SOUTHWESTERN ENERGY CO
Form 10-Q
October 23, 2006

FORWARD-LOOKING INFORMATION

All statements, other than historical fact or present financial information, may be deemed to be forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements that address activities, outcomes and other matters that should or may occur in the future, including, without limitation, statements regarding the financial position, business strategy, production and reserve growth and other plans and objectives for our future operations, are forward-looking statements. Although we believe the expectations expressed in such forward-looking statements are based on reasonable assumptions, such statements are not guarantees of future performance. We have no obligation and make no undertaking to publicly update or revise any forward-looking statements.

Forward-looking statements include the items identified in the preceding paragraph, information concerning possible or assumed future results of operations and other statements in this Form 10-Q identified by words such as "anticipate," "project," "intend," "estimate," "expect," "believe," "predict," "budget," "projection," "goal," "plan," "forecast," "target" or similar expressions.

You should not place undue reliance on forward-looking statements. They are subject to known and unknown risks, uncertainties and other factors that may affect our operations, markets, products, services and prices and cause our actual results, performance or achievements to be materially different from any future results, performance or achievements expressed or implied by the forward-looking statements. In addition to any assumptions and other factors referred to specifically in connection with forward-looking statements, risks, uncertainties and factors that could cause our actual results to differ materially from those indicated in any forward-looking statement include, but are not limited to:

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the timing and extent of changes in market conditions and prices for natural gas and oil (including regional basis differentials);

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the timing and extent of our success in discovering, developing, producing and estimating reserves;

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the economic viability of, and our success in drilling, our large acreage position in the Fayetteville Shale play, overall as well as relative to other productive shale gas plays;

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our ability to determine the most effective and economic fracture stimulation for the Fayetteville Shale formation;

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the costs and availability of oil field personnel services and drilling supplies, raw materials, and equipment and services, including pressure pumping equipment and crews in the Arkoma basin;

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our ability to fund our planned capital expenditures;

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our future property acquisition or divestiture activities;

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the effects of weather;

*

increased competition;

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the impact of federal, state and local government regulation;

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the financial impact of accounting regulations and critical accounting policies;

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the comparative cost of alternative fuels;

*

conditions in capital markets and changes in interest rates, and;

*

any other factors listed in the reports we have filed and may file with the Securities and Exchange Commission (SEC).

We caution you that these forward-looking statements are subject to all of the risks and uncertainties, many of which are beyond our control, incident to the exploration for and development, production and sale of natural gas and oil. These risks include, but are not limited to, commodity price volatility, third-party interruption of sales to market, inflation, lack of availability of goods and services, environmental risks, drilling and other operating risks, regulatory changes, the uncertainty inherent in estimating proved natural gas and oil reserves and in projecting future rates of production and timing of development expenditures and the other risks described in our Annual Report on Form 10-K for the year ended December 31, 2005 and all quarterly reports on Form 10-Q filed subsequently thereto, including this Form 10-Q (Form 10-Qs).

Should one or more of the risks or uncertainties described above or elsewhere in our 2005 Annual Report on Form 10-K or the Form 10-Qs occur, or should underlying assumptions prove incorrect, our actual results and plans could differ materially from those expressed in any forward-looking statements. We specifically disclaim all responsibility to publicly update any information contained in a forward-looking statement or any forward-looking statement in its entirety and therefore disclaim any resulting liability for potentially related damages.

All forward-looking statements attributable to us are expressly qualified in their entirety by this cautionary statement.

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SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
STATEMENTS OF OPERATIONS
(Unaudited)

	For the three months ended September 30,		For the nine months ended September 30,	
	2006	2005	2006	2005
	(in thousands, except share/per share amounts)			
Operating Revenues:				
Gas sales	$ 121,515	$ 118,466	$ 409,883	$ 337,929
Gas marketing	33,261	32,822	98,277	87,572
Oil sales	11,305	9,415	31,749	22,954
Gas transportation and other	2,313	1,424	9,186	7,188
	168,394	162,127	549,095	455,643
Operating Costs and Expenses:				
Gas purchases - gas distribution	2,174	5,971	50,994	44,872
Gas purchases - midstream services	31,314	30,770	91,474	82,900
Operating expenses	17,360	13,980	47,828	38,326
General and administrative expenses	16,947	11,437	46,738	32,048
Depreciation, depletion and amortization	40,459	25,527	100,512	68,783
Taxes, other than income taxes	7,022	7,241	20,333	18,106
	115,276	94,926	357,879	285,035
Operating Income	53,118	67,201	191,216	170,608
Interest Expense:				
Interest on long-term debt	2,871	6,047	7,690	16,211
Other interest charges	400	293	1,043	961
Interest capitalized	(3,051)	(1,629)	(8,232)	(3,268)
	220	4,711	501	13,904
Other Income	1,217	427	17,674	626
Income Before Income Taxes and Minority Interest	54,115	62,917	208,389	157,330

Minority Interest in Partnership	(120)	(477)	(525)	(885)
Income Before Income Taxes	53,995	62,440	207,864	156,445
Provision for Income Taxes - Deferred	20,518	22,971	78,988	57,541
Net Income	$ 33,477	$ 39,469	$ 128,876	$ 98,904
Earnings Per Share:				
Basic	$0.20	$0.27 (1)	$0.77	$0.68 (1)
Diluted	$0.20	$0.26 (1)	$0.75	$0.65 (1)
Weighted Average Common Shares Outstanding:				
Basic	167,514,249	148,192,648 (1)	167,114,831	145,895,536 (1)
Diluted	171,578,104	153,664,600 (1)	171,140,513	151,311,240 (1)

(1) Restated to reflect the two-for-one stock split effected on November 17, 2005.

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

	September 30, 2006	December 31, 2005
	(Unaudited)	
	(in thousands)	
Current Assets		
Cash and cash equivalents	$ 53,121	$ 223,705
Accounts receivable	82,041	128,948
Inventories, at average cost	61,167	49,513
Deferred income tax benefit	-	29,700
Hedging asset - FAS 133	41,976	17,467
Other	8,503	11,731
Total current assets	246,808	461,064
Investments	-	17,100
Property, Plant and Equipment, at cost		
Gas and oil properties, using the full cost method, including $169,731,933 in 2006 and $115,195,700 in 2005 excluded from amortization	2,399,920	1,897,613
Gas distribution systems	224,266	216,644

Drilling rigs and equipment - in service	80,574	-
Construction-in-progress - drilling rigs and equipment	28,318	35,128
Gathering systems	34,369	15,742
Gas in underground storage	32,254	32,254
Other	65,962	45,234
	2,865,663	2,242,615
Less: Accumulated depreciation, depletion and amortization	975,781	872,218
	1,889,882	1,370,397
Other Assets		
Long-term hedging asset	26,333	2,023
Other	17,520	17,940
Total other assets	43,853	19,963
Total Assets	$ 2,180,543	$ 1,868,524

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

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
BALANCE SHEETS
(Unaudited)

LIABILITIES AND SHAREHOLDERS' EQUITY

	September 30, 2006	December 31, 2005
	(in thousands)	
Current Liabilities		
Current portion of long-term debt	$ 1,200	$ -
Accounts payable	175,400	154,385
Taxes payable	9,764	14,519
Advances from partners and customer deposits	24,124	7,624
Hedging liability - FAS 133	20,459	112,293
Over-recovered purchased gas costs	7,175	7,323
Deferred income tax provision	9,500	-
Other	10,146	6,242
Total current liabilities	257,768	302,386
Long-Term Debt	137,200	100,000
Other Liabilities		
Deferred income taxes	359,189	254,528

Long-term hedging liability		7,909		60,442
Other		29,469		29,251
		396,567		344,221
Commitments and Contingencies				
Minority Interest in Partnership		11,383		11,613
Shareholders' Equity				
Common stock, $0.01 par value in 2006, $0.10 par value in 2005; authorized 540,000,000 shares in 2006 and 220,000,000 shares in 2005, issued 168,452,336 shares		1,684		16,845
Additional paid-in capital		731,134		711,196
Retained earnings		627,097		498,221
Accumulated other comprehensive income (loss)		18,289		(104,874)
Common stock in treasury, at cost, 207,196 shares at September 30, 2006 and 1,217,284 shares at December 31, 2005		(579)		(3,390)
Unamortized cost of restricted shares issued under stock incentive plan, 707,142 shares at December 31, 2005		-		(7,694)
		1,377,625		1,110,304
Total Liabilities and Shareholders' Equity	$	2,180,543	$	1,868,524

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

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
STATEMENTS OF CASH FLOWS
(Unaudited)

For the nine months ended September 30,

	2006	2005
	(in thousands)	
Cash Flows From Operating Activities		
Net income	$ 128,876	$ 98,904
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	101,425	70,651
Deferred income taxes	78,988	57,541
Unrealized (gain) loss on derivatives	3,542	(9,271)
Stock-based compensation expense	4,034	1,148
Gain on sale of investment in partnership	(10,863)	-
Equity in income of NOARK partnership	(925)	(354)
Minority interest in partnership	(230)	384
Change in operating assets and liabilities:		
Accounts receivable	47,468	(2,597)
Inventories	(11,654)	(12,236)
Under/over-recovered purchased gas costs	(148)	6,904
Accounts payable	(17,506)	3,906
Taxes payable	(4,756)	(617)
Interest Payable	1,622	3,812
Advances from partners and customer deposits	16,500	1,091
Other operating assets and liabilities	(5,237)	(3,444)
Net cash provided by operating activities	331,136	215,822
Cash Flows From Investing Activities		
Capital expenditures	(603,410)	(317,375)
Proceeds from sale of investment in partnership and other property	79,655	1,040
Other items	880	(448)
Net cash used in investing activities	(522,875)	(316,783)
Cash Flows From Financing Activities		
Net proceeds from equity offering	-	579,956
Debt retirement	(600)	-
Payments on revolving long-term debt	-	(563,800)
Borrowings under revolving long-term debt	-	463,800
Debt issuance costs	-	(1,180)
Tax benefit for stock-based compensation	7,447	-
Change in bank drafts outstanding	11,768	4,974
Proceeds from exercise of common stock options	2,540	4,177
Net cash provided by financing activities	21,155	487,927
Increase (decrease) in cash and cash equivalents	(170,584)	386,966
Cash and cash equivalents at beginning of year	223,705	1,235

Cash and cash equivalents at end of period	$	53,121	$	388,201

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

$	1,377,625

STATEMENT OF COMPREHENSIVE INCOME (LOSS)

	For the three months ended September 30,		For the nine months ended September 30,	
	2006	2005	2006	2005
	($ in thousands)		($ in thousands)	
Net income	$ 33,477	$ 39,469	$ 128,876	$ 98,904
Other comprehensive income, net of income tax:				
Changes in fair value of derivative instruments	44,973	(146,153)	133,667	(184,867)
Reclassification of loss on settled contracts	474	15,543	359	24,140
Ineffective portion of cash flow hedges	(6,396)	8,798	(10,863)	8,396
Comprehensive income	$ 72,528	$ (82,343)	$ 252,039	$ (53,427)

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Southwestern Energy Company and Subsidiaries

September 30, 2006

(1)

BASIS OF PRESENTATION

The financial statements included herein are unaudited; however, such information reflects all adjustments (consisting solely of normal recurring adjustments) which are, in the opinion of management, necessary for a fair presentation of the results for the interim periods. The Company's significant accounting policies, which have been reviewed and approved by the audit committee of the Company s Board of Directors, are summarized in Note 1 of the Notes to Consolidated Financial Statements included in Item 8 of the Company's Annual Report on Form 10-K for the year ended December 31, 2005 (the "2005 Annual Report on Form 10-K").

Historical per share information provided as of September 30, 2005 in the financial statements and footnotes has been adjusted to reflect the two-for-one stock split effected on November 17, 2005.

As discussed below in Note 9, the Company adopted Statement of Financial Accounting Standards No. 123(R) Share-Based Payment (FAS123(R)), effective January 1, 2006. The Company adopted the modified prospective transition method provided under FAS 123(R) and consequently has not restated the presentation of the results for prior periods. Additionally, the Company is currently evaluating alternative methods of calculating the historical pool of windfall tax benefits as permitted by FASB Staff Position No. FAS123(R)-3, Transition Election Related to Accounting for the Tax Effects of Share-Based Payment Awards. The realization of tax benefits from stock-based compensation in excess of amounts recognized for financial reporting purposes is recognized as a financing activity in the accompanying Consolidated Statements of Cash Flows.

On May 2, 2006, the Company sold its 25% partnership interest in the NOARK Pipeline System, Limited Partnership (NOARK), previously accounted for under the equity method of accounting, to Atlas Pipeline Partners, L.P., for $69.0 million. As part of the transaction, the Company assumed $39.0 million of debt obligations of NOARK Pipeline Finance, L.L.C., which the Company had previously guaranteed. The Company recognized a pre-tax gain of $10.9 million ($6.7 million after tax) in the second quarter relating to the transaction.

Effective June 30, 2006, Southwestern Energy Company reincorporated from Arkansas to Delaware. As a result of the reincorporation, the Company s common stock now has a par value of $0.01 per share. The reincorporation did not result in any change in the Company s business, management, employees, fiscal year, assets or liabilities.

In the second quarter of 2006, the state of Texas enacted legislation to replace its method of taxing businesses from a capital based tax to a tax on modified gross revenue. Although this change in taxation methods is not effective until 2007, the provisions of SFAS 109, "Accounting for Income Taxes," require the Company to record in the period of enactment the impact that this change had on its liability for deferred taxes. As a result, the Company recorded additional income tax expense of $1.8 million, net of federal income tax effect, in the second quarter of 2006. This one-time adjustment increased the effective tax rate to approximately 38% for the first nine months of 2006.

(2)

GAS AND OIL PROPERTIES

The Company follows the full cost method of accounting for the exploration, development, and acquisition of gas and oil reserves. Under this method, all such costs (productive and nonproductive) including salaries, benefits, and other internal costs directly attributable to these activities are capitalized and amortized on an aggregate basis over the estimated lives of the properties using the units-of-production method. The Company excludes all costs of unevaluated properties from immediate amortization. The Company s unamortized costs of natural gas and oil properties are limited to the sum of the future net revenues attributable to proved natural gas and oil reserves discounted at 10 percent plus the lower of cost or market value of any unproved properties. If the Company s unamortized costs in natural gas and oil properties exceed this ceiling amount, a provision for additional depreciation, depletion and amortization is required. Full cost companies must use the prices in effect at the end of each accounting quarter, including the impact of derivatives qualifying as hedges, to calculate the ceiling value of their reserves. However, subsequent commodity price increases may be utilized to calculate the ceiling value and reserves. At September 30, 2006, the ceiling value of the Company s reserves was calculated based upon quoted market prices of $4.18 per Mcf for Henry Hub gas and $59.38 per barrel for West Texas Intermediate oil, adjusted for market differentials. Using these prices, the Company s net book value of natural gas and oil properties would have exceeded the ceiling amount by $190.8 million (net of tax) at September 30, 2006. Cash flow hedges of gas and oil production in place at September 30, 2006 increased the calculated ceiling value by approximately $176.3 million (net of tax). However, subsequent to quarter end, the market price for Henry Hub gas increased to $6.26 per Mcf and the price for West Texas Intermediate changed to $56.00 per barrel on October 18, 2006, and utilizing these prices, the Company s net book value of natural gas and oil properties would not have exceeded the ceiling amount. As a result of the increase in the ceiling amount using the subsequent prices, the Company has not recorded a write down of its oil and gas property costs. The ceiling value calculated using the October 18, 2006 prices includes approximately $52.7 million related to the positive effects of future cash flow hedges of gas and oil production. The Company had approximately 90.0 Bcf and 30,000 barrels of future production hedged at September 30, 2006 (see Item 3 of this Form 10-Q for additional discussion of the Company s hedging activities). Decreases in market prices from October 18, 2006 levels, as well as changes in production rates, levels of reserves, the evaluation of costs excluded from amortization, future development costs, and service costs could result in future ceiling test impairments.

In early October, we entered a purchase and sale agreement to divest our South Louisiana properties representing approximately 9.0 Bcfe of proved reserves at year-end 2005. We expect the transaction to be closed during the fourth quarter, with estimated proceeds to us of $14.0 million. We expect that the impact on our total production from the sale of these properties will be approximately 0.2 Bcfe during the fourth quarter of 2006.

(3)

EARNINGS PER SHARE

Basic earnings per common share is computed by dividing net income by the weighted average number of common shares outstanding during each period. The diluted earnings per share calculation, using the average market price of our common stock for the period and the treasury stock method per FAS 128, Earnings Per Share (as amended), adds to the weighted average number of outstanding shares of common stock the incremental number of shares that would have been outstanding assuming the exercise of dilutive stock options and the vesting of unvested restricted shares of common stock.

For the nine months ended September 30, 2006, 5,887,703 of the Company s outstanding options with an average exercise price of $3.46 were included in the calculation of diluted shares. Options for 220,730 shares were excluded from the calculation because they would have had an antidilutive effect. Outstanding options for 7,328,804 shares at September 30, 2005, with a weighted average exercise price of $3.30, were included in the calculation of diluted shares. Restricted shares included in the calculation of diluted shares were 672,719 and 888,622 at September 30, 2006 and 2005, respectively. At September 30, 2006, 5,535 shares of restricted stock were excluded from the calculation because they would have had an antidilutive effect. The number of options, option exercise prices, and the number of restricted shares have been adjusted to reflect the two-for-one stock split effected in the fourth quarter of 2005.

(4)

DEBT

Debt balances as of September 30, 2006, and December 31, 2005, consisted of the following:

	September 30, 2006	December 31, 2005
	(in thousands)	
Short-term:		
7.15% Senior Notes due 2018 (current portion)	$ 1,200	$ -
Long-term:		
7.625% Senior Notes due 2027, putable at the holders' option	60,000	60,000

in 2009		
7.21% Senior Notes due 2017	40,000	40,000
7.15% Senior Notes due 2018	37,200	-
Total long-term debt	137,200	100,000
Total debt	$ 138,400	$ 100,000

The Company has a $500 million unsecured revolving credit facility that expires in January 2010. There were no amounts outstanding under the revolving credit facility at September 30, 2006, and December 31, 2005. The interest rate on the credit facility is calculated based upon the Company's debt rating and is currently 150 basis points over the current London Interbank Offered Rate (LIBOR). The revolving credit facility contains covenants which impose certain restrictions on the Company. Under the credit agreement, the Company may not issue total debt in excess of 60% of its total capital, must maintain a certain level of shareholders' equity, and must maintain a ratio of earnings before interest, taxes, depreciation and amortization (EBITDA) to interest expense of 3.5 or above. There are also restrictions on the ability of the Company's subsidiaries to incur debt. At September 30, 2006, the Company's capital structure consisted of 9% debt and 91% equity and the Company was in compliance with its debt agreements.

On May 2, 2006, in connection with the sale of the Company s interest in NOARK, the Company assumed $39.0 million of debt obligations which the Company had previously guaranteed. These debt obligations require semi-annual principal payments of $0.6 million, plus interest.

(5)

DERIVATIVES AND RISK MANAGEMENT

Management enters into various types of derivative instruments for a portion of its projected gas and oil sales to reduce its exposure to market price volatility for natural gas and oil. At September 30, 2006, our gas and oil derivative instruments consisted of price swaps, costless collars and basis swaps. Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities" (FAS 133), as amended by FAS 137, FAS 138 and FAS 149, requires that all derivatives be recognized in the balance sheet as either an asset or liability measured at its fair value. Special accounting for qualifying hedges allows a derivative's gains and losses to offset related results on the hedged item in the income statement or as a component of other comprehensive income. The Company s hedging practices are summarized in Item 7A of the 2005 Annual Report on Form 10-K.

Cash Flow Hedges

For cash flow hedges, all derivative instruments are reported as either a hedging asset or hedging liability on the balance sheet and are measured at fair value. The reporting of gains and losses on derivative hedging instruments depends on whether the gains or losses are effective at offsetting changes in the cash flows of the hedged item. The effective portion of the gain or loss on the derivative hedging instrument is recorded in other comprehensive income (OCI) until recognized in earnings during the period that the hedged transaction takes place. The ineffective portion of the gains and losses from derivative hedging instruments is recognized in earnings immediately.

Fair Value Hedges

The Company recognized a firm commitment asset of $0.7 million related to future gas sales. The Company has also recognized a liability of $0.7 million for derivative trades against the firm commitment asset.

Other Derivative Contracts

Although the Company s basis swaps meet the objectives to manage our commodity price exposure, some of these trades do not qualify for hedge accounting under FAS 133. The basis swaps that do qualify for hedge accounting treatment are classified as matched-basis swaps. These matched basis swaps have been combined with other derivative trades (i.e., costless collars and swaps) to form a single hedge where both trades are accounted for as a unit. The basis swap trades that have not been designated as hedges are recorded on the balance sheet at their fair values under hedging assets and hedging liabilities. All realized and unrealized gains and losses related to these contracts are recognized immediately in the statement of operations as a component of gas sales. As of September 30, 2006, the Company recorded an unrealized loss of $1.7 million related to basis swaps that do not meet the requirements of FAS 133 as hedges.

The Natural Gas Distribution segment periodically enters into derivative contracts designed to mitigate risk related to future gas prices. The Company does not recognize unrealized income/loss for these regulatory hedges as the effects of these hedges are passed through to utility customers. As of September 30, 2006, the Company recognized a liability of $5.0 million related to regulatory hedges.

At September 30, 2006, the Company's net asset related to its hedging activities was $39.9 million. Additionally, at September 30, 2006, the Company had recorded a cumulative gain to other comprehensive income net of tax (equity section of the balance sheet) of $23.3 million. The amount recorded in other comprehensive income will be relieved over time and taken to the income statement as the physical transactions being hedged occur. Assuming the market prices of gas and oil futures as of September 30, 2006, remain unchanged, the Company would expect to transfer an aggregate pre-tax gain of approximately $17.7 million from accumulated other comprehensive income to earnings during the next 12 months. The change in accumulated other comprehensive income (loss) related to derivatives was a gain of $62.0 million ($39.1 million after tax) compared to a loss of $193.4 million ($121.8 million after tax) for the three months ended September 30, 2006 and 2005, respectively, and a gain of $195.5 million ($123.2 million after tax) compared to a loss of $241.8 million ($152.3 million after tax) for the nine months ended September 30, 2006 and 2005, respectively. Additional volatility in earnings and other comprehensive income (loss) may occur in the future as a result of the application of FAS 133.

(6)

SEGMENT INFORMATION

The Company's three reportable business segments, Exploration and Production (E&P), Midstream Services and Natural Gas Distribution, have been identified based on the differences in products or services provided. Revenues for the E&P segment are derived from the production and sale of natural gas and crude oil. The Midstream Services segment generates revenue through the marketing of both Company and third-party produced gas volumes and through gathering fees associated with the transportation of natural gas to market. Gathering revenues have been insignificant in the past, but are expected to increase in the future depending upon the level of production from our Fayetteville Shale area. Revenues for the Natural Gas Distribution segment arise from the transportation and sale of natural gas at retail.

Summarized financial information for the Company's reportable segments is shown in the following table. The accounting policies of the segments are the same as those described in Note 1 to the financial statements in the 2005 Annual Report on Form 10-K. Management evaluates the performance of its segments based on operating income, defined as operating revenues less operating costs and expenses. Income before income taxes is the sum of operating income, interest expense, other income and minority interest in partnership. Other income in the Company s consolidated statements of operations includes interest income. The "Other" column includes items not related to the

Company's reportable segments including real estate, corporate items and for the periods ending prior to June 30, 2006, the Company s investment in the Ozark Gas Transmission system, which was sold to Atlas Pipeline Partners, L.P. during the second quarter of 2006.

	Exploration And Production	Midstream Services	Natural Gas Distribution	Other (in thousands)		
Three months ended September 30, 2006:						
Revenues from external customers	$ 116,289	$ 33,830	$ 18,275	$ -	$ 168,394	
Intersegment revenues	8,483	91,497	20	111	100,111	
Operating income (loss)	56,326	1,259	(4,530)	63	53,118	
Interest and other income (loss) [1]	1,330	-	(117)	4	1,217	
Depreciation, depletion and amortization expense	38,792	174	1,470	23	40,459	
Interest expense [1]	190	-	30	-	220	
Provision (benefit) for income taxes [1]	21,763	474	(1,776)	57	20,518	
Assets	1,818,899	73,937 [2]		185,918	101,789 [3]	2,180,543 [3]
Capital expenditures [4]	233,688	14,727	2,777	7,253	258,445	
Three months ended September 30, 2005:						
Revenues from external customers	$ 108,679	$ 33,205	$ 20,243	$ -	$ 162,127	
Intersegment revenues	5,590	100,407	23	112	106,132	
Operating income (loss)	68,861	1,520	(3,201)	21	67,201	
Interest and other income (loss) [1]	426	-	(76)	77	427	
Depreciation, depletion and amortization expense	23,813	10	1,681	23	25,527	
Interest expense [1]	3,245	240	965	261	4,711	
Provision (benefit) for income taxes [1]	23,974	466	(1,566)	97	22,971	
Assets	1,240,216	64,622	168,134	435,413 [3]		1,908,385 [3]
Capital expenditures [4]	145,961	3,753	3,042	1,469	154,225	
Nine months ended September 30, 2006:						
Revenue from external customers	$ 330,969	$ 99,166	$ 118,960	$ -	$ 549,095	

Intersegment revenues	29,276	238,295	180	336	268,087	
Operating income	186,606	3,128	1,285	197	191,216	
Interest and other income (loss) [(1)]	6,184	-	(312)	11,802	17,674	
Depreciation, depletion and amortization expense	95,225	580	4,636	71	100,512	
Interest expense [(1)]	394	-	107	-	501	
Provision for income taxes [(1)]	72,882	1,184	331	4,591	78,988	
Assets	1,818,899	73,937 [(2)]		185,918	101,789 [(3)]	2,180,543 [(3)]
Capital expenditures [(4)]	577,905	30,639	9,108	14,470	632,122	
<u>Nine months ended September 30, 2005:</u>						
Revenue from external customers	$ 260,386	$ 87,956	$ 107,301	$ -	$ 455,643	
Intersegment revenues	23,466	217,023	149	336	240,974	
Operating income	165,191	3,488	1,885	44	170,608	
Interest and other income (loss) [(1)]	450	-	(188)	364	626	
Depreciation, depletion and amortization expense	63,613	31	5,068	71	68,783	
Interest expense [(1)]	9,686	437	2,995	786	13,904	
Provision (benefit) for income taxes [(1)]	56,878	1,122	(477)	18	57,541	
Assets	1,240,216	64,622	168,134	435,413 [(3)]		1,908,385 [(3)]
Capital expenditures [(4)]	323,337	7,901	7,825	1,845	340,908	

(1)

Interest income, interest expense and the provision (benefit) for income taxes by segment are an allocation of corporate amounts as interest income, debt and income tax expense (benefit) are incurred at the corporate level. Other income (loss) for the nine-month period ended September 30, 2006, includes the $10.9 million pre-tax gain on the second quarter 2006 sale of the Company s investment in NOARK.

(2)

In the third quarter of 2006, Midstream Services sold a gathering system that was being constructed in East Texas to a third party.

(3)

Other assets include the Company's investment in cash equivalents, corporate assets not allocated to segments, assets for non-reportable segments and, for periods ended September 30, 2005, the Company s equity investment in NOARK.

(4)

Capital expenditures include $11.5 million and $26.8 million for the three- and nine-month periods ended September 30, 2006, respectively, and $14.2 million and $24.8 million for the three- and nine-month periods ended September 30, 2005, respectively, relating to the change in accrued expenditures between periods.

Included in intersegment revenues of the Midstream Services segment are $77.7 million and $90.5 million for the third quarters of 2006 and 2005, respectively, and $200.3 million and $199.2 million for the nine months ended September 30, 2006 and 2005, respectively, for marketing of the Company's E&P sales. Intersegment sales by the E&P segment and Midstream Services segment to the Natural Gas Distribution segment are priced in accordance with terms of existing contracts and current market conditions. Parent company assets include furniture and fixtures, prepaid debt costs and prepaid and intangible pension related costs. Parent company general and administrative costs, depreciation expense and taxes other than income are allocated to segments. All of the Company's operations are located within the United States.

(7)

INTEREST AND INCOME TAXES PAID

The following table provides interest and income taxes paid during each period presented:

	For the nine months ended September 30,	
	2006	2005
	(in thousands)	
Interest payments	$ 5,825	$ 12,392
Income tax payments	$ 6	$ 5

(8)

CONTINGENCIES AND COMMITMENTS

Operating Commitments

The Company s Natural Gas Distribution segment has entered into various non-cancelable agreements related to demand charges for the transportation and purchase of natural gas with third parties, including a transportation contract for 66.9 MMcf per day of firm capacity that expires in 2014. These costs are recoverable from the utility's end-use customers. At September 30, 2006, future payments under these non-cancelable demand contracts are $2,683,000 in 2006, $9,905,000 in 2007, $9,245,000 in 2008, $9,632,000 in 2009, $10,019,000 in 2010 and $42,086,000 thereafter. Additionally, our E&P and Midstream Services segments have commitments for demand transportation charges including a 3-year firm transportation agreement through March 2009 to transport volumes increasing to 220.0 MMcf per day in the later stages of the contract. At September 30, 2006, future payments under these non-cancelable demand contracts are $2,130,000 in 2006, $11,518,000 in 2007, $15,928,000 in 2008,

$6,990,000 in 2009, $5,495,000 in 2010 and $4,167,000 thereafter.

The Company leases certain office space and equipment under non-cancelable operating leases expiring through 2013. Under certain of these leases the Company is required to pay property taxes, insurance, repairs and other costs related to the leased property. At September 30, 2006, future minimum payments under non-cancelable leases accounted for as operating leases are approximately $1,133,000 in 2006, $4,469,000 in 2007, $4,108,000 in 2008, $3,662,000 in 2009, $2,604,000 in 2010 and $5,285,000 thereafter.

The Company leases compressors related to its Midstream Services and E&P operations under non-cancelable operating leases expiring through 2012. At September 30, 2006, future minimum payments under non-cancelable leases accounted for as operating leases are approximately $2,517,000 in 2006, $15,870,000 in 2007, $16,377,000 in 2008, $14,899,000 in 2009, $12,804,000 in 2010 and $12,131,000 thereafter.

In 2005, the Company entered into agreements to fabricate ten new land drilling rigs. In the first nine months of 2006, the Company entered into agreements to fabricate two smaller surface rigs and three additional land drilling rigs. Including ancillary equipment and supplies, the total cost of these fifteen rigs is approximately $139.4 million. As of September 30, 2006, payments made under these agreements were $105.5 million.

Subsequent to September 30, 2006, one of the Company s Midstream Services subsidiaries entered into a master lease agreement relating to compressor units. The units will be leased under either 84-month or 120-month terms at our discretion and are expected to be delivered from February 2007 to December 2007. Monthly lease payments will be indexed to the lender s cost of funds, and assuming current interest rates, the total estimated commitment for the units is $14.7 million. The Company has guaranteed its subsidiary s obligations under the lease up to an aggregate amount of $20.0 million.

Environmental Risk

The Company is subject to laws and regulations relating to the protection of the environment. The Company's policy is to accrue environmental and cleanup related costs of a non-capital nature when it is both probable that a liability has been incurred and when the amount can be reasonably estimated. Management believes any future remediation or other compliance related costs will not have a material effect on the financial position or reported results of operations of the Company.

Litigation

The Company is subject to litigation and claims that have arisen in the ordinary course of business. The Company accrues for such items when a liability is both probable and the amount can be reasonably estimated. In the opinion of management, the results of such litigation and claims will not have a material effect on the results of operations or the financial position of the Company.

A lawsuit was filed against the Company in 2001 alleging a breach of an agreement to indemnify the other party against settlement payments related to the Company's Boure' prospect in Louisiana. The allegations were contested and, in 2002, the Company was granted a motion for summary judgment by the trial court. The case was appealed to the First Court of Appeals in Houston, Texas, which subsequently transferred the appeal to the Thirteenth Court of Appeals in Corpus Christi. The appeal was briefed and argued during 2003. On April 14, 2005, the Thirteenth Court of Appeals reversed the orders of the trial court and rendered judgment denying the Company s motion for summary judgment and granting the motion for summary judgment of the other party. The Company s motion for rehearing with the Thirteenth Court of Appeals was denied on May 19, 2005. In August of 2005, the Company filed a petition for review with the Texas Supreme Court. In October of 2005, the Texas Supreme Court invited additional briefing by the parties. In March of 2006, the Texas Supreme Court requested that both parties submit full briefs on the merits of the case. The matter is currently pending before the Texas Supreme Court. Should the other party prevail on the appeal, the Company could be required to pay approximately $2.1 million, plus pre-judgment interest and attorney s fees. Based on an assessment of this litigation by the Company and its legal counsel, no accrual for loss is currently recorded.

(9)

STOCK-BASED COMPENSATION

On January 1, 2006, the Company adopted FAS 123(R), which requires companies to measure the cost of employee services received in exchange for an award of equity instruments based on the grant date fair value of the award. The Company has elected to use the modified prospective application method such that FAS 123(R) applies to new awards, the unvested portion of existing awards and to awards modified, repurchased or canceled after the effective date. The Company has equity incentive plans that provide for the issuance of stock options and restricted stock. These plans are discussed more fully in the 2005 Annual Report on Form 10-K. All options are issued at fair market value at the date of grant and expire seven years from the date of grant for awards under the 2004 Stock Incentive Plan (the 2004 Plan) and ten years from the date of grant for awards under all other plans. Generally, stock options granted to employees and directors vest ratably over three to four years from the grant date. No new stock options have been granted subsequent to January 1, 2006. The Company issues shares of restricted stock to employees and directors which generally vest over four years. The Company recognizes stock-based compensation expense on a straight-line basis over the requisite service period of the individual grants with the exception of awards granted to participants who have reached retirement age or will reach retirement age during the vesting period. In the fourth quarter of 2005, the Board of Directors prospectively revised the vesting for restricted stock and stock options granted to participants on or after December 8, 2005 under the 2004 Plan to immediately accelerate vesting upon death, disability or retirement (subject to a minimum of five years of service). This change did not affect awards issued prior to December 8, 2005.

Prior to January 1, 2006, the Company accounted for its long-term equity incentive plans under the intrinsic value method described in APB Opinion No. 25, Accounting for Stock Issued to Employees and related interpretation. The Company, applying the intrinsic value method, did not record stock-based compensation cost for stock options because the exercise price of the stock options equaled the market price of the underlying stock at the date of grant.

For the three and nine months ended September 30, 2006, the Company recognized compensation costs of $1,540,000 and $2,881,000 related to stock options issued prior to January 1, 2006. Of this amount, $131,000 and $385,000 were directly related to the acquisition, exploration and development activities for the Company's gas and oil properties and were capitalized into the full cost pool. The remaining costs were recorded in general and administrative expenses. Accordingly, the Company recorded a deferred tax benefit of $915,000 for the nine months ended September 30, 2006. A total of $3,204,000 of unrecognized compensation costs related to stock options not yet vested is expected to be recognized over future periods.

The fair value of stock options is estimated on the date of the grant using a Black-Scholes valuation model that uses the weighted average assumptions noted in the following table. Expected volatility is based on historical volatility of the Company s common stock and other factors. The Company uses historical data on exercise of stock options, post vesting forfeitures and other factors to estimate the expected term of the share-based payments granted. The risk free rate is based on the U.S. Treasury yield curve in effect at the time of grant.

Assumptions	2005
Risk-free interest rate	4.4%
Expected dividend yield	-
Expected volatility	40.6%
Expected term	4 years

The Company may utilize treasury shares or use authorized but unissued shares when a stock option is exercised or when restricted stock is granted.

For the three- and nine-month periods ended September 30, 2006, restricted stock expense recorded in general and administrative expenses, was $606,000 and $1,538,000, respectively. Additional amounts of $278,000 and $876,000 for the same periods were capitalized into the full cost pool.

The following table illustrates the effect on net income and earnings per share in the comparable quarter and nine-month period of the prior year as if the fair value based method under FASB Statement 123(R) had been applied to all outstanding vested and unvested awards in that period.

	For the three months ended September 30, 2005 (in thousands, except per share)	For the nine months ended September 30, 2005 (in thousands, except per share)

Net income, as reported	$ 39,469	$ 98,904
Add back: Stock option based compensation expense included in reported net income, net of related tax effects	403	1,207
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	(816)	(2,440)
Pro forma net income	$ 39,057	$ 97,672
Earnings per share:		
Basic - as reported [1]	$0.27	$0.68
Basic - pro forma [1]	$0.26	$0.67
Diluted - as reported [1]	$0.26	$0.65
Diluted - pro forma [1]	$0.25	$0.65

(1)Restated to reflect the two-for-one stock split effected on November 17, 2005

The following table summarizes stock option activity for the first nine months of 2006 and provides information for options outstanding at September 30, 2006:

	Number of Options	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value (in thousands)
Outstanding at December 31, 2005	7,126,465	$ 4.34		
Granted	-	-		
Exercised	1,012,156	2.54		
Forfeited or expired	5,876	24.41		
Outstanding at September 30, 2006	6,108,433	$ 4.61	4.7	$ 154,276
Exercisable at September 30, 2006	5,235,132	$ 2.84	4.4	$ 141,501

There were no options granted during the first nine months of 2006 and 2005. The total intrinsic value of options exercised during the first nine months of 2006 and 2005 was $25.6 million and $26.2 million, respectively.

The following table summarizes options outstanding and exercisable at ranges of exercise prices.

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Options Outstanding at September 30, 2006	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life (Years)	Options Exercisable at September 30, 2006	Weighted Average Exercise Price
$1.50 - $1.86	2,503,191	$ 1.74	3.7	2,503,191	$ 1.74
$1.87 - $2.85	702,828	2.52	4.4	702,828	2.52

$2.86 - $5.00	1,381,620	2.98	4.7	1,349,620	2.98
$5.01 - $12.00	879,795	5.55	7.3	553,083	5.52
$12.01 - $36.00	640,999	20.37	5.5	126,410	12.96
	6,108,433	$ 4.61	4.7	5,235,132	$ 2.84

The following table summarizes restricted stock award activity for the first nine months of 2006 and provides information for unvested restricted stock awards outstanding at September 30, 2006.

	Number of Nonvested Shares	Weighted Average Grant Date Fair Value
Nonvested shares at December 31, 2005	707,142	$ 11.13
Granted	21,300	33.58
Vested	(26,001)	13.28
Forfeited	(24,187)	18.08
Nonvested shares at September 30, 2006	678,254	$ 11.51

As of September 30, 2006, there was $5.6 million of total unrecognized compensation cost related to nonvested shares. That cost is expected to be recognized over a weighted-average period of 1.0 year. The

total fair value of shares vested during the first nine months of 2006 and 2005 was $345,000 and $147,000 respectively.

Associated with the exercise of stock options, the Company received a tax benefit of $7.4 million and $7.7 million in the first nine months of 2006 and 2005, respectively. The tax benefit is recorded as an increase in additional paid-in capital.

(10)

PENSION PLAN AND OTHER POSTRETIREMENT BENEFITS

The Company applies Statement of Financial Accounting Standards No. 132, "Employers' Disclosures about Pensions and Other Postretirement Benefits." Substantially all employees are covered by the Company's defined benefit pension and postretirement benefit plans. Net periodic pension and other postretirement benefit costs include the following components for the three- and nine-month periods ended September 30, 2006 and 2005:

	Pension Benefits			
	For the three months ended September 30,		For the nine months ended September 30,	
	2006	2005	2006	2005
	(in thousands)			
Service cost	$ 753	$ 631	$ 2,258	$ 1,893
Interest cost	971	941	2,911	2,823
Expected return on plan assets	(1,145)	(1,194)	(3,433)	(3,582)
Amortization of prior service cost	109	110	327	330
Amortization of net loss	189	81	569	243
Net periodic benefit cost	$ 877	$ 569	$ 2,632	$ 1,707

	Postretirement Benefits			
	For the three months ended September 30,		For the nine months ended September 30,	
	2006	2005	2006	2005
	(in thousands)			
Service cost	$ 68	$ 43	$ 203	$ 129
Interest cost	47	50	141	150
Expected return on plan assets	(18)	(14)	(52)	(42)
Amortization of net loss	9	10	26	30
Amortization of transition obligation	22	22	65	66
Net periodic benefit cost	$ 128	$ 111	$ 383	$ 333

We currently expect to contribute $3.4 million to our pension plans and $0.4 million to our postretirement benefit plans in 2006. As of September 30, 2006, $3.4 million has been contributed to our pension plans and $0.3 million has been contributed to our postretirement benefit plans.

(11)

(11)

ASSET RETIREMENT OBLIGATIONS

Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations," (FAS 143) requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made, and that the associated asset retirement costs be capitalized as part of the carrying amount of the long-lived asset. The Company owns natural gas and oil properties which require expenditures to plug and abandon the wells when reserves in the wells are depleted. The estimated liability for these future expenditures under FAS 143 are recorded in the period the liability is incurred (at the time the wells are drilled or acquired). The following table summarizes the Company's activity related to asset retirement obligations for the nine-month period ended September 30, 2006, and for the year ended December 31, 2005:

	2006	2005
	(in thousands)	
Asset retirement obligation at January 1	$ 9,229	$ 8,565
Accretion of discount	292	326
Obligations incurred	732	436
Obligations settled/removed	(34)	(1,553)
Revisions of estimates	-	1,455
Asset retirement obligation at September 30, 2006 and December 31, 2005	$ 10,219	$ 9,229
Current liability	527	358
Long-term liability	9,692	8,871
Asset retirement obligation at September 30, 2006 and December 31, 2005	$ 10,219	$ 9,229

(12)

NEW ACCOUNTING PRONOUNCEMENTS

In September 2006, the FASB released Statement of Financial Accounting Standards No. 158, Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132(R) (FAS 158). Under the new standard, companies must recognize a net liability or asset to report the funded status of their defined benefit pension and other postretirement benefit plans on their balance sheets. The recognition and disclosure provisions of FAS 158 will be required to be adopted for the Company as of December 31, 2006. The Company is currently reviewing the requirements of FAS 158 to determine the impact on its financial position and results of operations.

In September 2006, the FASB issued Statement of Financial Accounting Standards No. 157, Fair Value Measurements (FAS 157). This Statement defines fair value as used in numerous accounting pronouncements, establishes a framework for measuring fair value in generally accepted accounting principles and expands disclosure related to the use of fair value measures in financial statements. The Statement is to be effective for the Company s financial statements issued in 2008; however, earlier application is encouraged. The Company is currently evaluating the timing of adoption and the impact that adoption might have on its financial position or results of operations.

In July 2006, the FASB issued FASB Interpretation No. 48 (FIN 48) Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement No. 109, to clarify certain aspects of accounting for uncertain tax positions, including issues related to the recognition and measurement of those tax positions. This interpretation is effective for fiscal years beginning after December 15, 2006. The Company is in the process of evaluating the impact of the adoption of this interpretation on the Company s results of operations and financial condition.

In September 2006, the Securities and Exchange Commission ("SEC") issued Staff Accounting Bulletin No. 108 ("SAB 108"). Due to diversity in practice among registrants, SAB 108 expresses SEC staff views regarding the process by which misstatements in financial statements are evaluated for purposes of determining whether financial statement restatement is necessary. SAB 108 is effective for fiscal years ending after November 15, 2006, and early application is encouraged. The Company does not believe SAB 108 will have a material impact on its financial position or results from operations.

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following updates information as to Southwestern Energy Company's financial condition provided in our 2005 Annual Report on Form 10-K, and analyzes the changes in the results of operations between the three- and nine-month periods ended September 30, 2006 and 2005. For definitions of commonly used gas and oil terms used in this Form 10-Q, please refer to the "Glossary of Certain Industry Terms" provided in our 2005 Annual Report on Form 10-K.

This Form 10-Q contains forward-looking statements that involve risks and uncertainties. Our actual results could differ materially from those anticipated in forward-looking statements for many reasons, including the risks described in Item 1A, "Risk Factors" in Part I and elsewhere in our 2005 Annual Report on Form 10-K and Item 1A, Risk Factors in Part II in this Form 10-Q. You should read the following discussion with our financial statements, our Form 10-Q for the period ended June 30, 2006, and related notes included in this Form 10-Q. Historical per share information provided as of September 30, 2005, in the financial statements, footnotes and Management s Discussion and Analysis of Financial Condition and Results of Operations has been adjusted to reflect the two-for-one stock split effected on November 17, 2005.

OVERVIEW

Southwestern Energy Company is an independent energy company primarily focused on natural gas. Our primary business is the exploration, development and production of natural gas and crude oil within the United States, with operations principally located in Arkansas, Oklahoma, Texas, New Mexico and Louisiana. We are also focused on creating and capturing additional value at and beyond the wellhead through our established natural gas distribution and marketing businesses and our expanding gathering activities. Our marketing and our gas gathering businesses are collectively referred to as our Midstream Services. We operate principally in three segments: Exploration and Production (E&P), Midstream Services and Natural Gas Distribution.

We currently derive the vast majority of our operating income and cash flow from the natural gas production of our E&P business and expect this to continue in the future. We expect that growth in our operating income and revenues will primarily depend on natural gas prices and our ability to increase our natural gas production. There has been significant price volatility in the natural gas and crude oil market in recent years due to a variety of factors we cannot control or predict. These factors, which include weather conditions, political and economic events, and competition from other energy sources, impact supply and demand for natural gas. In addition, the price we realize for our gas production is affected by our hedging activities as well as locational differences in market prices. Our ability to increase our natural gas production is dependent upon our ability to economically find and produce natural gas, our ability to control costs, and our ability to market natural gas on economically attractive terms to our customers. For both the three months ended September 30, 2006 and 2005, 100% of our operating income was generated by our E&P and Midstream Services segments, as our Natural Gas Distribution segment generated a seasonal loss for the related periods. For both the first nine months of 2006 and 2005, 99% of our operating income was generated by our E&P and Midstream Services segments.

Recent Developments

-

Fayetteville Shale Play. Our gross production from the Fayetteville Shale has now reached approximately 70 MMcf per day, up from approximately 50 MMcf per day at August 1, 2006, and we expect it to reach approximately 100 MMcf per day by year-end. We currently have 14 rigs working in the play area, up from 10 rigs at July 31, 2006, and plan to have 19 rigs running in the play by year-end. We expect production from the Fayetteville Shale to continue to increase as we continue to develop the play.

-

Increase in 2006 Capital Investments. We have increased our projected capital investments for 2006 to $925.0 million, up approximately 11% from the $830.1 million capital program announced in December 2005. The increased amount includes projected capital expenditures of $865.0 million for our E&P segment, up from $770.3 million. The increase is attributable to our Fayetteville Shale play and is primarily related to changes during the year in our fracture stimulation practices, higher service costs, increased outside-operated activity and costs related to previously disclosed purchases of land drilling rigs.

Three Months Ended September 30, 2006, Compared with Three Months Ended September 30, 2005

Our revenues for the third quarter of 2006 were approximately 4% higher than the comparable period in 2005 due to increased production volumes partially offset by lower market-driven commodity prices received for our gas and oil sales. Net income decreased approximately 15% to $33.5 million, or $0.20 per share on a diluted basis, for the three months ended September 30, 2006 as compared to the prior year period. Operating income for our E&P segment was down 18% to $56.3 million for the quarter ended September 30, 2006, compared to $68.9 million for the same quarter in 2005, as revenues from increased production volumes were more than offset by increased operating costs and expenses. We expect operating costs and expenses for our E&P segment to continue to increase in the fourth quarter of 2006. Operating income for our Midstream Services segment decreased 17% to $1.3 million for the third quarter of 2006 as increased revenues for gas marketing and gathering activities were offset by increased compensation and operating costs associated with gathering activities related to our Fayetteville Shale play. We expect the compensation and operating costs for our Midstream Services segment to continue to increase in the fourth quarter. Our Natural Gas Distribution segment s seasonal operating loss was $4.5 million for the three months ended September 30, 2006, compared to $3.2 million for the third quarter of 2005.

In the third quarter of 2006, our gas and oil production increased approximately 19% to 19.3 Bcfe due primarily to increased production from our Fayetteville Shale play in Arkansas.

Our capital investments during the quarter increased approximately 68% from the prior year to $258.4 million, of which $233.7 million was invested in our E&P segment.

Nine Months Ended September 30, 2006, Compared with Nine Months Ended September 30, 2005

Net income for the nine months ended September 30, 2006, increased approximately 30% to $128.9 million, or $0.75 per share on a diluted basis, on revenues of $549.1 million, compared to the same period in 2005. Included in net income for the first nine months of 2006 is a $6.7 million after-tax gain resulting from the sale of our 25% interest in NOARK in the second quarter, which was partially offset by a one-time adjustment of $1.8 million to record additional deferred income tax expense as a result of tax legislation enacted in 2006 by the state of Texas. Our cash flow from operating activities increased 53% to $331.1 million for the nine months ended September 30, 2006, primarily due to the improved operating results of our E&P segment. Operating income for our E&P segment was up approximately 13% to $186.6 million for the first nine months of 2006 due to increased production volumes and higher prices realized for our production. Operating income for our Midstream Services segment was $3.1 million for the first nine months of 2006, down 10% from the prior year due to increased compensation and operating costs. Operating income for our Natural Gas Distribution segment decreased approximately 32% to $1.3 million for the first nine months ended September 30, 2006, as a $4.6 million annual rate increase effective October 31, 2005, was more than offset by warmer weather and increased operating costs.

In the first nine months of 2006, our gas and oil production increased approximately 14% to 51.6 Bcfe due primarily to increased production from our Fayetteville Shale play in Arkansas.

Our capital investments increased approximately 85% to $632.1 million for the first nine months of 2006 as compared to the same period last year, of which $577.9 million was invested in our E&P segment.

RESULTS OF OPERATIONS

Exploration and Production

	For the three months ended September 30,		For the nine months ended September 30,	
	2006	2005	2006	2005
Revenues (in thousands)	$124,772	$114,269	$360,245	$283,852
Operating income (in thousands)	$56,326	$68,861	$186,606	$165,191
Gas production (MMcf)	18,175	15,030	48,415	41,989
Oil production (MBbls)	180	200	527	543
Total production (MMcfe)	19,255	16,227	51,577	45,246
Average gas price per Mcf, including hedges	$6.23	$6.98	$6.73	$6.16
Average gas price per Mcf, excluding hedges	$6.04	$7.89	$6.56	$6.74
Average oil price per Bbl, including hedges	$62.78	$47.23	$60.24	$42.29
Average oil price per Bbl, excluding hedges	$68.31	$61.07	$65.31	$53.36
Average unit costs per Mcfe				
Lease operating expenses	$0.68	$0.51	$0.62	$0.46
General & administrative expenses	$0.54	$0.42	$0.56	$0.40

Taxes, other than income taxes	$0.32	$0.40	$0.34	$0.35
Full cost pool amortization	$1.97	$1.44	$1.79	$1.37

Revenues, Operating Income and Production

Revenues. Revenues for our E&P segment were up 9% for the three months ended September 30, 2006 primarily due to increased production volumes. For the nine months ended September 30, 2006, revenues for our E&P segment were up 27%, primarily due to increased production volumes and higher gas and oil prices realized. Revenues for the first nine months of 2006 and 2005 also include pre-tax gains of $1.9 million and $2.1 million, respectively, related to the sale of gas in storage inventory. We expect our production volumes to continue to increase primarily due to the development of our Fayetteville Shale play in Arkansas. Gas and oil prices are difficult to predict and subject to wide price fluctuations. As of October 19, 2006, we have hedged 12.7 Bcf of our remaining 2006 gas production, 55.0 Bcf of 2007 gas production and 22.0 Bcf of 2008 gas production to limit our exposure to price fluctuations.

Operating Income. Operating income for the E&P segment was down 18% for the third quarter of 2006 as increased revenues were more than offset by increased operating costs and expenses. Operating income for the E&P segment was up 13% for the first nine months of 2006 to $186.6 million from $165.2 million in 2005.

Production. Gas and oil production during the third quarter of 2006 was up approximately 19% to 19.3 Bcfe and was up approximately 14% to 51.6 Bcfe for the first nine months of 2006 as compared to prior periods. The increases were primarily the result of increased production from our Fayetteville Shale play. Our production rate from the play area continues to climb despite restrictions we have experienced due to a shortage of pressure pumping equipment and crews in the play area. At the end of the third quarter, we had an inventory of 27 wells in our Fayetteville Shale play waiting on completion compared to 12 wells at July 31, 2006. We currently have two completion crews operating in the area and have entered into supply arrangements with strategic partners to have up to five crews in the area by the end of the first quarter of 2007. We expect our inventory of wells waiting on completion to increase over the next few months. If our inventory of wells waiting on completion exceeds our expectations, our rate of production growth may not meet our projections.

Gas production was up approximately 21% to 18.2 Bcf for the third quarter of 2006, and up approximately 15% to 48.4 Bcf for the first nine months of 2006. Net production from the Fayetteville Shale was 3.8 Bcf in the third quarter of 2006, compared to 0.7 Bcf in the third quarter of 2005 and 0.7 Bcf and 1.8 Bcf in the first and second quarters of 2006, respectively.

In early October, we entered a purchase and sale agreement to divest our South Louisiana properties representing approximately 9.0 Bcfe of proved gas reserves at year-end 2005. We expect the transaction to close during the fourth quarter, with estimated proceeds to us of $14.0 million. We expect that the impact on our total production from the sale of these properties will be approximately 0.2 Bcfe during the fourth quarter of 2006.

We have lowered our production guidance for the fourth quarter of 2006 to 20.4 Bcfe to 21.4 Bcfe, and for calendar year 2006 to 72.0 to 73.0 Bcfe to reflect the current shortage of pressure pumping equipment and crews in the Arkoma basin and the pending sale of our South Louisiana properties. The revised guidance represents an increase of 18% to 20% compared to 2005.

Commodity Prices

We periodically enter into various hedging and other financial arrangements with respect to a portion of our projected natural gas and crude oil production in order to ensure certain desired levels of cash flow and to minimize the impact of price fluctuations, including fluctuations in locational market differentials (we refer you to Item 3 of this Form 10-Q for additional discussion). The average price realized for our gas production, including the effect of hedges, decreased approximately 11% to $6.23 per thousand cubic feet (Mcf) for the three months ended September 30, 2006, and increased 9% to $6.73 for the first nine months of 2006 as compared to the same periods last year. The change in the average price realized primarily reflects changes in average spot market prices and the effects of our price hedging activities. Our hedging activities increased our average gas price $0.19 per Mcf during the third quarter of 2006, compared to a decrease of $0.91 per Mcf during the same period of 2005. Our hedging activities increased the average gas price realized by $0.17 per Mcf for the first nine months of 2006, compared to a decrease of $0.58 per Mcf during the same period of 2005. Locational differences in market prices for natural gas have continued to be wider than historically experienced. We had financially protected approximately 74% of our production in the third quarter of 2006 from the impact of widening basis differentials. For the remainder of 2006, we have protected approximately 68% of our anticipated gas production from the impact of widening basis differentials through our hedging activities and sales arrangements. Disregarding the impact of hedges, the average price received for our gas production during the first nine months of 2006 was approximately $0.89 lower than average NYMEX spot prices.

For the remainder of 2006, we have NYMEX commodity price hedges in place for 12.7 Bcf of our gas production and for 2007 and 2008 we have 55.0 Bcf and 22.0 Bcf, respectively, of our future gas production hedged. Additionally, we have basis swaps on 10.0 Bcf for the remainder of 2006, and for 2007 and 2008 we have basis swaps on 52.5 Bcf and 19.1 Bcf, respectively, in order to reduce the effects of changes in market differentials on prices we receive.

We realized an average price of $60.24 per barrel for our oil production, including the effect of hedges, during the nine months ended September 30, 2006, up approximately 42% from the same period of 2005. The average price we received for our oil production in the first nine months of 2006 and 2005 was reduced by $5.07 and $11.07 per barrel, respectively, due to the effects of our hedging activities. For the remainder of 2006, we have hedged 30,000 barrels of our oil production at an average NYMEX price of $37.30 per barrel.

Operating Costs and Expenses

Lease operating expenses per Mcfe for our E&P segment increased 33% to $0.68 for the third quarter of 2006 and 35% to $0.62 for the first nine months of 2006 primarily as a result of increases in our gathering and compression costs primarily related to our operations in the Fayetteville Shale play. Based on our projected production, we expect our per unit operating costs for the remainder of 2006 to range between $0.65 and $0.70 per Mcfe.

General and administrative expenses per Mcfe increased 29% to $0.54 for the third quarter of 2006 and 40% to $0.56 for the first nine months of 2006, due primarily to increased compensation and other costs associated with increased staffing levels to meet the demands of our expanding E&P operations, primarily related to developing the Fayetteville Shale play. We added 389 new employees during the first nine months of 2006, most of which were hired in our E&P segment, and expect to hire an additional 115 to 130 employees by year-end 2006. Approximately 300 to 325 of the projected total new hires during 2006 are expected to be employed by our drilling company. We expect our per unit G&A expense for the remainder of 2006 to average between $0.50 and $0.55 per Mcfe.

Our full cost pool amortization rate averaged $1.97 per Mcfe for the third quarter of 2006 and $1.79 for the first nine months of 2006, up 37% and 31%, respectively, compared to the same periods in 2005. The amortization rate is impacted by reserve additions and the costs associated with those additions, revisions of previous reserve estimates due to both price and well performance, write-downs that result from full cost ceiling tests, and the level of unevaluated costs excluded from amortization. We cannot predict our future full cost pool amortization rate with accuracy due to the variability of each of the factors discussed above, as well as the uncertainty of the amount of future reserves attributed to our Fayetteville Shale play. Unevaluated costs excluded from amortization were $169.7 million at September 30, 2006, compared to $107.6 million at September 30, 2005. The increase in unevaluated costs since September 30, 2005 resulted primarily from an increase in our undeveloped leasehold acreage related to our Fayetteville Shale play and our increased drilling activity.

We utilize the full cost method of accounting for costs related to the exploration, development, and acquisition of oil and natural gas reserves. Under this method, all such costs (productive and nonproductive), including salaries, benefits and other internal costs directly attributable to these activities, are capitalized and amortized on an aggregate basis over the estimated lives of the properties using the units-of-production method. These capitalized costs are subject to a ceiling test that limits such pooled costs to the aggregate of the present value of future net revenues attributable to proved gas and oil reserves discounted at 10 percent (standardized measure) plus the lower of cost or market value of unproved properties. Any costs in excess of the ceiling are written off as a non-cash expense. The expense may not be reversed in future periods, even though higher natural gas and oil prices may subsequently increase the ceiling. Full cost companies must use the prices in effect at the end of each accounting quarter, including the impact of derivatives qualifying as hedges, to calculate the ceiling value of their reserves. However, subsequent commodity price increases may be utilized to calculate the ceiling value and reserves. At September 30, 2006, the ceiling value of our reserves was calculated based upon quoted market prices of $4.18 per Mcf for Henry Hub gas and $59.38 per barrel for West Texas Intermediate oil, adjusted for market differentials. Using these prices, our net book value of natural gas and oil properties would have exceeded the ceiling amount by $190.8 million (net of tax) at September 30, 2006. Cash flow hedges of gas and oil production in place at September 30, 2006 increased the calculated ceiling value by approximately $176.3 million (net of tax). However, subsequent to quarter end, the market price for Henry Hub gas increased to $6.26 per Mcf and the price for West Texas Intermediate changed to $56.00 per barrel on October 18, 2006, and utilizing these prices, our net book value of natural gas and oil properties would not have exceeded the ceiling amount. As a result of the increase in the ceiling amount using the subsequent prices, we have not recorded a write down of our oil and gas property costs. The ceiling value calculated using the October 18, 2006 prices includes approximately $52.7 million related to the positive affects of future cash flow hedges of gas and oil production. We have approximately 90 Bcf and 30,000 barrels of future production hedged at September 30, 2006 (see Item 3 of this Form 10-Q for additional discussion of our hedging activities). Decreases in market prices from October 18, 2006 levels, as well as changes in production rates, levels of reserves, the evaluation of costs excluded from amortization, future development costs, and service costs could result in future ceiling test impairments.

Taxes other than income taxes per Mcfe decreased 20% to $0.32 for the third quarter of 2006 and decreased 3% to $0.34 for the nine months ended September 30, 2006, due to the effects of lower gas prices in the third quarter of 2006.

The timing and amount of production and reserve additions attributed to our Fayetteville Shale play could have a material impact on per unit costs; if production or reserves additions are lower than projected, our per unit costs would increase.

Midstream Services

	For the three months ended September 30,		For the nine months ended September 30,	
	2006	2005	2006	2005
Revenues (in thousands)	$125,327	$133,612	$337,461	$304,979
Gas purchases (in thousands)	$120,571	$131,345	$325,957	$300,090
Operating income (in thousands)	$1,259	$1,520	$3,128	$3,488
Gas volumes marketed (Bcf)	20.1	17.1	50.5	46.5

Revenues from our Midstream Services segment were down 6% in the third quarter of 2006 and up 11% for the first nine months of 2006, as compared to prior year periods. The decrease in third quarter revenues primarily resulted from a decrease in natural gas commodity prices. The increase in revenues for the nine months ended September 30, 2006 was attributable to increases in volumes marketed and an increase in natural gas commodity prices. Operating income from our Midstream Services segment decreased 17% in the third quarter of 2006 and 10% for the first nine months of 2006 due primarily to increased staffing and operating costs associated with the gathering activities related to the Fayetteville Shale play. Operating income from natural gas marketing also fluctuates depending on the margin we are able to generate between the purchase of the commodity and the ultimate disposition of the commodity. We marketed 14.9 Bcf of affiliated gas in the third quarter of 2006, representing 74% of total volumes marketed, compared to 13.8 Bcf, or 81% of total volumes marketed, for the same period in 2005. In the first nine months of 2006, we marketed 36.2 Bcf of affiliated gas, representing 72% of total volumes marketed, compared to 35.5 Bcf, or 76% of total volumes marketed, for the same period in 2005. We enter into hedging activities from time to time with respect to our gas marketing activities to provide margin protection. We refer you to Item 3, "Qualitative and Quantitative Disclosure about Market Risks" in this Form 10-Q for additional information.

Midstream Services had gathering revenues of $2.8 million in the third quarter of 2006 and $4.7 million in the first nine months of 2006, related to its gathering systems in Arkansas. Gathering revenues and expenses for this segment are expected to continue to grow in the future as gathering systems supporting our Fayetteville Shale play are constructed.

In the third quarter of 2006, Midstream Services sold a gathering system that was being constructed in East Texas to a third party.

Natural Gas Distribution

	For the three months ended September 30,		For the nine months ended September 30,	
	2006	2005	2006	2005
Revenues (in thousands)	$18,295	$20,266	$119,140	$107,450
Gas purchases (in thousands)	$9,128	$11,154	$77,257	$67,886
Operating costs and expenses (in thousands)	$13,697	$12,313	$40,598	$37,679
Operating income (loss) (in thousands)	($4,530)	($3,201)	$1,285	$1,885
Deliveries (Bcf)				
Sales and end-use transportation	3.0	3.0	14.9	16.0
Sales customers at period-end	145,987	142,642	145,987	142,642
Average sales rate per Mcf	$14.21	$15.85	$13.11	$10.63
Heating weather - degree days	55	14	2,005	2,231
Percent of normal	117%	33%	79%	90%

Revenues and Operating Income

Revenues for the third quarter of 2006 decreased 10% from the comparable period of 2005 due primarily to lower average sales rates caused by lower prices paid for natural gas supplied to customers. Revenues for the nine months ended September 30, 2006 increased 11% from the comparable period of 2005 due primarily to higher average sales rates resulting from higher gas prices and the effects of a $4.6 million annual rate increase effective October 31, 2005.

Operating income for our Natural Gas Distribution segment decreased 42% in the third quarter of 2006 and 32% for the first nine months of 2006, as compared to the same periods of 2005, due primarily to an increase in operating costs, higher general and administrative expenses, and warmer weather for the nine months ended September 30, 2006, partially offset by the rate increase. Weather during the first nine months of 2006 was 21% warmer than normal and 11% warmer than the same period in 2005.

Deliveries and Rates

For the three-month period ended September 30, 2006, deliveries were unchanged compared to the same period of 2005. Deliveries decreased 7% for the nine-month period ended September 30, 2006, compared to the same period of 2005, due primarily to warmer weather. The average sales rate per Mcf decreased in the third quarter of 2006 and increased during the first nine months of 2006 due to changes in natural gas prices.

Our utility segment hedged 1.8 Bcf of derivative gas purchases in the first nine months of 2006 which had the effect of increasing its total gas supply cost by $6.8 million. In the first nine months of 2005, our utility hedged 2.9 Bcf of its gas supply which increased its total gas supply cost by $1.4 million. Additionally, our utility segment currently has hedges in place on 2.8 Bcf of gas purchases at an average purchase price of $9.37 per Mcf for the 2006-2007 winter season. See Item 3 of this Form 10-Q for additional information regarding our commodity price risk hedging activities.

Operating Costs and Expenses

For the third quarter and first nine months of 2006, operating costs and expenses (exclusive of purchased gas costs) for this segment were higher than the comparable periods of the prior year due primarily to higher general and administrative expenses. The increase in general and administrative expenses primarily resulted from increased compensation costs.

Regulatory Matters

On September 25, 2006, our Natural Gas Distribution segment filed with the Arkansas Public Service Commission (APSC) an application to modify its general rates and charges. The application seeks to increase annual operating revenues by $13.1 million, a 6.8% annual increase. The APSC has 10 months to render a decision on the application. Any increase approved is expected to take effect in July 2007.

Transportation

On May 2, 2006, we sold our 25% partnership interest in NOARK Pipeline System, Limited Partnership (NOARK) to Atlas Pipeline Partners, L.P. for $69.0 million and recognized a pre-tax gain of approximately $10.9 million ($6.7 million after tax) in the second quarter relating to the transaction. We recorded pre-tax income from operations related to our investment in NOARK of $0.9 million in 2006, compared to $0.4 million for the first nine months of 2005. Income from operations and the gain on the sale in the second quarter of 2006 were recorded in other income in our statements of operations.

Other Revenues

Other revenues for the first nine months of 2006 and 2005 included pre-tax gains of $1.9 million and $2.1 million, respectively, related to the sale of gas in storage inventory.

Interest Expense and Interest Income

Interest costs, net of capitalization, declined to $0.2 million and $0.5 million for the third quarter and the first nine months of 2006, respectively, due to decreased debt levels resulting from our equity offering in September 2005 and an increase in the level of capitalized interest. Interest capitalized increased to $8.2 million in the first nine months of 2006, as compared to $3.3 million for the same period in 2005. The increase in capitalized interest is primarily due to the level of investment in unevaluated properties and the capitalization of interest during the construction phase of our drilling rigs in our E&P segment. Costs excluded from amortization in the E&P segment increased to $169.7 million at September 30, 2006, compared to $107.6 million at September 30, 2005.

During the third quarter and first nine months of 2006, we earned interest income of $1.3 million and $6.1 million, respectively, related to our cash equivalents. This amount is recorded in other income.

Income Taxes

In 2006, the state of Texas enacted legislation to replace its method of taxing businesses from a capital based tax to a tax on modified gross revenue. Although this change in taxation methods is not effective until the year 2007, the provisions of SFAS 109, "Accounting for Income Taxes," requires us to record in the period of enactment the impact that this change has on our liability for deferred taxes. As a result, we recorded additional income tax expense of $1.8 million, net of federal income tax effect, in the second quarter of 2006. This one-time adjustment increased our effective tax rate to approximately 38% for the first nine months of 2006. Other than the change resulting from Texas taxes discussed above, the changes in the provision for deferred income taxes recorded each period result primarily from the level of income before income taxes, adjusted for permanent differences.

Pension Expense

We recorded expenses of $1.0 million and $3.0 million in the third quarter and first nine months of 2006, respectively, for our pension and other postretirement benefit plans, compared to $0.7 million and $2.0 million for same periods of 2005. The amount of pension expense recorded is determined by actuarial calculations and is also impacted by the funded status of our plans. We currently expect to contribute $3.8 million to our pension and other postretirement plans in 2006. As of September 30, 2006, $3.4 million has been contributed to our pension plans and $0.3 million has been contributed to our other postretirement plans. For further information regarding our pension plans, we refer you to Note 10 of the financial statements in this Form 10-Q.

Stock-Based Compensation

As of January 1, 2006, we adopted Statement of Financial Accounting Standards No.123(R), Share-Based Payment, (FAS 123(R)), which requires companies to recognize in the statement of operations the grant-date fair value of stock awards issued to employees and directors. We adopted FAS 123(R) using the modified prospective transition method. In accordance with the modified prospective transition method, our consolidated financial statements for prior periods have not been restated to reflect the impact of FAS 123(R). As a result of applying FAS 123(R), we recognized an expense of $4.0 million and capitalized $1.3 million to the full cost pool for the first nine months of 2006. In the first nine months of 2005, we expensed $1.1 million and capitalized $0.8 million for the amortization of restricted stock grants. We refer you to Note 9 of the financial statements in this Form 10-Q for additional discussion of our equity based compensation plans and our adoption of FAS 123(R).

LIQUIDITY AND CAPITAL RESOURCES

We depend on internally-generated funds, our unsecured revolving credit facility (discussed below under "Financing Requirements") and funds accessed through public debt and equity markets as our primary sources of liquidity. We may borrow up to $500 million under our revolving credit facility from time to time. As of September 30, 2006, and December 31, 2005, we had no indebtedness outstanding under our revolving credit facility. During the fourth quarter of 2006, we expect to draw on a portion of the funds available under our credit facility to fund our planned capital expenditures (discussed below under "Capital Expenditures"), which are expected to exceed the net cash generated by our operations and cash equivalents.

Net cash provided by operating activities increased 53% to $331.1 million in the first nine months of 2006 due mainly to increased net income, adjusted for increased depreciation, depletion and amortization expense and increased deferred income taxes generated by our E&P segment. For the first nine months of 2006, requirements for capital expenditures were met primarily by cash provided by operating activities, cash equivalents, and $69.0 million of proceeds from the sale of our investment in NOARK.

At September 30, 2006, our capital structure consisted of 9% debt and 91% equity. We believe that our operating cash flow and borrowings under our credit facility will be adequate to meet our capital and operating requirements for the remainder of 2006.

Our cash flow from operating activities is highly dependent upon market prices that we receive for our gas and oil production. The price received for our production is also influenced by our commodity hedging activities, as more fully discussed in Note 5 to the financial statements included in this Form 10-Q and Item 3, "Quantitative and Qualitative Disclosures about Market Risks." Natural gas and oil prices are subject to wide fluctuations. As a result, we are unable to forecast with certainty our future level of cash flow from operations. We adjust our discretionary uses of cash dependent upon cash flow available.

Capital Investments

Our capital investments increased 85% to $632.1 million (including $26.8 million relating to accrued expenditures) for the first nine months of 2006 as compared to the same period last year, of which $577.9 million was invested in our E&P segment. We have increased our projected capital investments for 2006 to $925.0 million, up approximately

11% from the $830.1 million capital program announced in December of 2005. The increased amount includes projected capital expenditures of $865.0 million for our E&P segment, up from $770.3 million. The increase is attributable to our Fayetteville Shale play and is primarily related to changes during the year in our fracture stimulation practices, higher service costs, increased outside-operated activity and costs related to previously disclosed purchases of land drilling rigs.

Our capital investment program for the remainder of 2006 is expected to be funded through cash flow from operations and borrowings under our revolving credit facility. We may adjust our level of 2006 capital investments dependent upon our level of cash flow generated from operations and our ability to borrow under our credit facility.

Financing Requirements

Our total debt outstanding was $138.4 million at September 30, 2006, (including $38.4 million of remaining debt assumed in connection with the sale of our investment in NOARK) and was $100.0 million at December 31, 2005. We have a $500 million revolving credit facility that expires in January 2010. At September 30, 2006, and December 31, 2005, we had no outstanding debt under our revolving credit facility. The interest rate on the facility is calculated based on our public debt rating. Our publicly traded notes were downgraded on August 1, 2006, by Standard and Poor's to BB+ with a stable outlook from BBB- with a negative outlook. Although we are rated Ba2 by Moody's, on September 19, 2006, our publicly traded notes were rated Ba3 by Moody's under Moody's Loss Given Default Assessment. This downgrade increases the costs of funds under our revolving credit facility by 25 basis points, which would make our current interest rate 150 basis points over LIBOR. Any future downgrades in our public debt ratings could increase our cost of funds under the credit facility. We do not expect our current ratings to impact our ability to obtain acceptable financing terms if we elect to access the public debt market in the future.

Our revolving credit facility contains covenants which impose certain restrictions on us. Under the credit agreement, we may not issue total debt in excess of 60% of our total capital, must maintain a certain level of shareholders equity and must maintain a ratio of EBITDA to interest expense of 3.5 or above. Additionally, there are certain limitations on the amount of indebtedness that may be incurred by our subsidiaries. We were in compliance with all of the covenants of our credit agreement at September 30, 2006. Although we do not anticipate any violations of our financial covenants, our ability to comply with those covenants is dependent upon the success of our exploration and development program and upon factors beyond our control, such as the market prices for natural gas and oil. If we are unable to borrow under our credit facility, we would have to decrease our capital expenditure plans.

At September 30, 2006, our capital structure consisted of 9% debt and 91% equity. Shareholders equity in the September 30, 2006, balance sheet includes an accumulated other comprehensive gain of $23.3 million related to our hedging activities that is required to be recorded under the provisions of SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities (FAS 133). This amount is based on current market values of our hedges at September 30, 2006, and does not necessarily reflect the value that we will receive or pay when the hedges ultimately are settled, nor does it take into account revenues to be received associated with the physical delivery of sales volumes hedged. Our credit facility s financial covenants with respect to capitalization percentages exclude the effects of non-cash entries that result from FAS 133 as well as the non-cash impact of any full cost ceiling write-downs. Our capital structure at September 30, 2006 would remain unchanged at 9% debt and 91% equity without consideration of the accumulated other comprehensive gain related to FAS 133 of $23.3 million.

As part of our strategy to ensure a certain level of cash flow to fund our operations, we have hedged approximately 70% to 75% of our expected 2006 gas production and 15% to 20% of our expected 2006 oil production. The amount of long-term debt we incur will be dependent upon commodity prices and our capital expenditure plans. If commodity prices remain at or near their current levels throughout the remainder of 2006 and our capital expenditure plans do not further change, we will increase our long-term debt in 2006. If commodity prices significantly decrease, we may decrease and/or reallocate our planned capital expenditures.

Off-Balance Sheet Arrangements

On May 2, 2006, we sold our 25% partnership interest in NOARK to Atlas Pipeline Partners, L.P., for $69.0 million. As part of the transaction, we assumed and recorded $39.0 million of debt obligations of NOARK Pipeline Finance, L.L.C., which we had previously guaranteed as part of the financing of NOARK. We did not advance funds to NOARK in 2005 or in the first nine months of 2006, and we did not derive any liquidity, capital resources, market risk support or credit risk support from our investment in NOARK.

Our share of the results of operations included in other income related to our NOARK investment was pre-tax income of $0.9 million and $0.4 million for the first nine months of 2006 and 2005, respectively. The increase in pre-tax income in 2006 was primarily due to increased throughput and higher average rates charged to customers.

Contractual Obligations and Contingent Liabilities and Commitments

We have various contractual obligations in the normal course of our operations and financing activities. Significant contractual obligations at September 30, 2006, were as follows:

***Contractual Obligations*:**

	Payments Due by Period				
	Total	Less than 1 Year	1 to 3 Years	3 to 5 Years	More than 5 Years
	(in thousands)				
Debt [1]	$ 138,400	$ 1,200	$ 62,400	$ 2,400	$ 72,400
Interest on senior notes [2]	70,361	9,954	18,215	10,616	31,576
Operating leases [3]	21,261	4,537	8,055	5,292	3,377
Unconditional purchase obligations [4]	-	-	-	-	-
Operating agreements [5]	118,765	52,298	57,731	8,736	-
Rental compression [6]	74,598	14,144	31,985	24,661	3,808
Demand charges [7]	129,798	20,291	44,006	31,171	34,330
Drilling rigs [8]	33,866	33,866	-	-	-
Other obligations [9]	17,604	17,299	305	-	-
	$ 604,653	$ 153,589	$ 222,697	$ 82,876	$ 145,491

[1] Debt includes $38.4 million of 7.15% Notes due 2018 and requires semi-annual principal payments of $0.6 million.

(2) Interest on the senior notes includes interest through 2009 on the $60 million notes that are due in 2027 and putable at the holder s option in 2009.

(3) We lease certain office space and equipment under non-cancelable operating leases expiring through 2013.

(4) Our Natural Gas Distribution segment has volumetric commitments for the purchase of gas under non-cancelable competitive bid packages and non-cancelable wellhead contracts. Volumetric purchase commitments at September 30, 2006, totaled 0.7 Bcf, comprised of 0.4 Bcf in less than one year, 0.2 Bcf in one to three years and 0.1 Bcf in three to five years. Our volumetric purchase commitments are priced primarily at regional gas indices set at the first of each future month. These costs are recoverable from the utility's end-use customers.

(5) Our E&P segment has commitments for up to $112.8 million in termination fees related to rig operator agreements and up to $6.0 million in termination fees related to rig servicing agreements in the event that the agreements are terminated.

(6) Our E&P and Midstream Services segments have commitments for approximately $74.6 million of compressor rental fees associated primarily with our Overton operations and our Fayetteville Shale play.

(7) Our Natural Gas Distribution segment has commitments for approximately $83.6 million of demand charges on non-cancelable firm gas purchase and firm transportation agreements. These costs are recoverable from the utility's end-use customers. Our E&P segment has commitments for

approximately $2.6 million of demand transportation charges and our Midstream Services segment has commitments for approximately $43.6 million of demand transportation charges.

(8) Our E&P segment has commitments related to the purchase of the remaining five drilling rigs of the fifteen expected to be delivered in 2006 for approximately $33.9 million, including ancillary equipment.

(9) Our other significant contractual obligations include approximately $15.4 million related to seismic services, approximately $1.0 million in land leases and approximately $1.0 million for various information technology support and data subscription agreements.

In 2005, the Company entered into agreements to fabricate ten new land drilling rigs. In the first nine months of 2006, the Company entered into agreements to fabricate two surface rigs, and three additional land drilling rigs. Including change orders, ancillary equipment and supplies, the total cost of these fifteen rigs is approximately $139.4 million. As of September 30, 2006, payments made under these agreements were $105.5 million. Ten of the fifteen drillings rigs have been delivered to date and are in service.

Subsequent to September 30, 2006, one of our Midstream Services subsidiaries entered into a master lease agreement relating to compressor units. The units will be leased under either 84-month or 120-month terms at our discretion and are expected to be delivered from February 2007 to December 2007. Monthly lease payments will be indexed to the lender s cost of funds, and assuming current interest rates, the total estimated commitment for this agreement is $14.7 million. We have guaranteed our subsidiary s obligations under the lease up to an aggregate amount of $20.0 million.

Contingent Liabilities and Commitments

Substantially all of our employees are covered by defined benefit and postretirement benefit plans. As a result of actuarial data, we expect to record expenses of $4.0 million in 2006 for these plans, of which $3.0 million has been recorded in the first nine months of 2006. At September 30, 2006, we recorded an accrued pension benefit liability of $7.1 million. For further information regarding our pension and other postretirement benefit plans, we refer you to Note 10 of the financial statements in this Form 10-Q.

We are subject to litigation and claims that arise in the ordinary course of business. Management believes, individually or in aggregate, such litigation and claims will not have a material adverse impact on our financial position or our results of operations, but these matters are subject to inherent uncertainties and management's view may change in the future. If an unfavorable final outcome were to occur, there exists the possibility of a material impact on our financial position and the results of operations for the period in which the effect becomes reasonably estimable. A lawsuit was filed against us in 2001 alleging a breach of an agreement to indemnify the other party against settlement payments related to the Company's Boure' prospect in Louisiana. The allegations were contested, and in 2002, we were granted a motion for summary judgment by the trial court. The case was appealed to the First Court of Appeals in Houston, Texas, which subsequently transferred the appeal to the Thirteenth Court of Appeals in Corpus Christi. The appeal was briefed and argued during 2003. On April 14, 2005, the Thirteenth Court of Appeals reversed the orders of the trial court and rendered judgment denying our motion for summary judgment and granting the motion for summary judgment of the other party. Our motion for rehearing with the Thirteenth Court of Appeals was denied on May 19, 2005. In August of 2005, we filed a petition for review with the Texas Supreme Court. In October of 2005, the Texas

Supreme Court invited additional briefing by the parties. In March of 2006, the Texas Supreme Court requested that both parties submit full briefs on the merits of the case. The matter is currently pending before the Texas Supreme Court. Should the other party prevail on the appeal, we could be required to pay approximately $2.1 million, plus pre-judgment interest and attorney's fees. Based on an assessment of this litigation by us and our legal counsel, no accrual for loss is currently recorded.

Working Capital

We maintain access to funds that may be needed to meet capital requirements through our credit facility described above. We had negative working capital of $11.0 million at September 30, 2006, and positive working capital of $158.7 million at December 31, 2005. Current assets at September 30, 2006, included $52.7 million of remaining proceeds from our 2005 equity offering that is invested in cash equivalents, compared to $222.4 million of cash equivalents at December 31, 2005. Current liabilities decreased $44.6 million, due primarily to a decrease in our current hedging liability at September 30, 2006.

Gas in Underground Storage

We record our gas stored in inventory that is owned by the E&P segment at the lower of weighted average cost or market. Gas expected to be cycled within the next 12 months is recorded in current assets with the remaining stored gas reflected as a long-term asset. The quantity and average cost of gas in storage was 9.6 Bcf at $3.96 at September 30, 2006, and 8.5 Bcf at $3.78 at December 31, 2005.

The gas in inventory for the E&P segment is used primarily to supplement field production in meeting the segment's contractual commitments including delivery to customers of our natural gas distribution business, especially during periods of colder weather. As a result, demand fees paid by the Natural Gas Distribution segment to the E&P segment, which are passed through to the utility's customers, are a part of the realized price of the gas in storage. In determining the lower of cost or market for storage gas, we utilize the gas futures market in assessing the price we expect to be able to realize for our gas in inventory. A significant decline in the future market price of natural gas could result in a write down of our gas in storage carrying cost.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market risks relating to our operations result primarily from the volatility in commodity prices, basis differentials and interest rates, as well as credit risk concentrations. We use natural gas and crude oil swap agreements and options and interest rate swaps to reduce the volatility of earnings and cash flow due to fluctuations in the prices of natural gas and oil and in interest rates. Our Board of Directors has approved risk management policies and procedures to utilize financial products for the reduction of defined commodity price and interest rate risks. These policies prohibit speculation with derivatives and limit swap agreements to counterparties with appropriate credit standings.

Credit Risk

Our financial instruments that are exposed to concentrations of credit risk consist primarily of trade receivables and derivative contracts associated with commodities trading. Concentrations of credit risk with respect to receivables are limited due to the large number of our customers and their dispersion across geographic areas. No single customer accounts for greater than 3% of accounts receivable at September 30, 2006. In addition, please see the discussion of credit risk associated with commodities trading below.

Interest Rate Risk

At September 30, 2006, we had $138.4 million of debt with an average fixed interest rate of 7.37%. Our $500 million revolving credit facility has a floating interest rate, and at September 30, 2006, we had no borrowings outstanding under the facility. Our policy is to manage interest rates through use of a combination of fixed and floating rate debt. Interest rate swaps may be used to adjust interest rate exposures when appropriate. We do not have any interest rate swaps in effect currently.

Commodities Risk

We use over-the-counter natural gas and crude oil swap agreements and options to hedge sales of our production, to hedge activity in our marketing segment, and to hedge the purchase of gas in our utility segment against the inherent price risks of adverse price fluctuations or locational pricing differences between a published index and the NYMEX futures market. These swaps and options include (1) transactions in which one party will pay a fixed price (or variable price) for a notional quantity in exchange for receiving a variable price (or fixed price) based on a published index (referred to as price swaps), (2) transactions in which parties agree to pay a price based on two different indices (referred to as basis swaps), and (3) the purchase and sale of index-related puts and calls (collars) that provide a "floor" price below which the counterparty pays (production hedge) or receives (gas purchase hedge) funds equal to the amount by which the price of the commodity is below the contracted floor, and a "ceiling" price above which we pay to (production hedge) or receive from (gas purchase hedge) the counterparty the amount by which the price of the commodity is above the contracted ceiling.

The primary market risks related to our derivative contracts are the volatility in market prices and basis differentials for natural gas and crude oil. However, the market price risk is offset by the gain or loss recognized upon the related sale or purchase of the natural gas or sale of the oil that is hedged. Credit risk relates to the risk of loss as a result of non-performance by our counterparties. The counterparties are primarily major investment and commercial banks that management believes present minimal credit risks. The credit quality of each counterparty and the level of financial exposure we have to each counterparty are periodically reviewed to limit our credit risk exposure.

The following table provides information about our financial instruments that are sensitive to changes in commodity prices and that are used to hedge prices for our gas and oil production, gas purchases and marketing activities. The table presents the notional amount in Bcf (billion cubic feet) and MBbls (thousand barrels), the weighted average contract prices, and the fair value by expected maturity dates. At September 30, 2006, the fair value of these financial instruments was a $34.2 million asset.

Production and Marketing

	Weighted Average Price to be Swapped Volume	Weighted Weighted Average Floor Price ($)	Weighted Average Ceiling Price ($)	Average Basis Differential ($)	Fair Value at Sept 30, 2006 ($)	($ in millions)
Natural Gas (Bcf):						
Fixed Price Swaps:						
2006	1.7	7.07	-	-	-	1.5
2007	22.3	7.64	-	-	-	1.6
2008	8.0	8.96	-	-	-	7.0
Floating Price Swaps:						
2006	0.3	(7.90)	-	-	-	(0.7)
2007	0.1	(9.54)	-	-	-	(0.1)
2008	-	-	-	-	-	-
Costless Collars:						
2006	11.5	-	5.41	9.21	-	5.6
2007	34.0	-	6.93	12.34	-	12.7
2008	14.0	-	7.95	15.04	-	11.4
Basis Swaps:						
2006	5.9	-	-	-	(0.42)	0.1
2007	20.1	-	-	-	(0.59)	(3.2)
2008	11.1	-	-	-	(0.48)	1.5
Matched-Basis Swaps:						
2006	4.1	-	-	-	(0.41)	0.3
2007	32.4	-	-	-	(0.47)	1.8
2008	8.0	-	-	-	(0.73)	0.5
Regulatory Swaps:						
2006	1.0	(9.14)	-	-	-	(2.1)
2007	1.5	(9.76)	-	-	-	(2.9)
2008	-	-	-	-	-	-
Oil (MBbls):						
Fixed Price Swaps:						
2006	30.0	37.30	-	-	-	(0.8)
2007	-	-	-	-	-	-
2008	-	-	-	-	-	-

At December 31, 2005, we had outstanding natural gas price swaps on total notional volumes of 7.9 Bcf at a weighted average price per Mcf of $6.64 in 2006 and 12.0 Bcf at a weighted average price per Mcf of $6.66 in 2007. Outstanding oil price swaps at December 31, 2005, on 120 MBbls are yielding us an average price of $37.30 per barrel during 2006. At December 31, 2005, our utility had outstanding natural gas price swaps on total notional gas purchase volumes of 1.8 Bcf in 2006 for which it paid an average fixed price of $12.71 per Mcf.

At December 31, 2005, we had collars in place on 43.0 Bcf in 2006, 28.0 Bcf in 2007 and 2.0 Bcf in 2008 of our expected gas production. The 43.0 Bcf in 2006 has a weighted average floor and ceiling price of $5.47 and $10.13 per Mcf, respectively. The 28.0 Bcf in 2007 has a weighted average floor and ceiling price of $6.64 and $11.91 per Mcf, respectively. The 2.0 Bcf in 2008 has a weighted average floor and ceiling price of $8.00 and $19.40 per Mcf, respectively.

ITEM 4. CONTROLS AND PROCEDURES

We have performed an evaluation under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of our disclosure controls and procedures, as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934, as amended (the Exchange Act). Our disclosure controls and procedures are the controls and other procedures that we have designed to ensure that we record, process, accumulate and communicate information to our management, including our Chief Executive Officer and Chief Financial Officer, to allow timely decisions regarding required disclosures and submissions within the time periods specified in the SEC's rules and forms. All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those determined to be effective can provide only a reasonable assurance with respect to financial statement preparation and presentation. Based on the evaluation, our management, including our Chief Executive Officer and Chief Financial Officer, concluded that our disclosure controls and procedures were effective as of September 30, 2006. There were no changes in our internal control over financial reporting during the three months ended September 30, 2006, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II

OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS.

We are subject to litigation and claims that have arisen in the ordinary course of business. Management believes, individually or in aggregate, such litigation and claims will not have a material adverse impact on our financial position or our results of operations but these matters are subject to inherent uncertainties and management's view may change in the future. If an unfavorable final outcome were to occur, there exists the possibility of a material impact on our financial position and the results of operations for the period in which the effect becomes reasonably estimable. We accrue for such items when a liability is both probable and the amount can be reasonably estimated.

A lawsuit was filed against us in 2001 alleging a breach of an agreement to indemnify the other party against settlement payments related to our Boure' prospect in Louisiana. The allegations were contested, and in 2002, we were granted a motion for summary judgment by the trial court. The case was appealed to the First Court of Appeals in Houston, Texas, which subsequently transferred the appeal to the Thirteenth Court of Appeals in Corpus Christi. The appeal was briefed and argued during 2003. On April 14, 2005, the Thirteenth Court of Appeals reversed the orders of the trial court and rendered judgment denying our motion for summary judgment and granting the motion for summary judgment of the other party. Our motion for rehearing with the Thirteenth Court of Appeals was denied on May 19, 2005. In August of 2005, we filed a petition for review with the Texas Supreme Court. In October of 2005, the

Texas Supreme Court invited additional briefing by the parties. In March of 2006, the Texas Supreme Court requested that both parties submit full briefs on the merits of the case. Should the other party prevail on the appeal, we could be required to pay approximately $2.1 million, plus pre-judgment interest and attorney's fees. Based on an assessment of this litigation by us and our legal counsel, no accrual for loss is currently recorded.

ITEM 1A. RISK FACTORS.

The following revised risk factors amend and supplement the Company's risk factors as disclosed in Item 1A of Part I of the Company's 2005 Annual Report on Form 10-K, as supplemented by the risk factor included in Item 1A of the Company s Form 10-Q for the period ended June 30, 2006:

Our drilling plans for the Fayetteville Shale play are subject to change.

The wells we have drilled in the Fayetteville Shale play through September 30, 2006 are located in areas that represent a relatively small sample of our large acreage position. Our drilling plans with respect to our Fayetteville Shale play are flexible and are dependent upon a number of factors, including the extent to which we can replicate the results of our most successful Fayetteville Shale wells on our other Fayetteville Shale acreage as well as the natural gas and oil commodity price environment. The determination as to whether we continue to drill prospects in the Fayetteville Shale may depend on any one or more of the following factors:

-

The economic viability of, and our success in drilling, our large acreage position overall as well as relative to other productive shale gas plays;

-

our ability to determine the most effective and economic fracture stimulation for the Fayetteville Shale formation;

-

the costs and availability of oil field personnel services, supplies, raw materials, and equipment, including pressure pumping equipment and crews in the Arkoma basin;

-

our ability to reduce and/or limit our exposure to costs and drilling risks;

-

the extent to which we are able to effectively operate the drillings rigs we acquire;

-

receipt of additional seismic or other geologic data or reprocessing of existing data; or

-

availability and cost of capital.

We continue to gather data about our prospects in the Fayetteville Shale, and it is possible that additional information may cause us to alter our drilling schedule or determine that prospects in some portion of our acreage position should not be pursued at all.

Shortages of oil field equipment, services and qualified personnel could adversely affect our results of operations, particularly with respect to our Fayetteville Shale play.

The demand for qualified and experienced field personnel to drill wells and conduct field operations, geologists, geophysicists, engineers and other professionals in the natural gas and oil industry can fluctuate significantly, often in correlation with natural gas and oil prices, causing periodic shortages. Shortages are also experienced when a geographic region with a limited history of oil and natural gas

exploration and production activities, like our Fayetteville Shale play, experiences a rapid increase in activity over a short period of time. We have experienced shortages of drilling rigs, stimulation crews, other equipment and services in our Fayetteville Shale play as we have increased the number of wells drilled by us. These factors can also cause significant increases in costs for equipment, services and personnel. Higher natural gas and oil prices generally stimulate increased demand and result in increased prices for drilling rigs, crews and associated supplies, equipment and services. We cannot be certain when we will experience shortages or price increases, which could adversely affect our profit margin, cash flow and operating results or restrict our ability to drill wells and conduct ordinary operations.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS.

Not applicable.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES.

Not applicable.

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

Not applicable.

ITEM 5. OTHER INFORMATION.

Not applicable.

ITEM 6. EXHIBITS.

(10.1)	Project Services Agreement by and between SEECO, Inc. and Schlumberger Technology Corporation dated as of August 17, 2006.
(31.1)	Certification of CEO filed pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
(31.2)	Certification of CFO filed pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
(32.1)	Certification of CEO and CFO furnished pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

Signatures

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

SOUTHWESTERN ENERGY COMPANY
Registrant

Dated: October 23, 2006 /s/ GREG D. KERLEY

Greg D. Kerley
Executive Vice President
and Chief Financial Officer