Rosetta Resources Inc.
Form 10-Q
August 08, 2011
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

x **Quarterly Report Pursuant To Section 13 or 15(d) of the Securities Exchange Act of 1934**
For The Quarterly Period Ended June 30, 2011

OR

¨ **Transition Report Pursuant To Section 13 or 15(d) of the Securities Exchange Act of 1934**
Commission File Number: 000-51801

ROSETTA RESOURCES INC.

(Exact name of registrant as specified in its charter)

Delaware	**43-2083519**
(State or other jurisdiction of	**(I.R.S. Employer**
incorporation or organization)	**Identification No.)**
717 Texas, Suite 2800, Houston, TX	**77002**
(Address of principal executive offices)	**(Zip Code)**

(Registrant s telephone number, including area code) (713) 335-4000

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ¨ No ¨

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See definitions of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Securities Exchange Act of 1934.

Large accelerated filer x	Accelerated filer ¨
Non-Accelerated filer ¨ (Do not check if a smaller reporting company)	Smaller Reporting Company ¨

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Securities Exchange Act of 1934). Yes ¨ No x

The number of shares of the registrant s Common Stock, $.001 par value per share, outstanding as of August 2, 2011 was 53,026,115.

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PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

Rosetta Resources Inc.

Consolidated Balance Sheet

(In thousands, except par value and share amounts)

	June 30, 2011 (Unaudited)	December 31, 2010
Assets		
Current assets:		
Cash and cash equivalents	$ 134,678	$ 41,634
Accounts receivable, net	55,741	44,028
Derivative instruments	892	19,145
Prepaid expenses	4,072	2,711
Other current assets	5,172	5,454
Total current assets	200,555	112,972
Oil and natural gas properties, full cost method, of which $96,590 thousand at June 30, 2011 and $91,148 thousand at December 31, 2010 were excluded from amortization	2,194,589	2,262,161
Other fixed assets	15,473	14,459
	2,210,062	2,276,620
Accumulated depreciation, depletion, and amortization, including impairment	(1,603,665)	(1,546,631)
Total property and equipment, net	606,397	729,989
Deferred loan fees	9,535	7,652
Deferred tax asset	128,805	142,710
Derivative instruments		1,523
Other assets	2,516	2,463
Total other assets	140,856	154,348
Total assets	$ 947,808	$ 997,309
Liabilities and Stockholders Equity		
Current liabilities:		
Accounts payable	$ 2,603	$ 3,669
Accrued liabilities	95,604	57,006
Royalties payable	24,599	14,542
Derivative instruments	621	
Prepayment on gas sales	5,994	7,869
Deferred income taxes	490	7,132
Total current liabilities	129,911	90,218
Long-term liabilities:		

Derivative instruments	10,883	1,011
Long-term debt	250,000	350,000
Other long-term liabilities	10,157	27,264
Total liabilities	400,951	468,493
Commitments and Contingencies (Note 9)		
Stockholders equity:		
Preferred stock, $0.001 par value; authorized 5,000,000 shares; no shares issued in 2011 or 2010		
Common stock, $0.001 par value; authorized 150,000,000 shares; issued 52,462,590 shares and 52,031,004 shares at June 30, 2011 and December 31, 2010, respectively	52	52
Additional paid-in capital	798,935	793,293
Treasury stock, at cost; 440,998 and 343,093 shares at June 30, 2011 and December 31, 2010, respectively	(10,884)	(6,896)
Accumulated other comprehensive (loss) income	(8,751)	11,259
Accumulated deficit	(232,495)	(268,892)
Total stockholders equity	546,857	528,816
Total liabilities and stockholders equity	$ 947,808	$ 997,309

The accompanying notes to the financial statements are an integral part hereof.

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Rosetta Resources Inc.

Consolidated Statement of Operations

(In thousands, except per share amounts)

(Unaudited)

	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
Revenues:				
Natural gas sales	$ 46,457	$ 47,491	$ 96,237	$ 103,298
Oil sales	34,312	10,773	63,061	17,756
NGL sales	30,788	10,358	49,330	17,716
Total revenues	111,557	68,622	208,628	138,770
Operating costs and expenses:				
Lease operating expense	9,010	13,310	23,530	27,987
Depreciation, depletion, and amortization	33,355	25,719	67,384	49,533
Treating, transportation and marketing	4,875	1,406	8,326	2,887
Production taxes	2,973	1,085	4,629	3,375
General and administrative costs	16,307	11,326	37,377	23,133
Total operating costs and expenses	66,520	52,846	141,246	106,915
Operating income	45,037	15,776	67,382	31,855
Other (income) expense:				
Interest expense, net of interest capitalized	5,066	9,100	11,412	13,846
Interest (income)	(5)	(8)	(33)	(19)
Other expense (income), net	381	(595)	654	(798)
Total other expense	5,442	8,497	12,033	13,029
Income before provision for income taxes	39,595	7,279	55,349	18,826
Income tax expense	14,195	2,967	18,952	7,251
Net income	$ 25,400	$ 4,312	$ 36,397	$ 11,575
Earnings per share:				
Basic	$ 0.49	$ 0.08	$ 0.70	$ 0.23
Diluted	$ 0.48	$ 0.08	$ 0.69	$ 0.22
Weighted average shares outstanding:				
Basic	51,991	51,355	51,923	51,287
Diluted	52,581	52,056	52,567	52,013

The accompanying notes to the financial statements are an integral part hereof.

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Rosetta Resources Inc.

Consolidated Statement of Cash Flows

(In thousands)

(Unaudited)

	Six Months Ended June 30, 2011	2010
Cash flows from operating activities		
Net income	$ 36,397	$ 11,575
Adjustments to reconcile net income to net cash from operating activities:		
Depreciation, depletion and amortization	67,384	49,533
Deferred income taxes	18,829	7,030
Amortization of deferred loan fees recorded as interest expense	1,232	2,296
Amortization of original issue discount recorded as interest expense		1,258
Stock compensation expense	16,132	4,628
Commodity derivative (income) expense	(6,234)	
Change in operating assets and liabilities:		
Accounts receivable	(11,713)	3,001
Prepaid expenses	(1,335)	(1,535)
Other current assets	282	(9)
Other assets	(52)	(293)
Accounts payable	(1,066)	1,904
Accrued liabilities	(2,502)	2,516
Royalties payable	8,182	(6,089)
Derivative instruments	4,928	
Net cash provided by operating activities	130,464	75,815
Cash flows from investing activities		
Acquisitions of oil and gas properties		(5,850)
Additions of oil and gas assets	(175,030)	(151,037)
Disposals of oil and gas properties and assets	242,910	11,885
Net cash provided by (used in) investing activities	67,880	(145,002)
Cash flows from financing activities		
Payments on Restated Term Loan		(80,000)
Borrowings on Restated Revolver		25,000
Payments on Restated Revolver	(100,000)	(114,000)
Issuance of Senior Notes		200,000
Deferred loan fees	(3,141)	(6,051)
Proceeds from stock options exercised	1,829	1,786
Purchases of treasury stock	(3,988)	(1,946)
Net cash (used in) provided by financing activities	(105,300)	24,789
Net increase (decrease) in cash	93,044	(44,398)
Cash and cash equivalents, beginning of period	41,634	61,256
Cash and cash equivalents, end of period	$ 134,678	$ 16,858

Supplemental disclosures:		
Capital expenditures included in accrued liabilities	$ 52,774	$ 27,170

The accompanying notes to the financial statements are an integral part hereof.

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Rosetta Resources Inc.

Notes to Consolidated Financial Statements (unaudited)

(1) Organization and Operations of the Company

Nature of Operations. Rosetta Resources Inc. (together with its consolidated subsidiaries, the Company) is an independent oil and gas company engaged in onshore oil and natural gas exploration, development, production and acquisition activities in the United States of America. The Company s operations are concentrated in South Texas, primarily in the Eagle Ford shale, and in the Southern Alberta Basin in northwest Montana.

These interim financial statements have not been audited. However, in the opinion of management, all adjustments, consisting of only normal recurring adjustments necessary to fairly state the financial statements, have been included. Results of operations for interim periods are not necessarily indicative of the results of operations that may be expected for the entire year. In addition, these financial statements have been prepared in accordance with the instructions to Form 10-Q and, therefore, do not include all disclosures required for financial statements prepared in conformity with accounting principles generally accepted in the United States of America. These financial statements and notes should be read in conjunction with the Company s audited Consolidated Financial Statements and the notes thereto included in the Company s Annual Report on Form 10-K for the year ended December 31, 2010 (2010 Annual Report).

Certain reclassifications of prior year balances have been made to conform them to the current year presentation. These reclassifications have no impact on net income.

(2) Summary of Significant Accounting Policies

The Company has provided a discussion of significant accounting policies, estimates and judgments in its 2010 Annual Report.

Recent Accounting Developments

The following recently issued accounting developments have been applied or may impact the Company in future periods.

Fair Value Measurements. In January 2010, the Financial Accounting Standards Board (FASB) issued authoritative guidance related to improving disclosures about fair value measurements. This guidance requires separate disclosures of the amounts of transfers in and out of Level 1 and Level 2 fair value measurements and a description of the reason for such transfers. In the reconciliation for Level 3 fair value measurements using significant unobservable inputs, information about purchases, sales, issuances and settlements shall be presented separately. These disclosures were required for interim and annual reporting periods effective January 1, 2010, except for the disclosures related to the purchases, sales, issuances and settlements in the roll forward activity of Level 3 fair value measurements, which were effective on January 1, 2011. This guidance requires additional disclosures but did not impact our consolidated financial position, results of operations or cash flows. See Note 5 Fair Value Measurements.

In April 2011, the FASB further expanded authoritative guidance clarifying common requirements for measuring fair value instruments and for disclosing information about fair value measurements in accordance with U.S. generally accepted accounting principles (GAAP) and International Financial Reporting Standards (IFRS). In this guidance, the FASB clarifies that the concept of highest and best use and valuation premise in a fair value measurement is only relevant when measuring the fair value of nonfinancial assets and is not relevant when measuring the fair value of financial assets or liabilities. The FASB also addressed measuring the fair value of an instrument classified in shareholders equity whereby an entity should measure the fair value of its own equity instrument from the perspective of a market participant. In addition, this guidance requires disclosure of quantitative information about unobservable inputs used in measuring the fair value of Level 3 instruments. This guidance will be required for interim and annual reporting periods effective January 1, 2012 and early application is not permitted. This guidance will require additional disclosures but will not impact our consolidated financial position, results of operations or cash flows.

Comprehensive Income. In June 2011, the FASB issued authoritative guidance to increase the prominence of items reported in other comprehensive income. This guidance requires an entity to present the total of comprehensive income, the components of net income and the components of other comprehensive income either in a single continuous statement of comprehensive income or in two separate and consecutive statements. Irrespective of the presentation method chosen, an entity will be required to present on the face of the financial statement reclassification adjustments for items that are reclassified from other comprehensive income to net income in the statement where the component is presented. This guidance will be required for interim and annual reporting periods effective January 1, 2012 and early application is permitted. This guidance will require presentation adjustments to the face of our consolidated financial statements, including historical periods, but will not impact our consolidated financial position, results of operations or cash flows.

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(3) Property and Equipment

The Company s total property and equipment consists of the following:

	June 30, 2011	December 31, 2010
	(In thousands)	
Proved properties	$ 2,075,878	$ 2,124,615
Unproved/unevaluated properties	96,590	91,148
Gas gathering system and compressor stations	22,121	46,398
Other fixed assets	15,473	14,459
Total property and equipment, gross	2,210,062	2,276,620
Less: Accumulated depreciation, depletion, and amortization, including impairment	(1,603,665)	(1,546,631)
Total property and equipment, net	$ 606,397	$ 729,989

On February 22, 2011, the Company executed a purchase and sale agreement for $55.0 million for the divestiture of the DJ Basin assets in Colorado. The sale of these assets closed on March 31, 2011 with an effective date of January 1, 2011 and the agreement was subject to due diligence and post-closing purchase price adjustments. Proceeds from the divestiture were recorded as an adjustment to the full cost pool with no gain or loss recognized.

Subsequently on February 24, 2011, the Company executed a purchase and sale agreement for $200.0 million for the divestiture of the Sacramento Basin assets in California. The sale of these assets initially closed on April 15, 2011 with an effective date of January 1, 2011 and was subject to post-closing purchase price adjustments. Approximately $43.6 million associated with a certain portion of the properties was placed in escrow pending the Company s receipt of appropriate consents for assignment. During the second quarter of 2011, the Company closed on a portion of the properties for which consents were received after the first closing and accordingly received from the escrow account approximately $42.8 million for these properties. On July 27, 2011, the remaining consents for assignment were received or waived and final proceeds of $0.8 million were released from the escrow account and provided to the Company. Proceeds from the divestiture were recorded as an adjustment to the full cost pool with no gain or loss recognized.

The Company capitalizes internal costs directly identified with acquisition, exploration and development activities. The Company capitalized $0.9 million and $2.2 million of internal costs for the three months ended June 30, 2011 and 2010, respectively, and $2.4 million and $3.9 million for the six months ended June 30, 2011 and 2010, respectively.

Oil and gas properties include costs of $96.6 million and $91.1 million as of June 30, 2011 and December 31, 2010, respectively, which were excluded from amortized capitalized costs. These amounts primarily represent acquisition costs of unproved properties and unevaluated exploration projects in which the Company owns a direct interest. The increase from December 31, 2010 to June 30, 2011 is the result of an increase in exploratory drilling costs primarily in the Eagle Ford shale and in the Southern Alberta Basin.

Continued well performance significantly in excess of prior estimates has necessitated a mid-year update to the Company s proved reserves. As of June 30, 2011, the Company had an estimated 969.8 Bcfe of proved reserves, including 458.8 Bcfe of natural gas, 35,900 MBbls of oil and condensate and 49,300 MBbls of NGLs of which 29% is proved developed. These proved reserves represent an increase of 490.5 Bcfe, or 102%, from proved reserves of 479.3 Bcfe at December 31, 2010. During the six months ended June 30, 2011, the Company replaced 28.6 Bcfe of production with 464.1 Bcfe of reserve additions. This increase resulted primarily from an additional 94 proved undeveloped locations (PUDs) in the Gates Ranch area. The Company s divestiture results, operating cash flows and development plans all indicate that these reserves will be developed over the next five years. For further discussion of the Company s mid-year reserve update, see Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations and Part II. Item 5. Other Information of this Form 10-Q.

The quantity of proved reserves is a significant input to the calculated depletion rate (depletion per Mcfe). Holding all other factors constant, an upward revision in the quantity of proved reserves will alter the relationship between the cost of developing reserves and the related reserve quantity and result in a lower depletion rate. Although, this upward revision in reserves did not affect the depletion rate for the three and six months ended June 30, 2011, a reduction in the depletion rate of approximately 20%-25% is anticipated during the second half of 2011.

Pursuant to full cost accounting rules, the Company must perform a ceiling test each quarter on its oil and gas assets within each separate cost center. The Company s ceiling test was calculated using a trailing twelve-month, unweighted-average first-day-of-the-month price, adjusted for hedges, of gas and oil as of June 30, 2011, which were based on a Henry Hub gas price of $4.21 per MMBtu and a West Texas Intermediate oil price of $86.60 per Bbl (adjusted for basis and quality differentials), respectively. Utilizing these prices, the calculated ceiling amount exceeded the net capitalized cost of oil and gas properties. As a result, no write-down was recorded at June 30, 2011. It is possible that a write-down of the Company s oil and gas properties could occur in the future should oil and natural gas prices decline, the Company experiences significant downward adjustments to its estimated proved reserves and/or the Company s commodity hedges settle and are not replaced.

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In 2010, the Company s ceiling test was also calculated using a trailing twelve-month, unweighted-average first-day-of-the-month price, adjusted for hedges, of gas and oil as of June 30, 2010, which were based on a Henry Hub gas price of $4.10 per MMBtu and a West Texas Intermediate oil price of $72.25 per Bbl (adjusted for basis and quality differentials), respectively. Utilizing these prices, the calculated ceiling amount also exceeded the net capitalized cost of oil and gas properties. As a result, no write-down was recorded at June 30, 2010.

(4) Commodity Hedging Contracts and Other Derivatives

The Company is exposed to various market risks, including volatility in oil and gas commodity prices, which are managed through derivative instruments. The level of derivative activity utilized depends on market conditions, operating strategy and available derivative prices. Forward contracts on various commodities are entered into to manage the price risk associated with forecasted sales of the Company s natural gas, oil and NGL production. Interest rate swaps were utilized in 2010 to manage interest rate risk associated with the Company s previous variable-rate borrowings. As these variable-rate borrowings were extinguished in 2010, the Company has not entered into any interest rate swaps during 2011.

The Company utilizes various types of derivative instruments to manage commodity price risk, including fixed price swaps, basis swaps, NYMEX roll swaps and costless collars. Many of these derivative financial instruments qualify for hedge accounting treatment as set forth in the authoritative accounting guidance. However, while the Company s crude oil basis and NYMEX roll swaps meet the objective of managing commodity price exposure; these trades are typically not entered into concurrent with the Company s derivative instruments that qualify as cash flow hedges and therefore do not generally qualify for hedge accounting. As a result, these derivative financial instruments are referred to as non-qualifying.

At June 30, 2011, the following financial fixed price swap, basis swap, NYMEX roll swap and costless collar transactions were outstanding with associated notional volumes and average underlying prices that represent hedged prices of commodities at various market locations:

Product	Settlement Period	Derivative Instrument	Hedge Strategy	Notional Daily Volume MMBtu	Total of Notional Volume MMBtu	Average Floor/Fixed Prices per MMBtu	Average Ceiling Prices per MMBtu	Fair Market Value Asset/(Liability) (In thousands)
Natural gas	2011	Swap	Cash flow	15,000	2,760,000	$ 5.99	$	$ 4,232
Natural gas	2011	Costless Collar	Cash flow	35,000	6,440,000	5.63	7.27	7,746
Natural gas	2012	Costless Collar	Cash flow	20,000	7,320,000	5.13	6.31	4,440
					16,520,000			$ 16,418

Product	Settlement Period	Derivative Instrument	Hedge Strategy	Notional Daily Volume Bbl	Total of Notional Volume Bbl	Average Floor/Fixed Prices per Bbl	Average Ceiling Prices per Bbl	Fair Market Value Asset/(Liability) (In thousands)
Crude oil	2011	Costless Collar	Cash flow	3,400	625,600	$ 75.59	$ 103.29	$ (1,798)
Crude oil	2012	Costless Collar	Cash flow	5,000	1,830,000	75.60	112.56	(5,540)
Crude oil	2013	Costless Collar	Cash flow	3,750	1,368,750	75.00	122.81	(1,715)
					3,824,350			$ (9,053)

Product	Settlement Period	Derivative Instrument	Hedge Strategy	Notional Daily Volume Bbl	Total of Notional Volume Bbl	Average Floor/Fixed Prices per Bbl	Average Ceiling Prices per Bbl	Fair Market Value Asset/(Liability) (In thousands)

Crude oil	May 2012- December 2012	Basis Swap	Non-qualifying	2,500	612,500	$ 8.70	$	$ (2,194)
Crude oil	May 2012- December 2012	NYMEX Roll Swap	Non-qualifying	2,500	612,500	(0.30)		(57)
Crude oil	2013	Basis Swap	Non-qualifying	1,875	684,375	5.80		(2,426)
Crude oil	2013	NYMEX Roll Swap	Non-qualifying	1,875	684,375	(0.18)		(107)
					2,593,750			$ (4,784)

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Product	Settlement Period	Derivative Instrument	Hedge Strategy	Notional Daily Volume Bbl	Total of Notional Volume Bbl	Average Floor/Fixed Prices per Bbl	Average Ceiling Prices per Bbl	Fair Market Value Asset/(Liability) (In thousands)
NGL - Propane	2011	Swap	Cash flow	1,000	184,000	$ 47.98	$	$ (3,292)
NGL - Isobutane	2011	Swap	Cash flow	270	49,680	64.02		(856)
NGL - Normal Butane	2011	Swap	Cash flow	330	60,720	63.79		(801)
NGL - Pentanes Plus	2011	Swap	Cash flow	400	73,600	83.04		(1,409)
NGL - Propane	2012	Swap	Cash flow	1,000	366,000	47.20		(3,746)
NGL - Isobutane	2012	Swap	Cash flow	260	95,160	66.63		(737)
NGL - Normal Butane	2012	Swap	Cash flow	280	102,480	65.30		(638)
NGL - Pentanes Plus	2012	Swap	Cash flow	410	150,060	86.62		(1,714)
					1,081,700			$ (13,193)

The Company s current cash flow hedge and non-qualifying derivative positions are with counterparties who are lenders under the Company s credit facilities. This allows the Company to secure any margin obligation resulting from a negative change in fair market value of the derivative contracts with the collateral securing its credit facilities, thus eliminating the need for independent collateral postings. As of June 30, 2011, the Company had no deposits for collateral in regard to commodity hedge positions.

The following table sets forth the results of derivative settlements for the respective periods as reflected in the Consolidated Statement of Operations:

	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
Natural Gas				
Quantity settled (MMBtu)	4,550,000	2,275,000	9,050,000	4,525,000
Increase in natural gas sales revenue (In thousands) (1) (2)	$ 3,133	$ 5,721	$ 10,404	$ 8,598
Crude Oil				
Quantity settled (Bbl)	309,400		334,200	
Decrease in crude oil sales revenue (In thousands) (3)	$ (5,917)	$	$ (6,238)	$
NGL				
Quantity settled (Bbl)	182,000		245,000	
Decrease in NGL sales revenue (In thousands)	$ (3,039)	$	$ (4,225)	$
Interest Rate Swaps				
(Increase) in interest expense (In thousands)	$	$ (238)	$	$ (490)

(1) For the three months ended June 30, 2011, excludes approximately $8.2 million of realized gain associated with the 2011 termination of derivatives used to hedge production from the Company s divested Sacramento Basin properties.

(2) For the six months ended June 30, 2011, excludes approximately $2.9 million and $8.2 million, respectively, of realized gains associated with the 2011 termination of derivatives used to hedge production from the Company s divested DJ Basin and Sacramento Basin properties.

(3) For the three and six months ended June 30, 2011, includes approximately $4.8 million of unrealized loss associated with the change in fair value of the Company s crude oil basis and NYMEX roll swaps.

As of June 30, 2011, the Company expects to reclassify net gains of $0.3 million from Accumulated other comprehensive income on the Consolidated Balance Sheet to earnings based upon settlement dates in the next twelve months and based upon current forward prices as of June 30, 2011.

Authoritative guidance for derivatives requires companies to recognize all derivative instruments as either assets or liabilities at fair value in the statement of financial position. In accordance with this guidance, the Company designates certain commodity forward contracts as cash flow hedges of forecasted sales of natural gas, oil and NGL production and interest rate swaps as cash flow hedges of interest rate payments due under variable-rate borrowings.

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Additional Disclosures about Derivative Instruments and Hedging Activities

Cash Flow Hedges

For derivative instruments that are designated and qualify as a cash flow hedge, the effective portion of the gain or loss on the derivative is reported as a component of other comprehensive income and reclassified into earnings in the same period or periods during which the hedged transaction affects earnings. Gains and losses on the derivative representing either hedge ineffectiveness or hedge components excluded from the assessment of effectiveness are recognized in current earnings.

Non-Qualifying Hedges

Crude oil basis and NYMEX roll swap derivative instruments that do not qualify as cash flow hedges are recorded on the balance sheet at their fair values under Derivative instruments, as assets and/or liabilities, as applicable, and are marked-to-market each period with the change in fair value representing unrealized gains and losses recognized immediately in the unaudited Consolidated Statement of Operations as a component of Oil sales. These mark-to-market adjustments produce a degree of earnings volatility that can be significant from period to period, but have no cash flow impact relative to changes in market prices. The cash flow impact occurs when the underlying financial instrument contract settlement is made.

As of June 30, 2011, the Company had outstanding natural gas, oil and NGL commodity forward contracts with notional volumes of 16,520,000 MMBtus, 6,418,100 Bbls and 1,081,700 Bbls, respectively, that were entered into to hedge forecasted natural gas, oil and NGL sales.

Information on the location and amounts of derivative fair values in the Consolidated Balance Sheet as of June 30, 2011 and December 31, 2010 and derivative gains and losses in the Consolidated Statement of Operations for the three and six months ended June 30, 2011 and 2010, respectively, is as follows:

Fair Values of Derivative Instruments
Derivative Assets (Liabilities)

	Balance Sheet Location	**Fair Value**	
		June 30, 2011	**December 31, 2010**
		(In thousands)	
Derivatives designated as hedging instruments			
Commodity contracts - natural gas	Derivative instruments - current assets	$ 14,337	$ 24,959
Commodity contracts - natural gas	Derivative instruments - non-current assets		3,614
Commodity contracts - crude oil	Derivative instruments - current assets	(3,304)	(2,696)
Commodity contracts - crude oil	Derivative instruments - non-current assets		(2,207)
Commodity contracts - NGL	Derivative instruments - current assets	(9,515)	(3,118)
Commodity contracts - NGL	Derivative instruments - non-current assets		116
Commodity contracts - natural gas	Derivative instruments - current liabilities		
Commodity contracts - natural gas	Derivative instruments - long-term liabilities	2,081	
Commodity contracts - crude oil	Derivative instruments - current liabilities	(398)	
Commodity contracts - crude oil	Derivative instruments - long-term liabilities	(5,351)	
Commodity contracts - NGL	Derivative instruments - current liabilities	(223)	
Commodity contracts - NGL	Derivative instruments - long-term liabilities	(3,455)	(1,011)
Total derivatives designated as hedging instruments		$ (5,828)	$ 19,657
Derivatives not designated as hedging instruments			
Commodity contracts - crude oil	Derivative instruments - current assets	$ (626)	$
Commodity contracts - crude oil	Derivative instruments - long-term liabilities	(4,158)	
Total derivatives not designated as hedging instruments		$ (4,784)	$

Total derivatives	$ (10,612)	$ 19,657

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Derivatives in Cash Flow Hedging Relationships	Amount Recognized in OCI on Derivative (Effective Portion) Three Months Ended June 30, 2011	June 30, 2010	Six Months Ended June 30, 2011	June 30, 2010
	(In thousands)			
Commodity contracts - natural gas	$ 1,422	$ 1,047	$ 2,078	$ 33,560
Commodity contracts - crude oil	2,833		(15,172)	
Commodity contracts - NGL	(1,032)		(13,405)	
Interest rate swap		15		(248)
Total	$ 3,223	$ 1,062	$ (26,499)	$ 33,312

Location of Gain or (Loss)	Amount Reclassified from Accumulated OCI into Income (Effective Portion) Three Months Ended June 30, 2011	June 30, 2010	Six Months Ended June 30, 2011	June 30, 2010
	(In thousands)			
Natural gas sales	$ 3,133	$ 5,721	$ 10,404	$ 8,598
Crude oil sales	(5,917)		(6,238)	
NGL sales	(3,039)		(4,225)	
Interest expense, net of interest capitalized		(238)		(490)
Total	$ (5,823)	$ 5,483	$ (59)	$ 8,108

Location of Gain or (Loss)	Amount Recognized in Income on Derivatives (Derivatives Not Designated as Cash Flow Hedges, Ineffective Portion of Cash Flow Hedges and Amount Excluded from Effectiveness Testing) Three Months Ended June 30, 2011	June 30, 2010	Six Months Ended June 30, 2011	June 30, 2010
	(In thousands)			
Natural gas sales (1) (2)	$ 8,151	$	$ 11,018	$
Crude oil sales (3)	(4,784)		(4,784)	
NGL sales				
Total	$ 3,367	$	$ 6,234	$

(1) For the three months ended June 30, 2011, this amount represents the realized gain associated with the 2011 termination of derivatives used to hedge production from the Company s divested Sacramento Basin properties.
(2) For the six months ended June 30, 2011, this amount represents the realized gain associated with the 2011 termination of derivatives used to hedge production from the Company s divested DJ Basin and Sacramento Basin properties.
(3) For the three and six months ended June 30, 2011, includes approximately $4.8 million of unrealized loss associated with the change in fair value of the Company s crude oil basis and NYMEX roll swaps.

(5) Fair Value Measurements

The Company s financial assets and liabilities are measured at fair value on a recurring basis. The Company measures its non-financial assets and liabilities, such as asset retirement obligations and other property and equipment, at fair value on a non-recurring basis. For non-financial assets and liabilities, the Company is required to disclose information that enables users of its financial statements to assess the inputs used to develop these measurements. As none of the Company s non-financial assets and liabilities were impaired during the period ended June 30, 2011, and the Company had no other material assets or liabilities that are reported at fair value on a non-recurring basis, no additional disclosures are provided as of June 30, 2011.

As defined in the guidance, fair value is the amount that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (an exit price). To estimate fair value, the Company utilizes market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated or generally unobservable. The guidance establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted market prices in active markets for identical assets or liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3). The three levels of the fair value hierarchy are as follows:

Level 1 inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities.

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Level 2 inputs are quoted prices for similar assets and liabilities in active markets or inputs that are observable for the asset or liability, either directly or indirectly through market corroboration, for substantially the full term of the financial instrument.

Level 3 inputs are measured based on prices or valuation models that require inputs that are both significant to the fair value measurement and less observable from objective sources.

Level 3 instruments include money market funds, natural gas and NGL fixed price swaps, crude oil basis and NYMEX roll swaps and natural gas and crude oil zero cost collars. The Company s money market funds represent cash equivalents whose investments are limited to United States Government securities, securities backed by the United States Government, or securities of United States Government agencies. The fair value represents cash held by the fund manager as of June 30, 2011 and December 31, 2010. The Company identified the money market funds as Level 3 instruments due to the fact that quoted prices for the underlying investments cannot be obtained and there is not an active market for the underlying investments. The Company utilizes, as one of its inputs, counterparty and third party broker quotes to determine the valuation of its derivative instruments. Fair values derived from counterparties and brokers are further verified using relevant New York Mercantile Exchange (NYMEX) futures contracts and exchange traded contracts for each derivative settlement location.

The following table sets forth by level within the fair value hierarchy the Company s financial assets and liabilities that were accounted for at fair value on a recurring basis as of June 30, 2011. As required, financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The Company s assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

	Fair value as of June 30, 2011			
	Level 1	Level 2	Level 3	Total
			(In thousands)	
Assets (liabilities):				
Money market funds	$	$	$ 1,035	$ 1,035
Commodity derivative contracts			(10,612)	(10,612)
Total	$	$	$ (9,577)	$ (9,577)

	Fair value as of December 31, 2010			
	Level 1	Level 2	Level 3	Total
			(In thousands)	
Assets (liabilities):				
Money market funds	$	$	$ 1,035	$ 1,035
Commodity derivative contracts			19,657	19,657
Total	$	$	$ 20,692	$ 20,692

The determination of the fair values above incorporates various factors. These factors include the credit standing of the counterparty involved, the impact of credit enhancements and the impact of the Company s nonperformance risk on its liabilities. The Company considered credit adjustments for the counterparties using the current credit default swap values and default probabilities for the Company and counterparties in determining fair value and recorded a downward adjustment to the fair value of its derivative liabilities in the amount of $0.2 million at June 30, 2011.

The tables below present reconciliations of the assets and liabilities classified as Level 3 in the fair value hierarchy during the indicated periods. Level 3 instruments presented in the table consist of net derivatives and money market funds that, in management s judgment, reflect the assumptions a marketplace participant would have used at June 30, 2011 and 2010.

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	Derivatives Asset (Liability)	Money Market Funds Asset (Liability)	Total
		(In thousands)	
Balance at January 1, 2011	$ 19,657	$ 1,035	$ 20,692
Total Gains or (Losses) (Realized or Unrealized):			
Included in Earnings (1)	(10,959)		(10,959)
Included in Other Comprehensive Income	(26,499)		(26,499)
Purchases, Issuances and Settlements			
Settlements	(3,829)		(3,829)
Purchases	11,018		11,018
Transfers in and out of Level 3			
Balance at June 30, 2011	$ (10,612)	$ 1,035	$ (9,577)

	Derivatives Asset (Liability)	Money Market Funds Asset (Liability)	Total
		(In thousands)	
Balance at January 1, 2010	$ 6,787	$ 2,035	$ 8,822
Total Gains or (Losses) (Realized or Unrealized):			
Included in Earnings (1)			
Included in Other Comprehensive Income	33,312		33,312
Purchases, Issuances and Settlements	(8,108)		(8,108)
Transfers in and out of Level 3			
Balance at June 30, 2010	$ 31,991	$ 2,035	$ 34,026

(1) No gains or losses were included in earnings attributable to the change in unrealized gains or losses relating to financial assets and liabilities still held at the end of the period.

As of June 30, 2011, the carrying value of cash and cash equivalents, accounts receivable, other current assets and current liabilities reported in the consolidated balance sheet approximate fair value because of their short-term nature. The carrying amount of long-term debt reported in the consolidated balance sheet as of June 30, 2011 is $250.0 million. The Company calculated the fair value of its long-term debt as of June 30, 2011, in accordance with the authoritative guidance for fair value measurements using a discounted cash flow technique that incorporates a market interest yield curve with adjustments for duration, optionality, and risk profile. Based on this calculation, the Company has determined the fair market value of its debt to be $275.7 million at June 30, 2011.

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(6) Asset Retirement Obligations

The following table provides a roll forward of the asset retirement obligations. Liabilities incurred during the period include additions to obligations. Liabilities settled during the period include settlement payments primarily related to offshore obligations of approximately $8.2 million and adjustments for obligations that were assumed by the purchasers of divested properties of approximately $10.5 million. Activity related to the Company s asset retirement obligations (ARO) is as follows:

	Six Months Ended June 30, 2011 (In thousands)
ARO as of December 31, 2010	$ 27,934
Revision of previous estimates	
Liabilities incurred during period	13
Liabilities settled during period	(19,306)
Accretion expense	842
ARO as of June 30, 2011	$ 9,483

As of June 30, 2011, the current portion of the total ARO is approximately $0.1 million and is included in Accrued liabilities and the long-term portion of ARO is approximately $9.4 million and is included in Other long-term liabilities on the Consolidated Balance Sheet.

(7) Long-Term Debt

Senior Secured Revolving Credit Facility. On May 10, 2011, the Company entered into an amendment to its Amended and Restated Senior Revolving Credit Agreement (the Restated Revolver). Under this amendment, among other things, the Company s senior secured revolving line of credit was increased from $600.0 million to $750.0 million and the term of the Restated Revolver was extended from July 1, 2012 to May 10, 2016. Availability under the Restated Revolver is restricted to the borrowing base, which is subject to review and adjustment on a semi-annual basis and other interim adjustments, including adjustments based on the Company s hedging arrangements as well as asset divestitures. The amount of the borrowing base is affected by a number of factors, including the Company s level of reserves, as well as the pricing outlook at the time of the redetermination. Therefore, a reduction in capital spending could result in a reduced level of reserves that could cause a reduction in the borrowing base. The borrowing base under the Restated Revolver is currently set at $325.0 million with the next semi-annual review scheduled to be completed in October 2011.

The Company utilized a portion of the proceeds from its asset divestitures to repay $100.0 million of outstanding debt under the Restated Revolver on April 21, 2011. As of June 30, 2011, the Company had $30.0 million outstanding with $295.0 million of available borrowing capacity under its Restated Revolver. Amounts outstanding under the Restated Revolver bear interest at specified margins over the London Interbank Offered Rate (LIBOR) of 1.75% to 2.75%. Borrowings under the Restated Revolver are collateralized by perfected first priority liens and security interests on substantially all of the Company s assets, including a mortgage lien on oil and natural gas properties having at least 80% of the pre-tax SEC PV-10 reserve value, a guaranty by all of the Company s domestic subsidiaries, and a pledge of 100% of the membership and limited partnership interests of the Company s domestic subsidiaries. Collateralized amounts under the mortgages are subject to semi-annual reviews based on updated reserve information. The Company is subject to the financial covenants as defined in the credit agreement. The terms of the agreement require the maintenance of a minimum current ratio of consolidated current assets, including the unused amount of available borrowing capacity, to consolidated current liabilities, excluding certain non-cash obligations, of not less than 1.0 to 1.0 as of the end of each fiscal quarter. The terms of the credit agreement also require the maintenance of a maximum leverage ratio of total debt to earnings before interest expense, income taxes and noncash items, such as depreciation, depletion, amortization and impairment, of not greater than 4.0 to 1.0, calculated at the end of each fiscal quarter for the four fiscal quarters then ended, measured quarterly after giving pro forma effect to acquisitions and divestitures. At June 30, 2011, the Company s current ratio was 3.8 and the leverage ratio was 0.9. In addition, the Company is subject to covenants limiting dividends and other restricted payments, transactions with affiliates, incurrence of debt, changes of control, asset sales, and liens on properties. The Company was in compliance with all covenants at June 30, 2011.

Second Lien Term Loan. The Company s amended and restated term loan (the Restated Term Loan) matures on October 2, 2012. As of June 30, 2011, the Company had $20.0 million of fixed rate borrowings outstanding bearing interest

at 13.75% under the Restated Term Loan. The Company has the right to prepay the fixed rate borrowings outstanding under the Restated Term Loan with a make-whole amount at a discount factor equal to 1% plus the U.S. Treasury yield security having a maturity closest to the remaining life of the loan. The loan is collateralized by second priority liens on substantially all of the Company s assets. The Company is subject to the financial covenants as defined in the term loan agreement. The Company is required under the term loan agreement to maintain a minimum reserve ratio of total reserve value to total debt of not less than 1.5 to 1.0 as of the end of each fiscal quarter. The terms of the agreement also require the Company to maintain a maximum leverage ratio of total debt to earnings before interest expense, income taxes and noncash items, such as depreciation, depletion, amortization and impairment, of not greater than 4.0 to 1.0, calculated at the end of each fiscal quarter for the four fiscal quarters then ended. At June 30, 2011, the Company s reserve coverage ratio was 4.8 and the leverage ratio was 0.9. In addition, the Company is subject to covenants, including limitations on dividends and other restricted payments, transactions with affiliates, incurrence of debt, changes of control, asset sales, and liens on properties. The Company was in compliance with all covenants at June 30, 2011.

Senior Notes. On April 15, 2010, the Company issued and sold $200.0 million in aggregate principal amount of 9.500% Senior Notes due 2018 (the Senior Notes) in a private offering. The Senior Notes were issued under an indenture (the Indenture) with Wells Fargo Bank, National Association, as trustee. Provisions of the Indenture limit the Company s ability to, among other things, incur additional indebtedness; pay dividends on capital stock or purchase, repurchase, redeem, defease or retire capital stock or subordinated indebtedness; make investments; incur liens; create any consensual restriction on the ability of the Company s restricted subsidiaries to pay dividends, make loans or transfer property to the Company; engage in transactions with affiliates; sell assets; and consolidate, merge or transfer assets. The Indenture also contains customary events of default. Proceeds from the Senior Notes offering were used to repay $114.0 million outstanding under the Restated Revolver and $80.0 million of variable rate borrowings outstanding under the Restated Term Loan and to pay for fees and expenses associated with the offering. Interest is payable on the Senior Notes semi-annually on April 15 and October 15. On September 21, 2010, the Company exchanged all of the privately placed Senior Notes for registered Senior Notes which contain terms substantially identical to the terms of the privately placed notes.

As of June 30, 2011, the Company had total outstanding borrowings of $250.0 million and for the six months ended June 30, 2011, the Company s weighted average borrowing rate was 8.04%.

(8) Income Taxes

The effective tax rate for the three and six months ended June 30, 2011 was 35.9% and 34.2%, respectively, and the effective tax rate for the three and six months ended June 30, 2010 was 40.8% and 38.5%, respectively. The provision for income taxes for the three months ended June 30, 2011 differs from the tax computed at the federal statutory income tax rate primarily due to the non-deductibility of certain incentive compensation and due the impact of state income taxes. For the six months ended June 30, 2011, the provision for income taxes differs from the tax computed at the federal statutory income tax rate primarily due to the non-deductibility of certain incentive compensation and an approximate $0.9 million adjustment for 2010 federal income taxes. The Company has determined that the impact of the 2010 tax adjustment was immaterial to its results of operations in all applicable prior interim and annual periods as well as to the projected results of operations for 2011. As of June 30, 2011 and December 31, 2010, the Company had no unrecognized tax benefits. The Company does not anticipate that total unrecognized tax benefits will significantly change due to the settlement of audits or the expiration of statute of limitations within the next twelve months.

The Company provides for deferred income taxes on the difference between the tax basis of an asset or liability and its carrying amount in the financial statements in accordance with authoritative guidance for accounting for income taxes. This difference will result in taxable income or deductions in future years when the reported amount of the asset or liability is recovered or settled, respectively. Considerable judgment is required in determining when these events may occur and whether recovery of an asset is more likely than not. Deferred tax assets are reduced by a valuation allowance when, in the opinion of management, it is more likely than not that some portion or all of the deferred tax assets will not be realized. As of June 30, 2011, the Company has a deferred tax asset of $128.8 million resulting primarily from the difference between the book basis and tax basis of oil and natural gas properties and net operating loss carryforwards. Realization of the deferred tax asset is dependent, in part, on generating sufficient taxable income from the production of oil and natural gas properties prior to the expiration of loss carryforwards.

In connection with the asset divestitures in the DJ Basin in Colorado and in the Sacramento Basin in California, the Company concluded that it is more likely than not that the deferred tax assets for these states including NOLs will not be realized. Therefore, valuation allowances were established at December 31, 2010 for these items as well as state NOLs in other jurisdictions in which the Company previously operated but has since divested of operating assets. The Company will continue to assess the need for a valuation allowance against deferred tax assets considering all available evidence obtained in future reporting periods.

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(9) Commitments and Contingencies

Firm Gas Transportation Commitments. The Company has entered into long-term contracts for firm transportation and processing capacity to reduce exposure to production constraints in the Eagle Ford shale. During the second quarter of 2011, the Company increased its daily transportation capacity from the Eagle Ford shale by 20 percent to 245 MMcf/d of gross wellhead production with 195 MMcf/d contracted to be available by the second quarter of 2012 and total contractual capacity reached by 2013.

Drilling Rig and Completion Services Commitments. As the Company s operations are concentrated in highly competitive plays, access to drilling rigs and other oilfield services can be aggressive, unavailable or costly. Should access to these services be restricted due to market conditions, the Company could be adversely affected. As of June 30, 2011, the Company has no outstanding drilling commitments with terms greater than one year.

In an effort to secure key oil field services, the Company entered into a two-year bundled service agreement effective January 1, 2011 with a major oil field services firm. The agreement includes stimulation, cementing and drilling fluids product service lines sufficient to support the current operations. As of June 30, 2011, the minimum remaining contractual commitment for this agreement was $5.4 million. This minimum commitment will decrease equally on a monthly basis for the remainder of the contract term.

Contingencies. The Company is party to various legal and regulatory proceedings arising in the normal course of business. The ultimate outcome of each of these matters cannot be absolutely determined, and in the event of negative outcome(s) as to any one or more of these proceedings, the liability the Company may ultimately incur with respect to any one or more of these matters may be in excess of amounts currently accrued as applicable, with respect to such matters. Net of the Company s and, as applicable, third parties , available insurance and the performance of contractual defense and indemnity rights and obligations, where applicable, management does not believe any such matters will have a material adverse effect on the Company s financial position, results of operations or cash flows.

(10) Comprehensive Income (Loss)

For the periods indicated, the Company s Accumulated other comprehensive income consisted of the following:

	Three Months Ended June 30,				Six Months Ended June 30,			
	2011		2010		2011		2010	
	(In thousands)							
Accumulated other comprehensive (loss) income, beginning of period		$ (12,725)		$ 22,848		$ 11,259		$ 4,259
Net income	$ 25,400		$ 4,312		$ 36,397		$ 11,575	
Change in fair value of derivative hedging instruments	$ 3,223		$ 1,062		$ (26,499)		$ 33,312	
Hedge settlements reclassed to (income) loss	2,456		(5,483)		(6,175)		(8,108)	
Tax provision related to hedges	(1,705)		1,696		12,664		(9,340)	
Total other comprehensive income (loss)	$ 3,974	$ 3,974	$ (2,725)	$ (2,725)	$ (20,010)	$ (20,010)	$ 15,864	$ 15,864
Comprehensive income	$ 29,374		$ 1,587		$ 16,387		$ 27,439	
Accumulated other comprehensive (loss) income, end of period		$ (8,751)		$ 20,123		$ (8,751)		$ 20,123

(11) Earnings Per Share

Basic earnings per share is computed by dividing income available to common stockholders by the weighted average number of shares outstanding for the period. Diluted earnings per share reflects the potential dilution that could occur if outstanding common stock awards and stock options were exercised at the end of the period.

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The following is a calculation of basic and diluted weighted average shares outstanding:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
	(In thousands)			
Basic weighted average number of shares outstanding	51,991	51,355	51,923	51,287
Dilution effect of stock option and awards at the end of the period	590	701	644	726
Diluted weighted average number of shares outstanding	52,581	52,056	52,567	52,013
Anti-dilutive stock awards and shares	1	45	2	64

(12) Stock-Based Compensation Expense

Stock-based compensation expense includes the expense associated with equity awards granted to employees and directors and the expense associated with the Performance Share Units (PSUs) granted to executive management. As of the indicated dates, stock-based compensation expense consisted of the following:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
	(in thousands)			
Total stock-based compensation expense	$ 5,743	$ 1,996	$ 16,474	$ 4,626
Capitalized in oil and gas properties	(201)	(141)	(342)	(283)
Net stock-based compensation expense	$ 5,542	$ 1,855	$ 16,132	$ 4,343

All stock-based compensation expense associated with stock-based equity awards granted to employees and directors is recognized on a straight-line basis over the applicable remaining vesting period. For the six months ended June 30, 2011, the Company recorded compensation expense of approximately $2.7 million related to these equity awards. As of June 30, 2011, unrecognized stock-based compensation expense related to unvested stock-based compensation equity awards was approximately $7.4 million.

Stock-based compensation expense associated with the PSUs granted to executive management is recognized over the vesting period when certain conditions have been met during a three-year service period. For the six months ended June 30, 2011, the Company recognized $12.5 million and $0.9 million, respectively, of compensation expense associated with the 2009 and 2010 PSU plans. No expenses or accruals have been recorded related to the 2011 PSU awards as of June 30, 2011. At the current fair value as of June 30, 2011 and assuming that the Board elects the maximum available payout of 200% for the PSUs for all metrics, total compensation expense related to the PSUs to be recognized during the three-year service periods would be $33.1 million, $12.6 million and $7.7 million, respectively, for the 2009, 2010 and 2011 PSU plans. The total compensation expense will be measured and adjusted quarterly until settlement based on the quarter-end closing common stock prices and the Monte Carlo model valuations. For a more detailed description of the PSU plans, conditions and structure, see our definitive proxy statement filed with respect to our 2011 annual meeting under headings Compensation Discussion and Analysis, and Executive Compensation.

(13) Geographic Area Information

The Company has one reportable segment, oil and natural gas exploration and production, as determined in accordance with authoritative guidance regarding disclosure about segments of an enterprise and related information. Furthermore, as all of the Company s operations are located in the United States, all of the Company s costs are included in one cost pool.

Geographic Area Information

In 2011, the Company has owned oil and natural gas interests in six main geographic areas, all within the United States or its territorial waters. Geographic revenue information below is based on physical location of the assets at the end of each period. Certain amounts in prior periods have been reclassified to conform to the current presentation.

	Three Months Ended June 30, 2011 (1)	2010 (1)	Six Months Ended June 30, 2011 (1)	2010 (1)
	(In thousands)		(In thousands)	
Natural gas, Oil and NGL Revenue				
Eagle Ford	$ 92,216	$ 17,693	$ 152,157	$ 22,015
South Texas	13,116	18,308	25,792	44,661
California (2)	2,980	17,090	14,930	38,487
Rockies (2)	92	6,496	3,526	15,014
Gulf Coast	825	1,350	1,264	5,500
Other Onshore		1,964		4,495
Total revenue, excluding gains on hedges	$ 109,229	$ 62,901	$ 197,669	$ 130,172

(1) Excludes the effects of hedging gains of $2.3 million and $11.0 million for the three and six months ended June 30, 2011, respectively, and $5.7 million and $8.6 million for the three and six months ended June 30, 2010, respectively.

(2) The Rockies and California assets include the DJ Basin and Sacramento Basin assets. The DJ Basin and Sacramento Basin assets were sold in March 2011 and April 2011, respectively. See Note 3 Property and Equipment. The decline in revenues was primarily due to the divestiture of these assets and suspension of capital programs in these areas that produce primarily from dry gas reservoirs.

(14) Restructuring and Reorganization Costs

In 2010, the Company announced an office closure affecting the Denver office and the restructuring and reorganization of Houston personnel as a result of strategic asset divestitures. All affected positions are located in the United States and as of June 2011, all employees covered under the programs have been terminated.

A before-tax charge of $1.3 million ($0.8 million after-tax) was recorded in the first six months of 2011 as General and administrative costs on the Consolidated Statement of Operations. The associated accrued liability is classified as current on the Consolidated Balance Sheet. Of the expenses incurred during the first six months of 2011, approximately $0.6 million related to severance costs, $0.6 million related to the cease-use of the Denver office space and approximately $0.1 million related to relocation costs. While all future costs associated with the restructuring and reorganization cannot be fully anticipated, the total amount estimated that will be incurred is approximately $5.0 million.

During the six months ended June 30, 2011, the Company made payments of approximately $3.2 million associated with these liabilities.

	Amounts before tax (In thousands)
Balance at January 1, 2011	$ 3,224
Accruals	1,010
Adjustments	287
Payments	(3,221)
Balance at June 30, 2011	$ 1,300

(15) Guarantor Subsidiaries

The Company s Senior Notes are guaranteed by its wholly owned subsidiaries. Rosetta Resources Inc., as the parent company, has no independent assets or operations. The guarantees are full and unconditional and joint and several, and the subsidiaries of Rosetta Resources Inc. other than the subsidiary guarantors are minor. In addition, there are no restrictions on the ability of Rosetta Resources Inc. to obtain funds from its subsidiaries by dividend or loan. Finally, none of Rosetta Resources Inc. s subsidiaries has restricted assets that exceed 25% of net assets as of the most recent fiscal year which may not be transferred to the parent company in the form of loans, advances or cash dividends by the subsidiaries without the consent of a third party.

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(16) Subsequent Events

On July 27, 2011, the remaining consents for assignment were received or waived related to the Sacramento Basin asset divestiture. As such, final proceeds of $0.8 million were released from the escrow account and provided to the Company.

Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

This report includes forward-looking statements regarding the Company 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 (the Exchange Act). All statements other than statements of historical fact included in this report are forward-looking statements, including without limitation all statements regarding future plans, business objectives, strategies, expected future financial position or performance, expected future operational position or performance, budgets and projected costs, future competitive position, or goals and/or projections of management for future operations. In some cases, you can identify a forward-looking statement by terminology such as may, will, could, should, expect, plan, project, intend, anticipate, believe, potential, pursue, target or continue, the negative of such terms or variations thereon, or other comparable terminology. Unless the context clearly indicates otherwise, references in this report to Rosetta, the Company, we, our, us or like terms refer to Rosetta Resources Inc. and its subsidiaries.

The forward-looking statements contained in this report reflect certain estimates and assumptions made by our management. These estimates and assumptions reflect our best judgment based on currently known market conditions, operating trends, and other factors. Although we believe such estimates and assumptions to be reasonable, they are inherently uncertain and involve a number of risks and uncertainties that are beyond our control. As such, management s assumptions about future events may prove to be inaccurate. For a more detailed description of the risks and uncertainties involved, see Item 1A. Risk Factors in our Annual Report on Form 10-K for the year ended December 31, 2010 (the 2010 Annual Report). We do not intend to publicly update or revise any forward-looking statements as a result of new information, future events, changes in circumstances, or otherwise. These cautionary statements qualify all forward-looking statements attributable to us, or persons acting on our behalf. Management cautions all readers that the forward-looking statements contained in this report are not guarantees of future performance, and we cannot assure any reader that such statements will be realized or that the events and circumstances they describe will occur. Factors that could cause actual results to differ materially from those anticipated or implied in the forward-looking statements herein include, but are not limited to:

- the supply and demand for natural gas, oil and NGLs;
- changes in the price of natural gas, oil and NGLs;
- general economic conditions, either internationally, nationally or in jurisdictions where we conduct business;
- conditions in the energy and financial markets;
- our ability to obtain credit and/or capital in desired amounts and/or on favorable terms;
- the ability and willingness of our current or potential counterparties or vendors to enter into transactions with us to fulfill their obligations to us;
- failure of our joint interest partners to fund any or all of their portion of any capital program;

the occurrence of property acquisitions or divestitures;

reserve levels;

inflation;

competition in the oil and natural gas industry;

the availability and cost of relevant raw materials, goods and services;

the availability and cost of processing and transportation;

changes or advances in technology;

potential reserve revisions;

limitations, availability, and constraints in infrastructure required to transport, process, and market, natural gas, oil and NGLs;

performance of contracted markets, and companies contracted to provide transportation, processing, and trucking of natural gas, oil and NGLs;

developments in oil-producing and natural gas-producing countries;

drilling and exploration risks;

legislative initiatives and regulatory changes potentially adversely impacting our business and industry, including, but not limited to, changes in national healthcare, cap and trade, hydraulic fracturing, state and federal corporate income taxes, retroactive royalty or production tax regimes, environmental regulations and environmental risks and liability under federal, state and local environmental laws and regulations;

effects of the application of applicable laws and regulations, including changes in such regulations or the interpretation thereof;

present and possible future claims, litigation and enforcement actions;

lease termination due to lack of activity or other disputes with mineral lease and royalty owners, whether regarding calculation and payment of royalties or otherwise;

the weather, including the occurrence of any adverse weather conditions and/or natural disasters affecting our business;

any other factors that impact or could impact the exploration of oil or natural gas resources, including but not limited to the geology of a resource, the total amount and costs to develop recoverable reserves, legal title, regulatory, natural gas administration, marketing and operational factors relating to the extraction of oil and natural gas; and

factors that could impact the cost, extent and pace of executing our capital program, including but not limited to, access to oilfield services, access to water for hydraulic fracture stimulations and permitting delays, unavailability of required permits, lease suspensions, drilling, exploration and production moratoriums and other legislative, executive or judicial actions by federal, state and local authorities, as well as actions by private citizens, environmental groups or other interested persons.

Overview

The following discussion addresses material changes in our results of operations for the three and six months ended June 30, 2011 compared to the three and six months ended June 30, 2010, and material changes in our financial condition since December 31, 2010. This discussion includes the operations of our DJ Basin and Sacramento Basin assets which were divested in March and April 2011, respectively, and should be read in conjunction with our 2010 Annual Report, which includes as part of Management s Discussion and Analysis of Financial Condition and Results of Operations disclosures regarding critical accounting policies.

The following summarizes our performance for the three months ended June 30, 2011 as compared to the same period for 2010:

production on a Bcfe basis increased 20% to 14.6 Bcfe for the three months ended June 30, 2011 from 12.2 Bcfe for the three months ended June 30, 2010;

13 gross (12 net) wells were drilled with a net success rate of 100% for the three months ended June 30, 2011 compared to 58 gross (57 net) wells drilled with a net success rate of 100% for the same period in 2010;

58% of revenue for the three months ended June 30, 2011 was generated from oil and NGL sales as compared to 31% for the same period in 2010, reflecting our shift to a higher total liquids mix;

average realized gas prices, including hedging, increased $1.08 per Mcf, or 23%, to $5.88 per Mcf for the three months ended June 30, 2011 from $4.80 per Mcf for the three months ended June 30, 2010;

average realized oil prices, including hedging, increased $6.88 per Bbl, or 9%, to $80.17 per Bbl for the three months ended June 30, 2011 from $73.29 per Bbl for the three months ended June 30, 2010;

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average realized NGL prices, including hedging, increased $3.16 per Bbl, or 8%, to $44.79 per Bbl for the three months ended June 30, 2011 from $41.63 per Bbl for the three months ended June 30, 2010;

total revenue, including the effects of hedging, increased $43.0 million, or 63%, to $111.6 million for the three months ended June 30, 2011 from $68.6 million for the three months ended June 30, 2010; and

diluted earnings per share increased $0.40 to $0.48 for the three months ended June 30, 2011 from $0.08 for the three months ended June 30, 2010.

The following summarizes our performance for the six months ended June 30, 2011 as compared to the same period for 2010:

production on a Bcfe basis increased 22% to 28.6 Bcfe for the six months ended June 30, 2011 from 23.4 Bcfe for the six months ended June 30, 2010;

24 gross (23 net) wells were drilled with a net success rate of 100% for the six months ended June 30, 2011 compared to 94 gross (92 net) wells drilled with a net success rate of 99% for the same period in 2010;

54% of revenue for the six months ended June 30, 2011 was generated from oil and NGL sales as compared to 26% for the same period in 2010, reflecting our shift to a higher total liquids mix;

average realized gas prices, including hedging, increased $0.26 per Mcf, or 5%, to $5.56 per Mcf for the six months ended June 30, 2011 from $5.30 per Mcf for the six months ended June 30, 2010;

average realized oil prices, including hedging, increased $7.74 per Bbl, or 10%, to $82.16 per Bbl for the six months ended June 30, 2011 from $74.42 per Bbl for the six months ended June 30, 2010;

average realized NGL prices, including hedging, increased $1.74 per Bbl, or 4%, to $44.50 per Bbl for the six months ended June 30, 2011 from $42.76 per Bbl for the six months ended June 30, 2010;

total revenue, including the effects of hedging, increased $69.8 million, or 50%, to $208.6 million for the six months ended June 30, 2011 from $138.8 million for the six months ended June 30, 2010; and

diluted earnings per share increased $0.47 to $0.69 for the six months ended June 30, 2011 from $0.22 for the six months ended June 30, 2010.

During 2011, Rosetta continues to build upon its success as an unconventional resource player with a portfolio of high-quality shale assets and a project inventory offering the potential for visible and sustainable growth. Our position is the result of a transition which began three years ago as we changed our business model from that of a conventional natural gas producer in more mature U.S. basins to now as an operator in emerging U.S. shale plays, offering a more balanced commodity mix and greater returns and opportunities.

We were an early entrant into the Eagle Ford shale in South Texas, accumulating a significant leasehold position during 2008 and 2009 in the highly-competitive industry play. Our efforts were underpinned with a conservative fiscal approach and a focus on cost control and efficiency. Overall, we now hold approximately 65,000 net acres with roughly 50,000 net acres located in the liquids-rich area of the play. Our 2010 activities were focused in our 26,500-acre position in the Gates Ranch area in Webb County where well results continue to exceed expectations. The Eagle Ford shale has become our largest producing area providing more than 80% of our total production for the three months ended June

30, 2011 and approximately 52% of that amount was from crude oil and natural gas liquids.

Our other shale focus area lies in the Southern Alberta Basin in northwest Montana. Rosetta holds approximately 300,000 net acres in the play that we believe is an analog to the prolific Williston Basin. In late 2009, we began an eleven-well vertical drilling program to assess the commerciality of the play. During the second quarter of 2011, we drilled and completed the last wells of that initiative. The results from that effort have significantly increased our understanding of the play and contributed to the design of a horizontal drilling program that is currently underway. Industry activity continues to grow in the Southern Alberta Basin which is accelerating play delineation as well as establishing the need for local service infrastructure.

Continued well performance significantly in excess of prior estimates has necessitated a mid-year update to our proved reserves. As of June 30, 2011, we had an estimated 969.8 Bcfe of proved reserves, including 458.8 Bcfe of natural gas, 35,900 MBbls of oil and condensate and 49,300 MBbls of NGLs of which 29% is proved developed. These proved reserves represent an increase of 490.5 Bcfe, or 102%, from proved reserves of 479.3 Bcfe at December 31, 2010. During the six months ended June 30, 2011, we replaced 28.6 Bcfe of production with 464.1 Bcfe of reserve additions. This increase resulted primarily from an additional 94 proved undeveloped locations (PUDs) in the Gates Ranch area. Our divestiture results, operating cash flows and development plans all indicate that these reserves will be developed over the next five years. We relied on the following technologies to estimate these reserve additions:

- Successfully drilled and completed 35 wells in all lease line directions and interior wells proving a continuous accumulation of hydrocarbons over the entire lease.

- Utilized 3-D seismic covering 48% of the Gates Ranch acreage indicating a continuous Eagle Ford formation over this portion of the lease.

- Conducted a Micro-seismic evaluation that verified effective stimulation of the reservoir from modern fracturing techniques and proppant materials leading to consistent production results and production histories.

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During the six months ended June 30, 2011, we spent $158.1 million for drilling and completions in the Eagle Ford shale including $84.9 million to reclass reserves from twelve Gates Ranch wells from proved undeveloped (PUD) to proved producing (PDP) for a total reclass of 45.5 Bcfe of reserves. Proved reserves also include a 132.4 Bcfe positive performance revision primarily due to an increase in the estimated ultimate recovery (EUR) of hydrocarbons on thirty-five Gates Ranch wells. Twenty-two of these Gates wells have greater than six months of production history and some of these wells have been producing over 18 months. The decline profiles on wells with significant production history indicate that the EURs are much more likely to increase or remain constant than to decline. The increase in proved reserves was slightly offset by the divestiture of 84.3 Bcfe of estimated proved reserves associated with the DJ Basin and Sacramento Basin asset divestitures.

The following table sets forth, by operating area, a summary of our estimated net proved reserve information as of June 30, 2011:

	Estimated Proved Reserves at June 30, 2011 (1)(2)									
	Developed				Undeveloped					Percent of
	Natural Gas (Bcf)	NGLs (MMBbls)	Oil (MMBbls)	Total (Bcfe) (3)	Natural Gas (Bcf)	NGLs (MMBbls)	Oil (MMBbls)	Total (Bcfe) (3)	Total (Bcfe) (3)	Total Reserves
Eagle Ford	87.0	10.3	8.0	196.7	302.9	36.6	27.4	687.1	883.8	91%
South Texas	67.6	2.4	0.4	84.3					84.3	9%
Gulf Coast	0.6			0.8					0.8	0%
Other Onshore	0.7		0.1	0.9					0.9	0%
Total	155.9	12.7	8.5	282.7	302.9	36.6	27.4	687.1	969.8	100%

(1) These estimates are based upon a reserve report prepared using internally developed reserve estimates and criteria in compliance with the SEC guidelines and audited by Netherland, Sewell & Associates, Inc. (NSAI), independent petroleum engineers. NSAI s report is attached as Exhibit 99.1 to this Form 10-Q.

(2) The reserve volumes and values were determined under the method prescribed by the SEC, which requires the use of an average price, calculated as the twelve-month first day of the month historical average price for the twelve-month period prior to the end of the reporting period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions. The calculated prices as of June 30, 2011 and based on twelve-month first day of the month historical average prices as adjusted for basis and quality differentials for West Texas Intermediate oil is $86.60 per Bbl and Henry Hub natural gas of $4.21 per MMBtu. The prices used for the December 31, 2010 reporting period was $75.96 per Bbl and $4.38 per MMBtu.

(3) Gas equivalents are determined under the relative energy content method by using the ratio of 1.0 Bbl of oil or natural gas liquid to 6.0 Mcf of gas.

The overall metrics of our business have been greatly improved with our success in the Eagle Ford shale. Our lease operating expense per Mcfe declined to $0.82 per Mcfe in the first six months of 2011 from $1.20 per Mcfe for the same period in 2010. In addition, production volume for the first six months of 2011 increased by 22% compared to the same period in 2010, while increasing the higher-valued oil and liquids component to approximately 39 percent of our overall mix for the six months ended June 30, 2011.

With the growth of our shale activities, we have streamlined our operations by divesting of assets that no longer fit our operating model and are redeploying the proceeds of such divestitures into our growth initiatives. In total, we have executed sale agreements for more than $340 million for properties in nine states. In February 2011, we announced the divestiture of assets in the DJ Basin in Colorado and the Sacramento Basin in California for a total sales price of $255 million, subject to customary adjustments. On March 31, 2011, we closed on the sale of our DJ Basin assets and through multiple stages, are closing on the sale of our Sacramento Basin assets which began on April 15, 2011 and continued throughout the current quarter. The completion of the remaining portion of the transaction occurred in the third quarter of 2011. Both of these asset divestitures are effective of as January 1, 2011. At this time, we believe that we have sufficient internal investment opportunities to grow without acquiring additional properties. However, we continue to evaluate opportunities that fit our business model and our strategic and economic objectives.

During the second quarter, we raised our previously announced 2011 capital budget of $360 million to approximately $475 million to take advantage of the timely completion of our divestiture program and accelerate our growth in shale activities. During 2011, we plan approximately 40 completions in the Gates Ranch area and have a fracture stimulation agreement in place to handle this activity. In addition, we intend to test our acreage position outside Gates Ranch that is also located in the liquids portion of the Eagle Ford shale. In the Southern Alberta Basin, we have entered the second phase of our delineation initiative by launching a horizontal drilling program. In total, approximately 85 percent of capital spending will be directed toward development and exploration activities in the Eagle Ford shale. We believe that the program economics of the Eagle Ford shale provide some of the strongest returns among U.S. onshore basins and our progress in the area will further shift our product mix toward a higher percentage of liquids. In addition, we are poised to take advantage of any recovery in natural gas prices with 15,000 net acres of Eagle Ford holdings that lie in the dry-gas window of the play.

As of June 30, 2011, we have completed 40 horizontal wells in the Eagle Ford shale. During the second quarter of 2011, we operated three rigs in the Eagle Ford area completing 9 horizontal wells. We have also identified two pilot areas to initiate infill drilling activity within Gates Ranch. Drilling within the first pilot area has been completed and operations are now underway in the second area. The wells drilled in both pilot areas should be completed and on production by year-end 2011.

The timely and efficient development of our Eagle Ford resources remains challenging in a region where midstream services are in high demand and infrastructure is still under construction. In response, Rosetta has entered into long-term contracts for firm transportation and processing capacity to reduce our exposure to production constraints. We also have secured firm processing capacity agreements with multiple providers to meet our projected growth in volumes from the area. During the second quarter, Rosetta increased its daily transportation capacity from the Eagle Ford shale by 20 percent to 245 MMcf/d of gross wellhead production with 195 MMcf/d contracted to be available by the second quarter of 2012 and total contractual capacity reached by 2013.

While our unconventional resource strategy is proving successful, we recognize that there are risks inherent to our industry that could impact our ability to meet future goals. Our business model takes into account the threats that could impede our achievement of our stated growth objectives and the building of our asset base. However, we cannot completely control all external factors that could affect our operating environment. We have diversified our production base toward crude oil and natural gas liquids that continue to be priced at more favorable levels than natural gas. With increasing industry activity in the Eagle Ford shale, our largest producing area, we have taken aggressive steps to ensure access to necessary services and infrastructure.

We announced the closing of our Denver office and the reorganization of Houston personnel starting in 2010. Since the initiation of the reorganization, we have incurred approximately $4.8 million of expenses primarily related to severance costs and the closing of our Denver office. We expect the reorganization to be completed by December 31, 2011 and while all future costs associated with the reorganization cannot be fully anticipated, we expect to incur total costs of approximately $5.0 million. We believe the consolidation of our technical resources to Houston is allowing us to capitalize on the dynamics and efficiencies of operating in a central location.

We believe that we can execute our 2011 capital program from internally generated cash flows, cash on hand and the proceeds from our asset divestitures. We monitor our liquidity continuously and will respond to changing market conditions, commodity prices or service costs. If our internal funds were insufficient to meet projected funding requirements, we would consider curtailing our capital spending, drawing on the unused capacity under our existing revolving credit facility or accessing the capital markets.

In May 2011, we amended our Restated Revolver to increase our revolving line of credit to $750.0 million and extended its term until May 10, 2016. Availability under the Restated Revolver is restricted to the borrowing base, which is subject to review and adjustment on a semi-annual basis and other interim adjustments, including adjustments based on our hedging arrangements, as well as asset divestitures. The amount of the borrowing base is dependent on a number of factors, including our level of reserves as well as the pricing outlook at the time of the redetermination. In April 2011, we used $100.0 million of the proceeds from our asset divestitures to reduce our outstanding debt under the Restated Revolver. As extended, the borrowing base under the Restated Revolver is currently set at $325.0 million with the next semi-annual review scheduled to be completed in October 2011. As of August 2, 2011, we had $30.0 million outstanding, with $295.0 million available for borrowing under the Restated Revolver.

Results of Operations

Revenues

Our revenues are derived from the sale of our natural gas, oil and NGL production, which includes the effects of commodity hedge contracts. Our revenues may vary significantly from period to period as a result of changes in commodity prices or volumes of production sold.

Total revenue, including the effects of hedging, for the three months ended June 30, 2011 was $111.6 million, which is an increase of $43.0 million, or 63%, from $68.6 million for the three months ended June 30, 2010. Total revenue, excluding the effects of hedging, for the three months ended June 30, 2011 was $109.2 million, which is an increase of $46.3 million, or 74%, from $62.9 million for the three months ended June 30, 2010. Approximately 58% of our revenue for the three months ended June 30, 2011 was attributable to oil and NGL sales as compared to 31% for the same period in 2010.

Total revenue, including the effects of hedging, for the six months ended June 30, 2011 was $208.6 million, which is an increase of $69.8 million, or 50%, from $138.8 million for the six months ended June 30, 2010. Total revenue, excluding the effects of hedging, for the six months ended June 30, 2011 was $197.7 million, which is an increase of $67.5 million, or 52%, from $130.2 million for the six months ended June 30, 2010. Approximately 54% of our revenue for the six months ended June 30, 2011 was attributable to oil and NGL sales as compared to 26% for the same period in 2010.

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The following table summarizes the components of our revenues (including the effects of hedging) for the periods indicated, as well as each period s production volumes and average prices:

	Three Months Ended June 30,			Six Months Ended June 30,		
	2011	2010	% Change Increase/ (Decrease)	2011	2010	% Change Increase/ (Decrease)
	(In thousands, except percentages and per unit amounts)			(In thousands, except percentages and per unit amounts)		
Revenues:						
Natural gas sales	$ 46,457	$ 47,491	(2%)	$ 96,237	$ 103,298	(7%)
Oil sales	34,312	10,773	218%	63,061	17,756	255%