties	2,858,466	2,360,943	2,738,093	2,309,193	2,090,623
Undeveloped leasehold not being amortized	181,503	146,940	175,065	140,129	160,034
Gas gathering and processing equipment	208,610	179,440	199,564	172,549	169,402
Transportation equipment	33,266	30,718	31,688	30,726	33,611
Other	30,268	22,856	28,511	22,747	22,484
	4,625,487	3,965,543	4,446,782	3,892,705	3,648,809
Less accumulated depreciation, depletion, amortization and impairment	2,106,979	1,901,659	2,047,031	1,879,112	1,447,157
Net property and equipment	2,518,508	2,063,884	2,399,751	2,013,593	2,201,652
Other long-term assets	78,521	86,565	81,309	86,711	93,629
Total assets	$2,786,044	$2,321,170	$2,669,240	$2,228,399	$2,581,866
Current liabilities	$ 176,274	$ 114,651	147,128	105,147	196,399
Long-term debt	185,000	30,000	163,000	30,000	199,500
Other long-term liabilities	100,821	81,339	92,389	81,126	75,807
Deferred income taxes	579,085	466,697	556,106	446,316	477,061
Total shareholders’ equity	1,744,864	1,628,483	1,710,617	1,565,810	1,633,099
Total liabilities and shareholders’ equity	$2,786,044	$2,321,170	$2,669,240	$2,228,399	$2,581,866

(In thousands, except ratio data)	Three Months Ended March 31, 2011	2010	Year Ended December 31, 2010	2009	2008
	(unaudited)				
Other financial data:					
Net cash provided by operating activities	$ 121,205	$ 79,667	$ 390,072	$ 490,475	$ 689,913
Net cash used in investing activities	(169,212)	(86,926)	(536,261)	(271,927)	(806,141)
Net cash provided by (used in) financing activities	47,884	7,158	146,408	(217,992)	115,736
EBITDA (1)	128,072	101,861	442,345	371,220	753,761
Ratio of earnings to fixed charges (2)(3)(4)	46.3x	71.1x	52.8x	—	31.0x
Pro forma ratio of earnings to fixed charges (5)	16.2x	N/A	14.4x	N/A	N/A

(1) EBITDA is a non-GAAP financial measure that we define as net income (loss) plus adjustments for income tax expense (benefit), interest expense, net, depreciation, depletion and amortization and impairment of long-lived assets. EBITDA, as used and defined by us, may not be comparable to similarly titled measures employed by other companies and is not a measure of performance calculated in accordance with GAAP. EBITDA should not be considered in isolation or as a substitute for operating income (loss), net income (loss), or statement of operations or statement of cash flow data prepared in accordance with GAAP. EBITDA provides no information regarding a company's capital structure, borrowings, interest costs, capital expenditures, working capital movement or tax position. EBITDA does not represent funds available for discretionary use, because those funds are required for debt service, capital expenditures and working capital, income taxes, and other commitments and obligations. However, our management believes EBITDA is useful to an investor in evaluating our operating performance because this measure:

- is widely used by investors in the natural gas and oil industry to measure a company's operating performance without regard to items excluded from the calculation of such term, which can vary substantially from company to company depending upon accounting methods and book value of assets, capital structure and the method by which assets were acquired, among other factors;

- helps investors to more meaningfully evaluate and compare the results of our operations from period to period by removing the effect of our capital structure from our operating structure; and

- is used by our management for various purposes, including as a measure of operating performance, as a basis for strategic planning and forecasting and by our lenders as defined in the credit agreement.

There are significant limitations to the use of EBITDA as a measure of performance, including the inability to analyze the effect of certain recurring and non-recurring items that materially affect our net income (loss), the lack of comparability of results of operations to different companies and the different methods of calculating EBITDA reported by different companies. The following presents a reconciliation of net income (loss) to EBITDA:

(In thousands)	Three Months Ended March 31, 2011	2010	Year Ended December 31, 2010	2009	2008
	(unaudited)				
Reconciliation of Non-GAAP EBITDA to GAAP Net Income (Loss):					
Net income (loss)	$ 41,027	$ 36,153	$146,484	$ (55,500)	$143,625
Interest, net	54	—	—	539	1,304
Depreciation, depletion and amortization	61,577	43,313	205,124	177,166	244,912
Impairment of oil and gas properties	—	—	—	281,241	281,966
Income tax expense (benefit)					

	25,414	22,395	90,737	(32,226)	81,954
EBITDA	$128,072	$101,861	$442,345	$371,220	$753,761

(2) Earnings available for fixed charges represent earnings from continuing operations before income taxes, interest expense and amortization of capitalized interest. Fixed charges represent interest incurred and guaranteed plus that portion of rental expense deemed to be the equivalent of interest.

(3) There were no shares of preferred stock outstanding during any of the time periods indicated in the table.

(4) Earnings for the year ended December 31, 2009 were insufficient to cover fixed charges by $87.7 million due to non-cash ceiling test write down of $281.2 million pre-tax ($175.1 million, net of tax) during the quarter ended March 31, 2009.

(5) Gives effect to the net increase in interest expense resulting from the sale of the principal amount of the notes and the application of the anticipated net proceeds to pay down loan amounts outstanding under our unsecured credit facility as described under “Use of Proceeds”, as if such issuance and repayment occurred on January 1, 2010 for year ended December 31, 2010 and on January 1, 2011 for three months ended March 31, 2011.

Reconciliation of non-GAAP Operating Income to GAAP Income (Loss) Before Income Taxes

The following presents a reconciliation of non-GAAP operating income to GAAP income (loss) before income taxes:

(in thousands, except percentages)	Three Months Ended March 31, 2011	2010	Year Ended December 31, 2010	2009	2008
	(unaudited)				
Oil and Natural Gas Revenue	$109,838	$ 99,053	$ 400,807	$ 357,879	$ 553,998
Less:					
Oil and Natural Gas Operating Expenses	(30,781)	(25,034)	(105,365)	(87,734)	(116,239)
Oil and Natural Gas Depreciation, Depletion and Amortization	(40,268)	(25,336)	(118,793)	(114,681)	(159,550)
Impairment of Oil and Gas Properties	—	—	—	(281,241)	(281,966)
Oil and Natural Gas Operating Income (Loss)	38,789	48,683	176,649	(125,777)	(3,757)
Impairment of Oil and Gas Properties	—	—	—	281,241	281,966
Oil and Natural Gas Operating Income Excluding Impairment of Oil and Gas Properties	$ 38,789	$ 48,683	$ 176,649	$ 155,464	$ 278,209
Oil and Natural Gas %	53%	82%	70%	74%	52%
Contract Drilling Revenue	$ 97,988	$ 60,854	$ 316,384	$ 236,315	$ 622,727
Less:					
Contract Drilling Operating Cost	(52,844)	(40,900)	(186,813)	(140,080)	(312,907)
Contract Drilling Depreciation	(17,297)	(13,786)	(69,970)	(45,326)	(69,841)
Contract Drilling Operating Income	$ 27,847	$ 6,168	$ 59,601	$ 50,909	$ 239,979
Contract Drilling %	38%	10%	23%	24%	45%
Gas Gathering and Processing Revenue	$ 39,764	$ 41,135	$ 154,516	$ 108,628	$ 181,730
Less:					
Gas Gathering and Processing Operating Cost	(29,055)	(32,726)	(122,146)	(87,908)	(150,466)
Gas Gathering and Processing Depreciation and Amortization	(3,773)	(3,941)	(15,385)	(16,104)	(14,822)
Gas Gathering Operating Income	$ 6,936	$ 4,468	$ 16,985	$ 4,616	$ 16,442
Gas Gathering and Processing %	9%	8%	7%	2%	3%

Total Operating Income Excluding Impairment of Oil and Gas Properties	$ 73,568	$ 59,319	$ 253,235	$ 210,989	$ 534,630
Impairment of Oil and Gas Properties	—	—	—	(281,241)	(281,966)
Operating Income (Loss)	73,568	59,319	253,235	(70,252)	252,664
General and Administrative Expenses	(6,892)	(6,279)	(26,152)	(24,011)	(25,419)
Interest Expense, Net	(54)	—	—	(539)	(1,304)
Other Income (Expense), Net	(181)	5,508	10,138	7,076	(362)
Income (Loss) Before Income Taxes	$ 66,441	$ 58,548	$ 237,221	$ (87,726)	$ 225,579

Operating income is a non-GAAP financial measure that we define as revenue less operating expenses, depreciation, depletion, amortization and impairment. Operating income as used and defined by us, may not be comparable to similarly titled measures employed by other companies and is not a measure of performance calculated in accordance with GAAP. Operating income should not be considered in isolation or as a substitute for income (loss) before income taxes, net income (loss), or statement of operations or statement of cash flow data prepared in accordance with GAAP. We have also excluded the impairment of oil and natural gas properties to help investors more meaningfully evaluate and compare the results of our oil and natural gas operations from period to period.

RISK FACTORS

Before you invest in the notes, you should carefully consider the following risks, as well as the other information set forth in this prospectus supplement and the information incorporated by reference herein. If any of the following risks actually occur, our business, financial condition or results of operations may suffer. As a result, we might be unable to repay the principal of and interest on the notes, and you could lose all or part of your investment.

Risks Related to the Notes

Our indebtedness could limit our flexibility, adversely affect our financial health and prevent us from making payments on the notes.

As of March 31, 2011, we had $185.0 million of outstanding borrowings under our credit facility. After giving effect to this offering and the application of the proceeds to repay our outstanding bank borrowings, we will have $250 million of indebtedness outstanding, and have the right to borrow up to an additional $325 million under our credit facility, to which the notes and the subsidiary guaranties will be subordinated.

Our substantial indebtedness could have important consequences to you. For example, it could:

- make it difficult for us to satisfy our obligations with respect to the notes;
- make us more vulnerable to general adverse economic and industry conditions;
- require us to dedicate a substantial portion of our cash flow from operations to payments on our indebtedness, thereby reducing the availability of our cash flow for operations and other purposes;
- limit our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate; and
- place us at a competitive disadvantage compared to competitors that may have proportionately less indebtedness.

In addition, our ability to make scheduled payments or to refinance our obligations depends on our successful financial and operating performance. We cannot assure you that our operating performance will generate sufficient cash flow or that our capital resources will be sufficient for payment of our indebtedness obligations in the future. Our financial and operating performance, cash flow and capital resources depend upon prevailing economic conditions and financial, business and other factors, many of which are beyond our control.

If our cash flow and capital resources are insufficient to fund our debt service obligations, we may be forced to sell material assets or operations, obtain additional capital or restructure our debt. In the event that we are required to dispose of material assets or operations or restructure our debt to meet our debt service and other obligations, we cannot assure you as to the terms of any such transaction or how quickly any such transaction could be completed, if at all.

We may incur substantial additional indebtedness in the future. Our incurrence of additional indebtedness would intensify the risks described above.

The instruments governing our indebtedness will contain various covenants limiting the conduct of our business.

The indenture governing the notes and our credit facility contain various restrictive covenants that limit the conduct of our business. In particular, these agreements will place certain limits on our ability to, among other things:

- incur additional indebtedness, guarantee obligations or issue disqualified capital stock;
- pay dividends or distributions on our capital stock or redeem, repurchase or retire our capital stock;

- make investments or other restricted payments;
- grant liens on assets;
- enter into transactions with stockholders or affiliates;
- engage in sale/leaseback transactions;
- sell assets;
- issue or sell capital stock of certain subsidiaries; and
- merge or consolidate.

In addition, our credit facility also requires us to maintain a minimum current ratio, a maximum leverage ratio and a minimum consolidated net worth.

If we fail to comply with the restrictions in the indenture governing the notes, our credit facility or any other subsequent financing agreements, a default may allow the creditors, if the agreements so provide, to accelerate the related indebtedness as well as any other indebtedness to which a cross-acceleration or cross-default provision applies. If that occurs, we may not be able to make all of the required payments or borrow sufficient funds to refinance such debt. Even if new financing were available at that time, it may not be on terms acceptable to us. In addition, lenders may be able to terminate any commitments they had made to make available further funds.

Any failure to meet our debt obligations could harm our business, financial condition and results of operations.

If our cash flow and capital resources are insufficient to fund our debt obligations, we may be forced to sell assets, seek additional equity or debt capital or restructure our debt. In addition, any failure to make scheduled payments of interest and principal on our outstanding indebtedness would likely result in a reduction of our credit rating, which could harm our ability to incur additional indebtedness on acceptable terms to us, if at all. Our cash flow and capital resources may be insufficient for payment of interest on and principal of our debt in the future, including payments on the notes, and any such alternative measures may be unsuccessful or may not permit us to meet scheduled debt service obligations, which could cause us to default on our obligations and impair our liquidity.

We may be unable to purchase your notes upon a change of control.

Upon the occurrence of a change of control, as defined in the indenture governing the notes, we will be required to offer to purchase your notes. We may not have sufficient financial resources to purchase all of the notes that holders tender to us upon a change of control offer, or might be prohibited from doing so under our credit facility or our other indebtedness. The occurrence of a change of control also could constitute an event of default under our credit facility or our other indebtedness. See "Description of the Notes—Change of Control."

The notes and the guarantees are contractually subordinated to all of our senior indebtedness and all indebtedness of our non-guarantor subsidiaries.

The notes and guarantees will be our and our subsidiary guarantors' general unsecured, senior subordinated obligations and the notes and the subsidiary guarantees will rank subordinated in right of payment to all of our and any subsidiary guarantors' existing and future senior indebtedness. Holders of the notes and subsidiary guaranties may recover less than holders of our senior indebtedness in the event of our insolvency, bankruptcy, reorganization, receivership or similar proceedings. In the event of a bankruptcy, liquidation or dissolution of any of the non-guarantor subsidiaries, holders of their indebtedness, their trade creditors and holders of their preferred equity will generally be entitled to payment on their claims from assets of those subsidiaries before any assets are made available for distribution to us.

As of March 31, 2011, after giving effect to this offering and assuming that we had applied the net proceeds we receive from the offering in the manner described under “Use of Proceeds,” we would have the right to borrow up to $325 million of senior indebtedness under our credit facility and we would have had no senior subordinated indebtedness other than the notes.

Federal and state statutes allow courts, under specific circumstances, to void the guarantees and require noteholders to return payments received from the guarantors.

Creditors of any business are protected by fraudulent conveyance laws which differ among various jurisdictions, and these laws may apply to the issuance of the guarantees by our subsidiary guarantors. The guarantee may be voided by a court, or subordinated to the claims of other creditors, if, among other things:

- the indebtedness evidenced by the guarantees was incurred by a subsidiary guarantor with actual intent to hinder, delay or defraud any present or future creditor of such subsidiary guarantor; or

- our subsidiary guarantors did not receive fair consideration—or reasonably equivalent value—for issuing the guarantees, and the applicable subsidiary guarantors:

  (1) were insolvent, or were rendered insolvent by reason of issuing the applicable guarantee,

  (2) were engaged or about to engage in a business or transaction for which the remaining assets of the applicable subsidiary guarantor constituted unreasonably small capital, or

  (3) intended to incur, or believed that we or they would incur, indebtedness beyond our or their ability to pay as they matured.

In addition, any payment by such subsidiary guarantor pursuant to any guarantee could be voided and required to be returned to such subsidiary guarantor, or to a fund for the benefit of creditors of such subsidiary guarantor.

The measures of insolvency for purposes of these fraudulent transfer laws will vary depending upon the law applied in any proceeding to determine whether a fraudulent transfer has occurred. Generally, however, a subsidiary guarantor would be considered insolvent if:

- the sum of such subsidiary guarantor’s debts, including contingent liabilities, were greater than the fair saleable value of all of such subsidiary guarantor’s assets;

- the present fair saleable value of such subsidiary guarantor’s assets were less than the amount that would be required to pay such subsidiary guarantor’s probable liability on existing debts, including contingent liabilities, as they become absolute and mature; or

- any subsidiary guarantor could not pay debts as they become due.

Based upon financial and other information, we believe that the guarantees are being incurred for proper purposes and in good faith and that each subsidiary guarantor is solvent and will continue to be solvent after this offering is completed, will have sufficient capital for carrying on its business after such issuance and will be able to pay its indebtedness as they mature. We cannot assure you, however, that a court reviewing these matters would agree with us. A legal challenge to a guarantee on fraudulent conveyance grounds may focus on the benefits, if any, realized by us or the subsidiary guarantors as a result of our issuance of the guarantees.

Receipt of payment on the notes, as well as the enforcement of remedies under the subsidiary guarantees, may be limited in bankruptcy or in equity.

An investment in the notes, as in any type of security, involves insolvency and bankruptcy considerations that investors should carefully consider. If we or any of our subsidiary guarantors become a debtor subject to insolvency proceedings under the bankruptcy code, it is likely to result in delays in the payment of the notes and in the exercise of enforcement remedies under the notes or the subsidiary guarantees. Provisions under the bankruptcy code or general principles of equity that could result in the impairment of your rights include the automatic stay, avoidance of preferential transfers by a trustee or a debtor-in-possession, substantive consolidation, limitations of collectability of unmatured interest or attorneys' fees and forced restructuring of the notes.

If a bankruptcy court substantively consolidated us and our subsidiaries, the assets of each entity would be subject to the claims of creditors of all entities. This would expose you not only to the usual impairments arising from bankruptcy, but also to potential dilution of the amount ultimately recoverable because of the larger creditor base. Furthermore, forced restructuring of the notes could occur through the "cram-down" provision of the bankruptcy code. Under this provision, the notes could be restructured over your objections as to their general terms, primarily interest rate and maturity.

Your ability to resell the notes may be limited by a number of factors and the prices for the notes may be volatile.

The notes will be a new class of securities for which there currently is no established market, and we cannot assure you that any active or liquid trading market for these notes will develop. We do not intend to apply for listing of the notes on any securities exchange or on any automated dealer quotation system.

Although we have been informed by the underwriters that they currently intend to make a market in the notes, they are not obligated to do so and any market-making may be discontinued at any time without notice. See "Underwriting." If a market for the notes were to develop, the notes could trade at prices that may be higher or lower than reflected by their initial offering price, depending on many factors, including among other things:

- changes in the overall market for non-investment grade securities;
- changes in our financial performance or prospects;
- the prospects for companies in our industry generally;
- the number of holders of the notes;
- the interest of securities dealers in making a market for the notes; and
- prevailing interest rates.

In addition, the market for non-investment grade indebtedness has been historically subject to disruptions that have caused substantial volatility in the prices of securities similar to the notes offered hereby. The market for the notes, if any, may be subject to similar disruptions. Any such disruption could adversely affect the value of your notes.

A ratings agency downgrade could lead to increased borrowing costs and credit stress.

If one or more rating agencies that rate the notes either assigns the notes a rating lower than the rating expected by the investors, or reduces its rating in the future, the market price of the notes, if any, would be adversely affected. In addition, if any of our other outstanding debt that is rated is downgraded, raising capital will become more difficult for us, borrowing costs under our bank credit facility and other future borrowings may increase and the market price of the notes, if any, may decrease.

If the notes receive an investment grade rating, many of the covenants in the indenture governing the notes will be suspended, thereby reducing some of your protections in the indenture.

If at any time the notes receive investment grade ratings from both Standard & Poor's Rating Services and Moody's Investor Services, subject to certain additional conditions, many of the covenants in the indenture governing the notes, applicable to us and our restricted subsidiaries, including the limitations on indebtedness and disqualified capital stock and restricted payments, will be suspended. While these covenants will be reinstated if we fail to maintain investment grade ratings on the notes or in the event of a continuing default or event of default thereunder, during the suspension period noteholders will not have the protection of these covenants and we will have greater flexibility to incur indebtedness and make restricted payments.

Risks Related to Our Business

Events in the financial markets and the economy could adversely affect our operations and financial condition.

As a result of volatility in oil and natural gas prices and substantial uncertainty in the capital markets due to the uncertain global economic environment, a number of our drilling customers have reduced spending on exploration and development drilling. In addition it is uncertain whether customers and/or vendors and suppliers will be able to access financing necessary to sustain their operations, fulfill their commitments or fund future operations and obligations. The uncertainty in the global economic environment may result in a decrease in demand for drilling rigs. These conditions could have a material adverse effect on our business, financial condition and results of operations.

If demand for oil, NGLs and natural gas is reduced, our ability to market as well as produce our oil, NGLs and natural gas may be negatively affected.

Historically, oil, NGLs and natural gas prices have been extremely volatile, with significant increases and significant price drops being experienced from time to time. In the future, various factors beyond our control will have a significant effect on oil, NGLs and natural gas prices. Such factors include, among other things, the domestic and foreign supply of oil, NGLs and natural gas, the price of foreign imports, the levels of consumer demand, the price and availability of alternative fuels, the availability of pipeline capacity and changes in existing and proposed federal regulation and price controls.

The natural gas market is also unsettled due to a number of factors. At times in the past, production from natural gas wells in some geographic areas of the United States was curtailed for considerable periods of time due to a lack of market demand. When demand for natural gas increased, the number of wells being shut-in for lack of demand was reduced. It is possible, however, that some of our wells may in the future be shut-in or that natural gas will be sold on terms less favorable than might otherwise be obtained should demand for gas lessen in the future. Competition for available markets has been vigorous and there remains great uncertainty about prices that purchasers will pay. Natural gas surpluses could result in our inability to market natural gas profitably, causing us to curtail production or receive lower prices for our natural gas, situations which would adversely affect us.

Disruptions in the financial markets could affect our ability to obtain financing or to refinance existing indebtedness on reasonable terms and may have other adverse effects.

Commercial-credit market disruptions may result in tight credit markets in the United States. Liquidity in the global-credit markets can be severely contracted by market disruptions making terms for certain financings less attractive, and in certain cases, result in the unavailability of certain types of financing. As a result of credit-market turmoil, we may not be able to obtain debt financing, or refinance existing indebtedness on favorable terms, which could affect operations and financial performance.

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.

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, NGLs 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, NGLs and natural gas exploration and production industry and also on the availability of funds to our third party customers.

Our contract drilling operations depend on the level of activity in oil, NGLs 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 demand for our drilling services and would have an adverse effect on our contract drilling revenues, cash flows and profitability. 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 the availability of funds to carry out their drilling operations. 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. Some 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.

Continued growth through acquisitions is not assured.

In the past, we have experienced growth in 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;
- 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.

We have experienced and may continue to experience substantial working capital needs in the growth of our operations. After giving effect to the offering of the notes and the use of proceeds to repay our outstanding bank borrowings, we will have $250 million of indebtedness outstanding, and have the right to borrow up to an additional $325 million under our credit facility. 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, NGLs 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.

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

Exploration and development operations involve numerous risks that may result in dry holes, the failure to produce oil, NGLs 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;
- capacity of pipeline systems;
- 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 midstream 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;
- capacity of pipeline systems;
- 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.

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 can be extremely intense, particularly when the industry is experiencing favorable conditions.

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, 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, NGLs 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 on the first day of the month for each month within the 12-month period before the end of the reporting period 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.

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. Effective December 31, 2010, application of the ceiling test generally requires pricing future revenue at the unweighted arithmetic average of the price on the first day of month for each month within the 12-month period prior to the end of the reporting period, unless prices were defined by contractual arrangements, 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. Prior to 2009, the price was based on the single-day period-end price. The revision to the 12-month average price was made to reduce the effect of short-term volatility and seasonality that previously occurred with single-day pricing. Using the 12-month average may or may not result in write-downs that would have been required had the single-day period-end price been used. 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.

As a result of these ceiling test rules, we recorded a non-cash ceiling test write down of $282.0 million pre-tax ($175.5 million, net of tax) during the year ended December 31, 2008, as well as a non-cash ceiling test write down of $281.2 million pre-tax ($175.1 million, net of tax) during the quarter ended March 31, 2009. No ceiling test write down was necessary during 2010.

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, including associated goodwill and other intangible assets, 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, equipment and related intangible assets. 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 midstream 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 (or to the extent we assume obligations of indemnity or assume liability for certain risks under our drilling contracts), 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 and environmental regulations, litigation or other liabilities could adversely affect our business or our results of operations.

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 environmental, health and safety matters. Many laws and regulations require drilling permits and govern the spacing of wells, rates of production, prevention or handling 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 (or could become) 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, water or fluids used in our operations 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;
- wastewater from our hydraulic fracturing operations;
- 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. The current Congress and White House administration may impose or change laws and regulations that will adversely affect our business. With the trend toward stricter standards, greater regulation and more extensive permit requirements, our risks related to environmental matters and our environmental expenditures could increase in the future. 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 oil, natural gas 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, NGLs 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.

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 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.

We may be affected by climate change and market or regulatory responses to climate change.

Climate change, including the impact of potential global warming regulations, could have a material adverse effect on our results of operations, financial condition, and liquidity. Restrictions, caps, taxes, or other controls on emissions of greenhouse gasses, including diesel exhaust and methane emissions, could significantly increase our operating costs. Restrictions on emissions could also affect our customers that (a) use commodities that we carry to produce energy, (b) use significant amounts of energy in producing or delivering the commodities we carry, or (c) manufacture or produce goods that consume significant amounts of energy or burn fossil fuels, including chemical producers, farmers and food producers, and automakers and other manufacturers. Significant cost increases, government regulation, or changes of consumer preferences for goods or services relating to alternative sources of energy or emissions reductions could materially affect the markets for the commodities associated with our business, which in turn could have a material adverse effect on our results of operations, financial condition, and liquidity. Government incentives encouraging the use of alternative sources of energy could also affect certain of our customers and the markets for certain of the commodities associated with our business in an unpredictable manner that could alter our business activities. Finally, we could face increased costs related to defending and resolving legal claims and other litigation related to climate change and the alleged impact of our operations on climate change. Any of these factors, individually or in operation with one or more of the other factors, or other unforeseen impacts of climate change could reduce the amount of business activity we conduct and have a material adverse effect on our results of operations, financial condition, and liquidity.

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

The marketability of our oil, NGLs and natural gas production depends in part on the availability, proximity and capacity of pipeline systems, refineries and other transportation sources. 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, NGLs 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 2010, our largest customer, QEP Resources, Inc., accounted for approximately 28% 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.

Shortages of completion equipment and services could delay or otherwise adversely affect our oil and natural gas segment's operations.

In the past year or so, the increase in horizontal drilling activity in certain areas has resulted in shortages in the availability of third party equipment and services required for the completion of wells drilled by our oil and natural gas segment. As a result, we have experienced delays in completing some of our wells. Although we have taken steps to try to reduce the delays associated with these services, we anticipate that these services will remain in high demand for the immediate future and could delay, restrict or curtail part of our exploration and development operations, which could in turn harm our results.

Our midstream segment depends on certain natural gas producers and pipeline operators 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 midstream segment unless we were able to acquire comparable volumes from other sources.

The counterparties to our commodity derivative contracts may not be able to perform their obligations to us, which could materially affect our cash flows and results of operations.

To reduce our exposure to adverse fluctuations in the prices of oil and natural gas, we currently, and may in the future, enter into commodity derivative contracts for a significant portion of our forecasted oil and natural gas production. The extent of our commodity price exposure is related largely to the effectiveness and scope of our derivative activities, as well as to the ability of counterparties under our commodity derivative contracts to satisfy their obligations to us. The worldwide financial and credit crisis may have adversely affected the ability of these counterparties to fulfill their obligations to us. If one or more of our counterparties is unable or unwilling to make required payments to us under our commodity derivative contracts, it could have a material adverse effect on our financial condition and results of operations.

We rely on the efforts of our executive officers and other key employees.

We depend greatly on the efforts of our executive officers and other key employees to manage our operations. The loss or unavailability of any of our executive officers or other key employees could have a material adverse effect on our business.

We are subject to various claims and litigation that could ultimately be resolved against us requiring material future cash payments and/or future material charges against our operating income and materially impairing our financial position.

The nature of our business makes us highly susceptible to claims and litigation. We are subject to various existing legal claims and lawsuits, which could have a material adverse effect on our consolidated financial position, results of operations or cash flows. Any claims or litigation, even if fully indemnified or insured, could negatively affect our reputation among our customers and the public, and make it more difficult for us to compete effectively or obtain adequate insurance in the future.

New legislation and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

The U.S. Environmental Protection Agency, or the EPA, has commenced a study of the potential environmental impacts of hydraulic fracturing, including the impact on drinking water sources and public health, and a committee of the U.S. House of Representatives is also conducting an investigation of hydraulic fracturing practices. Legislation has been introduced before Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. In addition, some states, including some in which we operate, have adopted and others are considering adopting regulations that could restrict hydraulic fracturing in certain circumstances. Any new laws, regulation or permitting requirements regarding hydraulic fracturing could lead to operational delay, or increased operating costs or third party or governmental claims, and could result in additional burdens that could serve to delay or limit the drilling services we provide to third parties whose drilling operations could be impacted by these regulations or increase our costs of compliance and doing business as well as delay the development of unconventional gas resources from shale formations which are not commercial without the use of hydraulic fracturing. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that we are ultimately able to produce from our reserves.

Derivatives regulation included in current financial reform legislation could impede our ability to manage business and financial risks by restricting our use of derivative instruments as hedges against fluctuating commodity prices and interest rates.

In July 2010, the Dodd-Frank Wall Street Reform and Consumer Protection Act (the Act) was passed by Congress and signed into law. The Act contains significant derivatives regulation, including a requirement that certain transactions be cleared on exchanges and a requirement to post cash collateral (commonly referred to as “margin”) for such transactions. The Act provides for a potential exception from these clearing and cash collateral requirements for commercial end-users and it includes a number of defined terms that will be used in determining how this exception applies to particular derivative transactions and the parties to those transactions. The Act requires the Commodities Futures and Trading Commission (the CFTC) to promulgate rules to define these terms, but we do not know the definitions that the CFTC will actually promulgate nor how these definitions will apply to us.

We use crude oil, NGLs and natural gas derivative instruments with respect to a portion of our expected production in order to reduce commodity price uncertainty and enhance the predictability of cash flows relating to the marketing of our crude oil, NGLs and natural gas. We also use interest rate derivative instruments to minimize the impact of interest rate fluctuations associated with anticipated debt issuances. As commodity prices increase or interest rates decrease, our derivative liability positions increase; however, none of our current derivative contracts require the posting of margin or similar cash collateral when there are changes in the underlying commodity prices or interest rates that are referred to in these contracts.

Depending on the rules and definitions adopted by the CFTC, we could be required to post collateral with our dealer counterparties for our commodities and interest rate derivative transactions. Such a requirement could have a significant impact on our business by reducing our ability to execute derivative transactions to reduce commodity price and interest rate uncertainty and to protect cash flows. Requirements to post collateral would cause significant liquidity issues by reducing our ability to use cash for investment or other corporate purposes, or would require us to increase our level of debt. In addition, a requirement for our counterparties to post collateral would likely result in additional costs being passed on to us, thereby decreasing the effectiveness of our hedges and our profitability.

USE OF PROCEEDS

We expect the net proceeds from this offering to be approximately $244 million, after deducting estimated fees and expenses (including underwriting discounts and commissions). We intend to use the net proceeds from this offering to repay outstanding borrowings under our credit facility and for general corporate purposes. At March 31, 2011, borrowings under our credit facility were $185.0 million. Amounts to be repaid were incurred for general corporate purposes, including to fund our capital expenditure program, and may be reborrowed from time to time. Our credit facility matures on May 24, 2012, and the average annual interest rate for 2010 and the first three months of 2011, which includes the effect of interest rate swaps, was 3.5% and 2.8%, respectively.

The underwriters may, from time to time, engage in transactions with and perform services for us and our affiliates in the ordinary course of their business. In addition, Merrill Lynch, Pierce, Fenner & Smith Incorporated and BMO Capital Markets Corp. are affiliates of lenders under our credit facility, and, accordingly, will receive a substantial portion of the proceeds from this offering. See "Underwriting—Conflicts of Interest."

Table of Contents

CAPITALIZATION

The following table sets forth our consolidated cash and cash equivalents and our consolidated capitalization as of March 31, 2011 (1) on a historical basis and (2) on an as adjusted basis to reflect this notes offering and the application of the estimated net proceeds as described in "Use of Proceeds." This information should be read in conjunction with our financial statements and the related notes included elsewhere in this prospectus supplement, as well as the sections "Selected Historical Consolidated Financial Data" and "Management's Discussion and Analysis of Financial Condition and Results of Operations" included in this prospectus supplement.

	As of March 31, 2011	
	Historical	As Adjusted
	(In thousands)	
Cash and cash equivalents	$ 1,236	$ 60,236
Total long-term debt:		
Revolving credit facility (1)	$ 185,000	$ —
Senior subordinated notes offered hereby	—	250,000
Total long-term debt	185,000	250,000
Shareholders' equity:		
Common stock	9,524	9,524
Capital in excess of par	400,543	400,543
Accumulated other comprehensive loss	(20,704)	(20,704)
Retained earnings	1,355,501	1,355,501
Total shareholders' equity	1,744,864	1,744,864
Total capitalization	$ 1,929,864	$ 1,994,864

(1) Total elected credit facility size of $325 million.

SELECTED HISTORICAL CONSOLIDATED FINANCIAL DATA

The following selected financial data should be read in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations" and our financial statements and related notes included in this prospectus supplement. The financial information included in this prospectus supplement may not be indicative of our future results of operations, financial position and cash flows. Presented below is our selected historical consolidated statement of operations data for the years ended December 31, 2010, 2009, 2008, 2007 and 2006 and our balance sheet data as of December 31, 2010, 2009, 2008, 2007 and 2006, which are derived from our audited consolidated financial statements. Also presented below is our selected historical condensed consolidated statement of operations data for the three months ended March 31, 2011 and 2010, and our condensed balance sheet data as of March 31, 2011 and 2010, which are derived from our unaudited condensed consolidated financial statements included in our Quarterly Reports on Form 10-Q for the quarters ended March 31, 2011 and 2010, respectively.

	Three Months Ended March 31,		Year Ended December 31,				
	2011	2010	2010	2009	2008	2007	2006
(In thousands)	(unaudited)						
Statement of operations data:							
Revenues:							
Contract drilling	$ 97,988	$ 60,854	$316,384	$236,315	$ 622,727	$ 627,642	$ 699,396
Oil and natural gas	109,834	99,053	400,807	357,879	553,998	391,480	357,599
Gas gathering and processing	39,764	41,135	154,516	108,628	181,730	138,595	101,863
Other	(181)	5,508	10,138	7,076	(362)	1,037	3,527
Total revenues	247,405	206,550	881,845	709,898	1,358,093	1,158,754	1,162,385
Expenses:							
Contract drilling:							
Operating costs	52,844	40,900	186,813	140,080	312,907	304,780	313,882
Depreciation	17,297	13,786	69,970	45,326	69,841	56,804	51,959
Oil and natural gas:							
Operating costs	30,781	25,034	105,365	87,734	116,239	97,109	81,120
Depreciation, depletion and amortization	40,268	25,336	118,793	114,681	159,550	127,417	108,124
Impairment of oil and natural gas properties (1)	—	—	—	281,241	281,966	—	—
Gas gathering and processing:							
Operating costs	29,055	32,726	122,146	87,908	150,466	119,776	88,834
Depreciation and amortization	3,773	3,941	15,385	16,104	14,822	11,059	6,247
General and administrative	6,892	6,279	26,152	24,011	25,419	22,036	18,690
Interest, net							

	54	—	—	539	1,304	6,362	5,273
Total expenses	180,964	148,002	644,624	797,624	1,132,514	745,343	674,129
Income (loss) before income taxes	66,441	58,548	237,221	(87,726)	225,579	413,411	488,256
Income tax expense (benefit):							
Current	—	2,240	(9,935)	(223)	40,877	66,642	112,812
Deferred	25,414	20,155	100,672	(32,003)	41,077	80,511	63,267
Total income taxes	25,414	22,395	90,737	(32,226)	81,954	147,153	176,079
Net income (loss)	$ 41,027	$ 36,153	$146,484	$ (55,500)	$ 143,625	$ 266,258	$ 312,177

(1) In December 2008, we incurred a non-cash ceiling test write down of our oil and natural gas properties of $282.0 million pre-tax ($175.5 million net of tax) due to low commodity prices at year-end. In March 2009, we incurred a non-cash ceiling test write down of our oil and natural gas properties of $281.2 million pre-tax ($175.1 million net of tax) due to low commodity prices at quarter-end. There was no impact on our compliance with the covenants contained in our credit facility for either of these write downs.

Table of Contents

(In thousands)	As of March 31, 2011	2010	As of December 31, 2010	2009	2008	2007	2006
	(unaudited)						
Balance sheet data:							
Cash and cash equivalents	$ 1,236	$ 1,039	$ 1,359	$ 1,140	$ 584	$ 1,076	$ 589
Other current assets	187,779	169,682	186,821	126,955	286,001	195,939	232,351
Total current assets	189,015	170,721	188,180	128,095	286,585	197,015	232,940
Property and equipment:							
Drilling equipment	1,313,374	1,224,646	1,273,861	1,217,361	1,172,655	987,184	781,190
Oil and natural gas properties, on the full cost method:							
Proved properties	2,858,466	2,360,943	2,738,093	2,309,193	2,090,623	1,624,478	1,330,010
Undeveloped leasehold not being amortized	181,503	146,940	175,065	140,129	160,034	64,722	53,687
Gas gathering and processing equipment	208,610	179,440	199,564	172,549	169,402	119,515	85,339
Transportation equipment	33,266	30,718	31,688	30,726	33,611	23,240	20,749
Other	30,268	22,856	28,511	22,747	22,484	19,974	17,082
	4,625,487	3,965,543	4,446,782	3,892,705	3,648,809	2,839,113	2,288,057
Less accumulated depreciation, depletion, amortization and impairment	2,106,979	1,901,659	2,047,031	1,879,112	1,447,157	927,759	735,394
Net property and equipment	2,518,508	2,063,884	2,399,751	2,013,593	2,201,652	1,911,354	1,552,663
Other long-term assets	78,521	86,565	81,309	86,711	93,629	91,450	88,493
Total assets	$ 2,786,044	$ 2,321,170	$ 2,669,240	$ 2,228,399	$ 2,581,866	$ 2,199,819	$ 1,874,096
Current liabilities	$ 176,274	$ 114,651	147,128	105,147	196,399	156,404	160,942
Long-term debt	185,000	30,000	163,000	30,000	199,500	120,600	174,300
Other long-term liabilities	100,821	81,339	92,389	81,126	75,807	59,115	55,741
Deferred income taxes	579,085	466,697	556,106	446,316	477,061	428,883	325,077
Total shareholders' equity	1,744,864	1,628,483	1,710,617	1,565,810	1,633,099	1,434,817	1,158,036
Total liabilities and shareholders' equity	$ 2,786,044	$ 2,321,170	$ 2,669,240	$ 2,228,399	$ 2,581,866	$ 2,199,819	$ 1,874,096

(In thousands, except ratio data)	Three Months Ended March 31, 2011	2010	Year Ended December 31, 2010	2009	2008	2007	2006
	(unaudited)						
Other financial data:							
Net cash provided by operating activities	$ 121,205	$ 79,667	$ 390,072	$ 490,475	$ 689,913	$ 577,571	$ 506,702

Net cash used in investing activities	(169,212)	(86,926)	(536,261)	(271,927)	(806,141)	(512,333)	(540,723)
Net cash provided by (used in) financing activities	47,884	7,158	146,408	(217,992)	115,736	(64,751)	33,663
EBITDA (1)	128,072	101,861	442,345	371,220	753,761	615,884	660,595
Ratio of earnings to fixed charges (2)(3)(4)	46.3x	71.1x	52.8x	—	31.0x	38.4x	56.6x
Pro forma ratio of earnings to fixed charges (5)	16.2x	N/A	14.4x	N/A	N/A	N/A	N/A

(1) EBITDA is a non-GAAP financial measure that we define as net income (loss) plus adjustments for income tax expense (benefit), interest expense, net, depreciation, depletion and amortization and impairment of long-lived assets. EBITDA, as used and defined by us, may not be comparable to similarly titled measures employed by other companies and is not a measure of performance calculated in accordance with GAAP. EBITDA should not be considered in isolation or as a substitute for operating income (loss), net income (loss), or statement of operations or statement of cash flow data prepared in accordance with GAAP. EBITDA provides no information regarding a company's capital structure, borrowings, interest costs, capital expenditures, working capital movement or tax position. EBITDA does not represent funds available for discretionary use, because those funds are required for debt service, capital expenditures and working

Table of Contents

capital, income taxes, and other commitments and obligations. However, our management believes EBITDA is useful to an investor in evaluating our operating performance because this measure:

- is widely used by investors in the natural gas and oil industry to measure a company's operating performance without regard to items excluded from the calculation of such term, which can vary substantially from company to company depending upon accounting methods and book value of assets, capital structure and the method by which assets were acquired, among other factors;
- helps investors to more meaningfully evaluate and compare the results of our operations from period to period by removing the effect of our capital structure from our operating structure; and
- is used by our management for various purposes, including as a measure of operating performance, as a basis for strategic planning and forecasting and by our lenders as defined in the credit agreement.

There are significant limitations to the use of EBITDA as a measure of performance, including the inability to analyze the effect of certain recurring and non-recurring items that materially affect our net income (loss), the lack of comparability of results of operations to different companies and the different methods of calculating EBITDA reported by different companies. The following presents a reconciliation of net income (loss) to EBITDA:

	Three Months Ended March 31,		Year Ended December 31,				
	2011	2010	2010	2009	2008	2007	2006
(In thousands)	(unaudited)						
Reconciliation of Non-GAAP EBITDA to GAAP Net Income (Loss):							
Net income (loss)	$ 41,027	$ 36,153	$ 146,484	$ (55,500)	$ 143,625	$ 266,258	$ 312,177
Interest, net	54	—	—	539	1,304	6,362	5,273
Depreciation, depletion and amortization	61,577	43,313	205,124	177,166	244,912	196,111	167,066
Impairment of oil and gas properties	—	—	—	281,241	281,966	—	—
Income tax expense (benefit)	25,414	22,395	90,737	(32,226)	81,954	147,153	176,079
EBITDA	$ 128,072	$ 101,861	$ 442,345	$ 371,220	$ 753,761	$ 615,884	$ 660,595

(2) Earnings available for fixed charges represent earnings from continuing operations before income taxes, interest expense and amortization of capitalized interest. Fixed charges represent interest incurred and guaranteed plus that portion of rental expense deemed to be the equivalent of interest.

(3) There were no shares of preferred stock outstanding during any of the time periods indicated in the table.

(4) Earnings for the year ended December 31, 2009 were insufficient to cover fixed charges by $87.7 million due to non-cash ceiling test write down of $281.2 million pre-tax ($175.1 million, net of tax) during the quarter ended March 31, 2009.

(5) Gives effect to the net increase in interest expense resulting from the sale of the principal amount of the notes and the application of the anticipated net proceeds to pay down loan amounts outstanding under our unsecured credit facility as described under "Use of Proceeds", as if such issuance and repayment occurred on January 1, 2010 for year ended December 31, 2010 and on January 1, 2011 for three months ended March 31, 2011.

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 elsewhere in this prospectus supplement.

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 wholly owned 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 others and for our own account.

- *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.

- *Midstream*—carried out by our subsidiary Superior Pipeline Company, L.L.C. and its subsidiaries. This segment buys, sells, gathers, processes and treats natural gas for third parties and for our own account.

Business Outlook

As discussed in other parts of this prospectus supplement, the success of our consolidated business, as well as each of our three operating segments depends, to a large extent, on: the prices received for our natural gas, NGLs and oil production; the demand for oil, NGLs and natural gas; and the demand for our drilling rigs which, in turn, influences the amounts we can charge for the use of those drilling rigs. Although all of our current operations (with the exception of a minor amount of production in Canada) are located within the United States, events outside the United States can and do impact us and our industry.

In addition to their direct impact on us, low commodity prices, if sustained for a long period of time, could impact the liquidity of some of our industry partners and customers which, in turn, could limit their ability to meet their financial obligations to us.

The slowdown in the United States and world economies starting in late 2008 resulted in less demand for oil and natural gas products. The long-term impact on our business and financial results as a consequence of the volatility in oil, NGLs and natural gas prices and the global economic downturn is uncertain.

Our 2011 consolidated capital budget forecasts a 16% increase over our 2010 capital expenditures, excluding acquisitions. Our oil and natural gas segment's capital budget is $415.0 million, a 12% increase over 2010, excluding acquisitions. We plan to continue our aggressive drilling program in 2011 with a significant portion of the wells being horizontal. Our drilling segment's capital budget is $143.0 million, a 20% increase over 2010. Our plans for 2011 include the construction of five new 1,500 horsepower diesel-electric drilling rigs (one of which has been completed and delivered), as well as refurbishing and upgrading several of our existing drilling rigs in our fleet in order that those drilling rigs can be used in horizontal drilling operations. Our midstream segment's capital budget is $47.0 million, a 58% increase over 2010. The increase is due to anticipated drilling activity by operators in the areas of our existing gathering systems resulting in new well connections as well as committing to build a 16-mile, 16" pipeline and a compressor station in Preston County, West Virginia, which will have a capacity of approximately 220 MMcf per day.

In developing our initial operating budget for 2011, we used average oil and natural gas prices of $82.00 per Bbl and $4.60 per Mcf. Our 2011 operating budget will be funded using internally generated cash flow and borrowings under our credit facility.

Executive Summary

Contract Drilling

Our utilization rate for the first quarter of 2011 was 58%, compared to 59% and 40% for the fourth quarter of 2010 and the first quarter of 2010, respectively.

Dayrates for the first quarter of 2011 averaged $17,704, an increase of 7% from the fourth quarter of 2010 and an increase of 25% from the first quarter of 2010. These increases were due primarily to increased demand for drilling rigs in the 1,000 to 1,500 horse power range which are used in horizontal drilling and provide for higher rates.

Direct profit (contract drilling revenue less contract drilling operating expense) for the first quarter of 2011 increased 1% from the fourth quarter of 2010 and 126% from the first quarter of 2010. The increase was primarily due to increases in dayrates and utilization over the first quarter 2010.

Operating cost per day for the first quarter of 2011 increased 1% from the fourth quarter of 2010 and decreased 6% from the first quarter of 2010. The increase over the fourth quarter of 2010 is primarily due to increases in indirect expenses because of increases in personnel cost. The decrease over the first quarter of 2010 was primarily due to decreased per day indirect cost and fixed cost spread over more days due to increased utilization.

Historically, our contract drilling segment has experienced a greater demand for natural gas drilling as opposed to drilling for oil and NGLs. With the current weakened demand and prices for natural gas, operators are focusing on drilling for oil and NGLs. Approximately 80% of our drilling rigs working today are drilling for oil or NGLs of which approximately 99% are drilling horizontal or directional wells.

During the first half of 2010, our contract drilling segment sold eight of its idle mechanical drilling rigs to an unaffiliated third party. These drilling rigs ranged in horsepower from 800 to 1,000. Proceeds from the sale of those drilling rigs were $23.9 million with a gain of $5.7 million. These proceeds are being used to refurbish and upgrade additional drilling rigs in our fleet allowing those drilling rigs to be used in horizontal drilling operations. We also placed into service in our Rocky Mountain division a 1,500 horsepower, diesel-electric drilling rig that previously had been placed on hold during 2009 by our customer.

In September 2010, we entered into a contract with an unaffiliated third party under which we conveyed three of our idle mechanical drilling rigs and, in exchange, we received a 1,200 horsepower electric drilling rig and $5.3 million. The three drilling rigs sold ranged in horsepower from 650 to 1,000. The transaction was closed in October and resulted in a gain of $3.5 million.

At the end of 2010, we began constructing five new 1,500 horsepower, diesel-electric drilling rigs. One of these new drilling rigs has been completed and was delivered and placed in service in the Bakken shale in March 2011. The second drilling rig began mobilizing to its first location in April. The remaining three drilling rigs are expected to be completed late in the third quarter of 2011. On completion of the additional four drilling rigs, we will have 126 drilling rigs in our fleet. Each of these five new drilling rigs will initially be dedicated to a two-year drilling contract.

Our anticipated 2011 capital expenditures for this segment are $143.0 million.

As of March 31, 2011, we had 41 long-term drilling contracts with original terms ranging from six months to two years. Thirty-two of these contracts are up for renewal during 2011 and nine are up for renewal in 2012 and beyond. These contracts include two of the five term contracts for the new drilling rigs discussed above. Of the 32 contracts renewing in 2011, 13 renew during the second quarter, nine during the third quarter and ten during the fourth quarter. Term contracts may contain a fixed rate for the duration of the contract or provide for the rate adjustments within a specific range from the existing rate.

Oil and Natural Gas

During the second quarter of 2010 we completed an acquisition of oil and natural gas properties from certain unaffiliated parties. The properties were purchased for approximately $73.7 million in cash. The acquisition included approximately 45,000 net leasehold acres and 10 producing oil wells. These properties are focused on the Marmaton horizontal oil play located mainly in Beaver County, Oklahoma. Proved developed producing net reserves associated with the 10 acquired producing wells is approximately 762,000 barrels of oil equivalent — consisting of 511,000 barrels of oil, 155,000 barrels of NGLs and 573 MMcf of natural gas.

During the first quarter of 2011 production was 2,739,000 barrels of oil equivalent (Boe) per day, a 2% increase over the fourth quarter of 2010 and a 16% increase over the first quarter of 2010. The increase in production is primarily due to new wells being completed and coming online and, to a lesser extent, production associated with the acquisition discussed above. Our production in 2010 was hindered by delays in securing third party fracture stimulation services and delays associated with connecting wells to gathering systems. In addition, our production was curtailed because of the unexpected shut-in of some of our production from operational issues experienced at a third party facility that processes our Segno field production.

During the first quarter of 2011 oil and natural gas revenues were decreased 4% from the fourth quarter of 2010 and increased 11% from the first quarter of 2010.

Our oil prices for the first quarter of 2011 increased 14% from the fourth quarter of 2010 and 25% from the first quarter of 2010. NGL and natural gas prices for the first quarter of 2011 decreased 1% and 21%, respectively, compared to fourth quarter 2010 and decreased 7% and 28%, respectively, compared to the first quarter of 2010.

Direct profit (oil and natural gas revenues less oil and natural gas operating expense) decreased 7% from the fourth quarter of 2010 and increased 7% from the first quarter of 2010. The decrease was primarily attributable to decreases in natural gas and liquids prices received including the effect of hedging and to a lesser extent from increases in operating expenses. The increase from the first quarter 2010 was primarily attributable to increases in production and oil prices partially offset by increased lease operating expense and gross production taxes.

Operating cost per Boe produced for the first quarter of 2011 increased 3% from the fourth quarter of 2010 and increased 6% from the first quarter of 2010. The increases were primarily due to the increase in lease operating expense (LOE) and an increase in production taxes. Production taxes increased due to commodity price increases between the periods and increased oil and NGL production.

For 2010, we hedged approximately 60% of our average daily oil production, approximately 69% of our average natural gas production and approximately 8% of our average natural gas liquids production (percentages based on our 2010 production) to help manage our cash flow and capital expenditure requirements. For 2011, we currently have hedged approximately 65% of our anticipated daily oil production, approximately 64% of our anticipated natural gas production and approximately 10% of our anticipated natural gas liquids production (percentages based on our first quarter 2011 production).

Currently for 2012 we have hedged 4,000 Bbls per day of oil production and 30,000 Mmbtu per day of natural gas production. The oil production is hedged under swap contracts at an average price of $95.01 per barrel. The natural gas production is hedged under swap contracts at a comparable average NYMEX price of $5.48. The average basis differential for the applicable swaps is ($0.28).

Currently for 2013 we have hedged 1,500 Bbls per day of oil production. The oil production is hedged under swap contracts at an average price of $102.18 per barrel.

We drilled 167 wells in 2010. Our first quarter 2010 drilling activity was slowed down by unusually wet weather, especially in the Texas Panhandle Granite Wash play, and operational delays as we shifted to drilling primarily horizontal wells. The delays in getting wells online were primarily due to delays in securing fracture stimulation services and connections to gathering systems. During the third quarter, we undertook steps that allowed us to obtain these required services so that by the end of the year we have eliminated the unusually large backlog of our well completions, especially in the Granite Wash and Marmaton plays. Additionally, we have pre-scheduled fracture stimulation services for 2011 for the wells we currently anticipate drilling in the Granite Wash and Marmaton plays.

During the first quarter of 2011, we drilled 34 gross wells (17.19 net wells). Our 2011 production guidance is approximately 11.0 to 11.3 MMBoe, although actual results will continue to be subject to a number of factors including the timing of third party services. For 2011, we plan to participate in the drilling of 180 wells and the level of our capital expenditures is $415.0 million.

Mid-Stream

During the first quarter of 2011 liquids sold per day increased 13% from the fourth quarter of 2010 and increased 29% from the first quarter of 2010. The increases resulted from upgrades and expansions to existing plants and the connection of new wells. For the first quarter of 2011, gas processed per day increased 1% from the fourth quarter of 2010 and 13% from the first quarter of 2010. In 2010, we upgraded several of our existing processing facilities and added processing plants which was the primary reason for increased volumes. For the first quarter of 2011, gas gathered per day decreased 1% from the fourth quarter of 2010 due to weather related issues experienced in the first quarter and increased 3% from the first quarter of 2010 primarily from the 52 well connects throughout 2010.

NGL prices in the first quarter of 2011 remained essentially unchanged from the price received in the fourth quarter of 2010 and decreased 1% from the price received in the first quarter of 2010. The price of liquids as compared to natural gas affects the revenue in our mid-stream operations and determines the fractionation spread which 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.

Direct profit (mid-stream revenues less mid-stream operating expense) for the first quarter of 2011 increased 9% from the fourth quarter of 2010 and increased 27% from the first quarter of 2010. The increases resulted primarily from increased liquids sold and gas processed volumes. Effective April 1, 2011, we had a change in arrangements with customers of one of our processing plants whereby the contracts changed from percent of index to percent of proceeds which could result in lower direct profit of up to $1.2 million per month based on current frac spreads.

Total operating cost for our mid-stream segment for the first quarter of 2011 decreased 2% from the fourth quarter of 2010 primarily due to the decrease in gas purchased and decreased 11% from the first quarter of 2010 due primarily to the decrease in price paid for the purchase of natural gas.

During the fourth quarter of 2010, we completed the installation and start up of a 50.0 MMcf per day turbo-expander natural gas processing plant at our Hemphill facility in Canadian, Texas. With the addition of this new processing plant, the total processing capacity at our Hemphill facility has increased to approximately 100.0 MMcf per day. In connection with our Appalachian operations, we recently started construction of a 16-mile, 16" pipeline and a compressor station in Preston County, West Virginia, which will have a capacity of approximately 220.0 MMcf per day. We anticipate this pipeline will be operational by mid-2011. We have signed an agreement to transport gas on this system for an unaffiliated party. In addition to the Preston County pipeline, we recently signed a contract to build a 12-mile pipeline system and compressor station in Tioga and Potter Counties, Pennsylvania. This system will deliver gas to Dominion Transmission pipeline and is scheduled to be completed in the fourth quarter of this year.

Our anticipated capital expenditures for 2011 are $47.0 million.

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.

Table of Contents

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 • Derivatives measured at fair value	• Oil and natural gas properties • Accumulated depletion, depreciation and amortization • Provision for depletion, depreciation and amortization • Impairment of oil and natural gas 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 depletion, depreciation and amortization • Provision for depletion, depreciation and amortization • Current and non-current liabilities • Operating expense
Accounting for impairment of long-lived assets	• Forecast of undiscounted estimated future net operating cash flows	• Drilling and midstream property and equipment • Accumulated depletion, depreciation and amortization • Provision for depletion, depreciation and amortization • Other intangible assets
Goodwill	• Forecast of discounted estimated future net operating cash flows • Terminal value • Weighted average cost of capital	• Goodwill
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 • General and administrative expenses
Accounting for derivative instruments and hedging	• Derivatives measured at fair value • Derivatives measured for effectiveness and ineffectiveness • Non-qualifying derivatives measured at fair value	• Current and non-current derivative assets and liabilities • Other comprehensive income as a component of equity • Oil and natural gas revenue

Significant Estimates and Assumptions

Full Cost Method of Accounting for Oil, NGLs and Natural Gas Properties. The determination of our oil, NGLs and natural gas reserves is a 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. Each year, we hire an independent petroleum engineering firm to audit our internal evaluation of our reserves. The wells or locations for which estimates of reserves were audited were those that comprised the top 83% of the total proved developed discounted future net income and 80% of the total proved undeveloped 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, 2010. Included in the Business section of this prospectus supplement are the qualifications of our independent petroleum engineering firm and the company's personnel responsible for the preparation of our reserve reports.

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	The above as well as logs, core samples, well tests, pressure data	More accurate
Proved developed producing	The above as well as 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. Starting December 31, 2009, companies using full cost accounting moved from using the commodity prices existing on the last day of the period to that of the unweighted arithmetic average of the commodity prices existing on the first day of each of the 12 months before the end of the reporting period to calculate discounted future revenues, unless prices were otherwise determined under contractual arrangements. The revision to the 12-month average price was made to reduce the affect of short-term volatility and seasonality that previously occurred with single-day pricing. Using the 12-month average may or may not result in write-downs that would have been required had the single-day period-end price been used. The average unescalated prices used in our reserve estimates were $79.43 per Bbl for oil, $49.35 per Bbl for NGLs and $4.38 per Mcf for natural gas, adjusted for price differentials.

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 / End of Period Reserves Adjusted for Current Period Production
- 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 2010 production level of 59,176,000 equivalent Mcf, a 5% decline in the amount of our 2010 oil, NGLs and natural gas reserves would increase our DD&A rate by $0.11 per Mcfe and would decrease pre-tax income by $6.5 million annually. A 5% increase in the amount of our 2010 oil, NGLs and natural gas reserves would decrease our DD&A rate by $0.11 per Mcfe and would increase pre-tax income by $6.5 million annually.

Our DD&A expense on our oil and natural gas properties is calculated each quarter utilizing period end reserve quantities adjusted for current period production.

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 the unescalated 12-month average price on our oil, NGLs and natural gas adjusted for any cash flow hedges, plus the cost of properties not being amortized, plus the lower of cost or estimated fair value of unproved properties 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 DD&A 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 the 12-month 2010 average unescalated prices of $79.43 per barrel of oil, $49.35 per barrel of NGLs and $4.38 per Mcf of natural gas, adjusted for price differentials, for the estimated life of the respective properties, the unamortized cost of our oil and natural gas properties did not exceed the ceiling of our proved oil, NGL and natural gas reserves. Prior to 2009, the price was based on the single-day period-end price. The revision to the 12-month average price was made to reduce the affect of short-term volatility and seasonality that previously occurred with single-day pricing. Using the 12-month average may or may not result in write-downs that would have been required had the single-day period-end price been used. Oil, NGLs and natural gas 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.

Derivative instruments qualifying as cash flow hedges are to be included in the computation of limitation on capitalized costs. Our qualifying cash flow hedges used in the ceiling test determination as of December 31, 2010, consisted of swaps and collars covering 26.3 Bcfe in 2011 and 8.8 Bcfe in 2012. The effect of those hedges on the December 31, 2010 ceiling test was a $22.8 million pre-tax increase in the discounted net cash flows of our oil and natural gas properties. Even without the impact of those hedges, we would not have been required to take a write-down for the quarter.

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 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 ARO 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 less accumulated depreciation. 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. No significant impairments were recorded at December 31, 2010, 2009 or 2008.

Goodwill. 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 based on the estimated discounted future net cash flows of our drilling segment, utilizing discount rates and other factors in determining the fair value of our drilling segment. No goodwill impairment was recorded at December 31, 2010, 2009 or 2008.

Turnkey and Footage Drilling Contracts. Because our contract drilling operations 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 2010, we drilled four wells under a footage contract and none under a turnkey contract, one in 2009 under footage and none under turnkey and in 2008, we did not drill any wells under turnkey or footage contracts.

Accounting for Value of Stock Compensation Awards. To account for stock-based compensation, 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, 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.

Accounting for Derivative Instruments and Hedging. We account for derivative contracts to hedge against possible future interest rate increases and 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 and natural gas production for the next 12 months. 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 must be recorded at fair value with gains (losses) recognized in earnings in the period of change.

New Accounting Standards

Improving Disclosures about Fair Value Measurements. In January 2010, the FASB issued ASU 2010-06—*Fair Value Measurements and Disclosures (ASC 820): Improving Disclosures about Fair Value Measurements*, which provides additional guidance to improve disclosures regarding fair value measurements. The ASU amends ASC 820-10, *Fair Value Measurements and Disclosures—Overall* (formerly FAS 157, *Fair Value Measurements)* to add two new disclosures: (1) transfers in and out of Level 1 and 2 measurements and the reasons for the transfers, and (2) a gross presentation of activity within the Level 3 roll forward. The ASU also includes clarifications to existing disclosure requirements on the level of disaggregation and disclosures regarding inputs and valuation techniques. The ASU applies to all entities required to make disclosures about recurring and nonrecurring fair value measurements. The effective date of the ASU is the first interim or annual reporting period beginning after December 15, 2009 and was adopted January 1, 2010, except for the gross presentation of the Level 3 roll forward information, which is required for annual reporting periods beginning after December 15, 2010 and for interim reporting periods within those years. This statement did not and will not have a significant impact on us due to it only requiring enhanced disclosures.

Financial Condition and Liquidity

Summary.

Our financial condition and liquidity depends on the cash flow from our operations and, when necessary, borrowings under our credit facility. The principal factors determining the amount of our cash flow are:

- 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 oil, natural gas 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 and for the periods presented.

	March 31,		Year Ended December 31,		
	2011	2010	2010	2009	2008
(In thousands except percentages)	(unaudited)				
Working capital	$ 12,741	$ 56,070	$ 41,052	$ 22,948	$ 90,186
Long-term debt	$ 185,000	$ 30,000	$ 163,000	$ 30,000	$ 199,500
Shareholders' equity (1)	$1,744,864	$1,628,483	$1,710,617	$1,565,810	$1,633,099
Ratio of long-term debt to total capitalization (1)	10%	2%	9%	2%	11%
Net income (loss) (1)	$ 41,027	$ 36,153	$ 146,484	$ (55,500)	$ 143,625
Net cash provided by operating activities	$ 121,205	$ 79,667	$ 390,072	$ 490,475	$ 689,913
Net cash used in investing activities	$ (169,212)	$ (86,926)	$ (536,261)	$ (271,927)	$ (806,141)
Net cash provided by (used in) financing activities	$ 47,884	$ 7,158	$ 146,408	$ (217,992)	$ 115,736

(1) In March 2009, we incurred a non-cash ceiling test write down of our oil and natural gas properties of $281.2 million pre-tax ($175.1 million net of tax) due to low commodity prices at quarter-end. The write down impacted our 2009 shareholders' equity, ratio of long-term debt to total capitalization and net income. There was no impact on our compliance with the covenants contained in our credit facility. In December 2008, we incurred a non-cash ceiling test write down of our oil and natural gas properties of $282.0 million pre-tax ($175.5 million net of tax) due to low commodity prices at year-end. The write down impacted our 2008 shareholders' equity, ratio of long-term debt to total capitalization and net income. There was no impact on our compliance with the covenants contained in our credit facility.

The following table summarizes certain operating information:

	Three Months Ended March 31,		Year Ended December 31,		
	2011	2010	2010	2009	2008
	(unaudited)				
Contract Drilling:					
Average number of our drilling rigs in use during the period	70.0	50.9	61.4	38.9	103.1
Total number of drilling rigs owned at the end of the period	122	125	121	130	132
Average dayrate	$ 17,704	$ 14,127	$ 15,478	$ 16,713	$ 18,458
Oil and Natural Gas:					
Oil production (MBbls)	556	303	1,521	1,286	1,261
Natural gas liquids production (MBbls)	478	377	1,549	1,488	1,388
Natural gas production (MMcf)	10,231	10,034	40,756	44,063	47,473
Average oil price per barrel received	$ 84.33	$ 67.33	$ 69.52	$ 56.33	$ 93.87
Average oil price per barrel received excluding hedges	$ 90.78	$ 75.70	$ 76.65	$ 56.64	$ 98.02
Average NGL price per barrel received	$ 39.61	$ 42.76	$ 37.04	$ 22.81	$ 47.42
Average NGL price per barrel received excluding hedges	$ 40.36	$ 42.76	$ 36.96	$ 25.66	$ 47.38
Average natural gas price per mcf received	$ 4.28	$ 5.95	$ 5.62	$ 5.59	$ 7.62
Average natural gas price per mcf received excluding hedges	$ 3.85	$ 5.14	$ 4.05	$ 3.26	$ 7.53
Midstream:					
Gas gathered—MMBtu/day	185,730	180,117	183,867	183,989	197,367
Gas processed—MMBtu/day	86,445	76,513	82,175	75,908	67,796
Gas liquids sold — gallons/day	328,333	253,707	271,360	243,492	195,837
Number of natural gas gathering systems	34	33	34	33	37
Number of processing plants	10	8	10	8	9

At March 31, 2011, we had unrestricted cash of $1.2 million and we had borrowed $185.0 million of the $325.0 million we had elected to have currently available under our credit facility. Our credit facility is used for working capital and capital expenditures. Most of our capital expenditures were discretionary and directed toward future growth. Beginning in the fourth quarter of 2008 and continuing through 2009, we significantly reduced our capital expenditures because of the uncertain economic environment. For 2010, we increased our capital expenditures and focused on growth which was funded mainly through internally generated cash flow and from borrowings under the credit facility. For 2011, we plan to increase our capital expenditures, focusing on growth which will be funded mainly through internally generated cash flow and from borrowings under the credit facility.

Working Capital

Typically, our working capital balance varies primarily because of the timing of our trade accounts receivable and accounts payable and from the fluctuation in current assets and liabilities associated with the mark to market value of our hedging activity. We had working capital of $12.7 million, $56.1 million, $41.1 million, $22.9 million and $90.2 million as of March 31, 2011 and 2010 and December 31, 2010, 2009 and 2008, respectively. The effect of our derivatives decreased working capital by $15.9 million as of March 31, 2011 and increased working capital by 24.3 million, $5.4 million, $4.7 million and $32.4 million as of March 31, 2010 and December 31, 2010, 2009 and 2008, respectively.

Contract Drilling

Many factors 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 in our areas of operation, 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.

As activity has increased over last year's levels, competition to keep qualified labor has likewise increased. Starting in the third quarter 2010, we increased compensation for drilling personnel in Oklahoma, Texas and Louisiana and again at the end of the first quarter for drilling personnel in all our divisions.

Over the past year as more of our customers shift to drilling horizontal wells, demand for drilling rigs in the 1,000 to 1,500 horsepower range has increased as drilling rigs within that horsepower range are ideally suited for horizontal drilling. The level of future demand for and the availability of drilling rigs to meet this demand will have an impact on our future dayrates. For the first quarter of 2011, our average dayrate was $17,704 per day compared to $14,127 per day for the first quarter of 2010. For 2010, our average dayrate was $15,478 per day compared to $16,713 per day for 2009. Our average number of drilling rigs used in the first quarter of 2011 was 70.0 drilling rigs (58%) compared with 50.9 drilling rigs (40%) in the first quarter of 2010. Based on the average utilization of our drilling rigs during the first quarter of 2011, a $100 per day change in dayrates has a $7,000 per day ($2.6 million annualized) change in our pre-tax operating cash flow. Our average number of drilling rigs used in 2010 was 61.4 drilling rigs (50%) compared with 38.9 drilling rigs (30%) in 2009. Based on the average utilization of our drilling rigs during 2010, a $100 per day change in dayrates has a $6,140 per day ($2.2 million annualized) change in our pre-tax operating cash flow.

Our contract drilling segment provides drilling services for our exploration and production segment. Depending on their timing some of the drilling services performed on our properties are also deemed to be associated with the acquisition of an ownership interest in the property. Revenues and expenses for such services are eliminated in our income statement, with any profit recognized as a reduction in our investment in our oil and natural gas properties. The contracts for these services are issued under the same conditions and rates as the contracts entered into with unrelated third parties. We eliminated revenue of $40.1 million, $15.0 million and $65.5 million for 2010, 2009 and 2008, respectively from our contract drilling segment and eliminated the associated operating expense of $31.0 million, $13.7 million and $37.6 million during 2010, 2009 and 2008, respectively, yielding $9.1 million, $1.3 million and $27.9 million during 2010, 2009 and 2008, respectively, as a reduction to the carrying value of our oil and natural gas properties. We eliminated revenue of $14.5 million and $6.6 million for the three months of 2011 and 2010, respectively, from our contract drilling segment and eliminated the associated operating expense of $9.5 million and $6.2 million during the three months of 2011 and 2010, respectively, yielding $5.0 million and $0.4 million during the three months of 2011 and 2010, respectively, as a reduction to the carrying value of our oil and natural gas properties.

Impact of Prices for Our Oil, NGLs and Natural Gas

Natural gas comprises approximately 68% of our oil, NGLs and natural gas reserves compared to 73% in 2009. Any significant change in natural gas prices has a material effect on our revenues, cash flow and the value of our oil, NGLs and natural gas reserves. Generally, prices and demand for domestic natural gas are influenced by weather conditions, supply imbalances and by worldwide oil price levels. Domestic oil prices are primarily influenced by world oil market developments. All of these factors are beyond our control and we cannot predict nor measure their future influence on the prices we will receive.

Based on our production in 2010, a $0.10 per Mcf change in what we are paid for our natural gas production, without the effect of hedging, would result in a corresponding $319,000 per month ($3.8 million annualized) change in our pre-tax operating cash flow. Based on our first quarter of 2011, this change would be $326,000 ($3.9 million annualized). Our 2010 average natural gas price was $5.62 compared to an average natural gas price of $5.59 for 2009 and $7.62 for 2008. The average price we received for our natural gas production, including the effect of hedging, during the first three months of 2011 was $4.28 compared to $5.95 for the first three months of 2010. A $1.00 per barrel change in our oil price, without the effect of hedging, would have a $119,000 per month ($1.4 million annualized) change in our pre-tax operating cash flow and a $1.00 per barrel change in our NGL prices, without the effect of hedging, would have a $122,000 per month ($1.5 million annualized) change in our pre-tax operating cash flow based on our production in 2010. These changes would be $177,000 per month ($2.1 million annualized) and $152,000 per month ($1.8 million annualized) based on our first quarter 2011 production. Our 2010 average oil price per barrel was $69.52 compared with an average oil price of $56.33 in 2009 and $93.87 in 2008 and our 2010 average NGL price per barrel was $37.04 compared with an average liquids price of $22.81 in 2009 and $47.42 in 2008. In the first three months of 2011, our average oil price per barrel received, including the effect of hedging, was $84.33 compared with an average oil price, including the effect of hedging, of $67.33 in the first three months of 2010 and our first three months of 2011 average NGLs price per barrel received was $39.61 compared with an average NGL price per barrel of $42.76 in the first three months of 2010.

Because natural gas prices have such a significant effect on the value of our oil, NGLs and natural gas reserves, declines in those 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.

Our natural gas production is sold to intrastate and interstate pipelines as well as to independent marketing firms and gatherers under contracts with terms generally ranging anywhere from one month to five years. Our oil production is sold to independent marketing firms generally in six month increments.

Midstream Operations

Our midstream operations are conducted through Superior Pipeline Company, L.L.C. and its subsidiary. Superior is a midstream company engaged primarily in the buying, selling, gathering, processing and treating of natural gas and operates three natural gas treatment plants, 10 processing plants, 34 gathering systems and 867 miles of pipeline. Superior operates in Oklahoma, Texas, Kansas, Pennsylvania and West Virginia and has been in business since 1996. This segment enhances our ability to gather and market not only our own natural gas but also that owned by third parties and serves as a mechanism through which we can construct or acquire existing natural gas gathering and processing facilities. During 2010, 2009 and 2008 this segment purchased $42.4 million, $29.3 million and $52.0 million, respectively, of our natural gas production and natural gas liquids and provided gathering and transportation services of $4.4 million, $4.6 million and $4.3 million, respectively. During the first three months of 2011 and 2010, our mid-stream operations purchased $16.1 million and $11.6 million, respectively, of our oil and natural gas segment's production and provided gathering and transportation services to the oil and natural gas segment of $1.1 million and $1.0 million, respectively. Intercompany revenue from services and purchases of production between this business segment and our oil and natural gas segment has been eliminated in our consolidated financial statements.

Our midstream segment gathered an average of 183,867 MMBtu per day in 2010 compared to 183,989 MMBtu per day in 2009 and 197,367 MMBtu per day in 2008, processed an average of 82,175 MMBtu per day in 2010 compared to 75,908 MMBtu per day in 2009 and 67,796 MMBtu per day in 2008 and sold NGLs of 271,360 gallons per day in 2010 compared to 243,492 gallons per day in 2009 and 195,837 gallons per day in 2008. The average gas gathering volumes per day remained constant. Volumes processed increased primarily due to the addition of wells connected and recent upgrades to several of our processing systems.

Our mid-stream segment gathered an average of 185,730 MMBtu per day in the first quarter of 2011 compared to 180,117 MMBtu per day in the first quarter of 2010. Processed volumes were 86,445 MMBtu per day in the first quarter of 2011 compared to 76,513 MMBtu per day in the first quarter of 2010. The amount of

NGLs we sold was 328,333 gallons per day in the first quarter of 2011 compared to 253,707 gallons per day in the first quarter of 2010. Gas gathering volumes per day in the first three months of 2011 increased 3% compared to the first three months of 2010 primarily from the 52 wells connected to our systems throughout 2010. Processed volumes increased 13% over the comparative three months and NGLs sold also increased 29% over the comparative period primarily due to the addition of wells connected, recent upgrades to several of our processing systems and the doubling in size of our Hemphill facility in the Texas Panhandle.

Our Credit Facility

Our existing credit facility has a maximum credit amount of $400.0 million and matures on May 24, 2012. The lenders' current commitment under the credit facility is $325.0 million. Our borrowings are limited to the commitment amount that we elect. As of March 31, 2011, the commitment amount was $325.0 million. We are charged a commitment fee ranging from 0.375 to 0.50 of 1% on the amount available but not borrowed. The rate varies based on the amount borrowed as a percentage of the amount of the total borrowing base. To date we have paid $1.2 million in origination, agency and syndication fees under the credit facility. We are amortizing these fees over the life of the agreement. The average interest rate for 2010 and 2009 and for the first three months of 2011 and 2010, which includes the effect of our two interest rate swaps, was 3.5%, 4.0%, 2.8% and 6.1%, respectively. At March 31, 2011 and April 25, 2011, borrowings were $185.0 million and $210.1 million, respectively.

The lenders under our credit facility and their respective participation interests are as follows:

Lender	Participation Interest
Bank of Oklahoma, N.A.	18.75%
Bank of America, N.A.	18.75%
BMO Capital Markets Financing, Inc.	18.75%
BBVA Compass Bank	17.50%
Comerica Bank	8.75%
BNP Paribas	8.75%
Crédit Agricole Corporate and Investment Bank	8.75%
	100.00%

The lenders' aggregate commitment is limited to the lesser of the amount of the borrowing base or $400.0 million. The amount of the borrowing base, which is subject to redetermination on April 1 and October 1 of each year, is based primarily on a percentage of the discounted future value of our oil and natural gas reserves and, to a lesser extent, the loan value the lenders reasonably attribute to the cash flow (as defined in the credit facility) of our midstream segment. The April 1, 2011 redetermination set the borrowing base at $600.0 million. We or the lenders may request a onetime special redetermination of the amount of the borrowing base between each scheduled redetermination. In addition, we may request a redetermination following the completion of an acquisition that meets the requirements set forth in the credit facility.

At our election, any part of the outstanding debt under the credit facility may be fixed at a London Interbank Offered Rate (LIBOR) for a 30, 60, 90 or 180 day period. During any LIBOR funding period, the outstanding principal balance of the promissory note to which the LIBOR option applies may be repaid after three days prior notice to the administrative agent and on payment of any applicable funding indemnification amounts. LIBOR interest is computed as the sum of the LIBOR base for the applicable term plus 1.75% to 2.50% depending on the level of debt as a percentage of the borrowing base and is 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, which cannot be less than LIBOR plus 1.00%, and is payable at the end of each month and the principal borrowed may be paid at any time, in part or in whole, without a premium or penalty. At March 31, 2011, all of our $185.0 million in outstanding borrowings were subject to LIBOR.

The credit facility prohibits:

- 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 properties, 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.

As of March 31, 2011, we were in compliance with the credit facility's covenants.

We are in the process of re-negotiating our credit facility to extend our maturity date past May 24, 2012.

We entered into the following interest rate swaps to manage our exposure to possible future interest rate increases. Under these transactions we swapped the variable interest rate we would otherwise incur on a portion of our bank debt for a fixed rate of interest:

Remaining Term	Amount	Fixed Rate	Floating Rate
January 2011 – May 2012	$ 15,000,000	4.53%	3 month LIBOR
January 2011 – May 2012	$ 15,000,000	4.16%	3 month LIBOR

Capital Requirements

Drilling Dispositions, Acquisitions and Capital Expenditures. For 2008, our capital expenditures for this segment were $196.2 million. During the second quarter of 2008, we completed the construction of two new 1,500 horsepower diesel electric drilling rigs for approximately $32.2 million and placed these drilling rigs into service in our Rocky Mountain division. During the fourth quarter of 2008, we completed the construction of another new 1,500 horsepower diesel electric drilling rig for approximately $14.1 million and placed that drilling rig into service in North Dakota.

In late 2008, we postponed the construction of eight additional drilling rigs we had previously anticipated building. In the third quarter 2009, we recognized an early termination fee associated with the cancellation of long-term contracts by a customer on two of these eight drilling rigs. In addition, as a result of an existing contractual obligation, we took delivery of a new 1,500 horsepower drilling rig during the fourth quarter of 2009 at a cost of $13.2 million. The customer, who had signed a two year term contract for this drilling rig when it was ordered, opted not to take delivery of the drilling rig and paid an early termination fee under the contract provisions during the fourth quarter of 2009.

During the first half of 2010, our contract drilling segment sold eight of its idle mechanical drilling rigs to an unaffiliated third party. These drilling rigs ranged in horsepower from 800 to 1,000. Proceeds from the sale of those drilling rigs were $23.9 million with a gain of $5.7 million which was recorded in the first quarter 2010. The proceeds were used to refurbish and upgrade additional drilling rigs in our fleet allowing those drilling rigs to be used in horizontal drilling operations. We also placed into service in our Rocky Mountain division a 1,500 horsepower, diesel-electric drilling rig that previously had been placed on hold during 2009 by our customer.

In September 2010, we entered into a contract with an unaffiliated third-party under which we conveyed three of our idle mechanical drilling rigs and, in exchange, we received a 1,200 horsepower electric drilling rig and $5.3 million. The three drilling rigs sold ranged in horsepower from 650 to 1,000. The transaction was closed in October and resulted in a gain of $3.5 million.

At the end of 2010, we signed contracts with two year terms for each of the five new 1,500 horse power drilling rigs which will be deployed in the Bakken play. All five of those drilling rigs are or will be built by us. One of the drilling rigs was delivered during the first quarter of 2011. One will be delivered during the second quarter and the remaining three during the third quarter of 2011.

Our anticipated 2011 capital expenditures for this segment are $143.0 million. At March 31, 2011, we had commitments to purchase approximately $10.8 million for drill pipe, top drives and related equipment over the next twelve months. We have spent $42.7 million for capital expenditures during the first three months of 2011 compared to $39.8 million in the first three months of 2010.

Oil and Natural Gas Acquisitions and Capital Expenditures. Most of our capital expenditures for this segment 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, all of which provide us with a large degree of flexibility in deciding when and if to incur these costs. We completed drilling 167 gross wells (87.52 net wells) in 2010 compared to 95 gross wells (42.51 net wells) in 2009 and 278 gross wells (134.31 net wells) in 2008. Our 2010 total capital expenditures for our oil and natural gas segment, excluding a $9.9 million ARO liability, and $92.6 million for acquisitions, totaled $361.4 million. We completed drilling 34 gross wells (17.19 net wells) in the first quarter of 2011 compared to 27 gross wells (12.16 net wells) in the first quarter of 2010. Total capital expenditures for the first three months of 2011 by this segment, excluding a $1.2 million ARO liability, and $4.1 million for acquisitions, totaled $121.6 million. Currently we plan to participate in drilling approximately 180 gross wells in 2011 and estimate our total capital expenditures (excluding acquisitions) for this segment will be approximately $415.0 million. Whether we are able to drill the full number of wells planned is dependent on a number of factors, many of which are beyond our control, including the availability of drilling rigs, availability of pressure pumping services, prices for oil, NGLs and natural gas, demand for oil, NGLs and natural gas, the cost to drill wells, the weather and the efforts of outside industry partners.

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.

In September 2008, we completed an acquisition consisting of a 75% working interest in four producing wells and other proved undeveloped properties for $22.2 million along with working interests in undeveloped leasehold valued at approximately $3.5 million, all located in the Texas Panhandle region.

During 2008 and 2009, we acquired interests in approximately 60,000 net undeveloped acres in the Marcellus Shale Play, located mainly in Pennsylvania and Maryland for approximately $43.6 million. In July 2009, we received $7.1 million and approximately 1,500 net undeveloped acres, representing payment for our 50% interest in 4,000 gross undeveloped acres and reimbursement for costs we paid on their behalf. On September 30, 2009, per our agreement with certain unaffiliated third parties, we were paid approximately $14.9 million for our 50% interest in approximately 18,000 gross undeveloped acres of the Marcellus Shale and $26.1 million for a receivable from the third parties for their 50% share of the costs we paid on their behalf to acquire the acreage. The sales proceeds reduced undeveloped leasehold and no gain or loss was recorded on this sale. We now have an interest in approximately 50,500 net undeveloped acres.

In June 2010, we completed an acquisition of oil and natural gas properties from certain unaffiliated third parties. The properties were purchased for approximately $73.7 million in cash after giving effect to certain post-closing adjustments. After these adjustments, the acquisition included approximately 45,000 net leasehold acres and 10 producing oil wells and is focused on the Marmaton horizontal oil play located mainly in Beaver County, Oklahoma. At the time of acquisition, estimated proved developed producing net reserves associated with the 10 acquired producing wells were approximately 762,000 BOE—consisting of 511,000 barrels of oil, 155,000 barrels of NGLs and 573 MMcf of natural gas.

Also during the second quarter of 2010, we completed an acquisition of approximately 32,000 net acres of undeveloped oil and gas leasehold located in Southwest Oklahoma and North Texas for approximately $17.6 million from an unaffiliated party.

Midstream Acquisitions and Capital Expenditures. As of December 31, 2008, we had commitments to purchase two new processing plants. In February 2009, we cancelled the purchase of one of these plants due to nonperformance of contractual terms. In December 2010, we wrote off $2.5 million of the progress payments we made toward the full purchase price before this contract was terminated because it was determined to be unrecoverable. In March 2009, we cancelled our remaining commitment for the second plant and incurred a $1.3 million penalty. Approximately half of the penalty was applied toward the purchase price of the plant we constructed in 2010.

During the fourth quarter of 2010, we completed the installation and start up of a 50.0 MMcf per day turbo-expander natural gas processing plant at our Hemphill facility in Canadian, Texas. With the addition of this new processing plant, the total processing capacity at our Hemphill facility increased to approximately 100.0 MMcf per day.

In connection with our Appalachian operations, we recently committed to build a 16-mile, 16” pipeline and a compressor station in Preston County, West Virginia, which will have a capacity of approximately 220 MMcf per day. Construction began during the first quarter of 2011 and we anticipate that the facility will be operational by mid-2011. We have signed an agreement to transport gas on this system for an unaffiliated third party.

During 2010, our midstream segment incurred $29.8 million in capital expenditures as compared to $9.9 million in 2009 and $49.9 million in 2008, including acquisitions. During the first quarter of 2011, our mid-stream segment incurred $9.0 million in capital expenditures as compared to $6.9 million in the first quarter of 2010. For 2011, we have budgeted capital expenditures of approximately $47.0 million.

Contractual Commitments

At March 31, 2011, we had certain contractual obligations including the following:

	Payments Due by Period				
	Total	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years
			(In thousands)		
Bank debt (1)	$191,533	$ 5,691	$185,842	$ 0	$ 0
Operating leases (2)	5,438	1,655	2,696	1,087	0
Drill pipe, drilling components and equipment purchases (3)	10,844	10,844	0	0	0
Total contractual obligations	$207,815	$ 18,190	$188,538	$1,087	$ 0

(1) See previous discussion in MD&A regarding our credit facility. This obligation is presented in accordance with the terms of the credit facility and includes interest calculated using our March 31, 2011 interest rate of 2.8% which includes the effect of our interest rate swaps.

(2) We lease office space or yards in Beaver, Elk City, Oklahoma City and Tulsa, Oklahoma; Canadian and Houston, Texas; Denver and Englewood, Colorado; Pinedale, Wyoming; and Pittsburgh, Pennsylvania under the terms of operating leases expiring through January, 2015. Additionally, we have several equipment leases and lease space on short-term commitments to stack excess drilling rig equipment and production inventory.

(3) We have committed to purchase approximately $10.8 million of new drilling rig components, drill pipe, drill collars and related equipment over the next twelve months.

At March 31, 2011, 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 (In thousands)	4-5 Years	After 5 Years
Deferred compensation plan (1)	$ 2,572	Unknown	Unknown	Unknown	Unknown
Separation benefit plans (2)	$ 5,953	$ 135	Unknown	Unknown	Unknown
Derivative liabilities—interest rate swaps	$ 1,361	$ 1,167	$ 194	$ 0	$ 0
Derivative liabilities—commodity hedges	$34,101	$ 24,391	$ 9,710	$ 0	$ 0
Asset retirement liability (3)	$71,338	$ 1,836	$ 14,843	$ 3,657	$ 51,002
Gas balancing liability (4)	$ 3,263	Unknown	Unknown	Unknown	Unknown
Repurchase obligations (5)	$ 0	Unknown	Unknown	Unknown	Unknown
Workers' compensation liability (6)	$17,666	$ 7,904	$ 3,058	$ 1,098	$ 5,606

(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 Condensed Consolidated Balance Sheets, 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 certain 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. On December 31, 2008, all these plans were amended to bring the plans into compliance with Section 409A of the Internal Revenue Code of 1986, as amended.

(3) When a well is drilled or acquired, under "Accounting for Asset Retirement Obligations," we record 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 2008, 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. Repurchases in any one year are limited to 20% of the units outstanding. We made repurchases of $22,000 in 2010, $1,000 in 2009. There have been no re-purchases in 2011 through the first quarter.

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

Derivative Activities

Periodically we enter into hedge transactions covering part of the interest rate payable under our credit facility as well as the prices to be received for a portion of our oil, NGLs and natural gas production.

Interest Rate Swaps. From time to time we enter into interest rate swaps to manage our exposure to possible future interest rate increases under our credit facility. Under these transactions we swap the variable interest rate we would otherwise incur on a portion of our bank debt for a fixed rate of interest. As of March 31, 2011, we had two outstanding interest rate swaps; both were cash flow hedges. There was no material amount of ineffectiveness. Our March 31, 2011 balance sheet recognized the fair value of these swaps as current and non-current derivative liabilities and is presented in the table below:

Term	Amount	Fixed Rate	Floating Rate	Fair Value Asset (Liability)
			($ in thousands)	
April 2010 – May 2012	$15,000	4.53%	3 month LIBOR	$ (713)
April 2010 – May 2012	$15,000	4.16%	3 month LIBOR	(648)
				$ (1,361)

Because of these interest rate swaps, our interest expense increased by $1.2 million and $1.0 million in 2010 and 2009, respectively, and $0.3 million for each of the three months ended March 31, 2011 and 2010. A loss of $0.8 million, net of tax, is reflected in accumulated OCI as of March 31, 2011.

Commodity Hedges. Our commodity hedging is intended to reduce our exposer to price volatility and manage price risks. Our decision on the type and quantity of our production and the price(s) of our hedge(s) is based, in part, on our view of current and future market conditions. Based on our first quarter 2011 average daily production, as of March 31, 2011, the approximated percentages of our production that we have hedged are as follows:

Oil and Natural Gas Segment:

	April – December 2011	January – December 2012	January – December 2013
Daily oil production	65%	49%	16%
Daily natural gas production	64%	24%	0%
Natural gas liquids production	10%	0%	0%

With respect to the commodities subject to our hedges, the use of hedging limits the risk of adverse downward price movements, however it also limits increases in future revenues that would otherwise result from price movements above the hedged prices.

The use of derivative transactions carries with it the risk that the counterparties will not be able to meet their financial obligations under the transactions. Based on our evaluation at March 31, 2011, we determined that there was no material risk of non-performance by our counterparties. At March 31, 2011, the fair values of the net assets (liabilities) we had with each of the counterparties to our commodity derivative transactions are as follows:

	March 31, 2011 (In millions)
Bank of Montreal	$ (1.3)
Bank of America, N.A.	(2.4)
Crédit Agricole Corporate and Investment Bank, London Branch	(15.6)
Comerica Bank	(9.7)
BBVA Compass Bank	(3.9)
Barclays Capital	(0.9)
BNP Paribas	(0.3)
Total assets (liabilities)	$ (34.1)

If a legal right of set-off exists, we net the value of the derivative arrangements we have with the same counterparty in our consolidated balance sheets. At March 31, 2011, we recorded the fair value of our commodity derivatives on our balance sheet as current and non-current derivative liabilities of $24.4 million and $9.7 million, respectively. At March 31, 2010, we recorded the fair value of our commodity derivatives on our balance sheet as current and non-current derivative assets of $40.2 million and $1.5 million, respectively.

We recognize in accumulated OCI the effective portion of any changes in fair value and reclassify the recognized gains (losses) on the sales to revenue and the purchases to expense as the underlying transactions are settled. As of March 31, 2011, we had a loss of $19.9 million, net of tax from our oil and natural gas segment derivatives in accumulated OCI.

Based on market prices at March 31, 2011, we expect to transfer to earnings a loss of approximately $15.9 million, net of tax, of the loss included in accumulated OCI during the next 12 months in the related month of production. The interest rate swaps and the commodity derivative instruments existing as of March 31, 2011 are expected to mature by May 2012 and December 2013, respectively.

Certain derivatives do not qualify as cash flow hedges. Currently, we have three basis swaps that do not qualify as cash flow hedges. For these types of derivatives, any changes in the fair value that occurs before their maturity (i.e., temporary fluctuations in value) are reported currently in the consolidated statements of income as unrealized gains (losses) within our oil and natural gas revenues. Changes in the fair value of derivative instruments designated as cash flow hedges, to the extent they are effective in offsetting cash flows attributable to the hedged risk, are recorded in OCI until the hedged item is recognized into earnings. Any change in fair value resulting from ineffectiveness is recognized currently in our oil and natural gas revenues as unrealized gains (losses). The effect of these realized and unrealized gains and losses on our revenues and expenses were as follows at March 31:

	2011 (In thousands)	2010
Increases (decreases) in:		
Oil and natural gas revenue:		
Realized gains (losses) on oil and natural gas derivatives	$ 453	$5,573
Unrealized gains (losses) on ineffectiveness of cash flow hedges	(1,909)	1,091
Unrealized gains (losses) on non-qualifying oil and natural gas derivatives	(419)	57
Total increase on oil and natural gas revenues due to derivatives	$(1,875)	$6,721

Stock and Incentive Compensation

During 2010 and the first three months of 2011, we granted awards covering 450,355 and 192,581 shares of restricted stock, respectively. These awards were granted as retention incentive awards. These stock awards had an estimated fair value as of the grant date of $16.9 million for 2010 and $10.0 million for the first quarter of 2011. Compensation expense will be recognized over their three year vesting periods, and during 2010 and the first three months of 2011, we recognized $6.1 million and $0.4 million, respectively, in additional compensation expense and capitalized $1.6 million and $0.1 million, respectively, for these awards. During 2010 and the first three months of 2011, we recognized compensation expense of $10.8 million and $2.3 million, respectively, for all of our restricted stock, stock options and SAR grants and capitalized $2.7 million and $0.6 million of compensation cost, respectively, for oil and natural gas properties. During 2008, we granted awards covering 30,855 shares of restricted stock. These awards were granted as retention incentive awards and have been recognized over the three year vesting periods. No SAR awards were made during 2008, 2009, 2010 or the first three months of 2011.

Insurance

We are self-insured for certain losses relating to workers' compensation, control of well and employee medical benefits. Insured policies for other coverage contain deductibles or retentions per occurrence that range from $50,000 to $1.0 million. 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 will adequately protect us against liability from all potential consequences. We have elected to use an ERISA governed occupational injury benefit plan to cover all Texas drilling operations in lieu of covering them under Texas Workers' Compensation. If insurance coverage becomes more expensive, we may choose to self-insure, decrease our limits, raise our deductibles or any combination of these rather than pay higher premiums.

Oil and Natural Gas Limited Partnerships and Other Entity Relationships.

We are the general partner of 16 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 2010, 2009 and 2008, the total we received for all of these fees was $1.5 million, $1.1 million and $1.9 million, respectively. For the first three months of 2011 and 2010, the total we received for all of these fees was $0.6 million and $0.3 million, respectively. We expect that these fees for 2011 will be comparable to those in 2010. 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, NGLs 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. Over the last several years, natural gas, NGLs 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. Historically, 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. 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 are subject to various contractual commitments.

Results of Operations

Quarter Ended March 31, 2011 versus Quarter Ended March 31, 2010

Provided below is a comparison of selected operating and financial data:

	Quarter Ended March 31,		Percent
	2011	2010	Change
Total revenue	$247,405,000	$206,550,000	20%
Net income	$ 41,027,000	$ 36,153,000	13%
Contract Drilling:			
Revenue	$ 97,988,000	$ 60,854,000	61%
Operating costs excluding depreciation	$ 52,844,000	$ 40,900,000	29%
Percentage of revenue from daywork contracts	100%	98%	2%
Average number of drilling rigs in use	70.0	50.9	38%
Average dayrate on daywork contracts	$ 17,704	$ 14,127	25%
Depreciation	$ 17,297,000	$ 13,786,000	25%
Oil and Natural Gas:			
Revenue	$109,834,000	$ 99,053,000	11%
Operating costs excluding depreciation, depletion and amortization	$ 30,781,000	$ 25,034,000	23%
Average oil price (Bbl)	$ 84.33	$ 67.33	25%
Average NGL price (Bbl)	$ 39.61	$ 42.76	(7)%
Average natural gas price (Mcf)	$ 4.28	$ 5.95	(28)%
Oil production (Bbl)	556,000	303,000	83%
NGL production (Bbl)	478,000	377,000	27%
Natural gas production (Mcf)	10,231,000	10,034,000	2%
Depreciation, depletion and amortization rate (Boe)	$ 14.58	$ 10.68	37%

Depreciation, depletion and amortization	$ 40,268,000	$ 25,336,000	59%
Mid-Stream Operations:			
Revenue	$ 39,764,000	$ 41,135,000	(3)%
Operating costs excluding depreciation and amortization	$ 29,055,000	$ 32,726,000	(11)%
Depreciation and amortization	$ 3,773,000	$ 3,941,000	(4)%
Gas gathered—MMBtu/day	185,730	180,117	3%
Gas processed—MMBtu/day	86,445	76,513	13%
Gas liquids sold—gallons/day	328,333	253,707	29%
General and administrative expense	$ 6,892,000	$ 6,279,000	10%
Interest expense, net	$ 54,000	$ 0	NM
Income tax expense	$ 25,414,000	$ 22,395,000	13%
Average interest rate	2.8%	6.1%	(54)%
Average long-term debt outstanding	$175,282,000	$ 31,081,000	NM

(1) NM – A percentage calculation is not meaningful due to a zero-value denominator or a percentage change greater than 200.

Contract Drilling

Drilling revenues increased $37.1 million or 61% in the first quarter of 2011 versus the first quarter of 2010 primarily due to a 38% increase in the average number of drilling rigs in use during the first quarter of 2011 compared to the first quarter of 2010 and a 25% higher average dayrate in the first quarter of 2011 compared to the first quarter of 2010. Average drilling rig utilization increased from 50.9 drilling rigs in the first quarter of 2010 to 70.0 drilling rigs in the first quarter of 2011. Oil prices improved in the first quarter of 2011 compared to the first quarter of 2010, creating increased demand for drilling rigs.

Drilling operating costs increased $11.9 million or 29% between the comparative first quarters of 2011 and 2010 primarily due to increased utilization and increased indirect cost due to higher personnel cost. Due to an increase in activity over last year's levels, competition to keep qualified labor has increased. Starting in the third quarter 2010, we increased compensation for drilling personnel in Oklahoma, Texas and Louisiana and again at the end of the first quarter for drilling personnel in all divisions. Contract drilling depreciation increased $3.5 million or 25% primarily due to capital expenditures for upgrades to existing drilling rigs in our fleet.

Oil and Natural Gas

Oil and natural gas revenues increased $10.8 million or 11% in the first quarter of 2011 as compared to the first quarter of 2010 primarily due to an increase in equivalent production volumes of 16% and an increase in oil prices somewhat offset by decreases in prices for NGLs and natural gas. Average oil prices between the comparative quarters increased 25% to $84.33 per barrel, NGL prices decreased 7% to $39.61 per barrel and natural gas prices decreased 28% to $4.28 per Mcf. In the first quarter of 2011, as compared to the first quarter of 2010, oil production increased 83%, NGL production increased 27% and natural gas production increased 2%. Production for first quarter 2010 was negatively impacted by an unexpected shut-in of some of our production from operational issues experienced at a third party facility that processes our Segno field production and production growth was hampered by the lack of availability of fracing services to complete wells.

Oil and natural gas operating costs increased $5.7 million or 23% between the comparative first quarters of 2011 and 2010 due to increases in lease operating expenses due to increased workover expense and higher saltwater disposal fees and higher gross production taxes due to higher oil prices and revenue from increased production between quarters. Lease operating expenses per Boe increased 9% to $6.96.

Depreciation, depletion and amortization ("DD&A") increased $14.9 million or 59% primarily due to a 37% increase in our DD&A rate and a 16% increase in equivalent production. The increase in our DD&A rate in the first quarter of 2011 compared to the first quarter of 2010 resulted primarily from increases throughout 2010 and the first quarter of 2011 from increased net book value on new reserves added. Our DD&A expense on our oil and natural gas properties is calculated each quarter utilizing period end reserve quantities adjusted for current period production.

Mid-Stream

Our mid-stream revenues were $1.4 million or 3% lower for the first quarter of 2011 as compared to the first quarter of 2010 primarily due to lower NGL and natural gas prices. The average price for natural gas sold decreased 24% and the average price for NGLs sold decreased 1%. Gas processing volumes per day increased 13% between the comparative quarters and NGLs sold per day increased 29% between the comparative quarters. The increase in volumes processed per day is primarily attributable to the volumes added from new wells connected to existing systems throughout 2010 and increased capacity of processing facilities. NGLs sold volumes per day increased due to both an increase in volumes processed, upgrades to several of our processing facilities and the doubling in size of our Hemphill facility in the Texas Panhandle. Gas gathering volumes per day increased 3% primarily from well connections throughout 2010.

Operating costs decreased $3.7 million or 11% in the first quarter of 2011 compared to the first quarter of 2010 primarily due to a 13% decrease in prices paid for natural gas purchased. Depreciation and amortization decreased $0.2 million, or 4%, primarily due to decreased amortization on our intangible asset. For 2011, we anticipate an increase in well connections over 2010 due to anticipated drilling activity by operators in the areas of our existing gathering systems as along with the benefit of the additional processing capacity from the Hemphill facility completed during the fourth quarter of 2010.

Other

Other revenue of $5.5 million for the first three months of 2010 was primarily attributable to the sale of six mechanical drilling rigs.

General and administrative expenses increased $0.6 million or 10% in the first quarter of 2011 compared to the first quarter of 2010 primarily due to increases in employee costs.

Interest expense, net of capitalized interest, increased $0.1 million between the comparative first quarters of 2011 and 2010. We capitalized interest based on the net book value associated with undeveloped leasehold not being amortized, the construction of additional drilling rigs and the construction of gas gathering systems. Our average interest rate decreased by 54% and our average debt outstanding was $144.2 million higher in the first quarter of 2011 as compared to the first quarter of 2010 due to the acquisition in 2010 and construction of new rigs in 2011. Total interest incurred increased $0.3 million for the first quarter of 2011 and $0.3 million for the first quarter of 2010 due to interest rate swap settlements.

Income tax expense increased $3.0 million or 13% in the first quarter of 2011 compared to the first quarter of 2010 primarily due to increased income. Our effective tax rate was 38.3% for both the first quarters of 2011 and 2010. There was no current income tax expense for the first quarter of 2011 as compared with $2.2 million or 10% of total income tax expense in the first quarter of 2010 due to expected bonus depreciation for 2011. We did not pay any income taxes in the first quarter of 2011.

[Table of Contents](#)

2010 versus 2009

Following is a comparison of selected operating and financial data:

	2010	2009	Percent Change
Total revenue	$881,845,000	$709,898,000	24%
Net income (loss)	$146,484,000	$ (55,500,000)	NM
Contract Drilling:			
Revenue	$316,384,000	$236,315,000	34%
Operating costs excluding depreciation	$186,813,000	$140,080,000	33%
Percentage of revenue from daywork contracts	100%	100%	0%
Average number of drilling rigs in use	61.4	38.9	58%
Average dayrate on daywork contracts	$ 15,478	$ 16,713	(7)%
Depreciation	$ 69,970,000	$ 45,326,000	54%
Oil and Natural Gas:			
Revenue	$400,807,000	$357,879,000	12%
Operating costs excluding depreciation, depletion, amortization and impairment	$105,365,000	$ 87,734,000	20%
Average oil price (Bbl)	$ 69.52	$ 56.33	23%
Average NGL price (Bbl)	$ 37.04	$ 22.81	62%
Average natural gas price (Mcf)	$ 5.62	$ 5.59	1%
Oil production (Bbl)	1,521,000	1,286,000	18%
NGL production (Bbl)	1,549,000	1,488,000	4%
Natural gas production (Mcf)	40,756,000	44,063,000	(8)%
Depreciation, depletion and amortization rate (Mcfe)	$ 1.99	$ 1.87	6%
Depreciation, depletion and amortization	$118,793,000	$114,681,000	4%
Impairment of oil and natural gas properties	$ 0	$281,241,000	NM
Midstream Operations:			
Revenue	$154,516,000	$108,628,000	42%
Operating costs excluding depreciation and amortization	$122,146,000	$ 87,908,000	39%
Depreciation and amortization			

	$ 15,385,000	$ 16,104,000	(4)%
Gas gathered—MMBtu/day	183,867	183,989	0%
Gas processed—MMBtu/day	82,175	75,908	8%
Gas liquids sold—gallons/day	271,360	243,492	11%
General and administrative expense	$ 26,152,000	$ 24,011,000	9%
Interest expense, net	$ 0	$ 539,000	NM
Income tax expense (benefit)	$ 90,737,000	$ (32,226,000)	NM
Average interest rate	3.5%	4.0%	(13)%
Average long-term debt outstanding	$ 94,873,000	$111,808,000	(15)%

(1) NM—A percentage calculation is not meaningful due to a zero-value denominator or a percentage change greater than 200.

Contract Drilling:

Drilling revenues increased $80.1 million or 34% in 2010 versus 2009 primarily due to a 58% increase in the average number of drilling rigs in use during 2010 compared to 2009 and increased mobilization revenue offset by a 7% lower average dayrate. Average drilling rig utilization increased from 38.9 drilling rigs in 2009 to 61.4 drilling rigs in 2010 as commodity prices improved in 2010 compared to 2009, creating increased demand for drilling rigs.

Drilling operating costs increased $46.7 million or 33% between the comparative years of 2010 and 2009 primarily due to increases in the number of drilling rigs used and increases in general and administrative expenses somewhat offset by decreases in worker's compensation. During 2009, competition to keep and attract qualified employees to meet our requirements did not materially affect us due to the depressed conditions within our industry. Due to an increase in activity over last year's levels, competition to keep qualified labor has increased in 2010. Starting in the third quarter 2010, we increased compensation for drilling personnel in

Oklahoma, Texas and Louisiana. Contract drilling depreciation increased $24.6 million or 54% primarily due to an increase in the number of drilling rigs being utilized and an increase in capital expenditures for upgrades to existing drilling rigs in our fleet.

Oil and Natural Gas

Oil and natural gas revenues increased $42.9 million or 12% in 2010 as compared to 2009 primarily due to an increase in average oil, NGL and natural gas prices partially offset by a 3% decrease in equivalent production volumes. Average oil prices between the comparative years increased 23% to $69.52 per barrel, NGL prices increased 62% to $37.04 per barrel and natural gas prices increased 1% to $5.62 per Mcf. In 2010, as compared to 2009, oil production increased 18%, NGL production increased by 4% and natural gas production decreased 8%. Production for 2010 was negatively impacted by an unexpected shut-in of some of our production from operational issues experienced at a third party facility that processes our Segno field production while production growth was hampered primarily during the first nine months of the year by the lack of availability of fracing services to complete wells.

Oil and natural gas operating costs increased $17.6 million or 20% between the comparative years of 2010 and 2009 due primarily to higher gross production taxes due to increased oil and natural gas sales revenue between the periods. Production taxes in 2009 were also reduced by $5.8 million for production tax credits attributable to high-cost gas wells.

Depreciation, depletion and amortization (DD&A) increased $4.1 million or 4% primarily due to a 6% increase in our DD&A rate slightly offset by a 3% decrease in equivalent production. The 2009 DD&A rate was lower after a $281.2 million pre-tax non-cash ceiling test write-down of the carrying value of our oil and natural gas properties at the end of the first quarter in 2009 as a result of a decline in commodity prices and the DD&A rate increases throughout 2010 from increased net book value on new reserves added. Our DD&A expense on our oil and natural gas properties is calculated each quarter utilizing period end reserve quantities adjusted for current period production.

Midstream

Our midstream revenues increased $45.9 million or 42% for 2010 as compared to 2009 primarily due to higher NGL and natural gas prices and higher NGL volumes processed and sold. The average price for NGLs sold increased 31% and the average price for natural gas sold increased 28%. Gas processing volumes per day increased 8% between the comparative periods and NGLs sold per day increased 11% between the comparative periods. The increase in volumes processed per day is primarily attributable to the volumes added from new wells connected to existing systems throughout 2010. NGLs sold volumes per day increased due to both an increase in volumes processed and upgrades to several of our processing facilities. Gas gathering volumes per day remained flat.

Operating costs increased $34.2 million or 39% in 2010 compared to 2009 primarily due to a 36% increase in prices paid for natural gas purchased and a 9% increase in purchased volumes. Depreciation and amortization decreased $0.7 million, or 4%, primarily due to decreased amortization on our intangible assets. For 2011, we anticipate an increase in well connections over 2010 due to anticipated drilling activity by operators in the areas of our existing gathering systems as well as the additional processing facility completed during the fourth quarter of 2010 to accommodate the increased drilling activity of our oil and natural gas segment and other third parties.

Other

Other revenue of $10.1 million for 2010 was primarily attributable to the sale of eight mechanical drilling rigs and the sale of a gas pipeline in which we owned a 60% interest, partially offset by a $2.5 million loss associated with the write-off of progress payments made on a gas plant contract that was terminated.

General and administrative expenses increased $2.1 million or 9% compared to 2009 primarily due to increases in employee costs.

Interest expense, net of capitalized interest, decreased $0.5 million between the comparative years. We capitalized interest based on the net book value associated with undeveloped leasehold not being amortized, the construction of additional drilling rigs and the construction of gas gathering systems. Our average interest rate decreased by 13% and our average debt outstanding was 15% lower in 2010 as compared to 2009. Total interest expense was increased $1.2 million for 2010 and $1.0 million for 2009 from interest rate swap settlements.

Income tax expense (benefit) changed from a benefit of $32.2 million in 2009 to an expense of $90.7 million in 2010 due to the non-cash ceiling test write-down of $281.2 million pre-tax ($175.1 million, net of tax) of our oil and natural gas properties during the quarter ended March 31, 2009, which was more than offset by improved performance of our operating segments. Our effective tax rate was 38.3% and 36.7% for 2010 and 2009, respectively. The portion of our taxes reflected as a current income tax benefit for 2010 was $9.9 million as compared to a benefit of $0.2 million in 2009. Income taxes paid in 2010 were $3.1 million.

Table of Contents

2009 versus 2008

Following is a comparison of selected operating and financial data:

	2009	2008	Percent Change
Total revenue	$709,898,000	$1,358,093,000	(48)%
Net income (loss)	$(55,500,000)	$ 143,625,000	(139)%
Contract Drilling:			
Revenue	$236,315,000	$ 622,727,000	(62)%
Operating costs excluding depreciation	$140,080,000	$ 312,907,000	(55)%
Percentage of revenue from daywork contracts	100%	100%	0%
Average number of drilling rigs in use	38.9	103.1	(62)%
Average dayrate on daywork contracts	$ 16,713	$ 18,458	(9)%
Depreciation	$ 45,326,000	$ 69,841,000	(35)%
Oil and Natural Gas:			
Revenue	$357,879,000	$ 553,998,000	(35)%
Operating costs excluding depreciation, depletion, amortization and impairment	$ 87,734,000	$ 116,239,000	(25)%
Average oil price (Bbl)	$ 56.33	$ 93.87	(40)%
Average NGL price (Bbl)	$ 22.81	$ 47.42	(52)%
Average natural gas price (Mcf)	$ 5. 59	$ 7.62	(27)%
Oil production (Bbl)	1,286,000	1,261,000	2%
NGL production (Bbl)	1,488,000	1,388,000	7%
Natural gas production (Mcf)	44,063,000	47,473,000	(7)%
Depreciation, depletion and amortization rate (Mcfe)	$ 1.87	$ 2.50	(25)%
Depreciation, depletion and amortization	$114,681,000	$ 159,550,000	(28)%
Impairment of oil and natural gas properties	$281,241,000	$ 281,966,000	0%
Midstream Operations:			
Revenue	$108,628,000	$ 181,730,000	(40)%

Operating costs excluding depreciation and amortization	$ 87,908,000	$ 150,466,000	(42)%
Depreciation and amortization	$ 16,104,000	$ 14,822,000	9%
Gas gathered—MMBtu/day	183,989	197,367	(7)%
Gas processed—MMBtu/day	75,908	67,796	12%
Gas liquids sold—gallons/day	243,492	195,837	24%
General and administrative expense	$ 24,011,000	$ 25,419,000	(6)%
Interest expense, net	$ 539,000	$ 1,304,000	(59)%
Income tax expense (benefit)	$ (32,226,000)	$ 81,954,000	(139)%
Average interest rate	4.0%	4.5%	(11)%
Average long-term debt outstanding	$111,808,000	$ 149,315,000	(25)%

Contract Drilling:

Drilling revenues decreased $386.4 million or 62% in 2009 versus 2008 primarily due to a 62% decrease in the average number of drilling rigs in use during 2009 compared to 2008. The decline in revenue was partially offset by $6.1 million of revenue recognized during the third and fourth quarters of 2009 from settlements of terminated drilling contracts. Average drilling rig utilization decreased from 103.1 drilling rigs in 2008 to 38.9 drilling rigs in 2009. Our average dayrate in 2009 was 9% lower than in 2008. In the third and fourth quarters of 2008, prices for oil and natural gas decreased substantially and natural gas prices continued to be at low levels during 2009. Entering the third quarter of 2009, the decline in utilization started to moderate and improved slightly through the end of 2009.

Drilling operating costs decreased $172.8 million or 55% between the comparative years of 2009 and 2008 primarily due to the decrease in the number of drilling rigs used. The utilization decreases experienced in the industry since the third quarter of 2008 has reduced the demand for rig personnel which reduced the pressure on our labor costs. Likewise, that pressure on our other daily direct drilling costs resulted in little change of those costs as well, but reduced utilization resulted in fewer drilling rigs to cover our indirect fixed costs. Contract drilling depreciation decreased $24.5 million or 35%, we utilize the units of production method for the depreciation of our drilling rigs, therefore in periods of reduced utilization a decrease in depreciation occurs.

Oil and Natural Gas:

Oil and natural gas revenues decreased $196.1 million or 35% in 2009 as compared to 2008 primarily due to a decrease in average oil, NGL and natural gas prices. Average oil prices between the comparative years decreased 40% to $56.33 per barrel, NGL prices decreased 52% to $22.81 per barrel and natural gas prices decreased 27% to $5.59 per Mcf. In 2009, as compared to 2008, oil production increased 2%, NGL production increased 7% and natural gas production decreased 7%. During 2009 approximately 1.2 Bcf of natural gas production was curtailed due to low commodity prices and the shut-in of third party plants. A large part of our increase in revenues during 2008 was determined by the prices we received for our production. Commodity prices decreased substantially during the third and fourth quarters of 2008 and natural gas prices stayed at low levels during 2009. As a result of these lower commodity prices as well as service costs that remained relatively high, we slowed our drilling activity during the fourth quarter of 2008 and continued to do so through the second quarter of 2009. We began increasing activity during the third quarter of 2009.

Oil and natural gas operating costs decreased $28.5 million or 25% between the comparative years of 2009 and 2008 primarily due to reduced production taxes associated with the large decrease in commodity prices and $5.1 million in production tax credits attributable to high-cost gas wells. Also contributing to the decrease was a reduction in general and administrative expenses as compensation costs were reduced in response to the downturn in the industry.

Total DD&A, excluding ceiling test impairments, decreased $44.9 million or 28% primarily due to a 25% decrease in our DD&A and lower production volumes. The decrease in our DD&A rate in 2009 compared to 2008 resulted primarily from the $282.0 million and $281.2 million pre-tax non-cash ceiling test write-down of the carrying value of our oil and natural gas properties in the fourth quarter of 2008 and the first quarter 2009, respectively, as a result of a decline in commodity prices. Our DD&A expense on our oil and natural gas properties is calculated each quarter utilizing period end reserve quantities. The new SEC oil and gas reserves measurement and disclosure rules that went into effect as of December 31, 2009 impacted our DD&A expense for the fourth quarter of 2009, increasing DD&A expense by $1.2 million (or $0.02 per share) for the quarter and year ended December 31, 2009.

Midstream:

Our midstream revenues were $73.1 million or 40% lower for 2009 as compared to 2008 primarily due to lower NGL and natural gas prices slightly offset by higher NGL volumes processed and sold. The average price for NGLs sold decreased 45% and the average price for natural gas sold decreased 55%. Gas processing volumes per day increased 12% between the comparative periods and NGLs sold per day increased 24% between the comparative periods. The increase in volumes processed per day is primarily attributable to the volumes added from new wells connected to existing systems throughout 2008 and 2009. NGLs sold volumes per day increased due to both an increase in volumes processed and upgrades to several of our processing facilities. Gas gathering volumes per day decreased 7% primarily from well production declines associated with the wells gathered from one of our gathering systems located in Southeast Oklahoma. NGL sales increased by $2.0 million in 2008 due to the impact of NGL hedges. There were no NGL hedges in place for 2009.

Operating costs decreased $62.6 million or 42% in 2009 compared to 2008 primarily due to a 52% decrease in prices paid for natural gas purchased and an 8% decrease in field operating expense. Depreciation and amortization increased $1.3 million, or 9%, primarily attributable to the additional depreciation associated with capital expenditures between the comparative periods. Operating costs increased by $1.4 million in 2008 due to the impact of natural gas purchase hedges; however there were no hedges in place during 2009.

Other:

Other revenue of $7.1 million for the year ended 2009 was primarily attributable to the sale of three mechanical drilling rigs during the year.

General and administrative expense decreased $1.4 million or 6% in 2009 compared to 2008. This decrease was primarily attributable to decreased payroll expenses due to efforts to manage cost in this economic environment.

Interest expense, net of capitalized interest, decreased $0.8 million or 59% between the comparative periods of 2009 and 2008. Capitalized interest reduced our interest expense by $5.1 million in 2009 versus $6.0 million in 2008. We capitalized interest based on the net book value associated with our undeveloped oil and natural gas properties, the construction of additional drilling rigs and the construction of gas gathering systems. Our average interest rate was 11% lower and our average debt outstanding was 25% lower in 2009 as compared to 2008. Interest expense was increased $1.0 million for 2009 and $0.3 million for 2008 from interest rate swap settlements.

Income tax expense (benefit) changed from an expense of $82.0 million in 2008 to a benefit of $32.2 million in 2009 due to declines in income from lower commodity prices and reduced drilling rig utilization and dayrates. Our effective tax rate was 36.7% and 37.0% for 2009 and 2008, respectively with the effect of the deferred tax benefit related to the ceiling test write-down of our oil and natural gas properties. The portion of our taxes reflected as a current income tax benefit for 2009 was $0.2 million or 0.7% of the total income tax benefit for 2009 as compared with $40.9 million or 50% of total income tax expense in 2008. The decrease in the percentage of tax expense (benefit) and the reduction in tax expense recognized as current were both the result of lower taxable income. Income taxes paid in 2009 were $12.3 million.

[Table of Contents](#)

BUSINESS

We were founded in 1963 as a domestic land contract drilling company. Today, in addition to our drilling operations, we engage in the domestic exploration, development and production of crude oil and natural gas and midstream operations. Our operations are generally conducted through our three principal wholly owned subsidiaries:

- Unit Drilling Company—which drills onshore oil and natural gas wells for others and for our own account (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, development and production), and
- Superior Pipeline Company, L.L.C.—which buys, sells, gathers, processes and treats natural gas for third parties and for our own account (midstream).

Each of these companies may conduct operations through subsidiaries of their own.

The following table provides certain information about us as of February 11, 2011:

Number of drilling rigs owned	121
Completed gross wells in which we own an interest	7,999
Number of natural gas treatment plants owned	3
Number of processing plants owned	10
Number of natural gas gathering systems owned	34

2010 SEGMENT OPERATION HIGHLIGHTS

During the year ended December 31, 2010, we

Contract Drilling

- Averaged 61.4 drilling rigs in use during 2010, an increase of 58% over the average of 38.9 drilling rigs in use during 2009.
- Sold 11 small mechanical drilling rigs to unaffiliated third parties. These drilling rigs ranged in horsepower from 650 to 1,000.
- Successfully refurbished and upgraded 30 drilling rigs to meet the increase in customers' horizontal drilling activity.
- Placed into service a new 1,500 horsepower, diesel-electric drilling rig in our Rocky Mountain division.
- Acquired a new 1,200 horsepower electric drilling rig.
- Signed two-year contracts for each of the five new 1,500 horsepower drilling rigs to be deployed in the Bakken Shale play. One of the drilling rigs has been delivered with another to be delivered in the second quarter of 2011 and the remaining three during the third quarter of 2011.

Oil and Natural Gas

- Increased our net proved oil, natural gas liquids (NGLs) and natural gas reserves at year-end 2010 to 622.2 Bcfe, an 8% increase over our 2009 year-end reserves.

- Continued to focus more of our development activities on oil and NGLs by increasing our year-end 2010 net proved oil and NGL reserves by 27% over those reserves at year-end 2009.
- Participated in the drilling of 167 wells, an increase of 76% over the number of wells drilled during 2009.
- Recognized favorable commodity hedge settlements of approximately $53.0 million.
- Acquired 45,000 net leasehold acres and 10 producing oil wells located mainly in Beaver County, Oklahoma from certain unaffiliated third parties.
- Pre-scheduled fracture stimulation services for 2011 for the wells we anticipate drilling in the Granite Wash and Marmaton plays.

Midstream

- Completed the construction of a 50.0 MMcf per day turbo-expander natural gas processing plant at our Hemphill facility in the Texas Panhandle.
- Committed to build a 16-mile, 16” pipeline and a compressor station in Preston County, West Virginia, which will have a capacity of approximately 220 MMcf per day. Construction began during the first quarter of 2011 and we anticipate that the system will be operational by mid-2011.
- Added an additional 21 miles of pipeline (approximately a 3% increase) and connected 52 new wells to our gathering systems.

CONTRACT DRILLING

General. Our contract drilling business is conducted through Unit Drilling Company and its subsidiary Unit Texas Drilling, L.L.C. Through these companies we drill onshore oil and natural gas wells for our own account as well as for a wide range of other oil and natural gas companies. Our drilling operations are mainly located in Oklahoma, Texas, Louisiana, Wyoming, Colorado, Utah, Montana and North Dakota.

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

	Year Ended December 31,		
	2010	2009	2008
Number of drilling rigs owned at end of year	121	130	132
Average number of drilling rigs owned during year	123.9	130.8	130.4
Average number of drilling rigs utilized	61.4	38.9	103.1
Utilization rate (1)	50%	30%	79%
Average revenue per day (2)	$14,115	$16,662	$16,498
Total footage drilled (feet in 1,000’s)	7,961	4,627	11,734
Number of wells drilled	593	409	1,028

(1) Utilization rate is determined by dividing the average number of drilling rigs used by the average number of drilling rigs owned during the year.
(2) Represents the total revenues from our contract drilling operations divided by the total number of days our drilling rigs were used during the year.

Description and Location of Our Drilling Rigs. An on-shore drilling rig is composed of major equipment components, such as engines, drawworks or hoists, derrick or mast, substructure, pumps to circulate the drilling fluid, blowout preventers and drill pipe that are collectively unitized into an operating system commonly referred to as a drilling rig. As a result of the normal wear and tear of operating 24 hours a day, several of the major components of a drilling rig, like engines, mud pumps and drill pipe, must be replaced or rebuilt on a periodic basis. Other components, like 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 top drives, skidding systems, 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 2010, 79 of our 121 available drilling rigs were used in drilling services.

The following table shows certain information about our drilling rigs (including their distribution) as of February 11, 2011:

Region	Contracted Rigs	Non-Contracted Rigs	Total Rigs	Average Rated Drilling Depth (ft)
Anadarko Basin Oklahoma	27	11	38	17,263
Panhandle of Texas	12	17	29	14,379
Arkoma Basin	3	3	6	13,583
East Texas, Louisiana, Gulf Coast and South Texas	13	3	16	18,063
North Texas Barnett Shale	2	5	7	11,643
Rocky Mountains	15	10	25	18,360
Totals	72	49	121	16,397

With the downturn in drilling activity that started in the fourth quarter of 2008, we consolidated our nine operating divisions into six at the beginning of 2009 to minimize our costs. In 2010, as drilling activity in the Barnett Shale in North Texas picked up, we reactivated our North Texas division. Currently our operating divisions consist of the following: Arkoma, Gulf Coast, Mid-continent, North Texas, Panhandle, Rocky Mountain and Woodward.

2010 brought a dramatic increase in our drilling rig utilization. In the middle of 2009 our active rig count bottomed out at 28 drilling rigs. Our active rig count at the start of 2010 was 42 drilling rigs and utilization continued to climb to 72 active drilling rigs at the end of 2010.

Anadarko Basin. The Anadarko Basin is a geologic feature covering approximately 50,000 square miles primarily in Central and Western Oklahoma, but also includes the upper Texas Panhandle, southwestern Kansas and southeastern Colorado region. The basin contains sedimentary deposits ranging in thickness from 2,000 feet on its northern and western flanks to 40,000 feet in its southern portion.

During 2010, our Mid-Continent and Woodward divisions averaged 17.4 and five drilling rigs operating during 2010, respectively.

Panhandle of Texas. During 2010, we averaged 5.7 drilling rigs operating in this division. We remain the largest drilling contractor in the combined Anadarko Basin of Oklahoma and the Texas Panhandle in terms of total rig count.

Arkoma Basin. The Arkoma Basin is a geologic feature that encompasses approximately 33,800 square miles of southeastern Oklahoma and west-central Arkansas. The Arkoma Basin holds deposits ranging in thickness from 3,000 to 20,000 feet. It contains multiple conventional gas plays as well as two of the more recent notable unconventional plays—the Woodford Shale and Fayetteville Shale.

During 2010, our Arkoma division averaged 3.5 drilling rigs operating. The Arkoma Basin has traditionally been a natural gas play. With lower natural gas commodity prices during 2010 and operators shifting their drilling emphasis to liquids, we moved two drilling rigs from this division to our Mid-Continent and Texas Panhandle divisions for greater utilization potential.

East Texas, Louisiana, Gulf Coast and South Texas. Our Gulf Coast division provides drilling rigs to the onshore areas of the south Louisiana Gulf Coast and upper Texas Gulf Coast region as well as the conventional and unconventional gas plays of northwest Louisiana, East Texas and South Texas. The Gulf Coast division averaged 13.6 drilling rigs operating during 2010. The Haynesville Shale play was an active area for us with six drilling rigs working there during most of 2010. In 2010, as a result of operators searching for oil and NGL's, a new market emerged in the Eagle Ford Shale in South Texas. We had five drilling rigs in the Eagle Ford at year end 2010.

North Texas Barnett Shale. North Central Texas is the home of the Barnett Shale, a tight gas bearing formation. It is touted as one of the largest natural gas fields in the U.S., and as being one of the first unconventional shale gas formations to have been unlocked by technological advances in the use of multi-stage high pressure fracturization completion processes.

We secured contracts for three drilling rigs to begin operations in the Barnett Shale in the first quarter of 2010 and those drilling rigs operated throughout the year.

Rocky Mountains. The Rocky Mountain area covers several states, including Colorado, Utah, Wyoming, Montana and North Dakota. This vast area has produced a number of conventional and unconventional oil and gas fields. Our drilling rig fleet in this division operated an average of 13.4 drilling rigs during 2010. We have drilling rigs operating in the Pinedale Anticline of western Wyoming, the Niobrara in southeast Wyoming, the Bakken Shale in Montana and North Dakota, as well as other areas throughout this expansive geographical area. With greater emphasis by our customers for oil prospects, in 2010 we repositioned several of our drilling rigs to the Bakken Shale in North Dakota. We closed out 2010 with eight drilling rigs working in the Bakken Shale, including one new 1,500 horsepower drilling rig which began operations during the second quarter of 2010. As mentioned earlier, we deployed one new 1,500 horsepower electric drilling rig with a skidding system to the Bakken Shale, with four more to be delivered during the second and third quarters of 2011.

At any given time our ability to use our drilling rigs is dependent on a number of conditions besides demand, including the availability of qualified labor and the availability of needed drilling supplies and equipment. Not surprisingly, the impact of these various conditions tends to fluctuate with the demand for our drilling rigs. In late 2008, our utilization rate was significantly affected by the U.S. and world economic downturn. For the first nine months of 2008 our average utilization rate was 81%. By December 2008, our average utilization rate had declined to 61%. For 2009, our average utilization rate declined to 30% and for 2010, our average utilization rate increased to 50%.

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

	2010	2009	2008
First quarter	50.9	52.8	100.6
Second quarter	58.1	31.6	104.5
Third quarter	65.4	34.6	110.7
Fourth quarter	70.9	36.7	96.7

Drilling Rig Fleet. The following table summarizes the 2010 changes made to our drilling rig fleet. A more complete discussion of these changes follows the table:

Drilling rigs owned at December 31, 2009	130
Drilling rigs sold	(11)
Drilling rigs purchased	1
Drilling rigs constructed	1
Total drilling rigs owned at December 31, 2010	121

Dispositions, Acquisitions, and Construction. During the first quarter 2009, we sold one 750 horsepower mechanical drilling rig for $3.1 million and recorded a $0.9 million gain. During the third quarter 2009, we sold a 1,000 horsepower mechanical drilling rig for $2.8 million and recorded a $1.9 million gain. During the fourth quarter 2009, we sold a 1,000 horsepower mechanical drilling rig for $2.7 million and recorded a $2.0 million gain and acquired one new 1,500 horsepower diesel electric drilling rig for $13.2 million.

During the first half of 2010, our contract drilling segment sold eight of its idle mechanical drilling rigs to an unaffiliated third party. These drilling rigs ranged in horsepower from 800 to 1,000. Proceeds from the sale of those drilling rigs were $23.9 million with a gain of $5.7 million which was recorded in the first quarter 2010. The proceeds were used to refurbish and upgrade additional drilling rigs in our fleet allowing those drilling rigs to be used in horizontal drilling operations. We also placed into service in our Rocky Mountain division a 1,500 horsepower, diesel-electric drilling rig that previously had been placed on hold during 2009 by our customer.

In September 2010, we entered into a contract with an unaffiliated third-party under which we conveyed three of our idle mechanical drilling rigs and, in exchange, we received a 1,200 horsepower electric drilling rig and $5.3 million. The three drilling rigs sold ranged in horsepower from 650 to 1,000. The transaction closed in October and resulted in a gain of $3.5 million.

Recently we signed two year contracts for each of the five new 1,500 horsepower drilling rigs which will be deployed in the Bakken Shale play. One of the drilling rigs has been delivered with another to be delivered in the second quarter of 2011 and the remaining three during the third quarter of 2011.

Historically, our contract drilling segment has experienced a greater demand for natural gas drilling as opposed to drilling for oil and NGLs. Today, with the weakened demand and price for natural gas, operators are primarily focusing on drilling for oil and NGLs. Approximately 73% of our drilling rigs working today are drilling for oil or NGLs and approximately 88% are drilling horizontal or directional wells.

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 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 indemnitees are subject to negotiation on a contract by contract basis.

The type of contract used determines our compensation. Contracts are generally one of three types: daywork; footage; or turnkey. Additional compensation may be charged for special risks and unusual conditions. Under a daywork contract, we provide the drilling rig with the required personnel and the leasehold 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. We drilled four wells under a footage contract in 2010, one well in 2009 and none in 2008. 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 that increase our costs or result in the loss of the well. To date, we have not experienced significant losses in performing turnkey contracts. We did not have any turnkey contracts during the last three years. With the exception of the footage contracts noted above, all of our work during the last three years was under daywork 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.

The majority of our contracts are on a well-to-well basis, with the rest under term contracts. Term contracts range from six months to two years and, depending on the contract, the rates can either be fixed throughout the term or allow for periodic adjustments.

Customers. During 2010, QEP Resources, Inc. was our largest drilling customer accounting for approximately 28% of our total contract drilling revenues. Our work for this customer was under multiple contracts and our business was not substantially dependent on any of these individual contracts. Consequently, none of these contracts were considered to be material. No other third party customer accounted for 10% or more of our contract drilling revenues. During 2010, 2009 and 2008, we drilled 75, 38 and 122 wells, respectively, or 13%, 9% and 12%, respectively, of our total wells drilled for our oil and natural gas segment.

Our contract drilling segment also provides drilling services for our oil and natural gas segment. Depending on the timing of the drilling services performed on our properties those services may be deemed, for financial reporting purposes, to be associated with the acquisition of an ownership interest in the property. Revenues and expenses for such services are eliminated in our income statement, with any profit recognized as a reduction in our investment in our oil and natural gas properties. The contracts for these services are issued under the same conditions and rates as the contracts entered into with unrelated third parties. We eliminated revenue of $40.1 million, $15.0 million and $65.5 million during 2010, 2009 and 2008, respectively from our contract drilling segment and eliminated the associated operating expense of $31.0 million, $13.7 and $37.6 million during 2010, 2009 and 2008, respectively, yielding $9.1 million, $1.3 million and $27.9 million during 2010, 2009 and 2008, respectively, as a reduction to the carrying value of our oil and natural gas properties.

OIL AND NATURAL GAS

General. We began to develop our exploration and production operations in 1979 as a means of diversifying our contract drilling business. 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, North Dakota, Colorado and Pennsylvania and, to a lesser extent, in Arkansas, New Mexico, Wyoming, Montana, Alabama, Kansas, Mississippi, Michigan, Maryland and a small portion in Canada.

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

The following table presents certain information regarding our oil and natural gas operations as of December 31, 2010:

Our Divisions/Area	Number of Gross Wells	Number of Net Wells	Number of Gross Wells in Process	Number of Net Wells in Process	2010 Average Net Daily Production		
					Natural Gas (Mcf)	Oil (Bbls)	NGL (Bbls)
West division (consists principally of the Rocky Mountain region, New Mexico, Western and Southern Texas and the Gulf Coast region)	3,278	538.23	6	3.39	29,989	1,997	1,717
East division (consists principally of the Appalachian region, Arkansas, East Texas, Northern Louisiana and Eastern Oklahoma)	1,146	294.62	1	0.21	38,436	37	12
Central division (consists principally of Kansas, Western Oklahoma and the Texas Panhandle)	3,560	878.06	12	5.32	43,235	2,133	2,515
Total	7,984	1,710.91	19	8.92	111,660	4,167	4,244

As of December 31, 2010, we did not have any material water floods, pressure maintenance operations or any other material operations that were in process.

Description and Location of Our Core Operations

West division. Our Segno play, located primarily in Polk, Tyler and Hardin Counties, Texas, continued to grow as the company expanded its prospect area to the south by entering into a joint exploration agreement with a third party for the use of a proprietary 3-D seismic survey covering approximately 151 square miles. Under the exploration agreement, we drilled three Wilcox wells during 2010. One of the wells resulted in a confirmed gas discovery that started selling gas in late November at an initial rate of approximately 151 Bbls of oil per day, 310 Bbls of NGLs per day, and 3.7 MMcf per day, or an equivalent rate of approximately 6.4 MMcfe per day. The other two wells are potential gas discoveries, one of which began sales in the second quarter of 2011 and the other of which is pending further testing after the pipeline connecting the wells is finished, which should occur in the second quarter 2011. For 2010, we operated and completed 22 wells at an average working interest of 62.5% and a 77% success rate. The overall production from our Segno area for December 2010 averaged 1,141 Bbls of oil per day, 1,371 Bbls of NGLs per day and 16.6 MMcf per day, or an equivalent rate of 31.7 MMcfe per day. The average completed gross well cost was approximately $3.4 million per well for 2010 wells. For 2011, we plan to drill approximately 20 gross wells with an approximate average working interest of 80% for an estimated cost of $54 million. We own approximately 57,000 gross and 48,000 net acres in the Segno play.

In the Bakken Shale play located in North Dakota, we participated in 20 wells in 2010 with a 100% success rate at an average working interest of 11% and a total cost of approximately $18.5 million. The finding cost for the 2010 wells averaged $21.24 per barrel of oil equivalent (BOE) with a total per well cost of approximately $7.9 million, which equates to gross reserves of approximately 500,000 BOE per well. For 2011, we anticipate participating in approximately 25 gross wells with an average working interest of 15% at a total cost of approximately $30 million. We own approximately 12,750 net acres in the play and anticipate two to three drilling rigs drilling on its North Dakota Bakken leasehold during 2011.

East division. In Shelby County, Texas, a second horizontal Haynesville well, the KC GU #1H (59% WI) has drilled 4,000 feet of Haynesville lateral. The well was successfully fracture stimulated in late January 2011 and first sales occurred during the first quarter of 2011. We expect to drill one to three horizontal Haynesville wells in Shelby County. In Harrison County, Texas, the Double K #1H (33% WI) had first gas sales in late September from the Cotton Valley sand at initial rates of approximately 8.8 MMcf per day and 127 Bbls of oil per day with 2,120 pounds flowing tubing pressure. The lateral length was 4,000 feet and the well was fracture stimulated in 10 stages and 2.3 million pounds of sand. An offset was drilled and we anticipate participating in one to two additional wells in 2011.

In the Marcellus play located in Somerset County, Pennsylvania, there were no new wells drilled in 2010 and we don't plan on drilling any new wells in 2011. The current plan is to delay drilling activity until the gas prices improve.

Central division. During 2010 in our Marmaton horizontal oil play located in Beaver County, Oklahoma, we drilled 19 horizontal Marmaton wells with an average working interest of 92% and participated in one outside operated horizontal Marmaton well with a 50% working interest. Completion of many of these wells was delayed until the beginning of the fourth quarter due to the unavailability of third party fracturing services. Early in the fourth quarter, we were able to obtain the needed fracturing services and by year end 2010, had successfully fracture stimulated 11 of the 20 wells, and subsequently had first oil sales on 10 of these wells in late 2010. The initial 30-day average production rate for the 10 wells ranged from 80 BOE per day to 480 BOE per day with an average rate of 230 BOE per day. The average ultimate recovery for each of the 10 completed wells is estimated to be 130,000 BOE at an average completed well cost of approximately $2.8 million. The current cost to drill and complete new wells is estimated at $2.5 million. We have secured frac dates for 2011, which should catch up the wells waiting to be fracture stimulated as well as the new wells that will be drilled. For 2011, we anticipate running a two drilling rig program in this play that should result in 30 to 35 gross wells at an approximate net cost of $52 million. We currently have leases on approximately 60,000 net acres in this play.

In our Granite Wash play located in the Texas Panhandle, we drilled and operated 12 horizontal wells with an average working interest of 73% and four vertical wells with an average working interest of 87% during 2010. In addition, we participated in 10 outside operated Granite Wash horizontal wells, with an average working interest of approximately 12%, located in the Texas Panhandle and Western Oklahoma. Focusing on the operated horizontal wells, 10 of the 12 completed wells had first oil and gas sales during 2010, consisting of one well in each of the first three quarters and seven wells during the fourth quarter. The Granite Wash laterals completed in 2010 include three Granite Wash "A" zone, six Granite Wash "B", one Granite Wash "C1" and two Granite Wash "F" zones. In 2009, we also completed a well in the Granite Wash "C". This brings the total Granite Wash zones that have been successfully completed on our leasehold to five and the plan is to test a sixth zone in the Granite Wash "D" zone in 2011. Highlights from the completed 2010 wells include an 83% working interest in a Granite Wash "B" zone completion with an initial daily peak rate of 1,135 Bbls of oil per day, 662 Bbls of NGLs per day and 6.2 MMcf per day or an equivalent daily rate of approximately 17 MMcfe per day and a 30 day average daily rate of 14.3 MMcfe per day. The first Granite Wash "F" zone completion (100% working interest) had a peak daily rate of 329 Bbls of oil per day, 366 Bbls of NGLs per day, and 3.4 MMcf per day, or an equivalent rate of approximately 7.6 MMcfe per day and a 30 day average rate of 5.8 MMcfe per day. The average daily peak rate for the 2010 completed wells was approximately 8.0 MMcfe per day with oil and liquids accounting for approximately 50% of the production stream at a completed well cost of approximately $5.1

million. We expect to work three to four Unit drilling rigs drilling Granite Wash horizontal wells in 2011 which equates to approximately 22 operated Granite Wash wells at an approximate net cost of $82 million. In addition, we anticipate we will participate in approximately 16 outside operated horizontal wells at an approximate net cost of $14 million.

Dispositions and Acquisitions. There were no material dispositions during 2010 or 2009. During 2008 and 2009, we acquired interests in approximately 60,000 net undeveloped acres in the Marcellus Shale Play, located mainly in Pennsylvania and Maryland for approximately $43.6 million.

In July 2009, we received $7.1 million and approximately 1,500 net undeveloped acres, representing payment for our 50% interest in 4,000 gross undeveloped acres and reimbursement for costs we paid on their behalf. On September 30, 2009, per our agreement with certain unaffiliated third parties, we were paid approximately $14.9 million for our 50% interest in approximately 18,000 gross undeveloped acres of the Marcellus Shale and $26.1 million for a receivable due from those third parties for their 50% share of the costs we paid on their behalf to acquire the acreage. The sales proceeds reduced undeveloped leasehold costs and no gain or loss was recorded on this sale. We now have an interest in approximately 50,500 net undeveloped acres.

In June 2010, we completed an acquisition of oil and natural gas properties from certain unaffiliated third parties for approximately $73.7 million in cash. The properties purchased included approximately 45,000 net leasehold acres and 10 producing oil wells and focused on the Marmaton horizontal oil play located mainly in Beaver County, Oklahoma. Proved developed producing net reserves associated with the 10 acquired producing wells are approximately 762,000 BOE—consisting of 511,000 barrels of oil, 155,000 barrels of NGLs and 573 MMcf of natural gas.

Also during the second quarter of 2010, we completed an acquisition of approximately 32,000 net acres of undeveloped oil and gas leasehold located in Southwest Oklahoma and North Texas for approximately $17.6 million.

Table of Contents

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

	Year Ended December 31,					
	2010		2009		2008	
	Gross	Net	Gross	Net	Gross	Net
Wells drilled:						
Exploratory:						
Oil:						
West division	3	1.41	2	0.28	2	0.95
East division	0	0	0	0	0	0
Central division	1	1.00	0	0	1	0.50
Total oil	4	2.41	2	0.28	3	1.45
Natural gas:						
West division	4	4.00	3	2.50	3	2.80
East division	0	0	0	0	0	0
Central division	1	0.05	0	0	2	1.38
Total natural gas	5	4.05	3	2.50	5	4.18
Dry:						
West division	5	4.12	3	2.10	7	2.60
East division	0	0	0	0	0	0
Central division	0	0	0	0	0	0
Total dry	5	4.12	3	2.10	7	2.60
Total exploratory	14	10.58	8	4.88	15	8.23
Development:						
Oil:						
West division	25	4.69	14	3.54	30	9.04
East division	0	0	0	0	0	0
Central division	43	25.90	6	1.80	25	17.58

Total oil	68	30.59	20	5.34	55	26.62
Natural gas:						
West division	13	10.85	1	1.00	19	11.36
East division	19	11.47	35	16.96	86	33.51
Central division	42	18.22	28	12.77	77	40.61
Total natural gas	74	40.54	64	30.73	182	85.48
Dry:						
West division	4	1.51	1	0.80	9	5.26
East division	1	0.36	1	0.16	2	0.41
Central division	6	3.94	1	0.60	15	8.31
Total dry	11	5.81	3	1.56	26	13.98
Total development	153	76.94	87	37.63	263	126.08
Total wells drilled	167	87.52	95	42.51	278	134.31

	Year Ended December 31,					
	2010		2009		2008	
	Gross	Net	Gross	Net	Gross	Net
Wells producing or capable of producing:						
Oil:						
West division	2,052	178.85	2,051	178.85	2,051	177.68
East division	52	2.58	52	2.75	52	2.59
Central division	552	234.05	552	227.73	562	238.00
Total oil	2,656	415.48	2,655	409.33	2,665	418.27
Natural gas:						
West division	1,167	324.33	1,128	314.37	1,113	308.43
East division	1,086	290.04	1,052	266.04	1,025	251.18
Central division	2,927	611.05	2,868	580.57	2,877	592.23
Total natural gas	5,180	1,225.42	5,048	1,160.98	5,015	1,151.84
Total	7,836	1,640.90	7,703	1,570.31	7,680	1,570.11

As of February 11, 2011, we had participated in 14 gross (10.13 net) wells started during 2011.

Cost incurred for development drilling includes $84.6 million, $24.5 million and $89.4 million in 2010, 2009 and 2008, respectively, to develop booked proved undeveloped oil and natural gas reserves.

The following table summarizes our leasehold acreage at December 31, 2010:

	Year Ended December 31, 2010					
	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net (1)	Gross	Net
West division	299,268	94,739	278,565	160,561	577,833	255,300
East division	190,073	61,478	241,389	72,263	431,462	133,741
Central division	603,934	182,677	211,316	123,524	815,250	306,201
Total	1,093,275	338,894	731,270	356,348	1,824,545	695,242

(1) Approximately 70% (West – 45%; East – 89% and Central – 91%) of the net undeveloped acres are covered by leases that will expire in the years 2011—2013 unless drilling or production extends the terms of those leases.

The future estimated development costs necessary to develop our proved undeveloped oil and natural gas reserves in the United States for the years 2011—2015, as disclosed in our December 31, 2010 oil and natural gas reserve report, are $102.6 million, $107.7 million, $25.4 million, $20.1 million and $5.6 million, respectively.

Price and Production Data. The following table identifies the average sales prices, 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,		
	2010	2009	2008
Average sales price per barrel of oil produced:			
Price before hedging	$76.65	$56.64	$98.02
Effect of hedging	(7.13)	(0.31)	(4.15)
Price including hedging	$69.52	$56.33	$93.87
Average sales price per barrel of NGLs produced:			
Price before hedging	$36.96	$25.66	$47.38
Effect of hedging	0.08	(2.85)	0.04
Price including hedging	$37.04	$22.81	$47.42
Average sales price per Mcf of natural gas produced:			
Price before hedging	$ 4.05	$ 3.26	$ 7.53
Effect of hedging	1.57	2.33	0.09
Price including hedging	$ 5.62	$ 5.59	$ 7.62

Table of Contents

	Year Ended December 31,		
	2010	2009	2008
Oil production (MBbls):			
West division	729	648	654
East division	14	13	14
Central division:			
Mendota field	149	138	127
All other central division fields	629	487	466
Total central division	778	625	593
Total oil production (MBbls)	1,521	1,286	1,261
NGL production (MBbls):			
West division	627	699	729
East division	4	5	4
Central division:			
Mendota field	494	475	375
All other central division fields	424	309	280
Total central division	918	784	655
Total NGL production (MBbls)	1,549	1,488	1,388
Natural gas production (MMcf):			
West division	10,946	12,395	14,554
East division	14,029	14,639	16,053
Central division:			
Mendota field	4,050	4,227	3,402
All other central division fields	11,731	12,802	13,464
Total central division	15,781	17,029	16,866
Total natural gas production (MMcf)	40,756	44,063	47,473

Total production (MMcfe):			
West division	19,079	20,474	22,852
East division	14,137	14,749	16,162
Central division:			
Mendota field	7,910	7,906	6,412
All other central division fields	18,050	17,580	17,942
Total central division	25,960	25,486	24,354
Total production (MMcfe)	59,176	60,709	63,368
Average production cost per equivalent Mcf	$ 1.54	$ 1.45	$ 1.86

Our Mendota field is the only field that contains greater than 15% or more of our total proved reserves expressed on an oil equivalent barrels basis.

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

	Year Ended December 31, 2010			
	Natural Gas (MMcf)	Oil (MBbls)	NGL (MBbls)	Total Proved Reserves (MMcfe)
Proved developed:				
West division	71,941	4,634	4,011	123,814
East division	121,937	58	36	122,500
Central division	153,050	8,081	8,041	249,780
Total proved developed	346,928	12,773	12,088	496,094
Proved undeveloped:				
West division	5,966	2,313	84	20,345
East division	13,434	0	0	13,433
Central division	54,158	2,408	3,945	92,280
Total proved undeveloped	73,558	4,721	4,029	126,058
Total proved	420,486	17,494	16,117	622,152

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 estimates made in connection with financial disclosures. We use Ryder Scott Company L.P. (Ryder Scott), independent petroleum consultants, to audit our reserves as prepared by our reservoir engineers. Ryder Scott has been providing petroleum consulting services throughout the world for over seventy years; their summary report is attached as Exhibit 99.1 to our Form 10-K for the fiscal year ended December 31, 2010. The wells or locations for which estimates of reserves were audited were reserves that comprised the top 83% of the total proved developed discounted future net income and 80% of the total proved undeveloped 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, 2010.

Our Reservoir Engineering department is responsible for reserve determination for all wells in which we have an interest. Their primary objective is to estimate our future reserves and their future net value to us. Data is incorporated from multiple sources including geological, production engineering, marketing, production, land and accounting departments. The engineers are responsible for reviewing this information for accuracy as it incorporated into the reservoir engineering database and the internal audit group has a checklist of review tasks to confirm the correctness of data transfer. New well reserve estimates are provided to management as well as the respective operational divisions for additional scrutiny. Major reserve changes on existing wells are reviewed on a regular basis with the operational divisions to confirm correctness and accuracy. As the external audit is being completed by Ryder Scott, the reservoir department performs a final review of all properties for accuracy of forecasting.

Technical Qualifications

Ryder Scott—Mr. Fred P. Richoux is the technical person designated to be in responsible charge on behalf of Ryder Scott for our audit of reserves.

Mr. Richoux, an employee of Ryder Scott Company L.P. (Ryder Scott) since 1978, is the Executive Vice President and member of the Board of Directors at Ryder Scott Company. He is responsible for coordinating and supervising staff and consulting engineers of the company in ongoing reservoir evaluation studies worldwide. Before joining Ryder Scott, Mr. Richoux served in a number of engineering positions with

Phillips Petroleum Company. For more information regarding Mr. Richoux's geographic and job specific experience, please refer to the Ryder Scott Company website at http://www.ryderscott.com/Experience/Employees.

Mr. Richoux earned a Bachelor of Science degree in Electrical Engineering from the University of Louisiana at Lafayette and is a registered Professional Engineer in the State of Texas and the Province of Alberta. He is also a member of the Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers.

In addition to gaining experience and competency through prior work experience, the Texas Board of Professional Engineers requires a minimum of 15 hours of continuing education annually, including at least one hour in the area of professional ethics, which Mr. Richoux fulfills. As part as his 2010 continuing education hours, Mr. Richoux attended nine hours of formalized training relating to the definitions and disclosure guidelines contained in the United States Securities and Exchange Commission Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register. Mr. Richoux attended an additional 26 hours of formalized in-house training as well as six hours of formalized external training covering such topics as the SPE/WPC/AAPG/SPEE Petroleum Resources Management System, reservoir engineering, geosciences and petroleum economics evaluation methods, procedures and software and ethics for consultants. Mr. Richoux also served as instructor for a full day course on reserve evaluations under SEC and PRMS guidelines. This course was presented five times. He also served as the technical presenter in a webinar related to the new SEC guidance on reserve evaluations.

Based on his educational background, professional training and more than 40 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Richoux has attained the professional qualifications as a Reserve Estimator, which requires appropriate degree and/or is registered as Professional Engineer and has a minimum of three years experience in the estimation and evaluation of reserves, and Reserve Auditor, which requires appropriate degree and/or is registered as Professional Engineer and has a minimum of 10 years experience in the estimation and evaluation of reserves of which at least five years of such experience is being in responsible charge of the estimation and evaluation of reserves, set forth in Article III of the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers as of February 19, 2007.

Unit Corporation—Responsibility for overseeing the preparation of Unit's reserve report is shared by reservoir engineers Trenton Mitchell and Robert Lyon.

Mr. Mitchell earned a Bachelor of Science degree in Petroleum Engineering from Texas A&M University in 1994. He has been an employee of Unit since 2002. Initially, he was the Outside Operated Engineer and since 2003 he has served in the capacity of Reservoir Engineer and in 2010 he was promoted to Manager of Reservoir Engineering. Before joining Unit, he served in a number of engineering field and technical support positions with Schlumberger Well Services in their pumping services segment (formerly Dowell Schlumberger). He obtained his Professional Engineer registration from the State of Oklahoma in 2004 and has been a member of SPE since 1991.

Mr. Lyon received a Bachelor of Science degree in Petroleum Engineering from the University of Tulsa in 1972 and has spent 32 of his 39 years in the industry directly involved in reserve calculation work. Included in this time were 15 years working for petroleum consulting firms Raymond F. Kravis and Associates and Southmayd and Associates performing independent reserve appraisals and audits for corporations and individuals. He joined Unit in 1996 and has shared responsibility for preparation of the company's reserve report since that time. Mr. Lyon is a registered professional engineer in the State of Oklahoma and a member of the Society of Petroleum Engineers.

As part of the continuing education requirement for maintaining their professional licenses Mr. Mitchell and Mr. Lyon have attended various seminars and forums to enhance their understanding of the recent changes that have occurred in SEC rules pertaining to reserves presentation. These forums have included those sponsored by various professional societies and professional service firms including Ryder Scott.

Definitions and Other. Proved oil, NGLs and natural gas reserves, as defined in SEC Rule 4-10(a), are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs and under existing economic conditions, operating methods and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

The area of the reservoir considered as proved includes:

- The area identified by drilling and limited by fluid contacts, if any, and
- Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geosciences and engineering data.

In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geosciences, engineering or performance data and reliable technology establishes a lower contact with reasonable certainty.

Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exist for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geosciences, engineering or performance data and reliable technology establish the higher contact with reasonable certainty.

Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

- Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or other evidence using reliable technology establishes reasonable certainty of the engineering analysis on which the project or program was based; and
- The project has been approved for development by all necessary parties and entities, including governmental entities.

Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first day of month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Proved undeveloped oil, NGLs and natural gas reserves are 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 shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances. Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time. Under no circumstances shall 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 projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

Proved Undeveloped Reserves. As of December 31, 2010, we had approximately 142 gross proved undeveloped wells (PUDs) all of which we have plans to develop within the next five years for a net cost of approximately $261.4 million. We do not have any aged PUDs (PUDs greater than five years). During 2010, we converted 35 PUDs into proved developed wells (PDPs) at a cost of approximately $84.6 million.

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 as most of them are market sensitive.

Customers. During 2010, we did not have a third party purchaser that accounted for 10% or more of our oil and natural gas revenues, the top five third party purchasers accounted for approximately 34% of our oil and natural gas revenues. During 2010, our midstream segment purchased $42.4 million of our natural gas and NGLs production and provided gathering and transportation services of $4.4 million. Intercompany revenue from services and purchases of production between our midstream segment and our oil and natural gas segment has been eliminated in our consolidated financial statements. In 2009 and 2008, we eliminated intercompany revenues of $33.9 million and $56.3 million, respectively, attributable to the production of natural gas and NGLs as well as gathering and transportation services.

MIDSTREAM

General. Superior Pipeline Company, L.L.C. is a midstream company engaged primarily in the buying, selling, gathering, processing and treating of natural gas and operates three natural gas treatment plants, 10 operating processing plants, 34 active gathering systems and 860 miles of pipeline. Superior and its subsidiary operate in Oklahoma, Texas, Kansas, Pennsylvania and West Virginia.

The following table presents certain information regarding our midstream segment for the years indicated:

	Year Ended December 31,		
	2010	2009	2008
Gas gathered—MMBtu/day	183,867	183,989	197,367
Gas processed—MMBtu/day	82,175	75,908	67,796
NGLs sold—gallons/day	271,360	243,492	195,837

Dispositions and Acquisitions. This segment did not have any significant dispositions or acquisitions during 2010 or 2009.

Contracts. Our midstream 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 customer 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 midstream'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, 2010, 51% of our midstream segment's total volumes and 15% of operating margins (as defined below) were under fee-based contracts.

- *Percent of Proceeds Contracts (POP).* These contracts provide for our midstream 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, 2010, 33% of our midstream segment's total volumes and 38% of operating margins (as defined below) were under POP contracts.

- *Percent of Index Contracts (POI).* Under these contracts our midstream'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 midstream 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, 2010, 16% of our midstream segment's total volumes and 47% 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.

Customers. During 2010, ONEOK, Gavilon and ConocoPhillips accounted for approximately 53%, 12% and 12%, respectively, of our midstream revenues. We believe that if we lost one or more of these three identified customers, there would be other customers available to purchase our gas and liquids.

Table of Contents

VOLATILE NATURE OF OUR BUSINESS

The prevailing prices for oil, NGLs and natural gas significantly affect our revenues, operating results, cash flow as well as our ability to grow our operations. Historically, oil, NGLs and natural gas prices have been volatile, and we expect them to continue to be so. The following table shows for each of the periods indicated the highest and lowest average prices our oil and natural gas segment received for its sales of oil, NGLs and natural gas without taking into account the effect of our hedging activity:

Quarter	Oil Price per Bbl		NGL Price per Bbl		Natural Gas Price per Mcf	
	High	Low	High	Low	High	Low
2010:						
Fourth	$ 85.37	$ 78.20	$43.34	$38.01	$ 4.00	$ 2.87
Third	$ 72.69	$ 72.23	$33.05	$29.15	$ 4.43	$ 3.12
Second	$ 81.18	$ 71.19	$36.20	$31.29	$ 3.99	$ 3.37
First	$ 78.08	$ 73.83	$43.39	$41.50	$ 5.57	$ 4.47
2009:						
Fourth	$ 75.11	$ 71.76	$43.22	$31.12	$ 4.38	$ 3.35
Third	$ 67.62	$ 60.69	$27.38	$21.38	$ 3.30	$ 2.37
Second	$ 66.48	$ 39.93	$27.30	$21.34	$ 2.90	$ 2.59
First	$ 42.26	$ 34.75	$19.95	$17.89	$ 4.67	$ 2.45
2008:						
Fourth	$ 75.09	$ 39.22	$29.27	$24.36	$ 4.76	$ 4.25
Third	$131.75	$102.26	$70.22	$54.14	$ 11.51	$ 5.39
Second	$134.81	$109.78	$60.98	$50.82	$ 10.68	$ 8.70
First	$102.74	$ 91.14	$54.43	$45.91	$ 8.33	$ 6.59

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

- 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 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, NGLs and natural gas;
- 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;
- the time period associated with the volatility in commodity prices; and
- overall economic conditions in the United States as well as the world.

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 this prospectus supplement 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 declined throughout 2009. This was followed by a gradual increase in activity (as well as dayrates) during 2010.

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

COMPETITION

All of our businesses are highly competitive and price sensitive. Competition in the contract drilling business traditionally involves factors such as demand, price, efficiency, condition of equipment, availability of labor and equipment, reputation and customer relations. We are the fifth largest U.S. deep onshore drilling contractor.

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 midstream segment competes 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 and NGLs, build gathering systems and deliver the natural gas and NGLs 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.

During 2009, competition to keep and attract qualified employees to conduct our operations did not materially affect us due to the depressed conditions within our operations. With the increase in our segment's 2010 operations over the prior year's levels, competition to keep qualified labor has increased and our operations beyond fourth quarter 2010 levels could be hampered by limited availability of personnel.

OIL AND NATURAL GAS PROGRAMS AND CONFLICTS OF INTEREST

Unit Petroleum Company serves as the general partner of 16 oil and gas limited partnerships. Three of these partnerships were formed for investment by third parties and 13 (the employee partnerships) were formed to allow our employees and directors the opportunity 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 combined into a single consolidated partnership. The employee partnerships each have a set annual percentage (ranging from 1% to 15%) of our interest that the partnership acquires 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 interests of the limited partners and the general partner are not always 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.

EMPLOYEES

As of February 11, 2011, we had approximately 1,888 employees in our contract drilling segment, 181 employees in our oil and natural gas segment, 88 employees in our midstream segment 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 varying 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 subsequent individual pipeline restructuring proceedings of the early to mid-1990s, 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 certain aspects of 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.

As a result of these changes, independent 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. However, 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.

Although in the past Congress has been very active in the area of natural gas regulation 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 currently are not regulated and are at market prices. The prices received from the sale of these products are affected by the cost of transporting these 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 could 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 and make any necessary adjustment in the index to be used during the ensuing five years. We are not able to predict with certainty what effect, if any, the periodic review of the index by the FERC will have on us.

Federal, state, and local agencies also 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 increasingly 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 used and/or 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 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.

Climate Regulation. Recent scientific studies have suggested that emissions of certain gases, commonly referred to as “greenhouse gases”, may be contributing to warming of the Earth’s atmosphere. As a result there have been a variety of regulatory developments, proposals or requirements and legislative initiatives that have been introduced in the United States (as well as other parts of the World) that are focused on restricting the emission of carbon dioxide, methane and other greenhouse gases.

In 2007, the United States Supreme Court in Massachusetts, et al. v. EPA, held that carbon dioxide may be regulated as an “air pollutant” under the federal Clean Air Act if it represents a health hazard to the public. On December 7, 2009, the U.S. Environmental Protection Agency (“EPA”) responded to the Massachusetts, et al. v. EPA decision and issued a finding that the current and projected concentrations of greenhouse gases in the atmosphere threaten the public health and welfare of current and future generations, and that certain greenhouse gases from new motor vehicles and motor vehicle engines contribute to the atmospheric concentrations of greenhouse gases and hence to the threat of climate change.

In June 2009 the U.S. House of Representatives passed the American Clean Energy and Security Act of 2009 (sometimes referred to as the Waxman-Markey global climate change bill). The bill includes many provisions that would potentially have a significant impact on us as well as our customers. The bill proposes a cap and trade regime, a renewable portfolio standard, electric efficiency standards, revised transmission policy and mandated investments in plug-in hybrid infrastructure and smart grid technology. Although proposals have been introduced in the U.S. Senate, including a proposal that would have required greater reductions in greenhouse gas emissions than the American Clean Energy and Security Act of 2009, it is uncertain at this time whether, and in what form, legislation will be adopted by the U.S. Senate. Both President Obama and the Administrator of the EPA have repeatedly indicated their preference for comprehensive legislation to address this issue and create the framework for a clean energy economy.

On September 22, 2009, EPA finalized a rule requiring nation-wide reporting of greenhouse gas emissions beginning January 1, 2010. The rule applies primarily to large facilities emitting 25,000 metric tons or more of carbon dioxide-equivalent greenhouse gas emissions per year, and to most upstream suppliers of fossil fuels and industrial greenhouse gas, as well as to manufacturers of vehicles and engines. However, in December 2010, the EPA issued three actions citing the need for more business data resulting in deferring the reporting of some information. In January 2011, the EPA began regulating greenhouse gas emissions from certain stationary sources pursuant to two Federal Clean Air Act programs: the Title V Operating Permit program and the Prevention of Significant Deterioration ("PSD") program. Obligations relating to Title V permits will include recordkeeping and monitoring requirements. With respect to PSD permits, projects that cause a significant increase in greenhouse gas emissions will be required to implement best available control technology ("BACT"). The EPA has issued guidance on what BACT entails and individual states are now required to determine what controls are required for facilities within their jurisdiction on a case-by-case basis.

The EPA, has commenced a study of the potential environmental impacts of hydraulic fracturing in the production of oil and natural gas, including the impact on drinking water sources and public health, and a committee of the U.S. House of Representatives is also conducting an investigation of hydraulic fracturing practices. Legislation has been introduced before Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. In addition, some states, as well as municipalities and other local governmental entities in some states, including some in which we operate, have adopted and others are considering adopting regulations and ordinances that could restrict or ban hydraulic fracturing in certain circumstances. Any new laws, regulation or permitting requirements regarding hydraulic fracturing could lead to operational delay, or increased operating costs or third party or governmental claims, and could result in additional burdens that could serve to delay or limit the drilling services we provide to third parties whose drilling operations could be impacted by these regulations or increase our costs of compliance and doing business as well as delay the development of unconventional gas resources from shale formations which are not commercial without the use of hydraulic fracturing. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that we are ultimately able to produce from our reserves.

We do not know and cannot predict whether any of the proposed legislation or regulations will be adopted as initially written, if at all, or how legislation or new regulations that may be adopted to address greenhouse gas emissions and/or hydraulic fracturing would impact our business segments. Depending on the final provisions of such legislation, rules or ordinances, it is possible that such future laws, regulations and/or ordinances could result in increasing our compliance costs or additional operating restrictions as well as those of our customers. It is also possible that such future developments could curtail the demand for fossil fuels which could adversely affect the demand for our services, which in turn could adversely affect our future results of operations. Likewise we cannot predict with any certainty whether any changes to temperature, storm intensity or precipitation patterns as a result of climate change (or otherwise) will have a material impact on our operations.

Compliance with applicable environmental requirements has not, to date, had a material effect on the cost of our operations, earnings or competitive position. However, as noted above in connection with our discussion of the regulation of greenhouse gases and hydraulic fracturing, compliance with amended, new or more stringent requirements of environmental regulations or requirements 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.

MANAGEMENT

The table below and accompanying text sets forth certain information as of March 31, 2011 concerning each of our directors, 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	56	President, Chief Executive Officer, Chief Operating Officer and Director
Mark E. Schell	53	Senior Vice President, General Counsel and Corporate Secretary
David T. Merrill	50	Chief Financial Officer and Treasurer
Brad J. Guidry	55	Executive Vice President, Unit Petroleum Company
John Cromling	63	Executive Vice President, Unit Drilling Company
Robert Parks	56	Manager and President, Superior Pipeline Company, L.L.C.
Richard E. Heck	50	Vice President, Safety, Health and Environment
King P. Kirchner	83	Director
John G. Nikkel	76	Director
John H. Williams	92	Director
William B. Morgan	66	Director
J. Michael Adcock	62	Director
Robert J. Sullivan Jr.	65	Director
Gary R. Christopher	61	Director
Steven B. Hildebrand	56	Director

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.

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 MBA 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, Inc. 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.

Mr. Kirchner, a co-founder of the company, has been a director since 1963. He served as Unit's President until November 1983, as it Chief Executive Officer until June 30, 2001, and served as Chairman of the Board until July 31, 2003. Mr. Kirchner is a Registered Professional Engineer within the State of Oklahoma, having received degrees in Mechanical Engineering from Oklahoma State University and Petroleum Engineering, with honors, from the University of Oklahoma. Following graduation, he was employed by Lufkin Manufacturing as a development engineer for hydraulic pumping units. Prior to co-founding Unit, he served in the U.S. Army during the Korean War and after that as vice-president of engineering and operations for Woolaroc Oil Company. Mr. Kirchner is a 2006 inductee into both the Oklahoma Hall of Fame and the University of Tulsa, Collins College of Business Hall of Fame.

Mr. Nikkel joined the company as its President, Chief Operating Officer and a director in 1983. He was elected its CEO in July 2001 and Chairman of the Board in August 2003. Mr. Nikkel retired as an employee and as the CEO of the company on April 1, 2005. He currently holds the position of Chairman of the Board. From 1976 until January 1982 when he co-founded Nike Exploration Company, Mr. Nikkel was an officer and director of Cotton Petroleum Corporation, serving as the President of Cotton from 1979 until his departure. Before joining Cotton, Mr. Nikkel was employed by Amoco Production Company for 18 years, last serving as Division Geologist for Amoco's Denver Division. Mr. Nikkel presently serves as President and a director of Nike Exploration Company, a family owned oil and gas investment company. Mr. Nikkel received a Bachelor of Science degree in Geology and Mathematics from Texas Christian University.

Mr. Williams was elected a director of the company in December 1988. Mr. Williams is engaged in personal investments and has been for more than five years. He was Chairman of the Board and CEO of The Williams Companies, Inc. before retiring in 1978, and he continues to serve as an honorary director. Mr. Williams is, and for more than the last five years has been, a director and audit committee member of Apco Oil & Gas International, Inc. as well as an honorary director of Willbros Group, Inc. He formerly served as a director of Petrolera Entre Lomas S.A. In addition, Mr. Williams is a member of the Tulsa Performing Arts Center Trust and is a finance committee member and has served in those capacities since 1977. Mr. Williams was a 1977 inductee into the Oklahoma Hall of Fame, and a 2006 inductee into the University of Tulsa, Collins College of Business Hall of Fame.

Mr. Morgan was elected a director of the company in 1988. Mr. Morgan retired in June 2007 from his position as Executive Vice President and General Counsel of St. John Health System, Inc., Tulsa, Oklahoma, and President of its principal for-profit subsidiary Utica Services, Inc., which positions he had held since 1995. Prior to joining St. John, he was a partner in the law firm of Doerner, Saunders, Daniel & Anderson, Tulsa, Oklahoma, and served as Adjunct Professor of Law at the University of Tulsa College of Law, where he taught Securities Regulation. During 1968 and 1969, he served as a United States Army Officer in Vietnam and was awarded several medals including the Bronze Star. Mr. Morgan has an undergraduate degree from Muhlenberg College, Allentown, Pennsylvania, and a Juris Doctor from the University of Tulsa College of Law. Mr. Morgan is a member of numerous professional and Bar associations and various federal Bars including the United States Supreme Court. He has been listed in *Who's Who in American Law, Who's Who in American Education* and *The Best Lawyers in America*. Mr. Morgan is a Fellow of the American College of Healthcare Executives.

Mr. Adcock was elected a director in December 1997. He is an attorney and is currently a Co-trustee of the Don Bodard Trust, which is a private business trust that deals in real estate, oil and natural gas properties and other equity investments. He is Chairman of the Board of Arvest Bank, Shawnee, and a director, finance chair, and compensation committee member of Community Health Partners, Inc. Mr. Adcock is also a past director of Midwest Consolidated Plastics, LLC. Between 1997 and September 1998 he was the Chairman of the Board of Ameribank and President and CEO of American National Bank and Trust Company of Shawnee, Oklahoma, and Chairman of AmeriTrust Corporation, Tulsa, Oklahoma. Prior to holding these positions, he was engaged in the private practice of law and served as General Counsel for Ameribank Corporation.

Mr. Sullivan was elected a director in 2005. He is a Principal with Sullivan and Company LLC, a family-owned independent oil and gas exploration and production company founded in 1958. He is also the Founder (1989) and served as Chairman and CEO of Lumen Energy Corporation prior to its sale in 2004. Mr. Sullivan was appointed to Oklahoma Governor Frank Keating's Cabinet as Secretary of Energy in March 2002. He received a BBA from the University of Notre Dame, and a MBA from the University of Michigan. Mr. Sullivan is a Board Member of the Oklahoma Independent Petroleum Association, St. John Medical Center, St. Joseph Residence, and former Board Member of University of Notre Dame Alumni Association, Catholic Charities and Gatesway Foundation. He also is Trustee for the Monte Casino Endowment Trust, a Member of the University of Notre Dame Irish Studies Advisory Council and Past Chairman of the following School Boards: Cascia Hall Preparatory School, Monte Cassino School and School of St. Mary.

Mr. Christopher was elected a director in 2005. He is engaged in personal investments and consulting. Between August 1999 and January 2004, he served as President and CEO of PetroCorp Incorporated (a public oil and gas exploration company), and from March 1996 to August 1999 he served as the Acquisition Coordinator of Kaiser-Francis Oil Company. His other past professional experience includes serving as Vice President of Acquisitions for Indian Wells Oil Company, Senior Vice President and Manager of the Energy Lending Division of First National Bank of Tulsa and from 1991 to 1996 Senior Vice President and Manager of Energy Lending for Bank of Oklahoma. Previous to that, Mr. Christopher worked for Amerada Hess Corporation as a Reservoir Engineer and for Texaco, Inc. as a Production Engineer. Mr. Christopher is a member of the Society of Petroleum Engineers, and the Oklahoma Independent Petroleum Association. Mr. Christopher received a B.S.

degree in Petroleum Engineering from the University of Missouri at Rolla. Mr. Christopher is a past Director of the Petroleum Club of Tulsa, Middle Bay Oil Company, Three Tech Energy, PetroCorp Incorporated and a present Director of the Summit Bank of Oklahoma.

Mr. Hildebrand was elected a director in October 2008. Since March 2008, he has been engaged in the business of personal investments. Mr. Hildebrand retired in March 2008 from a 21-year tenure at Dollar Thrifty Automotive Group (NYSE: DTG), a car rental compay and its subsidiaries. Mr. Hildebrand was the Chief Financial Officer during his last ten years with Dollar Thrifty Automotive Group and before that served as Executive Vice President and Chief Financial Officer of Thrifty Rent-A-Car System, Inc., a subsidiary of Dollar Thrifty. Mr. Hildebrand worked for Franklin Supply Company from 1980 to 1987, where he held several positions, including Controller and Vice President of Finance. From 1976 to 1980, Mr. Hildebrand was with the public accounting firm Coopers & Lybrand (now PricewaterhouseCoopers LLP), most recently as Audit Supervisor. Mr. Hildebrand has been designated by the board of directors as an audit committee financial expert. Mr. Hildebrand has served as a director for the Tulsa Area United Way since 2005, and has served on its Finance and Audit Committee since 2006.

DESCRIPTION OF OTHER INDEBTEDNESS

Our Credit Facility

Our existing credit facility has a maximum credit amount of $400.0 million and matures on May 24, 2012. The lenders' current commitment under the credit facility is $325.0 million. Our borrowings are limited to the commitment amount that we elect. As of March 31, 2011, the commitment amount was $325.0 million. We are charged a commitment fee ranging from 0.375 to 0.50 of 1% on the amount available but not borrowed. The rate varies based on the amount borrowed as a percentage of the amount of the total borrowing base. To date we have paid $1.2 million in origination, agency and syndication fees under the credit facility. We are amortizing these fees over the life of the agreement. The average interest rate for 2010, which includes the effect of our two interest rate swaps, was 3.5%. At December 31, 2010 and March 31, 2011, borrowings were $163.0 million and $185.0 million, respectively.

The lenders under our credit facility and their respective participation interests are as follows:

Lender	Participation Interest
Bank of Oklahoma, N.A.	18.75%
Bank of America, N.A.	18.75%
BMO Capital Markets Financing, Inc.	18.75%
BBVA Compass Bank	17.50%
Comerica Bank	8.75%
BNP Paribas	8.75%
Crédit Agricole Corporate and Investment Bank	8.75%
	100.00%

The lenders' aggregate commitment is limited to the lesser of the amount of the borrowing base or $400.0 million. The amount of the borrowing base, which is subject to redetermination on April 1 and October 1 of each year, is based primarily on a percentage of the discounted future value of our oil and natural gas reserves and, to a lesser extent, the loan value the lenders reasonably attribute to the cash flow (as defined in the credit facility) of our midstream segment. The April 1, 2011 redetermination set the borrowing base at $600.0 million. We or the lenders may request a onetime special redetermination of the amount of the borrowing base between each scheduled redetermination. In addition, we may request a redetermination following the completion of an acquisition that meets the requirements set forth in the credit facility.

At our election, any part of the outstanding debt under the credit facility may be fixed at a London Interbank Offered Rate (LIBOR) for a 30, 60, 90 or 180 day period. During any LIBOR funding period, the outstanding principal balance of the promissory note to which the LIBOR option applies may be repaid after three days prior notice to the administrative agent and on payment of any applicable funding indemnification amounts. LIBOR interest is computed as the sum of the LIBOR base for the applicable term plus 1.75% to 2.50% depending on the level of debt as a percentage of the borrowing base and is 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, which cannot be less than LIBOR plus 1.00%, and is payable at the end of each month and the principal borrowed may be paid at any time, in part or in whole, without a premium or penalty. At March 31, 2011 all of our $185.0 million in outstanding borrowings were subject to LIBOR.

The credit facility prohibits:

- 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 properties, 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.

As of March 31, 2011, we were in compliance with the credit facility's covenants.

DESCRIPTION OF THE NOTES

The Company will issue the Notes under an Indenture, dated as of May 18, 2011 (the "Base Indenture"), between the Company and Wilmington Trust FSB, as trustee (the "Trustee"), as supplemented by a Supplemental Indenture relating to the Notes among the Company, the Trustee and the Subsidiary Guarantors (the "Supplemental Indenture," and together with the Base Indenture, the "Indenture"). The Indenture is unlimited in aggregate principal amount, although the issuance of Notes in this offering will be limited to $250 million. We may issue an unlimited principal amount of additional notes having identical terms and conditions as the Notes (the "Additional Notes"). We will be permitted to issue such Additional Notes only if at the time of such issuance, we are in compliance with the covenants contained in the Indenture. Any Additional Notes will be part of the same series as the Notes that we are currently offering and will vote on all matters with the holders of the Notes.

This description of Notes is intended to be an overview of the material provisions of the Notes and the Indenture. Because this description of notes is only a summary, you should refer to the Indenture for a complete description of the Company's obligations and your rights in respect of the Notes. We have filed a copy of each of the Base Indenture and the Supplemental Indenture as exhibits to the registration statement which includes this Prospectus. You should read the Base Indenture and the Supplemental Indenture carefully and in their entirety. You may request copies of these documents at the Company's address set forth under the caption "Where You Can Find More Information" in the base prospectus.

You will find the definitions of capitalized terms used in this description under the heading "Certain Definitions." For purposes of this description, references to "the Company," "we," "our" and "us" refer only to Unit Corporation and not to its subsidiaries.

General

The Notes. The Notes:

- are general unsecured, senior subordinated obligations of the Company;
- are limited to an aggregate principal amount of $250 million, subject to our ability to issue Additional Notes;
- mature on May 15, 2021;
- will be issued only in fully registered form, without coupons;
- will be issued in denominations of $2,000 and integral multiples of $1,000 in excess of $2,000;
- will generally be represented by one or more registered Notes in global form, but in certain circumstances may be represented by Notes in definitive form, in each case as described in "Book-entry, Delivery and Form;"
- are subordinated in right of payment to all existing and future Senior Indebtedness of the Company, including the Senior Credit Agreement;
- rank equally in right of payment to any future Senior Subordinated Indebtedness of the Company; and
- are unconditionally guaranteed on a senior subordinated basis by Unit Drilling Company, Unit Petroleum Company, Superior Pipeline Company, L.L.C., Unit Texas Drilling, L.L.C., Unit Drilling USA Colombia, L.L.C., Unit Drilling Colombia, L.L.C., Unit Texas Company, Superior Pipeline Texas, L.L.C., Superior Appalachian Pipeline, L.L.C., Unit Drilling and Exploration Company, Petroleum Supply Company and Preston County Gas Gathering, L.L.C., each a Domestic Subsidiary of the Company, as described in "Subsidiary Guarantees."

Interest. Interest on the Notes will compound semi-annually and will:

- accrue at the rate of 6.625% per annum;

- accrue from the date of original issuance or, if interest has already been paid, from the most recent interest payment date;

- be payable in cash semi-annually in arrears on May 15 and November 15, commencing on November 15, 2011;

- be payable to the holders of record on the close of business on May 1 and November 1 immediately preceding the related interest payment dates; and

- be computed on the basis of a 360-day year comprised of twelve 30-day months.

Payments on the notes; paying agent and registrar

We will pay principal of, premium, if any, and interest on the Notes at the office or agency designated by the Company, except that we may, at our option, pay interest on the Notes by check mailed to holders of the Notes at their registered address as it appears in the security register for the Notes. We have initially designated the corporate trust office of the Trustee to act as our paying agent and registrar in respect of the Notes. We may, however, change the paying agent or registrar without prior notice to the holders of the Notes, and the Company or any of its Restricted Subsidiaries may act as paying agent or registrar in respect of the Notes.

We will pay principal of, premium, if any, and interest on, Notes in global form registered in the name of or held by The Depository Trust Company or its nominee in immediately available funds to The Depository Trust Company or its nominee, as the case may be, as the registered holder of the global Note.

Transfer and exchange

The Notes will be issued in registered form and will be transferable only upon the surrender of the Notes being transferred for registration of transfer. No service charge will be imposed by the Company, the Trustee or the registrar for any registration of transfer or exchange of Notes, but we may require a holder to pay a sum sufficient to cover any tax or other governmental charge that may be imposed in connection with any registration of transfer. The Company is not required to transfer or exchange any Note selected for redemption. Also, the Company is not required to transfer or exchange any Note for a period of 15 days before a selection of Notes to be redeemed.

The registered holder of a Note will be treated as its owner for all purposes.

Optional redemption

Except as described below, the Notes are not redeemable until May 15, 2016. On and after May 15, 2016, the Company may redeem all or, from time to time, a part of the Notes upon not less than 30 nor more than 60 days' notice, at the following redemption prices (expressed as a percentage of principal amount) plus accrued and unpaid interest on the Notes, if any, to the applicable redemption date (subject to the right of holders of record on the relevant record date to receive interest due on the relevant interest payment date), if redeemed during the twelve-month period beginning on May 15 of the years indicated below:

Year	Percentage
2016	103.313%
2017	102.208%
2018	101.104%
2019 and thereafter	100.000%

Prior to May 15, 2014, the Company may on any one or more occasions redeem up to 35% of the original principal amount of the Notes with the Net Cash Proceeds of one or more equity offerings at a redemption price of 106.625% of the principal amount thereof, plus accrued and unpaid interest, if any, to the redemption date (subject to the right of holders of record on the relevant record date to receive interest due on the relevant interest payment date); provided that:

(1) at least 65% of the original principal amount of the Notes remains outstanding after each such redemption; and

(2) the redemption occurs within 90 days after the closing of such equity offering.

If the optional redemption date is on or after an interest record date and on or before the related interest payment date, the accrued and unpaid interest, if any, will be paid to the Person in whose name the Note is registered at the close of business on the record date, and no additional interest will be payable to holders whose Notes will be subject to redemption.

In addition, at any time prior to May 15, 2016, the Company may redeem the Notes, in whole or in part, at a redemption price equal to 100% of the principal amount thereof plus the Applicable Premium plus accrued and unpaid interest, if any, to the redemption date (subject to the right of holders of record on the relevant record date to receive interest due on the relevant interest payment date).

In the case of any partial redemption, selection of the Notes for redemption will be made by the Trustee:

- in compliance with the requirements of the principal national securities exchange, if any, on which the Notes are listed; or

- if the Notes are not listed, then on a pro rata basis, by lot or by such other method as the Trustee in its sole discretion may deem to be fair and appropriate.

No Note of $2,000 in original principal amount or less will be redeemed in part. If any Note is to be redeemed in part only, the notice of redemption relating to such Note will state the portion of the principal amount thereof to be redeemed. A new Note in principal amount equal to the unredeemed portion thereof will be issued in the name of the holder upon cancellation of the original Note.

"Applicable Premium" means, with respect to a Note at any redemption date, the greater of (i) 1.0% of the principal amount of such Note and (ii) the excess of (A) the present value at such time of (1) the redemption price of such Note at May 15, 2016, (expressed as a percentage of principal amount) plus (2) all required interest payments due on such Note through May 15, 2016 computed using a discount rate equal to the Treasury Rate plus 50 basis points, over (B) the then outstanding principal amount of such Note.

"Treasury Rate" means the yield to maturity at the time of computation of United States Treasury securities with a constant maturity (as compiled and published in the most recent Federal Reserve Statistical Release H.15 (519) which has become publicly available at least two business days prior to the redemption date (or, if such Statistical Release is no longer published, any publicly available source or similar market data)) most nearly equal to the period from the redemption date to May 15, 2016; provided, however, that if the period from the redemption date to May 15, 2016 is not equal to the constant maturity of a United States Treasury security for which a weekly average yield is given, the Treasury Rate shall be obtained by linear interpolation (calculated to the nearest one-twelfth of a year) from the weekly average yields of United States Treasury securities for which such yields are given, except that if the period from the redemption date to May 15, 2016 is less than one year, the weekly average yield on actually traded United States Treasury securities adjusted to a constant maturity of one year shall be used.

The Company is not required to make mandatory redemption payments or sinking fund payments with respect to the Notes.

Ranking and subordination

The Notes will be unsecured Senior Subordinated Indebtedness of the Company, will be subordinated in right of payment to all existing and future Senior Indebtedness of the Company, will rank equally in right of payment with all existing and future Senior Subordinated Indebtedness of the Company and will be senior in right of payment to all existing and future Subordinated Obligations of the Company. The Notes will be effectively subordinated to all of our secured Indebtedness to the extent of the value of the assets securing such Indebtedness. However, payment from the money or the proceeds of U.S. Government Obligations held in trust in connection with any defeasance under the Indenture (as described under "Defeasance") will not be subordinated to any Senior Indebtedness or subject to these restrictions.

As a result of the subordination provisions described below, holders of the Notes may recover less than holders of the Company's Senior Indebtedness in the event of an insolvency, bankruptcy, reorganization, receivership or similar proceedings relating to the Company. Similarly, the Subsidiary Guarantees of the Notes will be subordinated to obligations in respect of Guarantor Senior Indebtedness to the same extent the Notes are subordinated to Senior Indebtedness. Moreover, the Notes will be structurally subordinated to the liabilities of non-guarantor Subsidiaries of the Company. Assuming that we had applied the net proceeds we receive from the offering in the manner described under "Use of proceeds," as of March 31, 2011:

- our outstanding Senior Indebtedness would have been $38.0 million, which includes letters of credit and hedging obligations with parties to our senior credit facilities;
- we would have had no Senior Subordinated Indebtedness other than the Notes;
- our Restricted Subsidiaries would have had $205.5 million of liabilities (excluding intercompany liabilities); and
- our non-guarantor Subsidiaries would not have had any liabilities (excluding intercompany liabilities).

Although the Indenture will limit the amount of indebtedness that we and our Restricted Subsidiaries may Incur, such indebtedness may be substantial and all of it may be Senior Indebtedness.

Only Indebtedness of the Company that is Senior Indebtedness will rank senior to the Notes in accordance with the provisions of the Indenture. The Notes will in all respects rank equally with all other Senior Subordinated Indebtedness of the Company. As described in "Limitation on layering," we may not Incur any Indebtedness that is senior in right of payment to the Notes, but junior in right of payment to Senior Indebtedness. Our unsecured Indebtedness is not deemed to be subordinate or junior to secured Indebtedness merely because it is unsecured.

The Company may not pay principal of, premium, if any, or interest on, or other payment obligations in respect of, the Notes or make any deposit pursuant to the provisions described under "Defeasance" and may not otherwise repurchase, redeem or retire any Notes (collectively, "pay the Notes") if:

(1) any Senior Indebtedness is not paid when due in cash or Cash Equivalents; or

(2) any other default on Senior Indebtedness occurs and the maturity of the Senior Indebtedness is accelerated in accordance with its terms;

unless, in either case, the Senior Indebtedness has been paid in full in cash or Cash Equivalents and, in the case of revolving Indebtedness, all commitments to lend thereunder have been terminated or the default has been cured or waived and any acceleration has been rescinded. However, the Company may pay the Notes if the Company and the Trustee receive written notice approving such payment from the Representative of the Senior

Indebtedness with respect to which either of the events set forth in clause (1) or (2) of the immediately preceding sentence has occurred and is continuing.

The Company also will not be permitted to pay the Notes for a Payment Blockage Period (as defined below) during the continuance of any default, other than a default described in clause (1) or (2) of the preceding paragraph, on any Designated Senior Indebtedness that permits the holders of the Designated Senior Indebtedness to accelerate its maturity immediately without either further notice (except such notice as may be required to effect such acceleration) or the expiration of any applicable grace periods.

A "Payment Blockage Period" commences on the receipt by the Trustee (with a copy to the Company) of written notice (a "Blockage Notice") of a default of the kind described in the immediately preceding paragraph from the Representative of the holders of the Designated Senior Indebtedness specifying an election to effect a Payment Blockage Period and ends 179 days after receipt of the notice. The Payment Blockage Period will end earlier if the Payment Blockage Period is terminated:

(1) by written notice to the Trustee and the Company from the Person or Persons who gave the Blockage Notice;

(2) because the default giving rise to the Blockage Notice is no longer continuing; or

(3) because the Designated Senior Indebtedness has been repaid in full.

The Company may resume payments on the Notes after the end of a Payment Blockage Period (including any missed payments) unless the holders of the Designated Senior Indebtedness or the Representatives of such holders have accelerated the maturity of the Designated Senior Indebtedness. Not more than one Blockage Notice may be given in any consecutive 360-day period, irrespective of the number of defaults with respect to Designated Senior Indebtedness during that period. However, if any Blockage Notice within such 360-day period is given by or on behalf of any holders of Designated Senior Indebtedness other than the Bank Indebtedness, the Representatives of the Bank Indebtedness may give another Blockage Notice within that period. In no event, however, may the total number of days during which any Payment Blockage Period or Periods is in effect exceed 179 days in the aggregate during any consecutive 360-day period. No default or event of default that existed or was continuing on the date of the commencement of any Payment Blockage Period with respect to the Designated Senior Indebtedness initiating the Payment Blockage Period shall be, or be made, the basis of the commencement of a subsequent Payment Blockage Period by the Representative of the Designated Senior Indebtedness, whether or not within a period of 360 consecutive days, unless such default or event of default shall have been cured or waived for a period of not less than 90 consecutive days.

In the event of:

(1) a total or partial liquidation or a dissolution of the Company;

(2) a reorganization, bankruptcy, insolvency, receivership of or similar proceeding relating to the Company or its property; or

(3) an assignment for the benefit of creditors or marshaling of the Company's assets and liabilities, then

the holders of Senior Indebtedness will be entitled to receive payment in full in cash or Cash Equivalents in respect of Senior Indebtedness (including interest accruing after, or which would accrue but for, the commencement of any proceeding at the rate specified in the applicable Senior Indebtedness, whether or not a claim for such interest would be allowed in such proceeding) before the holders of the Notes will be entitled to receive any payment or distribution, in the event of any payment or distribution of the assets or securities of the Company. In addition, until the Senior Indebtedness is paid in full in cash or Cash Equivalents, any payment or distribution to which holders of the Notes would be entitled but for the subordination provisions of the Indenture will be made to holders of the Senior Indebtedness as their interests may appear. If a payment or distribution is made to holders of the Notes that, due to the subordination provisions, should not have been made to them, the holders are required to hold it in trust for the holders of Senior Indebtedness and pay the payment or distribution over to holders of Senior Indebtedness, as their interests may appear.

If payment of the Notes is accelerated because of an event of default under the Indenture, the Company or the Trustee will promptly notify the holders of the Designated Senior Indebtedness or the Representatives of such holders of the acceleration. The Company may not pay the Notes until five business days after such holders or the Representatives of the Designated Senior Indebtedness receives notice of such acceleration and, after that five business day period, may pay the Notes only if the subordination provisions of the Indenture otherwise permit payment at that time.

Subsidiary guarantees

The Subsidiary Guarantors will, jointly and severally, fully and unconditionally guarantee, on a senior subordinated basis, the Company's obligations under the Notes and all obligations under the Indenture. The Subsidiary Guarantors will agree to pay, in addition to the amount stated above, any and all costs and expenses (including reasonable counsel fees and expenses) Incurred by the Trustee or the holders in enforcing any rights under the Subsidiary Guarantees.

Each Subsidiary Guarantee will be subordinated to the prior payment in full of all Guarantor Senior Indebtedness in the same manner and to the same extent that the Notes are subordinated to Senior Indebtedness. Each Subsidiary Guarantee will rank equally with all other Guarantor Senior Subordinated Indebtedness of that Subsidiary Guarantor and will be senior in right of payment to all future Guarantor Subordinated Obligations of that Subsidiary Guarantor. The Subsidiary Guarantees will be effectively subordinated to any secured Indebtedness of the applicable Subsidiary Guarantor to the extent of the value of the assets securing such Indebtedness. The Subsidiary Guarantors will not be permitted to Incur indebtedness that is junior in right of payment to Guarantor Senior Indebtedness but senior in right of payment to the Subsidiary Guarantee. Unsecured Indebtedness of the Subsidiary Guarantors is not deemed to be subordinate or junior to secured Indebtedness merely because it is unsecured.

Assuming that we had applied the net proceeds we receive from this offering in the manner described under "Use of proceeds," as of March 31, 2011, the Subsidiary Guarantors would have had no Guarantor Senior Subordinated Indebtedness other than the Subsidiary Guarantees.

Although the Indenture will limit the amount of indebtedness that Restricted Subsidiaries may Incur, such indebtedness may be substantial and all of it may be Guarantor Senior Indebtedness.

The obligations of each Subsidiary Guarantor under its Subsidiary Guarantee will be limited as necessary to prevent that Subsidiary Guarantee from constituting a fraudulent conveyance or fraudulent transfer under applicable law.

In the event a Subsidiary Guarantor is sold, disposed of or otherwise transferred (whether by merger, consolidation, the sale, disposition or transfer of its Capital Stock, the sale of all or substantially all of its assets (other than by lease) or otherwise and including any sale, disposition or other transfer following which the applicable Subsidiary Guarantor is no longer a Restricted Subsidiary) and whether or not the Subsidiary Guarantor is the surviving entity in such transaction to a Person that is not the Company or a Restricted Subsidiary, such Subsidiary Guarantor will be automatically released from its obligations under its Subsidiary Guarantee if:

(1) the sale or other disposition is in compliance with the Indenture, including the covenants "Limitation on sales of assets and subsidiary stock" and "Limitation on sales of capital stock of restricted subsidiaries;" and

(2) all of the obligations of the Subsidiary Guarantor under any Credit Facility and related documentation and any other agreements relating to any other Indebtedness of the Company or its Restricted Subsidiaries terminate upon consummation of such transaction.

In addition, a Subsidiary Guarantor will be released from its obligations under the Indenture and its Subsidiary Guarantee (x) if the Company designates the Subsidiary as an Unrestricted Subsidiary and the designation complies with the other applicable provisions of the Indenture and (y) upon the Company's exercise of its legal defeasance option or covenant defeasance option as described under "Defeasance."

Change of control

If a Change of Control occurs, unless the Company has exercised its right to redeem all of the Notes as described under "Optional redemption," the Company will be required to offer to repurchase from each holder all or any part (equal to $2,000 or an integral multiple of $1,000 in excess thereof) of such holder's Notes at a purchase price in cash equal to 101% of the principal amount of the Notes plus accrued and unpaid interest, if any, to the date of purchase (subject to the right of holders of record on the relevant record date to receive interest due on the relevant interest payment date).

Within 30 days following any Change of Control, unless the Company has exercised its right to redeem the Notes as described under "Optional redemption," the Company will mail a notice (the "Change of Control Offer") to each holder, with a copy to the Trustee, stating:

(1) that a Change of Control has occurred and that the Company is offering to purchase the holder's Notes at a purchase price in cash equal to 101% of the principal amount of the Notes plus accrued and unpaid interest, if any, to the date of purchase (subject to the right of holders of record at the close of business on a record date to receive interest on the relevant interest payment date) (the "Change of Control Payment");

(2) the repurchase date (which shall be no earlier than 30 days nor later than 60 days from the date such notice is mailed) (the "Change of Control Payment Date"); and

(3) the procedures determined by the Company, consistent with the Indenture, that a holder must follow in order to have its Notes repurchased.

On the Change of Control Payment Date, the Company will, to the extent lawful:

(1) accept for payment all Notes or portions of Notes (in a minimum principal amount of $2,000 and integral multiples of $1,000 in excess thereof) properly tendered pursuant to the Change of Control Offer;

(2) deposit with the paying agent for the Notes an amount equal to the Change of Control Payment in respect of all Notes or portions of Notes so tendered; and

(3) deliver or cause to be delivered to the Trustee the Notes so accepted together with an officers' certificate stating the aggregate principal amount of Notes or portions of Notes being purchased by the Company.

Our paying agent will promptly mail to each holder of Notes so tendered the Change of Control Payment for the Notes, and the Trustee will promptly authenticate and mail (or cause to be transferred by book entry) to each holder a new Note equal in principal amount to any unpurchased portion of the Notes surrendered, if any; provided that each new Note will be in a principal amount of $2,000 or an integral multiple of $1,000 in excess thereof.

If the Change of Control Payment Date is on or after an interest record date and on or before the related interest payment date, any accrued and unpaid interest will be paid to the Person in whose name a Note is registered at the close of business on the record date, and no additional interest will be payable to holders who tender pursuant to the Change of Control Offer.

Any failure by the Company to effect such repayment or obtain such consent within 30 days following any Change of Control, will constitute a default under the Indenture. A default under the Indenture may result in a cross-default under a Credit Facility. In the event of a default under a Credit Facility, the subordination provisions of the Indenture would likely restrict payments to the holders of the Notes.

The Company will not be required to make a Change of Control Offer upon a Change of Control if a third party makes the Change of Control Offer in the manner, at the times and otherwise in compliance with the requirements set forth in the Indenture applicable to a Change of Control Offer made by the Company and purchases all Notes validly tendered and not withdrawn under the Change of Control Offer.

A Change of Control Offer may be made in advance of a Change of Control, conditional upon such Change of Control, if a definitive agreement is in place for the Change of Control at the time of the making of the Change of Control Offer.

The Company will comply, to the extent applicable, with the requirements of Section 14(e) of the Exchange Act and any other securities laws or regulations in connection with the repurchase of Notes pursuant to this covenant. To the extent that the provisions of any securities laws or regulations conflict with provisions of the Indenture, the Company will comply with the applicable securities laws and regulations and will be deemed not to have breached its obligations described in the Indenture by virtue of such compliance.

The Company's ability to repurchase Notes pursuant to a Change of Control Offer may be limited by a number of factors. The occurrence of any of the events that constitute a Change of Control may constitute a default under the Senior Credit Agreement. In addition, certain events that may constitute a change of control under the Senior Credit Agreement and cause a default under that agreement may not constitute a Change of Control under the Indenture. Future Indebtedness of the Company and its Subsidiaries may also contain prohibitions of certain events that would constitute a Change of Control or require such Indebtedness to be repurchased upon a Change of Control. Moreover, the exercise by the holders of their right to require the Company to repurchase the Notes could cause a default under such Indebtedness, even if the Change of Control itself does not, due to the financial effect of such repurchase on the Company. Finally, the Company's ability to pay cash to the holders upon a repurchase may be limited by the Company's then existing financial resources. There can be no assurance that sufficient funds will be available when necessary to make any required repurchases.

Even if sufficient funds were otherwise available, the terms of the Senior Credit Agreement may (and other Indebtedness may) prohibit the Company's prepayment or repurchase of Notes before their scheduled maturity. Consequently, if the Company is not able to prepay the Bank Indebtedness and any other Indebtedness containing similar restrictions or obtain requisite consents, as described above, the Company will be unable to consummate a Change of Control Offer, resulting in a default under the Indenture. A default under the Indenture may result in a cross-default under the Senior Credit Agreement. In the event of a default under the Senior Credit Agreement, the subordination provisions of the Indenture would likely restrict payments to the holders of the Notes.

The Change of Control provisions described above may deter certain mergers, tender offers and other takeover attempts involving the Company by increasing the capital required to effectuate these transactions.

The definition of "Change of Control" includes a disposition of all or substantially all of the property and assets of the Company and its Restricted Subsidiaries taken as a whole to any Person. Although there is a limited body of case law interpreting the phrase "substantially all," there is no precise established definition of the phrase under applicable law. Accordingly, in certain circumstances there may be a degree of uncertainty as to whether a particular transaction would involve a disposition of "all or substantially all" of the property and assets of a Person. As a result, it may be unclear as to whether a Change of Control has occurred and the Company is obligated to make a Change of Control Offer. The provisions under the Indenture obligating the Company to make a Change of Control Offer may be waived or modified with the written consent of the holders of a majority in principal amount of the Notes.

Certain covenants

Effectiveness of covenants

From and after the first day on which:

(1) the Notes have an Investment Grade Rating from both of the Ratings Agencies; and

(2) no Default has occurred and is continuing under the Indenture;

the Company and its Restricted Subsidiaries will cease to be subject to the provisions of the Indenture summarized under the subheadings below:

(1) "Limitation on indebtedness,"

(2) "Limitation on restricted payments,"

(3) "Limitation on restrictions on distributions from restricted subsidiaries,"

(4) "Limitation on sales of assets and subsidiary stock,"

(5) "Limitation on affiliate transactions,"

(6) "Limitation on sale of capital stock of restricted subsidiaries,"

(7) "Limitation on lines of business," and

(8) Clause (4) of "Merger and consolidation"

(collectively, the "Suspended Covenants"). If at any time the credit rating of the Notes is downgraded from an Investment Grade Rating by either Rating Agency, then the Suspended Covenants will thereafter be reinstated and again be applicable pursuant to the terms of the Indenture, unless and until the Notes subsequently attain an Investment Grade Rating. Neither the failure of the Company or any of its Subsidiaries to comply with a Suspended Covenant after the Notes attain an Investment Grade Rating and before any reinstatement of the Suspended Covenants nor compliance by the Company or any of its Subsidiaries with any contractual obligation entered into in compliance with the Indenture during that period will constitute a Default, Event of Default or breach of any kind under the Indenture, the Notes or the Subsidiary Guarantees.

During any period when the Suspended Covenants are not in effect, the Board of Directors of the Company may not designate any of the Company's Subsidiaries as Unrestricted Subsidiaries pursuant to the Indenture.

Limitation on indebtedness

The Company may not, and may not permit any of its Restricted Subsidiaries to, Incur any Indebtedness (including Acquired Indebtedness); except, that the Company and any Subsidiary Guarantor may Incur Indebtedness if on the date thereof:

(1) the Consolidated Coverage Ratio for the Company and its Restricted Subsidiaries is at least 2.25 to 1.0; and

(2) no Default or Event of Default shall have occurred and be continuing or would occur as a consequence of Incurring the Indebtedness or the transactions relating to such Incurrence.

The first paragraph of this covenant will not prohibit the Incurrence of the following Indebtedness:

(1) Indebtedness of the Company and the Restricted Subsidiaries Incurred pursuant to a Credit Facility in an aggregate principal amount up to the greater of (x) $500 million or (y) 35% of Adjusted Consolidated Net Tangible Assets, in each case, determined as of the date of the Incurrence of the Indebtedness;

(2) Guarantees of Indebtedness of the Company or any Subsidiary Guarantor Incurred in accordance with the provisions of the Indenture; provided that if the Indebtedness that is being Guaranteed is Guaranteed by a Subsidiary Guarantor and is (a) Senior Subordinated Indebtedness or Guarantor Senior Subordinated Indebtedness, then the related Guarantee shall rank equally in right of payment to the Subsidiary Guarantee or (b) a Subordinated Obligation or a Guarantor Subordinated Obligation, then the related Guarantee shall be subordinated in right of payment to the Subsidiary Guarantee;

(3) Indebtedness of the Company owing to and held by any Restricted Subsidiary or Indebtedness of a Restricted Subsidiary owing to and held by the Company or any Restricted Subsidiary; provided, however, that:

   (a) if the Company is the obligor on the Indebtedness, the Indebtedness is subordinated in right of payment to all obligations with respect to the Notes;

   (b) if a Subsidiary Guarantor is the obligor on the Indebtedness and the Company or a Subsidiary Guarantor is not the obligee, such Indebtedness is subordinated in right of payment to the Subsidiary Guarantees of that Subsidiary Guarantor; and

   (c) any subsequent issuance or transfer of Capital Stock, sale or other transfer of any such Indebtedness or other event that results in any such Indebtedness being held by a Person other than the Company or a Restricted Subsidiary of the Company shall be deemed, in each case, to constitute an Incurrence of such Indebtedness by the Company or such Subsidiary, as the case may be, as of the date such Indebtedness first became held by such Person;

(4) Indebtedness represented by (a) the Notes issued on the Issue Date, and the Subsidiary Guarantees, (b) any Indebtedness (other than the Indebtedness described in clauses (1), (2), (3), (6), (8), (9) and (10)) outstanding on the Issue Date, and (c) any Refinancing Indebtedness Incurred in respect of any Indebtedness described in this clause (4) or clause (5) or Incurred pursuant to the first paragraph of this covenant;

(5) Indebtedness of a Person that becomes a Restricted Subsidiary or is acquired by the Company or a Restricted Subsidiary or merged into the Company or a Restricted Subsidiary Incurred and outstanding on the date on which such Person became a Restricted Subsidiary or was acquired by

or was merged into the Company or a Restricted Subsidiary (other than Indebtedness Incurred (a) to provide all or any portion of the funds utilized to consummate the transaction or series of related transactions pursuant to which such Person became a Restricted Subsidiary or was otherwise acquired by or merged into the Company or a Restricted Subsidiary or (b) otherwise in connection with, or in contemplation of, such acquisition); provided, however, that, at the time such Person became a Restricted Subsidiary or is acquired by or merged into the Company or a Restricted Subsidiary, the Company would have been able to Incur $1.00 of additional Indebtedness pursuant to the first paragraph of this covenant after giving effect to the Incurrence of such Indebtedness;

(6) Indebtedness under Currency Agreements, Commodity Agreements and Interest Rate Agreements; provided, that, in the case of Currency Agreements or Commodity Agreements, such Currency Agreements or Commodity Agreements are related to business transactions of the Company or its Restricted Subsidiaries entered into in the ordinary course of business and, in the case of Currency Agreements, Commodity Agreements and Interest Rate Agreements, such Currency Agreements, Commodity Agreements and Interest Rate Agreements are entered into for bona fide hedging purposes of the Company or its Restricted Subsidiaries (as determined in good faith by the senior management of the Company);

(7) the Incurrence by the Company or any of its Restricted Subsidiaries of Indebtedness represented by Capital Lease Obligations, mortgage financings or purchase money obligations, in each case Incurred for the purpose of financing all or any part of the purchase price or cost of construction or improvements of property used in the business of the Company or the Restricted Subsidiary, in an aggregate principal amount not to exceed the greater of (i) $50 million and (ii) 2.0% of Adjusted Consolidated Net Tangible Assets at any time outstanding and Refinancing Indebtedness Incurred to Refinance any Indebtedness Incurred pursuant to this clause (7);

(8) Indebtedness Incurred in respect of workers' compensation claims, self-insurance obligations, bid, reimbursement, performance, surety, appeal and similar bonds, asset retirement obligations, completion guarantees provided by the Company or a Restricted Subsidiary in the ordinary course of business, or required by regulatory authorities in connection with the conduct by the Company and its Restricted Subsidiaries of their businesses, including supporting Guarantees and letters of credit (in each case other than for an obligation for money borrowed);

(9) Indebtedness arising from agreements of the Company or a Restricted Subsidiary providing for indemnification, adjustment of purchase price or similar obligations, in each case, Incurred or assumed in connection with the disposition of any business, assets or Capital Stock of the Company or a Restricted Subsidiary;

(10) Indebtedness arising from the honoring by a bank or other financial institution of a check, draft or similar instrument (except in the case of daylight overdrafts) drawn against insufficient funds in the ordinary course of business; provided, however, that such Indebtedness is extinguished within five business days of the Incurrence;

(11) Indebtedness, including Refinancing Indebtedness, Incurred by a Foreign Subsidiary in an aggregate amount not to exceed the greater of $30 million or 15% of such Foreign Subsidiary's Adjusted Consolidated Net Tangible Assets at any time outstanding;

(12) any Guarantee by the Company or any Restricted Subsidiary that directly owns Capital Stock of an Unrestricted Subsidiary that is recourse only to, and secured only by, such Capital Stock; and

(13) in addition to the items referred to in clauses (1) through (12) above, Indebtedness of the Company and its Restricted Subsidiaries in an aggregate outstanding principal amount which, when taken

together with the principal amount of all other Indebtedness Incurred pursuant to this clause (13) and then outstanding, will not exceed the greater of $50 million or 3.0% of the Company's Adjusted Consolidated Net Tangible Assets, in each case, determined as of the date of the Incurrence of the Indebtedness.

For purposes of determining compliance with, and the outstanding principal amount of any particular Indebtedness Incurred pursuant to and in compliance with, this covenant:

(1) Indebtedness permitted by this covenant need not be permitted solely by one provision permitting such Indebtedness but may be permitted in part by one such provision and in part by one or more other provisions of this covenant permitting such Indebtedness;

(2) in the event that Indebtedness meets the criteria of more than one of the provisions permitting the Incurrence of Indebtedness described in the first and second paragraphs above, the Company, in its sole discretion, may classify (or subsequently reclassify) such item of Indebtedness as being permitted by one or more such provisions;

(3) all Indebtedness outstanding on the date of the Indenture under the Senior Credit Agreement shall be deemed Incurred under clause (1) of the second paragraph above and not the first paragraph or clause (4) of the second paragraph above;

(4) Guarantees of, or obligations in respect of letters of credit relating to, Indebtedness which is otherwise included in the determination of a particular amount of Indebtedness shall not be included;

(5) if obligations in respect of letters of credit are Incurred pursuant to a Credit Facility and are being treated as Incurred pursuant to clause (1) of the second paragraph above and the letters of credit relate to other Indebtedness, then such other Indebtedness shall not be included;

(6) no item of Indebtedness will be given effect more than once in any calculation contemplated by this covenant and no individual item or related items of Indebtedness will be given effect at an aggregate amount in excess of the aggregate amount required to satisfy and discharge the principal amount of such item or related items of Indebtedness;

(7) the principal amount of any Disqualified Stock of the Company or a Restricted Subsidiary, or Preferred Stock of a Restricted Subsidiary that is not a Subsidiary Guarantor, will be equal to the greater of the maximum mandatory redemption or repurchase price (not including, in either case, any redemption or repurchase premium) or the liquidation preference thereof; and

(8) the amount of Indebtedness issued at a price that is less than the principal amount thereof will be equal to the amount of the liability in respect thereof determined in accordance with GAAP.

Accrual of interest, accrual of dividends, the accretion of accreted value, the payment of interest in the form of additional Indebtedness and the payment of dividends in the form of additional shares of Preferred Stock or Disqualified Stock will not be deemed to be an Incurrence of Indebtedness for purposes of this covenant. The amount of any Indebtedness outstanding as of any date shall be (i) the accreted value thereof in the case of any Indebtedness issued with original issue discount and (ii) the principal amount or liquidation preference thereof, together with any interest thereon that is more than 30 days past due, in the case of any other Indebtedness.

In addition, the Company will not permit any of its Unrestricted Subsidiaries to Incur any Indebtedness or issue any shares of Disqualified Stock, other than Non-Recourse Debt. If at any time an Unrestricted Subsidiary becomes a Restricted Subsidiary, any Indebtedness of such Subsidiary shall be deemed to be Incurred by a Restricted Subsidiary as of such date (and, if such Indebtedness is not permitted to be Incurred as of such date under this “Limitation on indebtedness” covenant, the Company shall be in Default of this covenant).

For purposes of determining compliance with any U.S. dollar-denominated restriction on the Incurrence of Indebtedness, the U.S. dollar-equivalent principal amount of Indebtedness denominated in a foreign currency will be calculated based on the relevant currency exchange rate in effect on the date the Indebtedness was Incurred, in the case of term Indebtedness, or first committed, in the case of revolving credit Indebtedness; provided that if such Indebtedness is Incurred to refinance other Indebtedness denominated in a foreign currency, and the refinancing would cause the applicable U.S. dollar-dominated restriction to be exceeded if calculated at the relevant currency exchange rate in effect on the date of the refinancing, such U.S. dollar-dominated restriction shall be deemed not to have been exceeded so long as the principal amount of such refinancing Indebtedness does not exceed the principal amount of such Indebtedness being refinanced. Notwithstanding any other provision of this covenant, the maximum amount of Indebtedness that the Company may Incur pursuant to this covenant shall not be deemed to be exceeded solely as a result of fluctuations in the exchange rate of currencies. The principal amount of any Indebtedness Incurred to refinance other Indebtedness, if Incurred in a different currency from the Indebtedness being refinanced, will be calculated based on the currency exchange rate applicable to the currencies in which the Refinancing Indebtedness is denominated that is in effect on the date of such refinancing.

Limitation on layering

The Company will not Incur any Indebtedness if such Indebtedness is subordinate in right of payment to any Senior Indebtedness unless the Indebtedness is Senior Subordinated Indebtedness or is contractually subordinated in right of payment to Senior Subordinated Indebtedness. No Subsidiary Guarantor will Incur any Indebtedness if the Indebtedness is subordinate in right of payment to any Guarantor Senior Indebtedness of the Subsidiary Guarantor unless the Indebtedness is Guarantor Senior Subordinated Indebtedness of the Subsidiary Guarantor or is contractually subordinated in right of payment to Guarantor Senior Subordinated Indebtedness of the Subsidiary Guarantor.

Limitation on restricted payments

The Company will not, and will not permit any of its Restricted Subsidiaries, directly or indirectly, to:

(1) pay any dividend or make any distribution on or in respect of its Capital Stock (including any payment in respect of its Capital Stock in connection with any merger or consolidation involving the Company or any of its Restricted Subsidiaries) except:

  (a) dividends or distributions payable in Capital Stock of the Company (other than Disqualified Stock) or in options, warrants or other rights to purchase Capital Stock of the Company; and

  (b) dividends or distributions payable to the Company or a Restricted Subsidiary (and if the Restricted Subsidiary is not a Wholly-Owned Subsidiary, to its other holders of Capital Stock on a pro rata basis);

(2) purchase, redeem, retire or otherwise acquire for value any Capital Stock of the Company or any direct or indirect parent of the Company held by Persons other than the Company or a Restricted Subsidiary (other than in exchange for Capital Stock of the Company or any direct or indirect parent of the Company (other than Disqualified Stock));

(3) purchase, repurchase, redeem, defease or otherwise acquire or retire for value, prior to scheduled maturity, scheduled repayment or scheduled sinking fund payment, any Subordinated Obligations or Guarantor Subordinated Obligations (other than (x) the purchase, repurchase, redemption, defeasance or other acquisition or retirement of Subordinated Obligations or Guarantor

Subordinated Obligations purchased in anticipation of satisfying a sinking fund obligation, principal installment or final maturity, in each case due within one year of the date of purchase, repurchase, redemption, defeasance or other acquisition or retirement and (y) Indebtedness permitted under clause (3) of the second paragraph under "Limitation on indebtedness"); or

(4) make any Restricted Investment in any Person;

(any such dividend, distribution, purchase, redemption, repurchase, defeasance, other acquisition, retirement or Restricted Investment referred to in clauses (1) through (4) being referred to herein as a "Restricted Payment"), if at the time the Company or such Restricted Subsidiary makes such Restricted Payment:

(a) a Default shall have occurred and be continuing (or would result therefrom); or

(b) the Company is not able to Incur an additional $1.00 of Indebtedness pursuant to the first paragraph under "Limitation on indebtedness" above after giving effect, on a pro forma basis, to the Restricted Payment; or

(c) the aggregate amount of the Restricted Payment and all other Restricted Payments made subsequent to the Issue Date would exceed the sum of:

(i) 50% of Consolidated Net Income for the period (treated as one accounting period) from the beginning of the most recent fiscal quarter ended prior to the Issue Date to the end of the most recent fiscal quarter ending prior to the date of such Restricted Payment for which financial statements are in existence (or, in case such Consolidated Net Income is a deficit, minus 100% of such deficit);

(ii) 100% of the aggregate Net Cash Proceeds and the Fair Market Value of Additional Assets received by the Company from the issue or sale of its Capital Stock (other than Disqualified Stock) or other capital contributions subsequent to the Issue Date (other than Net Cash Proceeds received from an issuance or sale of such Capital Stock to a Subsidiary of the Company or an employee stock ownership plan, option plan or similar trust to the extent such sale to an employee stock ownership plan, option plan or similar trust is financed by loans from or Guaranteed by the Company or any Restricted Subsidiary unless such loans have been repaid with cash on or prior to the date of determination);

(iii) the amount by which Indebtedness of the Company or its Restricted Subsidiaries is reduced on the Company's balance sheet upon the conversion or exchange (other than by a Subsidiary of the Company) subsequent to the Issue Date of any Indebtedness of the Company or its Restricted Subsidiaries convertible into or exchangeable for Capital Stock (other than Disqualified Stock) of the Company (less the amount of any cash, or the fair market value of any other property, distributed by the Company upon such conversion or exchange); and

(iv) the amount equal to payments received by the Company or any Restricted Subsidiary in respect of, or the net reduction in, Restricted Investments made by the Company or any of its Restricted Subsidiaries in any Person resulting from:

(A) repurchases or redemptions of such Restricted Investments by the Person in which such Restricted Investments are made, proceeds realized upon the sale of such Restricted Investment to an unaffiliated purchaser or payments in respect of such Restricted Investment, whether through interest payments, principal payments, dividends, distributions or otherwise, by such Person to the Company or any Restricted Subsidiary; or

(B) the redesignation of Unrestricted Subsidiaries as Restricted Subsidiaries (valued in each case as provided in the definition of "Investment") not to exceed, in the case of any Unrestricted Subsidiary, the amount of Investments previously made by the Company or any Restricted Subsidiary in such Unrestricted Subsidiary;

which amount in each case under clause (iv) was included in the calculation of the amount of Restricted Payments; provided, however, that no amount will be included under clause (iv) to the extent it is already included in Consolidated Net Income.

The provisions of the preceding paragraph will not prohibit:

(1) any purchase, repurchase, redemption, defeasance or other acquisition or retirement of Capital Stock, Disqualified Stock or Subordinated Obligations or Guarantor Subordinated Obligations made by exchange for, or out of the proceeds of the substantially concurrent sale of, Capital Stock of the Company (other than Disqualified Stock and other than Capital Stock issued or sold to a Subsidiary or an employee stock ownership plan or similar trust to the extent such sale to an employee stock ownership plan or similar trust is financed by loans from or Guaranteed by the Company or any Restricted Subsidiary unless such loans have been repaid with cash on or prior to the date of determination); provided, however, that (a) such purchase, repurchase, redemption, defeasance, acquisition or retirement will be excluded in subsequent calculations of the amount of Restricted Payments and (b) the Net Cash Proceeds from such sale of Capital Stock will be excluded from clause (c)(ii) of the preceding paragraph;

(2) any purchase, repurchase, redemption, defeasance or other acquisition or retirement of Subordinated Obligations or Guarantor Subordinated Obligations made by exchange for, or out of the proceeds of the substantially concurrent sale of, Subordinated Obligations or any purchase, repurchase, redemption, defeasance or other acquisition or retirement of Guarantor Subordinated Obligations made by exchange for or out of the proceeds of the substantially concurrent sale of Guarantor Subordinated Obligations that, in each case, is permitted to be Incurred as described under "Limitation on indebtedness" and that in each case constitutes Refinancing Indebtedness; provided, however, that such purchase, repurchase, redemption, defeasance, acquisition or retirement will be excluded in subsequent calculations of the amount of Restricted Payments;

(3) any purchase, repurchase, redemption, defeasance or other acquisition or retirement of Disqualified Stock of the Company or a Restricted Subsidiary made by exchange for or out of the proceeds of the substantially concurrent sale of Disqualified Stock of the Company or such Restricted Subsidiary, as the case may be, that, in each case, is permitted to be Incurred pursuant to the covenant described under "Limitation on indebtedness" and that in each case constitutes Refinancing Indebtedness; provided, however, that such purchase, repurchase, redemption, defeasance, acquisition or retirement will be excluded in subsequent calculations of the amount of Restricted Payments;

(4) so long as no Default or Event of Default has occurred and is continuing, any purchase or redemption of Subordinated Obligations or Guarantor Subordinated Obligations from Net Available Cash to the extent permitted under "Limitation on sales of assets and subsidiary stock" below; provided, however, that such purchase or redemption will be excluded in subsequent calculations of the amount of Restricted Payments;

(5) dividends paid within 60 days after the date of declaration if at such date of declaration the dividend would have complied with this provision; provided, however, that such dividends will be included in subsequent calculations of the amount of Restricted Payments;

(6) so long as no Default or Event of Default has occurred and is continuing,

(a) the purchase, redemption or other acquisition, cancellation or retirement for value of Capital Stock, or options, warrants, equity appreciation rights or other rights to purchase or acquire Capital Stock of the Company or any Restricted Subsidiary or any direct or indirect parent of the Company held by any existing or former employees or directors of the Company or any Subsidiary of the Company or their assigns, estates or heirs, in each case in accordance with the terms of employee stock option or stock purchase agreements or other agreements to compensate employees or directors; provided that such purchases, redemptions acquisitions, cancellations or retirements pursuant to this clause will not exceed $2.0 million in the aggregate during any calendar year (with unused amounts carried over into the following year); provided further however, that the amount of any such purchases, redemptions, acquisitions, cancellations or retirements will be included in subsequent calculations of the amount of Restricted Payments; and

(b) loans or advances to employees or directors of the Company or any Subsidiary of the Company the proceeds of which are used to purchase Capital Stock of the Company, in an aggregate amount not in excess of $2.0 million at any one time outstanding; provided, however, that the amount of such loans and advances will be included in subsequent calculations of the amount of Restricted Payments;

(7) so long as no Default or Event of Default has occurred and is continuing, the declaration and payment of dividends to holders of any class or series of Disqualified Stock of the Company issued in accordance with the terms of the Indenture to the extent such dividends are included in the definition of "Consolidated Interest Expense;" provided, however, that the payment of such dividends will be excluded in subsequent calculations of the amount of Restricted Payments;

(8) repurchases of Capital Stock deemed to occur upon the exercise of stock options, warrants or other convertible securities if such Capital Stock represents a portion of the exercise price thereof; provided, however, that such repurchases will be excluded from subsequent calculations of the amount of Restricted Payments;

(9) the purchase, repurchase, redemption, defeasance or other acquisition or retirement for value of any Subordinated Obligation (i) at a purchase price not greater than 101% of the principal amount of such Subordinated Obligation in the event of a Change of Control in accordance with provisions similar to the "Change of control" covenant described herein or (ii) at a purchase price not greater than 100% of the principal amount thereof in accordance with provisions similar to the "Limitation on sales of assets and subsidiary stock" covenant described herein; provided that, prior to or simultaneously with such purchase, repurchase, redemption, defeasance or other acquisition or retirement, the Company has made the Change of Control Offer or Asset Disposition Offer, as applicable, as required with respect to the Notes and has completed the repurchase or redemption of all Notes validly tendered for payment in connection with such Change of Control Offer or Asset Disposition Offer; provided, however, that such repurchases will be excluded from subsequent calculations of the amount of Restricted Payments;

(10) any redemption of share purchase rights at a redemption price not to exceed $0.01 per right; provided, however, that such redemption will be included in subsequent calculations of the amount of Restricted Payments;

(11) the payment of cash in lieu of fractional shares of Capital Stock in connection with any transaction otherwise permitted under the Indenture; provided, however, that such payment will be included in subsequent calculations of the amount of Restricted Payments;

(12) payments to dissenting stockholders not to exceed $5 million (x) pursuant to applicable law or (y) in connection with the settlement or other satisfaction of legal claims made pursuant to or in connection with a consolidation, merger or transfer of assets in connection with a transaction that is not prohibited by the Indenture; provided, however, that such payments will be included in subsequent calculations of the amount of Restricted Payments;

(13) Restricted Payments in an amount not to exceed $40 million; provided, however, that the amount of the Restricted Payments will be included in subsequent calculations of the amount of Restricted Payments; and

(14) so long as (i) no Default or Event of Default has occurred and is continuing and (ii) immediately after giving effect to such dividend or distribution on a pro forma basis, the Company's Consolidated Leverage Ratio would be less than 1.50:1, the declaration and payment of a Permitted Distribution; provided, however, that the amount of the Permitted Distribution will not be included in subsequent calculations of the amount of Restricted Payments.

The amount of all Restricted Payments (other than cash) shall be the fair market value on the date of the Restricted Payment of the asset(s) or securities proposed to be paid, transferred or issued by the Company or such Restricted Subsidiary, as the case may be, pursuant to the Restricted Payment. The fair market value of any cash Restricted Payment shall be its face amount and any non-cash Restricted Payment shall be determined conclusively by the Board of Directors of the Company acting in good faith, such determination to be based upon an opinion or appraisal issued by an accounting, appraisal or investment banking firm of national standing if such fair market value is estimated in good faith by the Board of Directors of the Company to exceed $25 million.

Limitation on liens

The Company may not, and may not permit any of its Restricted Subsidiaries to, directly or indirectly, create, Incur or suffer to exist any Lien (the "Initial Lien") (other than Permitted Liens) upon any of its property or assets (including Capital Stock of Restricted Subsidiaries), whether owned on the Issue Date or acquired after that date, which Lien secures any Senior Subordinated Indebtedness, or Subordinated Obligations, Guarantor Senior Subordinated Indebtedness or Guarantor Subordinated Obligations, unless contemporaneously with the Incurrence of such Lien effective provision is made to secure the Indebtedness due with respect to the Notes or, with respect to Liens on any Restricted Subsidiary's property or assets, any Subsidiary Guarantee of such Restricted Subsidiary, equally and ratably with (or prior to in the case of Liens with respect to Subordinated Obligations or Guarantor Subordinated Obligations, as the case may be) the Indebtedness secured by such Lien for so long as such Indebtedness is so secured.

Any Lien created for the benefit of the holders of the Notes pursuant to the preceding paragraph shall provide by its terms that such Lien shall be automatically and unconditionally released and discharged upon the release and discharge of the Initial Lien.

Limitation on restrictions on distributions from restricted subsidiaries

The Company may not, and may not permit any Restricted Subsidiary to, create or otherwise cause or permit to exist or become effective any consensual encumbrance or consensual restriction on the ability of any Restricted Subsidiary to:

(1) pay dividends or make any other distributions on its Capital Stock or pay any Indebtedness or other obligations owed to the Company or any Restricted Subsidiary (the priority of any Preferred Stock in receiving dividends or liquidating distributions prior to dividends or liquidating distributions being paid on Common Stock and any subordination of any such Indebtedness or other obligations being deemed not to constitute such encumbrances or restrictions);

(2) make any loans or advances to the Company or any Restricted Subsidiary (the subordination of loans or advances made to the Company or any Restricted Subsidiary to other Indebtedness Incurred by the Company or any Restricted Subsidiary being deemed not to constitute such an encumbrance or restriction); or

(3) transfer any of its property or assets to the Company or any Restricted Subsidiary.

The preceding provisions will not prohibit:

(a) any encumbrance or restriction pursuant to an agreement in effect at or entered into on the Issue Date, including, without limitation, the Indenture, the Notes and the Senior Credit Agreement in effect on such date;

(b) any encumbrance or restriction with respect to a Restricted Subsidiary pursuant to an agreement relating to any Capital Stock or Indebtedness Incurred by a Restricted Subsidiary on or before the date on which the Restricted Subsidiary was acquired by the Company (other than Capital Stock or Indebtedness Incurred as consideration in, or to provide all or any portion of the funds utilized to consummate, the transaction or series of related transactions pursuant to which such Restricted Subsidiary became a Restricted Subsidiary or was acquired by the Company or in contemplation of the transaction or transactions) and outstanding on such date provided, that any such encumbrance or restriction shall not extend to any assets or property of the Company or any other Restricted Subsidiary other than the assets and property so acquired;

(c) any encumbrance or restriction with respect to a Restricted Subsidiary pursuant to an agreement effecting a refunding, replacement or refinancing of Indebtedness Incurred pursuant to an agreement referred to in clause (a) or (b) of this paragraph or this clause (c) or contained in any amendment, restatement, modification, renewal, supplemental, refunding, replacement or refinancing of an agreement referred to in clause (a) or (b) of this paragraph or this clause (c), including successive refundings, replacements or refinancings; provided, however, that the encumbrances and restrictions with respect to such Restricted Subsidiary contained in any such agreement taken as a whole are no less favorable in any material respect to the holders of the Notes than the encumbrances and restrictions contained in such agreements referred to in clauses (a) or (b) of this paragraph on the Issue Date or the date such Restricted Subsidiary became a Restricted Subsidiary or was merged into a Restricted Subsidiary, whichever is applicable;

(d) in the case of clause (3) of the first paragraph of this covenant, any encumbrance or restriction:

 (i) that restricts in a customary manner the subletting, assignment or transfer of any property or asset that is subject to a lease, license or similar contract, or the assignment or transfer of any such lease, license or other contract;

 (ii) contained in mortgages, pledges or other security agreements permitted under the Indenture securing Indebtedness of the Company or a Restricted Subsidiary to the extent such encumbrances or restrictions restrict the transfer of the property subject to such mortgages, pledges or other security agreements; or

 (iii) pursuant to customary provisions restricting dispositions of real property interests set forth in any reciprocal easement agreements of the Company or any Restricted Subsidiary;

(e) (i) purchase money obligations for property acquired in the ordinary course of business and (ii) Capital Lease Obligations permitted under the Indenture, in each case, that impose encumbrances or restrictions of the nature described in clause (3) of the first paragraph of this covenant on the property so acquired;

(f) any restriction with respect to a Restricted Subsidiary (or any of its property or assets) imposed pursuant to an agreement entered into for the direct or indirect sale or disposition of all or substantially all the Capital Stock or assets of such Restricted Subsidiary (or the property or assets that are subject to such restriction) pending the closing of such sale or disposition;

(g) customary encumbrances or restrictions imposed pursuant to any agreement referred to in the definition of "Permitted Business Investment;"

(h) net worth provisions in leases and other agreements entered into by the Company or any Restricted Subsidiary in the ordinary course of business;

(i) encumbrances or restrictions arising or existing by reason of applicable law or any applicable rule, regulation or order;

(j) encumbrances and restrictions contained in contracts entered into the ordinary course of business, not relating to any Indebtedness, and that do not individually or in the aggregate, detract from the value of, or from the ability of the Company and the Restricted Subsidiaries to realized the value of, property or assets of the Company or any Restricted Subsidiary in any manner material to the Company or any Restricted Subsidiary;

(k) with respect to any Foreign Subsidiary, any encumbrance or restriction contained in the terms of any Indebtedness or any agreement pursuant to which such Indebtedness was Incurred if:

(i) either (1) the encumbrance or restriction applies only in the event of a payment default or a default with respect to a financial covenant in such Indebtedness or agreement or (2) the Company determines that any such encumbrance or restriction will not materially affect the Company's ability to make principal or interest payments on the Notes, as determined in good faith by the Board of Directors of the Company, whose determination shall be conclusive, and

(ii) the encumbrance or restriction is not materially more disadvantageous to the holders of the Notes than is customary in comparable financing (as determined by the Company):

(l) restrictions on cash or other deposits imposed by customers under contracts entered into in the ordinary course or business; or

(m) provisions with respect to the disposition or distribution of assets or property in operating agreements, joint venture agreements, development agreements, area of mutual interest agreements and other agreements that are customary in the Oil and Gas Business and entered into in the ordinary course of business.

Limitation on sales of assets and subsidiary stock

The Company may not, and may not permit any of its Restricted Subsidiaries to, make any Asset Disposition unless:

(1) the Company or the Restricted Subsidiary, as the case may be, receives consideration at the time of the Asset Disposition at least equal to the fair market value of the assets subject to the Asset Disposition (determined on the date of contractually agreeing to such Asset Disposition), as determined in good faith by senior management of the Company or, if the consideration with respect to such Asset Disposition exceeds $75 million, the Board of Directors of the Company (including as to the value of all non-cash consideration); and

(2) at least 75% of the consideration from the Asset Disposition received by the Company or the Restricted Subsidiary, as the case may be, is in the form of cash or Cash Equivalents or Additional Assets or any combination thereof.

The Company or such Restricted Subsidiary, as the case may be, may elect to apply all or any portion of the Net Available Cash from such Asset Disposition either:

(1) to prepay, repay, purchase, repurchase, redeem, defease or otherwise acquire or retire Senior Indebtedness of the Company (other than Disqualified Stock or Subordinated Obligations) or Indebtedness of a Restricted Subsidiary (other than any Disqualified Stock or Guarantor Senior Subordinated Indebtedness or Guarantor Subordinated Obligation of a Wholly-Owned Subsidiary Guarantor) (in each case other than Indebtedness owed to the Company or an Affiliate of the Company) within 365 days from the later of the date of such Asset Disposition or the receipt of such Net Available Cash; provided, however, that, in connection with any prepayment, repayment, purchase, repurchase, redemption, defeasance, or acquisition of Indebtedness pursuant to this clause (1), the Company or such Restricted Subsidiary will retire such Indebtedness and, in the case of revolving Indebtedness, will cause the related commitment (if any) to be permanently reduced in an amount equal to the principal amount so retired; or

(2) to invest in Additional Assets or make Permitted Business Investments within 365 days from the later of the date of such Asset Disposition or the receipt of such Net Available Cash;

provided, that, pending the final application of any such Net Available Cash in accordance with clauses (1) or (2) above, the Company and its Restricted Subsidiaries may temporarily reduce Indebtedness or otherwise invest such Net Available Cash in any manner not prohibited by the Indenture.

Any Net Available Cash from Asset Dispositions that is not applied or invested as provided in the preceding paragraph will be deemed to constitute "Excess Proceeds." Not later than the 366th day after an Asset Disposition, if the aggregate amount of Excess Proceeds exceeds $25 million, the Company must make an offer ("Asset Disposition Offer") to all holders of Notes and to the extent required by the terms of other Senior Subordinated Indebtedness, to all holders of other Senior Subordinated Indebtedness outstanding with similar provisions requiring the Company to make an offer to purchase such Senior Subordinated Indebtedness with the proceeds from any Asset Disposition ("Pari Passu Notes"), to purchase the maximum principal amount of Notes and any Pari Passu Notes to which the Asset Disposition Offer applies that may be purchased out of the Excess Proceeds, at an offer price in cash in an amount equal to 100% of the principal amount of the Notes and Pari Passu Notes plus accrued and unpaid interest to the date of purchase, in accordance with the procedures set forth in the Indenture or the agreements governing the Pari Passu Notes, as applicable, in each case in a minimum principal amount of $2,000 and integral multiples of $1,000 in excess thereof. To the extent that the aggregate amount of Notes and Pari Passu Notes so validly tendered and not properly withdrawn pursuant to an Asset Disposition Offer is less than the Excess Proceeds, the Company may use any remaining Excess Proceeds for general corporate purposes, subject to the other covenants contained in the Indenture. If the aggregate principal amount of Notes surrendered by holders thereof and other Pari Passu Notes surrendered by holders or lenders, collectively, exceeds the amount of Excess Proceeds, the Trustee shall select the Notes and Pari Passu Notes to be purchased pro rata on the basis of the aggregate principal amount of tendered Notes and Pari Passu Notes. Upon completion of the Asset Disposition Offer, the amount of Excess Proceeds will be reset at zero.

The Asset Disposition Offer must remain open for a period of 20 business days following its commencement, except to the extent that a longer period is required by applicable law (the "Asset Disposition Offer Period"). No later than five Business Days after the termination of the Asset Disposition Offer Period (the "Asset Disposition Purchase Date"), the Company will purchase the principal amount of Notes and Pari Passu Notes required to be purchased pursuant to the Asset Disposition Offer (the "Asset Disposition Offer Amount") or, if less than the Asset Disposition Offer Amount has been so validly tendered, all Notes and Pari Passu Notes validly tendered in response to the Asset Disposition Offer.

If the Asset Disposition Purchase Date is on or after an interest record date and on or before the related interest payment date, any accrued and unpaid interest will be paid to the Person in whose name a Note is registered at the close of business on such record date, and no additional interest will be payable to holders who tender Notes pursuant to the Asset Disposition Offer.

On or before the Asset Disposition Purchase Date, the Company must, to the extent lawful, accept for payment, on a pro rata basis to the extent necessary, the Asset Disposition Offer Amount of Notes and Pari Passu Notes or portions of Notes and Pari Passu Notes so validly tendered and not properly withdrawn pursuant to the Asset Disposition Offer, or if less than the Asset Disposition Offer Amount has been validly tendered and not properly withdrawn, all Notes and Pari Passu Notes so validly tendered and not properly withdrawn, in each case in a minimum principal amount of $2,000 and integral multiples of $1,000 in excess thereof. The Company or the paying agent, as the case may be, must promptly (but in any case not later than five business days after the termination of the Asset Disposition Offer Period) mail or deliver to each tendering holder of Notes or holder or lender of Pari Passu Notes, as the case may be, an amount equal to the purchase price of the Notes or Pari Passu Notes so validly tendered and not properly withdrawn by such holder or lender, as the case may be, and accepted by the Company for purchase, and the Company must promptly issue a new Note, and the Trustee, upon delivery of an officers' certificate from the Company, must authenticate and mail or deliver such new Note to such holder, in a principal amount equal to any unpurchased portion of the Note surrendered; provided that each such new Note will be in a minimum principal amount of $2,000 or an integral multiple of $1,000 in excess thereof. In addition, the Company must take any and all other actions required by the agreements governing the Pari Passu Notes. Any Note not so accepted must be promptly mailed or delivered by the Company to the holder thereof. The Company will publicly announce the results of the Asset Disposition Offer on the Asset Disposition Purchase Date.

For the purposes of this covenant, the following will be deemed to be cash:

(1) the assumption by the transferee of Indebtedness (other than Senior Subordinated Indebtedness, Subordinated Obligations or Disqualified Stock) of the Company or Indebtedness of a Restricted Subsidiary (other than Guarantor Senior Subordinated Indebtedness, Guarantor Subordinated Obligations or Disqualified Stock of any Restricted Subsidiary that is a Subsidiary Guarantor) and the release of the Company or the Restricted Subsidiary from all liability on such Indebtedness in connection with the Asset Disposition; and

(2) securities, notes or other obligations received by the Company or any Restricted Subsidiary from the transferee that are converted by the Company or such Restricted Subsidiary into cash within 90 days after consummation of the receipt thereof.

The Company may not, and may not permit any Restricted Subsidiary to, engage in any Asset Swaps, unless:

(1) at the time of entering into the Asset Swap and immediately after giving effect to the Asset Swap, no Default or Event of Default shall have occurred and be continuing or would occur as a consequence thereof; and

(2) in the event the Asset Swap involves the transfer by the Company or any Restricted Subsidiary of assets having an aggregate fair market value, as determined by the Board of Directors of the Company in good faith, in excess of $25 million, the terms of the Asset Swap have been approved by a majority of the members of the Board of Directors of the Company.

The Company will comply, to the extent applicable, with the requirements of Section 14(e) of the Exchange Act and any other securities laws or regulations in connection with the repurchase of Notes pursuant to the Indenture. To the extent that the provisions of any securities laws or regulations conflict with provisions of this covenant, the Company will comply with the applicable securities laws and regulations and will be deemed not to have breached its obligations under the Indenture by virtue of such compliance.

Limitation on affiliate transactions

The Company may not, and may not permit any of its Restricted Subsidiaries to, directly or indirectly, enter into or conduct any transaction (including the purchase, sale, lease or exchange of any property or the rendering of any service) with any Affiliate of the Company (an "Affiliate Transaction") unless:

(1) the terms of the Affiliate Transaction are not materially less favorable to the Company or the Restricted Subsidiary, as the case may be, than those that might reasonably have been obtained in a comparable transaction at the time of such transaction on an arm's-length basis from a Person that is not an Affiliate of the Company;

(2) in the event the Affiliate Transaction involves an aggregate consideration in excess of $10 million but not greater than $50 million, the Company delivers to the Trustee an Officers' Certificate certifying that such Affiliate Transaction satisfies the criteria in clause (1) above; and

(3) in the event the Affiliate Transaction involves an aggregate consideration in excess of $50 million, the Company delivers to the Trustee an Officers' Certificate certifying that such Affiliate Transaction satisfies the criteria in clause (1) above and that the terms of such transaction have been approved by a majority of the members of the Board of Directors of the Company having no personal pecuniary interest in such transaction.

The preceding paragraph will not apply to:

(1) any Restricted Payment or Permitted Investment permitted to be made pursuant to the covenant described under "Limitation on restricted payments;"

(2) any issuance of securities, or other payments, awards or grants in cash, securities or otherwise pursuant to, or the funding of, employment agreements and other compensation arrangements, options to purchase Capital Stock of the Company, restricted stock plans, long-term incentive plans, stock appreciation rights plans, participation plans or similar employee plans and/or insurance and indemnification arrangements provided to or for the benefit of employees and directors approved by the Board of Directors of the Company;

(3) loans or advances to employees, officers or directors in the ordinary course of business of the Company or any of its Restricted Subsidiaries, but in any event not to exceed $2.0 million in the aggregate outstanding at any one time with respect to all loans or advances made since the Issue Date;

(4) any transaction between the Company and a Restricted Subsidiary or between Restricted Subsidiaries and Guarantees issued by the Company or a Restricted Subsidiary for the benefit of the Company or a Restricted Subsidiary, as the case may be, in accordance with the covenant described under "Limitations on indebtedness;"

(5) any transaction with a joint venture or other entity other than an Unrestricted Subsidiary which would constitute an Affiliate Transaction solely because the Company or a Restricted Subsidiary owns, directly or indirectly, an equity interest in or otherwise controls such joint venture or other entity;

(6) the issuance or sale of any Capital Stock (other than Disqualified Stock) of the Company or the receipt by the Company of any capital contribution from its shareholders;

(7) indemnities of officers, directors and employees of the Company or any of its Restricted Subsidiaries permitted by charter documents or statutory provisions and any employment

agreement or other employee compensation plan or arrangement entered into in the ordinary course of business by the Company or any of its Restricted Subsidiaries;

(8) the payment of reasonable compensation and fees paid to, and indemnity provided on behalf of, officers or directors of the Company or any Restricted Subsidiary;

(9) the performance of obligations of the Company or any of its Restricted Subsidiaries under the terms of any agreement to which the Company or any of its Restricted Subsidiaries is a party as of or on the Issue Date, as these agreements may be amended, modified, supplemented, extended or renewed from time to time; provided, however, that any future amendment, modification, supplement, extension or renewal entered into after the Issue Date will be so excluded only if its terms are not materially less favorable to the Company or the Restricted Subsidiary, as the case may be, than those that might reasonably have been obtained in a comparable transaction at the time of such transaction on an arm's-length basis from a Person that is not an Affiliate of the Company; and

(10) transactions with customers, clients, suppliers, or purchasers or sellers of goods or services, in each case in the ordinary course of business and otherwise in compliance with the terms of this Indenture which are fair to the Company and its Restricted Subsidiaries, in the reasonable determination of the Board of Directors of the Company or the senior management thereof, or are on terms at least as favorable as might reasonably have been obtained at such time from an unaffiliated party.

SEC reports

Notwithstanding that the Company may not be subject to the reporting requirements of Section 13 or 15(d) of the Exchange Act, the Company will file with the SEC (to the extent the SEC will accept such filing), and make available to the Trustee and the registered holders of the Notes, the annual reports and the information, documents and other reports (or copies of such portions of any of the foregoing as the SEC may by rules and regulations prescribe) that are specified in Sections 13 and 15(d) of the Exchange Act. If the SEC will not accept such filings, the Company will nevertheless make available such Exchange Act information to the Trustee and the holders of the Notes as if the Company were subject to the reporting requirements of Section 13 or 15(d) of the Exchange Act.

Merger and consolidation

The Company may not consolidate with or merge with or into any other Person, or transfer all or substantially all its properties and assets to another Person, unless:

(1) the Company is the continuing or surviving Person in the consolidation or merger; or

(2) the Person (if other than the Company) formed by the consolidation or into which the Company is merged or to which all or substantially all of the Company's properties and assets are transferred is a corporation, partnership, limited liability company, business trust, trust or other legal entity organized and validly existing under the laws of the United States, any State thereof, or the District of Columbia, and expressly assumes, by a supplemental indenture, all of the Company's obligations under the Notes and the Indenture; and

(3) immediately after the transaction and the Incurrence or anticipated Incurrence of any Indebtedness to be Incurred in connection therewith, no Event of Default exists; and

(4) immediately after giving effect to such transaction, the continuing or surviving Person would be able to Incur at least an additional $1.00 of Indebtedness pursuant to the first paragraph of the "Limitation on indebtedness" covenant; and

(5) each Subsidiary Guarantor shall have by supplemental indenture confirmed that its Subsidiary Guarantee shall apply to such Person's obligations (if other than the Company) in respect of the Indenture and the Notes shall continue to be in effect;

(6) an officer's certificate is delivered to the Trustee to the effect that the conditions set forth above have been satisfied and an opinion of counsel has been delivered to the Trustee to the effect that the conditions set forth above have been satisfied.

For purposes of this covenant, the sale, lease, conveyance, assignment, transfer, or other disposition of all or substantially all of the properties and assets of one or more Subsidiaries of the Company, which properties and assets, if held by the Company instead of its Subsidiaries, would constitute all or substantially all of the properties and assets of the Company on a consolidated basis, shall be deemed to be the transfer of all or substantially all of the properties and assets of the Company.

The continuing, surviving or successor person will succeed to and be substituted for the Company with the same effect as if it had been named in the Indenture as a party thereof, and thereafter the predecessor Person will be relieved of all obligations and covenants under the Indenture and the Notes.

Although there is a limited body of case law interpreting the phrase "substantially all," there is no precise established definition of the phrase under applicable law. Accordingly, in certain circumstances there may be a degree of uncertainty as to whether a particular transaction would involve "all or substantially all" of the property or assets of a Person.

Notwithstanding the preceding clauses (3) and (4) above and clause (1)(b) below, (x) any Restricted Subsidiary may consolidate with, merge into or transfer all or part of its properties and assets to the Company or another Restricted Subsidiary and (y) the Company may merge with an Affiliate incorporated solely for the purpose of reincorporating the Company in another jurisdiction; provided that, in the case of a Restricted Subsidiary that merges into the Company, the Company will not be required to comply with clause (5) above.

In addition, the Company may not permit any Subsidiary Guarantor to consolidate with or merge with or into any Person (other than another Subsidiary Guarantor) and may not permit the conveyance, transfer or lease of substantially all of the assets of any Subsidiary Guarantor (other than another Subsidiary Guarantor) unless:

(1) (a) the Person formed by the consolidation or into which the Subsidiary Guarantor merged or to which all, or substantially all of the Subsidiary Guarantor's properties and assets are transferred is a corporation, partnership, limited liability company, business trust, trust or other legal entity organized and validly existing under the laws of the United States, any State thereof, or the District of Columbia and such Person (if not such Subsidiary Guarantor) will expressly assume, by supplemental indenture, all the obligations of such Subsidiary Guarantor under its Subsidiary Guarantee; (b) immediately after the transaction and the Incurrence or anticipated Incurrence of any Indebtedness to be Incurred in connection therewith, no Event of Default exists; and (c) the Company will deliver to the Trustee an officers' certificate and an opinion of counsel, each to the effect that the conditions set forth above have been satisfied; and

(2) the transaction is made in compliance with the covenant described under "Limitation on sales of assets and subsidiary stock."

Future subsidiary guarantors

The Company will cause each Restricted Subsidiary (other than a Foreign Subsidiary) created or acquired by the Company or one or more of its Restricted Subsidiaries after the Issue Date to execute and deliver to the Trustee a Subsidiary Guarantee pursuant to which such Subsidiary Guarantor will unconditionally Guarantee, on a joint and several basis, the full and prompt payment of the principal of, premium, if any and interest on the Notes on a senior subordinated basis.

Limitation on lines of business

The Company may not, and may not permit any Restricted Subsidiary to, engage in any business other than the Oil and Gas Business, except to such extent as would not be material to the Company and its Restricted Subsidiaries taken as a whole.

Payments for consent

Neither the Company nor any of its Restricted Subsidiaries will, directly or indirectly, pay or cause to be paid any consideration, whether by way of interest, fees or otherwise, to any holder of any Notes for or as an inducement to any consent, waiver or amendment of any of the terms or provisions of the Indenture or the Notes unless such consideration is offered to be paid or is paid to all holders of the Notes that consent, waive or agree to amend in the time frame set forth in the solicitation documents relating to such consent, waiver or amendment.

Events of default

The following are Events of Default under the Indenture with respect to Notes:

(1) failure to pay principal of or premium, if any, on any Note when due at its Stated Maturity;

(2) failure to pay any interest on any Note when due, which failure continues for 30 calendar days;

(3) failure by the Company or any Subsidiary Guarantor to comply with its obligations under "Certain covenants—Merger and consolidation";

(4) failure by the Company to comply with any of its obligations under the provisions described under "Change of control" above or under the covenants described under "Certain covenants" above (in each case, other than a failure to purchase Notes which will constitute an Event of Default under clause (5) below and other than a failure to comply with "Certain covenants—Merger and consolidation" which is covered by clause (3)), which failure or breach continues for 30 calendar days after written notice thereof has been given to the Company as provided in the Indenture;

(5) failure to redeem or repurchase any Note when required to do so under the terms thereof;

(6) failure to perform, or breach of, any other covenant of the Company in the Indenture (other than a covenant included in the Indenture solely for the benefit of a series of debt securities other than the Notes), which failure or breach continues for 60 calendar days after written notice thereof has been given to the Company as provided in the Indenture;

(7) any nonpayment at maturity or other default (beyond any applicable grace period) under any agreement or instrument relating to any other Indebtedness of the Company or a Significant Subsidiary, the unpaid principal amount of which is not less than $25 million, which default results in the acceleration of the maturity of the Indebtedness prior to its stated maturity or occurs at the final maturity thereof;

(8) specified events of bankruptcy, insolvency, or reorganization involving the Company or a Significant Subsidiary;

(9) failure by the Company or any Significant Subsidiary or group of Restricted Subsidiaries that, taken together (as of the latest audited consolidated financial statements for the Company and its Restricted Subsidiaries), would constitute a Significant Subsidiary to pay final judgments aggregating in excess of $25 million (net of any amounts that a reputable and creditworthy insurance company has acknowledged liability for in writing), which judgments are not paid, discharged or stayed for a period of 60 days; or

(10) any Subsidiary Guarantee of a Significant Subsidiary or group of Subsidiary Guarantors that taken together as of the latest audited consolidated financial statements for the Company and its Restricted Subsidiaries would constitute a Significant Subsidiary ceases to be in full force and effect (except as contemplated by the terms of the Indenture) or is declared null and void in a judicial proceeding or any Subsidiary Guarantor that is a Significant Subsidiary or group of Subsidiary Guarantors that taken together as of the latest audited consolidated financial statements of the Company and its Restricted Subsidiaries would constitute a Significant Subsidiary denies or disaffirms its obligations under the Indenture or its Subsidiary Guarantee.

Pursuant to the Trust Indenture Act, the Trustee is required, within 90 calendar days after the occurrence of a Default in respect of the Notes, to give to the holders of the Notes notice of all uncured Defaults known to it, except that:

- in the case of a Default in the performance of any covenant of the character contemplated in clause (4) above, no notice will be given until at least 30 calendar days after the occurrence of the Default; and
- other than in the case of a Default of the character contemplated in clause (1) or (2) above, the Trustee may withhold notice if and so long as it in good faith determines that the withholding of notice is in the interests of the holders of the Notes.

If an Event of Default described in clause (8) above occurs, the principal of, premium, if any, and accrued interest on the Notes will become immediately due and payable without any declaration or other act on the part of the Trustee or any holder of the Notes. If any other Event of Default with respect to Notes occurs and is continuing, either the Trustee or the holders of at least 25% in principal amount of the Notes may declare the principal amount of all Notes to be due and payable immediately. However, at any time after a declaration of acceleration with respect to the Notes has been made, but before a judgment or decree based on such acceleration has been obtained, the holders of a majority in principal amount of the Notes may, under specified circumstances, rescind and annul such acceleration.

Subject to the duty of the Trustee to act with the required standard of care during an Event of Default, the Trustee will have no obligation to exercise any of its rights or powers under the Indenture at the request or direction of the holders of the Notes, unless holders of the Notes shall have furnished to the Trustee reasonable security or indemnity. Subject to the provisions of the Indenture, including those requiring security or indemnification of the Trustee, the holders of a majority in principal amount of the Notes will have the right to direct the time, method and place of conducting any proceeding for any remedy available to the Trustee, or exercising any trust or power conferred on the Trustee, with respect to the Notes.

No holder of a Note will have any right to institute any proceeding with respect to the Indenture or for any remedy thereunder unless:

- the holder has previously given to the Trustee written notice of a continuing Event of Default;
- the holders of at least 25% in aggregate principal amount of the outstanding Notes have requested the Trustee to institute a proceeding in respect of the Event of Default;
- the holder or holders have furnished reasonable indemnity to the Trustee to institute the proceeding as Trustee;
- the Trustee has not received from the holders of a majority in principal amount of the outstanding Notes a direction inconsistent with the request; and
- the Trustee has failed to institute the proceeding within 60 calendar days.

However, the limitations described above do not apply to a suit instituted by a holder of a Note for enforcement of payment of the principal of and interest on or after the applicable due dates for the payment of such principal and interest.

We are required to furnish to the Trustee annually a statement as to our performance of our obligations under the Indenture and as to any default in our performance.

Modification and waiver

In general, modifications and amendments of the Indenture or the Notes may be made by the Company and the Trustee with the consent of the holders of not less than a majority in principal amount of the Notes. However, no modification or amendment of the Indenture or the Notes may, without the consent of each holder of an outstanding Note affected thereby:

- reduce the principal amount of, the rate of interest on, or the premium, if any, payable upon the redemption or repurchase of, the Notes;
- change the Stated Maturity of, or any installment of principal of, or interest on, the Notes;
- change the time at which any Note may be redeemed or repurchased as described above under “Optional redemption,” “Change of control” or “Certain covenants—Limitation on sales of assets and subsidiary stock”;
- change the place or currency of payment of principal of, or premium, if any, or interest on the Notes;
- impair the right to institute suit for the enforcement of any payment on or with respect to the Notes on or after the Stated Maturity or prepayment date thereof;
- reduce the percentage in principal amount of the Notes required for modification or amendment of the Indenture or the Notes or for waiver of compliance with certain provisions of the Indenture or the Notes or for waiver of certain defaults; or
- modify the Subsidiary Guarantees in any manner adverse to the holders of the Notes.

The holders of at least a majority in principal amount of the Notes may, on behalf of the holders of all of the Notes, waive our compliance with specified covenants of the Indenture. The holders of at least a majority in principal amount of the Notes may, on behalf of the holders of all of the Notes, waive any past default under the Indenture with respect to the Notes, except:

- a default in the payment of the principal of, or premium, if any, or interest on, the Notes; or
- a default of a provision of the Indenture that cannot be modified or amended without the consent of the each holder of the Notes.

No amendment may be made to the subordination provisions of the Indenture that adversely affects the rights of any holder of Senior Indebtedness then outstanding unless the holders of such Senior Indebtedness (or any group or representative thereof authorized to give a consent) consent to such change. In addition, any amendment to the subordination provisions of the Indenture that adversely affects the rights of any holder of the Notes will require the consent of the holders of at least 66 2/3% in aggregate principal amount of the Notes then outstanding.

Defeasance

Upon compliance with the applicable requirements described below, the Company and all of the Subsidiary Guarantors:

(1) will be deemed to have been discharged from their obligations with respect to the Notes and the Guarantees; or

(2) will be released from their obligations to comply with certain covenants in the Indenture with respect to the Notes, and the occurrence of an event described in any of clauses (3), (4), (6), (7), (8) (only as clause (8) applies to a Significant Subsidiary), (9) and (10) under "Events of default" above will no longer be an Event of Default with respect to the Notes except to the limited extent described below.

Following any defeasance described in clause (1) or (2) above, the Company will continue to have specified obligations under the Indenture, including obligations to register the transfer or exchange of Notes; replace destroyed, stolen, lost, or mutilated debt securities of the applicable series; maintain an office or agency in respect of the Notes; and hold funds for payment to holders of Notes in trust. In the case of any defeasance described in clause (2) above, any failure by the Company to comply with its continuing obligations may constitute an Event of Default with respect to the Notes as described in clause (6) under "Events of default" above.

In order to effect any defeasance described in clause (1) or (2) above, the Company must irrevocably deposit with the Trustee, in trust, money or specified government obligations (or depositary receipts therefor) that through the payment of principal and interest in accordance with their terms will provide money in an amount sufficient to pay all of the principal of, premium, if any, and interest on the Notes on the dates such payments are due in accordance with the terms of the Notes. In addition:

- no Event of Default or event which with the giving of notice or lapse of time, or both, would become an Event of Default under the Indenture shall have occurred and be continuing on the date of such deposit;

- no Event of Default described in clause (8) under "Events of default" above or event that with the giving of notice or lapse of time, or both, would become an Event of Default described in such clause (8) shall have occurred and be continuing at any time on or prior to the 90th calendar day following the date of deposit;

- in the event of any defeasance described in clause (1) above, the Company shall have delivered an opinion of counsel, stating that (a) the Company has received from, or there has been published by, the IRS a ruling or (b) there has been a change in applicable federal law, in either case to the effect that, among other things, the holders of the Notes will not recognize gain or loss for United States federal income tax purposes as a result of such deposit or defeasance and will be subject to United States federal income tax in the same manner as if such defeasance had not occurred;

- in the event of any defeasance described in clause (2) above, the Company shall have delivered an opinion of counsel to the effect that, among other things, the holders of the Notes will not recognize gain or loss for United States federal income tax purposes as a result of such deposit or defeasance and will be subject to United States federal income tax in the same manner as if such defeasance had not occurred;

- the Company shall have delivered to the Trustee a certificate from a nationally recognized firm of independent accountants or other Person acceptable to the Trustee expressing their opinion that the payments of principal and interest when due and without reinvestment on the deposited U.S. Government Obligations plus any deposited money without investment will provide the case at such times and in such amounts as will be sufficient to pay the principal of and any premium and interest when due on the Notes on the Stated Maturity of the Notes or on any earlier date on which the Notes shall be subject to redemption; and

- such defeasance must not result in a breach or violation of, or constitute a default under, any other agreement to which the Company is a party.

If the Company fails to comply with its remaining obligations under the Indenture with respect to the Notes following a defeasance described in clause (2) above and the Notes are declared due and payable because of the occurrence of any undefeased Event of Default, the amount of money and government obligations on deposit with the Trustee may be insufficient to pay amounts due on the Notes at the time of the acceleration resulting from such Event of Default. However, the Company will remain liable in respect of such payments.

No personal liability of directors, officers, employees and stockholders

No director, officer, employee, incorporator or stockholder of the Company or any Subsidiary Guarantor, as such, shall have any liability for any obligations of the Company or any Subsidiary Guarantor under the Notes, the Indenture or the Subsidiary Guarantees or for any claim based on, in respect of, or by reason of, such obligations or their creation. Each holder by accepting a Note waives and releases all such liability. The waiver and release are part of the consideration for issuance of the Notes. Such waiver may not be effective to waive liabilities under the federal securities laws and it is the view of the SEC that such a waiver is against public policy.

Concerning the trustee

Wilmington Trust FSB is the Trustee under the Indenture and has been appointed by the Company as registrar and paying agent with regard to the Notes.

Governing law

The Indenture provides that it and the Notes will be governed by, and construed in accordance with, the laws of the State of New York.

Certain definitions

"Acquired Indebtedness" means Indebtedness (i) of a Person or any of its Subsidiaries existing at the time such Person becomes or is merged with and into a Restricted Subsidiary or (ii) assumed in connection with the acquisition of assets from such Person, in each case whether or not Incurred by such Person in connection with, or in anticipation or contemplation of, such Person becoming a Restricted Subsidiary or such acquisition. Acquired Indebtedness shall be deemed to have been Incurred, with respect to clause (i) of the preceding sentence, on the date such Person becomes or is merged with and into a Restricted Subsidiary and, with respect to clause (ii) of the preceding sentence, on the date of consummation of such acquisition of assets.

"Additional Assets" means:

(1) any property or assets (other than Indebtedness and Capital Stock) to be used by the Company or a Restricted Subsidiary in the Oil and Gas Business;

(2) capital expenditures by the Company or a Restricted Subsidiary in the Oil and Gas Business;

(3) the Capital Stock of a Person that becomes a Restricted Subsidiary as a result of the acquisition of such Capital Stock by the Company or a Restricted Subsidiary; or

(4) Capital Stock constituting a minority interest in any Person that at such time is a Restricted Subsidiary;

provided, however, that, in the case of clauses (3) and (4), such Restricted Subsidiary is primarily engaged in the Oil and Gas Business.

"Adjusted Consolidated Net Tangible Assets" means (without duplication), as of the date of determination, the remainder of:

(a) the sum of:

(i) estimated discounted future net revenues from proved oil and gas reserves of the Company and its Restricted Subsidiaries calculated in accordance with SEC guidelines before any provincial, territorial, state, federal or foreign income taxes, as estimated by the Company in a reserve report prepared as of the end of the Company's most recently completed fiscal year for which audited financial statements are available, as increased by, as of the date of determination, the estimated discounted future net revenues from

(A) estimated proved oil and gas reserves acquired since such year end, which reserves were not reflected in such year end reserve report, and

(B) estimated oil and gas reserves attributable to upward revisions of estimates of proved oil and gas reserves since such year end due to exploration, development, exploitation or other activities, in each case calculated in accordance with SEC guidelines (utilizing the prices for the fiscal quarter ending prior to the date of determination),

and decreased by, as of the date of determination, the estimated discounted future net revenues from

(C) estimated proved oil and gas reserves included therein that shall have been produced or disposed of since such year end, and

(D) estimated oil and gas reserves included therein that are subsequently removed from the proved oil and gas reserves of the Company and its Restricted Subsidiaries as so calculated due to downward revisions of estimates of proved oil and gas reserves since such year end due to changes in geological conditions or other factors which would, in accordance with standard industry practice, cause such revisions, in each case calculated on a pre-tax basis and substantially in accordance with SEC guidelines (utilizing the prices for the fiscal quarter ending prior to the date of determination), in each case as estimated by the Company's petroleum engineers or any independent petroleum engineers engaged by the Company for that purpose;

(ii) the capitalized costs that are attributable to oil and gas properties of the Company and its Restricted Subsidiaries to which no proved oil and gas reserves are attributable, based on the Company's books and records as of a date no earlier than the date of the Company's latest available consolidated annual or quarterly financial statements;

(iii) the Net Working Capital on a date no earlier than the date of the Company's latest annual or quarterly consolidated financial statements; and

(iv) the greater of

(A) the net book value of other tangible assets of the Company and its Restricted Subsidiaries, as of a date no earlier than the date of the Company's latest annual or quarterly consolidated financial statement, and

(B) the appraised value, as estimated by independent appraisers, of other tangible assets of the Company and its Restricted Subsidiaries, as of a date no earlier than the date of the Company's latest audited financial statements (provided that the Company shall not be required to obtain any appraisal of any assets); minus

(b) the sum of:

(i) any amount included in (a)(i) through (a)(iv) above that is attributable to Minority Interests;

(ii) any net gas balancing liabilities of the Company and its Restricted Subsidiaries reflected in the Company's latest audited consolidated financial statements;

(iii) to the extent included in (a)(i) above, the estimated discounted future net revenues, calculated in accordance with SEC guidelines (utilizing the prices utilized in the Company's year end reserve report), attributable to reserves which are required to be delivered to third parties to fully satisfy the obligations of the Company and its Restricted Subsidiaries with respect to Volumetric Production Payments (determined, if applicable, using the schedules specified with respect thereto); and

(iv) to the extent included in (a)(i) above, the estimated discounted future net revenues, calculated in accordance with SEC guidelines, attributable to reserves subject to Dollar-Denominated Production Payments which, based on the estimates of production and price assumptions included in determining the estimated discounted future net revenues specified in (a)(i) above, would be necessary to fully satisfy the payment obligations of the Company and its Restricted Subsidiaries with respect to Dollar-Denominated Production Payments (determined, if applicable, using the schedules specified with respect thereto).

"Affiliate" of any specified Person means any other Person, that directly or indirectly, is in Control of, is Controlled by, or is under common Control with, such Person.

"Asset Disposition" means any direct or indirect sale, lease (other than an operating lease entered into in the ordinary course of the Oil and Gas Business), transfer, issuance or other disposition, or a series of related sales, leases, transfers, issuances or dispositions that are part of a common plan, of shares of Capital Stock of a Subsidiary (other than directors' qualifying shares), property or other assets (each referred to for the purposes of this definition as a "disposition") by the Company or any of its Restricted Subsidiaries, in each case outside the ordinary course of business including any disposition by means of a merger, consolidation or similar transaction.

Notwithstanding the preceding, the following items shall not be deemed to be Asset Dispositions:

(1) a disposition by a Restricted Subsidiary to the Company or by the Company or a Restricted Subsidiary to a Restricted Subsidiary;

(2) the disposition of cash or Cash Equivalents in the ordinary course of business;

(3) a disposition of Hydrocarbons or mineral products in the ordinary course of the Oil and Gas Business;

(4) a disposition of obsolete or worn out equipment or equipment that is no longer useful in the conduct of the business of the Company and its Restricted Subsidiaries and that is disposed of in each case in the ordinary course of business;

(5) transactions permitted by the covenant described under "Certain covenants—Merger and consolidation;"

(6) an issuance of Capital Stock by a Restricted Subsidiary to the Company or to a Wholly-Owned Subsidiary;

(7) for purposes of the covenant described under "Certain covenants—Limitation on sales of assets and subsidiary stock" only, the making of a Permitted Investment or a disposition subject to the covenant described under "Certain covenants—Limitation on restricted payments;"

(8) dispositions of assets with an aggregate fair market value since the Issue Date of less than $10 million;

(9) dispositions in connection with the creation, Incumbrance or existence of Permitted Liens or the exercise of any rights or remedies with respect thereof;

(10) dispositions of receivables in connection with the compromise, settlement or collection thereof in the ordinary course of business or in bankruptcy or similar proceedings and exclusive of factoring or similar arrangements;

(11) the licensing or sublicensing of intellectual property or other general intangibles and licenses, leases or subleases of other property in the ordinary course of business and which do not materially interfere with the business of the Company and its Restricted Subsidiaries;

(12) any Production Payments and Reserve Sales, provided that any such Production Payments and Reserve Sales, other than incentive compensation programs on terms that are reasonably customary in the Oil and Gas Business for geologists, geophysicists and other providers of technical services to the Company or a Restricted Subsidiary, shall have been created, Incurred, issued, assumed or Guaranteed in connection with the acquisition or financing of, and no later than 60 days after the acquisition of, the property that is subject thereto;

(13) the sale or transfer (whether or not in the ordinary course of the Oil and Gas Business) of oil and/or gas properties or direct or indirect interests in real property; provided, that at the time of such sale or transfer such properties do not have associated with them any proved reserves capable of being produced in material economic quantities;

(14) the abandonment, farm-out, exchange, lease or sublease of developed or undeveloped oil and/or gas properties or interests therein in the ordinary course of business or in exchange for oil and/or gas properties or interests therein owned or held by another Person;

(15) an Asset Swap effected in compliance with the covenant described under "Certain covenants—Limitation on sales of assets and subsidiary stock;"

(16) a disposition of oil and natural gas properties in connection with tax credit transactions complying with Section 29 or any successor or analogous provisions of the Code;

(17) surrender or waiver of contract rights, oil and gas leases, or the settlement, release or surrender of contract, tort or other claims of any kind; and

(18) Permitted Liens.

"Asset Swap" means a substantially concurrent purchase and sale or exchange of oil and gas properties or interests therein or other assets or properties used or useful in the Oil and Gas Business, including Capital Stock of any Person who holds any such properties, interests or assets, between the Company or any of its Restricted Subsidiaries and another Person; provided that any cash received must be applied in accordance with "Limitation on sales of assets and subsidiary stock."

"Attributable Indebtedness" in respect of a Sale/ Leaseback Transaction means, as at the time of determination, the present value (discounted at the interest rate borne by the Notes, compounded semi-annually) of the total obligations of the lessee for rental payments during the remaining term of the lease included in such Sale/ Leaseback Transaction (including any period for which such lease has been extended).

"Average Life" means, as of the date of determination, with respect to any Indebtedness or Preferred Stock, the quotient obtained by dividing (1) the sum of the products of the numbers of years from the date of determination to the dates of each successive scheduled principal payment of such Indebtedness or redemption or similar payment with respect to such Preferred Stock multiplied by the amount of such payment by (2) the sum of all such payments.

"Bank Indebtedness" means any and all amounts, whether outstanding on the Issue Date or Incurred after the Issue Date, payable by the Company under or in respect of a Credit Facility, including the Senior Credit Agreement, and any related notes, collateral documents, letters of credit and guarantees and any Interest Rate Agreement entered into in connection with the Credit Facility, including principal, premium, if any, interest (including interest accruing on or after the filing of any petition in bankruptcy or for reorganization relating to the Company at the rate specified therein, whether or not a claim for post-filing interest is allowed in such proceedings), fees, charges, expenses, reimbursement obligations, guarantees and all other amounts payable thereunder or in respect thereof.

"Board of Directors" means, as to any Person, the board of directors of such Person or a duly authorized committee of such board of directors.

"Capital Lease" means, with respect to any Person, any lease of property (whether real, personal, or mixed) by such Person or its Subsidiaries as lessee that would be capitalized on a balance sheet of such Person or its Subsidiaries prepared in conformity with GAAP, other than, in the case of such Person or its Subsidiaries, any such lease under which such Person or any of its Subsidiaries is the lessor.

"Capital Lease Obligations" means, with respect to any Person, the capitalized amount of all obligations of such Person and its Subsidiaries under Capital Leases, as determined on a consolidated basis in conformity with GAAP.

"Capital Stock" of any Person means any and all shares, interests, rights to purchase, warrants, options, participation or other equivalents of or interests in (however designated) equity of such Person, including any Preferred Stock, but excluding any debt securities convertible into such equity.

"Cash Equivalents" means:

(1) securities issued or directly and fully guaranteed or insured by the United States Government or any agency or instrumentality of the United States (provided that the full faith and credit of the United States is pledged in support thereof), having a maturity within one year after the date of acquisition thereof;

(2) marketable general obligations issued by any state of the United States of America or any political subdivision of any such state or any public instrumentality thereof maturing within one year after the date of acquisition thereof and, at the time of such acquisition, having a credit rating of at least "A" or the equivalent thereof from either Standard & Poor's Ratings Services or Moody's Investors Service, Inc. (or an equivalent rating by another nationally recognized rating agency if both of the two named rating agencies cease publishing ratings of investments);

(3) certificates of deposit, time deposits, eurodollar time deposits, overnight bank deposits or bankers' acceptances having maturities of not more than one year after the date of acquisition thereof issued

by any commercial bank the long-term debt of which is rated at the time of acquisition at least "A" or the equivalent thereof by Standard & Poor's Ratings Services, or "A" or the equivalent thereof by Moody's Investors Service, Inc. (or an equivalent rating by another nationally recognized rating agency if both of the two named rating agencies cease publishing ratings of investments), and having combined capital and surplus in excess of $500 million;

(4) repurchase obligations with a term of not more than seven days for underlying securities of the types described in clauses (1), (2) and (3) entered into with any bank meeting the qualifications specified in clause (3) above;

(5) commercial paper rated at the time of acquisition thereof at least "A-2" or the equivalent thereof by Standard & Poor's Ratings Services or "P-2" or the equivalent thereof by Moody's Investors Service, Inc. (or an equivalent rating by another nationally recognized rating agency if both of the two named rating agencies cease publishing ratings of investments), and in any case maturing within one year after the date of acquisition thereof; and

(6) interests in any investment company or money market fund which invests 95% or more of its assets in instruments of the type specified in clauses (1) through (5) above.

"Change of Control" means:

(1) Any "person" or "group" of related persons (as such terms are used in Sections 13(d) and 14(d) of the Exchange Act) is or becomes the beneficial owner (as defined in Rules 13d-3 and 13d-5 under the Exchange Act, except that such person or group shall be deemed to have "beneficial ownership" of all shares that such person or group has the right to acquire, whether such right is exercisable immediately or only after the passage of time), directly or indirectly, of more than 50% of the total voting power of the Voting Stock of the Company (or its successor by merger, consolidation or purchase of all or substantially all of its assets) (for the purposes of this clause, such person or group shall be deemed to beneficially own any Voting Stock of the Company held by a parent entity of the Company, if such person or group "beneficially owns" (as defined above), directly or indirectly, more than 50% of the voting power of the Voting Stock of such parent entity); or

(2) the first day on which a majority of the members of the Board of Directors of the Company are not Continuing Directors; or

(3) the sale, lease, transfer, conveyance or other disposition (other than by way of merger or consolidation), in one or a series of related transactions, of all or substantially all of the assets of the Company and its Restricted Subsidiaries taken as a whole to any "person" (as such term is used in Sections 13(d) and 14(d) of the Exchange Act); or

(4) the adoption by the stockholders of the Company of a plan or proposal for the liquidation or dissolution of the Company.

"Commodity Agreements" means, in respect of any Person, any futures contract, forward contract, commodity swap agreement, commodity option agreement or other similar agreement or arrangement in respect of Hydrocarbons purchased, used, produced, processed or sold by such Person and designed to protect such Person against fluctuations in Hydrocarbon prices.

"Common Stock" means with respect to any Person, any and all shares, interests or other participations in, and other equivalents (however designated and whether voting or nonvoting) of such Person's common stock whether or not outstanding on the Issue Date, and includes, without limitation, all series and classes of such common stock.

"Consolidated Coverage Ratio" means as of any date of determination, the ratio of (x) the aggregate amount of Consolidated EBITDA for the period of the most recent four consecutive fiscal quarters ending prior to the date of such determination for which consolidated financial statements of the Company are in existence to (y) Consolidated Interest Expense for such four fiscal quarters; provided, however, that:

(1) if the Company or any Restricted Subsidiary:

(a) has Incurred any Indebtedness since the beginning of such period that remains outstanding on such date of determination or if the transaction giving rise to the need to calculate the Consolidated Coverage Ratio is an Incurrence of Indebtedness, Consolidated EBITDA and Consolidated Interest Expense for such period will be calculated after giving effect on a pro forma basis to such Indebtedness as if such Indebtedness had been Incurred on the first day of such period (except that in making such computation, the amount of Indebtedness under any revolving credit facility outstanding on the date of such calculation will be deemed to be (i) the average daily balance of such Indebtedness during such four fiscal quarters or such shorter period for which such facility was outstanding or (ii) if such facility was created after the end of such four fiscal quarters, the average daily balance of such Indebtedness during the period from the date of creation of such facility to the date of such calculation) and the discharge of any other Indebtedness repaid, repurchased, defeased or otherwise discharged with the proceeds of such new Indebtedness as if such discharge had occurred on the first day of such period; or

(b) has repaid, repurchased, defeased or otherwise discharged any Indebtedness since the beginning of the period that is no longer outstanding on such date of determination or if the transaction giving rise to the need to calculate the Consolidated Coverage Ratio involves a discharge of Indebtedness (in each case other than Indebtedness Incurred under any revolving credit facility unless such Indebtedness has been permanently repaid and the related commitment terminated), Consolidated EBITDA and Consolidated Interest Expense for such period will be calculated after giving effect on a pro forma basis to such discharge of such Indebtedness, including with the proceeds of such new Indebtedness, as if such discharge had occurred on the first day of such period;

(2) if since the beginning of such period the Company or any Restricted Subsidiary shall have made any Asset Disposition or the transaction giving rise to the need to calculate the Consolidated Coverage Ratio is such an Asset Disposition:

(a) the Consolidated EBITDA for such period will be reduced by an amount equal to the Consolidated EBITDA (if positive) directly attributable to the assets which are the subject of such Asset Disposition for such period or increased by an amount equal to the absolute value of the Consolidated EBITDA (if negative) directly attributable thereto for such period; and

(b) Consolidated Interest Expense for such period will be reduced by an amount equal to the Consolidated Interest Expense directly attributable to any Indebtedness of the Company or any Restricted Subsidiary repaid, repurchased, defeased or otherwise discharged with respect to the Company and its continuing Restricted Subsidiaries in connection with such Asset Disposition for such period (or, if the Capital Stock of any Restricted Subsidiary is sold, the Consolidated Interest Expense for such period directly attributable to the Indebtedness of such Restricted Subsidiary to the extent the Company and its continuing Restricted Subsidiaries are no longer liable for such Indebtedness after such sale);

(3) if since the beginning of such period the Company or any Restricted Subsidiary (by merger or otherwise) shall have made an Investment in any Restricted Subsidiary (or any Person which becomes a Restricted Subsidiary or is merged with or into the Company or a Restricted Subsidiary)

or an acquisition of assets, including any acquisition of assets occurring in connection with a transaction giving rise to the need to calculate the Consolidated Coverage Ratio, which constitutes all or substantially all of a company, division, operating unit, segment, business, group of related assets or line of business, Consolidated EBITDA and Consolidated Interest Expense for such period will be calculated after giving pro forma effect thereto (including the Incurrence of any Indebtedness) as if such Investment or acquisition occurred on the first day of such period; and

(4) if since the beginning of such period any Person that subsequently became a Restricted Subsidiary or was merged with or into the Company or any Restricted Subsidiary since the beginning of such period shall have Incurred any Indebtedness or discharged any Indebtedness, made any Asset Disposition or any Investment or acquisition of assets that would have required an adjustment pursuant to clause (2) or (3) above if made by the Company or a Restricted Subsidiary during such period, Consolidated EBITDA and Consolidated Interest Expense for such period will be calculated after giving pro forma effect thereto as if such Asset Disposition or Investment or acquisition of assets occurred on the first day of such period.

For purposes of this definition, whenever pro forma effect is to be given to any calculation under this definition, the pro forma calculations will be determined in good faith by a responsible financial or accounting officer of the Company (including pro forma expense and cost reductions calculated on a basis consistent with Regulation S-X under the Securities Act). If any Indebtedness bears a floating rate of interest and is being given pro forma effect, the interest expense on such Indebtedness will be calculated as if the rate in effect on the date of determination had been the applicable rate for the entire period (taking into account any Interest Rate Agreement applicable to such Indebtedness but if the remaining term of such Interest Rate Agreement is less than 12 months, then such Interest Rate Agreement shall only be taken into account for that portion of the period equal to the remaining term thereof). If any Indebtedness that is being given pro forma effect bears an interest rate at the option of the Company, the interest rate shall be calculated by applying such optional rate chosen by the Company.

"Consolidated EBITDA" for any period means, without duplication, the Consolidated Net Income for such period, plus the following to the extent deducted in calculating such Consolidated Net Income:

(1) Consolidated Interest Expense;

(2) Consolidated Income Taxes;

(3) consolidated depletion, depreciation and amortization expenses;

(4) consolidated impairment charges recorded in connection with the application of GAAP codification of Accounting Standards (ASC) 350 "Goodwill and Other Intangibles" and ASC 360 "Accounting for the Impairment or Disposal of Long Lived Assets;"

(5) consolidated exploration expenses, if applicable;

(6) (a) any write-off of deferred financing costs, (b) any capitalized interest, and (c) the interest portion of any deferred payment obligations; and

(7) other consolidated non-cash charges reducing Consolidated Net Income (excluding any such non-cash charge to the extent it represents an accrual of or reserve for cash charges in any future period or amortization of a prepaid cash expense that was paid in a prior period not included in the calculation);

less, to the extent included in calculating such Consolidated Net Income and in excess of any costs or expenses attributable thereto that were deducted in calculating such Consolidated Net Income, the sum of (x) the amount of deferred revenues that are amortized during such period and are attributable to reserves that are subject to Volumetric Production Payments, and (y) amounts recorded in accordance with GAAP as repayments of principal and interest pursuant to Dollar-Denominated Production Payments.

Notwithstanding the preceding sentence, the items described in clauses (2) through (6) relating to amounts of a Restricted Subsidiary of a Person will be added to Consolidated Net Income to compute Consolidated EBITDA of such Person only to the extent (and in the same proportion) that the net income (loss) of such Restricted Subsidiary was included in calculating the Consolidated Net Income of such Person and, to the extent the amounts set forth in clauses (2) through (6) are in excess of those necessary to offset a net loss of such Restricted Subsidiary or if such Restricted Subsidiary has net income for such period included in Consolidated Net Income, only if a corresponding amount would not be prohibited at the date of determination to be dividended to the Company by such Restricted Subsidiary pursuant to the terms of its charter and all agreements, instruments, judgments, decrees, orders, statutes, rules and governmental regulations applicable to that Restricted Subsidiary or its stockholders, except for restrictions under any Credit Facility.

"Consolidated Income Taxes" means, with respect to any Person for any period, taxes imposed upon such Person or other payments required to be made by such Person by any governmental authority which taxes or other payments are (x) calculated by reference to the income or profits of such Person or such Person and its Subsidiaries, or (y) any franchise taxes or equity taxes (in each case to the extent included in computing Consolidated Net Income for such period), regardless of whether such taxes or payments are required to be remitted to any governmental authority.

"Consolidated Interest Expense" means, for any period, the consolidated interest expense of the Company and its consolidated Restricted Subsidiaries, whether paid or accrued, plus, to the extent not included in such interest expense:

(1) interest expense attributable to Capital Lease Obligations and the interest portion of rent expense associated with Attributable Indebtedness in respect of the relevant lease giving rise thereto, determined as if such lease were a Capital Lease in accordance with GAAP and the interest component of any deferred payment obligations;

(2) amortization of debt discount and debt issuance cost (provided that any amortization of bond premium will be credited to reduce Consolidated Interest Expense unless, pursuant to GAAP, such amortization of bond premium has otherwise reduced Consolidated Interest Expense);

(3) non-cash interest expense;

(4) commissions, discounts and other fees and charges owed with respect to letters of credit and bankers' acceptance financing;

(5) the interest expense on Indebtedness of another Person that is Guaranteed by such Person or one of its Restricted Subsidiaries or secured by a Lien on assets of such Person or one of its Restricted Subsidiaries;

(6) costs associated with Hedging Obligations (including amortization of fees) provided, however, that if Hedging Obligations result in net benefits rather than costs, such net benefits shall be credited to reduce Consolidated Interest Expense unless, pursuant to GAAP, such net benefits are otherwise reflected in Consolidated Net Income;

(7) the consolidated interest expense of such Person and its Restricted Subsidiaries that was capitalized during such period;

(8) the product of (a) all dividends paid or payable, in cash, Cash Equivalents or Indebtedness or accrued during such period on any series of Disqualified Stock of such Person or on Preferred Stock of its Restricted Subsidiaries payable to a party other than the Company or a Wholly-Owned Subsidiary, times (b) a fraction, the numerator of which is one and the denominator of which is one minus the then current combined federal, state, provincial and local statutory tax rate of such Person, expressed as a decimal, in each case, on a consolidated basis and in accordance with GAAP;

(9) Receivables Fees; and

(10) the cash contributions to any employee stock ownership plan or similar trust to the extent such contributions are used by such plan or trust to pay interest or fees to any Person (other than the Company) in connection with Indebtedness Incurred by such plan or trust.

For the purpose of calculating the Consolidated Coverage Ratio in connection with the Incurrence of any Indebtedness described in the final paragraph of the definition of "Indebtedness," the calculation of Consolidated Interest Expense shall include all interest expense (including any amounts described in clauses (1) through (10) above) relating to any Indebtedness of the Company or any Restricted Subsidiary described in the final paragraph of the definition of "Indebtedness."

For purposes of the foregoing, total interest expense will be determined (i) after giving effect to any net payments made or received by the Company and its Subsidiaries with respect to Interest Rate Agreements and (ii) exclusive of amounts classified as other comprehensive income in the balance sheet of the Company. Notwithstanding anything to the contrary contained herein, commissions, discounts, yield and other fees and charges Incurred in connection with any transaction pursuant to which the Company or its Restricted Subsidiaries may sell, convey or otherwise transfer or grant a security interest in any accounts receivable or related assets shall be included in Consolidated Interest Expense.

"Consolidated Leverage Ratio" means, as of any date of determination, the ratio of total Indebtedness of the Company and its consolidated Restricted Subsidiaries as of that date to the Company's Consolidated EBITDA for the four full fiscal quarters immediately preceding the determination date, with such adjustments to the amount of Indebtedness and Consolidated EBITDA as are consistent with the adjustment provisions set forth in the definition of "Consolidated Coverage Ratio".

"Consolidated Net Income" means, for any period, the net consolidated income (loss) of the Company and its consolidated Subsidiaries determined in accordance with GAAP; provided, however, that there will not be included in such Consolidated Net Income:

(1) any net income (loss) of any Person (other than the Company) if such Person is not a Restricted Subsidiary, except that:

(a) subject to the limitations contained in clauses (3), (4) and (5) below, the Company's equity in the net income of any such Person for such period will be included in such Consolidated Net Income up to the aggregate amount of cash actually distributed by such Person during such period to the Company or a Restricted Subsidiary as a dividend or other distribution (subject, in the case of a dividend or other distribution to a Restricted Subsidiary, to the limitations contained in clause (2) below); and

(b) the Company's equity in a net loss of any such Person (other than an Unrestricted Subsidiary) for such period will be included in determining such Consolidated Net Income to the extent such loss has been funded with cash from the Company or a Restricted Subsidiary;

(2) any net income (but not loss) of any Restricted Subsidiary if such Subsidiary is subject to restrictions, directly or indirectly, on the payment of dividends or the making of distributions by such Restricted Subsidiary, directly or indirectly, to the Company, except that:

(a) subject to the limitations contained in clauses (3), (4) and (5) below, the Company's equity in the net income of any such Restricted Subsidiary for such period will be included in such Consolidated Net Income up to the aggregate amount of cash that could have been distributed by such Restricted Subsidiary during such period to the Company or another Restricted Subsidiary as a dividend (subject, in the case of a dividend to another Restricted Subsidiary, to the limitation contained in this clause; and

(b) the Company's equity in a net loss of any such Restricted Subsidiary for such period will be included in determining such Consolidated Net Income;

(3) any after tax gain (loss) realized upon the sale or other disposition of any property, plant or equipment of the Company or its consolidated Restricted Subsidiaries (including pursuant to any Sale/ Leaseback Transaction) which is not sold or otherwise disposed of in the ordinary course of business and any gain (loss) realized upon the sale or other disposition of any Capital Stock of any Person;

(4) any after tax extraordinary gain or loss, along with any related provisions for taxes on such gain or loss and all related fees and expenses;

(5) the cumulative effect of a change in accounting principles;

(6) any asset impairment writedowns on Oil and Gas Properties under GAAP or SEC guidelines;

(7) any consolidated impairment charges recorded in connection with the application of ASC 350 "Goodwill and Other Intangibles;"

(8) any unrealized non-cash gains or losses on charges in respect of Hedging Obligations (including those resulting from the application of ASC 815);

(9) income or loss attributable to discontinued operations (including, without limitation. operations disposed of during such period whether or not such operations were classified as discontinued);

(10) all deferred financing costs written off, and premiums paid, in connection with any early extinguishment of Indebtedness; and

(11) any non-cash compensation charge arising from any grant of stock, stock options or other equity based awards; provided that the proceeds resulting from any such grant will be excluded from clause (c)(ii) of the first paragraph of the covenant described under "—Limitation on Restricted Payments."

"Continuing Directors" means the individuals who, as of the Issue Date, are directors of the Company and any individual becoming a director of the Company subsequent to the Issue Date whose election, nomination for election by the Company's stockholders or appointment, was approved by a majority of the then Continuing Directors (either by a specific vote or by approval of the proxy statement of the Company in which such individual is named as a nominee for election as a director, without objection to such nomination).

"Control" of a Person means the power to direct the management and policies of such Person, directly or indirectly, whether through the ownership of voting securities, by contract or otherwise; and the terms "Controlling" and "Controlled" have meanings correlative of the foregoing.

"Credit Facility" means, with respect to the Company or any Subsidiary Guarantor, one or more credit facilities (including, without limitation, the Senior Credit Agreement) or commercial paper facilities providing for revolving credit loans, term loans, receivables financing (including through the sale of receivables to such lenders or to special purpose entities formed to borrow from such lenders against such receivables) or letters of credit, in each case, as amended, restated, modified, renewed, refunded, replaced or refinanced in whole or in part from time to time (including successive amendments, restatements, modifications, renewals, refunds, replacements or refinancings and whether or not with the original administrative agent and lenders or another administrative agent or agents or other lenders and whether provided under the original Senior Credit Agreement or any other credit or other agreement or indenture).

"Currency Agreement" means in respect of a Person any foreign exchange contract, currency swap agreement, futures contract, option contract or other similar agreement as to which such Person is a party or a beneficiary.

"Default" means any event which, with notice or passage of time or both, would constitute an Event of Default.

"Designated Senior Indebtedness" means (1) the Bank Indebtedness (to the extent such Bank Indebtedness constitutes Senior Indebtedness), including the Senior Credit Agreement, and (2) any other Senior Indebtedness which, at the date of determination, has an aggregate principal amount outstanding of, or under which, at the date of determination, the holders thereof are committed to lend up to, at least $25 million and is specifically designated in the instrument evidencing or governing such Senior Indebtedness as "Designated Senior Indebtedness" for purposes of the Indenture.

"Disqualified Stock" means, with respect to any Person, any Capital Stock of such Person which by its terms (or by the terms of any security into which it is convertible or for which it is exchangeable) or upon the happening of any event:

(1) matures or is mandatorily redeemable pursuant to a sinking fund obligation or otherwise;

(2) is convertible or exchangeable for Indebtedness or Disqualified Stock (excluding Capital Stock which is convertible or exchangeable solely at the option of the Company or a Restricted Subsidiary); or

(3) is redeemable at the option of the holder of the Capital Stock in whole or in part, in each case on or prior to the date that is 91 days after the earlier of the date (a) of the Stated Maturity of the Notes or (b) the first date after the Issue Date on which there are no Notes outstanding, provided that only the portion of Capital Stock which so matures or is mandatorily redeemable, is so convertible or exchangeable or is so redeemable at the option of the holder thereof prior to such date will be deemed to be Disqualified Stock; provided, further that any Capital Stock that would constitute Disqualified Stock solely because the holders thereof have the right to require the Company to repurchase such Capital Stock upon the occurrence of a change of control or asset disposition (each defined in a substantially identical manner to the corresponding definitions in the Indenture) shall not constitute Disqualified Stock if the terms of such Capital Stock (and all such securities into which it is convertible or for which it is ratable or exchangeable) provide that the Company may not repurchase or redeem any such Capital Stock (and all such securities into which it is convertible or for which it is ratable or exchangeable) pursuant to such provision prior to compliance by the Company with the provisions of the Indenture described under the captions "Change of control" and "Limitation on sales of assets and subsidiary stock" and such repurchase or redemption complies with "Certain covenants—Restricted payments."

"Dollar-Denominated Production Payments" means production payment obligations recorded as liabilities in accordance with GAAP, together with all undertakings and obligations in connection therewith.

"Domestic Subsidiary" means any Restricted Subsidiary that is organized under the laws of the United States of America or any state thereof or the District of Columbia.

"Foreign Subsidiary" means any Restricted Subsidiary that is not organized under the laws of the United States of America or any state thereof or the District of Columbia and any Subsidiary of such Restricted Subsidiary.

"GAAP" means generally accepted accounting principles in the United States which are in effect from time to time. At any time after the Issue Date, the Company may elect to apply International Financial Reporting Standards ("IFRS") accounting principles in lieu of GAAP and, upon any such election, references herein to GAAP shall thereafter be construed to mean IFRS from time to time; provided that any such election, once made, shall be irrevocable; provided, further, that any calculation or determination in the Indenture that requires the application of GAAP for periods that include fiscal quarters ended prior to the Company's election to apply IFRS shall remain as previously calculated or determined in accordance with GAAP. The Company shall give notice of any such election made in accordance with this definition to the Trustee.

"Guarantee" means any obligation, contingent or otherwise, of any Person directly or indirectly guaranteeing any Indebtedness of any other Person and any obligation, direct or indirect, contingent or otherwise, of such Person:

(1) to purchase or pay (or advance or supply funds for the purchase or payment of) such Indebtedness of such other Person (whether arising by virtue of partnership arrangements, or by agreement to keep-well, to purchase assets, goods, securities or services, to take-or-pay, or to maintain financial statement conditions or otherwise); or

(2) entered into for purposes of assuring in any other manner the obligee of such Indebtedness of the payment thereof or to protect such obligee against loss in respect thereof (in whole or in part);

provided, *however*, that the term "Guarantee" will not include endorsements for collection or deposit in the ordinary course of business. The term "Guarantee" used as a verb has a corresponding meaning.

"Guarantor Senior Indebtedness" means, with respect to a Subsidiary Guarantor, the following obligations, whether outstanding on the Issue Date or thereafter issued, without duplication:

(1) any Guarantee of the Bank Indebtedness by such Subsidiary Guarantor and all other Guarantees by such Subsidiary Guarantor of Senior Indebtedness of the Company or Guarantor Senior Indebtedness of any other Subsidiary Guarantor; and

(2) all obligations consisting of principal of and premium, if any, accrued and unpaid interest on, and fees and other amounts relating to, all other Indebtedness of the Subsidiary Guarantor. Guarantor Senior Indebtedness includes interest accruing on or after the filing of any petition in bankruptcy or for reorganization relating to the Subsidiary Guarantor regardless of whether post-filing interest is allowed in such proceeding.

Notwithstanding anything to the contrary in the preceding paragraph, Guarantor Senior Indebtedness will not include:

(1) any Indebtedness Incurred in violation of the Indenture;

(2) any obligations of such Subsidiary Guarantor to the Company or another Subsidiary;

(3) any liability for federal, state, local, foreign or other taxes owed or owing by such Subsidiary Guarantor;

(4) any accounts payable or other liability to trade creditors arising in the ordinary course of business (including Guarantees thereof or instruments evidencing such liabilities);

(5) any Indebtedness, Guarantee or obligation of such Subsidiary Guarantor that is expressly subordinate or junior in right of payment to any other Indebtedness, Guarantee or obligation of such Subsidiary Guarantor, including, without limitation, any Guarantor Senior Subordinated Indebtedness and Guarantor Subordinated Obligations of such Guarantor; or

(6) any Capital Stock.

"Guarantor Senior Subordinated Indebtedness" means, with respect to a Subsidiary Guarantor, the obligations of such Subsidiary Guarantor under the Subsidiary Guarantee and any other Indebtedness of such Subsidiary Guarantor (whether outstanding on the Issue Date or thereafter Incurred) that specifically provides that such Indebtedness is to rank equally in right of payment with the obligations of such Subsidiary Guarantor under the Subsidiary Guarantee and is not expressly subordinated by its terms in right of payment to any Indebtedness of such Subsidiary Guarantor which is not Guarantor Senior Indebtedness of such Subsidiary Guarantor.

"Guarantor Subordinated Obligation" means, with respect to a Subsidiary Guarantor, any Indebtedness of such Subsidiary Guarantor (whether outstanding on the Issue Date or thereafter Incurred) which is expressly subordinate in right of payment to the obligations of such Subsidiary Guarantor under its Subsidiary Guarantee pursuant to a written agreement.

"Hedging Obligations" of any Person means the obligations of such Person pursuant to any Interest Rate Agreement or Currency Agreement or Commodity Agreement.

"Holder" means a Person in whose name a Note is registered in the Security Registrar's books.

"Hydrocarbons" means oil, gas, casinghead gas, drip gasoline, natural gasoline, condensate, distillate, liquid hydrocarbons, gaseous hydrocarbons, and all products, by-products and all other substances refined, separated, settled or derived therefrom or the processing thereof, and all other minerals and substances, including, but not limited to, liquified petroleum gas, natural gas, kerosene, sulphur, lignite, coal, uranium, thorium, iron, geothermal steam, water, carbon dioxide, helium, and any and all other minerals, ores, or substances of value, and the products and proceeds therefrom, including, without limitation, all gas resulting from the in-situ combustion of coal or lignite.

"Incur" means issue, create, assume, Guarantee, incur or otherwise become liable for; provided, however, that any Indebtedness or Capital Stock of a Person existing at the time such person becomes a Restricted Subsidiary (whether by merger, consolidation, acquisition or otherwise) will be deemed to be Incurred by such Restricted Subsidiary at the time it becomes a Restricted Subsidiary; and the terms "Incurred" and "Incurrence" have meanings correlative to the foregoing.

"Indebtedness" means, as applied to any Person, without duplication:

(1) all obligations of such Person for borrowed money;

(2) all obligations of such Person for the deferred purchase price of property or services (other than property and services purchased, and expense accruals and deferred compensation items arising, in the ordinary course of business);

(3) all obligations of such Person evidenced by notes, bonds, debentures, mandatorily redeemable preferred stock or other similar instruments (other than performance, surety and appeals bonds arising in the ordinary course of business);

(4) all payment obligations created or arising under any conditional sale, deferred price or other title retention agreement with respect to property acquired by such Person (unless the rights and remedies of the seller or lender under such agreement in the event of default are limited to repossession or sale of such property);

(5) any Capital Lease Obligation of such Person, other than obligations under oil and gas leases entered into in the ordinary course of business;

(6) all reimbursement, payment or similar obligations, contingent or otherwise, of such Person under acceptance, letter of credit or similar facilities (other than letters of credit in support of trade obligations or incurred in connection with public liability insurance, workers' compensation, unemployment insurance, old-age pensions and other social security benefits other than in respect of employee benefit plans subject to ERISA);

(7) all obligations of such Person, contingent or otherwise, under any guarantee by such Person of the obligations of another Person of the type referred to in clauses (1) through (6) above; and

(8) the principal component or liquidation preference of all obligations of such Person with respect to the redemption, repayment or other repurchase of any Disqualified Stock or, with respect to any Subsidiary that is not a Subsidiary Guarantor, any Preferred Stock (but excluding, in each case, any accrued dividends);

(9) to the extent not otherwise included in this definition, net obligations of such Person under Commodity Agreements, Currency Agreements and Interest Rate Agreements (the amount of any such obligations to be equal at any time to the termination value of such agreement or arrangement giving rise to such obligation that would be payable by such Person at such time); and

(10) all obligations referred to in clauses (1) through (6) above secured by (or for which the holder of such Indebtedness has an existing right, contingent or otherwise, to be secured by) any mortgage or security interest in property (including without limitation accounts, contract rights and general intangibles) owned by such Person and as to which such Person has not assumed or become liable for the payment of such obligations other than to the extent of the property subject to such mortgage or security interest;

except that Indebtedness of the type referred to in clauses (7) and (10) above will be included within the definition of "Indebtedness" only to the extent of the least of (a) the amount of the underlying Indebtedness referred to in the applicable clause (1) through (6) above; (b) in the case of clause (7), the limit on recoveries, if any, from such Person under obligations of the type referred to in clause (7) above, and (c) in the case of clause (10), the aggregate value (as determined in good faith by the board of directors or similar governing body of such Person) of the property of such Person subject to such mortgage or security interest.

In addition, "Indebtedness" of any Person shall include Indebtedness described in the preceding paragraph that would not appear as a liability on the balance sheet of such Person if:

(1) such Indebtedness is the obligation of a partnership or joint venture that is not a Restricted Subsidiary (a "Joint Venture");

(2) such Person or a Restricted Subsidiary of such Person is a general partner of the Joint Venture (a "General Partner"); and

(3) there is recourse, by contract or operation of law, with respect to the payment of such Indebtedness to property or assets of such Person or a Restricted Subsidiary of such Person;

in which case, such Indebtedness shall be included in an amount not to exceed:

(a) the lesser of (i) the net assets of the General Partner and (ii) the amount of such obligations to the extent that there is recourse, by contract or operation of law, to the property or assets of such Person or a Restricted Subsidiary of such Person; or

(b) if less than the amount determined pursuant to clause (a) immediately above, the actual amount of such Indebtedness that is recourse to such Person or a Restricted Subsidiary of such Person, if the Indebtedness is evidenced by a writing and is for a determinable amount.

Notwithstanding the preceding, "Indebtedness" shall not include:

(1) Production Payments and Reserve Sales;

(2) any obligation of a Person in respect of a farm-in agreement or similar arrangement whereby such Person agrees to pay all or a share of the drilling, completion or other expenses of an exploratory or development well (which agreement may be subject to a maximum payment obligation, after which expenses are shared in accordance with the working or participation interest therein or in accordance with the agreement of the parties) or perform the drilling, completion or other operation on such well in exchange for an ownership interest in an oil or gas property;

(3) any obligations under Hedging Obligations; provided that such agreements are entered into for bona fide hedging purposes of the Company or its Restricted Subsidiaries (as determined in good faith by the Board of Directors or senior management of the Company, whether or not accounted for as a hedge in accordance with GAAP);

(4) any obligation arising from agreements of the Company or a Restricted Subsidiary providing for indemnification, Guarantees, adjustment of purchase price, holdbacks, contingency payment obligations or similar obligations (other than Guarantees of Indebtedness), in each case, Incurred or assumed in connection with the acquisition or disposition of any business, assets or Capital Stock of a Restricted Subsidiary, provided that such Indebtedness is not reflected on the face of the balance sheet of the Company or any Restricted Subsidiary;

(5) any obligation arising from the honoring by a bank or other financial institution of a check, draft or similar instrument (except in the case of daylight overdrafts) drawn against insufficient funds in the ordinary course of business; provided, however, that such Indebtedness is extinguished within five business days of Incurrence;

(6) in-kind obligations relating to net oil or natural gas balancing positions arising in the ordinary course of business; and

(7) all contracts and other obligations, agreements, instruments or arrangements described in clauses (20), (21) or (22), of the definition of "Permitted Liens."

"Interest Rate Agreement" means with respect to any Person any interest rate protection agreement, interest rate futures contracts, interest rate option agreement, interest rate swap agreement, interest rate cap agreement, interest rate collar agreement, interest rate hedge agreement or other similar agreement or arrangement as to which such Person is party or a beneficiary.

"Investment" means, with respect to any Person, all investments by such Person in other Persons (including Affiliates) in the form of any direct or indirect advance, loan (other than advances or extensions of credit to employees, directors or customers in the ordinary course of business) or other extensions of credit (including by way of Guarantee or similar arrangement, but excluding any debt or extension of credit represented by a bank deposit other than a time deposit) or capital contribution to (by means of any transfer of cash or other property or any payment for property or services), or any purchase or acquisition of Capital Stock, Indebtedness or other similar instruments issued by, such Person and all other items that are or would be classified as investments on a balance sheet prepared in accordance with GAAP; provided that none of the following will be deemed to be an Investment:

(1) Hedging Obligations Incurred in the ordinary course of business and in compliance with the Indenture;

(2) endorsements of negotiable instruments and documents in the ordinary course of business; and

(3) an acquisition of assets, Capital Stock or other securities by the Company or a Subsidiary for consideration to the extent such consideration consists of Common Stock of the Company.

For purposes of "Certain covenants—Limitation on restricted payments,"

(1) "Investment" will include the portion (proportionate to the Company's equity interest in a Restricted Subsidiary to be designated as an Unrestricted Subsidiary) of the fair market value of the net assets of such Restricted Subsidiary at the time that such Restricted Subsidiary is designated an Unrestricted Subsidiary; provided, however, that upon a redesignation of such Subsidiary as a Restricted Subsidiary, the Company will be deemed to continue to have a permanent "Investment" in an Unrestricted Subsidiary in an amount (if positive) equal to (a) the Company's "Investment" in such Subsidiary at the time of such redesignation less (b) the portion (proportionate to the Company's equity interest in such Subsidiary) of the fair market value of the net assets (as conclusively determined by the Board of Directors of the Company in good faith) of such Subsidiary at the time that such Subsidiary is so re-designated a Restricted Subsidiary; and

(2) any property transferred to or from an Unrestricted Subsidiary will be valued at its fair market value at the time of such transfer, in each case as determined in good faith by the Board of Directors of the Company.

"Investment Grade Rating" means a rating equal to or higher than Baa3 (or the equivalent) by Moody's Investors Service, Inc. and BBB- (or the equivalent) by Standard & Poor's Ratings Services (or an equivalent rating by another nationally recognized rating agency if both of the two named rating agencies cease publishing ratings of investments), in each case, with a stable or better outlook.

"Issue Date" means .

"Lien" means any mortgage, pledge, security interest, encumbrance, lien or similar charge of any kind (including any conditional sale or other title retention agreement or lease in the nature thereof); provided, that in no event shall an operating lease be deemed to constitute a Lien.

"Minority Interest" means the percentage interest represented by any shares of stock of any class of Capital Stock of a Restricted Subsidiary that are not owned by the Company or a Restricted Subsidiary.

"Moody's" means Moody's Investors Service, Inc., a subsidiary of Moody's Corporation, and its successors.

"Net Available Cash" from an Asset Disposition means cash payments received (including any cash payments received by way of deferred payment of principal pursuant to a note or installment receivable or otherwise and net proceeds from the sale or other disposition of any securities received as consideration, but only as and when received, but excluding any other consideration received in the form of assumption by the acquiring person of Indebtedness or other obligations relating to the properties or assets that are the subject of such Asset Disposition or received in any other non-cash form) therefrom, in each case net of:

(1) all legal, accounting, investment banking, title and recording tax expenses, commissions and other fees and expenses Incurred, and all Federal, state, provincial, foreign and local taxes required to be paid or accrued as a liability under GAAP (after taking into account any available tax credits or deductions and any tax sharing agreements), as a consequence of such Asset Disposition;

(2) all payments made on any Indebtedness which is secured by any assets subject to such Asset Disposition, in accordance with the terms of any Lien upon such assets, or which must by its terms, or in order to obtain a necessary consent to such Asset Disposition, or by applicable law be repaid out of the proceeds from such Asset Disposition;

(3) all distributions and other payments required to be made to minority interest holders in Subsidiaries or joint ventures as a result of such Asset Disposition; and

(4) amounts accrued in accordance with GAAP in respect of liabilities associated with the assets disposed of in such Asset Disposition and retained by the Company or any Restricted Subsidiary after such Asset Disposition or liabilities incurred in connection with such Asset Disposition.

"Net Cash Proceeds," with respect to any issuance or sale of Capital Stock, means the cash proceeds of such issuance or sale net of attorneys' fees, accountants' fees, underwriters' or placement agents' fees, listing fees, discounts or commissions and brokerage, consultant and other fees and charges actually Incurred in connection with such issuance or sale and net of taxes paid or payable as a result of such issuance or sale (after taking into account any available tax credit or deductions and any tax sharing arrangements).

"Net Working Capital" means (a) all current assets of the Company and its Restricted Subsidiaries except current assets under Commodity Agreements, less (b) all current liabilities of the Company and its Restricted Subsidiaries, except current liabilities included in Indebtedness and any current liabilities under Commodity Agreements, in each case as set forth in the consolidated financial statements of the Company prepared in accordance with GAAP.

"Non-Recourse Debt" means Indebtedness of a Person:

(1) as to which neither the Company nor any Restricted Subsidiary (a) provides any Guarantee or credit support of any kind (including any undertaking, guarantee, indemnity, agreement or instrument that would constitute Indebtedness) or (b) is directly or indirectly liable (as a guarantor or otherwise);

(2) no default with respect to which (including any rights that the holders thereof may have to take enforcement action against an Unrestricted Subsidiary) would permit (upon notice, lapse of time or both) any holder of any other Indebtedness of the Company or any Restricted Subsidiary to declare a default under such other Indebtedness or cause the payment thereof to be accelerated or payable prior to its stated maturity; and

(3) the explicit terms of which provide there is no recourse against any of the assets of the Company or its Restricted Subsidiaries.

"Oil and Gas Business" means (a) the business of acquiring, exploring, exploiting, developing, producing, operating and disposing of interests in oil, gas, liquid natural gas and other hydrocarbon properties, (b) the business of gathering, marketing, treating, processing, storing, refining, selling and transporting any production from such interests or properties and products produced therefrom or in association therewith, and

(c) any business or activity relating to, arising from, or necessary, appropriate or incidental to the activities described in the foregoing clauses (a) and (b) of this definition, including, without limitation, contract drilling, other oilfield services and alternative energy.

"Oil and Gas Properties" means all properties, including equity or other ownership interests therein, owned by such Person which contain or are believed to contain "proved oil and gas reserves" as defined in Rule 4-10 of Regulation S-X of the Securities Act.

"Opinion of Counsel" means a written opinion from legal counsel who is acceptable to the Trustee. The counsel may be an employee of or counsel to the Company or the Trustee.

"Pari Passu Indebtedness" means Indebtedness that ranks equally in right of payment to the Notes.

"Permitted Business Investment" means any Investment made in the ordinary course of the business of the Company or any Restricted Subsidiary or that is of a kind or character that is customarily made in the conduct of the Oil and Gas Business, including investments or expenditures for actively exploiting, exploring for, acquiring, developing, producing, processing, refining, gathering, marketing or transporting Hydrocarbons through agreements, transactions, interests or arrangements which permit one to share risks or costs, comply with regulatory requirements regarding local ownership or satisfy other objectives customarily achieved through the conduct of the Oil and Gas Business jointly with third parties, including:

(1) ownership interests in oil and gas properties, liquid natural gas facilities, refineries, drilling operations, processing facilities, gathering systems, pipelines or ancillary real property interests; and

(2) Investments in the form of or pursuant to oil and gas leases, operating agreements, gathering agreements, processing agreements, farm-in agreements, farm-out agreements, development agreements, area of mutual interest agreements, unitization or pooling designations, declarations, orders and agreements, gas balancing or deferred production agreements, joint bidding agreements, service contracts, joint venture agreements, partnership agreements (whether general or limited), subscription agreements, stock purchase agreements and other similar agreements (including for limited liability companies) with third parties.

"Permitted Distribution" means a dividend or distribution, on one occasion and not more than one occasion, to holders of shares of the Company's Capital Stock of shares of Capital Stock of Unit Drilling Company or any successor to the business thereof (the "Drilling Subsidiary"); provided that the portion of Consolidated EBITDA contributed by the Drilling Subsidiary (calculated assuming the Drilling Subsidiary and all of its subsidiaries are Restricted Subsidiaries) for the four full fiscal quarters immediately preceding the effective time of such dividend or distribution shall not exceed 30%.

"Permitted Investment" means an Investment by the Company or any Restricted Subsidiary in:

(1) the Company or a Restricted Subsidiary; provided, however, that the primary business of such Restricted Subsidiary is the Oil and Gas Business;

(2) another Person if as a result of such Investment such other Person becomes a Restricted Subsidiary or is merged or consolidated with or into, or transfers or conveys all or substantially all its assets to, the Company or a Restricted Subsidiary and in each case any Investment held by such Person; provided, however, that such Person's primary business is the Oil and Gas Business;

(3) cash and Cash Equivalents;

(4) receivables owing to the Company or any Restricted Subsidiary created or acquired in the ordinary course and payable or dischargeable in accordance with customary trade terms; provided, however, that such trade terms may include such concessionary trade terms as the Company or any such Restricted Subsidiary deems reasonable under the circumstances;

(5) payroll, travel and similar advances to cover matters that are expected at the time of such advances ultimately to be treated as expenses for accounting purposes and that are made in the ordinary course of business;

(6) loans or advances to employees and directors made in the ordinary course of business of the Company or such Restricted Subsidiary;

(7) Capital Stock, obligations or securities received in settlement of debts created in the ordinary course of business and owing to the Company or any Restricted Subsidiary or in satisfaction of judgments or pursuant to any plan of reorganization or similar arrangement upon the bankruptcy or insolvency of a debtor;

(8) Investments made as a result of the receipt of non-cash consideration from an Asset Disposition that was made pursuant to and in compliance with "Certain covenants—Limitation on sales of assets and subsidiary stock;"

(9) Investments in existence on the Issue Date or made pursuant to agreements or commitments in effect on the Issue Date;

(10) Commodity Agreements, Currency Agreements, Interest Rate Agreements and related Hedging Obligations, which transactions or obligations are Incurred in compliance with "Certain covenants—Limitation on indebtedness;"

(11) Guarantees made in accordance with "Certain covenants—Limitations on indebtedness;"

(12) Permitted Business Investments in an aggregate amount not to exceed 5% of Adjusted Consolidated Net Tangible Assets (with Adjusted Consolidated Net Tangible Assets and the fair market value of such Investment being measured at the time such Investment is made and without giving effect to subsequent changes in value); and

(13) any Person to the extent such Investments consist of prepaid expenses, negotiable instruments held for collection and lease, utility and workers' compensation, performance and other similar deposits made in the ordinary course of business by the Company or any Restricted Subsidiary;

(14) any Asset Swap; and

(15) acquisitions of assets, Equity Interests or other securities by the Company for consideration consisting solely of common equity securities of the Company.

In order to be a Permitted Investment, an Investment need not be permitted solely by one subsection of this definition but may be permitted in part of one such subsection and in part by one or more other subsections of this definition. In the event an Investment meets the criteria of one or more of the subsections of this definition, the Company, in its sole discretion, may classify all or any portion of such Investment as being permitted by any one or more of such subsections.

"Permitted Liens" means, with respect to any Person:

(1) Liens securing Indebtedness and other obligations under a Credit Facility, including the Senior Credit Agreement and related Hedging Obligations and other Senior Indebtedness and liens on assets of Restricted Subsidiaries securing Guarantees of Indebtedness and other obligations of the Company under a Credit Facility and other Guarantor Senior Indebtedness permitted to be Incurred under the Indenture under the covenants described in clause (1) of the second paragraph under "Certain covenants—Limitation on indebtedness;"

(2) pledges or deposits by such Person under workmen's compensation laws, unemployment insurance laws or similar legislation, or earnest money, good faith or similar deposits in connection with bids, tenders, contracts (other than for the payment of Indebtedness) or leases to which such Person is a party, or deposits to secure public, regulatory or statutory obligations of such Person or deposits of cash or Cash Equivalents to secure surety or appeal bonds to which such Person is a party, or deposits as security for contested taxes or import or customs duties or for the payment of rent, in each case Incurred in the ordinary course of business;

(3) Liens imposed by law, including carriers', warehousemen's, suppliers', materialmen's and mechanics' Liens, in each case for sums not yet due or being contested in good faith by appropriate proceedings if appropriate reserves or other provisions required by GAAP, if any, shall have been made in respect thereof;

(4) Liens for taxes, assessments or other governmental charges not yet subject to penalties for non-payment or which are being contested in good faith by appropriate proceedings if appropriate reserves or other provisions required by GAAP shall have been made in respect thereof;

(5) Liens in favor of issuers of surety or performance bonds or letters of credit or bankers' acceptances issued pursuant to the request of and for the account of such Person in the ordinary course of its business;

(6) survey exceptions, encumbrances, ground leases, easements or reservations of, or rights of others for, licenses, rights of way, servitudes, permits, sewers, electric lines, telegraph and telephone lines and other similar purposes, or zoning, building codes or surface leases and other similar rights in respect of surface operations or other restrictions (including, without limitation, minor defects or irregularities in title and similar encumbrances) as to the use of real properties or liens incidental to the conduct of the business of such Person or to the ownership of its properties which do not in the aggregate materially adversely affect the value of the assets of such Person and its Restricted Subsidiaries, taken as a whole, or materially impair their use in the operation of the business of such Person;

(7) Liens securing Hedging Obligations;

(8) leases, licenses, subleases and sublicenses of assets (including, without limitation, real property and intellectual property rights) which do not materially interfere with the ordinary conduct of the business of the Company or any of its Restricted Subsidiaries;

(9) judgment Liens not giving rise to an Event of Default so long as such Lien is adequately bonded and any appropriate legal proceedings which may have been duly initiated for the review of such judgment have not been finally terminated or the period within which such proceedings may be initiated has not expired;

(10) Liens for the purpose of securing the payment of all or a part of the purchase price of, or Capital Lease Obligations, purchase money obligations or other payments Incurred to finance the

acquisition, lease, improvement or construction of or repairs or additions to, assets or property acquired or constructed in the ordinary course of business; provided that:

(a) the aggregate principal amount of Indebtedness secured by such Liens is otherwise permitted to be Incurred under the Indenture and does not exceed the cost of the assets or property so acquired or constructed; and

(b) such Liens are created within 180 days of construction or acquisition of such assets or property and do not encumber any other assets or property of the Company or any Restricted Subsidiary other than such assets or property and assets affixed or appurtenant thereto;

(11) Liens arising solely by virtue of any statutory or common law provisions relating to banker's Liens, rights of set-off or similar rights and remedies as to deposit accounts or other funds maintained with a depositary institution; provided that:

(a) such deposit account is not a dedicated cash collateral account and is not subject to restrictions against access by the Company in excess of those set forth by regulations promulgated by the Federal Reserve Board; and

(b) such deposit account is not intended by the Company or any Restricted Subsidiary to provide collateral to the depository institution;

(12) Liens arising from Uniform Commercial Code financing statement filings regarding operating leases entered into by the Company and its Restricted Subsidiaries in the ordinary course of business;

(13) Liens existing on the Issue Date;

(14) Liens on property or shares of stock of a Person at the time such Person becomes a Restricted Subsidiary; provided, however, that such Liens are not created, Incurred or assumed in connection with, or in contemplation of, such other Person becoming a Restricted Subsidiary; provided further, however, that any such Lien may not extend to any other property owned by the Company or any Restricted Subsidiary;

(15) Liens on property at the time the Company or a Restricted Subsidiary acquired the property, including any acquisition by means of a merger or consolidation with or into the Company or any Restricted Subsidiary; provided, however, that such Liens are not created, Incurred or assumed in connection with, or in contemplation of, such acquisition; provided further, however, that such Liens may not extend to any other property owned by the Company or any Restricted Subsidiary;

(16) Liens securing Indebtedness or other obligations of a Restricted Subsidiary owing to the Company or a Wholly-Owned Subsidiary;

(17) Liens securing the Notes and Subsidiary Guarantees;

(18) Liens securing Refinancing Indebtedness Incurred to refinance Indebtedness that was previously so secured, provided that any such Lien is limited to all or part of the same property or assets (plus improvements, accessions, proceeds or dividends or distributions in respect thereof) that secured (or, under the written arrangements under which the original Lien arose, could secure) the Indebtedness being refinanced or is in respect of property that is the security for a Permitted Lien hereunder;

(19) any interest or title of a lessor under any Capital Lease Obligation or operating lease;

(20) Liens in respect of Production Payments and Reserve Sales, which Liens shall be limited to the oil and gas property or other interest that is subject to such Production Payments and Reserve Sales;

(21) Liens arising under oil and gas leases, farm-out agreements, farm-in agreements, division orders, contracts for the sale, purchase, exchange, transportation, gathering or processing of Hydrocarbons, partnership agreements, joint venture agreements, unitizations and pooling designations, declarations, orders and agreements, development agreements, operating agreements, production sales contracts, area of mutual interest agreements, gas balancing or deferred production agreements, injection, repressuring and recycling agreements, salt water or other disposal agreements, seismic or geophysical permits or agreements, and other agreements which are customary in the Oil and Gas Business; provided, however, in all instances that such Liens are limited to the assets that are subject to the relevant agreement, program, order or contract;

(22) Liens on pipelines or pipeline facilities that arise by operation of law;

(23) Liens securing Indebtedness (other than Subordinated Obligations and Guarantor Subordinated Obligations) in an aggregate principal amount outstanding at any one time not to exceed the greater of $30 million or 2% of the Company's Adjusted Consolidated Net Tangible Assets, as determined on the date of Incurrence of this Indebtedness after giving pro forma effect to the Incurrence and the application of the proceeds therefrom;

(24) Liens in favor of the Company or any Subsidiary Guarantor;

(25) Deposits made in the ordinary course of business to secure liability to insurance carriers;

(26) any (a) interest or title of a lessor or sublessor under any lease, liens reserved in oil, gas or other Hydrocarbons, minerals, leases for bonus, royalty or rental payments and for compliance with the terms of such leases; (b) restriction or encumbrance that the interest or title of such lessor or sublessor may be subject to (including, without limitation, ground leases or other prior leases of the demised premises, mortgages. mechanics' liens, tax liens, and easements); or (c) subordination of the interest of the lessee or sublessee under such lease to any restrictions or encumbrance referred to in the preceding clause (b);

(27) Liens arising under the Indenture in favor of the Trustee for its own benefit and similar Liens in favor of other trustees, agents and representatives arising under instruments governing Indebtedness permitted to be incurred under the Indenture, provided, however, that such Liens are solely for the benefit of the trustees, agents or representatives in their capacities as such and not for the benefit of the holders of such Indebtedness; and

(28) Liens in favor of collecting or payer banks having a right of setoff, revocation, or charge back with respect to money or instruments of the Company or any Subsidiary of the Company on deposit with or in possession of such bank.

In each case set forth above, notwithstanding any stated limitation on the assets that may be subject to such Lien, a Permitted Lien on a specified asset or group or type of assets may include Liens on all improvements, additions and accessions thereto and all products and proceeds thereof (including dividends, distributions and increases in respect thereof).

"Person" means any individual, partnership, corporation, limited liability company, joint stock company, business trust, trust, unincorporated association, joint venture, or other entity, or government or political subdivision or agency.

"Preferred Stock," as applied to the Capital Stock of any corporation, means Capital Stock of any class or classes (however designated) which is preferred as to the payment of dividends, or as to the distribution of assets upon any voluntary or involuntary liquidation or dissolution of such corporation, over shares of Capital Stock of any other class of such corporation.

"Production Payments and Reserve Sales" means the grant or transfer by the Company or a Restricted Subsidiary to any Person of a royalty, overriding royalty, net profits interest, production payment (whether volumetric or dollar denominated), partnership or other interest in oil and gas properties or the right to receive all or a portion of the production or the proceeds from the sale of production attributable to such properties, where the grantee or transferee thereof has recourse solely to such production or proceeds of production, subject to the obligation of the grantor or transferor to operate and maintain, or cause to be operated and maintained, the related oil and gas properties or other related interests in a reasonably prudent manner or other customary standard or subject to the obligation of the grantor or transferor to indemnify for environmental, title or other matters customary in the Oil and Gas Business, including any such grants or transfers pursuant to incentive compensation programs on terms that are reasonably customary in the Oil and Gas Business for geologists, geophysicists or other providers of technical services to the Company or a Restricted Subsidiary.

"Rating Agency" means S&P and Moody's or if S&P or Moody's or both shall not make a rating on the Notes publicly available, a nationally recognized statistical rating agency or agencies, as the case may be, selected by the Company (as certified by a resolution of the Board of Directors or a committee thereof) which shall be substituted for S&P or Moody's or both, as the case may be.

"Receivables" means a right to receive payment arising from a sale or lease of goods or the performance of services by a Person pursuant to an arrangement with another Person pursuant to which such other Person is obligated to pay for goods or services under terms that permit the purchase of such goods and services on credit and shall include, in any event, any items of property that would be classified as an "account," "chattel paper," "payment intangible" or "instrument" under the Uniform Commercial Code as in effect in the State of New York and any "supporting obligations" as so defined.

"Receivables Fees" means any fees or interest paid to purchasers or lenders providing the financing in connection with a factoring agreement or other similar agreement, including any such amounts paid by discounting the face amount of Receivables or participations therein transferred in connection with a factoring agreement or other similar arrangement, regardless of whether any such transaction is structured as on-balance sheet or off-balance sheet or through a Restricted Subsidiary or an Unrestricted Subsidiary.

"Refinancing Indebtedness" means Indebtedness that is Incurred to refund, refinance, replace, exchange, renew, repay or extend (including pursuant to any defeasance or discharge mechanism) (collectively, "refinance," "refinances," and "refinanced" shall have a correlative meaning) any Indebtedness existing on the Issue Date or Incurred in compliance with the Indenture (including Indebtedness of the Company that refinances Indebtedness of any Restricted Subsidiary and Indebtedness of any Restricted Subsidiary that refinances Indebtedness of another Restricted Subsidiary) including Indebtedness that refinances Refinancing Indebtedness, provided, however, that:

(1) (a) if the Stated Maturity of the Indebtedness being refinanced is earlier than the Stated Maturity of the Notes, the Refinancing Indebtedness has a Stated Maturity no earlier than the Stated Maturity of the Indebtedness being refinanced or (b) if the Stated Maturity of the Indebtedness being refinanced is later than the Stated Maturity of the Notes, the Refinancing Indebtedness has a Stated Maturity at least 91 days later than the Stated Maturity of the Notes;

(2) the Refinancing Indebtedness has an Average Life at the time such Refinancing Indebtedness is Incurred that is equal to or greater than the Average Life of the Indebtedness being refinanced;

(3) such Refinancing Indebtedness is Incurred in an aggregate principal amount (or if issued with original issue discount, an aggregate issue price) that is equal to or less than the sum of the aggregate principal amount (or if issued with original issue discount, the aggregate accreted value) then outstanding of the Indebtedness being refinanced (plus, without duplication, any additional Indebtedness Incurred to pay interest or premiums required by the instruments governing such existing Indebtedness and fees and expenses Incurred in connection therewith); and

(4) if the Indebtedness being refinanced is subordinated in right of payment to the Notes or the Subsidiary Guarantee, such Refinancing Indebtedness is subordinated in right of payment to the Notes or the Subsidiary Guarantee on terms at least as favorable to the holders as those contained in the documentation governing the Indebtedness being extended, refinanced, renewed, replaced, defeased or refunded.

"Representative" means any trustee, agent or representative (if any) of an issue of Senior Indebtedness; provided that when used in connection with the Senior Credit Agreement, the term "Representative" shall refer to the global administrative agent under the Senior Credit Agreement.

"Restricted Investment" means any Investment other than a Permitted Investment.

"Restricted Subsidiary" means any Subsidiary of the Company other than an Unrestricted Subsidiary.

"S&P" means Standard & Poor's Ratings Services, a division of The McGraw-Hill Companies, Inc., and its successors.

"Sale/ Leaseback Transaction" means an arrangement relating to property now owned or hereafter acquired whereby the Company or a Restricted Subsidiary transfers such property to a Person and the Company or a Restricted Subsidiary leases it from such Person.

"Senior Indebtedness" means, whether outstanding on the Issue Date or thereafter issued, created, Incurred or assumed, the Bank Indebtedness and all amounts payable by the Company under or in respect of all other Indebtedness of the Company, including premiums and accrued and unpaid interest (including interest accruing on or after the filing of any petition in bankruptcy or for reorganization relating to the Company at the rate specified in the documentation with respect thereto whether or not a claim for post-filing interest is allowed in such proceeding) and fees relating thereto; provided, however, that Senior Indebtedness will not include:

(1) any Indebtedness Incurred in violation of the Indenture;

(2) any obligation of the Company to any Subsidiary;

(3) any liability for Federal, state, foreign, local or other taxes owed or owing by the Company;

(4) any accounts payable or other liability to trade creditors arising in the ordinary course of business (including Guarantees thereof or instruments evidencing such liabilities);

(5) any Indebtedness, Guarantee or obligation of the Company that is expressly subordinate or junior in right of payment to any other Indebtedness, Guarantee or obligation of the Company, including, without limitation, any Senior Subordinated Indebtedness and any Subordinated Obligations; or

(6) any Capital Stock.

"Senior Credit Agreement" means the First Amended and Restated Senior Credit Agreement, dated May 24, 2007, among Unit Corporation, Superior Pipeline Company, L.L.C., Unit Drilling Company, Unit

Petroleum Company, and Unit Texas Drilling, L.L.C., as Borrowers, The Lenders, Bank of Oklahoma, National Association, as Administrative Agent for the Lenders and as Co-Arranger, Bank of America, National Association, as Co-Arranger, BMO Capital Markets Financing, Inc., as Syndication Agent and Compass Bank, as Documentation Agent.

"Senior Subordinated Indebtedness" means the Notes and any other Indebtedness of the Company that specifically provides that such Indebtedness is to rank equally with the Notes in right of payment and is not subordinated by its terms in right of payment to any Indebtedness or other obligation of the Company which is not Senior Indebtedness.

"Significant Subsidiary" means any Restricted Subsidiary that would be a "Significant Subsidiary" of the Company within the meaning of Rule 1-02 under Regulation S-X promulgated by the SEC.

"Stated Maturity" means, with respect to any security, the date specified in such security as the fixed date on which the payment of principal of such security is due and payable, including pursuant to any mandatory redemption provision, but shall not include any contingent obligations to repay, redeem or repurchase any such principal prior to the date originally scheduled for the payment thereof.

"Subordinated Obligation" means any Indebtedness of the Company (whether outstanding on the Issue Date or thereafter Incurred) that is subordinate or junior in right of payment to the Notes pursuant to a written agreement.

"Subsidiary" of any Person means (a) any corporation, association or other business entity (other than a partnership, joint venture, limited liability company or similar entity) of which more than 50% of the total ordinary voting power of shares of Capital Stock entitled (without regard to the occurrence of any contingency) to vote in the election of directors, managers or trustees thereof (or persons performing similar functions) or (b) any partnership, joint venture limited liability company or similar entity of which more than 50% of the capital accounts, distribution rights, total equity and voting interests or general or limited partnership interests, as applicable, is, in the case of clauses (a) and (b), at the time owned or controlled, directly or indirectly, by (1) such Person, (2) such Person and one or more Subsidiaries of such Person or (3) one or more Subsidiaries of such Person. Unless otherwise specified herein, each reference to a Subsidiary will refer to a Subsidiary of the Company.

"Subsidiary Guarantee" means, individually, any Guarantee of payment of the Notes by a Subsidiary Guarantor pursuant to the terms of the Indenture and any supplemental indenture thereto, and, collectively, all such Guarantees. Each such Subsidiary Guarantee will be in the form prescribed by the Indenture.

"Subsidiary Guarantor" means (i) each of Unit Drilling Company, Unit Petroleum Company, Superior Pipeline Company, L.L.C., Unit Texas Drilling, L.L.C., Unit Drilling USA Colombia, L.L.C., Unit Drilling Colombia, L.L.C., Unit Texas Company, Superior Pipeline Texas, L.L.C., Superior Appalachian Pipeline, L.L.C., Unit Drilling and Exploration Company, Petroleum Supply Company and Preston County Gas Gathering, L.L.C., and (ii) any Restricted Subsidiary (other than a Foreign Subsidiary) created or acquired by the Company or one or more of its Restricted Subsidiaries after the Issue Date.

"Unrestricted Subsidiary" means

(1) any Subsidiary of the Company that at the time of determination shall be designated an Unrestricted Subsidiary by the Board of Directors of the Company in the manner provided below; and

(2) any Subsidiary of an Unrestricted Subsidiary.

The Board of Directors of the Company may designate any Subsidiary of the Company (including any newly acquired or newly formed Subsidiary or a Person becoming a Subsidiary through merger or consolidation or Investment therein) to be an Unrestricted Subsidiary only if:

(1) such Subsidiary or any of its Subsidiaries does not own any Capital Stock or Indebtedness of or have any Investment in, or own or hold any Lien on any property of, any other Subsidiary of the Company which is not a Subsidiary of the Subsidiary to be so designated or otherwise an Unrestricted Subsidiary;

(2) all the Indebtedness of such Subsidiary and its Subsidiaries shall, at the date of designation and at all times thereafter, consist of Non-Recourse Debt;

(3) such designation and the Investment of the Company in such Subsidiary complies with "Certain covenants—Limitation on restricted payments;"

(4) such Subsidiary, either alone or in the aggregate with all other Unrestricted Subsidiaries, does not operate, directly or indirectly, all or substantially all of the business of the Company and its Subsidiaries;

(5) such Subsidiary is a Person with respect to which neither the Company nor any of its Restricted Subsidiaries has any direct or indirect obligation:

(a) to subscribe for additional Capital Stock of such Person; or

(b) to maintain or preserve such Person's financial condition or to cause such Person to achieve any specified levels of operating results; and

(6) on the date such Subsidiary is designated an Unrestricted Subsidiary, such Subsidiary is not a party to any agreement, contract, arrangement or understanding with the Company or any Restricted Subsidiary with terms materially less favorable to the Company than those that might have been reasonably obtained from Persons that are not Affiliates of the Company.

Any such designation by the Board of Directors of the Company shall be evidenced to the Trustee by filing with the Trustee a resolution of the Board of Directors of the Company giving effect to such designation and an Officers' Certificate certifying that such designation complies with the foregoing conditions. If, at any time, any Unrestricted Subsidiary would fail to meet the foregoing requirements as an Unrestricted Subsidiary, it shall thereafter cease to be an Unrestricted Subsidiary for purposes of the Indenture and any Indebtedness of such Subsidiary shall be deemed to be Incurred as of such date.

The Board of Directors of the Company may designate any Unrestricted Subsidiary to be a Restricted Subsidiary; provided that immediately after giving effect to such designation, no Default or Event of Default shall have occurred and be continuing or would occur as a consequence thereof and the Company could Incur at least $1.00 of additional Indebtedness under the first paragraph of the "Limitation on indebtedness" covenant on a pro forma basis taking into account such designation.

"U.S. Government Obligations" means securities that are (a) direct obligations of the United States of America for the timely payment of which its full faith and credit is pledged or (b) obligations of a Person controlled or supervised by and acting as an agency or instrumentality of the United States of America the timely payment of which is unconditionally guaranteed as a full faith and credit obligation of the United States of America, which, in either case, are not callable or redeemable at the option of the issuer thereof, and shall also include a depositary receipt issued by a bank (as defined in Section 3(a)(2) of the Securities Act), as custodian with respect to any such U.S. Government Obligations or a specific payment of principal of or interest on any such U.S. Government Obligations held by such custodian for the account of the holder of such depositary receipt; provided that (except as required by law) such custodian is not authorized to make any deduction from the amount payable to the holder of such depositary receipt from any amount received by the custodian in respect of the U.S. Government Obligations or the specific payment of principal of or interest on the U.S. Government Obligations evidenced by such depositary receipt.

"Volumetric Production Payments" means production payment obligations recorded as deferred revenue in accordance with GAAP, together with all undertakings and obligations in connection therewith.

"Voting Stock" of a corporation means all classes of Capital Stock of such corporation then outstanding and normally entitled to vote in the election of directors.

"Wholly-Owned Subsidiary" means a Restricted Subsidiary, all of the Capital Stock of which (other than directors' qualifying shares) is owned by the Company or another Wholly-Owned Subsidiary.

BOOK-ENTRY, DELIVERY AND FORM

We have obtained the information in this section concerning DTC, Clearstream, Luxembourg and Euroclear, and their book-entry systems and procedures from sources that we believe to be reliable. We take no responsibility for an accurate portrayal of this information. In addition, the description of the clearing systems in this section reflects our understanding of the rules and procedures of DTC, Clearstream, Luxembourg and Euroclear as they are currently in effect. Those systems could change their rules and procedures at any time.

The new notes will initially be represented by one or more fully registered global notes. Each such global note will be deposited with, or on behalf of, DTC or any successor thereto and registered in the name of Cede & Co. (DTC's nominee). You may hold your interests in the global notes in the United States through DTC, or in Europe through Clearstream, Luxembourg or Euroclear, either as a participant in such systems or indirectly through organizations which are participants in such systems. Clearstream, Luxembourg and Euroclear will hold interests in the global notes on behalf of their respective participating organizations or customers through customers' securities accounts in Clearstream, Luxembourg's or Euroclear's names on the books of their respective depositaries, which in turn will hold those positions in customers' securities accounts in the depositaries' names on the books of DTC. Citibank, N.A. acts as depositary for Clearstream, Luxembourg and JPMorgan Chase Bank, N.A. acts as depositary for Euroclear.

So long as DTC or its nominee is the registered owner of the global securities representing the notes, DTC or such nominee will be considered the sole owner and holder of the notes for all purposes of the notes and the indenture. Except as provided below, owners of beneficial interests in the notes will not be entitled to have the notes registered in their names, will not receive or be entitled to receive physical delivery of the notes in definitive form and will not be considered the owners or holders of the notes under the indenture, including for purposes of receiving any reports delivered by us or the trustee pursuant to the indenture. Accordingly, each person owning a beneficial interest in a note must rely on the procedures of DTC or its nominee and, if such person is not a participant, on the procedures of the participant through which such person owns its interest, in order to exercise any rights of a holder of notes.

Unless and until we issue the notes in fully certificated, registered form under the limited circumstances described below under the heading "—Certificated Notes":

- you will not be entitled to receive a certificate representing your interest in the notes;
- all references in this prospectus supplement to actions by holders will refer to actions taken by DTC upon instructions from its direct participants; and
- all references in this prospectus supplement to payments and notices to holders will refer to payments and notices to DTC or Cede & Co., as the registered holder of the notes, for distribution to you in accordance with DTC procedures.

The Depository Trust Company

DTC acts as securities depositary for the notes. The new notes will be issued as fully registered notes registered in the name of Cede & Co. DTC is:

- a limited-purpose trust company organized under the New York Banking Law;
- a "banking organization" under the New York Banking Law;
- a member of the Federal Reserve System;
- a "clearing corporation" under the New York Uniform Commercial Code; and
- a "clearing agency" registered under the provisions of Section 17A of the Exchange Act.

DTC holds securities that its direct participants deposit with DTC. DTC facilitates the post-trade settlement among direct participants of securities transactions, such as transfers and pledges, in deposited securities through electronic computerized book-entry changes in direct participants' accounts, thereby eliminating the need for physical movement of securities certificates.

Direct participants of DTC include both U.S. and non-U.S. securities brokers and dealers (including the underwriters), banks, trust companies, clearing corporations and certain other organizations. DTC is owned by a number of its direct participants. Indirect participants of DTC, such as U.S. and non-U.S. securities brokers and dealers, banks and trust companies, can also access the DTC system if they maintain a custodial relationship with a direct participant.

Purchases of notes under DTC's system must be made by or through direct participants, which will receive a credit for the notes on DTC's records. The ownership interest of each beneficial owner is in turn to be recorded on the records of direct participants and indirect participants. Beneficial owners will not receive written confirmation from DTC of their purchase, but beneficial owners are expected to receive written confirmations providing details of the transaction, as well as periodic statements of their holdings, from the direct participants or indirect participants through which such beneficial owners entered into the transaction. Transfers of ownership interests in the notes are to be accomplished by entries made on the books of participants acting on behalf of beneficial owners. Beneficial owners will not receive certificates representing their ownership interests in notes, except as provided below in "—Certificated Notes."

To facilitate subsequent transfers, all notes deposited with DTC are registered in the name of DTC's nominee, Cede & Co., or such other nominee as may be requested by DTC. The deposit of notes with DTC and their registration in the name of Cede & Co. or such other DTC nominee effect no change in beneficial ownership. DTC has no knowledge of the actual beneficial owners of the notes. DTC's records reflect only the identity of the direct participants to whose accounts such notes are credited, which may or may not be the beneficial owners. The participants will remain responsible for keeping account of their holdings on behalf of their customers.

Conveyance of notices and other communications by DTC to direct participants, by direct participants to indirect participants and by direct participants and indirect participants to beneficial owners will be governed by arrangements among them, subject to any statutory or regulatory requirements as may be in effect from time to time.

Book-Entry Format

Under the book-entry format, the paying agent will pay interest or principal payments to Cede & Co., as nominee of DTC. DTC will forward the payment to the direct participants, who will then forward the payment to the indirect participants (including Clearstream, Luxembourg or Euroclear) or to you as the beneficial owner. You may experience some delay in receiving your payments under this system. None of us, any subsidiary guarantor, the trustee under the indenture or any paying agent has any direct responsibility or liability for the payment of principal or interest on the notes to owners of beneficial interests in the notes.

DTC is required to make book-entry transfers on behalf of its direct participants and is required to receive and transmit payments of principal, premium, if any, and interest on the notes. Any direct participant or indirect participant with which you have an account is similarly required to make book-entry transfers and to receive and transmit payments with respect to the notes on your behalf. We, the subsidiary guarantors and the trustee under the indenture have no responsibility for any aspect of the actions of DTC, Clearstream, Luxembourg or Euroclear or any of their direct or indirect participants. In addition, we, the subsidiary guarantors and the trustee under the indenture have no responsibility or liability for any aspect of the records kept by DTC, Clearstream, Luxembourg, Euroclear or any of their direct or indirect participants relating to or payments made on account of beneficial ownership interests in the notes or for maintaining, supervising or reviewing any records relating to such beneficial ownership interests. We also do not supervise these systems in any way.

The trustee will not recognize you as a holder under the indenture, and you can only exercise the rights of a holder indirectly through DTC and its direct participants. DTC has advised us that it will only take action regarding a note if one or more of the direct participants to whom the note is credited direct DTC to take such action and only in respect of the portion of the aggregate principal amount of the notes as to which that participant or participants has or have given that direction. DTC can only act on behalf of its direct participants. Your ability to pledge notes to non-direct participants, and to take other actions, may be limited because you will not possess a physical certificate that represents your notes.

Neither DTC nor Cede & Co. (nor any other DTC nominee) will consent or vote with respect to the notes unless authorized by a direct participant in accordance with DTC's procedures. Under its usual procedures, DTC will mail an omnibus proxy to its direct participant as soon as possible after the record date. The omnibus proxy assigns Cede & Co.'s consenting or voting rights to those direct participants to whose accounts the notes are credited on the record date (identified in a listing attached to the omnibus proxy).

Clearstream, Luxembourg or Euroclear will credit payments to the cash accounts of Clearstream, Luxembourg customers or Euroclear participants in accordance with the relevant system's rules and procedures, to the extent received by its depositary. These payments will be subject to tax reporting in accordance with relevant United States tax laws and regulations. Clearstream, Luxembourg or Euroclear, as the case may be, will take any other action permitted to be taken by a holder under the indenture on behalf of a Clearstream, Luxembourg customer or Euroclear participant only in accordance with its relevant rules and procedures and subject to its depositary's ability to effect those actions on its behalf through DTC.

DTC, Clearstream, Luxembourg and Euroclear have agreed to the foregoing procedures in order to facilitate transfers of the notes among participants of DTC, Clearstream, Luxembourg and Euroclear. However, they are under no obligation to perform or continue to perform those procedures, and they may discontinue those procedures at any time.

Transfers Within and Among Book-Entry Systems

Transfers between DTC's direct participants will occur in accordance with DTC rules. Transfers between Clearstream, Luxembourg customers and Euroclear participants will occur in accordance with their respective applicable rules and operating procedures.

DTC will effect cross-market transfers between persons holding directly or indirectly through DTC, on the one hand, and directly or indirectly through Clearstream, Luxembourg customers or Euroclear participants, on the other hand, in accordance with DTC rules on behalf of the relevant European international clearing system by its depositary. However, cross-market transactions will require delivery of instructions to the relevant European international clearing system by the counterparty in that system in accordance with its rules and procedures and within its established deadlines (European time). The relevant European international clearing system will, if the transaction meets its settlement requirements, instruct its depositary to effect final settlement on its behalf by delivering or receiving securities in DTC and making or receiving payment in accordance with normal procedures for same-day funds settlement applicable to DTC. Clearstream, Luxembourg customers and Euroclear participants may not deliver instructions directly to the depositaries.

Because of time-zone differences, credits of securities received in Clearstream, Luxembourg or Euroclear resulting from a transaction with a DTC direct participant will be made during the subsequent securities settlement processing, dated the business day following the DTC settlement date. Those credits or any transactions in those securities settled during that processing will be reported to the relevant Clearstream, Luxembourg customer or Euroclear participant on that business day. Cash received in Clearstream, Luxembourg or Euroclear as a result of sales of securities by or through a Clearstream, Luxembourg customer or a Euroclear participant to a DTC direct participant will be received with value on the DTC settlement date but will be available in the relevant Clearstream, Luxembourg or Euroclear cash amount only as of the business day following settlement in DTC.

Although DTC, Clearstream, Luxembourg and Euroclear have agreed to the foregoing procedures in order to facilitate transfers of debt securities among their respective participants, they are under no obligation to perform or continue to perform such procedures and such procedures may be discontinued at any time.

Certificated Notes

Unless and until they are exchanged, in whole or in part, for notes in definitive form in accordance with the terms of the notes, the notes may not be transferred except (1) as a whole by DTC to a nominee of DTC or (2) by a nominee of DTC to DTC or another nominee of DTC or (3) by DTC or any such nominee to a successor of DTC or a nominee of such successor.

We will issue notes to you or your nominees, in fully certificated registered form, rather than to DTC or its nominees, only if:

- we advise the trustee in writing that DTC is no longer willing or able to discharge its responsibilities properly or that DTC is no longer a registered clearing agency under the Exchange Act, and we have not appointed a qualified successor within 90 days;
- an event of default has occurred and is continuing under the indenture and DTC has notified us and the trustee of its desire to exchange the global notes for certificated notes; or
- subject to DTC's rules, we, at our option, elect to terminate the book-entry system through DTC.

If any of the three above events occurs, DTC is required to notify all direct participants that notes in fully certificated registered form are available through DTC. DTC will then surrender the global note representing the notes along with instructions for re-registration. We will re-issue the notes in fully certificated registered form and will recognize the registered holders of the certificated notes as holders under the indenture.

Unless and until we issue the notes in fully certificated, registered form, (1) you will not be entitled to receive a certificate representing your interest in the notes; (2) all references in this prospectus supplement to actions by holders will refer to actions taken by the depositary upon instructions from its direct participants; and (3) all references in this prospectus supplement to payments and notices to holders will refer to payments and notices to the depositary or its nominee, as the registered holder of the notes, for distribution to you in accordance with its policies and procedures.

Same Day Settlement and Payment

We will make payments in respect of the notes represented by the global notes (including principal, premium, if any, and interest) by wire transfer of immediately available funds to the accounts specified by DTC or its nominee. We will make all payments of principal, interest and premium, if any, with respect to certificated notes by wire transfer of immediately available funds to the accounts specified by the holders of the certificated notes or, if no such account is specified, by mailing a check to each such holder's registered address. The notes represented by the global notes are eligible to trade in DTC's Same-Day Funds Settlement System, and any permitted secondary market trading activity in such notes is, therefore, required by DTC to be settled in immediately available funds. We expect that secondary trading in any certificated notes will also be settled in immediately available funds.

Because of time zone differences, the securities account of a Clearstream, Luxembourg customer or Euroclear participant purchasing an interest in a global note from another customer or participant will be credited, and any such crediting will be reported to the relevant Clearstream, Luxembourg customer or Euroclear participant, during the securities settlement processing day (which must be a business day for Euroclear and Clearstream) immediately following the settlement date of DTC. DTC has advised us that cash received in Clearstream, Luxembourg or Euroclear as a result of sales of interests in a global note by or through a Clearstream, Luxembourg customer or Euroclear participant to another customer or participant will be received with value on the settlement date of DTC but will be available in the relevant Clearstream, Luxembourg or Euroclear cash account only as of the business day for Euroclear or Clearstream, Luxembourg following DTC's settlement date.

CERTAIN UNITED STATES FEDERAL INCOME TAX CONSIDERATIONS

The following is a summary of certain material United States federal income tax consequences of the acquisition, ownership and disposition of the notes offered hereby, but does not purport to be a complete analysis of all potential tax considerations relating to the notes. The federal income tax considerations set forth below are based upon provisions of the Internal Revenue Code of 1986, as amended (the "Code"), applicable Treasury Regulations, judicial authority, and current administrative rulings and pronouncements of the Internal Revenue Service ("IRS") currently in effect. There can be no assurance that the IRS will not take a contrary view, and no ruling from the IRS has been, or will be, sought on the issues discussed in this summary. Legislative, judicial, or administrative changes or interpretations may be forthcoming that could alter or modify the statements and conclusions set forth herein. Any such changes or interpretations may or may not be retroactive and could affect the tax consequences discussed below.

The summary does not address all potential federal tax considerations, such as estate and gift tax considerations, that may be relevant to particular holders of notes and does not address foreign, state, local or other tax consequences. This summary does not address the federal income tax consequences to taxpayers who may be subject to special tax treatment, including, without limitation:

- holders subject to the alternative minimum tax;
- banks, insurance companies, or other financial institutions;
- regulated investment companies;
- small business investment companies;
- real estate investment trusts;
- certain U.S. expatriates;
- dealers in securities or currencies;
- broker-dealers;
- traders in securities that elect to use a mark-to-market method of accounting for their securities holdings;
- holders whose functional currency is not the United States dollar;
- tax-exempt organizations;
- partnerships or other entities classified as partnerships for United States federal income tax purposes;
- persons that hold the notes in a tax-deferred or tax-advantaged account; or
- persons that hold the notes as part of a position in a straddle, or as part of a hedging, conversion, or other integrated investment transaction.

This summary is limited to holders that are initial purchasers of the notes at their original issue price and that hold the notes as capital assets within the meaning of Section 1221 of the Code.

If a partnership (including an entity treated as a partnership for U.S. federal income tax purposes) holds notes, the tax treatment of a partner generally will depend upon the status of the partner and the activities of the partnership. If you are a partner of a partnership acquiring the notes, you are urged to consult your own tax advisor about the U.S. federal income tax consequences of acquiring, holding and disposing of the notes.

THIS SUMMARY OF MATERIAL UNITED STATES FEDERAL INCOME TAX CONSIDERATIONS IS FOR GENERAL INFORMATION ONLY AND IS NOT TAX ADVICE. YOU ARE URGED TO CONSULT YOUR TAX ADVISOR WITH RESPECT TO THE APPLICATION OF UNITED STATES FEDERAL INCOME TAX LAWS WITH RESPECT TO YOUR PARTICULAR SITUATION AS WELL AS ANY TAX CONSEQUENCES ARISING UNDER THE UNITED STATES FEDERAL ESTATE OR GIFT TAX RULES, UNDER THE LAWS OF ANY STATE, LOCAL, FOREIGN OR OTHER TAXING JURISDICTION AND UNDER ANY APPLICABLE TAX TREATY AS IT RELATES TO YOUR PURCHASE, HOLDING AND DISPOSITION OF THE NOTES.

In certain circumstances (see “Description of the Notes—Redemption—Optional Redemption”, “Description of the Notes—Certain Covenants—Change of Control”, and “Description of the Notes—General—Interest Rate Adjustment”), we may elect to or be obligated to pay amounts on the notes that are in excess of stated interest or principal on the notes. We do not intend to treat the possibility of paying such additional amounts as causing the notes to be treated as contingent payment debt instruments. Our treatment is binding on you unless you disclose your contrary position in the manner required by applicable Treasury Regulations. Our determination is not binding on the IRS however. If the IRS successfully challenges our determination, you could be required to treat any gain recognized on the sale or disposition of a note as ordinary income, and the timing and amount of income inclusions could be different from the consequences discussed herein. The remainder of this discussion assumes that the notes will not be treated as contingent payment debt instruments. Prospective investors should consult their own tax advisors regarding the possible application of the contingent payment debt instrument rules to the notes.

Consequences to United States Holders

United States Holders

The discussion in this section will apply to you only if you are a “United States holder” of a note. A “United States holder” is a beneficial owner of the notes who or which is:

- an individual who is a citizen or resident, as defined in Section 7701(b) of the Code, of the United States;
- a corporation, including any entity treated as a corporation for United States federal income tax purposes, created or organized in or under the laws of the United States, any state or political subdivision thereof, or the District of Columbia;
- an estate if its income is subject to United States federal income taxation regardless of its source; or
- a trust if (a) a United States court can exercise primary supervision over its administration and one or more United States persons have the authority to control all of its substantial decisions, or (b) such trust has in effect a valid election to be treated as a domestic trust for United States federal income tax purposes.

Interest on the Notes

The notes will be issued without original issue discount for U.S. federal income tax purposes. Accordingly, if you are a United States holder, interest on a note will generally be taxable to you as ordinary income at the time it accrues or is received in accordance with your method of accounting for United States federal income tax purposes.

Sale, Exchange, Redemption or Retirement of the Notes

You generally will recognize taxable gain or loss upon the sale, exchange, redemption, retirement at maturity or other taxable disposition of a note in an amount equal to the difference between the amount of cash plus the fair market value of all property received on such disposition (except to the extent such cash or property is attributable to accrued interest, which is taxable as ordinary income to the extent not previously included in income) and your adjusted tax basis in the note. In general, your adjusted tax basis in a note will equal the price paid for the note. In general, gain or loss recognized on the disposition of a note will be capital gain or loss, and will generally be long-term capital gain or loss if at the time of disposition, the note has been held for more than one year. The deductibility of capital losses may be subject to limitations.

Information Reporting and Back-Up Withholding

You may be subject to back-up withholding (currently at a rate of 28% but scheduled to increase to 31% for payments made after December 31, 2012) with respect to certain reportable payments, including interest payments, and, under certain circumstances, principal payments on the notes and payments of the proceeds of the sale of notes, if you, among other things

- fail to provide the payor with an IRS Form W-9 or substitute Form W-9 which is signed under penalties of perjury, and in which you furnish a social security number or other taxpayer identification number, within a reasonable time after the request for such Form W-9;
- furnish an incorrect taxpayer identification number; or
- fail to report interest properly.

Back-up withholding is not an additional tax. Any amount withheld from a payment to you under the back-up withholding rules is creditable against your income tax liability, if any, and a refund may be obtained of any amounts withheld in excess of your actual U.S. federal income tax liability, provided that you timely file the appropriate forms and/or returns with the IRS. Back-up withholding does not apply, however, if you properly establish your eligibility for an exemption from back-up withholding. Information reporting generally will apply to such reportable payments unless you are an exempt recipient, such as a corporation.

New Legislation Relating to Net Investment Income

For taxable years beginning after December 31, 2012, newly-enacted legislation is scheduled to impose a 3.8% tax on the “net investment income” of certain United States individuals and on the undistributed “net investment income” of certain estates and trusts. “Net investment income” generally includes interest and certain net gain from the disposition of property.

Prospective holders should consult their tax advisors with respect to the tax consequences of the new legislation described above with respect to your investment in the notes.

Consequences to Non-United States Holders

Non-United States Holders

The discussion in this section will apply to you only if you are “Non-United States holder” of a note. A “Non-United States holder” is a beneficial owner of the notes that is an individual, corporation, estate or trust and that is not a “United States holder” as defined in “Consequences to United States Holders—United States Holders” above.

Interest Income

Interest paid or accrued on your note will not be subject to United States federal income tax or withholding tax if the interest is not effectively connected with the conduct of a trade or business within the United States by you (or attributable to a permanent establishment maintained by you in the United States, if a tax treaty applies) and each of the following conditions are met:

- you do not actually or constructively own 10% or more of the total combined voting power of all classes of our voting stock;
- you are not a controlled foreign corporation that is related to us through stock ownership;
- you are not a bank whose receipt of interest on a note is described in Section 881(c)(3)(A) of the Code; and
- (A) you certify, under penalties of perjury, that you are not a United States person (which certification may be made on IRS Form W-8BEN or substitute form) and provide the relevant withholding agent your name and address or (B) you are a securities clearing organization, bank, or other financial institution that holds customers' securities in the ordinary course of its trade or business and you certify, under penalties of perjury, you have received the certification and information described in (A) above from the Non-United States holder and you furnish the relevant withholding agent with a copy thereof.

Special certification rules apply to foreign partnerships, estates and trusts. In certain circumstances, certifications as to foreign status of partners, trust owners, or beneficiaries may be required to be provided to our paying agent or to us. In addition, special rules apply to payments made through a qualified intermediary.

Payments of interest that do not meet the above requirements will generally be subject to a United States federal income tax of 30% (or such lower rate provided by an applicable income tax treaty if you establish that you are qualified to receive the benefits of such treaty), collected by means of withholding, except to the extent provided below.

If you are a Non-United States holder engaged in a trade or business in the United States, and if interest on the note (or gain realized on its sale, exchange or other taxable disposition) is effectively connected with the conduct of such trade or business (and, if a tax treaty applies, is attributable to a permanent establishment maintained by you in the United States), you will generally be subject to United States income tax on such effectively connected income in the same manner as if you were a United States holder. In addition, if you are a foreign corporation, you may be subject to a 30% branch profits tax (unless reduced or eliminated by an applicable tax treaty) on your effectively connected earnings and profits for the taxable year, subject to certain adjustments. You will generally be exempt from withholding tax if you provide to the withholding agent a properly executed IRS Form W-8ECI to claim an exemption from withholding tax.

Non-United States holders should consult their tax advisors regarding any applicable income tax treaties, which may provide for rules different from those described above.

Sale, Exchange, Redemption or Retirement of the Notes

If you are a Non-United States holder, you will generally not be subject to United States federal income tax on gain recognized on a sale, redemption or other taxable disposition of a note (except to the extent the disposition proceeds represent accrued interest, the exemption described above with respect to interest is not applicable and the interest is not exempt from United States federal income taxation under an applicable treaty) unless (i) the gain is effectively connected with the conduct of a trade or business within the United States by you (and is attributable to a permanent establishment maintained in the United States, if a tax treaty applies), in which case you generally will be subject to United States income tax on such gain in the same manner as a United States holder and may also be subject to a branch profits tax of 30% (or lower rate provided by an applicable tax treaty) if you are a corporation, or (ii) you are a nonresident alien individual who is present in the United States for 183 or more days during the taxable year of the disposition and certain other conditions are met, in which case you will generally be subject to a 30% United States federal income tax on any gain recognized (net of certain United States source net capital loss).

Information Reporting and Backup Withholding

Payments of interest to Non-United States holders with respect to which the requisite certification has been received (or for which an exemption has otherwise been established) generally will not be subject to back-up withholding. This exemption does not apply if we or our payment agent has actual knowledge that you are a United States person or that the conditions of any such exemption are not in fact satisfied. Information reporting (on Form 1042-S) will generally apply to payments of interest even if certification is provided and the interest is exempt from the 30% United States federal withholding tax. Copies of these information returns may also be made available to the tax authorities of the country in which you reside under the provisions of a specific treaty or agreement.

Neither information reporting nor backup withholding generally will apply to a payment of the proceeds of a disposition of the notes which is effected by or through the foreign office of a foreign broker so long as the foreign broker does not have certain types of specified relationships to the United States. Information reporting and backup withholding generally will apply to a payment of the proceeds of a disposition of the notes which is effected by or through a United States office of any broker, unless the broker can reliably associate the payment with a Form W-8BEN or other documentation that establishes that the person is the foreign beneficial owner of the payment. Information reporting generally will also apply to a payment of the proceeds of a disposition of the notes which is effected through a foreign office of a United States broker or a foreign broker with certain types of specified relationships to the United States, unless the broker can reliably associate the payment with a Form W-8BEN or other documentation that establishes that the person is the foreign beneficial owner of the payment.

Back-up withholding is not an additional tax. Any amount withheld from a payment to you under the back-up withholding rules is creditable against your actual U.S. federal income tax liability, if any, and a refund may be obtained of any amounts withheld in excess of your actual U.S. federal income tax liability, provided that you timely file the appropriate forms and/or returns with the IRS.

UNDERWRITING

Merrill Lynch, Pierce, Fenner & Smith Incorporated is acting as representative of each of the underwriters named below. Subject to the terms and conditions set forth in an underwriting agreement among us and the underwriters, we have agreed to sell to the underwriters, and each of the underwriters has agreed, severally and not jointly, to purchase from us, the principal amount of notes set forth opposite its name below.

Underwriter	Principal Amount of Notes
Merrill Lynch, Pierce, Fenner & Smith Incorporated	$ 128,125,000
BMO Capital Markets Corp.	49,859,000
Banco Bilbao Vizcaya Argentaria, S.A.	17,727,000
Credit Agricole Securities (USA) Inc.	13,849,000
BNP Paribas Securities Corp.	13,849,000
Comerica Securities, Inc.	13,849,000
Bosc, Inc.	8,310,000
BB&T Capital Markets, a division of Scott & Stringfellow, LLC	4,432,000
Total	$ 250,000,000

Subject to the terms and conditions set forth in the underwriting agreement, the underwriters have agreed, severally and not jointly, to purchase all of the notes sold under the underwriting agreement if any of these notes are purchased. If an underwriter defaults, the underwriting agreement provides that the purchase commitments of the nondefaulting underwriters may be increased or the underwriting agreement may be terminated.

We have agreed to indemnify the underwriters and their controlling persons against certain liabilities in connection with this offering, including liabilities under the Securities Act, or to contribute to payments the underwriters may be required to make in respect of those liabilities.

The underwriters are offering the notes, subject to prior sale, when, as and if issued to and accepted by them, subject to approval of legal matters by their counsel, including the validity of the notes, and other conditions contained in the underwriting agreement, such as the receipt by the underwriters of officer's certificates and legal opinions. The underwriters reserve the right to withdraw, cancel or modify offers to the public and to reject orders in whole or in part.

Commissions and Discounts

The representative has advised us that the underwriters propose initially to offer the notes to the public at the public offering price set forth on the cover page of this prospectus supplement. After the initial offering, the public offering price or any other term of the offering may be changed.

The expenses of the offering, not including the underwriting discount, are estimated at $1 million and are payable by us.

New Issue of Notes

The notes are a new issue of securities with no established trading market. We do not intend to apply for listing of the notes on any national securities exchange or for inclusion of the notes on any automated dealer quotation system. We have been advised by the underwriters that they presently intend to make a market in the notes after completion of the offering. However, they are under no obligation to do so and may discontinue any market-making activities at any time without any notice. We cannot assure the liquidity of the trading market for the notes or that an active public market for the notes will develop. If an active public trading market for the notes does not develop, the market price and liquidity of the notes may be adversely affected. If the notes are traded, they may trade at a discount from their initial offering price, depending on prevailing interest rates, the market for similar securities, our operating performance and financial condition, general economic conditions and other factors.

Settlement

We expect that delivery of the notes will be made to investors on or about May 18, 2011, which will be the fifth business day following the date of this prospectus supplement (such settlement being referred to as "T+5"). Under Rule 15c6-1 under the Securities Exchange Act of 1934, trades in the secondary market are required to settle in three business days, unless the parties to any such trade expressly agree otherwise. Accordingly, purchasers who wish to trade notes prior to the delivery of the notes hereunder will be required, by virtue of the fact that the notes initially settle in T+5, to specify an alternate settlement arrangement at the time of any such trade to prevent a failed settlement. Purchasers of the notes who wish to trade the notes prior to their date of delivery hereunder should consult their advisors.

No Sales of Similar Securities

We have agreed that we will not, for a period of 180 days after the date of this prospectus supplement, without first obtaining the prior written consent of Merrill Lynch, Pierce, Fenner & Smith Incorporated, directly or indirectly, issue, sell, offer to contract or grant any option to sell, pledge, transfer or otherwise dispose of, any debt securities or securities exchangeable for or convertible into debt securities, except for the notes sold to the underwriters pursuant to the underwriting agreement.

Short Positions

In connection with the offering, the underwriters may purchase and sell the notes in the open market. These transactions may include short sales and purchases on the open market to cover positions created by short sales. Short sales involve the sale by the underwriters of a greater principal amount of notes than they are required to purchase in the offering. The underwriters must close out any short position by purchasing notes in the open market. A short position is more likely to be created if the underwriters are concerned that there may be downward pressure on the price of the notes in the open market after pricing that could adversely affect investors who purchase in the offering.

Similar to other purchase transactions, the underwriters' purchases to cover the syndicate short sales may have the effect of raising or maintaining the market price of the notes or preventing or retarding a decline in the market price of the notes. As a result, the price of the notes may be higher than the price that might otherwise exist in the open market.

Neither we nor any of the underwriters make any representation or prediction as to the direction or magnitude of any effect that the transactions described above may have on the price of the notes. In addition, neither we nor any of the underwriters make any representation that the representative will engage in these transactions or that these transactions, once commenced, will not be discontinued without notice.

Conflicts of Interest

More than 5% of the net proceeds of the offering will be used to repay borrowings we have received from both Bank of America, N.A., an affiliate of Merrill Lynch, Pierce, Fenner & Smith Incorporated, and BMO Capital Markets Financing, Inc., an affiliate of BMO Capital Markets Corp. Because Merrill Lynch, Pierce, Fenner & Smith Incorporated and BMO Capital Markets Corp. are participating underwriters in this offering, a "conflict of interest" is deemed to exist under the applicable provisions of Rule 5121 of the Financial Industry Regulatory Authority, Inc., or FINRA. Accordingly, this offering will be made in compliance with the applicable provisions of Rule 5121, which require that a "qualified independent underwriter," as defined by the FINRA rules, participate in the preparation of the registration statement and the prospectus and exercise the usual standards of due diligence in respect thereto. BB&T Capital Markets, a division of Scott & Stringfellow, LLC, is serving in that capacity. We have agreed to indemnify BB&T Capital Markets, a division of Scott & Stringfellow, LLC, against certain liabilities incurred in connection with acting as qualified independent underwriter for the offering, including liabilities under the Securities Act. In addition, in accordance with Rule 5121, neither Merrill Lynch, Pierce, Fenner & Smith Incorporated nor BMO Capital Markets Corp. will make sales to discretionary accounts without the prior written consent of the customer.

Other Relationships

Some of the underwriters and their affiliates have engaged in, and may in the future engage in, investment banking and other commercial dealings in the ordinary course of business with us or our affiliates. They have received, or may in the future receive, customary fees and commissions for these transactions.

Merrill Lynch, Pierce Fenner & Smith Incorporated and BMO Capital Markets Corp. are affiliates of lenders under our credit facility. At March 31, 2011, there was $185 million outstanding under our credit facility. We intend to use the proceeds of this offering to repay the amounts outstanding under the credit facility. See “Conflicts of Interest” above.

In addition, in the ordinary course of their business activities, the underwriters and their affiliates may make or hold a broad array of investments and actively trade debt and equity securities (or related derivative securities) and financial instruments (including bank loans) for their own account and for the accounts of their customers. Such investments and securities activities may involve securities and/or instruments of ours or our affiliates. The underwriters and their affiliates may also make investment recommendations and/or publish or express independent research views in respect of such securities or financial instruments and may hold, or recommend to clients that they acquire, long and/or short positions in such securities and instruments.

Notice to Prospective Investors in the European Economic Area

In relation to each member state of the European Economic Area which has implemented the Prospectus Directive (each, a “Relevant Member State”), including each Relevant Member State that has implemented the 2010 PD Amending Directive with regard to persons to whom an offer of securities is addressed and the denomination per unit of the offer of securities (each, an “Early Implementing Member State”), with effect from and including the date on which the Prospectus Directive is implemented in that Relevant Member State (the “Relevant Implementation Date”), no offer of securities will be made to the public in that Relevant Member State (other than offers (the “Permitted Public Offers”) where a prospectus will be published in relation to the securities that have been approved by the competent authority in a Relevant Member State or, where appropriate, approved in another Relevant Member State and notified to the competent authority in that Relevant Member State, all in accordance with the Prospectus Directive), except that with effect from and including that Relevant Implementation Date, offers of securities may be made to the public in that Relevant Member State at any time:

A. to “qualified investors” as defined in the Prospectus Directive, including:

(a) (in the case of Relevant Member States other than Early Implementing Member States), legal entities which are authorized or regulated to operate in the financial markets or, if not so authorized or regulated, whose corporate purpose is solely to invest in securities, or any legal entity which has two or more of (i) an average of at least 250 employees during the last financial year; (ii) a total balance sheet of more than €43.0 million and (iii) an annual turnover of more than €50.0 million as shown in its last annual or consolidated accounts; or

(b) (in the case of Early Implementing Member States), persons or entities that are described in points (1) to (4) of Section I of Annex II to Directive 2004/39/EC, and those who are treated on request as professional clients in accordance with Annex II to Directive 2004/39/EC, or recognized as eligible counterparties in accordance with Article 24 of Directive 2004/39/EC unless they have requested that they be treated as non-professional clients; or

B. to fewer than 100 (or, in the case of Early Implementing Member States, 150) natural or legal persons (other than "qualified investors" as defined in the Prospectus Directive), as permitted in the Prospectus Directive, subject to obtaining the prior consent of the representative for any such offer; or

C. in any other circumstances falling within Article 3(2) of the Prospectus Directive, provided that no such offer of securities shall result in a requirement for the publication of a prospectus pursuant to Article 3 of the Prospectus Directive or of a supplement to a prospectus pursuant to Article 16 of the Prospectus Directive.

Each person in a Relevant Member State (other than a Relevant Member State where there is a Permitted Public Offer) who initially acquires any securities or to whom any offer is made will be deemed to have represented, acknowledged and agreed that (A) it is a "qualified investor", and (B) in the case of any securities acquired by it as a financial intermediary, as that term is used in Article 3(2) of the Prospectus Directive, (x) the securities acquired by it in the offering have not been acquired on behalf of, nor have they been acquired with a view to their offer or resale to, persons in any Relevant Member State other than "qualified investors" as defined in the Prospectus Directive, or in circumstances in which the prior consent of the Subscribers has been given to the offer or resale, or (y) where securities have been acquired by it on behalf of persons in any Relevant Member State other than "qualified investors" as defined in the Prospectus Directive, the offer of those securities to it is not treated under the Prospectus Directive as having been made to such persons.

For the purpose of the above provisions, the expression "an offer to the public" in relation to any securities in any Relevant Member State means the communication in any form and by any means of sufficient information on the terms of the offer of any securities to be offered so as to enable an investor to decide to purchase any securities, as the same may be varied in the Relevant Member State by any measure implementing the Prospectus Directive in the Relevant Member State and the expression "Prospectus Directive" means Directive 2003/71 EC (including the 2010 PD Amending Directive, in the case of Early Implementing Member States) and includes any relevant implementing measure in each Relevant Member State and the expression "2010 PD Amending Directive" means Directive 2010/73/EU.

Notice to Prospective Investors in Switzerland

This prospectus supplement and the accompanying prospectus do not constitute an issue prospectus pursuant to Article 652a or Article 1156 of the Swiss Code of Obligations and the notes will not be listed on the SIX Swiss Exchange. Therefore, this prospectus supplement and the accompanying prospectus may not comply with the disclosure standards of the listing rules (including any additional listing rules or prospectus schemes) of the SIX Swiss Exchange. Accordingly, the notes may not be offered to the public in or from Switzerland, but only to a selected and limited circle of investors who do not subscribe to the notes with a view to distribution. Any such investors will be individually approached by the underwriters from time to time.

Notice to Prospective Investors in the Dubai International Financial Centre

This prospectus supplement and the accompanying prospectus relates to an Exempt Offer in accordance with the Offered Securities Rules of the Dubai Financial Services Authority ("DFSA"). This prospectus supplement and the accompanying prospectus is intended for distribution only to persons of a type specified in the Offered Securities Rules of the DFSA. They must not be delivered to, or relied on by, any other person. The DFSA has no responsibility for reviewing or verifying any documents in connection with Exempt Offers. The DFSA has not approved this prospectus supplement and the accompanying prospectus nor taken steps to verify the information set forth herein and has no responsibility for the prospectus supplement and the accompanying prospectus. The notes to which this prospectus supplement and the accompanying prospectus relate may be illiquid and/or subject to restrictions on their resale. Prospective purchasers of the notes offered should conduct their own due diligence on the notes. If you do not understand the contents of this prospectus supplement and the accompanying prospectus you should consult an authorized financial advisor.

Notice to Prospective Investors in Hong Kong

This prospectus supplement and the accompanying prospectus have not been approved by or registered with the Securities and Futures Commission of Hong Kong or the Registrar of Companies of Hong Kong. The notes will not be offered or sold in Hong Kong other than (a) to "professional investors" as defined in the Securities and Futures Ordinance (Cap. 571) of Hong Kong and any rules made under that Ordinance; or (b) in other circumstances which do not result in the document being a "prospectus" as defined in the Companies Ordinance (Cap. 32) of Hong Kong or which do not constitute an offer to the public within the meaning of that Ordinance. No advertisement, invitation or document relating to the notes which is directed at, or the contents of which are likely to be accessed or read by, the public of Hong Kong (except if permitted to do so under the securities laws of Hong Kong) has been issued or will be issued in Hong Kong or elsewhere other than with respect to notes which are or are intended to be disposed of only to persons outside Hong Kong or only to "professional investors" as defined in the Securities and Futures Ordinance and any rules made under that Ordinance.

Notice to Prospective Investors in Singapore

This prospectus supplement and the accompanying prospectus have not been registered as a prospectus with the Monetary Authority of Singapore. Accordingly, this prospectus supplement and the accompanying prospectus and any other document or material in connection with the offer or sale, or invitation for subscription or purchase, of the notes may not be circulated or distributed, nor may the notes be offered or sold, or be made the subject of an invitation for subscription or purchase, whether directly or indirectly, to persons in Singapore other than (i) to an institutional investor under Section 274 of the Securities and Futures Act (Chapter 289) (the "SFA"), (ii) to a relevant person, or any person pursuant to Section 275(1A), and in accordance with the conditions, specified in Section 275 of the SFA or (iii) otherwise pursuant to, and in accordance with the conditions of, any other applicable provision of the SFA. Where the notes are subscribed or purchased under Section 275 by a relevant person which is: (a) a corporation (which is not an accredited investor) the sole business of which is to hold investments and the entire share capital of which is owned by one or more individuals, each of whom is an accredited investor; or (b) a trust (where the trustee is not an accredited investor) whose sole purpose is to hold investments and each beneficiary is an accredited investor, then securities, debentures and units of securities and debentures of that corporation or the beneficiaries' rights and interest in that trust shall not be transferable for 6 months after that corporation or that trust has acquired the notes under Section 275 except: (i) to an institutional investor under Section 274 of the SFA or to a relevant person, or any person pursuant to Section 275(1A), and in accordance with the conditions, specified in Section 275 of the SFA; (ii) where no consideration is given for the transfer; or (iii) by operation of law.

VALIDITY OF THE NOTES

The validity of the notes offered hereby, will be passed upon for us by Conner & Winters, LLP, Tulsa, Oklahoma, and for the underwriters by Davis Polk & Wardwell LLP, New York, New York. Lynnwood R. Moore, Jr., a partner in Conner & Winters, LLP, beneficially owns 4,500 shares of our common stock.

EXPERTS

The financial statements incorporated in this Prospectus Supplement by reference to Unit Corporation's Current Report on Form 8-K dated May 3, 2011 and management's assessment of the effectiveness of internal control over financial reporting (which is included in Management's Report on Internal Control over Financial Reporting) incorporated in this Prospectus Supplement by reference to the Annual Report on Form 10-K of Unit Corporation for the year ended December 31, 2010 have been so incorporated in reliance on the report of PricewaterhouseCoopers LLP, an independent registered public accounting firm, given on the authority of said firm as experts in auditing and accounting.

GLOSSARY

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

ARO—Asset retirement obligations.

ASC—FASB Accounting Standards Codification.

ASU—Accounting Standards update.

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.

BOE—Barrels of oil equivalent. Determined using the ratio of six Mcf to one barrel of crude oil.

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.

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.

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.

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

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 or NGLs to six Mcf of natural gas.

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 or NGLs to six Mcf of natural gas.

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

NGLs—Natural gas liquids.

NYMEX—The New York Mercantile Exchange.

Play—A term applied by geologists and geophysicists identifying an area with potential oil and gas reserves.

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

Proved developed reserves—Are reserves from any category that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and through installed extraction equipment and infrastructure operational at the time of the reserves estimate is by means not involving a well. For additional information, see the SEC's definition in Rule 4-10(a)(3) of Regulation S-X.

Proved reserves—Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geosciences and engineering data, can be estimated with reasonable certainty to be economically producible – from a given date forward, from known reservoirs and under existing economic conditions, operating methods and government regulations – prior to the time at which contracts providing the right to operate expire, unless evidence indicated that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. 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. For additional information, see the SEC's definition in Rule 4-10(a)(4) of Regulation S-X.

Put—Is a contract that allows the holder to sell the underlying at a specific price within a designated period of time.

Reasonable certainty (in regards to reserves)—If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate.

Reliable technology—Is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

SARs—Stock appreciation rights.

Swaps—Is a transaction where 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 from the counterparty.

Unconventional play—Plays targeting tight sand, coal bed or gas shale reservoirs. The reservoirs tend to cover large areas and lack the readily apparent traps, seals and discrete hydrocarbon-water boundaries that typically define conventional reservoirs. These reservoirs generally require stimulation treatments or other special recovery processes in order to produce economically.

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

Index to Financial Statements
Unit Corporation and Subsidiaries

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, 2010. 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, 2010, 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, 2010, 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 operations, 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, 2010 and 2009, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2010, 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 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, 2010, 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.

As discussed in Note 2 to the consolidated financial statements, at December 31, 2009 the Company changed the manner in which it estimates oil and gas reserves.

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.

/s/ PricewaterhouseCoopers LLP

Tulsa, Oklahoma
February 24, 2011, except with respect to our opinion on the consolidated financial statements insofar as it relates to guaranteed subsidiaries discussed in Note 6, as to which the date is May 3, 2011.

Table of Contents

UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	As of December 31, 2010	As of December 31, 2009
	(In thousands except share and par value amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,359	$ 1,140
Restricted cash	0	20
Accounts receivable (less allowance for doubtful accounts of $5,083 and $5,186)	130,142	74,382
Materials and supplies	6,316	6,914
Current derivative asset (Note 13)	5,568	9,945
Current income tax receivable	25,211	15,236
Current deferred tax asset (Note 8)	13,537	14,423
Prepaid expenses and other	6,047	6,035
Total current assets	188,180	128,095
Property and equipment:		
Drilling equipment	1,273,861	1,217,361
Oil and natural gas properties, on the full cost method:		
Proved properties	2,738,093	2,309,193
Undeveloped leasehold not being amortized	175,065	140,129
Gas gathering and processing equipment	199,564	172,549
Transportation equipment	31,688	30,726
Other	28,511	22,747
	4,446,782	3,892,705
Less accumulated depreciation, depletion, amortization and impairment	2,047,031	1,879,112
Net property and equipment	2,399,751	2,013,593
Goodwill (Note 2)	62,808	62,808
Other intangible assets, net	3,022	5,633
Non-current derivative asset (Note 13)	2,537	0

Other assets	12,942	18,270
Total assets	$ 2,669,240	$ 2,228,399

LIABILITIES AND SHAREHOLDERS' EQUITY

Current liabilities:		
Accounts payable	$ 89,885	$ 55,880
Accrued liabilities (Note 5)	30,093	34,571
Contract advances	2,582	3,124
Current portion of derivative liabilities (Note 13)	14,446	2,230
Current portion of other long-term liabilities (Note 6)	10,122	9,342
Total current liabilities	147,128	105,147
Long-term debt (Note 6)	163,000	30,000
Long-term derivative liabilities (Note 13)	4,359	1,142
Other long-term liabilities (Note 6)	88,030	79,984
Deferred income taxes (Note 8)	556,106	446,316
Commitments and contingencies (Note 15)		
Shareholders' equity:		
Preferred stock, $1.00 par value, 5,000,000 shares authorized, none issued	0	0
Common stock, $0.20 par value, 175,000,000 shares authorized, 47,910,431 and 47,530,669 shares issued as of December 31, 2010 and 2009, respectively	9,493	9,405
Capital in excess of par value	393,501	383,957
Accumulated other comprehensive income (loss) (net of tax of ($4,243) and $2,757, respectively)	(6,851)	4,458
Retained earnings	1,314,474	1,167,990
Total shareholders' equity	1,710,617	1,565,810
Total liabilities and shareholders' equity	$ 2,669,240	$ 2,228,399

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

[Table of Contents](#)

UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2010	2009	2008
	(In thousands except per share amounts)		
Revenues:			
Contract drilling	$316,384	$236,315	$ 622,727
Oil and natural gas	400,807	357,879	553,998
Gas gathering and processing	154,516	108,628	181,730
Other	10,138	7,076	(362)
Total revenues	881,845	709,898	1,358,093
Expenses:			
Contract drilling:			
Operating costs	186,813	140,080	312,907
Depreciation	69,970	45,326	69,841
Oil and natural gas:			
Operating costs	105,365	87,734	116,239
Depreciation, depletion and amortization	118,793	114,681	159,550
Impairment of oil and natural gas properties (Note 2)	0	281,241	281,966
Gas gathering and processing:			
Operating costs	122,146	87,908	150,466
Depreciation and amortization	15,385	16,104	14,822
General and administrative	26,152	24,011	25,419
Interest, net	0	539	1,304
Total expenses	644,624	797,624	1,132,514
Income (loss) before income taxes	237,221	(87,726)	225,579
Income tax expense (benefit):			

Current	(9,935)	(223)	40,877
Deferred	100,672	(32,003)	41,077
Total income taxes	90,737	(32,226)	81,954
Net income (loss)	$146,484	$ (55,500)	$ 143,625
Net income (loss) per common share:			
Basic	$ 3.10	$ (1.18)	$ 3.08
Diluted	$ 3.09	$ (1.18)	$ 3.06

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

UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY
Year Ended December 31, 2008, 2009 and 2010

	Common Stock	Capital In Excess of Par Value	Accumulated Other Compre- hensive Income	Retained Earnings	Total
Balances, January 1, 2008	$ 9,280	$344,512	$ 1,160	$1,079,865	$1,434,817
Comprehensive income:					
Net Income	0	0	0	143,625	143,625
Other comprehensive income (net of tax of $18,704, $275 and ($94)):					
Change in value of cash flow derivative instruments used as cash flow hedges	0	0	31,816	0	31,816
Reclassification—derivative settlements	0	0	469	0	469
Ineffective portion of derivatives qualifying for cash flow hedge accounting	0	0	(161)	0	(161)
Total comprehensive income	0	0	0	0	175,749
Activity in employee compensation plans (220,875 shares)	45	22,488	0	0	22,533
Balances, December 31, 2008	9,325	367,000	33,284	1,223,490	1,633,099
Comprehensive income (loss):					
Net loss	0	0	0	(55,500)	(55,500)
Other comprehensive income (loss) (net of tax of $20,430, ($37,560), $340):					
Change in value of cash flow derivative instruments used as cash flow hedges	0	0	32,307	0	32,307
Reclassification—derivative settlements	0	0	(61,690)	0	(61,690)
Ineffective portion of derivatives qualifying for cash flow hedge accounting	0	0	557	0	557
Total comprehensive loss	0	0	0	0	(84,326)
Activity in employee compensation plans (274,705 shares)	80	16,957	0	0	17,037
Balances, December 31, 2009	9,405	383,957	4,458	1,167,990	1,565,810
Comprehensive income (loss):					
Net income					

	0	0	0	146,484	146,484
Other comprehensive income (loss) (net of tax of $13,254, ($19,987), ($267)):					
Change in value of cash flow derivative instruments used as cash flow hedges	0	0	21,392	0	21,392
Reclassification—derivative settlements	0	0	(32,268)	0	(32,268)
Ineffective portion of derivatives qualifying for cash flow hedge accounting	0	0	(433)	0	(433)
Total comprehensive income	0	0	0	0	135,175
Activity in employee compensation plans (379,762 shares)	88	9,544	0	0	9,632
Balances, December 31, 2010	$ 9,493	$393,501	$ (6,851)	$1,314,474	$1,710,617

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

UNIT CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31, 2010	2009	2008
	(In thousands)		
OPERATING ACTIVITIES:			
Net income (loss)	$ 146,484	$ (55,500)	$ 143,625
Adjustments to reconcile net income (loss) to net cash provided (used) by operating activities:			
Depreciation, depletion and amortization	205,124	177,166	244,912
Impairment of oil and natural gas properties (Note 2)	0	281,241	281,966
Unrealized (gain) loss on derivatives	(1,036)	1,944	(1,302)
(Gain) loss on disposition of assets	(9,687)	(6,224)	725
Deferred tax expense (benefit)	100,672	(32,003)	41,077
Employee stock compensation plans	10,067	10,708	15,863
Bad debt expense	0	975	1,543
ARO liability accretion	2,937	2,585	2,174
Other, net	(69)	(130)	(247)
Changes in operating assets and liabilities increasing (decreasing) cash:			
Accounts receivable	(58,965)	116,472	(34,495)
Materials and supplies	598	3,009	3,635
Prepaid expenses and other	6,957	(1,525)	(9,996)
Accounts payable	(8,913)	(7,068)	3,685
Accrued liabilities	(3,555)	(1,410)	684
Contract advances	(542)	235	(3,936)
Net cash provided by operating activities	390,072	490,475	689,913
INVESTING ACTIVITIES:			
Capital expenditures	(484,080)	(316,660)	(782,434)
Producing property and other acquisitions	(92,573)	0	(25,727)

Proceeds from disposition of property and equipment	40,048	44,733	4,735
Acquisition of other assets	344	0	(2,715)
Net cash used in investing activities	(536,261)	(271,927)	(806,141)
FINANCING ACTIVITIES:			
Borrowings under line of credit	286,900	95,600	397,600
Payments under line of credit	(153,900)	(265,100)	(318,700)
Proceeds from exercise of stock options	149	282	2,507
Tax (expense) benefit from stock options	40	(252)	1,449
Increase (decrease) in book overdrafts (Note 2)	13,219	(48,522)	32,880
Net cash provided by (used in) financing activities	146,408	(217,992)	115,736
Net increase (decrease) in cash and cash equivalents	219	556	(492)
Cash and cash equivalents, beginning of year	1,140	584	1,076
Cash and cash equivalents, end of year	$ 1,359	$ 1,140	$ 584
Supplemental disclosure of cash flow information:			
Cash paid during the year for:			
Interest paid (net of capitalized)	$ 0	$ 682	$ 1,679
Income taxes	$ 3,143	$ 12,302	$ 45,700
Changes in accounts payable and accrued liabilities related to purchases of property, plant and equipment	$ (29,700)	$ 18,285	$ 7,068

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

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 and 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) Midstream.

Contract Drilling. Carried out by our subsidiary, Unit Drilling Company and its subsidiary, 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 oil and natural gas producing provinces of Oklahoma, Texas, Louisiana, Wyoming, Colorado, Utah, Montana and North Dakota. 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 producing oil and natural gas properties, undeveloped leaseholds and related assets are located mainly in Oklahoma, Texas, Louisiana, North Dakota, Colorado and Pennsylvania and, to a lesser extent, in Arkansas, New Mexico, Wyoming, Montana, Alabama, Kansas, Mississippi, Michigan, Maryland and a small portion in Canada. The majority of our contract drilling and exploration and production activities are oriented toward drilling for and producing natural gas.

Midstream. Carried out by our subsidiary, Superior Pipeline Company, L.L.C. and its subsidiary, 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, Kansas, Pennsylvania and West Virginia.

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. The 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 deter- minable. 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 current assets. Typically, any one of these three types of contracts can be used for the drilling of one well which can take from 20 to 90 days. At December 31, 2010, substantially all of our contracts were daywork contracts of which 38 were multi-well and had durations which ranged from six months to two years. These 38 contracts do not include the five term contracts for the new drilling rigs we are adding in 2011. 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, 2009 we did not have any book overdrafts and at December 31, 2010, book overdrafts were $13.1 million and included in accounts payable.

Accounts Receivable. Accounts receivable are carried on a gross basis, with no discounting, less an allowance for doubtful accounts. 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 and Non-performance 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. Below are the third-party customers that accounted for more than 10% of our segment’s revenues:

	2010	2009 (In thousands)	2008
Drilling:			
QEP Resources, Inc.	28%	35%	19%
Mid-stream:			
ONEOK	53%	52%	79%
Gavilon	12%	0%	0%
ConocoPhillips	12%	15%	0%
Tenaska	7%	17%	0%

There was not a third party customer that accounted for more than 10% of our oil and natural gas revenues during 2010, 2009 or 2008.

We had a concentration of cash of $23.8 million and $35.0 million at December 31, 2010 and 2009, respectively with one bank.

The use of derivative transactions also involves the risk that the counterparties will be unable to meet the financial terms of the transactions. We considered this non-performance risk with regard to our counterparties and our own non-performance risk in our derivative valuation at December 31, 2010 and determined there was no material risk at that time. At December 31, 2010, the fair values of the net assets (liabilities) we had with each of the counterparties with respect to all of our commodity derivative transactions are listed in the table below:

	December 31, 2010 (In millions)
Bank of Montreal	$ 7.4
Bank of America, N.A.	(0.3)
Crédit Agricole Corporate and Investment Bank, London Branch	(8.5)
Comerica Bank	(5.6)
BBVA Compass Bank	(2.3)
Barclays Capital	0.1
BNP Paribas	0.2
ConocoPhillips	(0.1)
Total	$ (9.1)

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 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. No significant impairments were recorded at December 31, 2010, 2009 or 2008.

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 accreting an interest charge. 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 and is performed additionally when events indicate an impairment may have occurred. Goodwill is all related to our contract drilling segment, and accordingly, the impairment test is generally based on the estimated discounted future net cash flows of our drilling segment, utilizing discount rates and other factors in determining the fair value of our drilling segment. No goodwill impairment was recorded for the years ended December 31, 2010, 2009, or 2008. There were no additions to goodwill in 2010, 2009 or 2008. Goodwill of $6.5 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. No intangible asset impairment was recorded for the years ended December 31, 2010 or 2009. Amortization of $2.6 million, $3.7 million and $4.4 million was recorded in 2010, 2009 and 2008, respectively. Accumulated amortization for 2010 and 2009 was $14.9 million and $12.3 million, respectively. Amortization of $1.2 million, $1.2 million and $0.7 million is expected to be recorded in 2011, 2012 and 2013, respectively.

Oil and Natural Gas Operations. We account for our oil and natural gas exploration and development activities using 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 our oil and natural gas reserves, including directly related overhead costs and related asset retirement costs, are capitalized and amortized on a units-of-production method based on proved oil and natural gas reserves. Directly related overhead costs of $13.4 million, $13.2 million and $15.3 million were capitalized in 2010, 2009 and 2008, respectively. Independent petroleum engineers annually audit our internal evaluation of our reserves. The average rates used for depreciation, depletion and amortization (DD&A) were $1.99, $1.87 and $2.50 per Mcfe in 2010, 2009 and 2008, 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 undeveloped leasehold properties totaling $175.1 million are excluded from the DD&A calculation.

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.

Under the full cost rules, at the end of each quarter, we review the carrying value of our oil and natural gas properties. The full cost ceiling is based principally on the estimated future discounted net cash flows from our oil and natural gas properties discounted at 10%. Starting December 31, 2009, companies using full cost accounting moved from using the commodity prices existing on the last day of the period to that of the unweighted arithmetic average of the commodity prices existing on the first day of each of the 12 months before the end of the reporting period to calculate discounted future revenues, unless prices were otherwise determined under contractual arrangements. 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, even if prices are depressed for only a short period of time. Once incurred, a write-down of oil and natural gas properties is not reversible.

We recorded a non-cash ceiling test write down of $282.0 million pre-tax ($175.5 million, net of tax) during the year ended December 31, 2008 as a result of declines in commodity prices. Derivative instruments qualifying as cash flow hedges were included in determining the limitation on the capitalized costs in our December 31, 2008 ceiling test calculation. The effect of including those hedges was a $96.0 million pre-tax increase in the discounted net cash flow of our oil and natural gas properties. Our qualifying cash flow hedges as of December 31, 2008, which consisted of swaps and collars, covered 2009 production of 40.2 Billion cubic feet of natural gas equivalent (Bcfe) and 2010 production of 23.7 Bcfe.

We recorded a non-cash ceiling test write-down of $281.2 million pre-tax ($175.1 million, net of tax) during the quarter ending March 31, 2009. This write-down resulted from the reduction in commodity prices existing at the end of the first quarter of 2009 as compared to at the end of 2008. Derivative instruments qualifying as cash flow hedges were included in determining the limitation on the capitalized costs in our March 31, 2009 ceiling test calculation. The effect of including those hedges was a $197.9 million pre-tax increase in the discounted net cash flow of our oil and natural gas properties. Our qualifying cash flow hedges as of March 31, 2009, which consisted of swaps and collars, covered 2009 production of 30.3 Bcfe and 2010 production of 33.2 Bcfe.

At December 31, 2010, using the existing 12-month average commodity prices, including the discounted value of our commodity hedges, we were not required to record a ceiling test write-down. However, if there are declines in the 12-month average prices, including the discounted value of our commodity hedges, we may be required to record a write-down in future periods. Our qualifying cash flow hedges used in the ceiling test determination as of December 31, 2010, consisted of swaps and collars covering 26.3 Bcfe in 2011 and 8.8 Bcfe in 2012. The effect of those hedges on the December 31, 2010 ceiling test was a $22.8 million pre-tax increase in the discounted net cash flows of our oil and natural gas properties. Even without the impact of those hedges, we would not have been required to take a write-down for the quarter. Our oil and natural gas hedging is discussed in Note 13 of the Notes to our Consolidated Financial Statements.

Our contract drilling segment provides drilling services for our exploration and production segment. Depending on their timing some of the drilling services performed on our properties are also deemed to be associated with the acquisition of an ownership interest in the property. Revenues and expenses for such services are eliminated in our income statement, with any profit recognized as a reduction in our investment in our oil and natural gas properties. The contracts for these services are issued under the same conditions and rates as the contracts entered into with unrelated third parties. We eliminated revenue of $40.1 million, $15.0 million and $65.5 million for 2010, 2009 and 2008, respectively from our contract drilling segment and eliminated the associated operating expense of $31.0 million, $13.7 million and $37.6 million during 2010, 2009 and 2008, respectively, yielding $9.1 million, $1.3 million and $27.9 million during 2010, 2009 and 2008, respectively, as a reduction to the carrying value of our oil and natural gas properties.

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.

Insurance. We are self-insured for certain losses relating to workers' compensation, control of well and employee medical benefits. Insured policies for other coverage contain deductibles or retentions per occurrence that range from $50,000 for fiduciary liability to $1.0 million for 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 will adequately protect us against liability from all potential consequences. We have elected to use an ERISA governed occupational injury benefit plan to cover all Texas drilling operations in lieu of covering them under Texas Workers' Compensation. If insurance coverage becomes more expensive, we may choose to self-insure, decrease our limits, raise our deductibles or any combination of these rather than pay higher premiums.

Hedging Activities. All derivatives are recognized on the balance sheet and measured at fair value. If a derivative is designated as a cash flow hedge, we 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 are 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 16 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.

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.

The accounting for uncertainty in income taxes 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 have no unrecognized tax benefits and we do not expect any significant changes in unrecognized tax benefits in the next twelve months.

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, 2010 balancing position to be approximately 3.0 Bcf on under-produced properties and approximately 3.2 Bcf on over- produced properties. We have recorded a receivable of $1.5 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 $3.3 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. We recognize in our financial statements the cost of employee services received in exchange for awards of equity instruments based on the grant date fair value of those awards. The amount of our equity compensation cost relating to employees directly involved in our oil and natural gas segment is capitalized to our oil and natural gas properties. Amounts not capitalized to our 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 (SARs). The value of our restricted stock grants is based on the closing stock price on the date of the grants.

Impact of Financial Accounting Pronouncements.

Improving Disclosures about Fair Value Measurements. In January 2010, the FASB issued ASU 2010-06—*Fair Value Measurements and Disclosures (ASC 820): Improving Disclosures about Fair Value Measurements*, which provides additional guidance to improve disclosures regarding fair value measurements. The ASU amends ASC 820-10, *Fair Value Measurements and Disclosures—Overall* (formerly FAS 157, *Fair Value Measurements)* to add two new disclosures: (1) transfers in and out of Level 1 and 2 measurements and the reasons for the transfers, and (2) a gross presentation of activity within the Level 3 roll forward. The ASU also includes clarifications to existing disclosure requirements on the level of disaggregation and disclosures regarding inputs and valuation techniques. The ASU applies to all entities required to make disclosures about recurring and nonrecurring fair value measurements. The effective date of the ASU is the first interim or annual reporting period beginning after December 15, 2009 and was adopted January 1, 2010, except for the gross presentation of the Level 3 roll forward information, which is required for annual reporting periods beginning after December 15, 2010 and for interim reporting periods within those years. This statement did not and will not have a significant impact on us due to it only requiring enhanced disclosures.

Modernization of Oil and Gas Reporting. On December 31, 2008, the Securities and Exchange Commission (SEC) adopted major revisions to its rules governing oil and gas company reporting requirements. These include provisions that permit the use of new technologies to determine proved reserves, and that allow companies to disclose their probable and possible reserves to investors. The current rules limit disclosure to only proved reserves. The new rules also require companies to report the independence and qualifications of the auditor of the reserve estimates and file reports when a third party is relied on to prepare reserves estimates. The new rules also require that oil and gas reserves be reported and the full cost ceiling value calculated using an average price based on the first-of-month posted price for each month in the prior 12-month period. On January 5, 2010, the FASB issued Accounting Standards update (ASU) 2010-03—*Extractive Activities—Oil and Gas (ASC 932): Oil and Gas Reserve Estimation and Disclosures*, an update of ASC 932 *Extractive Activities—Oil and Gas*, which subsequently aligns the reserve estimation, disclosure requirements, and definitions of ASC 932 with the disclosure requirements of the new rules issued by the SEC. The new oil and gas reserve measurement and reporting requirements were adopted for oil and gas reserves as of December 31, 2009. For accounting purposes, the new requirements constitute a change in accounting principle inseparable from a change in estimate. As such, prior reserve disclosures were not modified and the impact of the new requirements on our oil and gas reserves was reflected as a change in estimate.

Note 3. Acquisitions

On June 2, 2010, we completed an acquisition of oil and natural gas properties from certain unaffiliated third parties in an effort to explore and develop more oil rich plays. The properties were purchased for approximately $73.7 million in cash, after post close adjustments. The purchase price allocation was $48.7 million for proved properties and $25.0 million for undeveloped leasehold not being amortized. The acquisition included approximately 45,000 net leasehold acres and 10 producing oil wells and is focused on the Marmaton horizontal oil play located mainly in Beaver County, Oklahoma. Proved developed producing net reserves associated with the 10 acquired producing wells is approximately 762,000 BOE—consisting of 511,000 barrels of oil, 155,000 barrels of NGLs and 573 MMcf of natural gas.

Also during the second quarter of 2010, we completed an acquisition of approximately 32,000 net acres of undeveloped oil and gas leasehold located in Southwest Oklahoma and North Texas for approximately $17.6 million.

During 2008 and 2009, we acquired interests in approximately 60,000 net undeveloped acres in the Marcellus Shale Play, located mainly in Pennsylvania and Maryland for approximately $43.6 million. In July 2009, we received $7.1 million and approximately 1,500 net undeveloped acres, representing payment for our 50% interest in 4,000 gross undeveloped acres and reimbursement for costs we paid on their behalf. On September 30, 2009, per our agreement with certain unaffiliated third parties, we were paid approximately $14.9 million for our 50% interest in approximately 18,000 gross undeveloped acres of the Marcellus Shale and $26.1 million for a receivable from the third parties for their 50% share of the costs we paid on their behalf to acquire the acreage. The sales proceeds reduced undeveloped leasehold and no gain or loss was recorded on this sale. We now have an interest in approximately 50,500 net undeveloped acres.

Note 4. Earnings (Loss) Per Share

The following data shows the amounts used in computing earnings (loss) per share:

	Income (Numerator)	Weighted Shares (Denominator)	Per-Share Amount
	(In thousands except per share amounts)		
For the year ended December 31, 2010:			
Basic earnings per common share	$ 146,484	47,278	$ 3.10
Effect of dilutive stock options, restricted stock and SARs	0	176	(0.01)
Diluted earnings per common share	$ 146,484	47,454	$ 3.09
For the year ended December 31, 2009:			
Basic earnings (loss) per common share	$ (55,500)	46,990	$ (1.18)
Effect of dilutive stock options, restricted stock and SARs	0	0	0
Diluted earnings (loss) per common share	$ (55,500)	46,990	$ (1.18)
For the year ended December 31, 2008:			
Basic earnings per common share	$ 143,625	46,586	$ 3.08
Effect of dilutive stock options and restricted stock	0	323	(0.02)
Diluted earnings per common share	$ 143,625	46,909	$ 3.06

Due to the net loss for 2009, approximately 373,000 weighted average shares related to stock options, restricted stock and SARs were antidilutive and were excluded from the earnings per share calculation above. 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:

	2010	2009	2008
Options and SARs	222,901	358,821	84,900
Average exercise price	$ 52.59	$ 47.83	$ 64.39

Note 5. Accrued Liabilities

Accrued liabilities consisted of the following as of December 31:

	2010	2009
	(In thousands)	
Employee costs	$ 16,499	$ 13,307
Lease operating expenses	6,214	6,244
Taxes	1,310	5,085
Hedge settlements	1,634	2,503

Other	4,436	7,432
Total accrued liabilities	$ 30,093	$ 34,571

Note 6. Long-Term Debt and Other Long-Term Liabilities

Long-Term Debt

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

	2010	2009
	(In thousands)	
Revolving credit facility, with interest, including the effect of hedging, at December 31, 2010 and 2009 of 3.5% and 4.3%, respectively	$163,000	$30,000
Less current portion	0	0
Total long-term debt	$163,000	$30,000

Our Credit Facility has a maximum credit amount of $400.0 million and matures on May 24, 2012. The lenders' commitment under the Credit Facility is $325.0 million. Our borrowings are limited to the commitment amount that we elect. As of September 30, 2010, the commitment amount was $325.0 million. We are charged a commitment fee ranging from 0.375 to 0.50 of 1% on the amount available but not borrowed. The rate varies based on the amount borrowed as a percentage of the amount of the total borrowing base. To date we have paid $1.2 million in origination, agency and syndication fees under the Credit Facility. We are amortizing these fees over the life of the agreement.

The lenders' aggregate commitment is limited to the lesser of the amount of the borrowing base or $400.0 million. The amount of the borrowing base, which is subject to redetermination on April 1 and October 1 of each year, is based primarily on a percentage of the discounted future value of our oil and natural gas reserves 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 segment. The October 1, 2010 redetermination maintained the borrowing base at $500.0 million. We or the lenders may request a onetime special redetermination of the amount of the borrowing base between each scheduled redetermination. In addition, we may request a redetermination following the completion of an acquisition that meets the requirements set forth in the Credit Facility.

At our election, any part of the outstanding debt under the Credit Facility may be fixed at a London Interbank Offered Rate (LIBOR) for a 30, 60, 90 or 180 day period. During any LIBOR funding period, the outstanding principal balance of the promissory note to which the LIBOR option applies may be repaid after three days prior notice to the administrative agent and on payment of any applicable funding indemnification amounts. LIBOR interest is computed as the sum of the LIBOR base for the applicable term plus 1.75% to 2.50% depending on the level of debt as a percentage of the borrowing base and is 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, which cannot be less than LIBOR plus 1.00%, and is payable at the end of each month and the principal borrowed may be paid at any time, in part or in whole, without a premium or penalty. At December 31, 2010, $160.0 million of our $163.0 million in outstanding borrowings were subject to LIBOR.

The Credit Facility prohibits:

- 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 limited exceptions; and
- the creation or existence of mortgages or liens, other than those in the ordinary course of business, on any of our properties, except in favor of our 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.

As of December 31 2010, we were in compliance with our Credit Facility's covenants.

Based on the borrowing rates currently available to us for debt with similar terms and maturities and consideration of our non-performance risk, long-term debt at December 31, 2010 approximates its fair value.

At December 31, 2010, the carrying values on the consolidated balance sheets for cash and cash equivalents, accounts receivable, accounts payable, other current assets and current liabilities approximate their fair value because of their short term nature.

Securities being registered under the registration statement are debt securities guaranteed by our wholly-owned domestic direct and indirect subsidiaries. Unit Corporation (Unit), as the parent company, has no independent assets or operations. The guarantees registered under the registration statement are full and unconditional and joint and several, and subsidiaries of Unit other than the subsidiary guarantors are minor. There are no significant restrictions on the ability of our parent company to receive funds from our subsidiaries through dividends, loans, advances or otherwise.

Other Long-Term Liabilities

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

	2010	2009
	(In thousands)	
ARO liability	$ 69,265	$ 56,404
Workers' compensation	17,566	22,974
Separation benefit plans	5,690	4,681
Gas balancing liability	3,263	3,263
Deferred compensation plan	2,368	2,004
	98,152	89,326
Less current portion	10,122	9,342
Total other long-term liabilities	$ 88,030	$ 79,984

Estimated annual principle payments under the terms of debt and other long-term liabilities from 2011 through 2015 are $10.1 million, $165.9 million, $14.0 million, $2.5 million and $2.7 million, respectively.

Note 7. Asset Retirement Obligations

We are required to record the estimated fair value of the liabilities relating to the future retirement of our long-lived assets. Our oil and natural gas wells are plugged and abandoned when the oil and natural gas reserves in those wells are depleted or the wells are no longer able to produce. The plugging and abandonment expense for a well is recorded in the period in which the obligation is incurred (at the time the well is drilled or acquired). None of our assets are restricted for purposes of settling these AROs.

[Table of Contents](#)

The following table shows certain information about our AROs for the periods indicated:

	2010	2009
	(In thousands)	
ARO liability, January 1:	$56,404	$49,230
Accretion of discount	2,937	2,585
Liability incurred	4,768	3,447
Liability settled	(763)	(1,331)
Revision of estimates (1)	5,919	2,473
ARO liability, December 31:	69,265	56,404
Less current portion	1,915	1,080
Total long-term ARO liability	$67,350	$55,324

(1) ARO liability estimates were revised upward in 2010 and 2009 due to the increase in the cost of contract services utilized to plug wells over the preceding years.

Note 8. Income Taxes

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

	2010	2009	2008
		(In thousands)	
Income tax expense (benefit) computed by applying the statutory rate	$83,027	$(30,704)	$78,943
State income tax, net of federal benefit	6,030	(2,409)	4,547
Domestic production activities deduction	0	0	(2,081)
Statutory depletion and other	1,680	887	545
Income tax expense (benefit)	$90,737	$(32,226)	$81,954

For the periods indicated, the total provision for income taxes consisted of the following:

	2010	2009	2008
		(In thousands)	
Current taxes:			
Federal	$ (6,856)	$ (5,124)	$38,535
State	(3,079)	4,901	2,342
	(9,935)	(223)	40,877
Deferred taxes:			
Federal	88,021	(23,510)	37,180

State	12,651	(8,493)	3,897
	100,672	(32,003)	41,077
Total provision	$ 90,737	$(32,226)	$81,954

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

	2010	2009
	(In thousands)	
Deferred tax assets:		
Allowance for losses and nondeductible accruals	$ 47,742	$ 41,882
Net operating loss carryforward	2,926	2,941
Alternative minimum tax credit carryforward	0	8,857
	50,668	53,680
Deferred tax liability:		
Depreciation, depletion, amortization and impairment	(593,237)	(485,573)
Net deferred tax liability	(542,569)	(431,893)
Current deferred tax asset	13,537	14,423
Non-current—deferred tax liability	$ (556,106)	$ (446,316)

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, 2010, we have net operating loss carryforwards of approximately $5.4 million which expire from 2015 to 2021.

Note 9. 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 74,205, 202,655 and 89,910 shares of common stock and recognized expense of $3.6 million, $3.6 million and $5.0 million in 2010, 2009 and 2008, 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. The liability recorded under the Deferral Plan at December 31, 2010 and 2009 was $2.4 million and $2.0 million, respectively. We recognized payroll expense and recorded a liability at the time of deferral.

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. 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.

On December 31, 2008, we amended all three Plans to be in compliance with Section 409A of the Internal Revenue Code of 1986, as amended. The key amendments to the Plans address, among other things, when distributions may be made, the timing of payments, and the circumstances under which employees become eligible to receive benefits. None of the amendments materially increase the benefits, grants or awards issuable under the Plans. We recognized expense of $1.6 million, $1.5 million and $1.6 million in 2010, 2009 and 2008, respectively, for benefits associated with anticipated payments from these separation plans.

We have entered into key employee change of control contracts with three 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 10. Transactions with Related Parties

Unit Petroleum Company serves as the general partner of 16 oil and gas limited partnerships. Three were formed for investment by third parties and 12 (the employee partnerships) were formed to allow certain of our qualified employees and our directors 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. 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 2010, 2009 and 2008) 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 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 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:

	2010	2009	2008
		(In thousands)	
Contract drilling	$529	$368	$916
Well supervision and other fees	$386	$352	$375
General and administrative expense reimbursement	$536	$376	$584

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 11. 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.

Note 12. Stock-Based Compensation

For restricted stock awards, stock options and SARs, we had:

	2010	2009	2008
		(In millions)	
Recognized stock compensation expense	$10.8	$9.2	$11.1
Capitalized stock compensation cost for our oil and natural gas properties	2.7	2.1	3.3
Tax benefit on stock based compensation	4.1	2.6	4.1

The remaining unrecognized compensation cost related to unvested awards at December 31, 2010 is approximately $9.2 million with $1.9 million of this amount anticipated to be capitalized. The weighted average period of time over which this cost will be recognized is 0.8 years.

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:

	2010	2009	2008
Options granted (1)	52,504	3,496	28,000
Stock appreciation rights	0	0	0
Estimated fair value (in millions)	$ 0.8	$ 0.1	$ 0.7
Estimate of stock volatility	0.45	0.41	0.32
Estimated dividend yield	0%	0%	0%
Risk free interest rate	2%	2%	3%
Expected life range based on prior experience (in years)	5	5	5
Forfeiture rate	0%	5%	5%

(1) On May 29, 2009, eight of our directors were each awarded 3,063 options contingent on shareholder approval which was received at the May 5, 2010 annual shareholder's meeting. These 24,504 options granted and vested simultaneously with that approval. On May 6, 2010, eight of our directors each received 3,500 options which vested on November 6, 2010.

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.

During 2009, there were 116,826 shares of other stock-based awards issued under this plan. These shares vested immediately and the fair value on the grant date was $3.3 million.

Table of Contents

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, 2008	145,901	$ 46.59
Granted	0	0
Exercised	0	0
Forfeited	0	0
Outstanding at December 31, 2008	145,901	46.59
Granted	0	0
Exercised	0	0
Forfeited	0	0
Outstanding at December 31, 2009	145,901	46.59
Granted	0	0
Exercised	0	0
Forfeited	0	0
Outstanding at December 31, 2010	145,901	$ 46.59

There were no SARs granted in 2010, 2009 or 2008. The SARs expire after 10 years from the date of the grant. In 2010, 2009 and 2008, 48,632, 48,633 and 14,891 shares vested. The aggregate intrinsic value of the 145,901 shares outstanding subject to vesting at December 31, 2010 was zero with a weighted average remaining contractual term of 6.7 years.

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, 2008	636,054	$ 47.09
Granted	30,855	55.44
Vested	(20,245)	50.38
Forfeited	(29,516)	47.19
Nonvested at December 31, 2008	617,148	47.40
Granted	0	0
Vested		

	(68,836)	46.18
Forfeited	(41,241)	48.69
Nonvested at December 31, 2009	507,071	47.46
Granted	450,355	41.09
Vested	(496,497)	47.09
Forfeited	(14,804)	44.25
Nonvested at December 31, 2010	446,125	$ 47.39

The restricted stock awards vest in periods ranging from one to three years. The fair value of the restricted stock granted in 2010 and 2008 at the grant date was $16.9 million and $1.5 million, respectively. There was no restricted stock granted in 2009. The aggregate intrinsic value of the 496,497 shares of restricted stock on their 2010 vesting date was $18.3 million. The aggregate intrinsic value of the 446,125 shares outstanding subject to vesting at December 31, 2010 was $20.7 million with a weighted average remaining life of 1.2 years.

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 were made under the prior Employee Stock Bonus Plan. Under the terms of the old plan, awards were granted to employees in either cash or stock or a combination thereof, and were 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 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.

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, 2008	18,374	$ 58.30
Granted	0	0
Vested	(18,374)	58.30
Forfeited	0	0
Nonvested at December 31, 2008	0	0
Granted	0	0
Vested	0	0
Forfeited	0	0
Nonvested at December 31, 2009	0	0
Granted	0	0
Vested	0	0
Forfeited	0	0
Nonvested at December 31, 2010	0	$ 0

The grant date fair value of the 18,749 shares vesting in 2007 and the 18,374 shares vesting in 2008 was $1.0 million each. As of December 31, 2008 all shares in this plan have been vested or forfeited.

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.

[Table of Contents](#)

Activity pertaining to the Stock Option Plan is as follows:

	Number of Shares	Weighted Average Exercise Price
Outstanding at January 1, 2008	354,500	$ 25.96
Granted	0	0
Exercised	(122,810)	18.75
Forfeited	(3,400)	35.20
Outstanding at December 31, 2008	228,290	29.68
Granted	0	0
Exercised	(4,065)	23.45
Forfeited	(4,600)	38.60
Outstanding at December 31, 2009	219,625	29.61
Granted	0	0
Exercised	(32,360)	20.35
Forfeited	(2,500)	37.83
Outstanding at December 31, 2010	184,765	$ 31.11

The total grant date fair value of the 6,200, 27,100 and 47,070 shares vesting in 2010, 2009 and 2008 was $0.2 million, $1.0 million and $0.8 million. The intrinsic value of options exercised in 2010 was $0.8 million. Total cash received from the options exercised in 2010 was $0.3 million.

	Outstanding Options at December 31, 2010		
Exercise Prices	Number of Shares	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price
$16.69 - $19.04	26,600	2.0 years	$ 19.04
$21.50 - $26.28	52,645	2.9 years	$ 22.81
$34.75 - $37.83	102,020	4.0 years	$ 37.75
$53.90	3,500	5.2 years	$ 53.90

The aggregate intrinsic value of the 184,765 shares outstanding subject to options at December 31, 2010 was $2.9 million with a weighted average remaining contractual term of 3.4 years.

	Exercisable Options At December 31, 2010	
Exercise Prices	Number of Shares	Weighted Average Exercise Price

$19.04	26,600	$ 19.04
$21.50 - $22.95	52,645	$ 22.81
$36.42 - $37.83	102,020	$ 37.75
$53.90	2,800	$ 53.90

Options for 184,065, 212,725 and 191,390 shares were exercisable with weighted average exercise prices of $31.02, $29.25 and $27.92 at December 31, 2010, 2009 and 2008, respectively. The aggregate intrinsic value of shares exercisable at December 31, 2010 was $2.9 million with a weighted average remaining contractual term of 3.4 years.

On May 29, 2009, the compensation committee and board of directors, approved amendments to the existing Unit Corporation 2000 Non-Employee Directors' Stock Option Plan. The amendments extended the plan term from May 30, 2010 to May 30, 2017, and increased the aggregate number of shares that may be issued or delivered due to exercise of non-employee director option awards from 210,000 shares of common stock to 510,000 shares of common stock. 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 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.

On the first day following the 2009 annual meeting, each non-employee director was granted 437 shares of common stock. Effective with the adoption of the amendments mentioned above, a contingent one-time grant of 3,063 shares to each non-employee director was made on May 29, 2009. These contingent option awards vested when the stockholders approved the amended plan at the May 5, 2010 annual meeting.

Activity pertaining to the Directors' Plan is as follows:

	Number of Shares	Weighted Average Exercise Price
Outstanding at January 1, 2008	142,500	$ 39.26
Granted	28,000	73.26
Exercised	(17,500)	27.30
Outstanding at December 31, 2008	153,000	46.85
Granted	3,496	31.30
Exercised	(13,000)	14.74
Outstanding at December 31, 2009	143,496	49.38
Granted	52,504	37.62
Exercised	(3,500)	17.54
Forfeited	(14,000)	58.20
Outstanding at December 31, 2010	178,500	$ 48.77

The total grant date fair value of the 52,504, 3,496 and 28,000 shares vesting in 2010, 2009 and 2008, respectively, was $0.8 million, $0.1 million and $0.7 million, respectively. The intrinsic value of options exercised in 2010 was $0.1 million. Total cash received from options exercised in 2010 was $0.1 million.

	Outstanding and Exercisable Options at December 31, 2010		
Exercise Prices	Number of Shares	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price
$17.54	3,500	0.3 years	$ 17.54
$20.10 - $20.46	17,500	1.9 years	$ 20.32
$28.23 - $41.20	84,000	7.2 years	$ 36.10
$57.63 - $73.26	73,500	6.3 years	$ 64.43

Options for 178,500, 143,496 and 153,000 shares were exercisable with weighted average exercise prices of $45.86, $49.38 and $46.85 at December 31, 2010, 2009 and 2008, respectively. The aggregate intrinsic value of the shares outstanding subject to options at December 31, 2010 was $1.4 million with a weighted average remaining contractual term of 6.2 years.

[Table of Contents](#)

Note 13. Derivatives

Interest Rate Swaps

From time to time we enter into interest rate swaps to manage our exposure to possible future interest rate increases. Under these transactions we swap the variable interest rate we would otherwise pay on a portion of our bank debt for a fixed interest rate. As of December 31, 2010, we had two outstanding interest rate swaps; both were cash flow hedges. There was no material amount of ineffectiveness. This table provides certain information about those interest rate swaps:

Remaining Term	Amount	Fixed Rate	Floating Rate
January 2011 – May 2012	$ 15,000,000	4.53%	3 month LIBOR
January 2011 – May 2012	$ 15,000,000	4.16%	3 month LIBOR

Commodity Derivatives

We have entered into various types of derivative instruments covering some of our projected natural gas, natural gas liquids and oil production. These transactions are intended to reduce our exposure to market price volatility by setting the price(s) we will receive for that production. Our decisions on the price(s), type and quantity of our production hedged is based, in part, on our view of current and future market conditions. As of December 31, 2010, our derivative instruments consisted of the following types 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 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.

- *Basis Swaps.* We receive or pay the NYMEX settlement value plus or minus a fixed delivery point price for the hedged commodity and pay or receive the published index price at the specified delivery point. We use basis swaps to hedge the price risk between NYMEX and its physical delivery points.

Oil and Natural Gas Segment:

At December 31, 2010, the following cash flow hedges were outstanding:

Term	Commodity	Hedged Volume	Weighted Average Fixed Price for Swaps	Hedged Market
Jan'11 – Dec'11	Crude oil—swap	4,000 Bbl/day	$ 84.28	WTI—NYMEX
Jan'12 – Dec'12	Crude oil—swap	1,500 Bbl/day	$ 82.49	WTI—NYMEX
Jan'11 – Dec'11	Natural gas—swap	45,000 MMBtu/day	$ 4.93	IF—NYMEX (HH)
Jan'11 – Dec'11	Natural gas—basis differential swap	15,000 MMBtu/day	($ 0.14)	Tenn Zone 0—NYMEX
Jan'12 – Dec'12	Natural gas—swap	15,000 MMBtu/day	$ 5.62	IF—PEPL
Jan'11 – Dec'11	Liquids—swap (1)	644,406 Gal/mo	$ 0.97	OPIS—Conway

(1) Types of liquids involved are natural gasoline, ethane, propane, isobutane and normal butane.

Table of Contents

At December 31, 2010, the following non-qualifying cash flow derivatives were outstanding:

Term	Commodity	Hedged Volume	Basis Differential	Hedged Market
Jan'11 – Dec'11	Natural gas—basis differential swap	15,000 MMBtu/day	($0.14)	Tenn Zone 0—NYMEX
Jan'11 – Dec'11	Natural gas—basis differential swap	10,000 MMBtu/day	($0.21)	CEGT—NYMEX
Jan'11 – Dec'11	Natural gas—basis differential swap	10,000 MMBtu/day	($0.23)	PEPL—NYMEX

The following tables present the fair values and locations of derivative instruments recorded in the balance sheet:

	Balance Sheet Location	Derivative Assets Fair Value December 31, 2010	Derivative Assets Fair Value December 31, 2009
		(In thousands)	
Derivatives designated as hedging instruments			
Commodity derivatives:			
Current	Current derivative assets	$ 5,091	$ 9,945
Long-term	Non-current derivative assets	2,537	0
Total derivatives designated as hedging instruments		7,628	9,945
Derivatives not designated as hedging instruments			
Commodity derivatives:			
Current	Current derivative assets	477	0
Total derivatives not designated as hedging instruments		477	0
Total derivative assets		$ 8,105	$ 9,945

	Balance Sheet Location	Derivative Liabilities Fair Value December 31, 2010	December 31, 2009
		(In thousands)	
Derivatives designated as hedging instruments			
Interest rate swaps:			
Current	Current portion of derivative liabilities	$ 1,139	$ 806
Long-term	Long-term derivative liabilities	475	1,142
Commodity derivatives:			
Current	Current portion of derivative liabilities	13,166	1,424
Long-term	Long-term derivative liabilities	3,884	0
Total derivatives designated as hedging instruments		18,664	3,372
Derivatives not designated as hedging instruments			
Commodity derivatives (basis swaps):			
Current	Current portion of derivative liabilities	141	0
Total derivatives not designated as hedging instruments		141	0
Total derivative liabilities		$ 18,805	$ 3,372

If a legal right of set-off exists, we net the value of the derivative arrangements we have with the same counterparty on our balance sheets.

We recognize in accumulated other comprehensive income (OCI) the effective portion of any changes in fair value and reclassify the recognized gains (losses) on the sales to revenue and on the purchases to expense as each of the underlying transactions are settled. As of December 31, 2010 and 2009, we had a loss of $6.9 million and a gain of $4.5 million, net of tax, respectively, in accumulated OCI.

Based on market prices at December 31, 2010, we expect to transfer to earnings a loss of approximately $5.4 million, net of tax, of the loss included in accumulated OCI over the next 12 months as the various transactions are settled. The interest rate swaps and the commodity derivative instruments existing as of December 31, 2010 are expected to mature by May 2012 and December 2012, respectively.

Certain derivatives do not qualify as cash flow hedges. Currently, we have three basis swaps that do not qualify as cash flow hedges. For these, any changes in their fair value that occurs before their maturity (i.e., temporary fluctuations in value) are reported in the consolidated statements of operations within our oil and natural gas revenues. Any changes in the fair value of derivative instruments designated as cash flow hedges, to the extent they are effective in offsetting cash flows attributable to the hedged risk, are recorded in our OCI until the hedged item is recognized into earnings. Any change in fair value resulting from ineffectiveness is recognized in our oil and natural gas revenues.

Table of Contents

Effect of Derivative Instruments on the Consolidated Balance Sheets (cash flow hedges) for the year ended December 31:

Derivatives in Cash Flow Hedging Relationships	Amount of Gain or (Loss) Recognized in Accumulated OCI on Derivative (Effective Portion) (1)	
	2010	2009
	(In thousands)	
Interest rate swaps	$ (996)	$ (1,204)
Commodity derivatives	(5,855)	5,662
Total	$ (6,851)	$ 4,458

(1) Net of taxes.

Effect of derivative instruments on the Consolidated Statement of Operations (cash flow hedges) for the year ended December 31:

Derivative Instrument	Location of Gain or (Loss) Reclassified from Accumulated OCI into Income & Location of Gain or (Loss) Recognized in Income	Amount of Gain or (Loss) Reclassified from Accumulated OCI into Income (1)		Amount of Gain or (Loss) Recognized in Income(2)	
		2010	2009	2010	2009
		(In thousands)			
Commodity derivatives	Oil and natural gas revenue	$ 53,473	$ 100,286	$700	$(897)
Interest rate swaps	Interest, net	(1,218)	(1,036)	0	0
	Total	$ 52,255	$ 99,250	$700	$(897)

(1) Effective portion of gain (loss).
(2) Ineffective portion of gain (loss).

Effect of Derivative Instruments on the Consolidated Statement of Operations (derivatives not designated as hedging instruments) for the year ended December 31:

Derivatives Not Designated as Hedging Instruments	Location of Gain or (Loss) Recognized in Income on Derivative	Amount of Gain or (Loss) Recognized in Income on Derivative	
		2010	2009
		(In thousands)	
Commodity derivatives (basis swaps)	Oil and natural gas revenue	$ 336	$ (3,469)
Total		$ 336	$ (3,469)

Note 14. Fair Value Measurements

Fair value is defined as the amount that would be received from the sale of an asset or paid for the transfer of a liability in an orderly transaction between market participants (an exit price). To estimate an exit price, a three-level hierarchy is used prioritizing the valuation techniques used to measure fair value into three levels with the highest priority given to Level 1 and the lowest priority given to Level 3. The levels are summarized as follows:

- Level 1—unadjusted quoted prices in active markets for identical assets and liabilities.
- Level 2—significant observable pricing inputs other than quoted prices included within level 1 that are either directly or indirectly observable as of the reporting date. Essentially, inputs (variables used in the pricing models) that are derived principally from or corroborated by observable market data.
- Level 3—generally unobservable inputs which are developed based on the best information available and may include our own internal data.

The inputs available to us determine the valuation technique we use to measure the fair values of our financial instruments.

The following tables set forth our recurring fair value measurements:

	December 31, 2010			
	Level 1	Level 2	Level 3	Total
	(In thousands)			
Financial assets (liabilities):				
Interest rate swaps	$ 0	$ 0	$(1,614)	$(1,614)
Commodity derivatives	$ 0	$(19,954)	$10,868	$(9,086)

	December 31, 2009			
	Level 1	Level 2	Level 3	Total
	(In thousands)			
Financial assets (liabilities):				
Interest rate swaps	$ 0	$ 0	$(1,948)	$(1,948)
Commodity derivatives	$ 0	$(11,427)	$19,948	$ 8,521

The following methods and assumptions were used to estimate the fair values of the assets and liabilities in the table above.

Level 2 Fair Value Measurements

Commodity Derivatives. The fair values of our crude oil swaps are measured using estimated internal discounted cash flow calculations using NYMEX futures index.

Level 3 Fair Value Measurements

Interest Rate Swaps. The fair values of our interest rate swaps are based on estimates provided by our respective counterparties and reviewed internally using established index prices and other sources.

Commodity Derivatives. The fair values of our natural gas and natural gas liquids swaps, basis swaps and crude oil and natural gas collars are estimated using internal discounted cash flow calculations based on forward price curves, quotes obtained from brokers for contracts with similar terms or quotes obtained from counterparties to the agreements.

The following tables are reconciliations of our level 3 fair value measurements:

	Net Derivatives			
	For the Year Ended December 31, 2010		For the Year Ended December 31, 2009	
	Interest Rate Swaps	Commodity Swaps and Collars	Interest Rate Swaps	Commodity Swaps and Collars
	(In thousands)			
Beginning of period	$ (1,948)	$ 19,948	$ (2,516)	$ 58,508
Total gains or losses (realized and unrealized):				
Included in earnings (loss) (1)	(1,218)	64,470	(1,036)	100,018
Included in other comprehensive income (loss)	334	(10,116)	568	(36,616)
Purchases, issuance and settlements	1,218	(63,434)	1,036	(101,962)
End of period	$ (1,614)	$ 10,868	$ (1,948)	$ 19,948
Total gains (losses) for the period included in earnings attributable to the change in unrealized gain (loss) relating to assets still held as of December 31, 2010 and 2009	$ 0	$ 1,036	$ 0	$ (1,944)

(1) Interest rate swaps and commodity sales swaps and collars are reported in the consolidated statements of operations in interest expense and revenues, respectively. Our mid-stream natural gas purchase swaps are reported in the consolidated statements of operations in expense.

Based on our valuation at December 31 2010, we determined that the non-performance risk with regard to our counterparties was immaterial.

Note 15. Commitments and Contingencies

We lease office space or yards in Elk City, Oklahoma City and Tulsa, Oklahoma; Houston, Texas; Denver, Colorado; Pinedale, Wyoming; and Pittsburgh, Pennsylvania under the terms of operating leases expiring through January, 2015. 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 $1.7 million, $1.4 million, $1.3 million, $1.3 million and $0.2 million in 2011-2015, respectively. Total rent expense incurred was $1.8 million, $2.1 million and $2.1 million in 2010, 2009 and 2008, 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 $22,000 in 2010, $1,000 in 2009 and $241,000 in 2008.

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.

For the next twelve months, we have committed to purchase approximately $13.7 million of new drilling rig components, drill pipe, drill collars and related equipment.

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 16. Industry Segment Information

Our three main business segments and the different products and services they offer are:

Segment	Services or Products
Contract drilling	Onshore contract drilling of oil and natural gas wells
Oil and natural gas	Development, acquisition and production of oil and natural gas properties
Midstream	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). Each segment’s performance is evaluated based on its operating income (loss) which is defined as its operating revenues less operating expenses and depreciation, depletion, amortization and impairment.

Although we have some production in Canada, it is not significant and therefore not split out below.

[Table of Contents](#)

The following table provides certain information about each of our segments:

	2010	2009	2008
		(In thousands)	
Revenues:			
Contract drilling	$ 356,527	$ 251,364	$ 688,196
Elimination of inter-segment revenue	(40,143)	(15,049)	(65,469)
Contract drilling net of inter-segment revenue	316,384	236,315	622,727
Oil and natural gas	400,807	357,879	553,998
Gas gathering and processing	201,320	142,491	237,999
Elimination of inter-segment revenue	(46,804)	(33,863)	(56,269)
Gas gathering and processing net of inter-segment revenue	154,516	108,628	181,730
Other	10,138	7,076	(362)
Total revenues	$ 881,845	$ 709,898	$1,358,093
Operating income (loss) (1):			
Contract drilling	$ 59,601	$ 50,909	$ 239,979
Oil and natural gas	176,649	(125,777)(4)	(3,757)(3)
Gas gathering and processing	16,985	4,616	16,442
Total operating income (loss)	253,235	(70,252)	252,664
General and administrative expense	(26,152)	(24,011)	(25,419)
Interest expense, net	0	(539)	(1,304)
Other income (expense)—net	10,138	7,076	(362)
Income (loss) before income taxes	$ 237,221	$ (87,726)	$ 225,579
Identifiable assets (2):			
Contract drilling	$ 998,658	$ 951,702	$1,009,292
Oil and natural gas	1,441,797	1,068,970(4)	1,363,534(3)
Gas gathering and processing	176,596	163,625	169,687

Total identifiable assets	2,617,051	2,184,297	2,542,513
Corporate assets	52,189	44,102	39,353
Total assets	$2,669,240	$2,228,399	$2,581,866
Capital expenditures:			
Contract drilling	$ 118,806	$ 67,686	$ 196,229
Oil and natural gas	463,870	230,550	561,548
Gas gathering and processing	29,815	9,899	49,887
Other	6,417	474	9,860
Total capital expenditures	$ 618,908	$ 308,609	$ 817,524
Depreciation, depletion, amortization and impairment:			
Contract drilling	$ 69,970	$ 45,326	$ 69,841
Oil and natural gas			
Depreciation, depletion and amortization	118,793	114,681	159,550
Impairment of oil and natural gas properties	0	281,241(4)	281,966(3)
Gas gathering and processing	15,385	16,104	14,822
Other	976	1,055	699
Total depreciation, depletion, amortization and impairment	$ 205,124	$ 458,407	$ 526,878

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

(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) In December 2008, we incurred a $282.0 million pre-tax ($175.5 million net of tax) non-cash write down of oil and natural gas properties due to low commodity prices at year-end 2008.
(4) In March 2009, we incurred a $281.2 million pre-tax ($175.1 million net of tax) non-cash write down of our oil and natural gas properties due to low commodity prices existing at the end of the first quarter 2009.

Note 17. Selected Quarterly Financial Information

Summarized unaudited quarterly financial information is as follows:

	Three Months Ended			
	March 31	June 30	September 30	December 31
	(In thousands except per share amounts)			
2010:				
Revenues	$ 206,550	$204,603	$ 218,116	$ 252,576
Gross profit (1)	$ 59,319	$ 53,499	$ 63,371	$ 77,046
Net income	$ 36,153	$ 32,175	$ 34,491	$ 43,665
Net income per common share:				
Basic	$ 0.77	$ 0.68	$ 0.73	$ 0.92
Diluted	$ 0.76	$ 0.68	$ 0.73	$ 0.92
2009:				
Revenues	$ 201,062	$164,074	$ 167,430	$ 177,332
Gross profit (loss) (1)	$(232,004)	$ 55,970	$ 54,111	$ 51,671
Net income (loss)	$(147,493)	$ 32,031	$ 31,449	$ 28,513
Net income (loss) per common share:				
Basic (2)	$ (3.14)	$ 0.68	$ 0.67	$ 0.61
Diluted (2)	$ (3.14)	$ 0.68	$ 0.66	$ 0.60

(1) Gross profit excludes other revenues, general and administrative expense and interest expense.
(2) Due to the effect of rounding the basic earnings or diluted per share for the year's four quarters does not equal annual earnings per share.

Table of Contents

SUPPLEMENTAL OIL AND GAS DISCLOSURES
(UNAUDITED)

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:

	2010	2009	2008
		(In thousands)	
Capitalized costs:			
Proved properties	$ 2,738,093	$ 2,309,193	$ 2,090,623
Unproved properties	175,065	140,129	160,034
	2,913,158	2,449,322	2,250,657
Accumulated depreciation, depletion, amortization and impairment	(1,542,352)	(1,424,559)	(1,029,617)
Net capitalized costs	$ 1,370,806	$ 1,024,763	$ 1,221,040
Cost incurred:			
Unproved properties acquired	$ 75,739	$ 37,137	$ 113,104
Proved properties acquired	50,000	3,722	41,227
Exploration	48,304	30,547	41,474
Development	279,903	154,579	351,876
Asset retirement obligation	9,924	4,565	13,867
Total costs incurred	$ 463,870	$ 230,550	$ 561,548

The following table shows a summary of the oil and natural gas property costs not being amortized at December 31, 2010, by the year in which such costs were incurred:

	2010	2009	2008	2007 and Prior	Total
			(In thousands)		
Undeveloped Leasehold Acquired	$68,078	$24,490	$53,790	$28,707	$175,065

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 as follows:

	2010	2009	2008
		(In thousands)	
Revenues	$ 392,229	$ 352,572	$ 545,937
Production costs	(91,143)	(75,214)	(102,207)
Depreciation, depletion, amortization and impairment	(117,793)	(394,942)	(440,588)
	183,293	(117,584)	3,142

Income tax (expense) benefit	(70,110)	43,153	(1,141)
Results of operations for producing activities (excluding corporate overhead and financing costs)	$ 113,183	$ (74,431)	$ 2,001

[Table of Contents](#)

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:

	Oil Bbls	Liquids Bbls	Natural Gas Mcf
		(In thousands)	
2010:			
Proved developed and undeveloped reserves:			
Beginning of year	11,669	14,653	419,061
Revision of previous estimates (1)	434	(1,559)	(25,007)
Extensions and discoveries	3,473	878	31,328
Infill reserves in existing proved fields	2,152	3,482	34,128
Purchases of minerals in place	1,293	212	1,732
Production	(1,521)	(1,549)	(40,756)
Sales	(6)	0	0
End of Year	17,494	16,117	420,486
Proved developed reserves:			
Beginning of year	9,183	11,538	338,217
End of year	12,773	12,088	346,928
Proved undeveloped reserves:			
Beginning of year	2,486	3,115	80,844
End of year	4,721	4,029	73,558
2009:			
Proved developed and undeveloped reserves:			
Beginning of year	9,699	10,171	450,135
Revision of previous estimates (1)	459	2,793	(57,393)
Extensions and discoveries	2,135	1,996	50,480
Infill reserves in existing proved fields (2)	618	1,174	19,872
Purchases of minerals in place	44	7	30

Production	(1,286)	(1,488)	(44,063)
End of Year	11,669	14,653	419,061
Proved developed reserves:			
Beginning of year	7,508	8,638	355,824
End of year	9,183	11,538	338,217
Proved undeveloped reserves:			
Beginning of year	2,191	1,533	94,311
End of year	2,486	3,115	80,844
2008:			
Proved developed and undeveloped reserves:			
Beginning of year	9,676	6,149	419,616
Revision of previous estimates (3)	(1,278)	2,023	(23,431)
Extensions and discoveries	1,511	1,522	60,369
Infill reserves in existing proved fields (2)	830	1,657	29,848
Purchases of minerals in place	221	208	11,206
Production	(1,261)	(1,388)	(47,473)
End of Year	9,699	10,171	450,135
Proved developed reserves:			
Beginning of year	7,770	5,133	326,071
End of year	7,508	8,638	355,824
Proved undeveloped reserves:			
Beginning of year	1,906	1,016	93,545
End of year	2,191	1,533	94,311

(1) Natural gas revisions of previous estimates decreased primarily due to a decline in natural gas prices and/or deleting PUDs that were stale or uneconomical.

(2) Previously included in 'Extensions, discoveries and other additions'.
(3) 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.

Estimates of oil, NGLs and natural gas reserves require extensive judgments of reservoir engineering data. 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 12-month average prices and year-end costs and 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:

	2010	2009	2008
		(In thousands)	
Future cash flows	$ 3,745,046	$2,403,892	$2,694,217
Future production costs	(1,054,630)	(777,725)	(769,325)
Future development costs	(303,152)	(195,486)	(253,941)
Future income tax expenses	(799,260)	(433,366)	(510,361)
Future net cash flows	1,588,004	997,315	1,160,590
10% annual discount for estimated timing of cash flows	(732,918)	(450,980)	(536,116)
Standardized measure of discounted future net cash flows relating to proved oil, NGLs and natural gas reserves	$ 855,086	$ 546,335	$ 624,474

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

	2010	2009	2008
		(In thousands)	
Sales and transfers of oil and natural gas produced, net of production costs	$(301,086)	$(277,358)	$(443,729)
Net changes in prices and production costs	379,097	(145,839)	(548,683)
Revisions in quantity estimates and changes in production timing	(67,116)	(54,327)	(34,066)
Extensions, discoveries and improved recovery, less related costs	340,771	136,695	229,928
Changes in estimated future development costs	15,974	100,304	20,273
Previously estimated cost incurred during the period	45,327	16,301	55,763
Purchases of minerals in place	42,280	1,288	20,797
Sales of minerals in place	(120)	0	0
Accretion of discount	77,536	89,256	148,160
Net change in income taxes	(200,815)	39,062	223,188
Other—net	(23,097)	16,479	(37,488)

Net change	308,751	(78,139)	(365,857)
Beginning of year	546,335	624,474	990,331
End of year	$ 855,086	$ 546,335	$ 624,474

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.

The December 31, 2010, future cash flows were computed by applying the unescalated 12-month average prices of $79.43 per barrel for oil, $49.35 per barrel for NGLs and $4.38 per Mcf for natural gas, adjusted for price differentials, relating to proved reserves and to the year-end quantities of those reserves. Prior to 2009, the price was based on the single-day period-end price. 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.

[Table of Contents](#)

UNIT CORPORATION AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS (UNAUDITED)

	March 31, 2011	December 31, 2010
	(In thousands except share amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,236	$ 1,359
Accounts receivable, net of allowance for doubtful accounts of $5,083 both at March 31, 2011 and at December 31, 2010	134,858	130,142
Materials and supplies	6,290	6,316
Current derivative assets (Note 10)	0	5,568
Current income tax receivable	19,316	25,211
Current deferred tax asset	19,757	13,537
Prepaid expenses and other	7,558	6,047
Total current assets	189,015	188,180
Property and equipment:		
Drilling equipment	1,313,374	1,273,861
Oil and natural gas properties on the full cost method:		
Proved properties	2,858,466	2,738,093
Undeveloped leasehold not being amortized	181,503	175,065
Gas gathering and processing equipment	208,610	199,564
Transportation equipment	33,266	31,688
Other	30,268	28,511
	4,625,487	4,446,782
Less accumulated depreciation, depletion, amortization and impairment	2,106,979	2,047,031
Net property and equipment	2,518,508	2,399,751
Goodwill	62,808	62,808
Other intangible assets, net	2,741	3,022
Non-current derivative assets (Note 10)	0	2,537
Other assets	12,972	12,942
Total assets		

	$ 2,786,044	$ 2,669,240
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 108,495	$ 89,885
Accrued liabilities (Note 5)	27,099	30,093
Contract advances	5,247	2,582
Current portion of derivative liabilities (Note 10)	25,558	14,446
Current portion of other long-term liabilities (Note 6)	9,875	10,122
Total current liabilities	176,274	147,128
Long-term debt (Note 6)	185,000	163,000
Long-term derivative liabilities (Note 10)	9,904	4,359
Other long-term liabilities (Note 6)	90,917	88,030
Deferred income taxes	579,085	556,106
Shareholders' equity:		
Preferred stock, $1.00 par value, 5,000,000 shares authorized, none issued	0	0
Common stock, $.20 par value, 175,000,000 shares authorized, 48,169,566 and 47,910,431 shares issued, respectively	9,524	9,493
Capital in excess of par value	400,543	393,501
Accumulated other comprehensive loss	(20,704)	(6,851)
Retained earnings	1,355,501	1,314,474
Total shareholders' equity	1,744,864	1,710,617
Total liabilities and shareholders' equity	$ 2,786,044	$ 2,669,240

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

UNIT CORPORATION AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME (UNAUDITED)

	Three Months Ended March 31, 2011	Three Months Ended March 31, 2010
	(In thousands)	
Revenues:		
Contract drilling	$ 97,988	$ 60,854
Oil and natural gas	109,834	99,053
Gas gathering and processing	39,764	41,135
Other	(181)	5,508
Total revenues	247,405	206,550
Expenses:		
Contract drilling:		
Operating costs	52,844	40,900
Depreciation	17,297	13,786
Oil and natural gas:		
Operating costs	30,781	25,034
Depreciation, depletion and amortization	40,268	25,336
Gas gathering and processing:		
Operating costs	29,055	32,726
Depreciation and amortization	3,773	3,941
General and administrative	6,892	6,279
Interest, net	54	0
Total operating expenses	180,964	148,002
Income before income taxes	66,441	58,548
Income tax expense:		
Current	0	2,240

Deferred	25,414	20,155
Total income taxes	25,414	22,395
Net income	$ 41,027	$ 36,153
Net income per common share:		
Basic	$ 0.86	$ 0.77
Diluted	$ 0.86	$ 0.76

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

UNIT CORPORATION AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

	Three Months Ended March 31, 2011	2010
	(In thousands)	
OPERATING ACTIVITIES:		
Net income	$ 41,027	$ 36,153
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	61,577	43,313
Unrealized (gain) loss on derivatives	2,328	(1,148)
Deferred tax expense	25,414	20,155
(Gain) loss on disposition of assets	170	(5,435)
Stock compensation plans	3,286	3,316
Other	895	676
Changes in operating assets and liabilities increasing (decreasing) cash:		
Accounts receivable	(4,716)	(13,304)
Accounts payable	(15,952)	966
Material and supplies inventory	26	245
Accrued liabilities	101	(4,269)
Contract advances	2,665	(1,537)
Other - net	4,384	536
Net cash provided by operating activities	121,205	79,667
INVESTING ACTIVITIES:		
Capital expenditures	(165,617)	(105,269)
Producing property and other acquisitions	(4,052)	(294)
Proceeds from disposition of assets	457	18,313
Other - net	0	324
Net cash used in investing activities	(169,212)	(86,926)

FINANCING ACTIVITIES:		
Borrowings under line of credit	88,800	19,100
Payments under line of credit	(66,800)	(19,100)
Proceeds from exercise of stock options	513	246
Book overdrafts	25,371	6,912
Net cash provided by financing activities	47,884	7,158
Net decrease in cash and cash equivalents	(123)	(101)
Cash and cash equivalents, beginning of period	1,359	1,140
Cash and cash equivalents, end of period	$ 1,236	$ 1,039

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

UNIT CORPORATION AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (UNAUDITED)

	Three Months Ended March 31,	
	2011	2010
	(In thousands)	
Net income	$ 41,027	$36,153
Other comprehensive income, net of taxes:		
Change in value of derivative instruments used as cash flow hedges, net of tax of ($9,184) and $14,667	(14,827)	23,672
Reclassification - derivative settlements, Net of tax of ($127) and ($2,014)	(205)	(3,252)
Ineffective portion of derivatives, net of tax of $730 and ($417)	1,179	(674)
Comprehensive income	$ 27,174	$55,899

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

Table of Contents

UNIT CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 – BASIS OF PREPARATION AND PRESENTATION

The accompanying unaudited condensed consolidated financial statements in this quarterly report include the accounts of Unit Corporation and all its subsidiaries and affiliates and have been prepared under the rules and regulations of the SEC. The terms “company,” “Unit,” “we,” “our” and “us” refer to Unit Corporation, a Delaware corporation, and, as appropriate, one or more of its subsidiaries and affiliates, except as otherwise indicated or as the context otherwise requires.

The accompanying condensed consolidated financial statements are unaudited and do not include all the notes in our annual financial statements. This quarterly report should be read in conjunction with the audited consolidated financial statements and notes included in our Form 10-K, filed February 24, 2011, for the year ended December 31, 2010.

In the opinion of management, the accompanying unaudited condensed consolidated financial statements contain all normal recurring adjustments (including the elimination of all intercompany transactions) necessary to fairly state the following:

- Balance Sheets at March 31, 2011 and December 31, 2010;
- Statements of Income for the three months ended March 31, 2011 and 2010;
- Cash Flows for the three months ended March 31, 2011 and 2010; and
- Statements of Comprehensive Income for the three months ended March 31, 2011 and 2010.

Our financial statements are prepared in conformity with generally accepted accounting principles in the United States (GAAP). GAAP requires us to make certain estimates and assumptions that may affect the amounts reported in our condensed consolidated financial statements and accompanying notes. Actual results may differ from those estimates. Results for the three months ended March 31, 2011 and 2010 are not necessarily indicative of the results to be realized for the full year in the case of 2011, or that we realized for the full year of 2010.

With respect to the unaudited financial information for the three month periods ended March 31, 2011 and 2010, included in this quarterly report, PricewaterhouseCoopers LLP reported that it applied limited procedures in accordance with professional standards in reviewing that information. Its separate report, dated May 3, 2011, which is included in this quarterly report, states that it did not audit and it does not express an opinion on that unaudited financial information. Accordingly, the degree of reliance placed on its report should be restricted in light of the limited review procedures applied. PricewaterhouseCoopers LLP is not subject to the liability provisions of Section 11 of the Securities Act of 1933 (Act) for its report on the unaudited financial information because that report is not a “report” or a “part” of a registration statement prepared or certified by PricewaterhouseCoopers LLP within the meaning of Sections 7 and 11 of the Act.

NOTE 2 – OIL AND NATURAL GAS PROPERTIES

Full cost accounting rules require us to review the carrying value of our oil and natural gas properties at the end of each quarter. Under those rules, the maximum amount allowed as the carrying value of those properties is referred to as the ceiling. The ceiling is the sum of the present value (using a 10% discount rate) of the estimated future net revenues from our proved reserves based on the unescalated 12-month average price on our oil, natural gas liquids (NGLs) and natural gas adjusted for any cash flow hedges, plus the cost of properties not being amortized, plus the lower of cost or estimated fair value of unproved properties included in the costs being amortized, less related income taxes. In the event the unamortized cost of the amortized oil and natural gas properties exceeds the full cost ceiling, the excess amount is charged to expense in the period during which the excess occurs, even if prices are depressed for only a short period of time. Once incurred, a write-down of oil and natural gas properties is not reversible.

At March 31, 2011, using the existing 12-month average commodity prices, including the discounted value of our commodity hedges, we were not required to record a ceiling test write-down. However, if there are declines in the 12-month average prices, including the discounted value of our commodity hedges, we may be required to record a write-down in future periods. Our qualifying cash flow hedges used in the ceiling test determination as of March 31, 2011, consisted of swaps covering 29.4 Bcfe in 2011, 17.6 Bcfe in 2012 and 2.2 Bcfe in 2013. The effect of those hedges on the March 31, 2011 ceiling test was a $40.9 million pre-tax increase in the discounted net cash flows of our oil and natural gas properties. Even without the impact of those hedges, we would not have been required to take a write-down for the quarter. Our oil and natural gas hedging is discussed in Note 10 of the Notes to our Condensed Consolidated Financial Statements.

NOTE 3 – ACQUISITIONS

On June 2, 2010, we completed an acquisition of oil and natural gas properties from certain unaffiliated parties in an effort to explore and develop more oil rich plays. The properties were purchased for approximately $73.7 million in cash, after post close adjustments. The purchase price allocation was $48.7 million for proved properties and $25.0 million for undeveloped leasehold not being amortized. The acquisition included approximately 45,000 net leasehold acres and 10 producing oil wells. These properties focused on the Marmaton horizontal oil play located mainly in Beaver County, Oklahoma. At the time of acquisition, proved developed producing net reserves associated with the 10 acquired producing wells was approximately 762,000 BOE – consisting of 511,000 barrels of oil, 155,000 barrels of NGLs and 573 MMcf of natural gas.

Also during the second quarter of 2010, we completed an acquisition from unaffiliated parties of approximately 32,000 net acres of undeveloped oil and gas leasehold located in Southwest Oklahoma and North Texas for approximately $17.6 million.

NOTE 4 – EARNINGS PER SHARE

Information related to the calculation of earnings per share follows:

	Income (Numerator)	Weighted Shares (Denominator)	Per-Share Amount
	(In thousands except per share amounts)		
For the three months ended March 31, 2011:			
Basic earnings per common share	$ 41,027	47,584	$ 0.86
Effect of dilutive stock options, restricted stock and stock appreciation rights (SARs)	0	321	0
Diluted earnings per common share	$ 41,027	47,905	$ 0.86
For the three months ended March 31, 2010:			
Basic earnings per common share	$ 36,153	47,121	$ 0.77
Effect of dilutive stock options, restricted stock and SARs	0	565	(0.01)
Diluted earnings per common share	$ 36,153	47,686	$ 0.76

The following table shows the number of stock options and SARs (and their average exercise price) excluded because their option exercise prices were greater than the average market price of our common stock:

	Three Months Ended March 31,	
	2011	2010
Stock options and SARs	73,500	132,165
Average Exercise Price	$ 64.43	$ 59.87

Table of Contents

NOTE 5 – ACCRUED LIABILITIES

Accrued liabilities consisted of the following:

	March 31, 2011	December 31, 2010
	(In thousands)	
Employee costs	$ 9,520	$ 16,499
Lease operating expense accrual	6,064	6,214
Taxes	3,486	1,310
Hedge settlements	2,475	1,634
Other	5,554	4,436
Total accrued liabilities	$ 27,099	$ 30,093

NOTE 6 – LONG-TERM DEBT AND OTHER LONG-TERM LIABILITIES

Long-Term Debt

As of the dates in the table, long-term debt consisted of the following:

	March 31, 2011	December 31, 2010
	(In thousands)	
Revolving credit facility with average interest rates, including the effect of hedging, of 2.8% at March 31, 2011 and 3.5% at December 31, 2010	$185,000	$ 163,000
Less current portion	0	0
Total long-term debt	$185,000	$ 163,000

Our credit facility has a maximum credit amount of $400.0 million and matures on May 24, 2012. The lenders' current commitment under the credit facility is $325.0 million. Our borrowings are limited to the commitment amount that we from time to time elect. As of March 31, 2011, the commitment amount was $325.0 million. We are charged a commitment fee ranging from 0.375 to 0.50 of 1% on the amount available but not borrowed. The rate varies based on the amount borrowed as a percentage of the amount of the total borrowing base. To date we have paid $1.2 million in origination, agency and syndication fees under the credit facility. We are amortizing these fees over the life of the agreement.

The lenders' aggregate commitment is limited to the lesser of the amount of the borrowing base or $400.0 million. The amount of the borrowing base, which is subject to redetermination on April 1 and October 1 of each year, is based primarily on a percentage of the discounted future value of our oil and natural gas reserves 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 segment. The April 1, 2011 redetermination increased the borrowing base to $600.0 million. We or the lenders may request a onetime special redetermination of the amount of the borrowing base between each scheduled redetermination. In addition, we may request a redetermination following the completion of an acquisition that meets the requirements set forth in the credit facility.

At our election, any part of the outstanding debt under the credit facility may be fixed at a London Interbank Offered Rate (LIBOR) for a 30, 60, 90 or 180 day period. During any LIBOR funding period, the outstanding principal balance of the promissory note to which the LIBOR option applies may be repaid after three days prior notice to the administrative agent and on payment of any applicable funding indemnification amounts. LIBOR interest is computed as the sum of the LIBOR base for the applicable period plus 1.75% to 2.50% depending on the level of debt as a percentage of the borrowing base and is payable at the end of each period, or every 90 days, whichever is less. Borrowings not under LIBOR bear interest at the BOK Financial Corporation (BOKF) National Prime Rate, which cannot be less than LIBOR plus 1.00%, and is payable at the end of each month and the principal borrowed may be paid at any time, in part or in whole, without a premium or penalty. At March 31, 2011, all of our $185.0 million in outstanding borrowings were subject to LIBOR.

The credit facility prohibits:

- 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 limited exceptions; and
- the creation or existence of mortgages or liens, other than those in the ordinary course of business, on any of our properties, except in favor of our 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.

As of March 31 2011, we were in compliance with our credit facility's covenants.

Based on the borrowing rates currently available to us for debt with similar terms and maturities and consideration of our non-performance risk, long-term debt at March 31, 2011 approximates its fair value.

At March 31, 2011, the carrying values on the consolidated balance sheets for cash and cash equivalents, accounts receivable, accounts payable, other current assets and current liabilities approximate their fair value because of their short term nature.

Securities being registered under the registration statement are debt securities guaranteed by our wholly-owned domestic direct and indirect subsidiaries. Unit Corporation (Unit), as the parent company, has no independent assets or operations. The guarantees registered under the registration statement are full and unconditional and joint and several, and subsidiaries of Unit other than the subsidiary guarantors are minor. There are no significant restrictions on the ability of our parent company to receive funds from our subsidiaries through dividends, loans, advances or otherwise.

Other Long-Term Liabilities

Other long-term liabilities consisted of the following:

	March 31, 2011	December 31, 2010
	(In thousands)	
Asset retirement obligations (ARO) liability	$ 71,338	$ 69,265
Workers' compensation	17,666	17,566
Separation benefit plans	5,953	5,690
Gas balancing liability	3,263	3,263
Deferred compensation plan	2,572	2,368
	100,792	98,152
Less current portion	9,875	10,122
Total other long-term liabilities	$ 90,917	$ 88,030

The estimated annual payments due under the terms of our debt and other long-term liabilities during each of the five successive twelve month periods beginning April 1, 2011 (and through 2016) are $9.9 million, $199.6 million, $3.3 million, $2.7 million and $2.1 million, respectively.

NOTE 7 – ASSET RETIREMENT OBLIGATIONS

We are required to record the estimated fair value of the liabilities relating to the future retirement of our long-lived assets. Our oil and natural gas wells are plugged and abandoned when the oil and natural gas reserves in those wells are depleted or the wells are no longer able to produce. The plugging and abandonment liability for a well is recorded in the period in which the obligation is incurred (at the time the well is drilled or acquired). None of our assets are restricted for purposes of settling these AROs. All of our AROs relate to the plugging costs associated with our oil and gas wells.

The following table shows certain information about our AROs for the periods indicated:

	Three Months Ended March 31, 2011	Three Months Ended March 31, 2010
	(In thousands)	
ARO liability, January 1:	$69,265	$56,404
Accretion of discount	874	687
Liability incurred	1,559	472
Liability settled	(359)	(270)
Revision of estimates	(1)	49
ARO liability, March 31:	71,338	57,342
Less current portion	1,836	1,632
Total long-term plugging liability	$69,502	$55,710

NOTE 8 – NEW ACCOUNTING PRONOUNCEMENTS

Improving Disclosures about Fair Value Measurements. In January 2010, the FASB issued ASU 2010-06 – *Fair Value Measurements and Disclosures (ASC 820): Improving Disclosures about Fair Value Measurements*, which provides additional guidance to improve disclosures regarding fair value measurements. The ASU amends ASC 820-10, *Fair Value Measurements and Disclosures—Overall* (formerly FAS 157, *Fair Value Measurements)* to add two new disclosures: (1) transfers in and out of Level 1 and 2 measurements and the reasons for the transfers, and (2) a gross presentation of activity within the Level 3 roll forward. The ASU also includes clarifications to existing disclosure requirements on the level of disaggregation and disclosures regarding inputs and valuation techniques. The ASU applies to all entities required to make disclosures about recurring and nonrecurring fair value measurements. The effective date of the ASU was the first interim or annual reporting period beginning after December 15, 2009 and was adopted January 1, 2010, except for the gross presentation of the Level 3 roll forward information, which was adopted January 1, 2011. Because it only includes enhanced disclosures, this statement did not have a significant impact on us.

NOTE 9 – STOCK-BASED COMPENSATION

For the three months ended March 31, 2011 and 2010, we recognized stock compensation expense for restricted stock awards, stock options and stock settled SARs of $2.3 million and $2.5 million, respectively, and capitalized stock compensation cost for oil and natural gas properties of $0.6 million and $0.5 million, respectively. For these same periods, the tax benefit related to this stock based compensation was $0.9 million each period. The remaining unrecognized compensation cost related to unvested awards at March 31, 2011 is approximately $16.3 million of which $3.1 million is anticipated to be capitalized. The weighted average period of time over which this cost will be recognized is 0.9 years.

We did not grant any stock options or SARs during either of the three month periods ending March 31, 2011 and 2010.

The following table shows the fair value of any restricted stock awards granted during the periods indicated:

	Three Months Ended March 31, 2011	Three Months Ended March 31, 2010
Shares granted	192,581	248,383
Estimated fair value (in millions)	$ 10.0	$ 10.6
Percentage of shares granted expected to be distributed	93%	93%

The restricted stock awards granted during the first three months of 2011 will be recognized over a three year vesting period except for certain designated executive officers. For grants to those executive offers covering 66,869 shares of the total granted, 70% will vest in equal one-third annual increments, the other 30% of the shares awarded will cliff vest in the first quarter of 2014, but only if certain performance criteria are met which could result in fewer or additional shares vesting. These awards increased the stock compensation expense and the capitalized cost related to oil and natural gas properties for the first quarter of 2011 by an aggregate of $0.5 million.

NOTE 10 – DERIVATIVES

Interest Rate Swaps

From time to time we enter into interest rate swaps to manage our exposure to possible future interest rate increases under our credit facility. Under these transactions we swap the variable interest rate we would otherwise pay on a portion of our bank debt for a fixed interest rate. As of March 31, 2011, we had two outstanding interest rate swaps; both were cash flow hedges. There was no material amount of ineffectiveness. This table provides certain information about those interest rate swaps:

Remaining Term	Amount	Fixed Rate	Floating Rate
April 2011 – May 2012	$ 15,000,000	4.53%	3 month LIBOR
April 2011 – May 2012	$ 15,000,000	4.16%	3 month LIBOR

Commodity Derivatives

We have entered into various types of derivative transactions covering some of our projected natural gas, NGLs and oil production. These transactions are intended to reduce our exposure to market price volatility by setting the price(s) we will receive for that production. Our decisions on the price(s), type and quantity of our production hedged is based, in part, on our view of current and future market conditions. As of March 31, 2011, our derivative transactions consisted of the following types of swaps:

- *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 from the counterparty.

- *Basis Swaps.* We receive or pay the NYMEX settlement value plus or minus a fixed delivery point price for the hedged commodity and pay or receive the published index price at the specified delivery point. We use basis swaps to hedge the price risk between NYMEX and its physical delivery points.

Oil and Natural Gas Segment:

At March 31, 2011, the following cash flow hedges were outstanding:

Term	Commodity	Hedged Volume	Weighted Average Fixed Price for Swaps	Hedged Market
Apr'11 – Dec'11	Crude oil—swap	4,000 Bbl/day	$ 84.28	WTI—NYMEX
Jan'12 – Dec'12	Crude oil—swap	3,000 Bbl/day	$ 90.92	WTI—NYMEX
Jan'13 – Dec'13	Crude oil—swap	1,000 Bbl/day	$ 101.08	WTI—NYMEX
Apr'11 – Dec'11	Natural gas—swap	10,000 MMBtu/day	$ 4.43	CEGT
Apr'11 – Dec'11	Natural gas—swap	70,000 MMBtu/day	$ 4.87	IF—NYMEX (HH)
Apr'11 – Dec'11	Natural gas—basis differential swap	15,000 MMBtu/day	($ 0.14)	Tenn Zone 0—NYMEX
Jan'12 – Dec'12	Natural gas—swap	15,000 MMBtu/day	$ 5.06	IF—NYMEX (HH)
Jan'12 – Dec'12	Natural gas—swap	15,000 MMBtu/day	$ 5.62	IF—PEPL
Apr'11 – Dec'11	Liquids—swap (1)	644,406 Gal/mo	$ 0.96	OPIS—Conway

(1) Types of liquids involved are natural gasoline, ethane, propane, isobutane and normal butane.

At March 31, 2011, the following non-qualifying cash flow derivatives were outstanding:

Term	Commodity	Hedged Volume	Basis Differential	Hedged Market
Apr'11 – Dec'11	Natural gas—basis differential swap	15,000 MMBtu/day	($0.14)	Tenn Zone 0—NYMEX
Apr'11 – Dec'11	Natural gas—basis differential swap	10,000 MMBtu/day	($0.21)	CEGT—NYMEX
Apr'11 – Dec'11	Natural gas—basis differential swap	10,000 MMBtu/day	($0.23)	PEPL—NYMEX

After March 31, 2011, we entered into the following cash flow hedges:

Term	Commodity	Hedged Volume	Weighted Average Fixed Price	Hedged Market
Jan'12 – Dec'12	Crude oil—swap	1,000 Bbl/day	$ 107.31	WTI—NYMEX
Jan'13 – Dec'13	Crude oil—swap	500 Bbl/day	$ 104.40	WTI—NYMEX

[Table of Contents](#)

The following tables present the fair values and locations of the derivative transactions recorded in our balance sheets:

	Balance Sheet Location	Derivative Assets Fair Value March 31, 2011	Derivative Assets Fair Value December 31, 2010
		(In thousands)	
Derivatives designated as hedging instruments			
Commodity derivatives:			
Current	Current derivative assets	$ 0	$ 5,091
Long-term	Non-current derivative assets	0	2,537
Total derivatives designated as hedging instruments		0	7,628
Derivatives not designated as hedging instruments			
Commodity derivatives:			
Current	Current derivative assets	0	477
Total derivatives not designated as hedging instruments		0	477
Total derivative assets		$ 0	$ 8,105

	Balance Sheet Location	Derivative Liabilities Fair Value March 31, 2011	Derivative Liabilities Fair Value December 31, 2010
		(In thousands)	
Derivatives designated as hedging instruments			
Interest rate swaps:			
Current	Current portion of derivative liabilities	$ 1,167	$ 1,139
Long-term	Long-term derivative liabilities	194	475
Commodity derivatives:			
Current	Current portion of derivative liabilities	24,308	13,166
Long-term	Long-term derivative liabilities	9,710	3,884
Total derivatives designated as hedging instruments		35,379	18,664
Derivatives not designated as hedging instruments			
Commodity derivatives (basis swaps):			

Current	Current portion of derivative liabilities	83	141
Total derivatives not designated as hedging instruments		83	141
Total derivative liabilities		$ 35,462	$ 18,805

If a legal right of set-off exists, we net the value of the derivative transactions we have with the same counterparty in our balance sheets.

We recognize in accumulated other comprehensive income (OCI) the effective portion of any changes in fair value and reclassify the recognized gains (losses) on the sales to revenue and the purchases to expense as the underlying transactions are settled. As of March 31, 2011 and 2010, we had a loss of $20.7 million and a gain of $24.2 million, net of tax, respectively, in accumulated OCI.

Based on market prices at March 31, 2011, we expect to transfer a loss of approximately $15.9 million, net of tax, included in accumulated OCI during the next 12 months in the related month of settlement. The interest rate swaps and the commodity derivative instruments existing as of March 31, 2011 are expected to mature by May 2012 and December 2013, respectively.

Certain derivatives do not qualify as cash flow hedges. Currently, we have three basis swaps that do not qualify as cash flow hedges. For these types of derivatives, any changes in the fair value that occurs before their maturity (i.e., temporary fluctuations in value) are reported in the condensed consolidated statements of operations within our oil and natural gas revenues. Changes in the fair value of derivative instruments designated as cash flow hedges, to the extent they are effective in offsetting cash flows attributable to the hedged risk, are recorded in OCI until the hedged item is recognized into earnings. Any change in fair value resulting from ineffectiveness is recognized in our oil and natural gas revenues.

Effect of Derivative Instruments on the Condensed Consolidated Statement of Income (cash flow hedges) for the three months ended March 31:

Derivatives in Cash Flow Hedging Relationships	Amount of Gain or (Loss) Recognized in Accumulated OCI on Derivative (Effective Portion) (1)	
	2011	2010
	(In thousands)	
Interest rate swaps	$ (840)	$ (1,247)
Commodity derivatives	(19,864)	25,451
Total	$ (20,704)	$ 24,204

(1) Net of taxes.

Effect of Derivative Instruments on the Condensed Consolidated Statement of Income (cash flow hedges) for the three months ended March 31:

Derivative Instrument	Location of Gain or (Loss) Reclassified from Accumulated OCI into Income & Location of Gain or (Loss) Recognized in Income	Amount of Gain or (Loss) Reclassified from Accumulated OCI into Income (1)		Amount of Gain or (Loss) Recognized in Income (2)	
		2011	2010	2011	2010
		(In thousands)			
Commodity derivatives	Oil and natural gas revenue	$ 635	$ 5,573	$(1,909)	$1,091
Interest rate swaps	Interest, net	(303)	(307)	0	0
	Total	$ 332	$ 5,266	$(1,909)	$1,091

(1) Effective portion of gain (loss).
(2) Ineffective portion of gain (loss).

Table of Contents

Effect of Derivative Instruments on the Condensed Consolidated Statement of Income (derivatives not designated as hedging instruments) for the three months ended March 31:

Derivatives Not Designated as Hedging Instruments	Location of Gain or (Loss) Recognized in Income on Derivative	Amount of Gain or (Loss) Recognized in Income on Derivative 2011	2010
		(In thousands)	
Commodity derivatives (basis swaps)	Oil and natural gas revenue	$ (601)	$ 57
Total		$ (601)	$ 57

NOTE 11 – FAIR VALUE MEASUREMENTS

Fair value is defined as the amount that would be received from the sale of an asset or paid for the transfer of a liability in an orderly transaction between market participants (in either case, an exit price). To estimate an exit price, a three-level hierarchy is used prioritizing the valuation techniques used to measure fair value into three levels with the highest priority given to Level 1 and the lowest priority given to Level 3. The levels are summarized as follows:

- Level 1—unadjusted quoted prices in active markets for identical assets and liabilities.
- Level 2—significant observable pricing inputs other than quoted prices included within level 1 that are either directly or indirectly observable as of the reporting date. Essentially, inputs (variables used in the pricing models) that are derived principally from or corroborated by observable market data.
- Level 3—generally unobservable inputs which are developed based on the best information available and may include our own internal data.

The inputs available to us determine the valuation technique we use to measure the fair values of our financial instruments.

The following tables set forth our recurring fair value measurements:

	March 31, 2011		
	Level 2	Level 3	Total
		(In thousands)	
Financial assets (liabilities):			
Interest rate swaps	$ 0	$(1,361)	$ (1,361)
Commodity derivatives	$(43,469)	$ 9,368	$(34,101)

	December 31, 2010		
	Level 2	Level 3	Total
		(In thousands)	
Financial assets (liabilities):			
Interest rate swaps	$ 0	$(1,614)	$(1,614)
Commodity derivatives	$(19,954)	$10,868	$(9,086)

The following methods and assumptions were used to estimate the fair values of the assets and liabilities in the table above.

Level 2 Fair Value Measurements

Commodity Derivatives. We measure the fair values of our crude oil swaps using estimated internal discounted cash flow calculations based on the NYMEX futures index.

Level 3 Fair Value Measurements

Interest Rate Swaps. The fair values of our interest rate swaps are based on estimates provided by our respective counterparties and reviewed internally against established index prices and other sources.

Commodity Derivatives. The fair values of our natural gas, natural gas liquids and basis swaps are estimated using internal discounted cash flow calculations based on forward price curves, quotes obtained from brokers for contracts with similar terms, or quotes obtained from counterparties to the agreements.

The following tables are reconciliations of our level 3 fair value measurements:

	Net Derivatives			
	For the Three Months Ended March 31, 2011		For the Three Months Ended March 31, 2010	
	Interest Rate Swaps	Commodity Swaps	Interest Rate Swaps	Commodity Swaps and Collars
	(In thousands)			
Beginning of period	$ (1,614)	$ 10,868	$ (1,948)	$ 19,948
Total gains or losses (realized and unrealized):				
Included in earnings (1)	(303)	4,305	(307)	9,074
Included in other comprehensive income (loss)	253	(1,765)	(71)	30,343
Settlements	303	(4,040)	307	(7,926)
End of period	$ (1,361)	$ 9,368	$ (2,019)	$ 51,439
Total gains for the period included in earnings attributable to the change in unrealized gain relating to assets still held at end of period	$ 0	$ 265	$ 0	$ 1,148

(1) Interest rate swaps and commodity swaps and collars are reported in the condensed consolidated statements of income in interest, net and revenues, respectively.

Based on our valuation at March 31, 2011, we determined that the non-performance risk with regard to our counterparties was immaterial.

NOTE 12 – INDUSTRY SEGMENT INFORMATION

We have three main business segments offering different products and services:

- Contract drilling,
- Oil and natural gas and
- Mid-stream

The contract drilling segment is engaged in the land contract drilling of oil and natural gas wells. The oil and natural gas 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.

We evaluate each segment's performance based on its operating income, which is defined as operating revenues less operating expenses and depreciation, depletion, amortization and impairment. Our natural gas production in Canada is not significant.

Table of Contents

The following table provides certain information about the operations of each of our segments:

	Three Months Ended March 31, 2011	Three Months Ended March 31, 2010
	(In thousands)	
Revenues:		
Contract drilling	$112,508	$ 67,501
Elimination of inter-segment revenue	(14,520)	(6,647)
Contract drilling net of inter-segment revenue	97,988	60,854
Oil and natural gas	109,834	99,053
Gas gathering and processing	57,008	53,734
Elimination of inter-segment revenue	(17,244)	(12,599)
Gas gathering and processing net of inter-segment revenue	39,764	41,135
Other	(181)	5,508
Total revenues	$247,405	$206,550
Operating income (1):		
Contract drilling	$ 27,847	$ 6,168
Oil and natural gas	38,785	48,683
Gas gathering and processing	6,936	4,468
Total operating income	73,568	59,319
General and administrative expense	(6,892)	(6,279)
Interest expense, net	(54)	0
Other	(181)	5,508
Income before income taxes	$ 66,441	$ 58,548

(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.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders Unit Corporation

We have reviewed the accompanying condensed consolidated balance sheet of Unit Corporation and its subsidiaries as of March 31, 2011, and the related condensed consolidated statements of income and comprehensive income for the three-month periods ended March 31, 2011 and 2010 and the condensed consolidated statements of cash flows for the three-month periods ended March 31, 2011 and 2010. These interim financial statements are the responsibility of the Company's management.

We conducted our review in accordance with standards of the Public Company Accounting Oversight Board (United States). A review of interim financial information consists principally of applying analytical procedures and making inquiries of persons responsible for financial and accounting matters. It is substantially less in scope than an audit conducted in accordance with the standards of the Public Company Accounting Oversight Board (United States), the objective of which is the expression of an opinion regarding the financial statements taken as a whole. Accordingly, we do not express such an opinion.

Based on our review, we are not aware of any material modifications that should be made to the accompanying condensed consolidated interim financial statements for them to be in conformity with accounting principles generally accepted in the United States of America.

We previously audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet as of December 31, 2010, and the related consolidated statements of operations, shareholders' equity and of cash flows for the year then ended (not presented herein), and in our report dated February 24, 2011, we expressed an unqualified opinion on those consolidated financial statements. In our opinion, the information set forth in the accompanying consolidated balance sheet information as of December 31, 2010, is fairly stated in all material respects in relation to the consolidated balance sheet from which it has been derived.

/s/ PricewaterhouseCoopers LLP

Tulsa, Oklahoma
May 3, 2011

Table of Contents

PROSPECTUS

UNIT CORPORATION

Debt Securities
Preferred Stock
Common Stock
Warrants
Purchase Contracts
Units

By this prospectus, we may offer and sell from time to time:

- senior debt securities;
- subordinated debt securities;
- preferred stock;
- common stock;
- warrants;
- purchase contracts; or
- units.

One or more of our subsidiaries may guarantee the senior or subordinated debt securities offered by this prospectus.

This prospectus provides you with a general description of the securities that may be offered. Each time we offer securities under this prospectus, we will provide you with one or more supplements to this prospectus that will contain additional information about the specific offering. The supplements may also add, update or change information contained in this prospectus. You should read this prospectus and any supplements to this prospectus carefully before you invest in the securities.

Our common stock is listed on the New York Stock Exchange under the symbol "UNT." Our executive offices are located at 7130 South Lewis, Suite 1000, Tulsa, Oklahoma 74136, and our telephone number is (918) 493-7700.

There are significant risks associated with an investment in our securities. You should read carefully the risks we describe in the accompanying prospectus supplement as well as the risk factors discussed in our periodic reports that we file with the Securities and Exchange Commission (the "SEC") for a better understanding of the risks and uncertainties that investors in our securities should consider.

We may offer and sell these securities to or through one or more underwriters, dealers or agents, or directly to investors, on a continuous or delayed basis.

Neither the SEC nor any state securities commission has approved or disapproved of these securities or determined if this prospectus is truthful or complete. Any representation to the contrary is a criminal offense.

This prospectus may not be used to sell securities unless accompanied by a prospectus supplement.

The date of this prospectus is May 3, 2011.

Table of Contents

TABLE OF CONTENTS

ABOUT THIS PROSPECTUS

This prospectus is part of a registration statement that we filed with the SEC using a "shelf" registration process. Under this shelf process, we may, from time to time, sell any combination of the securities described in this prospectus in one or more offerings.

This prospectus provides you with a general description of the securities we may offer. Each time we sell securities, we will provide a prospectus supplement that will contain specific information about the terms of that offering. The prospectus supplement may also add, update or change information contained in this prospectus. You should read both this prospectus and any prospectus supplement together with additional information described under the heading below "Where You Can Find More Information."

We have not authorized anyone to provide you any information other than that contained or incorporated by reference in this prospectus or any related prospectus supplement. We take no responsibility for, and can provide no assurance as for the reliability of, any other information that others may give you. You may obtain copies of the registration statement, or of any document which we have filed as an exhibit to the registration statement or to any other SEC filing, either from the SEC or from our corporate secretary as described below. We are not making an offer of these securities in any state where the offer is not permitted. You should not assume that the information in this prospectus or in the accompanying prospectus supplement is accurate as of any date other than the dates printed on the front of each document.

Unless otherwise indicated or otherwise required by the context in which the term occurs, all references in this prospectus or a supplement to "we," "our," "us," "company" or similar terms refer to Unit Corporation together with its subsidiaries.

FORWARD-LOOKING STATEMENTS

This prospectus, any accompanying prospectus supplement and the documents incorporated by reference herein or therein may include "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended (the "Securities Act"), and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). All statements, other than statements of historical facts, included or incorporated by reference in this prospectus, 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 also intended to identify forward-looking statements.

These forward-looking statements are based on assumptions which we believe are reasonable based on current expectations and projections about future events and industry conditions and trends affecting our business. However, whether actual results and developments will conform to our expectations and predictions is subject to a number of risks and uncertainties that, among other things, could cause actual results to differ materially from those contained in the forward-looking statements, including without limitation the following:

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

Table of Contents

- 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;
- 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;
- demand for our drilling rigs and drilling rig rates;
- our belief that the final outcome of our legal proceedings will not materially affect our financial results; and
- our ability to timely secure third party services used in completing our wells.

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 the documents we incorporate by reference;
- general economic, market or business conditions;
- the nature or lack of business opportunities that may be presented to and pursued by us;
- demand for our land drilling services;
- changes in laws or regulations;
- the time period associated with decreases or increases in commodity prices; and
- other factors, most of which are beyond our control.

We describe these risks and uncertainties in greater detail under the caption "Risk Factors" in our Form 10-K for the year ended December 31, 2010, filed with the SEC. See "Where You Can Find More Information" and "Documents Incorporated by Reference."

You should not place undue reliance on any these forward-looking statements. 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 prospectus or the accompanying prospectus supplement to reflect the occurrence of unanticipated events.

WHO WE ARE

We were founded in 1963 as a contract drilling company. Today, in addition to our drilling operations, we engage in the domestic exploration, development and production of crude oil and natural gas and midstream operations. Our operations are generally conducted through our three principal wholly owned subsidiaries:

- Unit Drilling Company – which contracts to drill onshore oil and natural gas wells for others and for our own account (contract drilling);

- Unit Petroleum Company – which explores, develops, acquires and produces oil and natural gas properties for our own account (oil and natural gas); and
- Superior Pipeline Company, L.L.C. – which buys, sells, gathers, processes and treats natural gas for third parties and for our own account (midstream).

Our operations are mainly located in the Mid-Continent, Rocky Mountain and Gulf Coast Basins. Our principal executive offices are located at 7130 South Lewis, Suite 1000, Tulsa, Oklahoma 74136, and our telephone number is (918) 493-7700. Our common stock trades on the New York Stock Exchange under the symbol "UNT."

RATIO OF EARNINGS TO FIXED CHARGES

The following table shows our ratio of earnings to fixed charges for the periods indicated:

	Three Months Ended	Year Ended December 31,				
	March 31, 2011	2010	2009(3)	2008	2007	2006
Ratio of Earnings to Fixed Charges(1)(2)	46.3x	52.8x	—	31.0x	38.4x	56.6x

(1) Earnings available for fixed charges represent earnings from continuing operations before income taxes and fixed charges. Fixed charges represent interest incurred and guaranteed plus that portion of rental expense deemed to be the equivalent of interest.
(2) There were no shares of preferred stock outstanding during any of the time periods indicated in the table.
(3) Earnings for the year ended December 31, 2009 were insufficient to cover fixed charges by $87.7 million due to non-cash ceiling test write down of $281.2 million pre-tax ($175.1 million, net of tax) during the quarter ended March 31, 2009.

USE OF PROCEEDS

Except as otherwise described in any prospectus supplement, the net proceeds from the sale of securities offered from time to time will be used for general corporate purposes, which may include:

- repayment or refinancing of our debt;
- working capital;
- capital expenditures;
- purchases of oil and natural gas properties, midstream assets or drilling rigs; and
- repurchases and redemptions of securities.

THE SECURITIES WE MAY OFFER

This prospectus is part of a shelf registration statement. Under this shelf registration statement, we may offer and sell from time to time any of the following securities:

- debt securities;
- preferred stock;
- common stock;
- warrants to purchase debt securities, preferred stock or common stock;

- purchase contracts; and
- units.

DESCRIPTION OF DEBT SECURITIES

The following description of the terms of the debt securities, which may consist of senior notes and debentures and subordinated notes and debentures, describes certain general terms and provisions of the debt securities to which any prospectus supplement may relate. The particular terms of the debt securities offered by any prospectus supplement and the extent, if any, to which the general provisions may apply to the debt securities being offered will be described in the prospectus supplement relating to the debt securities. You will need to review both the prospectus supplement and the following description for a description of the terms of a particular issue of our debt securities.

The debt securities will be general obligations and may be subordinated to our senior indebtedness (as discussed below) to the extent described in the applicable prospectus supplement. See "Description of Debt Securities—Subordination" below. Debt securities will be issued under an indenture to be entered into between us and an indenture trustee to be selected by us and named in a prospectus supplement. A copy of the form of indenture has been filed as an exhibit to the registration statement. This discussion of certain provisions of the indenture is a summary only and is not a complete description of the terms and provisions of the indenture. This discussion is completely qualified by reference to the actual terms of the indenture. Whenever defined terms are used but not defined in this prospectus, those terms have the meanings specified in the indenture.

General

The indenture does not limit the aggregate principal amount of debt securities that we may issue. We may issue the debt securities from time to time in one or more series. The indenture does not limit the amount of other unsecured indebtedness or securities which we may issue. Unless otherwise indicated in the applicable prospectus supplement, the debt securities will not benefit from any covenant or other provision that would give holders of debt securities special protection in the event of a highly leveraged transaction involving us. The applicable prospectus supplement will contain the following terms of the debt securities of the series for which the prospectus supplement is being delivered:

- the title;
- any limit on the aggregate principal amount of the debt securities;
- the date or dates on which the principal and premium, if any, are payable;
- the rate or rates (which may be fixed or variable), or the method of determining the rate or rates, at which the debt securities will bear interest, the date or dates from when interest will accrue, the dates when interest will be payable or the method by which the dates will be determined, the record dates for determining who the interest will be paid to, and the basis on which interest will be calculated if other than a 360-day year (twelve 30-day months);
- where principal, premium, if any, and interest will be paid;
- the terms and conditions on which the debt securities may be redeemed;
- our obligation, if any, to redeem, purchase, or repay the debt securities because of any sinking fund or analogous provisions or at the option of a holder of the debt securities and the price or prices at which, the period or periods within which, and the terms on which the debt securities of the series will be redeemed, purchased, or repaid, in whole or in part;
- the terms, if any, on which the debt securities may be convertible into or exchanged for our securities or any other issuer or obligor and the terms and conditions on which the conversion or exchange will

be effected, including the initial conversion or exchange price or rate, the conversion or exchange period and any other provision;

- the denominations in which the debt securities will be issuable;
- if the amount of principal, premium, if any, or interest with respect to the debt securities may be determined with reference to an index or under a formula, the manner in which the amounts will be determined;
- if the principal amount payable at the stated maturity of the debt securities will not be determinable as of any one or more dates before the stated maturity, the amount that will be deemed to be the principal amount as of that date for any purpose, including the principal amount that will be due and payable on any maturity other than the stated maturity or that will be deemed to be outstanding as of that date (or, in some cases, the manner in which the deemed principal amount is to be determined), and if necessary, the manner of determining the equivalent principal amount in United States currency;
- any changes or additions to the provisions of the indenture dealing with defeasance, including the addition of additional covenants that may be subject to our covenant defeasance option;
- if other than United States dollars, the coin or currency or currencies or units of two or more currencies in which payment of the principal, premium, if any, and interest with respect to debt securities will be payable;
- if other than the principal amount of debt securities, the portion of the principal amount of debt securities which will be payable on declaration of acceleration or provable in bankruptcy;
- the terms, if any, of the transfer, mortgage, pledge or assignment as security for the debt securities of any properties, assets, moneys, proceeds, securities or other collateral, including whether certain provisions of the Trust Indenture Act are applicable and any corresponding changes to provisions of the indenture as currently in effect;
- any addition to or change in the events of default with respect to the debt securities and any change in the right of the trustee or the holders to declare the principal of and interest on the debt securities due and payable;
- whether the debt securities will be issued in whole or in part in global form, the terms and conditions on which any global security may be exchanged in whole or in part for other individual debt securities in definitive registered form and the depositary for the global security;
- any trustees, authenticating or paying agents, transfer agents or registrars;
- any addition to or change in the covenants applicable to the debt securities;
- the terms, if any, of any guarantee of the payment of principal of, and premium, if any, and interest on, debt securities and any corresponding changes to the provisions of the indenture as currently in effect;
- the subordination, if any, of the debt securities and any changes or additions to the provisions of the indenture relating to subordination;
- if debt securities do not bear interest, the dates for certain required reports to the trustee;
- any other terms of the debt securities not prohibited by the indenture; and
- any material United States federal income tax consequences or other special considerations applicable to the series of debt securities offered.

Senior debt securities may be issued as original issue discount senior debt securities, which bear no interest or interest at a rate which at the time of issuance is below market rates, to be sold at a substantial discount below their stated principal amount due at the stated maturity of the senior debt securities. There may not be periodic payments of interest on original issue discount securities. In the event of an acceleration of the maturity of any original issue discount security, the amount payable to the holder of the original issue discount security on acceleration will be determined in accordance with the prospectus supplement, the terms of the security and the indenture, but will be an amount less than the amount payable at the maturity of the principal of the original issue discount security.

If the senior debt securities are issued with "original issue discount" within the meaning of the Internal Revenue Code of 1986, as amended, then a holder of those senior debt securities will be required under the Internal Revenue Code to include original issue discount in ordinary income for federal income tax purposes as it accrues, in accordance with a constant interest method that takes into account the compounding of interest, in advance of receipt of cash attributable to that income. Generally, the total amount of original issue discount on a senior debt security will be the excess of the stated redemption price at maturity of the security over the price at which the security is sold to the public. To the extent a holder of a senior debt security receives a payment (at the time of acceleration of maturity, for example) that represents payment of original issue discount already included by the holder in ordinary income or reflected in the holder's tax basis in the security, that holder generally will not be required to include the payment in income. The specific terms of any senior debt securities that are issued with original issue discount and the application of the original discount rules under the Internal Revenue Code to those securities will be described in a prospectus supplement for those securities.

Payments of interest on debt securities will be made at the corporate trust office of the trustee or at our option by check mailed to the registered holders of debt securities or, if so provided in the applicable prospectus supplement, at the option of a holder by wire transfer to an account designated by the holder.

Unless otherwise provided in the applicable prospectus supplement, debt securities may be transferred or exchanged at the office of the trustee at which its corporate trust business is principally administered in the United States, subject to the limitations provided in the indenture, without the payment of any service charge, other than any applicable tax or governmental charge.

Global Securities

The debt securities of a series may be issued in whole or in part in the form of one or more fully registered global securities that will be deposited with a depositary or its nominee identified in the prospectus supplement relating to the series. In that case, one or more global securities will be issued in a denomination or aggregate denominations equal to the portion of the aggregate principal amount of outstanding registered debt securities of the series to be represented by the global security or securities. Until it is exchanged in whole or in part for debt securities in definitive registered form, a global security may not be transferred except as a whole by the depositary for the global security to a nominee of the depositary or by a nominee of the depositary to the depositary or another nominee of the depositary or by the depositary or any nominee to a successor of the depositary or a nominee of the successor.

The specific terms of any depositary arrangement will be described in the prospectus supplement relating to the series. We anticipate that the following provisions will apply to all depositary arrangements.

If we issue a global security, the depositary for the global security will credit on its system, the respective principal amounts of the debt securities represented by the global security to the accounts of persons that have accounts with the depositary ("participants"). The underwriters or agents participating in the distribution of the debt securities will designate the amounts to be credited. Ownership of beneficial interests in a global security will be limited to participants or persons that may hold interests through participants. Ownership and transfer of beneficial interests in the global security will be effected only through records maintained by the depositary for the global security (with respect to interests of participants) or by participants or persons that hold through participants (with respect to interests of persons other than participants). While the depositary for a global security, or its nominee, is the registered owner of the global security, the depositary or the nominee, as the case may be, will be the sole owner or holder of the debt securities represented by the global security for all purposes under the indenture. Except as described below, owners of a beneficial interest in a global security will not be entitled to have the debt securities represented by the global security registered in their names, will not receive or be entitled to receive physical delivery of the debt securities and will not be considered the owners or holders of the debt securities under the indenture.

Principal, premium, if any, and interest payments on debt securities represented by a global security registered in the name of a depositary or its nominee will be made to the depositary or its nominee, as the case may be, as the registered owner of the global security. We, the trustee or any paying agent for the debt securities will not have any responsibility or liability for the records relating to or payments made on account of beneficial ownership interests in the global securities or for maintaining, supervising or reviewing any records relating to those beneficial ownership interests.

We expect that the depositary for any debt securities represented by a global security, on receipt of any payment of principal, premium, or interest, will immediately credit participants' accounts with payments in amounts proportionate to their respective beneficial interests in the principal amount of the global security as shown on the records of the depositary. We also expect that payments by participants to owners of beneficial interests in the global security held through the participants will be governed by standing instructions and customary practices, as is now the case with the securities held for the accounts of customers registered in "street name," and will be the responsibility of the participants.

If the depositary for any debt securities represented by a global security is at any time unwilling or unable to continue as depositary and a successor depositary is not appointed by us within 90 days, we will issue the debt securities in exchange for the global security. Also, we may determine not to have any of the debt securities of a series represented by one or more global securities. In that event, we will issue debt securities of that series in definitive form in exchange for the global security or securities representing the debt securities.

Subordination

Debt securities may be subordinated to the prior payment of all our indebtedness that is designated as "senior indebtedness." Senior indebtedness, with respect to any series of subordinated debt securities, will consist of any of our indebtedness that is designated in a resolution of our board of directors or the supplemental indenture establishing the series as senior indebtedness with respect to the series.

If we make a payment or distribution of our assets to our creditors or if there is a total or partial liquidation or we are dissolved or we file for bankruptcy, receivership, or similar proceeding, the holders of the senior indebtedness will be paid in full before the holders of the subordinated debt would receive any payment with respect to the subordinated debt securities. Until the senior indebtedness is paid in full, there will be no distribution to the holders of the subordinated debt securities (except that the holders may receive shares of stock and any debt securities that are subordinated to senior indebtedness to at least the same extent as the subordinated debt securities).

We may not make any payments of principal, premium, or interest with respect to subordinated debt securities, make any deposit for the purpose of defeasance of the subordinated debt securities, or repurchase, redeem, or otherwise retire (except, in the case of subordinated debt securities that provide for a mandatory sinking fund, by the delivery of subordinated debt securities by us to the trustee in satisfaction of our sinking fund obligation) any subordinated debt securities if:

(a) any principal, premium, if any, or interest with respect to senior indebtedness is not paid within any applicable grace period (including maturity), or

(b) any other default on senior indebtedness occurs and the maturity of the senior indebtedness is accelerated in accordance with its terms,

unless, in either case,

(i) the default has been cured or waived and the acceleration has been rescinded,

(ii) the senior indebtedness has been paid in full in cash, or

(iii) we and the trustee receive written notice approving the payment from the representatives of each issue of "designated senior indebtedness" (which will include any specified issue of senior indebtedness).

During any default (other than a default described in clause (a) or (b) above) on any senior indebtedness under which the maturity of the senior indebtedness may be accelerated without further notice (except any notice required to effect the acceleration) or the expiration of any applicable grace periods, we may not pay the subordinated debt securities for a period (the "payment blockage period") starting on our receipt and the trustee's receipt of written notice of the election to effect a payment blockage period and ending after 179 days. The payment blockage period may be terminated before its expiration by written notice to the trustee and to us from the person who gave the blockage notice, by repayment in full in cash of the senior indebtedness with respect to which the blockage notice was given, or because the default giving rise to the payment blockage period is no longer continuing. Unless the holders of the senior indebtedness have accelerated the maturity of the senior indebtedness, we may resume payments on the subordinated debt securities after the expiration of the payment blockage period. Not more than one blockage notice may be given in any period of 360 consecutive days unless the first blockage notice within the 360-day period is given by or on behalf of holders of designated senior indebtedness other than the bank indebtedness, in which case the representative of the bank indebtedness may give another blockage notice within the period. In no event, however, may the total number of days during which any payment blockage period or periods is in effect exceed 179 days in the aggregate during any period of 360 consecutive days. After all senior indebtedness is paid in full and until the subordinated debt securities are paid in full, holders of the subordinated debt securities will be subrogated to the rights of holders of senior indebtedness to receive distributions applicable to senior indebtedness.

As a result of the subordination provisions, in the event of our bankruptcy or insolvency, our creditors who are holders of senior indebtedness, as well as certain of our general creditors, may recover ratably more than the holders of the subordinated debt securities.

Subsidiary Guarantees

If specified in a prospectus supplement, one or more of our subsidiaries may guarantee our obligations relating to our debt securities issued under this prospectus. The specific terms and provisions of each subsidiary guarantee, including any provisions relating to the subordination of any subsidiary guarantee, will be described in the applicable prospectus supplement. The obligations of each subsidiary guarantor under its subsidiary guarantee will be limited as necessary to seek to prevent that subsidiary guarantee from constituting a fraudulent conveyance or fraudulent transfer under applicable federal or state law.

Events of Default and Remedies

The following events are defined in the indenture as "events of default" with respect to a series of debt securities:

(a) a default in the payment of any installment of interest (whether or not, in the case of subordinated debt securities, the payment will be prohibited by reason of the subordination provision described above) and continuance of the default for a period of 30 days;

(b) a default in the payment of principal or premium, if any, whether at maturity, on redemption, by declaration, on required repurchase, or otherwise (whether or not, in the case of subordinated debt securities, the payment will be prohibited by reason of the subordination provision described above;

(c) a default in the payment of any sinking fund payment;

(d) we fail to comply with the provisions of the indenture relating to consolidations, mergers and sale of assets;

(e) we fail to observe or perform any other covenants or agreements in the debt securities, in any resolution of our board of directors authorizing the issuance of the debt securities, in the indenture, or in any supplemental indenture (other than a covenant or agreement a default in the performance of which is otherwise specifically dealt with) for a period of 60 days following the date we receive proper written notice specifying the failure;

(f) we do not pay our indebtedness within any applicable grace period after final maturity or the indebtedness is accelerated by the holders of the indebtedness because of a default, the total amount of the indebtedness unpaid or accelerated exceeds the amount specified or the United States dollar equivalent of the amount specified at the time, and the default remains uncured or the acceleration is not rescinded for 10 days after the date on which written notice specifying the failure and requiring us to remedy the failure will have been given to us by the trustee or to us and the trustee by the holders of at least 25% in aggregate principal amount of the debt securities of that series at the time outstanding;

(g) we

 (i) voluntarily commence any proceeding or file any petition seeking relief under the United States Bankruptcy Code or other federal or state bankruptcy, insolvency, or similar law,

 (ii) consent to the institution of, or fail to controvert within the time and in the manner prescribed by law, any bankruptcy proceeding or the filing of any bankruptcy petition,

 (iii) apply for or consent to the appointment of a receiver, trustee, custodian, sequestrator, or similar official for us for a substantial part of our property,

 (iv) file an answer admitting the material allegations of a petition field against us in any bankruptcy proceeding,

 (v) make a general assignment for the benefit of our creditors,

 (vi) admit in writing our inability or generally fail to pay our debts as they become due,

 (vii) take corporate action for the purpose of effecting any of the foregoing, or

 (viii) take any comparable action to items (i) through (vii) under any foreign laws relating to insolvency;

(h) the entry of an order or decree by a court having competent jurisdiction for

 (i) relief with respect to us or a substantial part of our property under the United States Bankruptcy Code or any other federal or state bankruptcy, insolvency, or similar law,

 (ii) the appointment of a receiver, trustee, custodian, sequestrator, or similar official for us or for a substantial part of our property, or

 (iii) our winding-up or liquidation;

 and the order or decree continues unstayed and in effect for 60 consecutive days, or any similar relief is granted under any foreign laws and the order or decree stays in effect for 60 consecutive days; or

(i) any other event of default provided under the terms of the debt securities of that series.

An event of default with respect to one series of debt securities is not necessarily an event of default for another series.

If an event of default occurs and is continuing with respect to any series of debt securities, unless the principal and interest with respect to all the debt securities of the series have already become due and payable, either the trustee or the holders of not less than 25% in aggregate principal amount of the debt securities of the series then outstanding may declare the principal of (or, if original issue discount debt securities, the portion of the principal amount as may be specified in the series) and interest on all the debt securities of the series due and payable immediately.

If an event of default occurs and is continuing, the trustee will be entitled to institute any action or proceeding for the collection of the sums due and unpaid or to enforce the performance of any provision of the debt securities of the affected series or the indenture, to prosecute the action or proceeding to judgment or final decree, and to enforce any judgment or final decree against us or any other obligor on the debt securities of the series. In addition, if there is pending proceedings for the bankruptcy or reorganization of the company or any other obligor on the debt securities, or if a receiver, trustee, or similar official is appointed for our property, the trustee will be entitled to file and prove a claim for the whole amount of principal, premium and interest (or, in the case of original issue discount debt securities, the portion of the principal amount as may be specified in the terms of the series) owing and unpaid with respect to the debt securities. No holder of any debt securities of any series will have any right to institute any action or proceeding with respect to the indenture, for the appointment of a receiver or trustee, or for any other remedy, unless:

(a) the holder previously will have given to the trustee written notice of an event of default with respect to debt securities of that series and of the continuance of the event of default;

(b) the holders of not less than 25% in aggregate principal amount of the outstanding debt securities of that series will have made written request to the trustee to institute the action or proceeding with respect to the event of default and will have offered to the trustee the reasonable indemnity as it may require against the costs, expenses, and liabilities to be incurred in connection with the action or proceeding; and

(c) the trustee, for 60 days after its receipt of the notice, request, and offer of indemnity will have failed to institute the action or proceeding and no direction inconsistent with the written request will have been given to the trustee under the provisions of the indenture.

Before the acceleration of the maturity of the debt securities of any series, the holders of a majority in aggregate principal amount of the debt securities of that series at the time outstanding may, on behalf of the holders of all debt securities of that series, waive any past default or event of default and its consequences for that series, except:

(a) default in the payment of the principal, premium, if any, or interest with respect to the debt securities; or

(b) a default with respect to a provision of the indenture that cannot be amended without the consent of each holder that is affected.

In the case of a waiver, the default will cease to exist, any event of default arising from the default will be deemed to have been cured for all purposes, and we, the trustee and the holders of the debt securities of that series will each be restored to their former positions and rights under the indenture.

The trustee will, within 90 days after the occurrence of a default known to it with respect to a series of debt securities, give to the holders of the debt securities notice of all uncured defaults known to it, unless the defaults have been cured or waived before giving the notice; provided, however, that except in the case of default in the payment of principal, premium, or interest with respect to the debt securities or in the making of any sinking fund payment with respect to the debt securities, the trustee will be protected in withholding the notice if it in good faith determines that withholding the notice is in the interest of the holders of the debt securities.

Modification of the Indenture

We and the trustee may enter into supplemental indentures without the consent of the holders of debt securities issued under the indenture for one or more of the following purposes:

(a) to evidence our succession by another person and the assumption by the successor of our covenants, agreements, and obligations in the indenture and in the debt securities;

(b) to surrender any right or power conferred on us by the indenture, to add further covenants, restrictions, conditions, or provisions for the protection of the holders of all or any series of debt securities, and to make the occurrence, or the occurrence and continuance of a default in any of the additional covenants, restrictions, conditions, or provisions, a default or an event of default under the indenture;

(c) to cure any ambiguity or to correct or supplement any provision contained in the indenture, in any supplemental indenture, or in any debt securities that may be defective or inconsistent with any other provision contained in the indenture, in any supplemental indenture, or in any debt securities, to convey, transfer, assign, mortgage, or pledge any property to or with the trustee, or to make such other provisions in regard to matters or questions arising under the indenture that do not adversely affect the interests of any holders of debt securities of any series;

(d) to modify or amend the indenture in a manner as to permit the qualification of the indenture or any supplemental indenture under the Trust indenture Act as then in effect;

(e) to add or change any of the provisions of the indenture to change or eliminate any restriction on the payment of principal or premium with respect to debt securities so long as it action does not adversely affect the interest of the holders of debt securities in any material respect or permit or facilitate the issuance of debt securities of any series in uncertificated form;

(g) in the case of subordinated debt securities, to make any change in the provisions of the indenture relating to subordination that would limit or terminate the benefits available to any holder of senior indebtedness under the provisions (but only if the holder of senior indebtedness consents to the change);

(h) to add guarantees with respect to the debt securities or to secure the debt securities;

(i) to add to, change, or eliminate any of the provisions of the indenture with respect to one or more series of debt securities, as long as the addition, change, or elimination that is not otherwise permitted under the indenture

  (i) does not apply to any debt securities of any series created before the signing of the supplemental indenture and entitled to the benefit of the provision or modify the rights of the holders of any debt security with respect to the provision, or

  (ii) becomes effective only when there is no debt security outstanding;

(j) to evidence and provide for the acceptance of appointment by a successor or separate trustee with respect to the debt securities of one or more series and to add to or change any of the provisions of the indenture as necessary to provide for or facilitate the administration of the indenture by more than one trustee; and

(k) to establish the form or terms of any series of debt securities.

With the consent of the holders of a majority in aggregate principal amount of the outstanding debt securities of each series affected, we and the trustee may from time to time and at any time enter into a supplemental indenture for the purpose of adding any provisions to, changing in any manner, or eliminating any of the provisions of the indenture or of any supplemental indenture or modifying in any manner the rights of the holder of the debt securities of the series. However, without the consent of the holders of each debt security that is affected, the supplemental indenture may not:

(i) reduce the percentage in principal amount of debt securities of any series whose holders must consent to an amendment;

(ii) reduce the interest rate or extend the time for payment of interest on any debt security;

(iii) reduce the principal of or extend the stated maturity of any debt security;

(iv) reduce the premium payable on the redemption of any debt security or change the time at which any debt security may or must be redeemed;

(v) make any debt security payable in a currency other than that stated in the debt security;

(vi) in the case of any subordinated debt security, make any change in the provisions of the indenture relating to subordination that adversely affects the rights of any holder under the provisions;

(vii) release any security that may have been granted with respect to the debt securities; or

(viii) make any change in the provisions of the indenture relating to waivers of defaults or amendments that require unanimous consent.

Consolidation, Merger, and Sale of Assets

The indenture provides that we may not consolidate with or merge with or into any person, or convey, transfer, or lease all or substantially all of our assets, unless the following conditions have been satisfied:

(a) Either

(i) We are the continuing person the case of a merger; or

(ii) The successor corporation is a corporation organized and existing under the laws of the United States, any State, or the District of Columbia and will expressly assume all of our obligations under the debt securities and the indenture;

(b) Immediately after giving effect to the transaction (and treating any indebtedness that becomes an obligation of the successor corporation or any of our subsidiaries as a result of the transaction as having been incurred by the successor corporation or a subsidiary at the time of the transaction), no default or event of default would occur or be continuing; and

(c) We have delivered to the trustee an officers' certificate and an opinion of counsel, each stating that the consolidation, merger, or transfer complies with the indenture.

Satisfaction and Discharge of the Indenture

The indenture provides, among other things, that when all debt securities not previously delivered to the trustee for cancellation (1) have become due and payable or (2) will become due and payable at their stated maturity within one year, we may deposit with the trustee funds, in trust, for the purpose and in an amount sufficient to pay and discharge the entire indebtedness on the debt securities not previously delivered to the trustee for cancellation. Those funds will include all principal, premium, if any, and interest, if any, to the date of the deposit or to the stated maturity, as applicable. At the time of the deposit, the indenture will cease to be of further effect, except as to our obligations to pay all other sums due under the indenture and to provide the officers' certificates and opinions of counsel required under the indenture. At that time we will be deemed to have satisfied and discharged the indenture.

Governing Law

The indenture and the debt securities will be governed by, and construed in accordance with, the laws of the State of New York.

Regarding the Trustee

Information concerning the trustee for a series of debt securities will be described in the prospectus supplement relating to that series of debt securities.

We may have normal banking relationships with the trustee in the ordinary course of business.

DESCRIPTION OF CAPITAL STOCK

We have 180,000,000 authorized shares of capital stock, consisting of (a) 175,000,000 shares of common stock, having a par value of $.20 per share, and (b) 5,000,000 shares of preferred stock, having a par value of $1.00 per share. As of April 25, 2011, there were 48,167,687 shares of our common stock outstanding. No preferred stock is outstanding.

Common Stock

All of the outstanding shares of common stock are fully paid and nonassessable.

Our stockholders are entitled to receive dividends, when, as and if declared by our board of directors out of assets legally available for their payment. In certain cases, we may not pay dividends to common stockholders until our dividend obligations to the holder of any preferred stock then outstanding have been satisfied. The provisions of our credit arrangements subject us to certain restrictions on the payment of dividends.

In the event of our voluntary or involuntary liquidation, dissolution or winding up, our stockholders will be entitled to share equally in our assets remaining after payment of all liabilities and after holders of all series of outstanding preferred stock have received their liquidation preferences in full.

Our stockholders have no preemptive subscription, conversion or redemption rights, and are not subject to further calls or assessments by us. There are no sinking fund provisions applicable to the common stock.

Our stockholders are entitled to one vote per share for the election of directors and on all other matters submitted to a vote of stockholders. Holders of common stock have no right to cumulate their votes in the election of directors.

Preferred Stock

As of the date of this prospectus, there were no shares of preferred stock outstanding.

Preferred stock may be issued from time to time in one or more series, and our board of directors, without further approval of the stockholders, is authorized to fix the dividend rates and terms, conversion rights, voting rights, redemption rights and terms, liquidation preferences, sinking fund and any other rights, preferences, privileges and restrictions applicable to each series of preferred stock. The purpose of authorizing the board of directors to determine these rights, preferences, privileges and restrictions is to eliminate delays associated with a stockholder vote on specific issuances. The issuance of preferred stock, while providing flexibility in connection with possible acquisitions and other corporate purposes, could, among other things, decrease the amount of earnings and assets available for distribution to holders of common stock, adversely affect the rights and powers, including voting rights, of holders of common stock and have the effect of delaying, deferring or preventing a change in control of us.

Stockholder Rights Agreement

Each share of common stock includes one right (“Right”) entitling the registered holder to purchase from us one one-hundredth of a share (a “Fractional Share”) of Series A Participating Cumulative Preferred Stock (the “Preferred Shares”), at a purchase price per Fractional Share of $160.00, subject to adjustment (the “Purchase Price”).

With certain exceptions, on the earlier of (1) 10 days following the date we learn that a person or group of affiliated or associated persons (an “Acquiring Person”) has acquired, or obtained the right to acquire, beneficial ownership of 15% or more of our outstanding shares of common stock, or (2) 10 business days following the commencement of, or the first public disclosure of an intent to commence, a tender offer or exchange offer that would result in a person becoming an Acquiring Person, a “Distribution Date” will occur and the Rights will be separated from the common stock. In certain circumstances, our board of directors may defer the Distribution Date. Certain inadvertent acquisitions will not result in a person becoming an Acquiring Person if the person promptly divests itself of sufficient common stock. Until the Distribution Date, (1) the Rights are evidenced by the certificates representing outstanding shares of common stock and will be transferred with and only with the certificates, which contain a notation incorporating the Rights Agreement by reference, and (2) the surrender for transfer of any certificate for common stock will also constitute the transfer of the Rights associated with the common stock represented by the certificate.

The Rights are not exercisable until the Distribution Date and will expire at the close of business on May 19, 2015, unless earlier redeemed or exchanged by us as described below.

As soon as practicable after the Distribution Date, Rights certificates will be mailed to holders of record of the common stock as of the close of business on the Distribution Date and, from and after the Distribution Date, the separate Rights certificates alone will represent the Rights. All shares of common stock issued before the Distribution Date will be issued with Rights. Shares of common stock issued after the Distribution Date in connection with certain employee benefit plans or on conversion of certain securities will be issued with Rights. Except as otherwise determined by our board of directors, no other shares of the common stock issued after the Distribution Date will be issued with Rights.

In the event (a “Flip-In Event”) that a person becomes an Acquiring Person (except under a tender or exchange offer for all outstanding shares of common stock at a price and on terms that a majority of our independent directors determines to be fair to and otherwise in our and our stockholders best interests (a “Permitted Offer”)), each holder of a Right will thereafter have the right to receive, on exercise of the Right, the number of Fractional Shares equivalent to the number of shares of common stock (or, in certain circumstances, cash, property or other securities) having a market value equal to two times the Purchase Price. Notwithstanding the foregoing, following the occurrence of any Triggering Event (as defined below), all Rights that are, or (under certain circumstances specified in the Rights Agreement) were, beneficially owned by or transferred to an Acquiring Person (or by certain related parties) will be null and void in the circumstances described in the Rights Agreement.

In the event (a “Flip-Over Event”) that, at any time from and after the time an Acquiring Person becomes such, (1) we are acquired in a merger or other business combination transaction by any Acquiring Person or any affiliate or associate of an Acquiring Person (other than certain mergers that follow a Permitted Offer) or (2) 50% or more of our assets or earning power is sold or transferred by any Acquiring Person or any affiliate or associate of an Acquiring Person, each holder of a Right (except Rights that are voided as described above) will thereafter have the right to receive, on exercise, a number of shares of common stock of the acquiring company having a market value equal to two times the exercise price of the Right as set by the Board of Directors. Flip-In Events and Flip-Over Events are collectively referred to as "Triggering Events."

The number of outstanding Rights associated with a share of common stock, or the number of Preferred Shares issuable on exercise of a Right and the Purchase Price, are subject to adjustment in the event of a stock dividend on, or a subdivision, combination or reclassification of, the common stock occurring before the Distribution Date. The Purchase Price payable, and the number of Fractional Shares of Preferred Shares or other securities or property issuable, on exercise of the Rights are subject to adjustment from time to time to prevent dilution in the event of certain transactions affecting the Preferred Shares.

At any time until ten days following the first date of public announcement of the occurrence of a Flip-In Event, we may redeem the Rights in whole, but not in part, at a price of $0.01 per Right, payable, at our option, in cash, shares of common stock or other consideration as our board of directors may determine. Immediately on the effectiveness of the action of the Board of Directors ordering redemption of the Rights, the Rights will terminate and the only right of the holders of Rights will be to receive the $0.01 redemption price.

Until a Right is exercised, the holder will have no rights as a stockholder, including, without limitation, the right to vote or to receive dividends.

Other than the redemption price, our board of directors may amend any of the provisions of the Rights Agreement as long as the Rights are redeemable.

The Rights have certain antitakeover effects. They will cause substantial dilution to any person or group that attempts to acquire us without the approval of our board of directors. As a result, the overall effect of the Rights may be to render more difficult or discourage any attempt to acquire us, even if the acquisition may be favorable to the interests of our stockholders. Because our board of directors can redeem the Rights or approve a Permitted Offer, the Rights should not interfere with a merger or other business combination approved by our board of directors. The Rights were issued to protect our stockholders from coercive or abusive takeover tactics and inadequate takeover offers and to afford our board of directors more negotiating leverage in dealing with prospective acquirors.

Certain Other Possible Anti-takeover Provisions

Our by-laws, charter and Delaware law contain certain provisions that might be characterized as anti-takeover provisions. These provisions may make it more difficult to acquire control of us or remove our management.

Classified Board of Directors

Our by-laws provides for our board of directors to be divided into three classes of directors serving staggered three-year terms, with the number of directors in each class to be as nearly equal as possible. As a result, and assuming all classes have the same number of directors, only one-third of our directors are elected each year.

Issuance of Preferred Stock

As described above, our charter authorizes a class of undesignated preferred stock consisting of 5,000,000 shares. The issuance of preferred stock could, among other things, make it more difficult for a third party to gain control of us.

Fair Price Provisions

Our charter also contains certain "fair price provisions" designated to provide safeguards for stockholders when an "interested stockholder" (defined as a stockholder owning 5% or more of our voting stock) attempts to effect a "business combination" with us. The term "business combination" includes:

- any merger or consolidation of us involving the interested stockholder;
- certain dispositions of our assets;
- any issuance of our securities meeting certain threshold amounts, to the interested stockholder;
- the adoption of any plan for the liquidation or dissolution of the corporation proposed on behalf of an interested stockholder; and
- any reclassification of our securities having the effect of increasing the proportionate share of ownership of the interested stockholder.

In general, a business combination between us and the interested stockholder must be approved by the affirmative vote of 80% of the outstanding voting stock unless the transaction is approved by a majority of the members of the Board of Directors who are not affiliated with the interested stockholder or certain minimum price and form of consideration requirements are satisfied.

Delaware Business Combination Statute

We are incorporated under the laws of the State of Delaware. Section 203 of the Delaware General Corporation Law prevents an "interested stockholder" (defined as a stockholder owning 15% or more of a corporation's voting stock) from engaging in a business combination with that corporation for a period of three years from the date the stockholder became an interested stockholder unless:

- the corporation's board of directors had earlier approved either the business combination or the transaction by which the stockholder became an interested stockholder;
- on attaining that status, the interested stockholder had acquired at least 85% of the corporation's voting stock (not counting shares owned by persons who are directors and also officers); or
- the business combination is later approved by the board of directors and authorized by a vote of two-thirds of the stockholders (not including the shares held by the interested stockholder).

Since we have not amended our charter or by-laws to exclude the application of Section 203, its provisions apply to us. Accordingly, Section 203 may inhibit an interested stockholder's ability to acquire additional shares of common stock or otherwise engage in a business combination with us.

Advance Notice for Raising Business or Making Nominations at Meetings

Our by-laws establish an advance notice procedure for stockholder proposals to be brought before an annual meeting of stockholders and for nominations by stockholders of candidates for election as directors at an annual or special meeting at which directors are to elected.

The only business that may be conducted at an annual meeting of stockholders is that which has been brought before the meeting by, or at the direction of, the board of directors or by a stockholder who has given to our secretary timely written notice, in proper form, of the stockholder's intention to bring that business before the meeting. Only persons who are nominated by, or at the direction of, the board of directors, or who are nominated by a stockholder who has given timely written notice, in proper form, to the secretary before a meeting at which directors are to be elected will be eligible for election as directors. The person presiding at the meeting will have the authority to make determinations whether a stockholder's notice complies with the procedures in our by-laws.

To be timely, notice of business to be brought before an annual meeting or nominations of candidates for election as directors at an annual meeting is generally required to be received by our secretary not later than 90 days nor earlier than 120 days before the first anniversary of the prior year's annual meeting date.

The notice of any nomination for election as a director is required to describe the information regarding that person required in our by-laws as well as by paragraphs (a), (e), and (f) of Item 401 of regulation S-K adopted by the SEC.

Stockholders may also nominate persons for election as directors under Rule 14a-11 of the Exchange Act. In addition, under Rule 14a-8(i)(8) of the Exchange Act, stockholders may adopt, through either a management recommendation or stockholder's proposal, access rules that provide for greater access to the proxy.

Transfer Agent and Registrar

The Transfer Agent and Registrar for our common stock is American Stock Transfer & Trust Company, LLC.

DESCRIPTION OF WARRANTS

General

We may issue warrants to purchase debt securities or, warrants to purchase common stock or preferred stock. Warrants may be issued independently of or together with any other securities and may be attached to or separate from those securities. Each series of warrants will be issued under a separate warrant agreement to be entered into between us and a warrant agent. The warrant agent will act solely as our agent in connection with any warrant and will not assume any obligation or relationship of agency for or with holders or beneficial owners of warrants. The following summaries describe certain general terms and provisions of the warrants. Further terms of the warrants and the applicable warrant agreement will be described in the applicable prospectus supplement.

Debt Warrants

The applicable prospectus supplement will describe the terms of any debt warrants, including the following:

- their title;
- the offering price, if any;
- the aggregate number of the debt warrants;
- the designation and terms of the debt securities purchasable on exercise of the debt warrants;
- if applicable, the designation and terms of the securities with which the debt warrants are issued and the number of the debt warrants issued with each security;
- if applicable, the date from and after which the debt warrants and any securities issued with the debt warrants will be separately transferable;
- the principal amount of debt securities purchasable on exercise of a debt warrant and the price at which the principal amount of debt securities may be purchased on exercise;
- the date on which the right to exercise the debt warrants will commence and the date on which the right will expire;
- if applicable, the minimum or maximum amount of the debt warrants which may be exercised at any one time;

- whether the debt warrants represented by the debt warrant certificates or debt securities that may be issued on exercise of the debt warrants will be issued in registered or bearer form;
- information with respect to book-entry procedures, if any;
- the currency, currencies or currency units in which the offering price, if any, and the exercise price are payable;
- if applicable, a discussion of certain United States federal income tax considerations;
- the antidilution provisions of the debt warrants, if any;
- the redemption or call provisions, if any, applicable to the debt warrants; and
- any additional terms of the debt warrants, including terms, procedures and limitations relating to the exchange and exercise of the debt warrants.

Stock Warrants

The applicable prospectus supplement will describe the terms of any stock warrants, including the following:

- their title;
- the offering price, if any;
- the aggregate number of the stock warrants;
- if applicable, the designation, number of shares and terms (including, without limitation, liquidation, dividend, conversion and voting rights) of the series of preferred stock purchasable on exercise of the stock warrants;
- if applicable, the date from and after which the stock warrants and any securities issued with the stock warrants will be separately transferable;
- the number of shares of common stock, or preferred stock purchasable on exercise of a stock warrant and the price at which the shares may be purchased on exercise;
- the date on which the right to exercise the stock warrants will commence and the date on which the right will expire;
- if applicable, the minimum or maximum amount of the stock warrants which may be exercised at any one time;
- the currency, currencies or currency units in which the offering price, if any, and the exercise price are payable;
- if applicable, a discussion of certain United States federal income tax considerations;
- the antidilution provisions of the stock warrants, if any;
- the redemption or call provisions, if any, applicable to the stock warrants; and
- any additional terms of the stock warrants, including terms, procedures and limitations relating to the exchange and exercise of the stock warrants.

DESCRIPTION OF PURCHASE CONTRACTS

We may issue purchase contracts, including contracts obligating holders to purchase from us and us to sell to the holders, a specified principal amount of debt securities or a specified number of shares of common stock or preferred stock or any of the other securities that we may sell under this prospectus (or a range of principal amount or number of shares under a predetermined formula) at a future date or dates. The consideration payable on settlement of the purchase contracts may be fixed at the time the purchase contracts are issued or may be determined by a specific reference to a formula described in the purchase contracts. The purchase contracts may be issued separately or as part of units consisting of a purchase contract and other securities or obligations issued by us or third parties, including United States treasury securities, securing the holders' obligations to purchase the relevant securities under the purchase contracts.

The purchase contracts may require us to make periodic payments to the holders of the purchase contracts or units or vice versa, and the payments may be unsecured or prefunded on some basis. The purchase contracts may require holders to secure their obligations under the purchase contracts in a specified manner and in some circumstances we may deliver newly issued prepaid purchase contracts, often referred to as "prepaid securities," on release to a holder of any collateral securing the holder's obligations under the original purchase contract.

The applicable prospectus supplement will describe the terms of any purchase contracts or purchase units and, if applicable, other securities or obligations. The description in the prospectus supplement will not necessarily be complete and will be qualified in its entirety by reference to the purchase contracts, and, if applicable, collateral arrangements, relating to the purchase contracts.

DESCRIPTION OF UNITS

We may issue units consisting of one or more purchase contracts, warrants, debt securities, shares of preferred stock, shares of common stock or any combination of those securities. The applicable prospectus supplement will describe:

- the terms of the units and of the purchase contracts, warrants, debt securities, preferred stock and common stock comprising the units, including whether and under what circumstances the securities comprising the units may be traded separately;
- a description of the terms of any unit agreement governing the units; and
- a description of the provisions for the payment, settlement, transfer or exchange of the units.

PLAN OF DISTRIBUTION

We may sell offered securities in any one or more of the following ways from time to time:

- through agents,
- to or through underwriters,
- through dealers,
- directly to purchasers, or
- through a combination of these methods or through any other method permitted by law.

Any underwriter, dealer or agent may be deemed to be an "underwriter" within the meaning of the Securities Act.

The prospectus supplement with respect to the offered securities will describe the terms of the offering, including:

- the name or names of any underwriters, dealers or agents,
- the purchase price and the proceeds to us from the sale,

- any underwriting discounts and commissions or agency fees and other items constituting underwriters' or agents' compensation,
- any over-allotment options under which underwriters may purchase additional securities from us,
- any initial public offering price and any discounts or concessions allowed or reallowed or paid to dealers, or
- any trading market or securities exchange on which the offered securities may be listed.

Any initial public offering price, discounts or concessions allowed or reallowed or paid to dealers may be changed from time to time.

The distribution of the offered securities may be effected from time to time in one or more transactions:

- at a fixed price or prices (which may be changed),
- at market prices prevailing at the time of sale,
- at prices related to the prevailing market prices, or
- at negotiated prices.

Offers to purchase offered securities may be solicited by agents designated by us from time to time. Any agent involved in the offer or sale of the offered securities will be named, and any commissions payable by us to the agent will be described in the applicable prospectus supplement. Unless otherwise indicated in the prospectus supplement, the agent will be acting on a reasonable best efforts basis for the period of its appointment.

If offered securities are sold by means of an underwritten offering, we will execute an underwriting agreement with an underwriter or underwriters, and the names of the specific managing underwriter or underwriters, as well as any other underwriters, and the terms of the transaction, including commissions, discounts and any other compensation of the underwriters and dealers, if any, will be described in the prospectus supplement which will be used by the underwriters to make resales of the offered securities. If underwriters are utilized in the sale of the offered securities, the offered securities will be acquired by the underwriters for their own account and may be resold from time to time in one or more transactions, including negotiated transactions, at fixed public offering prices or at varying prices determined by the underwriters at the time of sale. Our offered securities may be offered to the public either through underwriting syndicates represented by managing underwriters or directly by the managing underwriters. If any underwriter or underwriters are utilized in the sale of the offered securities, unless otherwise indicated in the prospectus supplement, the underwriting agreement will provide that the obligations of the underwriters are subject to certain conditions precedent and that the underwriters with respect to a sale of offered securities will be obligated to purchase all offered securities of a series if any are purchased.

We may grant to the underwriters options to purchase additional offered securities, to cover over-allotments, if any, at the public offering price, with additional underwriting discounts or commissions, as may be described in the prospectus supplement relating thereto. If we grant any over-allotment option, the terms of the over-allotment option will be described in the prospectus supplement relating to the offered securities.

If a dealer is utilized in the sales of offered securities we will sell the offered securities to the dealer as principal. The dealer may then resell the offered securities to the public at varying prices to be determined by the dealer at the time of resale. The dealer may be deemed to be an underwriter, as the term is defined in the Securities Act, of the offered securities so offered and sold. The name of the dealer and the terms of the transaction will be described in the related prospectus supplement.

Offers to purchase offered securities may be solicited directly by us and the sale may be made by us directly to institutional investors or others, who may be deemed to be underwriters within the meaning of the Securities

Act with respect to any resale of the securities. The terms of the sales will be described in the related prospectus supplement.

Offered securities may also be offered and sold, if so indicated in the applicable prospectus supplement, in connection with a remarketing on their purchase, in accordance with a redemption or repayment under their terms, or otherwise, by one or more firms acting as principals of their own accounts or as agents for us. Any remarketing firm will be identified and the terms of its agreements, if any, with us and its compensation will be described in the applicable prospectus supplement. Remarketing firms may be deemed to be underwriters, as that term is defined in the Securities Act, in connection with the offered securities remarketed thereby.

Agents, underwriters, dealers and remarketing firms may be entitled under relevant agreements entered into with us to indemnification by us against certain civil liabilities, including liabilities under the Securities Act that may arise from any untrue statement or alleged untrue statement of a material fact or any omission or alleged omission to state a material fact in this prospectus, any supplement or amendment hereto, or in the registration statement of which this prospectus forms a part, or to contribution with respect to payments which the agents, underwriters or dealers may be required to make.

Each class or series of securities will be a new issue of securities with no established trading market, other than our common stock, which is listed on the New York Stock Exchange. We may elect to list any other class or series of securities on any exchange, but are not obligated to do so. Any underwriters to whom securities are sold by us for public offering and sale may make a market in the securities, but the underwriters will not be obligated to do so and may discontinue any market making at any time without notice. No assurance can be given as to the liquidity of the trading market for any securities.

LEGAL MATTERS

The validity of the offered securities will be passed upon for us by Conner & Winters, LLP, Tulsa, Oklahoma. Certain other legal matters will be passed upon for us by Conner & Winters, LLP, Tulsa, Oklahoma, and for the underwriters, dealers or agents, if any, by their own legal counsel. Lynnwood R. Moore, Jr., a partner in Conner & Winters, LLP, beneficially owns 4,500 shares of our common stock.

EXPERTS

The financial statements incorporated in this Prospectus by reference to Unit Corporation's Current Report on Form 8-K dated May 3, 2011 and the financial statement schedule and management's assessment of the effectiveness of internal control over financial reporting (which is included in Management's Report on Internal Control over Financial Reporting) incorporated in this Prospectus by reference to the Annual Report on Form 10-K of Unit Corporation for the year ended December 31, 2010 have been so incorporated in reliance on the report of PricewaterhouseCoopers LLP, an independent registered public accounting firm, given on the authority of said firm as experts in auditing and accounting.

We have derived the estimates of proved oil and natural gas reserves and related future net revenues and their present value as of December 31, 2010 included in our Annual Report on Form 10-K for the year ended December 31, 2010 and incorporated by reference in this prospectus the audit of our oil and natural gas reserves contained in the reserve report of Ryder Scott Company, L.P., independent petroleum engineers, by the authority of Ryder Scott Company, L.P. as experts in those matters.

WHERE YOU CAN FIND MORE INFORMATION

We file annual, quarterly and current reports, proxy statements and other information and documents with the SEC. You may read and copy any document we file with the SEC at:

- the public reference room maintained by the SEC in: Washington, D.C. (450 Fifth Street, N.W., Room 1024, Washington, D.C. 20549). Copies of the materials can be obtained from the SEC's public reference section at prescribed rates. You may obtain information on the operation on the public reference rooms by calling the SEC at (800) SEC-0330, or
- the SEC website located at www.sec.gov.

This prospectus is one part of a registration statement filed on Form S-3 (together with all amendments, supplements, schedules and exhibits to the registration statement, referred to as the registration statement) with the SEC under the Securities Act. This prospectus does not contain all of the information described in the registration statement and the exhibits and schedules to the registration statement. For further information concerning us and the securities, you should read the entire registration statement and the additional information described under "Documents Incorporated By Reference" below. The registration statement has been filed electronically and may be obtained in any manner listed above. Any statements contained herein concerning the provisions of any document are not necessarily complete, and, in each instance, reference is made to the copy of the document filed as an exhibit to the registration statement or otherwise filed with the SEC. Each statement is qualified in its entirety buy the documents incorporated by reference.

DOCUMENTS INCORPORATED BY REFERENCE

The SEC allows us to "incorporate by reference" into this prospectus the information we file with them, which means we can disclose important business and financial information about us to you by referring you to those documents. The information incorporated by reference is considered to be a part of this prospectus, except for any information that is superseded by information included directly in this prospectus and any prospectus supplement. Information that we file later with the SEC will also automatically update and supersede the information in this prospectus. We incorporate by reference the documents listed below that we previously filed with the SEC and any future filings we make with the SEC under Section 13(a), 13(c), 14 or 15(d) of the Exchange Act (other than any portions of the filings that are furnished rather than filed under applicable SEC rules) until the termination of the offering made under this prospectus:

- our Annual Report on Form 10-K for the fiscal year ended December 31, 2010;
- our Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2011;
- our Current Report on Form 8-K, filed with the SEC on May 3, 2011; and
- the amended and restated rights agreement, between us and American Stock Transfer & Trust Company, LLC, as rights agent, contained in Form 8-K filed with the SEC on May 24, 2005, as amended pursuant to that certain amendment thereto contained in Form 8-K filed with the SEC on March 25, 2009. The rights agreement relates to the rights to purchase Series A Participating Cumulative Preferred Stock.

We will provide at no cost to each holder, including any beneficial owner of the offered securities, to whom this prospectus or any supplement is delivered, a copy of the reports and any or all of the information that has been incorporated by reference but not delivered with this prospectus or any supplement. Please direct your oral or written request to Mark E. Schell, Senior Vice President, Secretary and General Counsel, at our principal executive offices located at:

7130 South Lewis
Suite 1000
Tulsa, Oklahoma 74136
(918) 493-7700

Table of Contents

$250,000,000

Unit Corporation

6 5/8% Senior Subordinated Notes due 2021

PROSPECTUS SUPPLEMENT

Joint Book-Running Managers

BofA Merrill Lynch

BMO Capital Markets

Co-Managers

BBVA

Credit Agricole CIB

BNP PARIBAS

Comerica Securities

BOSC, Inc.

BB&T Capital Markets

May 11, 2011