UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-Q

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

For the quarterly period ended June 30, 2010

Commission File Number 001-31539

SM ENERGY COMPANY
(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	**41-0518430** (I.R.S. Employer Identification No.)
1775 Sherman Street, Suite 1200, Denver, Colorado (Address of principal executive offices)	**80203** (Zip Code)

(303) 861-8140
(Registrant's telephone number, including area code)

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

Indicate by check mark 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 the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ☒	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 Exchange Act). Yes ☐ No ☒

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

As of July 28, 2010 the registrant had 63,007,624 shares of common stock, $0.01 par value, outstanding.

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PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

SM ENERGY COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS (UNAUDITED)
(In thousands, except share amounts)

	June 30, 2010	December 31, 2009
ASSETS		
Current assets:		
Cash and cash equivalents	$ 10,249	$ 10,649
Accounts receivable	108,427	116,136
Refundable income taxes	23,215	32,773
Prepaid expenses and other	14,284	14,259
Derivative asset	45,481	30,295
Deferred income taxes	—	4,934
Total current assets	201,656	209,046
Property and equipment (successful efforts method), at cost:		
Land	1,483	1,371
Proved oil and gas properties	3,066,300	2,797,341
Less - accumulated depletion, depreciation, and amortization	(1,203,841)	(1,053,518)
Unproved oil and gas properties, net of impairment allowance of $62,507 in 2010 and $66,570 in 2009	138,531	132,370
Wells in progress	97,312	65,771
Materials inventory, at lower of cost or market	31,305	24,467
Oil and gas properties held for sale less accumulated depletion, depreciation, and amortization	7,115	145,392
Other property and equipment, net of accumulated depreciation of $16,478 in 2010 and $14,550 in 2009	15,472	14,404
	2,153,677	2,127,598
Other noncurrent assets:		
Derivative asset	30,169	8,251
Restricted cash subject to Section 1031 Exchange	19,595	—
Other noncurrent assets	12,288	16,041
Total other noncurrent assets	62,052	24,292
Total Assets	**$ 2,417,385**	**$ 2,360,936**
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued expenses	$ 270,030	$ 236,242
Derivative liability	37,903	53,929
Deposit associated with oil and gas properties held for sale	—	6,500
Deferred income taxes	4,970	—
Total current liabilities	312,903	296,671
Noncurrent liabilities:		
Long-term credit facility	—	188,000
Senior convertible notes, net of unamortized discount of $16,288 in 2010, and $20,598 in 2009	271,212	266,902
Asset retirement obligation	64,284	60,289
Asset retirement obligation associated with oil and gas properties held for sale	1,526	18,126
Net Profits Plan liability	136,420	170,291
Deferred income taxes	408,997	308,189
Derivative liability	24,046	65,499
Other noncurrent liabilities	15,164	13,399
Total noncurrent liabilities	921,649	1,090,695
Commitments and contingencies		
Stockholders' equity:		
Common stock, $0.01 par value - authorized: 200,000,000 shares; issued: 63,110,068 shares in 2010 and 62,899,122 shares in 2009; outstanding, net of treasury shares: 63,007,433 shares in 2010 and 62,772,229 shares in 2009	631	629
Additional paid-in capital	174,973	160,516
Treasury stock, at cost: 102,635 shares in 2010 and 126,893 shares in 2009	(489)	(1,204)
Retained earnings	992,685	851,583
Accumulated other comprehensive income (loss)	15,033	(37,954)
Total stockholders' equity	1,182,833	973,570
Total Liabilities and Stockholders' Equity	**$ 2,417,385**	**$ 2,360,936**

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

SM ENERGY COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS (UNAUDITED)
(In thousands, except per share amounts)

	For the Three Months Ended June 30, 2010	For the Three Months Ended June 30, 2009	For the Six Months Ended June 30, 2010	For the Six Months Ended June 30, 2009
Operating revenues and other income:				
Oil and gas production revenue	$ 175,887	$ 145,279	$ 388,774	$ 275,696
Realized oil and gas hedge gain	9,329	43,279	11,924	98,899
Gain on divestiture activity	7,021	1,244	127,999	645
Marketed gas system and other operating revenue	19,460	15,396	43,135	29,178
Total operating revenues and other income	211,697	205,198	571,832	404,418
Operating expenses:				
Oil and gas production expense	45,168	49,465	93,508	105,294
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	79,770	70,391	157,535	162,103
Exploration	14,498	19,490	28,396	33,088
Impairment of proved properties	—	6,043	—	153,092
Abandonment and impairment of unproved properties	2,375	11,631	3,279	15,533
Impairment of materials inventory	—	2,719	—	11,335
General and administrative	25,398	18,160	48,884	34,559
Change in Net Profits Plan liability	(6,599)	2,449	(33,871)	(20,842)
Marketed gas system expense	15,807	13,609	37,853	26,992
Unrealized derivative (gain) loss	(2,087)	11,288	(9,822)	13,134
Other expense	578	5,814	1,530	11,456
Total operating expenses	174,908	211,059	327,292	545,744
Income (loss) from operations	36,789	(5,861)	244,540	(141,326)
Nonoperating income (expense):				
Interest income	54	105	183	127
Interest expense	(6,343)	(7,663)	(13,130)	(13,759)
Income (loss) before income taxes	30,500	(13,419)	231,593	(154,958)
Income tax benefit (expense)	(12,432)	5,097	(87,347)	59,013
Net income (loss)	**$ 18,068**	**$ (8,322)**	**$ 144,246**	**$ (95,945)**
Basic weighted-average common shares outstanding	62,917	62,418	62,855	62,377
Diluted weighted-average common shares outstanding	64,566	62,418	64,493	62,377
Basic net income (loss) per common share	**$ 0.29**	**$ (0.13)**	**$ 2.29**	**$ (1.54)**
Diluted net income (loss) per common share	**$ 0.28**	**$ (0.13)**	**$ 2.24**	**$ (1.54)**

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

SM ENERGY COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY AND COMPREHENSIVE INCOME (LOSS) (UNAUDITED)
(In thousands, except share amounts)

	Common Stock Shares	Common Stock Amount	Additional Paid-in Capital	Treasury Stock Shares	Treasury Stock Amount	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Stockholders' Equity
Balances, December 31, 2009	**62,899,122**	**$ 629**	**$ 160,516**	**(126,893)**	**$ (1,204)**	**$ 851,583**	**$ (37,954)**	**$ 973,570**
Comprehensive income, net of tax:								
Net income	—	—	—	—	—	144,246	—	144,246
Change in derivative instrument fair value	—	—	—	—	—	—	53,765	53,765
Reclassification to earnings	—	—	—	—	—	—	(782)	(782)
Minimum pension liability adjustment	—	—	—	—	—	—	4	4
Total comprehensive income								197,233
Cash dividends, $ 0.05 per share	—	—	—	—	—	(3,144)	—	(3,144)
Issuance of common stock under Employee Stock Purchase Plan	27,456	—	799	—	—	—	—	799
Issuance of common stock upon settlement of RSUs following expiration of restriction period, net of shares used for tax withholdings, including income tax cost of RSUs	34,588	1	(545)	—	—	—	—	(544)
Sale of common stock, including income tax benefit of stock option exercises	148,902	1	3,054	—	—	—	—	3,055
Stock-based compensation expense	—	—	11,149	24,258	715	—	—	11,864

Balances, June 30, 2010	**63,110,068**	**$ 631**	**$ 174,973**	**(102,635)**	**$ (489)**	**$ 992,685**	**$ 15,033**	**$ 1,182,833**
Balances, December 31, 2008	**62,465,572**	**$ 625**	**$ 141,283**	**(176,987)**	**$ (1,892)**	**$ 957,200**	**$ 65,293**	**$ 1,162,509**
Comprehensive loss, net of tax:								
Net loss	—	—	—	—	—	(95,945)	—	(95,945)
Change in derivative instrument fair value	—	—	—	—	—	—	(11,852)	(11,852)
Reclassification to earnings	—	—	—	—	—	—	(45,494)	(45,494)
Minimum pension liability adjustment	—	—	—	—	—	—	4	4
Total comprehensive loss								(153,287)
Cash dividends, $ 0.05 per share	—	—	—	—	—	(3,120)	—	(3,120)
Issuance of common stock under Employee Stock Purchase Plan	49,767	—	858	—	—	—	—	858
Issuance of common stock upon settlement of RSUs following expiration of restriction period, net of shares used for tax withholdings, including income tax cost of RSUs	86,505	1	(3,249)	—	—	—	—	(3,248)
Sale of common stock, including income tax benefit of stock option exercises	19,570	—	207	—	—	—	—	207
Stock-based compensation expense	1,250	—	6,873	50,094	636	—	—	7,509
Balances, June 30, 2009	**62,622,664**	**$ 626**	**$ 145,972**	**(126,893)**	**$ (1,256)**	**$ 858,135**	**$ 7,951**	**$ 1,011,428**

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

SM ENERGY COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)
(In thousands)

	For the Six Months Ended June 30, 2010	For the Six Months Ended June 30, 2009
Cash flows from operating activities:		
Net income (loss)	$ 144,246	$ (95,945)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Gain on divestiture activity	(127,999)	(645)
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	157,535	162,103
Exploratory dry hole expense	327	4,667
Impairment of proved properties	—	153,092
Abandonment and impairment of unproved properties	3,279	15,533
Impairment of materials inventory	—	11,335
Stock-based compensation expense	11,864	7,509
Change in Net Profits Plan liability	(33,871)	(20,842)
Unrealized derivative (gain) loss	(9,822)	13,134
Loss related to hurricanes	—	7,120
Amortization of debt discount and deferred financing costs	6,657	5,703
Deferred income taxes	78,820	(63,148)
Plugging and abandonment	(6,222)	(2,355)
Other	2,937	1,619
Changes in current assets and liabilities:		
Accounts receivable	7,628	49,149
Refundable income taxes	9,558	13,161
Prepaid expenses and other	(148)	(7,091)
Accounts payable and accrued expenses	26,299	(12,338)
Excess income tax benefit from the exercise of stock options	(938)	—
Net cash provided by operating activities	**270,150**	**241,761**
Cash flows from investing activities:		
Net proceeds from sale of oil and gas properties	247,998	1,081
Capital expenditures	(304,627)	(215,826)
Acquisition of oil and gas properties	—	(44)
Deposits to restricted cash	(19,595)	—
Receipts from restricted cash	—	14,398
Receipts from short-term investments	—	1,002
Other	(6,492)	—
Net cash used in investing activities	**(82,716)**	**(199,389)**
Cash flows from financing activities:		
Proceeds from credit facility	204,059	1,766,000
Repayment of credit facility	(392,059)	(1,791,000)
Debt issuance costs related to credit facility	—	(11,060)
Proceeds from sale of common stock	2,916	1,066
Dividends paid	(3,144)	(3,120)
Excess income tax benefit from the exercise of stock options	938	—
Other	(544)	—
Net cash used in financing activities	**(187,834)**	**(38,114)**
Net change in cash and cash equivalents	(400)	4,258
Cash and cash equivalents at beginning of period	10,649	6,131
Cash and cash equivalents at end of period	**$ 10,249**	**$ 10,389**

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

SM ENERGY COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED) (Continued)

Supplemental schedule of additional cash flow information and noncash investing and financing activities:

	For the Six Months Ended June 30,	
	2010	2009
	(In thousands)	
Cash paid for interest	$ 8,152	$ 8,837
Cash refunded for income taxes	$ (2,392)	$ (10,441)

As of June 30, 2010, and 2009, $105.4 million, and $57.9 million, respectively, are included as additions to oil and gas properties and accounts payable and accrued expenses in the accompanying condensed consolidated balance sheets. These oil and gas additions are reflected as cash used in investing activities in the periods that the payables are settled.

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

SM ENERGY COMPANY AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

June 30, 2010

Note 1 — The Company and Business

SM Energy Company ("SM Energy" or the "Company"), formerly named St. Mary Land & Exploration Company or referred to as St. Mary, is an independent energy company engaged in the exploration, exploitation, development, acquisition, and production of natural gas, natural gas liquids, and crude oil. The Company's operations are conducted entirely in the continental United States.

Note 2 — Basis of Presentation and Significant Accounting Policies

Basis of Presentation

The accompanying unaudited condensed consolidated financial statements of SM Energy have been prepared in accordance with accounting principles generally accepted in the United States for interim financial information and the instructions to Form 10-Q and Regulation S-X. They do not include all information and notes required by generally accepted accounting principles for complete financial statements. However, except as disclosed herein, there has been no material change in the information disclosed in the notes to consolidated financial statements included in SM Energy's Annual Report on Form 10-K for the year ended December 31, 2009, (the "2009 Form 10-K"). In the opinion of management, all adjustments, consisting of normal recurring accruals that are considered necessary for a fair presentation of the interim financial information, have been included. Operating results for the periods presented are not necessarily indicative of expected results for the full year. In connection with the preparation of the condensed consolidated financial statements of SM Energy, the Company evaluated subsequent events after the balance sheet date of June 30, 2010, through the filing date of this report.

Other Significant Accounting Policies

The accounting policies followed by the Company are set forth in Note 1 to the Company's consolidated financial statements in the 2009 Form 10-K, and are supplemented throughout the notes to condensed consolidated financial statements in this report. It is suggested that these condensed consolidated financial statements be read in conjunction with the consolidated financial statements and notes included in the 2009 Form 10-K.

Note 3 —Divestitures and Assets Held for Sale

Legacy Divestiture

In February 2010 the Company completed the divestiture of certain non-strategic oil properties located in Wyoming to Legacy Reserves Operating LP, a wholly-owned subsidiary of Legacy Reserves LP ("Legacy"). The transaction had an effective date of November 1, 2009. Total cash received, before commission costs and Net Profits Interest Bonus Plan ("Net Profits Plan") payments, was $125.2 million, of which $6.5 million was received as a deposit in December 2009. The final sale price is subject to normal post-closing adjustments and is expected to be finalized during the second half of 2010. The estimated gain on sale related to the divestiture is approximately $65.1 million and may be impacted by the forthcoming post-closing adjustments mentioned above. The Company determined that the sale does not qualify for discontinued operations accounting under Financial Accounting Standards Board ("FASB") Accounting Standards Codification ("ASC") Topic 205, "Presentation of Financial Statements" ("ASC Topic 205"). A portion of the transaction was structured to qualify as a like-kind exchange under Section 1031 of the Internal Revenue Code of 1986, as amended (the "Internal Revenue Code").

Sequel Divestiture

In March 2010 the Company completed the divestiture of certain non-strategic oil properties located in North Dakota to Sequel Energy Partners, LP, Bakken Energy Partners, LLC, and Three Forks Energy Partners, LLC (collectively referred to as "Sequel"). The transaction had an effective date of November 1, 2009. Total cash received, before commission costs and Net Profits Plan payments, was $126.9 million. The final sale price is subject to normal post-closing adjustments and is expected to be finalized during the second half of 2010. The estimated gain on sale related to the divestiture is approximately $50.4 million and may be impacted by the forthcoming post-closing adjustments mentioned above. The Company determined that the sale does not qualify for discontinued operations accounting under ASC Topic 205. A portion of the transaction was structured to qualify as a like-kind exchange under Section 1031 of the Internal Revenue Code.

Assets Held for Sale

In accordance with FASB ASC Topic 360, "Property, Plant, and Equipment" ("ASC Topic 360"), assets are classified as held for sale when the Company commits to a plan to sell the assets and there is reasonable certainty that the sale will take place within one year. Upon classification as held-for-sale, long-lived assets are no longer depreciated or depleted, and a measurement for impairment is performed to determine if there is any excess of carrying value over fair value less costs to sell. Subsequent changes to estimated fair value less the cost to sell will impact the measurement of assets held for sale if the fair value is determined to be less than the carrying value of the assets.

As of June 30, 2010, the accompanying condensed consolidated balance sheets present $7.1 million in book value of assets held for sale, net of accumulated depletion, depreciation, and amortization. Additionally, the corresponding asset retirement obligation liability of $1.5 million is separately presented. The Company determined that these planned asset sales do not qualify for discontinued operations accounting under ASC Topic 205. Subsequent to June 30, 2010, the Company has completely divested of the assets held for sale.

Note 4 — Income Taxes

Income tax (expense) benefit for the six-month periods ended June 30, 2010, and 2009, differs from the amounts that would be provided by applying the statutory U.S. federal income tax rate to income (loss) before income taxes as a result of the estimated effect of the domestic production activities deduction, percentage depletion, the effect of state income taxes, and other permanent differences. The provision for income taxes consists of the following:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2010	2009	2010	2009
	(In thousands)			
Current portion of income tax (expense) benefit:				
Federal	$ 1,759	$ (2,166)	$ (8,216)	$ (3,249)
State	21	(495)	(311)	(886)
Deferred portion of income tax (expense) benefit	(14,212)	7,758	(78,820)	63,148
Total income tax (expense) benefit	$ (12,432)	$ 5,097	$ (87,347)	$ 59,013
Effective tax rate	40.8 %	38.0 %	37.7 %	38.1 %

A change in the Company's effective tax rate between reported periods will generally reflect differences in its estimated highest marginal state tax rate due to changes in the composition of income between state tax jurisdictions resulting from Company activities. Non-core asset sales through June 30, 2010, and the Company's anticipated drilling budget for the rest of 2010 applied against the Company's cumulative temporary timing differences caused an increase in tax rate for the second quarter of 2010 when compared to the same period of 2009. The rate is also being impacted period to period as estimates for the domestic production activities deduction, percentage depletion and the impact of potential permanent state tax items affect the presented periods differently because of oil and gas price variability and the impact of non-core asset sales.

The Company and its subsidiaries file income tax returns in the U.S. federal jurisdiction and in various states. With few exceptions, the Company is no longer subject to U.S. federal or state income tax examinations by these tax authorities for years before 2006. In late 2009 the Internal Revenue Service announced a National Research Program ("NRP") study of employment tax compliance that includes audits of randomly selected taxpayers for data collection purposes. During the first quarter of 2010, the Internal Revenue Service initiated an audit of SM Energy for the 2006 tax year focused primarily on compensation. In the second quarter of 2010 the Company determined its 2006 audit was not part of the NRP study. At June 30, 2010, the Company is awaiting a $5.5 million refund related to its 2006 tax year as a result of a net operating loss carry back from the Company's 2008 tax year. This refund claim was combined with the audit discussed above and cannot be received until the audit is completed and submitted to the Joint Committee on Taxation ("JCT") for review. The Company believes the 2006 audit will conclude in the third quarter of 2010 with no material adjustments, and its claim will be submitted to the JCT soon thereafter. The Company's remaining refundable income tax balance at June 30, 2010, reflects its utilization of carry backs to claim a taxable net operating loss generated for the 2009 tax year against its 2005 taxable income. On July 20, 2010, the Company received $22.9 million relating to this carry back claim.

The Company's 2005 federal income tax audit was concluded in the first quarter of 2009 with a refund to the Company of $278,000 plus interest of $41,000. There was no change to the provision for income tax expense as a result of the 2005 examination.

Note 5 — Earnings per Share

Basic net income or loss per common share of stock is calculated by dividing net income or loss available to common stockholders by the basic weighted-average common shares outstanding for the respective period. The shares represented by vested restricted stock units ("RSUs") are included in the calculation of the basic weighted-average common shares outstanding. The earnings per share calculations reflect the impact of any repurchases of shares of common stock made by the Company.

Diluted net income or loss per common share of stock is calculated by dividing adjusted net income or loss by the diluted weighted-average common shares outstanding, which includes the effect of potentially dilutive securities. Potentially dilutive securities for the diluted earnings per share calculation consist of unvested RSUs, in-the-money outstanding options to purchase the Company's common stock, contingent Performance Share Awards ("PSAs"), and shares into which the 3.50% Senior Convertible Notes due 2027 (the "3.50% Senior Convertible Notes") are convertible.

The Company's 3.50% Senior Convertible Notes have a net-share settlement right whereby each $1,000 principal amount of notes may be surrendered for conversion to cash in an amount equal to the principal amount and, if applicable, shares of common stock or cash or any combination of common stock and cash for the amount of conversion value in excess of the principal amount. The treasury stock method is used to measure the potentially dilutive impact of shares associated with this conversion feature. The 3.50% Senior Convertible Notes have not been dilutive for any reporting period that they have been outstanding and therefore do not impact the diluted earnings per share calculation for the three-month and six-month periods ended June 30, 2010, and 2009.

The PSAs represent the right to receive, upon settlement of the PSAs after the completion of the three-year performance period, a number of shares of the Company's common stock that may be from zero to two times the number of PSAs granted on the award date. The number of potentially dilutive shares related to PSAs is based on the number of shares, if any, which would be issuable at the end of the respective reporting period, assuming that date was the end of the contingency period. For additional discussion on PSAs, please refer to Note 7 — Compensation Plans under the heading *Performance Share Awards Under the Equity Incentive Compensation Plan.*

The treasury stock method is used to measure the dilutive impact of stock options, RSUs, 3.50% Senior Convertible Notes, and PSAs. In accordance with FASB

ASC Topic 260, "Earnings Per Share" when there is a loss from continuing operations, all potentially dilutive shares will be anti-dilutive. There were no dilutive shares for the three-month or six-month periods ended June 30, 2009, because the Company recorded a loss for each of those periods. Unvested RSUs, contingent PSAs, and in-the-money options had a dilutive impact for the three-month and six-month periods ended June 30, 2010, as calculated in the table below.

The following table sets forth the calculation of basic and diluted earnings per share:

	For the Three Months Ended June 30, 2010	For the Three Months Ended June 30, 2009	For the Six Months Ended June 30, 2010	For the Six Months Ended June 30, 2009
	(In thousands, except per share amounts)			
Net income (loss)	$ 18,068	$ (8,322)	$ 144,246	$ (95,945)
Basic weighted-average common stock outstanding	62,917	62,418	62,855	62,377
Add: dilutive effect of stock options, unvested RSUs, and contingent PSAs	1,649	—	1,638	—
Add: dilutive effect of 3.50% senior convertible notes	—	—	—	—
Diluted weighted-average common shares outstanding	64,566	62,418	64,493	62,377
Basic net income (loss) per common share	$ 0.29	$ (0.13)	$ 2.29	$ (1.54)
Diluted net income (loss) per common share	$ 0.28	$ (0.13)	$ 2.24	$ (1.54)

Note 6 — Commitments and Contingencies

In February 2010 the Company entered into an agreement whereby it is subject to certain natural gas gathering through-put commitments that require a minimum volume delivery of 100 Bcf by the end of the ten year contract term. As of June 30, 2010, the pipeline volume commitments associated with this agreement for the next five years and thereafter are presented below:

Years Ending December 31,	Committed Volumes (In Bcf)	Undiscounted Cash Outflows (In thousands)
2010	3.0	$ 540
2011	6.0	1,080
2012	6.0	1,080
2013	10.0	1,800
2014	10.0	1,800
Thereafter	65.0	11,700
Total	100.0	$ 18,000

On July 2, 2010, the Company entered into an agreementwhereby it is subject to certain natural gas gathering through-put commitments during the ten year contract term. The Company will be required to make periodic deficiency payments for any shortfalls in delivering the minimum volume commitments. In the event that no gas is delivered pursuant to the agreement, the aggregate deficiency payments will total $154.7 million over the life of the contract.

Note 7 — Compensation Plans

Cash Bonus Plan

During the first quarters of 2010 and 2009, the Company paid $7.7 million and $6.0 million for cash bonuses earned in the 2009 and 2008 performance years, respectively. Within the general and administrative expense and exploration expense line items in the accompanying condensed consolidated statements of operations is $2.9 million of cash bonus expense related to the specific performance year for each of the three-month periods ended June 30, 2010, and 2009, and $6.0 million and $5.3 million for the six-month periods ended June 30, 2010, and 2009, respectively.

Performance Share Awards Under the Equity Incentive Compensation Plan

The PSAs represent the right to receive, upon settlement of the PSAs after the completion of the three-year performance period, a number of shares of the Company's common stock that may be from zero to two times the number of PSAs granted on the award date, depending on the extent to which the Company's performance criteria have been achieved and the extent to which the PSAs have vested. The performance criteria for the PSAs are based on a combination of the Company's total shareholder return ("TSR") for the performance period and the relative performance of the Company's TSR compared with the TSR of an index of certain peer companies for the performance period.

Total stock-based compensation expense related to PSAs for the three-month periods ended June 30, 2010, and 2009, was $3.8 million and $1.1 million, respectively, and $7.4 million and $2.5 million for the six-month periods ended June 30, 2010, and 2009, respectively. As of June 30, 2010, there was $14.7 million of total unrecognized compensation expense related to unvested PSAs. The unrecognized compensation expense will be amortized through 2012.

A summary of the status and activity of PSAs for the six-month period ended June 30, 2010, is presented in the following table:

	PSAs	Weighted-Average Grant-Date Fair Value
Non-vested, at January 1, 2010	1,069,090	$ 32.52
Granted	—	$ —
Vested	(8,128)	$ 30.50
Forfeited	(87,527)	$ 31.73
Non-vested and outstanding, at June 30, 2010	973,435	$ 32.61

Subsequent to June 30, 2010, the Company granted 387,651 PSAs as part of its regular annual compensation process. These PSAs will vest 1/7th on July 1, 2011, 2/7ths on July 1, 2012, and 4/7ths on July 1, 2013.

Restricted Stock Unit Incentive Program Under the Equity Incentive Compensation Plan

Total RSU compensation expense for both the three-month periods ended June 30, 2010, and 2009, was $1.7 million, and $3.5 million and $3.8 million for the six-month periods ended June 30, 2010, and 2009, respectively. As of June 30, 2010, there was $5.4 million of total unrecognized compensation expense related to unvested RSU awards. The unrecognized compensation expense will be amortized through 2012.

During the first half of 2010, the Company settled 51,115 RSUs that relate to awards granted in 2008 and 2007 through the issuance of shares of the Company's common stock in accordance with the terms of the RSU awards. The Company and the majority of the grant participants mutually agreed to net-share settle the awards to cover income and payroll tax withholdings as provided for in the plan document and the award agreements. As a result, the Company issued 34,588 shares of common stock associated with these grants. The remaining 16,527 shares were withheld to satisfy income and payroll tax withholding obligations that occurred upon the delivery of the shares underlying those RSUs.

A summary of the status and activity of RSUs for the six-month period ended June 30, 2010, is presented in the following table:

	RSUs		Weighted-Average Grant-Date Fair Value
Non-vested, at January 1, 2010	407,123	$	34.67
Granted	—	$	—
Vested	(49,882)	$	36.23
Forfeited	(26,877)	$	36.48
Non-vested and outstanding, at June 30, 2010	330,364	$	34.28

Subsequent to June 30, 2010, the Company granted 126,821 RSUs as part of its regular annual compensation process. Each RSU represents a right to receive one share of the Company's common stock

to be delivered upon settlement of the vested RSUs. These RSUs will vest 1/7th on July 1, 2011, 2/7ths on July 1, 2012, and 4/7ths on July 1, 2013.

Stock Option Grants Under Prior Stock Option Plans

The following table summarizes stock option activity for the six months ended June 30, 2010:

	Options		Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Term (In years)		Aggregate Intrinsic Value (In thousands)
Outstanding, at January 1, 2010	1,274,920	$	13.31			
Exercised	(148,902)	$	14.22			
Forfeited	—	$	—			
Outstanding, end of period	1,126,018	$	13.19	2.6	$	30,369
Vested, or expect to vest, at end of period	1,126,018	$	13.19	2.6	$	30,369
Exercisable, end of period	1,126,018	$	13.19	2.6	$	30,369

As of June 30, 2010, there was no unrecognized compensation expense related to stock option awards.

Director Shares

In May 2010 and 2009 the Company issued 24,258 and 50,094 shares, respectively, of the Company's common stock from treasury to the Company's non-employee directors. The shares were issued pursuant to the Company's Equity Incentive Compensation Plan. The Company recorded $690,000 and $517,000 of compensation expense for the three-month periods ended June 30, 2010, and 2009, respectively, and $715,000 and $636,000 for the six-month periods ended June 30, 2010, and 2009, respectively.

Employee Stock Purchase Plan

Under the Company's Employee Stock Purchase Plan (the "ESPP"), eligible employees may purchase shares of the Company's common stock through payroll deductions of up to 15 percent of eligible compensation. The purchase price of the stock is 85 percent of the lower of the fair market value of the stock on the first or last day of the purchase period, and shares issued under the ESPP are restricted for a period of six months from the date issued. The ESPP is intended to qualify under Section 423 of the Internal Revenue Code. The Company has set aside 2,000,000 shares of its common stock to be available for issuance under the ESPP, of which 1,440,819 shares are available for issuance as of June 30, 2010. The fair value of ESPP grants is measured at the date of grant using the Black-Scholes option-pricing model. There were 27,456 and 49,767 shares issued under the ESPP during the first half of 2010 and 2009, respectively. The Company expensed $124,000 and $390,000 for the three-month periods ended June 30, 2010, and 2009, respectively, and $263,000 and $541,000 for the six-month periods ended June 30, 2010, and 2009, respectively, based on the estimated fair values on the respective grant dates.

Net Profits Plan

Prior to 2008, all oil and gas wells that were completed or acquired during each year were assigned to a specific pool for that respective year under the Company's legacy Net Profits Plan. Key employees become entitled to payments under the Net Profits Plan after the Company has received net cash flows

returning 100 percent of all costs associated with a pool. Thereafter, ten percent of future net cash flows generated by the pool are allocated among the participants and distributed at least annually. The portion of net cash flows from the pool to be allocated among the participants increases to 20 percent after the Company has recovered both 200 percent of the total costs for the pool and 100 percent of pool payments made under the Net Profits Plan at the ten percent level. The 2007 Net Profits Plan pool was the last pool established by the Company.

Cash payments made or accrued under the Net Profits Plan that have been recorded as either general and administrative expense or exploration expense are detailed in the table below:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2010	2009	2010	2009
	(In thousands)			
General and administrative expense	$ 5,381	$ 4,541	$ 12,315	$ 7,774
Exploration expense	667	471	1,258	876
Total	$ 6,048	$ 5,012	$ 13,573	$ 8,650

Additionally, the Company made cash payments under the Net Profits Plan of $1.9 million and $20.1 million for the three-month and six-month periods ended June 30, 2010, respectively, as a result of sales proceeds mainly from the Legacy and Sequel divestitures. The cash payments are accounted for as a reduction of proceeds, which reduced the gain (loss) on divestiture activity in the accompanying condensed consolidated statements of operations. There were no cash payments made under the Net Profits Plan as a result of divestitures that occurred during the first half of 2009.

The Company records changes in the present value of estimated future payments under the Net Profits Plan as a separate line item in the accompanying condensed consolidated statements of operations. The change in the estimated liability is recorded as a non-cash expense or benefit in the current period. The amount recorded as an expense or benefit associated with the change in the estimated liability is not allocated to general and administrative expense or exploration expense because it is associated with the future net cash flows from oil and gas properties in the respective pools rather than results being realized through current period production. The table below presents the estimated allocation of the change in the liability if the Company did allocate the adjustment to these specific functional line items based on the current allocation of actual distributions made by the Company. As time progresses, less of the distributions relate to prospective exploration efforts as more of the distributions are made to participants that have terminated employment and do not provide ongoing exploration support to the Company.

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2010	2009	2010	2009
	(In thousands)			
General and administrative expense (benefit)	$ (5,959)	$ 1,964	$ (32,604)	$ (18,730)
Exploration expense (benefit)	(640)	485	(1,267)	(2,112)
Total	$ (6,599)	$ 2,449	$ (33,871)	$ (20,842)

Note 8 — Pension Benefits

Pension Plans

The Company has a non-contributory pension plan covering substantially all employees who meet age and service requirements (the “Qualified Pension Plan”). The Company also has a supplemental non-contributory pension plan covering certain management employees (the “Nonqualified Pension Plan”).

Components of Net Periodic Benefit Cost for Both Plans

The following table presents the total components of the net periodic cost for both the Qualified Pension Plan and the Nonqualified Pension Plan:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2010	2009	2010	2009
	(In thousands)			
Service cost	$ 848	$ 625	$ 1,696	$ 1,250
Interest cost	280	233	560	467
Expected return on plan assets	(159)	(107)	(318)	(215)
Amortization of net actuarial loss	91	93	182	186
Net periodic benefit cost	$ 1,060	$ 844	$ 2,120	$ 1,688

Prior service costs are amortized on a straight-line basis over the average remaining service period of active participants. Gains and losses in excess of ten percent of the greater of the benefit obligation or the market-related value of assets are amortized over the average remaining service period of active participants.

Contributions

Under the Pension Protection Act of 2006, SM Energy is not required to make a minimum contribution to the pension plans in 2010.

Note 9 — Asset Retirement Obligations

The Company recognizes an estimated liability for future costs associated with the plugging and abandonment of its oil and gas properties. A liability for the fair value of an asset retirement obligation and a corresponding increase to the carrying value of the related long-lived asset are recorded at the time a well is completed or acquired. The increase in carrying value is included in proved oil and gas properties in the accompanying condensed consolidated balance sheets. The Company depletes the amount added to proved oil and gas property costs and recognizes expense in connection with the accretion of the discounted liability over the remaining estimated economic lives of the respective oil and gas properties. Cash paid to settle asset retirement obligations is included in the operating section of the Company’s accompanying condensed consolidated statements of cash flows.

The Company’s estimated asset retirement obligation liability is based on estimated economic lives, historical experience in plugging and abandoning wells, estimated cost to plug and abandon the wells in the future, and federal and state regulatory requirements. The liability is discounted using a credit-adjusted risk-free rate estimated at the time the liability is incurred or revised. The credit-adjusted risk-free rates used to discount the Company’s abandonment liabilities range from 6.5 percent to 12.0 percent. Revisions to the liability could occur due to changes in estimated abandonment costs or well commerciality, or if federal or state regulators enact new requirements regarding the abandonment of wells. The asset retirement obligation is considered settled when the well has been plugged and abandoned or divested.

A reconciliation of the Company's asset retirement obligation liability is as follows:

		For the Six Months Ended June 30, 2010 (In thousands)
Beginning asset retirement obligation	$	102,080
Liabilities incurred		1,373
Liabilities settled		(24,583)
Accretion expense		2,845
Revision to estimated cash flow		(715)
Ending asset retirement obligation	$	81,000

As of June 30, 2010, the Company had $1.5 million of asset retirement obligation associated with the oil and gas properties held for sale included in a separate line item on the Company's accompanying condensed consolidated balance sheets. Additionally, as of June 30, 2010, accounts payable and accrued expenses contained $15.2 million related to the Company's current asset retirement obligation liability associated with the estimated retirement of some of the Company's offshore platforms.

Note 10 — Derivative Financial Instruments

Oil, Natural Gas and NGL Commodity Hedges

To mitigate a portion of the exposure to potentially adverse market changes in oil and gas prices and the associated impact on cash flows, the Company has entered into various derivative contracts. The Company's derivative contracts in place include swap and collar arrangements for oil, natural gas, and natural gas liquids ("NGLs"). As of June 30, 2010, the Company has hedge contracts in place through the first quarter of 2013 for a total of approximately 5 million Bbls of anticipated crude oil production, 46 million MMBtu of anticipated natural gas production, and 2 million Bbls of anticipated natural gas liquids production. As of July 28, 2010, the Company has hedge contracts in place through the second quarter of 2013 for a total of approximately 6 million Bbls of anticipated crude oil production, 50 million MMBtu of anticipated natural gas production, and 2 million Bbls of anticipated natural gas liquids production.

The Company attempts to qualify its oil, natural gas, and NGL derivative instruments as cash flow hedges for accounting purposes under FASB ASC Topic 815, "Derivatives and Hedging" ("ASC Topic 815"). The Company formally documents all relationships between the derivative instruments and the hedged production, as well as the Company's risk management objective and strategy for the particular derivative contracts. This process includes linking all derivatives that are designated as cash flow hedges to the specific forecasted sale of oil, natural gas or NGLs. The Company also formally assesses (both at the derivative's inception and on an ongoing basis) whether the derivatives being utilized have been highly effective in offsetting changes in the cash flows of hedged production and whether those derivatives may be expected to remain highly effective in future periods. If it is determined that a derivative has ceased to be highly effective as a hedge, the Company will discontinue hedge accounting for that derivative prospectively. If hedge accounting is discontinued and the derivative remains outstanding, the Company will recognize all subsequent changes in its fair value in the Company's consolidated statements of operations for the period in which the change occurs. As of June 30, 2010, all oil, natural gas, and NGL derivative instruments qualified as cash flow hedges for accounting purposes. The Company anticipates that all forecasted transactions will occur by the end of their originally specified periods. All contracts are entered into for other-than-trading purposes.

The Company's oil, natural gas, and NGL hedges are measured at fair value and are included in the accompanying condensed consolidated balance sheets as derivative assets and liabilities. The Company

derives internal valuation estimates taking into consideration the counterparties' credit worthiness, the Company's credit worthiness, and the time value of money. Those internal valuations are then compared to the counterparties' mark-to-market statements. The consideration of the factors results in an estimated exit-price for each derivative asset or liability under a market place participant's view. Management believes that this approach provides a reasonable, non-biased, verifiable, and consistent methodology for valuing commodity derivative instruments. The derivative instruments utilized by the Company are not considered by management to be complex, structured, or illiquid. The oil, natural gas, and NGL derivative markets are highly active. The fair value of oil, natural gas, and NGL derivative contracts designated and qualifying as cash flow hedges under ASC Topic 815 was a net asset of $13.7 million and a net liability of $80.9 million at June 30, 2010, and December 31, 2009, respectively.

The following table details the fair value of derivatives recorded in the consolidated balance sheets, by category:

	Location on Consolidated Balance Sheets		Fair Value at June 30, 2010 (In thousands)		Fair Value at December 31, 2009
Derivative assets designated as cash flow hedges:					
Oil, natural gas, and NGL commodity	Current assets	$	45,481	$	30,295
Oil, natural gas, and NGL commodity	Other noncurrent assets		30,169		8,251
Total derivative assets designated as cash flow hedges under ASC Topic 815		$	75,650	$	38,546
Derivative liabilities designated as cash flow hedges:					
Oil, natural gas, and NGL commodity	Current liabilities	$	(37,903)	$	(53,929)
Oil, natural gas, and NGL commodity	Noncurrent liabilities		(24,046)		(65,499)
Total derivative liabilities designated as cash flow hedges under ASC Topic 815		$	(61,949)	$	(119,428)

Realized gains or losses from the settlement of oil, natural gas, and NGL derivative contracts are reported in the total operating revenues and other income section of the accompanying condensed consolidated statements of operations. The Company realized a net gain of $9.3 million and $43.3 million from its oil, natural gas, and NGL derivative contracts for the three months ended June 30, 2010, and 2009, respectively, and realized a net gain of $11.9 million and $98.9 million from its oil, natural gas, and NGL derivative contracts for the six months ended June 30, 2010, and 2009, respectively.

After-tax changes in the fair value of derivative instruments designated as cash flow hedges, to the extent they are effective in offsetting cash flows attributed to the hedged risk, are recorded in accumulated other comprehensive income in the accompanying condensed consolidated balance sheets until the hedged item is realized in earnings upon the sale of the associated hedged production. As of June 30, 2010, the amount of unrealized gain (loss) net of deferred income taxes to be reclassified from accumulated other comprehensive income to realized oil and gas hedge gain (loss) in the Company's accompanying condensed consolidated statements of operations in the next twelve months is $11.3 million.

The Company seeks to minimize ineffectiveness by entering into oil derivative contracts indexed to the New York Mercantile Exchange West Texas Intermediate ("NYMEX WTI") index, natural gas derivative contracts indexed to regional index prices associated with pipelines in proximity to the Company's areas of production, and NGL derivative contracts indexed to Oil Price Information Service Mont Belvieu. The Company's derivative contracts utilize the same respective indices or pricing points as the Company’s sales contracts. As a result, the derivative contracts used by the Company are highly correlated with the underlying hedged production.

The following table details the effect of derivative instruments on other comprehensive income (loss) and the condensed consolidated balance sheets (net of income tax):

	Derivatives Qualifying as Cash Flow Hedges	For the Six Months Ended June 30, 2010	2009
		(In thousands)	
Amount of (gain) loss on derivatives recognized in OCI during the period (effective portion)	Commodity hedges	$ (53,765)	$ 11,852
Amount of (gain) loss reclassified from AOCI to realized oil and gas hedge gain (loss) (effective portion)	Commodity hedges	$ (782)	$ (45,494)

Any change in fair value resulting from hedge ineffectiveness is recognized currently in unrealized derivative (gain) loss in the accompanying condensed consolidated statements of operations. The following table details the effect of derivative instruments on the condensed consolidated statements of operations:

		(Gain) Loss Recognized in Earnings (Ineffective Portion)			
		For the Three Months Ended June 30,		For the Six Months Ended June 30,	
Derivatives Qualifying as Cash Flow Hedges	Classification of (Gain) Loss Recognized in Earnings	2010	2009	2010	2009
		(In thousands)			
Commodity hedges	Unrealized derivative (gain) loss	$ (2,087)	$ 11,288	$ (9,822)	$ 13,134

Credit Related Contingent Features

As of June 30, 2010, only one of the Company’s hedge counterparties was not a member of the Company’s credit facility bank syndicate. Member banks are secured by the Company’s oil and gas assets, and therefore do not require the Company to post collateral in instances where the Company is in a liability position. When the Company is in a liability position with a non-member bank, posting of collateral may be required if the Company’s liability balance exceeds the limit set forth in the agreement with the non-member bank. With the one non-member bank, the amount of collateral, if any, that the Company is required to post depends on a number of financial metrics that are calculated quarterly. No collateral was posted as of June 30, 2010, or July 28, 2010.

Convertible Note Derivative Instruments

The contingent interest provision of the 3.50% Senior Convertible Notes is an embedded derivative instrument. As of June 30, 2010, and December 31, 2009, the value of this derivative was determined to be immaterial.

Note 11 — Fair Value Measurements

The Company follows the authoritative accounting guidance under FASB ASC Topic 820, “Fair Value Measurements and Disclosures” (“ASC Topic 820”) for all assets and liabilities measured at fair value. ASC Topic 820 establishes a framework for measuring fair value and requires enhanced disclosures about fair value measurements. ASC Topic 820 defines fair value as the price that would be received to sell an asset or paid to transfer a liability (an exit price) in an orderly transaction between market participants at the measurement date. The topic establishes market or observable inputs as the preferred sources of values, followed by assumptions based on hypothetical transactions in the absence of market inputs. The topic establishes a hierarchy for grouping these assets and liabilities based on the significance level of the following inputs:

- Level 1 — Quoted prices in active markets for identical assets or liabilities
- Level 2 — Quoted prices in active markets for similar assets and liabilities, quoted prices for identical or similar instruments in markets that are not active, and model-derived valuations whose inputs are observable or whose significant value drivers are observable
- Level 3 — Significant inputs to the valuation model are unobservable

The following is a listing of the Company’s financial assets and liabilities that are measured at fair value on a recurring basis and where they are classified within the hierarchy as of June 30, 2010:

	Level 1	Level 2	Level 3
		(In thousands)	
Assets:			
Derivatives	$ —	$ 75,650	$ —
Liabilities:			
Derivatives	$ —	$ 61,949	$ —
Net Profits Plan	$ —	$ —	$ 136,420

There were no nonfinancial assets or liabilities measured at fair value on a nonrecurring basis at June 30, 2010.

The following is a listing of the Company’s assets and liabilities that are measured at fair value and where they are classified within the hierarchy as of December 31, 2009:

	Level 1	Level 2	Level 3
		(In thousands)	
Assets:			
Derivatives(a)	$ —	$ 38,546	$ —
Proved oil and gas properties(b)	$ —	$ —	$ 11,740
Materials inventory(b)	$ —	$ 13,882	$ —
Liabilities:			
Derivatives(a)	$ —	$ 119,428	$ —
Net Profits Plan(a)	$ —	$ —	$ 170,291

(a) This represents a financial asset or liability that is measured at fair value on a recurring basis.
(b) This represents a nonfinancial asset or liability that is measured at fair value on a nonrecurring basis.

Both financial and non-financial assets and liabilities are categorized within the hierarchy based on the lowest level of input that is significant to the fair value measurement. The following is a description of the valuation methodologies used by the Company as well as the general classification of such instruments pursuant to the hierarchy.

Derivatives

The Company uses Level 2 inputs to measure the fair value of oil and gas hedges. Fair values are based upon interpolated data. The Company derives internal valuation estimates taking into consideration the counterparties' credit ratings, the Company's credit rating, and the time value of money. These valuations are then compared to the respective counterparties' mark-to-market statements. The considered factors result in an estimated exit-price that management believes provides a reasonable and consistent methodology for valuing derivative instruments.

Generally, market quotes assume that all counterparties have near zero, or low, default rates and have equal credit quality. However, an adjustment may be necessary to reflect the credit quality of a specific counterparty to determine the fair value of the instrument. The Company monitors the credit ratings of its counterparties and may ask counterparties to post collateral if their ratings deteriorate. In some instances the Company may attempt to novate trades with parties deemed to have more risk on a relative basis to a more stable and less risky counterparty.

Valuation adjustments are necessary to reflect the effect of the Company's credit quality on the fair value of any liability position with a counterparty. This adjustment takes into account any credit enhancements, such as collateral margin that the Company may have posted with a counterparty, as well as any letters of credit between the parties. The methodology to determine this adjustment is consistent with how the Company evaluates counterparty credit risk, taking into account the Company's credit rating, current credit facility margins, and any change in such margins since the last measurement date. The majority of the Company's derivative counterparties are members of SM Energy's credit facility bank syndicate.

The methods described above may result in a fair value estimate that may not be indicative of net realizable value or may not be reflective of future fair values and cash flows. While the Company believes that the valuation methods utilized are appropriate and consistent with the requirements of ASC Topic 820 and with other marketplace participants, the Company recognizes that third parties may use different methodologies or assumptions to determine the fair value of certain financial instruments that could result in a different estimate of fair value at the reporting date.

Net Profits Plan

The Net Profits Plan is a standalone liability for which there is no available market price, principal market, or market participants. The inputs available for this instrument are unobservable, and therefore classified as Level 3 inputs. The Company employs the income approach, which converts expected future cash flow amounts to a single present value amount. This technique uses the estimate of future cash payments, expectations of possible variations in the amount and/or timing of cash flows, the risk premium, and nonperformance risk to calculate the fair value. There is a direct correlation between realized oil and gas commodity prices and their impact on net cash flows and the amount of the Net Profits Plan liability. Generally, higher commodity prices result in a larger Net Profits Plan liability and vice versa.

The Company records the estimated fair value of the long-term liability for estimated future payments under the Net Profits Plan based on the discounted value of estimated future payments associated with each individual pool. The calculation of this liability is a significant management estimate. For a predominate number of the pools, a discount rate of 12 percent is used to calculate this liability. This rate is intended to represent the best estimate of the present value of expected future payments under the Net Profits Plan.

The Company's estimate of its liability is highly dependent on commodity price, cost assumptions, and the discount rates used in the calculations. The Company continually evaluates the assumptions used in this calculation in order to consider the current market environment for oil and gas prices, costs, discount rates, and overall market conditions. The Net Profits Plan liability was determined using price assumptions that were computed using five one-year strip prices with the fifth year's pricing being carried out indefinitely. The average price was adjusted to include the effects of hedge prices for the percentage of forecasted production hedged in the relevant periods. The non-cash expense associated with this significant management estimate is highly volatile from period to period due to fluctuations that occur in the crude oil and natural gas commodity markets.

If the commodity prices used in the calculation changed by five percent, the liability recorded at June 30, 2010, would differ by approximately $11 million. A one percentage point increase in the discount rate would decrease the liability by approximately $6 million whereas a one percentage point decrease in the discount rate would increase the liability by $7 million. Actual cash payments to be made to participants in future periods are dependent on realized actual production, realized commodity prices, and costs associated with the properties in each individual pool of the Net Profits Plan. Consequently, actual cash payments are inherently different from the amounts estimated. No published market quotes exist on which to base the Company's estimate of fair value of the Net Profits Plan liability. As such, the recorded fair value is based entirely on management estimates that are described within this footnote. While some inputs to the Company's calculation of fair value on the Net Profits Plan's future payments are from published sources, others, such as the discount rate and the expected future cash flows, are derived from the Company's own calculations and estimates. The following table reflects the activity for the liabilities measured at fair value using Level 3 inputs:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2010	2009	2010	2009
	(In thousands)			

Beginning balance	$ 143,019	$ 154,075	$ 170,291	$ 177,366
Net increase (decrease) in liability (a)	1,318	7,461	(218)	(12,192)
Net settlements (a)(b)	(7,917)	(5,012)	(33,653)	(8,650)
Transfers in (out) of Level 3	—	—	—	—
Ending balance	$ 136,420	$ 156,524	$ 136,420	$ 156,524

(a) Net changes in the Net Profits Plan liability are shown in the Change in Net Profits Plan liability line item of the accompanying condensed consolidated statements of operations.

(b) Settlements represent cash payments made or accrued under the Net Profits Plan and include $1.9 million and $20.1 million of cash payments related primarily to the Legacy and Sequel divestitures for the three-month and six-month periods ending June 30, 2010, respectively. There were no cash payments made under the Net Profits Plan as a result of divestitures that occurred during the first half of 2009.

3.50% Senior Convertible Notes Due 2027

Based on the market price of the 3.50% Senior Convertible Notes, the estimated fair value of the notes was approximately $306 million and $290 million as of June 30, 2010, and December 31, 2009, respectively.

Proved Oil and Gas Properties

Proved oil and gas property costs are evaluated for impairment and reduced to fair value if the sum of the expected undiscounted future cash flows is less than net book value pursuant to ASC Topic 360. The Company uses Level 3 inputs and the income valuation technique, which converts future amounts to a single present value amount, to measure the fair value of proved properties through an application of discount rates and price forecasts selected by the Company's management. The discount rate is a rate that management believes is representative of current market conditions and includes the following factors: estimates of future cash payments, expectations of possible variations in the amount and/or timing of cash flows, the risk premium, and nonperformance risk. The price forecast is based on NYMEX strip pricing, adjusted for basis differentials, for the first five years. Future operating costs are also adjusted as deemed appropriate for these estimates.

In accordance with ASC Topic 820, of the $2.1 billion of long-lived assets, excluding materials inventory, $11.7 million were measured at fair value at December 31, 2009. There were no long-lived assets measured at fair value within the accompanying condensed consolidated balance sheets at June 30, 2010.

Asset Retirement Obligations

The Company estimates asset retirement obligations pursuant to the provisions of FASB ASC Topic 410, "Asset Retirement and Environmental Obligations." The income valuation technique is utilized by the Company to determine the fair value of the liability at the point of inception by applying a credit-adjusted risk-free rate, which takes into account the Company's credit risk, the time value of money, and the current economic state, to the undiscounted expected abandonment cash flows. Given the unobservable nature of the inputs, the initial measurement of the asset retirement obligation liability is deemed to use Level 3 inputs. There were no asset retirement obligations measured at fair value within the accompanying consolidated balance sheets at June 30, 2010, or December 31, 2009.

Refer to Note 10 — Derivative Financial Instruments and Note 9 — Asset Retirement Obligations for more information regarding the Company's hedging instruments and asset retirement obligations.

Note 12 — Recent Accounting Pronouncements

The Company partially adopted FASB ASC Update 2010-06, "Fair Value Measurements and Disclosures — Improving Disclosures about Fair Value Measurements" ("ASC Update 2010-06") that requires additional disclosures surrounding transfers between Levels 1 and 2, inputs and valuation techniques used to value Level 2 and 3 measurements, and push down of previously prescribed fair value disclosures to each class of asset and liability for Levels 1, 2, and 3. These disclosures were effective for the Company for the quarter ended March 31, 2010. The partial adoption of this pronouncement did not have a material impact on the Company's consolidated financial statements.

ASC Update 2010-06 also requires that purchases, sales, issuances, and settlements for Level 3 measurements be disclosed. This portion of the new authoritative guidance is effective for interim and annual reporting periods beginning after December 15, 2010. The Company will apply this new guidance in the Company's Quarterly Report on Form 10-Q for the period ended March 31, 2011. The adoption of these portions of ASC Update 2010-06 are not expected to have a material impact on the Company's financial statements.

The Company adopted FASB ASC Update 2010-09, "Subsequent Events - Amendments to Certain Recognition and Disclosure Requirements," that removes the requirement for SEC filers to disclose the date through which an entity has evaluated subsequent events. However, the date-disclosure exemption does not relieve management of an SEC filer from its responsibility to evaluate subsequent events through the date on which financial statements are issued. This authoritative guidance was effective upon issuance on February 24, 2010. The adoption of this pronouncement did not have a material impact on the Company's consolidated financial statements.

Note 13 — Carry and Earning Agreement

On April 29, 2010, the Company entered into a Carry and Earning Agreement (the "CEA"), which effectively provides for a third party to earn 95 percent of SM Energy's interest in approximately 8,400 net acres in a portion of the Company's East Texas Haynesville shale acreage, as well as an interest in several wells and five percent of SM Energy's interest in approximately 23,400 net acres in a separate portion of the Company's Haynesville acreage in East Texas. In exchange for these interests, the third party has agreed to invest $91.3 million to fund the drilling and completion costs of horizontal wells in the portion of the leases where the Company is retaining 95 percent of its current interest. Of this, $86.7 million represents SM Energy's carried drilling and completion costs, being 95 percent of the total amount invested by the third party. The Company received an initial payment of $45.6 million on April 29, 2010, and the CEA provides that the Company will receive the balance of the committed funds less any adjustments allowed under the CEA for title defects within 30 days of the completion of the fourth commitment well. Once SM Energy has completed the expenditure of the total carry amount, the parties will share all costs of operations within the area of joint ownership in accordance with their respective ownership interests.

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

This discussion and analysis contains forward-looking statements. Refer to "Cautionary Information about Forward-Looking Statements" at the end of this item for an explanation of these types of statements.

Overview of the Company, Highlights, and Outlook

General Overview

We are an independent energy company focused on the development, exploration, exploitation, acquisition, and production of natural gas, natural gas liquids, and crude oil in the continental United States. Generally, we generate nearly all our revenues and cash flows from the sale of produced natural gas and crude oil. In the first half of 2010 we have generated significant gains and cash proceeds from the sale of non-strategic oil and gas properties. Our oil and gas reserves and operations are concentrated primarily in the Rocky Mountain Williston Basin; the Mid-Continent Anadarko and Arkoma basins; the Permian Basin; the productive formations of East Texas and North Louisiana; north central Pennsylvania; the Maverick Basin in South Texas; and the onshore Gulf Coast. We have developed a balanced and diverse portfolio of proved reserves, development drilling opportunities, and unconventional resource prospects.

Our mission is to deliver outstanding net asset value per share growth to our investors via attractive oil and gas investments. Our strategy is to focus on early entrance into existing and emerging resource plays in North America. By entering these plays earlier, we believe that we can capture larger resource potential at lower cost. We believe this organic-centered model allows for more stable and predictable production and proved reserves growth.

Financial Standing and Liquidity

In the first quarter of 2010, the borrowing base on our credit facility was redetermined by our bank group and maintained at a value of $900 million despite the divestiture of non-strategic Rocky Mountain oil properties during the quarter. The commitment amount of the bank group remained unchanged at $678 million. At the end of the second quarter 2010 and through the filing date of this report, we had no outstanding borrowings under the revolving credit facility. We have no debt maturities until 2012, at which time our credit facility matures and our outstanding convertible notes can be put to us. Given our debt and asset levels, credit standing, and relationships with the participants in our bank group, we believe we will be able to extend or obtain a replacement credit facility before our current credit facility matures in 2012. We also believe our convertible notes could be put to us in 2012, at which time we have the option of settling with some combination of cash and/or common stock. The condition of the capital markets has improved significantly since last year, and therefore we believe we could access capital through the public markets, if necessary, to redeem these notes.

We expect our generated cash flows from operations in 2010 plus proceeds from our Rocky Mountain oil and other non-core asset divestitures to fund the majority of our capital budget for 2010. We plan to use our credit facility to fund the remaining balance of our capital program. Accordingly, we do not anticipate accessing the equity or public debt markets for the remainder of 2010. Given the size of and commitments associated with our existing inventory of potential drilling projects, our needs for capital could increase significantly in 2011 and beyond. As a result, we may consider accessing the capital markets, as well as other alternatives, as we determine how to best fund our capital program. We continue to believe we have adequate liquidity available as discussed under the caption Overview of Liquidity and Capital Resources.

Oil and Gas Prices

Our financial condition and the results of our operations are significantly affected by the prices we receive for oil, natural gas, and natural gas liquids, which can fluctuate dramatically. Please refer to *Comparison of Financial Results and Trends between the three months ended June 30, 2010, and 2009* for our realized price tables. We sell a majority of our natural gas under contracts that use first of the month index pricing, which means that gas produced in a given month is sold at the first of the month price regardless of the spot price on the day the gas is produced. We account for our natural gas sales as they occur at the wellhead and accordingly do not present a separate production stream for natural gas liquids that are processed from our natural gas production. We receive value for the NGL content in our natural gas stream, which can result in us realizing a higher per unit price for our reported gas production. Our crude oil is sold using contracts that pay us either the average of the NYMEX WTI daily settlement price or the average of alternative posted prices for the periods in which the crude oil is produced, adjusted for quality, transportation, and location differentials. The following table is a summary of commodity price data for the second quarters of 2010 and 2009 and the first quarter of 2010:

	For the Three Months Ended		
	June 30, 2010	March 31, 2010	June 30, 2009
Crude Oil (per Bbl):			
Average NYMEX price	$ 77.88	$ 78.84	$ 59.69
Realized price, before the effects of hedging	$ 70.92	$ 72.73	$ 53.96
Net realized price, including the effects of hedging	$ 65.17	$ 66.96	$ 56.72
Natural Gas (per Mcf):			
Average NYMEX price	$ 4.33	$ 5.09	$ 3.71
Realized price, before the effects of hedging	$ 4.54	$ 6.15	$ 3.07
Net realized price, including the effects of hedging	$ 5.59	$ 6.84	$ 5.19

We expect future prices for oil, NGLs, and natural gas to be volatile. In addition to supply and demand fundamentals, the relative strength of the U.S. Dollar will likely continue to impact crude oil prices. Generally, NGL prices historically have trended and correlated with the price for crude oil. The supply of NGLs is expected to grow in the near term as a result of a number of industry participants targeting projects that produce these products, which could negatively impact future pricing. Future natural gas prices are facing downward pressure as a result of a perceived supply overhang resulting from increased levels of drilling activity across the country, as well as tepid demand recovery due to the recession. The 12-month strip prices for NYMEX WTI crude oil and NYMEX Henry Hub gas as of June 30, 2010, were $77.74 per Bbl and $5.07 per MMBTU, respectively. Comparable prices as of July 28, 2010, were $79.69 per Bbl and $4.99 per MMBTU, respectively.

While changes in quoted NYMEX oil and natural gas prices are generally used as a basis for comparison within our industry, the price we receive for oil and natural gas is affected by quality, energy content, location, and transportation differentials for these products. We refer to this price as our realized price, which excludes the effects of hedging. Our realized price is further impacted by the results of our hedging arrangements that are settled in the respective periods. We refer to this price as our net realized price. For the three months ended June 30, 2010, our net natural gas price realization was positively impacted by $17.4 million of realized hedge settlements and our net oil price realization was negatively impacted by $8.1 million of realized hedge settlements.

Hedging Activities

On July 21, 2010, the Dodd-Frank Wall Street Reform and Consumer Protection Act was enacted into law. This financial reform legislation includes provisions that require over-the-counter derivative transactions to be executed through an exchange or centrally cleared. In addition, the legislation provides an exemption from mandatory clearing requirements based on regulations to be developed by the Commodity Futures Trading Commission and the Securities and Exchange Commission for transactions by non-financial institutions to hedge or mitigate commercial risk. At the same time, the legislation includes provisions under which the CFTC may impose collateral requirements for transactions, including those that are used to hedge commercial risk. However, during drafting of the legislation, members of Congress adopted report language and issued a public letter stating that it was not their intention to impose margin and collateral requirements on counterparties that utilize transactions to hedge commercial risk. Final rules on major provisions in the legislation, like new margin requirements, will be established through rulemakings and will not take effect until 12 months after the date of enactment.   Although we cannot predict the ultimate outcome of these rulemakings, new regulations in this area may result in increased costs and cash collateral requirements for the types of oil and gas derivative instruments we use to hedge and otherwise manage our financial risks related to volatility in oil and gas commodity prices.

Hedging is an important part of our financial risk management program. We have a Board-authorized financial risk management policy that governs our practices related to hedging. The amount of production we hedge is driven by the amount of debt on our consolidated balance sheet and the level of capital commitments and long-term obligations we have in place. In the case of a significant acquisition of producing properties, we will consider hedging a portion of the acquired production in order to protect the economics assumed in the acquisition. With the hedges we have in place, we believe we have established a base cash flow stream for our future operations, and our use of collars for a portion of the hedges allows us to participate in upward movements in oil and gas prices while also setting a price floor for a portion of our production. Please see Note 10 — Derivative Financial Instruments of Part I, Item 1 of this report for additional information regarding our oil and gas hedges, and see the caption, *Summary of Oil and Gas Production Hedges in Place,* later in this section.

We attempt to qualify our oil and gas derivative instruments as cash flow hedges for accounting purposes under ASC Topic 815. Changes in the value of our hedge positions are primarily reflected in our consolidated balance sheets. A portion of the change in the value of our hedge positions is recognized in our consolidated statements of operations due to hedges being partially ineffective at offsetting the fluctuations in cash flow due to change in the spot price for oil, natural gas and natural gas liquids. We recognized $2.1 million in non-cash unrealized derivative gain in the second quarter of 2010. Changes in the fair value of our hedge portfolio from March 31, 2010, through June 30, 2010, was primarily caused by decreases in prices of natural gas on the indexes on which we have hedges. As a result, our hedge position changed from a $22.4 million net liability at the end of the first quarter of 2010 to a $13.7 million net asset at the end of the second quarter of 2010. Corresponding changes are reflected in accumulated other comprehensive income on the consolidated balance sheets and unrealized derivative (gain) loss on the statement of operations.

Second Quarter 2010 Highlights

Operational activities. During the second quarter, we had an average of nine operated drilling rigs running company-wide. The thrust of our operated drilling activities this year has been focused on oil and NGL-rich gas programs and selected projects of potential strategic importance to the Company. Additionally, our operating partners have increased their levels of activity in oil and NGL-rich gas plays.

In the Eagle Ford shale in South Texas, we continued to operate two drilling rigs on our acreage during the second quarter. Our focus was on drilling in areas with higher MMBTU gas content and higher condensate yields. We have continued to test different ways to drill and complete these wells with the objective of optimizing our future development potential. Securing infrastructure to transport and process

production from the Eagle Ford has been an issue we have worked to address over the last year, particularly in recent months. Subsequent to quarter end, we entered into a gas services agreement whereby we committed a significant amount of production from the Eagle Ford to a ten year transportation and processing arrangement beginning in 2011. This agreement has shortfall penalties in the event that we are unable to deliver the committed volumes of gas. We are continuing to explore other arrangements to further address our infrastructure needs for this program. On our outside-operated acreage in the Eagle Ford, our operating partner has increased their rig count to six rigs at quarter-end, up from two rigs earlier in the year. This outside-operated acreage has limited infrastructure to support the development of the play and as a result we have been participating in the construction of infrastructure with our partner. The increase in partner-operated rigs and the infrastructure build-out have resulted in higher capital expenditures in this program than we initially planned for at the beginning of the year.

We operated an average of two drilling rigs in the Williston Basin during the second quarter of the year, both of which were focused on Bakken and Three Forks drilling. Our results in this program have met or exceeded expectations as several strong wells came online in the second quarter. Partners in the Williston Basin have steadily increased their activity during the second quarter. Elsewhere in the Rocky Mountain region, we drilled and completed our first operated horizontal well targeting the Niobrara formation in southeastern Wyoming. Interest in the Niobrara formation increased significantly during the first half of 2010 based on positive field reports coming out of the play. Our early results have been encouraging from this exploratory program.

In our Mid-Continent region, we drilled our first two wells in the horizontal Granite Wash in Beckham County in western Oklahoma. One of these wells was highly productive with strong condensate and NGL-rich gas contribution. Our acreage position is held by production and given the multiple productive formations in the play, we think the potential from this emerging program could be significant.

The Permian region ran two operated rigs in the second quarter, with the focus of the activity being on Wolfberry tight oil targets. In our operated Haynesville shale program, we had one or two drilling rigs operating in the play for most of the quarter and we are currently awaiting the completion of several wells. In the Marcellus shale, our first well in the play was turned to sales during the quarter and we continued to work on the gathering line that will service development of our acreage in McKean County, Pennsylvania.

Financial and production results. We recorded net income for the quarter ended June 30, 2010, of $18.1 million or $0.28 per diluted share compared to second quarter 2009 results of a net loss of $8.3 million or $0.13 per diluted share.

The table below details the regional breakdown of our second quarter 2010 production:

	Mid-Continent	**ArkLaTex**	**South Texas & Gulf Coast**	**Permian**	**Rocky Mountain**	**Total (1)**
Second Quarter 2010 Production:						
Oil (MBbl)	45.9	20.7	181.0	438.2	726.3	1,412.2
Gas (MMcf)	7,894.3	3,170.5	3,147.5	1,074.1	1,390.8	16,677.3
Equivalent (MMCFE)	8,169.6	3,294.9	4,233.6	3,703.6	5,748.7	25,150.5
Avg. Daily Equivalents (MMCFE/d)	89.8	36.2	46.5	40.7	63.2	276.4
Relative percentage	32%	13%	17%	15%	23%	100%

(1) Totals may not add due to rounding

For the second quarter of 2010 our production performance was led by our Eagle Ford shale and Woodford shale programs. Both our operated and partner-operated programs targeting the Eagle Ford have contributed more production than anticipated this year. The Woodford shale program in the Arkoma Basin of eastern Oklahoma has not been a focus area for us this year, however stronger than projected base production performance has benefited our 2010 production.   Please refer to *Comparison of Financial Results and Trends between the three months ended June 30, 2010, and 2009* for additional discussion on production.

First Six Months 2010 Highlights

Legacy Divestiture. On February 17, 2010, we closed on a divestiture of non-core properties in Wyoming to Legacy Reserves Operating LP. Total cash received, before commission costs and Net Profits Plan payments, was $125.2 million. The final sale price is subject to normal post-closing adjustments and is expected to be finalized during the second half of 2010. The estimated gain on sale of proved properties related to the divestiture is approximately $65.1 million and may be impacted by the forthcoming post-closing adjustments mentioned above. We diverted a portion of the proceeds from this divestiture to restricted cash and will attempt to use these funds to acquire other properties in a like-kind exchange tax deferral strategy under Section 1031 of the Internal Revenue Code.

Sequel Divestiture. On March 12, 2010, we completed the divestiture of certain non-strategic properties located in North Dakota to Sequel Energy Partners, LP, Bakken Energy Partners, LLC, and Three Forks Energy Partners, LLC. Total cash received, before commission costs and Net Profits Plan payments, was $126.9 million. The final sale price is subject to normal post-closing adjustments and is expected to be finalized during the second half of 2010. The estimated gain on sale of proved properties related to the divestiture is approximately $50.4 million and may be impacted by the forthcoming post-closing adjustments mentioned above. We diverted a portion of the proceeds from this divestiture to restricted cash and will attempt to use these funds to acquire other properties in a like-kind exchange tax deferral strategy under Section 1031 of the Internal Revenue Code.

Net Profits Plan. In 2008, the Net Profits Plan was replaced with grants of performance shares and thus the 2007 Net Profits Plan pool was the last pool established by the Company. The Company will continue to make payments from the existing Net Profits Plan pools and will continue to make prospective adjustments to the long-term liability as necessary.

For the six months ended June 30, 2010, the change in the value of this liability resulted in a non-cash benefit of $33.9 million compared with a $20.8 million benefit for the same period in 2009. Current year payments made or accrued as part of allocating the proceeds received from the first half of 2010 divestitures have decreased the estimated liability for the future amounts to be paid to plan participants. This liability is a significant management estimate. Adjustments to the liability are subject to estimation and may change dramatically from period to period based on assumptions used for production rates, reserve quantities, commodity pricing, discount rates, tax rates, and production costs.

Payments made from the Net Profits Plan have been expensed as compensation costs in the amounts of $13.6 million and $8.7 million for the six months ended June 30, 2010, and 2009, respectively. Additionally, the above described sales of oil and gas properties were included in a number of profit pools and resulted in payments under the Net Profits Plan of $20.1 million during the first half of 2010. These cash payments are accounted for as a reduction of net sale proceeds and impact the gain on divestiture activity in the accompanying condensed consolidated statements of operations. There were no significant cash payments made or accrued under the Net Profits Plan as a result of divestitures during the first half of 2009.

The recurring Net Profits Plan cash payments we make are dependent on actual production, realized prices, and operating and capital costs associated with the properties in each individual pool. Actual cash payments will be inherently different from the estimated liability amounts. More detailed discussion is included in Note 11 — Fair Value Measurements in Part I, Item 1. An increasing percentage of the costs

associated with the payments under the Net Profits Plan are now being categorized as general and administrative expense as compared to exploration expense. This is a function of the normal departure of employees who previously contributed to our exploration efforts.

The calculation of the estimated liability for the Net Profits Plan is highly sensitive to our price estimates and discount rate assumptions. For example, if we changed the commodity prices in our calculation by five percent, the liability recorded on the balance sheet at June 30, 2010, would differ by approximately $11 million. A one percentage point increase in the discount rate would decrease the liability by approximately $6 million whereas a one percentage point decrease in the discount rate would increase the liability by $7 million. We frequently re-evaluate the assumptions used in our calculations and consider the possible impacts stemming from the current market environment including current and future oil and gas prices, discount rates, and overall market conditions.

Production results. The table below details the regional breakdown of our first half of 2010 production.

	Mid-Continent	ArkLaTex	South Texas & Gulf Coast	Permian	Rocky Mountain	Total (1)
First six months of 2010 Production:						
Oil (MBbl)	107.2	40.2	317.8	884.0	1,588.5	2,937.7
Gas (MMcf)	16,247.1	6,275.2	5,795.5	2,023.4	2,902.7	33,243.9
Equivalent (MMCFE)	16,890.1	6,516.1	7,702.2	7,327.7	12,434.0	50,870.1
Avg. Daily Equivalents (MMCFE/d)	93.3	36.0	42.6	40.5	68.7	281.1
Relative percentage	33%	13%	15%	14%	25%	100%

(1) Totals may not add due to rounding

For the first half of 2010 our production has outperformed our expectations for 2010 due to stronger than anticipated production results from our South Texas & Gulf Coast and Mid-Continent regions. Please refer to the three months discussion under *Financial and production results* above and *A three-month and six-month overview of selected production and financial information, including trends* and *Comparison of Financial Results and Trends between the six months ended June 30, 2010, and 2009* for additional discussion on production.

Outlook for the Remainder of 2010

Our development program entering 2010 was focused on the drilling of oil and rich gas projects. This decision has been reinforced as natural gas prices have been under downward pressure most of this year. We continue to evaluate ways to shift capital away from natural gas drilling wherever possible, except for activities necessary to satisfy leasehold commitments or to test emerging resource plays.

We are increasing our 2010 capital investment forecast to $871 million, up from $725 million. The increase in capital reflects the success we have seen in several of our plays this year, as well as an increase in costs throughout the industry to drill and complete wells. The largest portion of the increase relates to our non-operated acreage in the Eagle Ford shale, where our operating partner has increased their rig count to six rigs and we anticipate them going to an even higher rig count by year end. This portion of the play is in an area with higher condensate yields and a richer gas stream. The increase in our partner-operated rig count accounts for over $100 million of our increased capital investment when compared to our original budget. Additionally, related to this increase in partner-operated drilling is an increase in the requirement for infrastructure on our non-operated Eagle Ford acreage. Accordingly, the revised capital expenditure forecast includes increased investments for facilities and infrastructure that will service development of this portion of our Eagle Ford shale position in the coming years.

We are adding a rig in our operated horizontal Granite Wash program where we now plan to drill seven operated wells this year, up from the four operated wells that we initially planned for the year. In the Williston Basin, recent success in our Bakken and Three Forks plays has resulted in an increase in this program's capital budget. We plan to drill several more wells with our operated rigs, and have allocated additional capital to account for increased levels of partner-operated activity in the Williston Basin. The balance of our capital program remains relatively consistent with our original budget. We have remained flexible with respect to deployment of our exploration capital. Based on early encouraging data from our Niobrara test, we have reallocated capital toward this program for later in the year and are currently looking for a rig to drill a second test well. We plan on operating two drilling rigs in the East Texas portion of our Haynesville shale position for the remainder of 2010 and we currently have two wells waiting on completion. Our activity level in the Haynesville has not changed significantly from what we planned at the beginning of the year, although our amount of capital investment was substantially reduced as a result of the carry and earning agreement we entered into in the second quarter of 2010.

Financial Results of Operations and Additional Comparative Data

The table below provides information regarding selected production and financial information for the quarter ended June 30, 2010, and the immediately preceding three quarters. Additional details of per MCFE costs are presented later in this section.

	For the Three Months Ended			
	June 30, 2010	March 31, 2010	December 31, 2009	September 30, 2009
	(In millions, except production sales data)			
Production (BCFE)	25.2	25.7	26.1	26.4
Oil and gas production revenue, excluding the effects of hedging	$ 175.9	$ 212.9	$ 187.6	$ 152.7
Realized oil and gas hedge gain	$ 9.3	$ 2.6	$ 13.4	$ 28.3
Gain (loss) on divestiture activity	$ 7.0	$ 121.0	$ 22.1	$ (11.3)
Lease operating expense	$ 29.0	$ 30.0	$ 34.3	$ 34.3
Transportation costs	$ 5.1	$ 4.1	$ 5.2	$ 5.3
Production taxes	$ 11.1	$ 14.2	$ 13.3	$ 9.0
DD&A	$ 79.8	$ 77.8	$ 75.1	$ 67.0
Exploration	$ 14.5	$ 13.9	$ 13.4	$ 15.7
Impairment of proved properties	$ —	$ —	$ 21.6	$ 0.1
Abandonment and impairment of unproved properties	$ 2.4	$ 0.9	$ 25.2	$ 4.8
General and administrative	$ 25.4	$ 23.5	$ 20.7	$ 20.8
Change in Net Profits Plan liability	$ (6.6)	$ (27.3)	$ 7.0	$ 6.8
Unrealized derivative (gain) loss	$ (2.1)	$ (7.7)	$ 3.2	$ 4.1
Net income (loss)	$ 18.1	$ 126.2	$ 1.0	$ (4.4)
Percentage change from previous quarter:				
Production (BCFE)	(2)%	(2)%	(1)%	(6)%
Oil and gas production revenue, excluding the effects of hedging	(17)%	13%	23%	5%
Realized oil and gas hedge gain	258%	(81)%	(53)%	(35)%
Gain (loss) on divestiture activity	(94)%	448%	(296)%	(969)%
Lease operating expense	(3)%	(13)%	—%	(4)%
Transportation costs	24%	(21)%	(2)%	15%
Production taxes	(22)%	7%	48%	(3)%
DD&A	3%	4%	12%	(5)%
Exploration	4%	4%	(15)%	(19)%
Impairment of proved properties	—%	(100)%	N/M	(98)%
Abandonment and impairment of unproved properties	167%	(96)%	425%	(59)%
General and administrative	8%	14%	—%	14%
Change in Net Profits Plan liability	(76)%	(490)%	3%	183%
Unrealized derivative (gain) loss	(73)%	(341)%	(22)%	(64)%
Net income (loss)	(86)%	12,520%	(123)%	(47)%

A three-month and six-month overview of selected production and financial information, including trends:

Selected Operations Data (In thousands, except sales price, volume, and per MCFE amounts):

	For the Three Months Ended June 30,		Percent Change Between Periods	For the Six Months Ended June 30,		Percent Change Between Periods
	2010	2009		2010	2009	
Net production volumes						
Oil (MBbl)	1,412	1,648	(14)%	2,938	3,288	(11)%
Natural gas (MMcf)	16,677	18,329	(9)%	33,244	36,844	(10)%
MMCFE (6:1)	25,150	28,219	*(11)%	50,870	56,573	*(10)%
Average daily production						
Oil (Bbl per day)	15,519	18,114	(14)%	16,230	18,166	(11)%
Natural gas (Mcf per day)	183,267	201,422	(9)%	183,668	203,561	(10)%
MCFE per day (6:1)	276,379	310,104	*(11)%	281,050	312,559	*(10)%
Oil & gas production revenue (1)						

Oil production revenue	$ 92,035	$ 93,487	(2)%	$ 194,184	$ 165,900	17%
Gas production revenue	93,181	95,071	(2)%	206,514	208,695	(1)%
Total	$ 185,216	$ 188,558	(2)%	$ 400,698	$ 374,595	7%
Oil & gas production expense						
Lease operating expense	$ 28,955	$ 35,602	(19)%	$ 58,984	$ 76,850	(23)%
Transportation costs	5,098	4,568	12%	9,192	10,027	(8)%
Production taxes	11,115	9,295	20%	25,332	18,417	38%
Total	$ 45,168	$ 49,465	(9)%	$ 93,508	$ 105,294	(11)%
Average net realized sales price (1)						
Oil (per Bbl)	$ 65.17	$ 56.72	15%	$ 66.10	$ 50.45	31%
Natural gas (per Mcf)	$ 5.59	$ 5.19	8%	$ 6.21	$ 5.66	10%
Per MCFE Data:						
Average net realized price (1)	$ 7.36	$ 6.68	10%	$ 7.88	$ 6.62	19%
Lease operating expenses	(1.15)	(1.26)	(9)%	(1.16)	(1.36)	(15)%
Transportation costs	(0.20)	(0.16)	25%	(0.18)	(0.18)	0%
Production taxes	(0.44)	(0.33)	33%	(0.50)	(0.33)	52%
General and administrative	(1.01)	(0.64)	58%	(0.96)	(0.61)	57%
Operating profit	$ 4.56	$ 4.29	6%	$ 5.08	$ 4.14	23%
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	$ 3.17	$ 2.49	27%	$ 3.10	$ 2.87	8%

(1) Includes the effects of hedging activities
(2) * Adjusting for divestitures our net production volumes from retained properties were essentially flat.

We present per MCFE information because we use this information to evaluate our performance relative to our peers and to identify and measure trends we believe require analysis. Average daily production for the first six months of 2010 decreased ten percent to 281.1 MMCFE compared with 312.6 MMCFE for the same period in 2009, primarily driven by reduced capital spending in 2009 and recent divestitures. Adjusting for divestitures, our average daily production from retained properties for the first six months of 2010 was 275.5 MMCFE, which was relatively flat compared with 277.6 MMCFE for the same period in 2009.

Changes in production volumes, oil and gas production revenues, and costs reflect the cyclical and highly volatile nature of our industry. Our average net realized price for the three months and six months ended June 30, 2010, was $7.36 per MCFE and $7.88 per MCFE, respectively, compared with $6.68 per MCFE and $6.62 per MCFE for the respective periods of 2009. The increase in our equivalent realized price for production corresponds with stronger commodity prices in the first half of 2010 when compared with the same periods of 2009.

Our LOE for the three months and six months ended June 30, 2010, decreased $0.11 per MCFE to $1.15 per MCFE and decreased $0.20 per MCFE to $1.16 per MCFE, respectively. The divestiture of non-strategic properties with meaningfully higher operating costs is the primary reason for the decline in LOE in the comparisons above. Additionally, pricing concessions made by service providers during a period of lower industry activity in early 2009 have allowed us to keep LOE on retained properties relatively flat. We believe that the steady increase in industry activity is at a point where we will begin to see upward pressure on lease operating costs that we have not experienced the last few quarters. Production taxes for the three months and six months ended June 30, 2010, increased $0.11 per MCFE to $0.44 and increased $0.17 per MCFE to $0.50 per MCFE, respectively. Production taxes are highly correlated to pre-hedge oil and gas revenues and stronger commodity prices have impacted results for this expense item. Transportation costs for the second quarter 2010 increased $0.04 per MCFE to $0.20 per MCFE compared to the same period in 2009, which was as a result of transportation costs associated with newly drilled wells in our Eagle Ford shale program. Transportation costs for the six months ended June 30, 2010, remained flat with the comparable period of 2009 at $0.18 per MCFE. Our operating profit for the three months and six months ended June 30, 2010, was $4.56 per MCFE and $5.08 per MCFE, respectively, compared with $4.29 per MCFE and $4.14 per MCFE for the comparable periods of 2009, which was an increase of $0.27, or six percent, and $0.94, or 23 percent, respectively.

Our general and administrative expense for the three months and six months ended June 30, 2010, was $1.01 per MCFE and $0.96 per MCFE, respectively, compared with $0.64 per MCFE and 0.61 per MCFE for the comparable respective periods of 2009. A portion of our general and administrative expense is linked to our profitability and cash flow, which are driven in large part by the realized commodity prices we receive for our production. The Net Profits Plan and a portion of our current short-term incentive compensation are tied to net revenues and therefore are subject to variability.

Our depletion, depreciation, and amortization, including asset retirement obligation accretion expense, for the three months and six months ended June 30, 2010, was $3.17 per MCFE and $3.10 per MCFE, respectively, compared with $2.49 per MCFE and $2.87 per MCFE for the comparable respective periods of 2009. Depreciation, depletion, and amortization was impacted by our divestiture of lower cost basis properties in the first quarter of 2010. Additionally, we have been impacted by higher early DD&A rates in the Eagle Ford, Haynesville, and Marcellus shales. We are incurring capital for infrastructure that will support future development in these plays but are limited in the amount of reserves that we can record to carry the costs, which results in higher per unit DD&A costs early in the lives of these plays. Our DD&A rate can also fluctuate as a result of impairments, divestitures, and changes in the mix of our production and the underlying proved reserve volumes. Additionally, the accounting treatment for assets that are classified as assets held for sale can also impact our DD&A rate since properties held for sale are no longer depleted.

Please refer to *Comparison of Financial Results and Trends between the three months ended June 30, 2010, and 2009* and *Comparison of Financial Results and Trends between the six months ended June 30, 2010 and 2009* for additional discussion on oil and gas production expense, DD&A, and general and administrative expense.

We present the following table as a summary of information relating to key indicators of financial condition and operating performance that we believe are important.

Financial Information (In thousands, except per share amounts):

	June 30, 2010	December 31, 2009	Percent Change Between Periods
Working capital deficit	$ 111,247	$ 87,625	27 %
Long-term debt	$ 271,212	$ 454,902	(40)%
Stockholders' equity	$ 1,182,833	$ 973,570	21 %

	For the Three Months Ended June 30, 2010	2009	Percent Change Between Periods	For the Six Months Ended June 30, 2010	2009	Percent Change Between Periods
Basic net income (loss) per common share	$ 0.29	$ (0.13)	(323)%	$ 2.29	$ (1.54)	(249)%
Diluted net income (loss) per common share	$ 0.28	$ (0.13)	(315)%	$ 2.24	$ (1.54)	(245)%
Basic weighted-average shares outstanding	62,917	62,418	1 %	62,855	62,377	1 %
Diluted weighted-average shares outstanding	64,566	62,418	3 %	64,493	62,377	3 %

We account for our 3.50% Senior Convertible Notes under the treasury stock method. There is no impact on the diluted share calculation for the periods presented since our average stock price for the relevant reporting periods has not exceeded the conversion price. The 3.50% Senior Convertible Notes were issued April 4, 2007, and have not been dilutive for any reporting period since their issuance. We have in-the-money stock options, unvested RSUs, and PSAs that may be potentially dilutive securities. Both basic and diluted earnings per share are presented in the table above. A detailed explanation is presented in Note 5 — Earnings per Share in Part I, Item 1 of this report.

Basic and diluted weighted-average common shares outstanding used in our June 30, 2010, and 2009, earnings per share calculations reflect increases in outstanding shares related to stock option exercises, ESPP shares issued, and the settlement of vested RSUs. We issued 148,902 and 19,570 shares of common stock during the six-month periods ended June 30, 2010, and 2009, respectively, as a result of stock option exercises. The number of RSUs that vested and settled during the first six months of 2010 and 2009 were 49,882 and 119,426, respectively.

Additional Comparative Data in Tabular Form:

	Change Between the Three Months Ended June 30, 2010, and 2009	Change Between the Six Months Ended June 30, 2010, and 2009
Increase (decrease) in oil and gas production revenues, net of hedging (In thousands)	$ (3,342)	$ 26,103
Components of revenue increases (decreases):		
<u>Oil</u>		
Realized price change per Bbl, including the effects of hedging	$ 8.45	$ 15.65
Realized price percentage change	15 %	31 %
Production change (MBbl)	(236)	(350)
Production percentage change	(14)%	(11)%
<u>Natural Gas</u>		
Realized price change per Mcf, including the effects of hedging	$ 0.40	$ 0.55
Realized price percentage change	8 %	10 %
Production change (MMcf)	(1,652)	(3,600)
Production percentage change	(9)%	(10)%

Production mix as a percentage of total oil and gas revenue, including impact of hedging, and production:

	For the Three Months Ended June 30, 2010	2009	For the Six Months Ended June 30, 2010	2009
<u>Revenue</u>				
Oil	50 %	50 %	48 %	44 %
Natural gas	50 %	50 %	52 %	56 %
<u>Production</u>				
Oil	34 %	35 %	35 %	35 %
Natural gas	66 %	65 %	65 %	65 %

Information regarding the effects of oil, natural gas and natural gas liquids hedging activity:

	For the Three Months Ended June 30, 2010	2009	For the Six Months Ended June 30, 2010	2009
<u>Oil Hedging</u>				
Percentage of oil production hedged	54 %	47 %	54 %	48 %
Oil volumes hedged (MBbl)	767	782	1,573	1,569
Increase (decrease) in oil revenue	$ (8.1) million	$ 4.6 million	$ (16.9) million	$ 20.6 million
Average realized oil price per Bbl before hedging	$ 70.92	$ 53.96	$ 71.86	$ 44.21

Average realized oil price per Bbl after hedging	$ 65.17	$ 56.72	$ 66.10	$ 50.45
Natural Gas Hedging				
Percentage of gas production hedged (includes NGLs)	47%	49%	49%	49%
Natural gas volumes hedged (in MMBtu, includes NGLs)	8.8 million	9.6 million	18.2 million	19.0 million
Increase in gas revenue (includes effects of NGL hedges)	$ 17.4 million	$ 38.7 million	$ 28.8 million	$ 78.3 million
Average realized gas price per Mcf before hedging (includes NGLs)	$ 4.54	$ 3.07	$ 5.34	$ 3.54
Average realized gas price per Mcf after hedging (includes NGLs)	$ 5.59	$ 5.19	$ 6.21	$ 5.66

Information regarding the components of exploration expense:

	For the Three Months Ended June 30, 2010	For the Three Months Ended June 30, 2009	For the Six Months Ended June 30, 2010	For the Six Months Ended June 30, 2009
	(In millions)			
Summary of Exploration Expense				
Geological and geophysical expenses	$ 5.2	$ 6.3	$ 8.8	$ 10.7
Exploratory dry hole expense	0.2	4.6	0.4	4.7
Overhead and other expenses	9.1	8.6	19.2	17.7
Total	$ 14.5	$ 19.5	$ 28.4	$ 33.1

Comparison of Financial Results and Trends between the three months ended June 30, 2010, and 2009

Oil and gas production revenue. Average daily production decreased 11 percent to 276.4 MMCFE for the quarter ended June 30, 2010, compared with 310.1 MMCFE for the quarter ended June 30, 2009. The following table presents the regional changes in our production and oil and gas revenues and costs between the two quarters.

	Average Net Daily Production Added (Decreased) (MMCFE/d)	Pre-Hedge Oil and Gas Revenue Added (Decreased) (In millions)	Production Costs Increase (Decrease) (In millions)
Mid-Continent	(14.8)	4.2	1.7
ArkLaTex	(7.3)	1.8	(1.3)
South Texas & Gulf Coast	20.6	19.1	3.6
Permian	(3.9)	7.7	(1.1)
Rocky Mountain	(28.3)	(2.2)	(7.2)
Total	(33.7)	30.6	(4.3)

The largest regional decrease occurred in the Rocky Mountain region as a result of the loss of production related to the divestiture of non-strategic oil and gas assets that occurred in the fourth quarter of 2009 and first quarter of 2010. Production in the Mid-Continent region decreased as a result of shut-in wells and natural production declines in our Constitution Field. Production in the ArkLaTex decreased as a result of natural production decline and decreased capital investment in 2009 and 2010. The only production growth occurred in the South Texas & Gulf Coast region as a result of production from drilling activity in our Eagle Ford shale program by ourselves and our partner. We anticipate sequential increases in production during the third and fourth quarters of 2010.

The following table summarizes the average realized prices we received in the second quarter of 2010 and 2009, before the effects of hedging. Prices for oil and gas increased between the two periods.

	For the Three Months Ended June 30, 2010	For the Three Months Ended June 30, 2009
Realized oil price ($/Bbl)	$ 70.92	$ 53.96
Realized gas price ($/Mcf)	$ 4.54	$ 3.07
Realized equivalent price ($/MCFE)	$ 6.99	$ 5.15

The combination of a 36 percent increase in average realized prices offset by an 11 percent decrease in production volumes between periods still resulted in higher oil and gas revenue. We expect our realized price to trend with commodity prices.

Realized oil and gas hedge gain. We recorded a net realized hedge gain of $9.3 million for the three-month period ended June 30, 2010, related to settlements on oil and gas hedges, compared with $43.3 million gain for the same period in 2009, as a result of an increase in commodity prices on a quarter-to-quarter basis. We expect our realized oil and gas hedge gains and losses to trend with commodity prices.

Gain on divestiture activity. We had a $7.0 million net gain on divestiture activity for the quarter ended June 30, 2010, compared with a $1.2 million net gain on sale for the comparable period of 2009, due to the divestiture of non-core oil and gas properties located in our South Texas & Gulf Coast region and sales of acreage in our Permian and Rocky Mountain regions that occurred in the second quarter of 2010. We expect to continue to evaluate potential divestitures of non-strategic properties in future periods.

Marketed gas system revenue and expense. Marketed gas system revenue increased $2.2 million to $16.4 million for the quarter ended June 30, 2010, compared with $14.2 million for the comparable period of 2009. Concurrent with the increase in marketed gas system revenue, marketed gas system expense increased $2.2 million to $15.8 million for the quarter ended June 30, 2010, compared with $13.6 million for the comparable period of 2009. The net margin has stayed relatively consistent with historical performance. We expect that marketed gas system revenue and expense will continue to coincide with increases and decreases in production and our net realized price.

Oil and gas production expense. Total production costs decreased $4.3 million, or nine percent, to $45.2 million for the second quarter of 2010 from $49.5 million in the comparable period of 2009. Total oil and gas production costs per MCFE increased $0.04 to $1.79 for the second quarter of 2010, compared with $1.75 for the same period in 2009. This increase is comprised of the following:

- An $0.11 per MCFE increase in production taxes is due to the increase in pre-hedge oil and gas revenues between periods, particularly in the South Texas & Gulf Coast and Mid-Continent regions

- A $0.04 increase in overall transportation cost on a per MCFE basis was as a result of transportation costs associated with newly drilled wells in our Eagle Ford shale program

- A $0.01 overall increase in workover LOE on a per MCFE basis relating to an increase in workover activity in the Rocky Mountain region associated with legacy oil production and workover in our Mid-Continent region at our Constitution Field

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- A $0.12 decrease in recurring LOE on a per MCFE basis reflects the sale of non-core properties with higher per unit LOE costs in the first quarter of 2010 resulting in lower LOE on a per unit basis quarter over quarter. Additionally, reductions in pricing offered by service providers as a result of the decrease in activity across the exploration and production sector in early 2009 allowed for LOE on retained properties to be held relatively flat. Activity in the sector has increased in recent months, particularly in areas with oil projects. We expect the various resources required to service our industry will become more sought after and harder to secure as a result of this increase in activity. We expect to see upward pressure on LOE throughout the remainder of the year.

Depletion, depreciation, amortization, and asset retirement obligation liability accretion. DD&A increased $9.4 million or 13 percent to $79.8 million for the three-month period ended June 30, 2010, compared with $70.4 million for the same period in 2009. The current year's DD&A per MCFE was higher when compared with the same period in 2009 due to the impact of our divestiture of lower cost basis properties in the first quarter of 2010 and production related to properties developed in a higher cost environment becoming a larger percentage of our production mix. Additionally, we have been impacted by higher DD&A rates in the Eagle Ford, Haynesville, and Marcellus shales. We are incurring capital for infrastructure that will support future development in these plays but are limited in the amount of reserves that we can book to carry the costs, which results in higher per unit DD&A costs early in the lives of these plays. Any future proved property impairments, divestitures, and changes in underlying proved reserve volumes will continue to impact our DD&A expense.

Exploration. Exploration expense decreased $5.0 million, or 26 percent, to $14.5 million for the three-month period ended June 30, 2010, compared with $19.5 million for the same period in 2009. We recorded $4.6 million of exploratory dry hole expense in the second quarter of 2009 that related to wells in the ArkLaTex. There were no significant exploratory dry hole costs in the second quarter of 2010. We continue to focus on our exploratory program for our current resource plays and expect to maintain a modest program for new areas of exploration in future periods. Any exploratory well incapable of producing oil or natural gas in commercial quantities will be deemed an exploratory dry hole, which will impact the amount of exploration expense we record.

Impairment of proved properties. There were no proved property impairments recorded in the second quarter of 2010. We recognized $6.0 million for impairment of proved properties in the second quarter of 2009 related principally to impairments of properties in the Gulf of Mexico in which we relinquished our ownership interests. We generally expect proved property impairments to occur in periods of low commodity prices.

Abandonment and impairment of unproved properties. Abandonment and impairment of unproved properties decreased $9.2 million, or 80 percent, to $2.4 million for the three months ended June 30, 2010, compared with $11.6 million for the comparable period in 2009. In 2009 we had write-offs related to our Floyd shale acreage located in Mississippi, as well as non-core acreage in Oklahoma. We generally expect impairments of unproved properties to be more likely to occur in periods of low commodity prices, since fewer dollars will be available for exploratory and development efforts.

General and administrative. General and administrative expense increased $7.2 million or 40 percent to $25.4 million for the three months ended June 30, 2010, compared with $18.2 million for the comparable period of 2009. On a per unit basis, G&A expense increased $0.37 to $1.01 per MCFE for the second quarter of 2010 compared to $0.64 per MCFE for the same three-month period in 2009.

General and administrative expense increased due to a $3.7 million increase in base compensation, cash bonus, and long-term incentive compensation expense for the three months ended June 30, 2010, compared with the same period in 2009, a $1.5 million decrease in COPAS overhead reimbursements

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caused by a decrease in our operated well count resulting from our recent divestiture efforts, and an $800,000 increase in cash payments accrued under the Net Profits Plan.

The increase in Net Profits Plan payments to plan participants was the result of higher commodity prices, pools entering the higher 20 percent payout level as described further in Note 7 of Part 1, Item 1of this report, and the 2005 pool entering payout for the first time. As of the end of the second quarter of 2010, 18 of our 21 pools are in payout status. No additional pools are expected to reach payout in 2010. We expect payments made under the Net Profits Plan to continue to trend with commodity prices. The increase in cash bonus and long-term incentive compensation expense reflects the improvement in our performance and the anticipated achievement of various performance criteria, approved by our Compensation Committee, as well as compensation expense associated with PSAs granted in the third quarter of 2009.

Change in Net Profits Plan liability. For the quarter ended June 30, 2010, this non-cash item was a benefit of $6.6 million compared to expense of $2.4 million for the same period in 2009. We saw a reduction in the Net Profits Plan liability as a result of a decrease in expected future cash flows thereby reducing the future liability for amounts to be paid to plan participants. We generally expect the change in this liability to trend with commodity prices.

Unrealized derivative (gain) loss. We recognized a gain of $2.1 million in the second quarter of 2010 compared to a loss of $11.3 million for the same period in 2009. This non-cash item is driven by the change in the value of our hedge position, as well as the portion of that position that is considered ineffective for accounting purposes. Please refer to our discussion under the heading *Hedging Activities* under Overview of the Company, Highlights, and Outlook.

Other expense. Other expense decreased $5.2 million to $578,000 for the quarter ended June 30, 2010, compared with $5.8 million for the same period in 2009. In the second quarter of 2009, we incurred an additional loss related to hurricanes of $5.0 million, which related to a decrease in our estimate of insurance reimbursements related to the Vermillion 281 platform that was lost in Hurricane Ike.

Income tax expense. We recorded income tax expense of $12.4 million for the second quarter of 2010 compared to income tax benefit of $5.1 million for the second quarter of 2009 resulting in effective tax rates of 40.8 percent and 38.0 percent, respectively. The change in income tax expense is primarily the result of the differences in components of net income discussed above. The 2010 increase in effective tax rate from 2009 primarily reflects changes in the mix of the highest marginal state tax rates and the resulting effect on year-to-date net income as a result of divestiture and drilling activity in 2010, and to a lesser extent, changes in the effects of other permanent differences including the domestic production activities deduction. The current portion of our income tax expense resulted in a nominal benefit in the second quarter of 2010 versus an expense in the second quarter of 2009 due to the impact of our drilling program from utilization of proceeds from non-core asset divestitures in 2010 and to a decreased drilling program in 2009 caused by lower commodity prices. These trends are expected to continue throughout the remainder of 2010 based upon our current projected capital expenditures program and commodity price outlook.

Comparison of Financial Results and Trends between the six months ended June 30, 2010, and 2009

Oil and gas production revenue. Average daily production decreased ten percent to 281.1 MMCFE for the six months ended June 30, 2010, compared with 312.6 MMCFE for the same period in 2009. The following table presents the regional changes in our production and oil and gas revenues and costs between the two six-month periods.

	Average Net Daily Production Added (Decreased) (MMCFE/d)	Pre-Hedge Oil and Gas Revenue Added (In millions)	Production Costs Increase (Decrease) (In millions)
Mid-Continent	(9.7)	21.9	2.0
ArkLaTex	(9.6)	2.7	(4.4)
South Texas & Gulf Coast	15.8	36.7	5.9
Permian	(4.3)	27.0	(0.6)
Rocky Mountain	(23.7)	24.8	(14.7)
Total	(31.5)	113.1	(11.8)

The largest regional decrease occurred in the Rocky Mountain region and was partially offset by the only regional increase in the South Texas & Gulf Coast region which is described in more detail above under *Comparison of Financial Results and Trends between the three months ended June 30, 2010, and 2009.*

The following table summarizes the average realized prices we received for the first six months of 2010 compared to the same period in 2009, before the effects of hedging. Prices for oil and gas increased between the two periods.

	For the Six Months Ended June 30, 2010	2009
Realized oil price ($/Bbl)	$ 71.86	$ 44.21
Realized gas price ($/Mcf)	$ 5.34	$ 3.54
Realized equivalent price ($/MCFE)	$ 7.64	$ 4.87

The combination of a 57 percent increase in average realized prices offset by a ten percent decrease in production volumes between periods still resulted in higher oil and gas revenue. Please refer to additional discussion under *Comparison of Financial Results and Trends between the three months ended June 30, 2010, and 2009.*

Realized oil and gas hedge gain. We recorded a net realized hedge gain of $11.9 million for the six-month period ended June 30, 2010, related to settlements on oil and gas hedges, compared with $98.9 million gain for the same period in 2009, as a result of an increase in commodity prices on a period-to-period comparison.

Gain on divestiture activity. We had a $128.0 million net gain on divestiture activity for the six-month period ended June 30, 2010, compared with a $645,000 net gain on sale for the comparable period of 2009, due primarily to the divestiture of non-core oil and gas properties located in our Rocky Mountain region that occurred in the first quarter of 2010. The final gain on sale of proved properties will be adjusted for normal post-closing adjustments and is expected to be finalized during the second half of 2010. We expect to continue to evaluate potential divestitures of non-strategic properties in future periods.

Marketed gas system revenue and expense. Marketed gas system revenue increased $10.6 million to $38.2 million for the six-month period ended June 30, 2010, compared with $27.6 million for the comparable period of 2009. Concurrent with the increase in marketed gas system revenue, marketed gas system expense increased $10.9 million to $37.9 million for the six-month period ended June 30, 2010, compared with $27.0 million for the comparable period in 2009.

Oil and gas production expense. Total production costs decreased $11.8 million, or 11 percent, to $93.5 million for the first six months of 2010 from $105.3 million in the comparable period of 2009. Total oil and gas production costs per MCFE decreased $0.03 to $1.84 for the first six months of 2010, compared with $1.87 for the same period in 2009. This decrease is comprised of the following:

- A $0.24 decrease in recurring LOE on a per MCFE basis reflects the divestiture of higher cost non-core properties in the first half of 2010. Please refer to additional discussion under *Comparison of Financial Results and Trends between the three months ended June 30, 2010, and 2009.*

- A $0.17 per MCFE increase in production taxes is due to the increase in pre-hedge oil and gas revenues between periods

- A $0.04 overall increase in workover LOE on a per MCFE basis relating to an increase in workover activity in the Rocky Mountain region due to our shift toward oil-weighted projects

- Overall transportation on a per MCFE basis was essentially flat from period to period.

Depletion, depreciation, amortization, and asset retirement obligation liability accretion. DD&A decreased $4.6 million, or three percent, to $157.5 million for the six-month period ended June 30, 2010, compared with $162.1 million for the same period in 2009. DD&A expense per MCFE increased eight percent to $3.10 for the six-month period ended June 30, 2010, compared to $2.87 for the same period in 2009. Please refer to additional discussion under *Comparison of Financial Results and Trends between the three months ended June 30, 2010, and 2009.*

Exploration. Exploration expense decreased $4.7 million, or 14 percent, to $28.4 million for the six-month period ended June 30, 2010, compared with $33.1 million for the same period in 2009. Please refer to additional discussion under *Comparison of Financial Results and Trends between the three months ended June 30, 2010, and 2009.*

Impairment of proved properties. There were no proved property impairments recorded for the six-month period ended June 30, 2010. We recorded a $153.1 million impairment of proved oil and gas properties for the comparable period in 2009, which was driven by a significant decrease in realized gas prices in the first quarter of 2009, particularly in the Mid-Continent region, and for our coalbed methane project at Hanging Woman Basin, which was divested of in late 2009.

Abandonment and impairment of unproved properties. Abandonment and impairment of unproved properties decreased $12.2 million or 79 percent to $3.3 million for the six months ended June 30, 2010, compared with $15.5 million for the comparable period in 2009. Please refer to additional discussion under *Comparison of Financial Results and Trends between the three months ended June 30, 2010, and 2009.*

Impairment of materials inventory. There were no materials inventory impairments recorded for the six-month period ended June 30, 2010. We recorded an $11.3 million impairment of materials inventory for the six-month period ended June 30, 2009, which was caused by a decrease in the value of tubular goods and other raw materials.

General and administrative. General and administrative expense increased $14.3 million or 41 percent to $48.9 million for the six months ended June 30, 2010, compared with $34.6 million for the comparable period of 2009. On a per unit basis, G&A expense increased $0.35 to $0.96 per MCFE for the first six months of 2010 compared to $0.61 per MCFE for the same six-month period in 2009.

General and administrative expense increased due to a $4.5 million increase in cash payments accrued under the Net Profits Plan, a $4.9 million increase in cash bonus and long-term incentive compensation expense, and a $1.8 million increase in compensation for the six months ended June 30, 2010, compared with the same period in 2009. Please refer to additional discussion under *Comparison of Financial Results and Trends between the three months ended June 30, 2010, and 2009.*

Change in Net Profits Plan liability. Please refer to discussion under the heading *Net Profits Plan* under Overview of the Company, Highlights, and Outlook.

Unrealized derivative (gain) loss. We recognized a gain of $9.8 million for the six months ended June 30, 2010, compared to a loss of $13.1 million for the same period in 2009. This non-cash item is driven by the change in the value of our hedge position, as well as the portion of that position that is considered ineffective for accounting purposes. Please refer to our discussion under the heading *Hedging Activities* under Overview of the Company, Highlights, and Outlook.

Other expense. Other expense decreased $10.0 million to $1.5 million for the six months ended June 30, 2010, compared with $11.5 million for the same period in 2009. In the first quarter of 2009, we incurred $2.6 million of expense related to the assignment of a drilling rig contract in our Rocky Mountain region. We also incurred an additional loss related to hurricanes of $7.1 million for the six months ended June 30, 2009, which related to an increase in our estimate of the remediation cost for the Vermilion 281 platform that was lost in Hurricane Ike.

Income tax expense. Income tax expense totaled $87.3 million for the six-month period of 2010 compared to an income tax benefit of $59.0 million for the same period of 2009 resulting in effective tax rates of 37.7 percent and 38.1 percent, respectively. The change in income tax expense is the result of the 2010 divestitures and the Company's 2009 loss before income taxes. The 2010 decrease in effective tax rate from 2009 reflects changes in the impact of other permanent differences including the domestic production activities deduction partially offset by an increase related to the mix of the highest marginal state tax rates resulting from divestiture and drilling activity in 2010. The current portion of our tax expense is greater in 2010 compared to 2009 due to the impact of our non-core asset divestitures in 2010 and the status of our capital expenditures drilling program at June 30, 2010.

Overview of Liquidity and Capital Resources

We believe that we have sufficient liquidity and capital resources to execute our business plans for the foreseeable future.

Sources of Cash

Based on our current outlook, we expect our generated cash flow from operations in 2010, including the net cash proceeds from the Rocky Mountain oil and other non-core asset divestiture packages, to fund the majority of our exploration and development budget for 2010. We intend to rely on our credit facility to fund the remaining balance of our capital program for the year. Accordingly, we do not expect to access the capital markets in 2010. We anticipate we will continue to periodically evaluate our property base to identify and divest of properties we consider non-core to our strategic goals.

Our primary sources of liquidity are the cash flows provided by our operating activities, use of our credit facility, sales of non-core properties, and accessing the capital markets. From time to time, we may be able to enter into carrying cost funding and sharing arrangements with third parties for particular exploration and development programs that provide capital. All of these sources can be impacted by the general condition of the broad economy and by significant fluctuations in oil and gas prices, operating costs, and volumes produced, all of which affect us and our industry. We have no control over the market prices for oil and natural gas, although we are able to influence the amount of our net realized revenues related to our oil and gas sales through the use of derivative contracts. The borrowing base on our credit facility could be reduced as a result of lower commodity prices or sales of non-core producing properties. Historically, decreases in commodity prices have limited our industry's access to the capital markets. We believe the public debt markets are currently accessible. Equity and convertible debt issuances are also available to us as alternative financing sources. We do not anticipate the need to raise public debt or equity financing in the near term, however these are options we would consider under the appropriate circumstances.

Current Credit Facility

On April 14, 2009, we entered into an amended $1.0 billion senior secured revolving credit facility with twelve participating banks. The initial borrowing base was set at $900 million. On March 17, 2010, the lending group redetermined our reserve-backed borrowing base under the credit facility at $900 million. We have been provided a $678 million commitment amount by the bank group. The new amended credit facility agreement has a maturity date of July 31, 2012. Management believes that the current commitment is sufficient for our current liquidity needs. To date, we have experienced no issues drawing upon our credit facility. No individual bank participating in the credit facility represents more than 16 percent of the lending commitments under the credit facility. We monitor the credit environment closely and have frequent discussions with the lending group.

As of July 28, 2010, we had $677.5 million of available borrowing capacity under this facility. We have a single letter of credit outstanding under our credit facility, in the amount of $483,000 as of

July 28, 2010, which reduces the amount available under the commitment amount on a dollar-for-dollar basis. Borrowings under the facility are secured by mortgages on the majority of our oil and gas properties. Please refer to Note 5 — Long-term Debt in Part IV, Item 15 of our Annual Report on Form 10-K for the year ended December 31, 2009, for our borrowing base utilization grid.

Our weighted-average interest rate for the three-month periods ended June 30, 2010, and 2009, was 9.4 percent and 5.5 percent, respectively. Our weighted-average interest rate for the six-month periods ended June 30, 2010, and 2009, was 8.1 percent and 4.9 percent, respectively. Our weighted-average interest rates in the current and prior year include cash interest payments, cash fees paid on the unused portion of the credit facility's aggregate commitment amount, letter of credit fees, amortization of the convertible notes debt discount, and amortization of deferred financing costs. The increase in our weighted-average interest rate from the comparative quarter in 2009 is the result of lower cash interest expense and non-cash charges being spread across a much lower average outstanding debt balance.

We are subject to customary financial and non-financial covenants under our credit facility, including limitations on dividend payments and requirements to maintain certain financial ratios, which include debt to earnings before interest, taxes, depreciation, and amortization of not more than 3.5 to 1.0 and also include a current ratio as defined by our credit agreement of not less than 1.0 to 1.0. As of June 30, 2010, our debt to EBITDA ratio and current ratio as defined by our credit agreement were 0.64 and 3.03, respectively. We are in compliance with all financial and non-financial covenants under our credit facility.

Uses of Cash

We use cash for the acquisition, exploration, and development of oil and gas properties, and for the payment of debt obligations, trade payables, income taxes, common stock repurchases, and stockholder dividends. In the first six months of 2010 we spent $304.6 million for exploration and development capital expenditures. These amounts differ from our costs incurred amounts based on the timing of cash payments associated with these activities as compared to the accrual based activity upon which costs incurred amounts are presented. These cash outflows were funded using cash inflows from operations, proceeds from the sale of assets, and available borrowing capacity under our revolving credit facility.

Expenditures for exploration and development of oil and gas properties and acquisitions are the primary use of our capital resources. We expect our capital and exploration expenditures in 2010 will exceed our operating cash flow, and we plan to fund this shortfall with the proceeds received from our non-core asset divestitures that closed during the first quarter of 2010 and borrowings under our credit facility. The amount and allocation of future capital expenditures will depend upon a number of factors including the number and size of available economic acquisitions and drilling opportunities, our cash flows from operating, investing and financing activities, and our ability to assimilate acquisitions. Also, the impact of oil and gas prices on investment opportunities, the availability of capital and borrowing facilities, and the success of our development and exploratory activities could lead to changes in funding requirements for future development. We regularly review our capital expenditure budget to assess changes in current and projected cash flows, acquisition and divestiture opportunities, debt requirements, and other factors.

As of the filing date of this report, we have Board authorization to repurchase up to 3,072,184 shares of our common stock under our stock repurchase program. Shares may be repurchased from time to time in open market transactions or privately negotiated transactions subject to market conditions and other factors including certain provisions of our existing bank credit facility agreement, compliance with securities laws, and the terms and provisions of our stock repurchase program. There have been no share repurchases to date in 2010, and we do not plan to repurchase shares for the remainder of 2010.

Current proposals to fund the federal budget include eliminating or reducing current tax deductions for intangible drilling costs, the domestic production activities deduction, and percentage depletion. Legislation modifying or eliminating these deductions would have the immediate effect of reducing

operating cash flows thereby reducing funding available for our exploration and development capital programs and those of our peers in the industry. These potential funding reductions in conjunction with a tight credit environment could have a significant adverse effect on drilling in the United States for a number of years.

The following table presents amount and percentage changes in cash flows between the six-month periods ended June 30, 2010, and 2009. The analysis following the table should be read in conjunction with our condensed consolidated statements of cash flows in Part I, Item 1 of this report.

	For the Six Months Ended June 30, 2010	2009	Change	Percent Change
	(In thousands)			
Net cash provided by operating activities	$ 270,150	$ 241,761	$ 28,389	12%
Net cash used in investing activities	$ 82,716	$ 199,389	$ (116,673)	(59)%
Net cash used in financing activities	$ 187,834	$ 38,114	$ 149,720	393%

Analysis of Cash Flow Changes Between the Six Months Ended June 30, 2010, and June 30, 2009

Operating activities. Cash received from oil and gas production revenue, net of the realized effects of hedging, increased $4.7 million to $403.6 million for the first six months of 2010, compared with $398.9 million for the first six months of 2009. Additionally, cash paid for lease operating expenses decreased $14.0 million to $63.7 million for the first six months of 2010, compared with $77.7 million for the first six months of 2009.

Investing activities. Cash used in investing activities for the six months ended June 30, 2010, was $82.7 million compared with $199.4 million of cash used for investing activities in the comparable period of 2009. We received $248.0 million from the sale of non-core properties primarily in the Rocky Mountain region for the six months ended June 30, 2010. In conjunction with the sale of non-core properties, we had a net $19.6 million deposit to restricted cash for the six months ended June 30, 2010. There were no major divestitures for the same period in 2009. Cash outflows for capital expenditures increased by $88.8 million for the six months ended June 30, 2010, compared with the same period in 2009. This is due to increased drilling activity as a result of more favorable commodity prices and an improved overall macro-economic environment.

Financing activities. Net repayments on our credit facility increased by $163.0 million for the six months ended June 30, 2010, compared with the same period in 2009. We reduced our credit facility balance to zero in the first quarter of 2010, and although it remains at zero at the end of the second quarter, we expect it to gradually increase during the rest of 2010.

Capital Expenditures

The following table sets forth certain historical information regarding the costs incurred by us in our oil and gas activities.

	For the Six Months Ended June 30, 2010	2009
	(In thousands)	
Development costs (1)	$ 92,820	$ 127,624
Exploration costs	212,385	38,730
Acquisitions		
Proved properties	—	51

Unproved properties - other	30,832	19,864
Total, including asset retirement obligations (2)	$ 336,037	$ 186,269

(1) Includes capitalized interest of $1.2 million in 2010 and $1.0 million in 2009.
(2) Includes amounts relating to estimated asset retirement obligations of $486,000 in 2010 and $506,000 in 2009.

Costs incurred for development and exploration activities during the first six months of 2010 increased $138.9 million or 83 percent compared to the same period in 2009. This increase in capital and exploration activities reflects a stable and improving economic environment and higher cash flows provided by operating activities and divestiture proceeds.

We believe our operating cash flows together with the full availability of our credit facility will be sufficient to fund our planned operating, drilling, and acquisition expenditures for the foreseeable future. The amount and allocation of future capital and exploration expenditures will depend upon a number of factors, including the number and size of available economic acquisition and drilling opportunities, our cash flows from operating and financing activities, and our ability to assimilate leasehold and producing property acquisitions. In addition, the impact of oil and natural gas prices on investment opportunities, the availability of capital and borrowing facilities, and the success of our development and exploratory activities may lead to changes in funding requirements for future development.

Commodity Price Risk and Interest Rate Risk

We are exposed to market risk, including the effects of changes in oil and gas commodity prices and changes in interest rates as discussed below under the caption *Summary of Interest Rate Risk.* Changes in interest rates can affect the amount of interest we earn on our cash, cash equivalents, and the amount of interest we pay on borrowings under our revolving credit facility. Changes in interest rates do not affect the amount of interest we pay on our fixed-rate 3.50% Senior Convertible Notes, but do affect their fair market value.

There has been no material change to the natural gas and crude oil price sensitivity analysis previously disclosed. Refer to the corresponding section under Part II, Item 7 of our Annual Report on Form 10-K for the year ended December 31, 2009.

Summary of Oil and Gas Production Hedges in Place

Our oil and natural gas derivative contracts include costless swaps and costless collar arrangements. All contracts are entered into for other-than-trading purposes. Please refer to Note 10 — Derivative Financial Instruments in Part I, Item 1 of this report for additional information regarding accounting for our derivative transactions.

Our net realized oil and gas prices are impacted by hedges we have placed on future forecasted production. Hedging is an important part of our financial risk management program. The amount of production we hedge is driven by the amount of debt on our consolidated balance sheet and the level of capital and long-term commitments we have made. In the case of a significant acquisition of producing properties, we will consider hedging a portion of the anticipated production in order to protect the economics assumed at the time of the acquisition. As of June 30, 2010, our hedged positions of anticipated production through the first quarter of 2013 totaled approximately 5 million Bbls of oil, 46 million MMBtu of natural gas, and 2 million Bbls of natural gas liquids. As of July 28, 2010, we have hedge contracts in place through the second quarter 2013 for a total of approximately 6 million Bbls of anticipated crude oil production, 50 million MMBtu of anticipated natural gas production, and 2 million Bbls of anticipated natural gas liquids production.

In a typical commodity swap agreement, if the agreed upon published third-party index price is lower than the swap fixed price, we receive the difference between the index price and the agreed upon swap fixed price. If the index price is higher than the swap fixed price, we pay the difference. For collar agreements, we receive the difference between an agreed upon index and the floor price if the index price is below the floor price. We pay the difference between the agreed upon contracted ceiling price and the index price if the index price is above the contracted ceiling price. No amounts are paid or received if the index price is between the contracted floor and ceiling prices.

The following tables describe the volumes, average contract prices, and fair values of contracts we have in place as of June 30, 2010, and July 28, 2010. The Company seeks to minimize ineffectiveness by entering into oil derivative contracts indexed to NYMEX WTI, natural gas derivative contracts indexed to regional index prices associated with pipelines in proximity to the Company's areas of production, and NGL derivative contracts indexed to Oil Price Information Service Mont Belvieu. As the Company's derivative contracts contain the same index as the Company's sales contracts, this results in derivative contracts that are highly correlated with the underlying hedged item.

Oil Contracts

Oil Swaps

Contract Period	NYMEX WTI Volumes (Bbls)	Weighted-Average Contract Price (per Bbl)	Fair Value at June 30, 2010 Asset (Liability) (in thousands)
Third quarter 2010	393,000	$ 68.77	$ (2,944)
Fourth quarter 2010	309,000	$ 66.06	(3,521)
2011	1,164,000	$ 67.06	(14,093)
2012	1,051,400	$ 82.19	1,066
All oil swap	2,917,400		$ (19,492)

Oil Collars

Contract Period	NYMEX WTI Volumes	Weighted-Average Floor Price	Weighted-Average Ceiling Price	Fair Value at June 30, 2010 Asset (Liability)

	(Bbls)		(per Bbl)		(per Bbl)		(in thousands)
Third quarter 2010	344,500	$	50.00	$	64.91	$	(4,129)
Fourth quarter 2010	344,500	$	50.00	$	64.91		(4,959)
2011	1,236,000	$	50.00	$	63.70		(22,434)
2012	163,700	$	80.00	$	100.85		959
2013	282,600	$	80.00	$	100.85		1,472
All oil collars	2,371,300					$	(29,091)

Gas Contracts

Gas Swaps

Contract Period	Volumes		Weighted-Average Contract Price		Fair Value at June 30, 2010 Asset
	(MMBtu)		(per MMBtu)		(in thousands)
Third quarter 2010					
IF ANR OK	70,000	$	5.64	$	95
IF CIG	240,000	$	5.38		334
IF EL PASO	370,000	$	6.33		741
IF HSC	1,350,000	$	8.03		4,656
IF NGPL	500,000	$	5.43		563
IF NNG VENTURA	360,000	$	5.89		520
IF PEPL	230,000	$	5.56		310
IF RELIANT	1,190,000	$	5.37		1,169
IF TETCO STX	230,000	$	5.81		304
NYMEX Henry Hub	960,000	$	6.94		2,180
Fourth quarter 2010					
IF ANR OK	140,000	$	5.97		191
IF CIG	270,000	$	5.87		390
IF EL PASO	370,000	$	6.43		713
IF HSC	590,000	$	8.61		2,246
IF NGPL	430,000	$	5.61		429
IF NNG VENTURA	360,000	$	6.34		558
IF PEPL	520,000	$	5.92		702
IF RELIANT	1,350,000	$	5.71		1,481
IF TETCO STX	180,000	$	6.23		268
NYMEX Henry Hub	840,000	$	7.52		2,118

Gas swaps (continued)

Contract Period	Volumes		Weighted-Average Contract Price		Fair Value at June 30, 2010 Asset
	(MMBtu)		(per MMBtu)		(in thousands)
2011					
IF ANR OK	500,000	$	6.10		528
IF CIG	1,030,000	$	5.96		1,102
IF EL PASO	1,780,000	$	6.35		2,403
IF HSC	360,000	$	9.01		1,356
IF NGPL	1,040,000	$	6.09		1,085
IF NNG VENTURA	1,200,000	$	6.36		1,395
IF PEPL	1,830,000	$	6.04		1,941
IF RELIANT	4,510,000	$	6.13		5,013
IF TETCO STX	1,420,000	$	6.51		1,958
NYMEX Henry Hub	2,130,000	$	6.72		2,995
2012					
IF ANR OK	360,000	$	6.18		314
IF CIG	1,020,000	$	5.77		528
IF EL PASO	850,000	$	6.04		539
IF NGPL	660,000	$	6.34		644
IF NNG VENTURA	620,000	$	6.51		548
IF PEPL	2,730,000	$	6.25		2,574
IF RELIANT	2,440,000	$	6.22		2,015
IF TETCO STX	660,000	$	6.30		505
All gas swap contracts	35,690,000			$	47,411

Gas Collars

Contract Period	Volumes (MMBtu)	Weighted-Average Floor Price (per MMBtu)	Weighted-Average Ceiling Price (per MMBtu)	Fair Value at June 30, 2010 Asset (in thousands)
Third quarter 2010				
IF CIG	510,000	$ 4.85	$ 7.08	$ 460
IF HSC	150,000	$ 5.57	$ 7.88	159
IF PEPL	1,240,000	$ 5.31	$ 7.61	1,301
NYMEX Henry Hub	60,000	$ 6.00	$ 8.38	79
Fourth quarter 2010				
IF CIG	510,000	$ 4.85	$ 7.08	385
IF HSC	150,000	$ 5.57	$ 7.88	153
IF PEPL	1,240,000	$ 5.31	$ 7.61	1,198
NYMEX Henry Hub	60,000	$ 6.00	$ 8.38	73
2011				
IF CIG	1,800,000	$ 5.00	$ 6.32	850
IF HSC	480,000	$ 5.57	$ 6.77	316
IF PEPL	4,225,000	$ 5.31	$ 6.51	2,576
NYMEX Henry Hub	120,000	$ 6.00	$ 7.25	108
All gas collars	10,545,000			$ 7,658

Natural Gas Liquid Contracts

Natural Gas Liquid Swaps

	Volumes (approx. Bbls)	Weighted-Average Contract Price (per Bbl)	Fair Value at June 30, 2010 Asset (in thousands)
Third quarter 2010	221,000	$ 45.34	$ 1,148
Fourth quarter 2010	205,000	$ 45.36	941
2011	714,000	$ 44.07	2,773
2012	492,000	$ 44.25	2,033
2013	84,000	$ 44.95	320
All natural gas liquid swaps*	1,716,000		$ 7,215

*Natural gas liquid swaps are comprised of OPIS Mont. Belvieu TET Propane (34%), OPIS Mont. Belvieu Purity Ethane (33%), OPIS Mont. Belvieu NON-TET Isobutane (6%), OPIS Mont. Belvieu NON-TET Natural Gasoline (14%), and OPIS Mont. Belvieu NON-TET Normal Butane (13%).

Hedge Contracts Entered into After June 30, 2010

The following table includes all hedges entered into subsequent to June 30, 2010 through July 28, 2010.

Oil Swaps

Contract Period	NYMEX WTI Volumes (Bbl)	Weighted-Average Contract Price (Per Bbl)
2012	462,800	$ 83.60
2013	294,600	$ 84.30
All oil swaps	757,400	

Natural Gas Swaps

Contract Period	Volumes (MMBtu)	Weighted-Average Contract Price (Per MMBtu)
2012		
IF RELIANT	1,100,000	$ 5.40
2013		
IF PEPL	1,250,000	$ 5.65
IF RELIANT	1,290,000	$ 5.64

All natural gas swaps	3,640,000

Natural Gas Liquid Swaps

Contract Period	Volumes (Bbls)		Weighted-Average Contract Price (per Bbl)
Fourth Quarter 2010	80,000	$	28.91
2011	193,000	$	23.19
All natural gas liquids swaps*	273,000		

*Natural gas liquid swaps are comprised of OPIS Mont. Belvieu TET Propane (8%), OPIS Mont. Belvieu Purity Ethane (84%), OPIS Mont. Belvieu NON-TET Isobutane (1%), OPIS Mont. Belvieu NON-TET Natural Gasoline (5%), and OPIS Mont. Belvieu NON-TET Normal Butane (2%).

Refer to Note 10 — Derivative Financial Instruments in Part I, Item 1 of this report for additional information regarding our oil and gas hedges.

Summary of Interest Rate Risk

Market risk is estimated as the potential change in fair value resulting from an immediate hypothetical one percentage point parallel shift in the yield curve. For fixed-rate debt, interest changes affect the fair market value but do not impact results of operations or cash flows. Conversely, interest rate changes for floating-rate debt generally do not affect the fair market value but do impact future results of operations and cash flows, assuming other factors are held constant. The carrying amount of our floating-

rate debt typically approximates its fair value. We had no floating-rate debt outstanding as of June 30, 2010. Our fixed-rate debt outstanding, net of debt discount, at this same date was $271.2 million.

Off-Balance Sheet Arrangements

As part of our ongoing business, we have not participated in transactions that generate relationships with unconsolidated entities or financial partnerships, such as entities often referred to as structured finance entities or special purpose entities, which would have been established for the purpose of facilitating off-balance sheet arrangements or other contractually narrow or limited purposes. As of June 30, 2010, we have not been involved in any unconsolidated SPE transactions.

We evaluate our transactions to determine if any variable interest entities exist. If it is determined that we are the primary beneficiary of a variable interest entity, that entity is consolidated into our consolidated financial statements.

Critical Accounting Policies and Estimates

We refer you to the corresponding section in Part II, Item 7 of our Annual Report on Form 10-K for the year ended December 31, 2009, and to the footnote disclosures included in Part I, Item 1 of this report.

New Accounting Pronouncements

Please see Note 12 — Recent Accounting Pronouncements under Part I, Item 1 of this report for new accounting matters.

Environmental

SM Energy's compliance with applicable environmental regulations has to date not resulted in significant capital expenditures or material adverse effects on our liquidity or results of operations. We believe we are in substantial compliance with environmental regulations and do not currently anticipate that material future expenditures will be required under the existing regulatory framework. However, we are unable to predict the impact that compliance with future laws or regulations, such as those currently being considered as discussed below, may have on future capital expenditures, liquidity, and results of operations.

The U.S. Congress is currently considering legislation that would amend the Safe Drinking Water Act to eliminate an existing exemption from federal regulation of hydraulic fracturing activities. Hydraulic fracturing is a common and reliable process in our industry of creating artificial cracks, or fractures, in deep underground rock formations through the pressurized injection of water, sand and other additives to enable oil or natural gas to move more easily through the rock pores to a production well. This process is often necessary to produce commercial quantities of oil and natural gas from many reservoirs, especially shale rock formations. We routinely utilize hydraulic fracturing in many of our reservoirs, and our Eagle Ford, Haynesville, Marcellus, Woodford, and other shale programs utilize or contemplate the utilization of hydraulic fracturing. Currently, regulation of hydraulic fracturing is primarily conducted at the state level through permitting and other compliance requirements. If adopted, the proposed amendment to the Safe Drinking Water Act could result in additional regulations and permitting requirements at the federal level. On March 18, 2010, the Environmental Protection Agency ("EPA") announced that it has allocated $1.9 million in 2010 and has requested funding in fiscal year 2011 for conducting a comprehensive research study on the potential adverse impacts that hydraulic fracturing may have on water quality and public health. In addition, various state and local governments are considering increased regulatory oversight of hydraulic fracturing through additional permit requirements, operational restrictions, and temporary or permanent bans on hydraulic fracturing in certain environmentally sensitive areas, such as watersheds. Additional regulations and permitting requirements could lead to significant operational delays and increased operating costs, could make it more difficult to perform hydraulic fracturing, and could impair our ability to produce commercial quantities of oil and natural gas from certain reservoirs.

In December 2009, the EPA published its findings that emissions of carbon dioxide, which is a byproduct of the burning of refined oil products and natural gas, methane, which is a primary component of natural gas, and other "greenhouse gases" present an endangerment to human health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the Earth's atmosphere and other climatic changes. These findings by the EPA allow the agency to proceed with the adoption and implementation of regulations that would restrict emissions of greenhouse gases under existing provisions of the federal Clean Air Act. Accordingly, the EPA had proposed regulations that would require a reduction in emissions of greenhouse gases from motor vehicles and that could also lead to the imposition of greenhouse gas emission limitations in Clean Air Act permits for certain stationary sources. In addition, on October 30, 2009, the EPA published a final rule requiring the reporting of greenhouse gas emissions from specified large greenhouse gas emission sources in the United States beginning in 2011 for emissions occurring in 2010. On

March 23, 2010, the EPA announced a proposed rulemaking that would expand its final rule on reporting of greenhouse gas emissions to include owners and operators of onshore oil and natural gas production. If the proposed rule is finalized in its current form, monitoring of those newly covered sources would commence on January 1, 2011. On May 13, 2010, the EPA issued rules to regulate greenhouse gas emissions from large stationary sources such as power plants and oil refineries. The adoption and implementation of any regulations imposing reporting obligations on, or limiting emissions of greenhouse gases from, our equipment and operations could require us to incur increased costs to reduce emissions of greenhouse gases associated with our operations and could adversely affect demand for the oil and natural gas that we produce.

In addition, in June 2009, the U.S. House of Representatives passed the "American Clean Energy and Security Act of 2009" ("ACESA"), which would establish an economy-wide cap-and-trade program to reduce U.S. emissions of greenhouse gases, including carbon dioxide and methane. ACESA would require a 17% reduction in greenhouse gas emissions from 2005 levels by 2020, and just over an 80% reduction of such emissions by 2050. Under this legislation, the EPA would issue a capped and steadily declining number of tradable emissions allowances to certain major sources of greenhouse gas emissions so that such sources could continue to emit greenhouse gases into the atmosphere. The cost of these allowances would be expected to escalate significantly over time. The net effect of ACESA would be to impose increasing costs on the combustion of carbon-based fuels such as oil, refined petroleum products, and natural gas. The U.S. Senate has begun work on its own legislation for restricting domestic greenhouse gas emissions, and the Obama administration has indicated its support of legislation to reduce greenhouse gas emissions through an emission allowance system. In addition, several states have considered initiatives to regulate emissions of greenhouse gases, primarily through the planned development of greenhouse gas emissions inventories and/or regional greenhouse gas cap and trade programs. Although it is not possible at this time to predict when the U.S. Senate may act on climate change legislation or how any bill passed by the Senate would be reconciled with ACESA, any future federal or state laws or regulations that may be adopted to address greenhouse gas emissions could require us to incur increased operating costs and could adversely affect the demand for the oil and natural gas that we produce. Additional information about the potential effect of climate change issues on our business is presented under the "Climate Change" caption in the Management's Discussion and Analysis of Financial Condition and Results of Operations section of our Annual Report on Form 10-K for the year ended December 31, 2009.

In response to the widely reported recent oil spill in the Gulf of Mexico resulting from a deepwater drilling rig explosion in April 2010, the U.S. Congress is considering a number of legislative proposals relating to the upstream oil and gas industry both onshore and offshore that could result in significant additional laws or regulations affecting our operations, including a proposal to raise or eliminate the cap on liability for oil spill cleanups under the Oil Pollution Act of 1990.

Although it is not possible at this time to predict whether proposed legislation or regulations will be adopted as initially written, if at all, or how legislation or new regulations that may be adopted would impact our business, any such future laws and regulations could result in increased compliance costs or additional operating restrictions. Additional costs or operating restrictions associated with legislation or

regulations could have a material adverse effect on our operating results and cash flows, in addition to the demand for the crude oil, natural gas, and other hydrocarbon products that we produce.

Cautionary Information about Forward-Looking Statements

This Quarterly Report on Form 10-Q contains "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements, other than statements of historical facts, included in this Form 10-Q that address activities, events, or developments with respect to our financial condition, results of operations, or economic performance that we expect, believe, or anticipate will or may occur in the future, or that address plans and objectives of management for future operations, are forward-looking statements. The words "anticipate," "assume," "believe," "budget," "estimate," "expect," "forecast," "intend," "plan," "project," "will," and similar expressions are intended to identify forward-looking statements. Forward-looking statements appear in a number of places in this Form 10-Q, and include statements about such matters as:

- *The amount and nature of future capital expenditures and the availability of liquidity and capital resources to fund capital expenditures*
- *The drilling of wells and other exploration and development activities and plans, as well as possible future acquisitions*
- *Proved reserve estimates and the estimates of both future net revenues and the present value of future net revenues that are included in their calculation*
- *Future oil and natural gas production estimates*
- *Our outlook on future oil and natural gas prices and service costs*
- *Cash flows, anticipated liquidity, and the future repayment of debt*
- *Business strategies and other plans and objectives for future operations, including plans for expansion and growth of operations or to defer capital investment, and our outlook on our future financial condition or results of operations*
- *Other similar matters such as those discussed in the "Management's Discussion and Analysis of Financial Condition and Results of Operations" section of this Form 10-Q.*

Our forward-looking statements are based on assumptions and analyses made by us in light of our experience and our perception of historical trends, current conditions, expected future developments, and other factors that we believe are appropriate under the circumstances. These statements are subject to a number of known and unknown risks and uncertainties which may cause our actual results and performance to be materially different from any future results or performance expressed or implied by the forward-looking statements. These risks are described in the "Risk Factors" section of our 2009 Annual Report on Form 10-K and include such factors as:

- *The volatility and level of realized oil and natural gas prices*
- *A contraction in demand for oil and natural gas as a result of adverse general economic conditions or climate change initiatives*
- *The availability of economically attractive exploration, development, and property acquisition opportunities and any necessary financing, including constraints on the availability of opportunities and financing due to distressed capital and credit market conditions*

- *Our ability to replace reserves and sustain production*
- *Unexpected drilling conditions and results*
- *Unsuccessful exploration and development drilling*

- *The risks of hedging strategies, including the possibility of realizing lower prices on oil and natural gas sales as a result of commodity price risk management activities*
- *The pending nature of reported divestiture plans for certain non-core oil and gas properties as well as the ability to complete divestiture transactions*
- *The uncertain nature of the expected benefits from acquisitions and divestitures of oil and natural gas properties, including uncertainties in evaluating oil and natural gas reserves of acquired properties and associated potential liabilities, and uncertainties with respect to the amount of proceeds that may be received from divestitures*
- *The imprecise nature of oil and natural gas reserve estimates*
- *Uncertainties inherent in projecting future rates of production from drilling activities and acquisitions*
- *Declines in the values of our oil and natural gas properties resulting in impairment charges and write-downs*
- *The ability of purchasers of production to pay for amounts purchased*
- *Drilling and operating service availability*
- *Uncertainties in cash flow*
- *The financial strength of hedge contract counterparties and credit facility participants, and the risk that one or more of these parties may not satisfy their contractual commitments*
- *The negative impact that lower oil and natural gas prices could have on our ability to borrow and fund capital expenditures*
- *The potential effects of increased levels of debt financing*
- *Our ability to compete effectively against other independent and major oil and natural gas companies and*
- *Litigation, environmental matters, the potential impact of government regulations, and the use of management estimates.*

We caution you that forward-looking statements are not guarantees of future performance and that actual results or performance may be materially different from those expressed or implied in the forward-looking statements. Although we may from time to time voluntarily update our prior forward-looking statements, we disclaim any commitment to do so except as required by securities laws.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The information required by this item is provided under the captions *Commodity Price Risk and Interest Rate Risk*, *Summary of Oil and Gas Production Hedges in Place*, and *Summary of Interest Rate Risk* in Item 2 above and is incorporated herein by reference.

ITEM 4. CONTROLS AND PROCEDURES

We maintain a system of disclosure controls and procedures that is designed to ensure that information required to be disclosed in our SEC reports is recorded, processed, summarized, and reported within the time periods specified in the SEC's rules and forms, and to ensure that such information is accumulated and communicated to our management, including the Chief Executive Officer and the Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

We carried out an evaluation, under the supervision and with the participation of our management, including the Chief Executive Officer and the Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures as of the end of the period covered by the Quarterly Report on Form 10-Q. Based upon that evaluation, the Chief Executive Officer and the Chief Financial Officer, concluded that our disclosure controls and procedures are effective for the purposes discussed above as of the end of the period covered by this Quarterly Report on Form 10-Q. There was no change in our internal control over financial reporting that occurred during our most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the effectiveness of our internal control over financial reporting.

PART II. OTHER INFORMATION

ITEM 1A. RISK FACTORS

There have been no material changes from the risk factors as previously disclosed in our Form 10-K for the year ended December 31, 2009, in response to Item 1A of Part I of such Form 10-K.

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

(c) The following table provides information about purchases by the Company or any "affiliated purchaser" (as defined in Rule 10b-18(a)(3) under the Exchange Act) during the fiscal quarter ended June 30, 2010, of shares of the Company's common stock, which is the sole class of equity securities registered by the Company pursuant to Section 12 of the Exchange Act.

PURCHASES OF EQUITY SECURITIES BY ISSUER AND AFFILIATED PURCHASERS

Period	(a) Total Number of Shares Purchased (1)	(b) Average Price Paid per Share	(c) Total Number of Shares Purchased as Part of Publicly Announced Program	(d) Maximum Number of Shares that May Yet Be Purchased Under the Program (2)
04/01/10 —04/30/10	339	$ 39.99	—	3,072,184
05/01/10 — 05/31/10	88	$ 43.24	—	3,072,184
06/01/10 — 06/30/10	—	$ —	—	3,072,184
Total:	427	$ 40.47	—	3,072,184

(1) Includes 427 shares withheld (under the terms of grants under the Equity Incentive Compensation Plan) to offset tax withholding obligations that occur upon the delivery of outstanding shares underlying restricted stock units.

(2) In July 2006 the Company's Board of Directors approved an increase in the number of shares that may be repurchased under the original August 1998 authorization to 6,000,000 as of the effective date of the resolution. Accordingly, as of the date of this filing, the Company has Board authorization to repurchase 3,072,184 shares of common stock on a prospective basis. The shares may be repurchased from time to time in open market transactions or privately negotiated transactions, subject to market conditions and other factors, including certain provisions of SM Energy's existing bank credit facility agreement and compliance with securities laws. Stock repurchases may be funded with existing cash balances, internal cash flow, and borrowings under SM Energy's bank credit facility. The stock repurchase program may be suspended or discontinued at any time.

The payment of dividends and stock repurchases are subject to covenants in our bank credit facility, including the requirement that we maintain certain levels of stockholders' equity and the limitation that does not allow our annual dividend rate to exceed $0.25 per share.

ITEM 6. EXHIBITS

The following exhibits are filed or furnished with or incorporated by reference into this report:

Exhibit	Description
3.1*	Restated Certificate of Incorporation of SM Energy Company, as amended through June 1, 2010,
3.2	Certificate of Amendment of Restated Certificate of Incorporation effective June 1, 2010 (filed as Exhibit 3.1 to the registrant's Current Report on Form 8-K filed on June 2, 2010, and incorporated herein by reference.)
3.3	Restated By-Laws of SM Energy Company amended effective as of June 1, 2010 (filed as Exhibit 3.2 to the registrant's Current Report on Form 8-K filed on June 2, 2010, and incorporated herein by reference)
10.1	Equity Incentive Compensation Plan As Amended and Restated as of April 1, 2010 (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on June 2, 2010, and incorporated herein by reference)
10.2*	Carry and Earning Agreement between St. Mary Land & Exploration Company and Encana Oil & Gas (USA) Inc. executed as of April 29, 2010
10.3*†	SM Energy Company Form of Performance Share and Restricted Stock Unit Award Agreement as of July 1, 2010
10.4*†	SM Energy Company Form of Performance Share and Restricted Stock Unit Award Notice as of July 1, 2010
10.5*†	SM Energy Company Form of Non-Employee Director Restricted Stock Award Agreement as of May 27, 2010
31.1*	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes — Oxley Act of 2002
31.2*	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes — Oxley Act of 2002
32.1**	Certification pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes — Oxley Act of 2002
99.1*	Audit Committee Pre-Approval of Non-Audit Services
101.INS***	XBRL Instance Document
101.SCH***	XBRL Schema Document
101.CAL***	XBRL Calculation Linkbase Document
101.LAB***	XBRL Label Linkbase Document
101.PRE***	XBRL Presentation Linkbase Document

* Filed with this report.
** Furnished with this report.
*** Furnished, not filed. Users of this data submitted electronically herewith are advised pursuant to Rule 406T of Regulation S-T that this interactive data file is deemed not filed or part of a registration statement or prospectus for purposes of sections 11 or 12 of the Securities Act of 1933, is deemed not filed for purposes of section 18 of the Securities Exchange Act of 1934, and otherwise is not subject to liability under these sections.
† Exhibit constitutes a management contract or compensatory plan or agreement.

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 hereunto duly authorized.

SM ENERGY COMPANY

August 3, 2010 By: /s/ ANTHONY J. BEST

		Anthony J. Best President and Chief Executive Officer
August 3, 2010	By:	/s/ A. WADE PURSELL A. Wade Pursell Executive Vice President and Chief Financial Officer
August 3, 2010	By:	/s/ MARK T. SOLOMON Mark T. Solomon Controller

EXHIBIT 3.1

[THE FOLLOWING COMPOSITE RESTATED CERTIFICATE OF INCORPORATION OF SM ENERGY COMPANY (THE “CORPORATION”) REFLECTS THE PROVISIONS OF THE RESTATED CERTIFICATE OF INCORPORATION OF ST. MARY LAND & EXPLORATION COMPANY (THE FORMER NAME OF THE CORPORATION) FILED WITH THE DELAWARE SECRETARY OF STATE ON NOVEMBER 17, 1992, AND ALL AMENDMENTS THERETO FILED WITH THE DELAWARE SECRETARY OF STATE THROUGH JUNE 1, 2010, BUT IS NOT AN AMENDMENT AND/OR FURTHER RESTATEMENT THEREOF]

RESTATED CERTIFICATE OF INCORPORATION

OF

SM ENERGY COMPANY

FIRST: The name of this Corporation is SM Energy Company.

SECOND: Its registered office in the State of Delaware is to be located in the City of Wilmington, County of New Castle. The agent in charge thereof is The Corporation Trust Company, Corporation Trust Center, 1209 Orange Street, Wilmington, Delaware 19801.

THIRD: The purpose of the Corporation is to engage in any lawful act or activities for which corporations may be organized under the General Corporation Law of the State of Delaware.

FOURTH: The total number of shares of capital stock which the Corporation shall have authority to issue is 200,000,000 shares, of $.01 par value each.

FIFTH: The existence of this Corporation is to be perpetual.

SIXTH: The private property of the stockholders shall not be subject to the payment of corporate debts to any extent whatever.

SEVENTH: The Directors shall have the power to adopt, amend or repeal the By-Laws, to fix reserves, and to authorize and cause to be executed, mortgages and liens, without limit as to the amount, upon the property and franchises of this Corporation.

EIGHTH: The Directors may, by resolution passed by a majority of the whole Board of Directors, designate one or more committees, each committee to consist of one or more of the Directors of the Corporation, who, to the extent provided in said resolution or in the By-Laws of the Corporation, shall have the power and authority of the Board of Directors in the management of the business and affairs of the Corporation and may have power to authorize the seal of the Corporation to be affixed to all papers which may require it.

NINTH: The Directors shall have authority to dispose, in any manner, of all or substantially all of the property of the Corporation, when as authorized by a resolution adopted by a majority of the outstanding capital stock of the Corporation.

TENTH: The By-Laws shall determine whether and to what extent the accounts and books of this Corporation, or any of them, shall be open to the inspection of the stockholders; and no

stockholder shall have any right of inspecting any account, or book or document of this Corporation, except as conferred by law or the By-Laws, or by resolution adopted by a majority of the outstanding capital stock of the Corporation or by resolution of a majority of the whole Board of Directors.

ELEVENTH: The stockholders and Directors shall have power to hold their meetings and keep the books, documents and papers of the Corporation outside of the State of Delaware, at such places as may be from time to time designated by the By-Laws, except as otherwise required by the laws of Delaware.

TWELFTH: The Directors may exercise, in addition to the powers and authorities hereinbefore or by law conferred upon them, any such powers and authorities and may do all such acts and things as may be exercised or done by the Corporation, subject, nevertheless, to the provisions of law, and of this Certificate of Incorporation and of the By-Laws of the Corporation.

THIRTEENTH: No contract or transaction between the Corporation and one or more of its Directors or officers, or between the Corporation and any other corporation, partnership, association, or other organization in which one or more of its Directors or officers are directors or officers, or have a financial interest, shall be void or voidable solely for this reason, or solely because the Director or officer is present at or participates in the meeting of the Board of Directors or committee thereof which authorizes the contract or transaction, or solely because his or their votes are counted for such purpose, if: (a) the material facts as to his relationship or interest and as to the contract or transaction are disclosed or are known to the Board of Directors or the committee, and the Board of Directors or the committee in good faith authorizes the contract or transaction by the affirmative votes of a majority of the disinterested Directors, even though the disinterested Directors be less than a quorum, or (b) the material facts as to his relationship or interest and as to the contract or transaction are disclosed or are known to the stockholders entitled to vote thereon, and the contract or transaction is specifically approved in good faith by vote of the stockholders, or (c) the contract or transaction is fair as to the Corporation as of the time it is authorized, approved or ratified by the Board of Directors, a committee thereof, or the stockholders. Common or interested Directors may be counted in determining the presence of a quorum at a meeting of the Board of Directors or of a committee which authorizes the contract or transaction.

FOURTEENTH: (a) The Corporation shall indemnify any person who was or is a party or is threatened to be made a party to any threatened, pending or completed action, suit or proceeding, whether civil, criminal, administrative or investigative (other than an action by or in the right of the Corporation) by reason of the fact that he is or was a Director, officer, employee or agent of the Corporation, or is or was serving at the request of the Corporation as a director, officer, employee or agent of another corporation, partnership, joint venture, trust or other enterprise, against expenses (including attorneys' fees), judgments, fines and amounts paid in settlement actually and reasonably incurred by him in connection with such action, suit or proceeding if he acted in good faith and in a manner he reasonably believed to be in or not opposed to the best interests of the Corporation, and, with respect to any criminal action or proceeding, had no reasonable cause to believe his conduct was unlawful.

(b) The Corporation shall indemnify any person who was or is a party or is threatened to be made a party to any threatened, pending or completed action or suit by or in the right of the Corporation to procure a judgment in its favor by reason of the fact that he is or was a Director, officer, employee or agent of the Corporation, or is or was serving at the request of the Corporation as a director, officer, employee or agent of another corporation, partnership, joint venture, trust or other enterprise against expenses (including attorneys' fees) actually and reasonably incurred by him in connection with the defense or settlement of such action or suit if he acted in good faith and in a manner he reasonably believed to be in or not opposed to the best interests of the Corporation and except that no

indemnification shall be made in respect of any claim, issue or matter as to which such person shall have been adjudged to be liable for negligence or misconduct in the performance of his duty to the Corporation unless and only to the extent that the Court of Chancery of the State of Delaware or the court in which such action or suit was brought shall determine upon application that, despite the adjudication of liability but in view of all the circumstances of the case, such person is fairly and reasonably entitled to indemnity for such expenses which the Court of Chancery or such other court shall deem proper.

(c) To the extent that a Director, officer, employee or agent of the Corporation has been successful on the merits or otherwise in the defense of any action, suit or proceeding referred to in paragraphs (a) and (b) of this Article, or in defense of any claim, issue or matter therein, he shall be indemnified against expenses (including attorneys' fees) actually and reasonably incurred by, him in connection therewith without the necessity of any action being taken by the Corporation other than a determination in good faith that such defense has been successful.

In all other cases, any indemnification under paragraphs (a) and (b) of this Article (unless ordered by a court) shall be made by the Corporation only as authorized in the specific case upon a determination that indemnification of the Director, officer, employee or agent is proper in the circumstances because he has met the applicable standard of conduct set forth in paragraphs (a) and (b) of this Article. Such determination shall be made (1) by the Board of Directors by a majority vote of a quorum consisting of Directors who were not parties to such action, suit or proceeding, or (2) if such a quorum is not obtainable, or, even if obtainable if a quorum of disinterested Directors so directs, by independent legal counsel in a written opinion, or (3) by the stockholders.

(d) The termination of any, action, suit or proceeding by judgment, order, settlement, conviction or upon a plea of nolo contendere or its equivalent, shall not, of itself, create a presumption that the person seeking indemnification did not act in good faith and in a manner which he reasonably believed to be in or not opposed to the best interests of the Corporation, and, with respect to any criminal action or proceeding, had reasonable cause to believe that his conduct was unlawful. Entry of a judgment by consent as part of a settlement shall not be deemed a final adjudication of liability for negligence or misconduct in the performance of duty, or of any other issue or matter.

(e) Expenses incurred in defending a civil or criminal action, suit or proceeding may be paid by the Corporation in advance of the final disposition of such action, suit or proceeding as authorized by the Board of Directors in the specific case upon receipt of an undertaking by or on behalf of the Director, officer, employee or agent involved to repay such amount unless it shall ultimately be determined that he is entitled to be indemnified by the Corporation as authorized in this Article.

(f) The indemnification provided by this Article shall not be deemed exclusive of any other rights to which those seeking indemnification may be entitled under any by-law, agreement, vote of stockholders or disinterested Directors or otherwise, both as to action in his official capacity and as to action in another capacity while holding such office, and shall continue as to a person who has ceased to be a Director, officer, employee or agent and shall inure to the benefit of the heirs, executors and administrators of such a person.

(g) The Corporation may purchase and maintain insurance on behalf of any person who is or was a Director, officer, employee or agent of the Corporation, or is or was serving at the request of the Corporation as a director, officer, employee or agent of another corporation, partnership, joint venture, trust or other enterprise against any liability, asserted against him and incurred by him in any such capacity, or arising out of his status as such, whether or not the Corporation would have the power to indemnify him against such liability under the provisions of this Article.

(h) The provisions of this Article shall be separable and the invalidity of all or any part thereof as applied to any particular type of liability or any particular person shall not preclude application of any remaining portion thereof to such situation or such person, nor application of the provisions of this Article to any other situation or person.,

FIFTEENTH: (a) A Director of the Corporation shall not be personally liable to the Corporation or its stockholders for monetary damages for breach of fiduciary duty as a director, except that this Article FIFTEENTH shall not eliminate or limit a Director's liability (i) for any breach of the Director's duty of loyalty to the Corporation or its stockholders, (ii) for acts or omissions not in good faith or which involve intentional misconduct or a knowing violation of law, (iii) under Section 174 of the Delaware General Corporation Law or (iv) for any transaction from which the Director derived an improper personal benefit. If the Delaware General Corporation Law is amended after approval by the stockholders of this Article FIFTEENTH to authorize corporate action further eliminating or limiting the personal liability of directors, then the liability of a Director of the Corporation shall be eliminated or limited to the fullest extent permitted by the Delaware Corporation Law, as so amended from time to time.

(b) Any repeal or modification of this Article FIFTEENTH shall not increase the personal liability of any Director of the Corporation for any act or occurrence taking place prior to such repeal or modification, or otherwise adversely affect any right or protection of a Director of the Corporation existing at the time of such repeal or modification.

(c) The provisions of this Article FIFTEENTH shall not be deemed to limit or preclude indemnification of a Director by the Corporation for any liability of a Director which has not been eliminated by the provisions of this Article FIFTEENTH.

SIXTEENTH: This Corporation reserves the right to amend, alter, change or repeal any provision contained in this Certificate of Incorporation, in the manner now or hereafter prescribed by the statutes of the State of Delaware, and all rights conferred on officers, Directors and stockholders herein are granted, subject to this reservation.

Carry and Earning Agreement
By and Among
ST. MARY LAND & EXPLORATION COMPANY
and
ENCANA OIL & GAS (USA) INC.
Dated April 29, 2010

CARRY AND EARNING AGREEMENT

This CARRY AND EARNING AGREEMENT (this "Agreement"), executed as of April 29, 2010, effective as of the date of signing hereof (the "Effective Date"), is by and among ST. MARY LAND & EXPLORATION COMPANY, a Delaware corporation ("STML") and ENCANA OIL & GAS (USA) INC., a Delaware corporation ("EnCana"). STML and EnCana may each also be referred to herein as a "Party" or collectively as the "Parties."

BACKGROUND

1 STML is the current owner and holder of approximately 31,738 net acres of oil, gas and mineral leases covering lands in Shelby and San Augustine Counties, Texas, and the leasehold interest in the lands covered thereby, limited, however, to the Assigned Interval (individually, a "Lease" and collectively, the "Leases," as identified by name and STML property number on Exhibits A-1 and A-2). Each portion of Exhibit A also sets forth, for each Lease, STML's Working Interest and associated Net Revenue Interest therein, as well as the number of Net Mineral Acres covered by the Lease.

2 The Leases will be developed in two blocks, as depicted on the plat attached hereto as Exhibit B: (i) a northern block consisting of a supposed 8,375 Net Mineral Acres of Leases (the "North Block"); and (ii) a southern block consisting of a supposed 23,363 Net Mineral Acres of Leases (the "South Block"). The Leases within the North Block are described on Exhibit A-1 and the Leases within South Block are described on Exhibit A-2. Either the North Block or the South Block may be referred to individually as a Block or collectively as the "Blocks."

3 The Parties desire to enter into this Agreement in order to provide the terms and conditions under which EnCana will earn an undivided 5% interest in the Assets in the South Block and an undivided 95% interest in the Assets in the North Block, through the payment for the drilling of horizontal wells in the South Block, as further provided herein. As to each respective Block, these ownership interests to be assigned shall be referred to herein as the "Assigned Interest."

4 Capitalized terms used herein will have the meaning given to such terms herein. A list of the capitalized terms and all Exhibits and Schedules is set forth in the Schedule of Definitions attached hereto as Schedule 1.

NOW, THEREFORE, in consideration of the mutual promises and covenants contained herein, the Parties agree as follows:

ARTICLE I
PROPERTIES SUBJECT TO AGREEMENT

1.1 Assigned Interval.

(a) The rights to be earned by EnCana are limited to the undivided interests assigned in the

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Leases insofar and only insofar as those rights pertain to the correlative interval corresponding to the depths from the top of the Bossier Shale Formation to the base of the Haynesville Formation (the "Assigned Interval").

(b) The Assigned Interval is defined as the stratigraphic equivalent of the interval from 11,570 feet to 12,882 feet as shown on the electrical log of the St. Mary Land & Exploration, Black Stone PB#1 well (API No. 42-419-31498), Shelby County, Texas.

1.2 Description of the Assets. To the extent associated with the respective Assigned Interest in the Assigned Interval, and further subject to the Excluded Assets and the other express limitations and reservations set forth herein and on Exhibits A-1 and A-2, the respective Assigned Interest shall include the following which together with the Assigned Interest in the Leases shall be collectively referred to herein as the "Assets:"

(a) the Leases and all rights resulting from the pooling, unitizing or communitizing of the Leases;

(b) an undivided 95% of STML's interest in the four wells operated by XH, LLC whose units include North Block Leases and in which operations have either commenced or there exists an approved AFE therefor, and an undivided 5% of STML's interest in that certain well also operated by XH, LLC whose unit includes South Block Leases, such five wells being more fully described on Exhibit A-3, such five wells being referred to herein as the "XTO Drilling Wells," with the interest to be assigned in these five wells each being subject to separate operating agreements dated December 1, 2009(being a portion of the XTO Agreements, as such term is hereafter defined);

(c) to the extent related to the Assigned Interval, the Assigned Interest in the North Block share of all rights, titles and interest of STML in and to the seven operating agreements each dated December 1, 2009, and an eighth operating agreement dated February 1, 2009, each naming XH, LLC as operator with each of these operating agreements being described on the attached Exhibit A-4 (the "XTO Agreements");

(d) to the extent related to the Assigned Interest in the North Block, an undivided 95% of STML's rights, titles and interest in and to that certain wellbore for the Hinton 1-H well located in the James English Survey A-186, Shelby County, Texas (API # 42-419-31554), which well is currently being drilled by STML, together with EnCana's proportionate share of all equipment, personal property and fixtures associated with this assigned wellbore, it being understood and agreed by and between the Parties that STML will operate the drilling of this well until the Effective Date at which point, EnCana shall assume the role of Operator for such well with the understanding that EnCana shall operate this well thereafter including any Completion operations (as hereinafter defined), and to the extent related to the Assigned Interest in the South Block, an undivided 5% of STML's rights, titles and interest in and to those certain wellbores for the Ironosa No. 1 well (API #42-405-30308), which well has been drilled as a vertical well but not Completed, and the Crockett No. 1-H well (API #42-419-31570), which well was recently commenced, which three wells are more fully described on Exhibit A-3, and which three wells may be referred to herein as the "STML Drilling Wells;"

(e) equal rights with STML to the right of ingress and egress and use of the surface of the lands covered by the Leases in the North Block to the same extent currently owned or enjoyed by STML;

(f) a subsurface easement through, over and across the Leases to the extent reasonably necessary for EnCana to transit the rights retained by STML hereunder to allow EnCana to enjoy the rights to be granted to it in the Assigned Interval;

(g) To the extent related to the Assigned Interval, the respective Assigned Interest in all rights, titles and interests of STML in and to, or otherwise derived from, all presently existing and valid oil, gas and/or mineral unitization, pooling, and/or communitization agreements, declarations and/or orders (including, without limitation, all units formed under orders, rules, regulations, or

other official acts of any federal, state or other authority having jurisdiction, and voluntary unitization agreements, designations and/or declarations);

(h) To the extent related to and binding upon the Assigned Interval, the respective Assigned Interest in the Material Contracts (as hereafter defined); and

(i) To the extent related to the Assigned Interval, the respective Assigned Interest in all right, title and interest of STML in and to all existing and valid, enforceable contracts and agreements to the extent such are binding on the Leases or lands covered thereby.

1.3 Excluded Assets. STML reserves to itself, and there is hereby excepted from this Agreement (collectively, the "Excluded Assets"):

(a) All rights in and to the Leases to the extent not associated with the Assigned Interests in the Assigned Interval;

(b) The wellbore and the production therefrom, together with the equipment, personal property and fixtures associated therewith, but not the Leases insofar as such pertain to the Assigned Interests in the Assigned Interval (except as such Lease rights pertain to these wellbores) associated with the two existing vertical wells producing from the Assigned Interval in the South Block, the Cabot-King Gas Unit 1-H well located in a pooled area including a portion of the Leases in the South Block and, the two wells described in Section 1.3(d) all such wells being referred to as the "Excluded Wells" and each of them being described with particularity onExhibit A-5 attached hereto and made a part hereof;

(c) all STML field offices and yards and equipment stored therein;

(d) STML will specifically except and reserve from the Assigned Interest in the North Block (i) all of its overriding royalty interest in the Ellora-Ellington No. 1-H well located in the James English Survey, A-186, Shelby County, Texas (API #42-419-31505) and (ii) all of its overriding royalty interest and conversion rights associated therewith in the Raymond No. 1 well located in the Benjamin Odell Heirs Survey, A-534 Shelby County, Texas (API #42-419-31432); and

(e) any gas gathering system owned and operated by STML within the South Block.

1.4 Additional Assets. Subject to Section 3.8(c)(i), STML will assign to EnCana all of STML's interest in the rights of way it has acquired in the North Block that are related to a proposed pipeline relating to the Hinton 1-H well, which rights-ofway are described on Exhibit A-6 attached hereto and made a part hereof and will be a part of the Assets.

ARTICLE II
INITIAL OBLIGATIONS

2.1 Deliveries.

(a) Simultaneously with the execution of this Agreement, STML and EnCana will each execute and deliver to the other:

(i) the JOA attached hereto as Exhibit C, including the Tax Partnership Agreement attached thereto (the "JOA");

(ii) an executed and acknowledged Memorandum of the JOA for recording in the counties in which the Assets are located; and

(iii) such other instruments, agreements and other documents as either may reasonably request in conjunction with the consummation of the closing contemplated herein.

(b) Simultaneously with the execution of this Agreement, STML will execute and deliver to EnCana: (i) assignments of the Assigned Interest in the Leases limited to the Assigned Interval, in substantially the form attached hereto as Exhibits D-1 (North Block) and D-2 (South Block) (collectively, the "Assignments"); and (ii) the assignment provided for in Section 1.4, on a mutually agreeable form of assignment based upon the Assignments.

(c) STML will deliver, within 30 days of the execution of this Agreement, copies of their land files related to the Leases. Notwithstanding this delivery requirement, STML shall make all of its land files related to the Leases available to EnCana for title review purposes from and after the Effective Date and the payments required upon signing this Agreement have been made.

(d) STML will deliver a summary with appropriate back-up of the costs incurred as of the Effective Date in the STML Drilling Wells.

(e) Simultaneously with the execution of this Agreement, EnCana will deliver to STML $45,649,933.00 (the "Initial Payment"), in immediately available funds by wire transfer to an account designated by STML.

(f) STML and EnCana will each execute and deliver the Letter Agreement between each of them and Scandrill Inc. that acts to substitute EnCana as Operator under the drilling contract for the Hinton 1-H well.

2.2 Existing Wells.

(a) With regard to the eight wells described in Sections 1.2(b) and 1.2(d), which wells are described on Exhibit A-3 (being the XTO Drilling Wells and the STML Drilling Wells), within thirty (30) days of the Effective Date, EnCana will deliver to STML in immediately available funds by wire transfer to an account designated by STML, EnCana's Proportionate Share of all actual costs incurred in and related to the STML Drilling Wells. Schedule 2.2(a) sets forth the current estimate of the costs of the STML Drilling Wells to be reimbursed pursuant to the preceding sentence. It is assumed by STML that if the costs incurred as of the Effective Date in the XTO Drilling Wells have not been billed to STML on or before the Effective Date, that such billings will be received by STML shortly thereafter. If this occurs before EnCana is added to the joint interest billing process for the XTO Drilling Wells, STML will remit payment to the operator and will promptly invoice EnCana for its Proportionate Share of such costs. EnCana will remit its Proportionate Share of such invoices to STML with thirty (30) days of EnCana's receipt thereof. From and after the Effective Date, with regard to the XTO Drilling Wells, STML shall endeavor to have EnCana billed directly for costs incurred, and for the wells operated by STML, STML shall bill EnCana for its Proportionate Share of costs incurred after those reflected in these payments. The eight wells are: (i) the XTO Drilling Wells, namely the five operated by XH, LLC, being the Bruins, Lumberjacks, Ducks, Badgers, and Jayhawks, all described more fully on Exhibit A-3; and (ii) the STML Drilling Wells, namely the Hinton 1-H, Crockett No. 1-H, and Ironosa No. 1, each operated by STML. EnCana shall be responsible for its Proportionate Share of all actual, direct costs related to these eight wells insofar as its Assigned Interest is concerned from commencement of operations, including any title examination, permitting, surveying, site preparation, or other costs or expenses related to the drilling of these wells and EnCana shall thereafter remain responsible for its Proportionate Share of the costs associated with these wells as an undivided interest owner therein; provided, however, that, with respect to the Hinton 1-H and the Ironosa No. 1, EnCana will not reimburse STML for any costs associated with the evaluation of zones outside the Assigned Interval (including the costs of cores and drilling rig time to obtain cores). Within 60 days of the Completion of any of these eight wells, STML and EnCana shall use their best efforts to true-up their respective Proportionate Share of costs based on actual costs incurred and paid to insure that each Party has paid its appropriate Proportionate Share of costs in these eight wells. With regard to the Crockett No. 1-H well and the Ironosa No. 1 well, EnCana shall pay only its Proportionate Share of costs incurred prior to the Effective Date; thereafter, the provisions of Article III pertaining to Carried Well Costs in a Commitment Well shall apply to the Crockett No. 1-H well and the Ironosa No. 1 well.

(b) Subject to this Agreement becoming fully effective as between the Parties, EnCana agrees to Complete the Hinton 1-H well referred to in the preceding paragraph if such well would be Completed by a reasonably prudent operator under the same or similar circumstances. STML shall turn over operation of this well to EnCana as of the Effective Date such that EnCana shall

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complete the drilling operations which include determining the landing depth for the horizontal section of this well, the total lateral length, running production casing and its attendant cementing, and Completing the well as either a dry hole or as a well capable of producing hydrocarbons.

2.3 The Assignment. The Assignment will occur in two separate documents, one pertaining to the North Block and the other to the South Block, and each will deliver the Assigned Interest in the Assigned Interval in the affected Leases to EnCana with the same Net Revenue Interest in each such Lease as owned by STML as of the Effective Date prior to delivery of the Assignment, reserving no overriding royalty interest or other burden on production (other than the overriding royalty interest noted in Section 1.3(d)) not existing of record as of the Effective Date, and will be made without warranty of title whatsoever except by, through and under STML and its affiliates, but to no further extent. The Assignment will provide that the Party owning the undivided 95% interest in the Leases in the respective Blocks shall have the right to pool the interests of the undivided 5% owner consistent with the terms of the affected Leases, such pooling rights limited to the Assigned Interval only.

2.4 Title and Other Information Held By STML. To the extent not limited or precluded by operation of any valid third party licensing or confidentiality agreement, STML will make available to EnCana copies of its oil and gas lease files, including, but not limited to, all title data, such as broker's run sheets, title opinions and abstracts, covering the Leases. STML will make available to EnCana all other information in STML's or any of its Affiliates' possession relating to the Assets, including geological, geophysical and engineering information. EnCana may examine such information and materials at EnCana's sole cost and expense during regular business hours at the location at which STML makes the materials available. Also, to the extent available, STML will transmit to EnCana such information and materials in electronic form. Except as is otherwise expressly provided herein, all information is provided without warranty of any kind, including any regarding the completeness or accuracy of this information. STML will not be required to make available any information covered by existing agreements of confidentiality to which it is bound; provided, however, that STML will make commercially reasonable efforts to obtain the release of any such information. Subject to the foregoing, EnCana shall have the right to examine all title with respect to the Assets as described in Section 4.2 and EnCana and STML shall handle any Title Defects as described in Article IV.

ARTICLE III
CARRY AMOUNT, INTEREST, COMMITMENT WELLS

3.1 Proportionate Share. The term "Proportionate Share" means:

(a) With respect to EnCana: an undivided 5% in the South Block and an undivided 95% in the North Block of the interest STML owns in the Assets as of the Effective Date immediately prior to the delivery of the Assignment of the Assigned Interest in each Block to EnCana; and

(b) With respect to STML: an undivided 95% in the South Block and an undivided 5% in the North Block of the interest STML owns in the Assets as of the Effective Date immediately prior to the delivery of the Assignment of the Assigned Interest in each Block to EnCana.

3.2 The Carry.

(a) The term "Carry Amount" means a total of $91,299,866 (subject to adjustment as provided in Section 3.2(a)(ii)) paid as follows:

(i) the Initial Payment; and

(ii) a subsequent payment equal to the difference between (x) and (y) with (x) being $91,299,866 less the amount for any Title Defects determined in accordance with Article IV and Section 3.9; and (y) being the Initial Payment. This subsequent payment must be made by wire transfer within thirty days of the Completion of the fourth Commitment Well or November 1, 2010, whichever last occurs, in immediately available funds to an account designated in writing by STML, such designation to be made at least three days prior to the date the payment will be made.

(b) The term "Carried Well Costs" means 100% of the costs to drill and Complete (as each are hereafter defined) a Commitment Well. The Carry Amount will be used solely to pay Carried Well Costs.

(c) The "Carry Period" is the period of time between the Effective Date and the date that the Carried Well Costs equal the Carry Amount. If the Carry Amount is expended during the pendency of either drilling or Completion operations on a Commitment Well, all future costs and expenses incurred in such well shall thereafter be paid by the Parties in their respective Proportionate Shares.

(d) Costs incurred after Completion operations in a Commitment Well shall not be included in Carried Well Costs, and such costs shall be borne by the Parties in their respective Proportionate Shares.

3.3 Commitment Wells.

(a) Beginning on the Effective Date, EnCana will be responsible for paying 100% of the Carried Well Costs attributable to the interests of the Parties, up to the Carry Amount, to drill and Complete (or plug and abandon with the drilling rig), horizontal wells landed in the Assigned Interval at locations of STML's choice in the South Block in accordance with the provisions of this Article III and the AFEs (each such well, subject to the terms hereof, a "Commitment Well" and collectively, the "Commitment Wells").

(b) STML will be the operator of the Commitment Wells.

(c) EnCana may not non-consent the drilling or Completion of a Commitment Well.

(d) The terms "Complete," "Completing" or "Completion" means, with respect to a Commitment Well:

(i) running production casing, testing, logging, coring, surveying, or any other type of testing or diagnostic procedure that a reasonably prudent operator would conduct;

(ii) attempting a fracture stimulation that a reasonable and prudent operator would conduct in the well that is based on generally accepted engineering practices appropriate for the area, including, but without any obligation to do so, any operation necessary to conduct a micro seismic survey pertaining to the fracture stimulation, and further including the conducting of simul-fracture stimulation ; and

(iii) procuring and installing flowlines, wellheads, tanks and other production equipment, through and including the well production meter that is located on the wellsite for the affected well downstream of any production treating equipment or facilities located at the wellsite for each Commitment Well, but not including the construction of any pipelines or other facilities downstream of the well production meter.

(e) The terms "drill" or "drilling" with respect to a Commitment Well means:

(i) All activity and operations necessary to drill a Commitment Well to its final total length, including the drilling of any pilot hole down through the Assigned Interval to allow for an evaluation of the Assigned Interval, and including any title examination,

permitting, surveying, site preparation, casing, cementing, testing, logging, coring, or other work or operations necessary or incident to preparing the Commitment Well for Completion operations, or if a dry hole, through the plugging and abandonment of the Commitment Well and abandonment of the surface location;

(ii) with regard to the existing two vertical wells that STML has included in the Excluded Assets as two of the Excluded Wells from and after the dated this Agreement is signed by

both Parties, STML is specifically granted the right by EnCana to utilize either of these existing wellbores as a Commitment Well, and in such event, the drilling component of any such Commitment Well will include any and all permitting and all operations necessary to convert either of the two existing vertical wells (being the USABL No.1 and the Black Stone PB#1) from a vertical well to a horizontal well in the Assigned Interval, and, if necessary, STML will assign the appropriate Assigned Interest to EnCana in either or both of these two vertical wellbores not assigned to EnCana upon the signing of this Agreement once production from the affected vertical well has been terminated, if the well is then a producing well, and operations incident to converting this vertical well to a horizontal well have been commenced. All costs associated in any manner with converting either of these two vertical wells to a Commitment Well shall be Carried Well Costs until such time as the Carry Amount has been expended.

(iii) with regard to the Ironosa No. 1 and the Crockett No. 1-H wells from and after the date this Agreement is signed by both Parties, STML is specifically granted the right by EnCana to utilize either or both of these existing wellbores as a Commitment Well, and in such event, the drilling component of any such Commitment Well will include any and all permitting and all operations necessary to convert the Ironosa No. 1 from a vertical well to a horizontal well in the Assigned Interval. All costs associated in any manner with converting this vertical well to a Commitment Well and the costs incurred after signing this Agreement in the Crockett No. 1-H well shall be Carried Well Costs until such time as the Carry Amount has been expended.

3.4 Procedure for Drilling Commitment Wells. From and after the execution of this Agreement, if STML desires to drill a Commitment Well, it will notify EnCana of such decision by sending a written notice, including:

(a) An Authorization for Expenditure (an "AFE") detailing the estimated cost of drilling and Completing the Well;

(b) The location of the well; and

(c) Any other information it desires to provide concerning the geology, title and prospects for the well.

3.5 Drilling Schedule.

(a) The Commitment Wells must be drilled within two years of the Effective Date. If the Carried Well Costs incurred as of the second anniversary of the Effective Date are less than the Carry Amount as adjusted by operation of this Agreement, STML shall promptly refund to EnCana the difference between the incurred Carried Well Costs as of this date and the adjusted Carry Amount. Further, this Agreement shall terminate and be of no further force or effect two years from the Effective Date except that obligations existing as of this date of termination shall remain binding obligations of the Party subject to such obligations in accordance with the terms hereof.

(b) STML will use its best efforts consistent with sound engineering and financial practices to commence Completion operations on each Commitment Well within 90 days of the date the drilling rig is released from the applicable well.

3.6 Third Party Wells. The Carry Amount may be applied to wells drilled by third parties in the South Block on the Leases or lands pooled therewith upon the mutual agreement of EnCana and STML, which agreement shall not be unreasonably withheld.

3.7 Information Rights.

(a) STML shall maintain with respect to each Commitment Well, as and when drilled, all drilling reports, logs, drillstem test data, and geological and geophysical maps and all other relevant data. EnCana will be entitled, at all reasonable times, upon reasonable notice and subject to compliance with STML's reasonable health, safety, and environmental rules and regulations, at EnCana's sole risk and expense, to access to the rig floor and location of all Commitment Wells.

(b) EnCana shall have the right to audit the books and records of STML in connection with its operations in connection with the Commitment Wells in accordance with the audit provisions of the JOA.

3.8 Gas Gathering.

(a) Tenaska Agreement. The Parties understand and acknowledge that STML has entered into that certain Gas Gathering Agreement dated February 8, 2010, by and between TPF II East Texas Gathering, LLC as "Gatherer" and STML as "Shipper" (herein the "Tenaska Agreement"). This Tenaska Agreement is attached hereto as Exhibit E. In accordance with the terms of the Tenaska Agreement, there are various rights, benefits, duties and obligations imposed on Gatherer and Shipper. Subject to the provisions of Section XV of the Tenaska Agreement, STML agrees to assign to EnCana a partial interest in the rights, benefits, duties and obligations as created by the Tenaska Agreement, such interest being a fraction the numerator of which is the Net Mineral Acres acquired by EnCana in the North Block and South Block combined and the denominator of which are the total number of Net Mineral Acres owned by STML in the North Block and the South Block combined as of the Effective Date immediately preceding the Assignment, with such determination of this numerator and denominator to be made after EnCana has conducted its title review as allowed by Article IV hereof.

(b) Gathering Systems.

(i) EnCana System. The Parties recognize that it will be necessary for EnCana to construct, own, maintain and operate a gathering system to move production from the North Block from EnCana operated wells to the facilities contemplated by the Tenaska Agreement. Assuming the existence of this EnCana operated or controlled gathering system, EnCana agrees that STML shall have the right, but not the obligation, to transport gas on this gathering system from wells in which STML owns an interest and that produce from an interval outside of the Assigned Interval. This right by STML shall be on a space available basis with no obligation on the part of EnCana to provide space on the gathering system, unless such space is readily available. EnCana will also allow STML the right to use its rights-of-way related to the gathering system provided such use is not prohibited by the terms of the particular right-of-way grant. If STML moves gas on the EnCana gathering system in accordance with this paragraph, EnCana shall charge STML a reasonable market-based fee to which the Parties mutually agree acting in a commercially reasonable manner. In addition, EnCana agrees that STML shall have the right, but not the obligation, to transport gas on this gathering system from wells in the North Block in which STML owns an interest within the Assigned Interval. If STML moves gas produced from the Assigned Interval in the North Block on the EnCana gathering system in accordance with this paragraph, EnCana shall charge STML a reasonable market-based fee to which the Parties mutually agree acting in a commercially reasonable manner.

(ii) STML North Block System. EnCana will have the right, but not the obligation, to transport gas on STML's existing 8 inch pipeline in the North Block from wells in which EnCana owns an interest, provided that such right cannot be exercised if such use by EnCana will cause the existing STML wells to go off-line on such gathering system. This right by EnCana shall be on a space available basis with no obligation on the part of STML to provide space on the gathering system, unless such space is readily available. STML will also allow EnCana the right to use its rights-of-way related to the 8 inch pipeline provided such use is not prohibited by the terms of the particular right-of-way grant. If EnCana

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moves gas on the STML 8 inch pipeline in accordance with this paragraph, STML shall charge EnCana a reasonable market-based fee to which the Parties mutually agree acting in a commercially reasonable manner.

(iii) STML South Block System. The Parties recognize that it will be necessary for STML to construct, own, maintain and operate a gathering system to move production from the South Block from STML operated wells to the facilities contemplated by the Tenaska Agreement. Assuming the existence of this STML operated or controlled gathering system, STML agrees that EnCana shall have the right, but not the obligation, to transport gas on this gathering system from wells in the South Block in which EnCana owns an interest within the Assigned Interval. If EnCana moves gas on the STML gathering system in accordance with this paragraph, STML shall charge EnCana a reasonable market-based fee to which the Parties mutually agree acting in a commercially reasonable manner.

3.9 Consents to Assign. In the context of preparing this Agreement, various consents to assign have been reviewed affecting a portion of the Leases. The Leases affected by these consents to assign are set forth on Schedule 3.9 attached hereto. While the Parties expect that all necessary consents to assign will be granted in due course, it is recognized that some or all of these may not have been obtained prior to the Effective Date. For all consents to assign not obtained prior to the Effective Date: (i) the Parties acknowledge that EnCana is claiming all such consents to assign as Title Defects pursuant to Section 4.4(a)(iv); (ii) STML will have until the date that is ninety (90) days following the Effective Date in which to procure the necessary consent for each such Lease (the "Cure Period"); and (iii) the affected Lease will be excluded from the respective assignment. Within a reasonable time of obtaining the consent to assign, the affected Lease will be assigned to EnCana in accordance with the terms and conditions of this Agreement. During the interim between the Effective Date and the assignment of an affected Lease to EnCana or the end of the Cure Period, whichever is earlier, STML shall not encumber or burden the affected Lease in any manner so as to prevent STML from assigning the affected Lease to EnCana with the unencumbered working interest and net revenue interest as described for such Lease on Exhibit A-1 or A-2, as applicable. Once the affected Lease or Leases are assigned to EnCana, they shall be subject to the same title review process as described in Article IV subject to modifying the dates of the Examination Period so that EnCana retains its full review rights as otherwise prescribed by Article IV of this Agreement as to such Lease or Leases. If STML is unable to secure a necessary consent to assign by the end of the Cure Period, it shall retain such Lease and the Carry Amount will be reduced by an amount calculated by multiplying the Net Mineral Acres included in the affected Lease times the Per Acre Value. This reduction in the Carry Amount shall be taken into account in the determination of the payment due pursuant to Section 3.2(a)(ii).

ARTICLE IV
TITLE MATTERS

4.1 Title Procedure. From the Effective Date until 5:00 p.m. Central Time on the date that is 45 days following the Effective Date (the "Examination Period"), STML will afford to EnCana and its representatives reasonable access during normal business hours to the offices, personnel and books and records of STML in order for EnCana to conduct a title examination as it may in its sole discretion choose to conduct with respect to the Assets in order to determine whether Title Defects exist.

4.2 Accessible Information; Expenses; Confidential Information; Indemnification. EnCana and its representatives may examine all abstracts of title, title opinions, title files, ownership

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maps, lease files, assignments, division orders, operating records and agreements, well files, financial and accounting records, geological, geophysical, engineering and environmental records pertaining to the Leases, in each case insofar as the same may now be in existence and in the possession of STML, provided, however, that STML may withhold access to (a) all legally privileged documents and (b) information that STML is prohibited from disclosing by bona fide third party confidentiality restrictions; provided further that STML will use its reasonable efforts to obtain a waiver of any such restrictions in favor of EnCana. The cost and expense of EnCana's review of the title to the Assets will be borne solely by EnCana.

4.3 Notice of Asserted Title Defects.

(a) If EnCana discovers any Title Defect affecting any portion of the Leases, EnCana may notify STML of such alleged Title Defect from time to time prior to the expiration of the Examination Period. To be effective, such notice ("Title Defect Notice") must:

(i) be in writing;

(ii) be received by STML prior to the expiration of the Examination Period;

(iii) describe the Title Defect in reasonable detail including the basis therefor (including any alleged variance in the Net Revenue Interest or Working Interest of any Lease) and provide any supporting documents in EnCana's possession;

(iv) identify the specific Lease to which such Title Defect relates; and

(v) include the Title Defect Amount attributable to such Title Defect, as determined by EnCana in good faith.

(b) Except for EnCana's remedies for any breach by STML of its special warranty of title under the Assignment, at the end of the Examination Period, any matters that may otherwise constitute a Title Defect, but of which STML has not been specifically notified by EnCana in accordance with the foregoing, will be deemed to have been waived by EnCana for all purposes.

4.4 Title Defects, Title Defect Amounts.

(a) The term "Title Defect" means:

(i) STML has defensible title to less than the number of Net Mineral Acres in any Lease than the number of Net Mineral Acres shown for the applicable Lease on either Exhibit A-1 or A-2;

(ii) STML has defensible title to a lesser Net Revenue Interest in a Lease than the Net Revenue Interest shown for such Lease on either Exhibit A-1 or A-2;

(iii) STML has defensible title to a lesser Working Interest in a Lease than the Working Interest shown for such Lease on either Exhibit A-1 or A-2 (and there is a corresponding decrease in STML's Net Revenue Interest in such Lease);

(iv) A Lease is subject to a consent to assign that would materially affect the value of the Lease, and such consent has not been obtained by the end of the Examination Period;

(v) A Lease in the North Block has less than six months from the Effective Date remaining in the primary term or is subject to commitments to drill a well thereon within six months of the Effective Date in order to preserve the Lease or the rights therein to the Assigned Interval with the understanding that this Title Defect shall not be asserted with regard to any Lease in the pooled area for the Hinton 1-H well; or

(vi) A Lease is subject to a lien, charge, encumbrance, claim, easement, servitude, right, burden or defect, other than a Permitted Encumbrance.

(b) Without limiting STML's right to dispute the existence of a Title Defect, the value of each asserted Title Defect (the "Title Defect Amount") shall be determined as follows:

(i) If the Title Defect results from a lien or similar encumbrance, other than a Permitted

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Encumbrance, the Title Defect Amount will be the amount of money required to remove the Lien or similar encumbrance;

(ii) If the Title Defect relates to the failure of title to the entirety of a Lease, the Title Defect Amount shall be an amount equal to: (i) the number of Net Mineral Acres shown for such Lease on either Exhibit A-1 or A-2; times (ii) $9,506.00 per Net Mineral Acre (the "Per Acre Value");

(iii) If the Title Defect results in STML having defensible title to less than the number of Net Mineral Acres shown for such Lease on either Exhibit A-1 or A-2, the Title Defect Amount will be an amount equal to: (i) the reduction in the number of Net Mineral Acres below the amount shown for such Lease on either Exhibit A_1 or A-2; times (ii) the Per Acre Value;

(iv) If the Title Defect results in STML having a lesser Net Revenue Interest in a Lease than that set forth for such Lease on either Exhibit A-1 or A-2, the Title Defect Amount will be an amount of money calculated by multiplying the number of Net Mineral Acres affected by the Title Defect by the Per Acre Value and multiplying the result by a fraction, the numerator of which is STML's actual Net Revenue Interest in the affected Lease, and the denominator of which is the Net Revenue Interest set forth for such Lease on either Exhibit A-1 or A-2;

(v) If the Title Defect results from STML having defensible title to a lesser Working Interest in a Lease than the Working Interest shown for such Lease on either Exhibit A-1 or A-2 (with a corresponding decrease in Seller's Net Revenue Interest), the Title Defect Amount will be calculated as in subparagraph (iv), above;

(vi) If the Title Defect results from any matter described in subparagraph (a)(v) above, and such Lease is not renewed or extended for a period of at least six months beyond its stated termination date, or a well is not commenced that extends the affected Lease, and the Lease terminates, STML shall reimburse EnCana by multiplying the number of Net Mineral Acres shown for such Lease on either Exhibit A-1 or A-2 times the Per Acre Value.

(vii) If an unsatisfied or unwaived consent to assignment affecting any Lease is discovered during the Examination Period, the affected Lease or Leases shall, if necessary, be reconveyed to STML, and the Carry Amount reduced by the amount derived by multiplying the number of Net Mineral Acres by the Per Acre Value if this Title Defect remains uncured. STML shall have the right to cure within ninety days as provided in Section 4.6(a).

4.6 Procedures for Title Defects.

(a) Upon the receipt of an effective Title Defect Notice, STML will have the option, but not the obligation, to attempt to cure such Title Defect at STML's sole cost and expense, which cure shall be accomplished to EnCana's reasonable satisfaction within 90 days of STML's receipt of an effective Title Defect Notice.

(b) The Carry Amount will be reduced by an amount of money equal to the aggregate Title Defect Amounts of all Title Defects agreed-upon by the Parties or not cured by STML as provided in Section 4.6(a).

(c) If, as of the date set forth in paragraph (a), above, there are any Title Defects or Title Defect Amounts claimed by EnCana, but not agreed to by STML, such defects and/or the amounts therefor will be submitted to binding arbitration as set forth in Section 4.8.

4.7 Title Benefits. If during the Examination Period it should be discovered that STML owns a greater number of Net Mineral Acres in either the North Block or the South Block affecting any portion of the Leases, and including any oil and gas leases that are discovered to be owned by STML as of the Effective Date, such additional leasehold Net Mineral Acres

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shall be referred to as a Title Benefit. Such Title Benefits can exist as a result of any survey affecting any of the existing Leases, clerical errors, title matters such as succession, among other reasons, and notice of such shall be given to EnCana by STML in accordance with the provisions of Section 4.3 hereof. The value for any Title Benefit shall be calculated as the increase in the number of Net Mineral Acres either shown for an existing Lease or the Net Mineral Acres for a new oil and gas lease times Per Acre Value. If the Parties cannot agree upon either the existence of a Title Benefit or the value therefor, such dispute shall be subject to the arbitration provisions contained in Section 4.8 hereof.

4.8 Arbitration.

(a) If any Party hereto elects to submit any dispute to arbitration as specifically provided in this Section 4.8, then such Party will notify the other Party in writing. Within 15 days following such notice, STML and EnCana agree to jointly select an arbitrator. For disputes regarding Title Defects or Title Defect Amounts, the arbitrator will be an experienced oil and gas attorney, familiar by training and experience with U.S. oil and gas legal and business matters including titles and oil and gas transactions. This person will be the sole arbitrator (the "Title Arbitrator") to hear and decide all existing disputes regarding asserted Title Defects and Title Defect Amounts. If STML and EnCana are unable to agree on the Title Arbitrator within 15 day period, any Party hereto may apply to a Texas court for the selection of a Title Arbitrator with the qualifications set forth in this Section.

(b) Any arbitration hearing, if one is desired by the Title Arbitrator, will be held in Dallas, Texas, or such other location acceptable to both STML and EnCana and the Title Arbitrator. The proceeding shall be conducted by written submissions from STML and EnCana with exhibits, including interrogatories, supplemented with appearances by EnCana and STML as the Title Arbitrator may desire. The arbitration proceeding, subject only to the terms hereof, will be conducted informally and expeditiously and in such a manner as to result in a good faith resolution as soon as reasonably possible under the circumstances. The decision of the Title Arbitrator with respect to such remaining disputed matters will be reduced to writing, binding on the Parties and not appealable. Judgment upon the award(s) rendered by the Title Arbitrator may be entered and execution had in any court of competent jurisdiction, or application may be made to such court for a judicial acceptance of the award and an order of enforcement. STML and EnCana, respectively, will bear its own legal fees and other costs incurred in presenting its respective case. The charges and expenses of the Title Arbitrator will be shared equally by STML and EnCana.

(c) The arbitration will commence as soon as possible after the Title Arbitrator is selected in accordance with the provisions of this Section 4.8. In fulfilling his or her duties with respect to determining the amount of a Title Defect Amount, the Title Arbitrator, as applicable, may consider such matters as, in the opinion of the Title Arbitrator, are necessary or helpful to make a proper valuation; however, the Title Arbitrator will be bound by those factors set forth in Sections 4.3 and 4.4. Furthermore, the Title Arbitrator may consult with and engage disinterested third parties to advise the Title Arbitrator including, without limitation, geologists, geophysicists, petroleum engineers, title and oil and gas lawyers, accountants and consultants, and the fees and expenses of such third parties will be considered to be charges and expenses of the Title Arbitrator. The sole remedy in any arbitration award will be resolution of alleged Title Defects, and Title Defect Amounts which will then be applied as provided in Section 4.5 and the Title Arbitrator will not award any other remedy, including, without limitation, equitable relief, actual damages, consequential, exemplary or punitive damages, attorneys' fees or interest reflecting the time value of money.

(d) Any replacement Title Arbitrator, should one become necessary, will be selected in accordance with the procedure provided above for the initial selection of the Title Arbitrator.

(e) As to any determination of amounts owing under the terms of this Section 4.8, no

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lawsuit based on such claimed amounts owing will be instituted by either EnCana or STML, other than to compel arbitration proceedings or enforce the award of the Title Arbitrator.

(f) All privileges under state and federal law, including attorney-client and work-product privileges, will be preserved and protected to the same extent that such privileges would be protected in a federal or state court proceeding applying state or federal law, as the case may be.

4.9 Certain Defined Terms.

(a) "Net Mineral Acres" means with respect to any Lease, STML's undivided ownership interest in that Lease as lessee only as to the Assigned Interval, multiplied by the number of acres in the leased premises within the Assigned Interval that are in fact leased by that particular Lease.

(b) "Net Revenue Interest" means the percentage ownership of the lessee in production from a well on a Lease after deducting the lessee's share of all applicable royalties, overriding royalties and other burdens on production affecting such Lease.

(c) "Permitted Encumbrances" means: (i) lessors' royalties, overriding royalties, and similar burdens that do not operate to reduce the Net Revenue Interest of STML below that Net Revenue Interest set forth on Exhibit A-1 or A-2 or increase the Working Interest of STML above that Working Interest set forth on Exhibit A-1 or A-2 (without a proportionate increase in the corresponding Net Revenue Interest); (ii) all rights to consent by, required notices to, and filings with or other actions by governmental authorities, if any, in connection with the change of ownership or control of an interest in any Lease; (iii) any required third-party consent to change of ownership or control of the Lease or similar agreements; (iv) materialmen's, mechanics', repairmen's, employees', contractors', operators', tax and other similar liens or charges arising pursuant to operations or in the ordinary course of business incidental to construction, maintenance, or operation of the Leases if they are not now due and payable; (v) easements in respect of surface operations, pipelines, or the like and easements on, over, or in respect of the Leases that are not such as to interfere materially with the operation, value or use of the Leases; (vi) all other inchoate liens, charges, encumbrances, contracts, agreements, instruments, obligations, defects and irregularities, affecting any of the Leases that individually or in the aggregate are customary in the industry and are not such as to interfere materially with the operation, value or use of any of the Leases, that do not operate to reduce the Net Revenue Interest of STML in a Lease below that Net Revenue Interest set forth on Exhibit A-1 or A-2 or increase the Working Interest of STML in a Lease above that Working Interest set forth on Exhibit A-1 or A-2 (without a proportionate increase in the corresponding Net Revenue Interest); (vii) all applicable laws, rules and orders of any governmental authority; and (viii) liens for Taxes not due and payable.

(d) "Working Interest" means that interest which bears a share of all costs and expenses proportionate to the interest owned associated with the exploration, development and operation of a Lease that the owner thereof is required to bear and pay by reason of such ownership, expressed as a percentage.

ARTICLE V
OTHER COVENANTS

5.1 Joint Operations.

(a) There will be a single JOA covering both the North Block and the South Block. Notwithstanding that there is only one JOA, however, the JOA will provide that STML will be the operator of the South Block and EnCana will be operator of the North Block. Each Party will be entitled to the rights, and subject to the obligations, of the Operator under the JOA, with respect to the Block of which they are the Operator. With regard to wells in the North Block proposed by EnCana, STML recognizes and agrees that it must participate in the first nine wells proposed by EnCana; but may thereafter elect to not participate in compliance with the terms of the JOA. Likewise, to the extent a well in the South Block proposed by STML is a Commitment Well, EnCana may not elect to not participate in any such well; but thereafter may elect to participate or

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not in accordance with the terms and provisions of the JOA.

(b) In the event of any conflict or inconsistency between the terms of this Agreement and a JOA, this Agreement shall prevail to the extent of such conflict. The fact that a matter is addressed in this Agreement but not the JOA, or vice versa, shall not in and of itself create a conflict between the respective agreements.

(c) Except as expressly provided otherwise in this Agreement, the JOA will govern all operations on the Blocks including each of the Commitment Wells.

(d) Only STML may propose the drilling of a well in the South Block and only EnCana may propose the drilling of a well in the North Block.

(e) Except as to the XTO Agreements, if a well is drilled by pooling any of the Leases with other oil and gas leases or mineral interests which are not subject to the JOA, as between STML and EnCana, the JOA will still control operations as between the Parties, even if STML or EnCana is also a party to a separate joint operating agreement due to the existence of leases not included in the Leases being included in the pooled area for such well. The XTO Agreements will control operations of the applicable portion of the Leases included in the contract areas described in the XTO Agreements.

5.2 Lease Administration.

(a) STML must pay 100% of all lease renewals and extensions due for Leases within the North Block that are expiring within 6 months of the Effective Date, without reimbursement by EnCana.

(b) STML shall pay, or cause to be paid, all delay rentals, shut-in royalties, minimum royalties and lease extensions that may be required or permitted under the terms of the Leases. Except as provided in paragraph (a) of this Section 5.2, EnCana shall be responsible for paying, upon invoice by STML, its Proportionate Share of such payments applicable to periods of time on and after the Effective Date.

5.3 Indemnity for Existing Production and Wells. STML agrees to defend, indemnify and hold harmless EnCana, its parent, affiliate and subsidiary companies and its and their officers, directors, shareholders and employees from and against any and all claims, demands, damages, losses, costs (including court costs, consultants, experts and reasonable attorneys fees), liabilities, suits and penalties (including civil fines) relating to, arising out of or in connection with all wells that were drilled and completed on the Leases (including the Excluded Wells) as of the Effective Date and which are now operated, or were ever operated, by STML. This indemnity will not apply to any of the Excluded Wells that are converted to a Commitment Well for matters accruing from and after the time EnCana is entitled to its Assigned Interest in such well.

5.4 Existing Pooled Units in the North Block.

(a) To the extent that STML has formed pooled units that include the Leases in the North Block, and such units include the Assigned Interval and other depths, STML will participate with EnCana to amend such units to exclude the Assigned Interval provided that such amendment does not constitute a violation of an express provision of any affected Lease. EnCana agrees to defend, indemnify and hold harmless STML, its parent, affiliate and subsidiary companies and its and their officers, directors, shareholders and employees from and against any and all claims, demands, damages, losses, costs (including court costs, consultants, experts and reasonable attorneys fees), liabilities, suits and penalties (including civil fines) relating to, arising out of or in connection with the amendment of these existing units pursuant to this Section 5.4(a).

(b) In addition to the rights provided in Section 2.2, the owner of the 95% Proportionate Share in each Block may form pooled units at its sole discretion, including forming pooled units that include leases other than the Leases, or lease owned by third parties consistent with the terms

of the affected Leases and all applicable laws, orders, rules, and regulations.

5.5 Production Reporting. STML will provide EnCana, in writing or by electronic mail, with respect to its wells in the North Block producing from zones outside the Assigned Interval: (i) on a monthly basis, information on such wells' production; and (ii) notification that any such well has ceased producing within two weeks of such cessation. EnCana will provide STML, in writing or by electronic mail, with respect to EnCana's wells in the North Block producing from zones inside the Assigned Interval notification that any such well has ceased producing within two weeks of such cessation.

ARTICLE VI
AMI

6.1 Area of Mutual Interest.

(a) There is hereby created an Area of Mutual Interest (the "AMI") which shall consist of the lands covered by the Leases in the North Block. The Parties acknowledge that to the extent that they are currently parties to any existing area of mutual interest that affects any of the lands covered by the Leases, then the Parties will comply with any area of mutual interest to which they are a party (including the AMI created hereby) in the order in which each area of mutual interest was created.

(b) If, during the period of time beginning with the execution of this Agreement and ending two years later, either EnCana or STML or an affiliate of any such Party acquires (including by extension or renewal) an oil, gas and mineral lease, mineral interest, overriding royalty interest, royalty interest or any other interest in oil or gas or any contractual right to acquire interests in oil and gas leases, such as through farmin agreements (any of which is referred to herein as an "Interest" or collectively as "Interests") within the AMI, the acquiring Party shall, within 30 days of finalizing the acquisition, offer to the non-acquiring Party the right to purchase its Proportionate Share of such Interest by paying its Proportionate Share of the acquiring Party's actual third party costs incurred in connection with the acquisition of such Interest (such costs to include, but are not necessarily limited to, the acquiring Party's land work with respect to the Interest, the lease bonus, option payments, broker fees, filing fees and cost of third party title examination). If two or more Interests are included in a single notice, the non-acquiring Party will have the right to make separate elections as to each of the acquired Interests.

(c) An offer made pursuant to this AMI must be in writing and include sufficient information for such non-acquiring Party to reasonably evaluate the offer, including a complete description of the acquired Interest and information (to the extent known) specifying the number of gross and net lease acres, existing overriding royalties or other burdens affecting the Interest, the purchase price and the terms of the acquisition, as well as the actual acquisition costs, the obligations required to earn such interest, including bonus considerations or equivalent if other than cash, broker's fees, recording fees, and rentals, and any other information the acquiring Party deems relevant to the acquisition of the Interest. The offer should be made in the manner for giving any other notices under this Agreement. The Party receiving the offer shall have 30 days (the "Acceptance Period") following receipt of such notice in which to elect to participate in the acquisition, and if such an election is made within the Acceptance Period, payment for such Party's Proportionate Share shall be made within 30 days of such Party's acceptance.

(d) If such non-acquiring Party elects to participate, the acquiring Party shall assign the applicable percentage interest in the Interest to such non-acquiring Party within 10 business days of receiving such non-acquiring Party's payment, free and clear of any burdens created by the acquiring Party other than those burdens placed on such Interest by the transferor of the Interest to such acquiring Party. Any Interest acquired after the date of this Agreement, including any Interest in which both STML and EnCana participate, shall be subject to the provisions of the JOA but such Interest shall not be part of the Leases or Assets hereunder or subject to the terms

of this Agreement (other than this Article VI) and the costs and expenses attributable to such Interest shall be borne by STML and EnCana in proportion to their Proportionate Shares in such Interest. Failure of the non-acquiring Party to (i) respond in writing to an acquisition notice within the Acceptance Period, or (ii) pay for its share of costs within five business days of the Party's election to take its Proportionate Share of the Interest will be deemed an election not to acquire a share of the Interest.

(e) If an Interest is to be earned by drilling wells or shooting seismic, the non-acquiring Party must ratify all appropriate agreements within the Acceptance Period and agree to participate in and pay for its share of such required operations. If the non-acquiring Party turns down any Interest or fails to timely pay for its share of such Interest, the acquiring Party shall hold such interest free and clear of any further obligations under this Agreement and the JOA.

(f) Notwithstanding anything herein to the contrary, the provisions set forth in this Article will not apply to any (i) acquisitions which (A) result from a merger, consolidation, reorganization with, by, or between a Party (or such Party's affiliate) and another party, or (B) result from a merger or acquisition of the stock or equity of another EnCana, entity or partnership or an acquisition of at least 51% of all of the assets of an entity by the acquiring Party (or such Party's affiliate), whether by cash, like-kind exchange, stock purchase or otherwise; (ii) transfers between a Party and any of its affiliates; or (iii) transfers between the parties to any operating agreement binding on the Interests.

ARTICLE VII
REPRESENTATIONS AND WARRANTIES

7.1 Mutual Representations. Each Party, with respect to itself only, hereby represents and warrants to the other Parties the following:

(a) Corporate Existence. It is duly organized, validly existing and in good standing under the applicable laws of its state of incorporation or formation, and is qualified to do business and is in good standing in the State of Texas and in every other jurisdiction where the failure to so qualify would have a material adverse effect on its ability to execute, deliver and perform this Agreement and the other agreements contemplated herein;

(b) Authority. It has all requisite power and authority to (i) own, lease or operate its assets and properties and to carry on the business as now conducted, and (ii) enter into and perform its obligations under this Agreement and to carry out the transactions contemplated hereby;

(c) Authorization. It has taken (or caused to be taken) all acts and other proceedings required to be taken by such Party to authorize the execution, delivery and performance by such Party of this Agreement and the other agreements contemplated herein. This Agreement has been duly executed and delivered by such Party and constitutes the valid and binding obligation of such Party, enforceable against such Party in accordance with its terms, except as enforceability may be limited by applicable bankruptcy, moratorium, reorganization or similar laws affecting the rights of creditors generally and by principles of equity, whether considered in a proceeding at law or in equity;

(d) Litigation. There are no actions, suits or proceedings pending or, to such Party's knowledge, threatened against such Party which if decided unfavorably to such Party could have a material adverse effect on the ability of such Party to execute, deliver or perform this Agreement or the other agreements contemplated herein or have a material adverse effect on the Assets;

(e) Broker Fees. It has not incurred any obligation or liability, contingent or otherwise, for any fee payable to a broker or finder with respect to the matters provided for in this Agreement or the other agreements contemplated herein which could be attributable to or charged to any other Party. Each of STML and EnCana shall indemnify, defend and hold harmless the other from any

claims, damages, liabilities, costs and expenses, including reasonable attorney's fees in the event the prior sentence should be or become untrue as to such Party;

(f) Disclaimer. It is not a "consumer" within the meaning of such term in the Texas Deceptive Trade Practices Consumer Protection Act, by virtue of being a corporation which seeks or acquires by purchase or lease, goods for commercial or business use and which has assets of $25 million or more, or is owned or controlled by a corporation or entity with assets of $25 million or more; and

(g) Non-contravention. The execution, delivery and performance of this Agreement by it will not, in any material respect, violate, nor be in conflict with, any provisions of any such Party's governing documents or any agreement or instrument to which such Party is a party or is bound, or any judgment decree, order, statute, rule or regulation applicable to such Party (assuming the receipt of all consents and approvals applicable to the transactions contemplated hereby).

7.2 STML Representations. For a period of time ending twelve months following the Effective Date, STML makes the following representations and warranties to EnCana:

(a) Contractual Restrictions. Except as set forth on Schedule 7.2(a), STML has not entered into any contracts: (i) for or received prepayments under or pursuant to take-or-pay arrangements, buydowns, buyouts or similar agreements for hydrocarbons, or storage of the same relating to the Assets which EnCana shall be obligated to honor and make deliveries of hydrocarbons or pay refunds of amounts previously paid under such contracts or arrangements or which otherwise relate to deliveries of hydrocarbons or payments of refunds on or after the Effective Date; or (ii) dedicating the Leases or any portion thereof to a gas sales, gathering, transportation, treating or processing agreement.

(b) Imbalances. Except as set forth on Schedule 7.2(b) or for normal immaterial pipeline imbalances that are adjusted by the pipeline each month, there are no wellhead imbalances or other imbalances attributable to the Assets as of the Effective Date which require payment from EnCana to a third party or for which EnCana would otherwise be responsible.

(c) Preferential Rights. Except as set forth on Schedule 7.2(c), there are no preferential rights to purchase attributable or with respect to any of the Assets that are applicable to the transactions contemplated hereby.

(d) Consents. Except as set forth on Schedule 3.9, there are no required consents, approvals or authorizations of, or notification to, any person or entity (excluding any of the foregoing customarily obtained following assignment of the Assets), in each case, that are applicable to the transactions contemplated hereby.

(e) Taxes. (i) all Taxes owed with respect to the Assets have been timely paid in full, (ii) none of such Taxes with respect to the Assets is now under audit or examination by any Taxing authority and there is no claim pending or, to the knowledge of STML, threatened by any Taxing authority in connection with any such tax, (iii) there are no liens on any of the Assets that arose in connection with any alleged failure to pay any tax, (iv) none of the Assets is "Tax-exempt use property" (within the meaning of section 168(h) of the Internal Revenue Code) or "Tax-exempt bond financed property" (within the meaning of section 168(g)(5) of the Internal Revenue Code), and (v) to the knowledge of STML, all of the Assets have been properly listed and described on the property Tax rolls for the Taxing units in which the Assets are located and no portion of the Assets constitutes omitted property for property Tax purposes. For purposes of this Agreement, "Tax" means any federal, state or local sales, use, ad valorem, property, production, severance or similar taxes or assessments based upon or measured by the ownership or operations of the Assets or the production of hydrocarbons therefrom or revenue or income derived therefrom, including any interest, penalty, or addition thereto.

(f) Non-Foreign Representation. STML is not a non-resident alien, foreign corporation,

foreign partnership, foreign trust or foreign estate (as those terms are defined in Internal Revenue Code and Income Tax Regulations).

(g) Hydrocarbon Sales Contracts. Except as set forth on Schedule 7.2(g), no hydrocarbons produced from the Assets are subject to a sales contract other than division orders or sales agreements terminable on no more than 30 days notice. Proceeds from the sale of hydrocarbons produced from the Assets are being received in all respects by STML in a timely manner and are not being held in suspense by the purchaser for any reason. To the knowledge of STML, STML is presently receiving a price for all production from, or attributable to, each Property covered by a hydrocarbon sales contract in accordance with the terms of such contract.

(h) Material Contracts. Schedule 7.2(h) lists all of the contracts and agreements that (i) involve expenditures by or revenues to STML in the aggregate in excess of $100,000.00, (ii) that are included in the Assets and that constitute (A) any indenture, mortgage, loan, credit or similar contract for borrowed money or any hedge or derivative contract (in each case) for which EnCana will be responsible or which affects any revenues or expenses attributable to the Assets on or after the Effective Date, (B) any guaranty of any obligation, bond or letter of credit for which EnCana will be responsible or be bound, (C) any contract with STML or any affiliate of STML which affects any revenues or expenses attributable to the Assets on or after the Effective Date, (D) any agreement for the gathering, treatment, processing, refining, handling, storage or transportation of hydrocarbons that is not terminable without penalty upon 60 days' notice or less, (E) any agreement for the use or sharing of drilling rigs, (F) any purchase agreement, farmin and farmout agreement, exploration agreement, participation agreement, agreement of development, or similar agreement providing for the earning of an ownership interest, (G) any non-competition agreement or any agreement that purports to restrict, limit or prohibit the manner in which, or the localities in which, EnCana conducts its business, or (H) any agreement respecting any partnership or joint venture, or (iii) are confidentiality agreements or agreements relating to areas of mutual interest ("Material Contracts"). All Material Contracts are in full force and effect and STML is not, and to the knowledge of STML, no other party is, in default with respect to any of the obligations thereunder.

(i) Tax Partnerships. Except as created pursuant to this Agreement, none of the Assets is held in an arrangement treated as a partnership for Income Tax purposes.

(j) No Written Notice of Adverse Environmental Conditions. None of STML or STML's affiliates has received written notice from any person or entity of any release, disposal, event, condition, circumstance, activity, practice or incident concerning any land, facility or property included in the Assets that constitutes a violation of, interferes with or prevents compliance by STML, or after assignment, EnCana, with, any environmental law or the terms of any permit issued pursuant thereto.

(k) No Expenses Owed and Delinquent. No material expenses (including bills for labor, materials and supplies used or furnished for use in connection with the Assets, royalties, overriding royalties and other burdens on production and amounts payable to co-owners of the Assets) are owed and delinquent in payment by STML or an operator of the Assets that relate to the ownership or operation of the Assets.

(l) Maintenance of Uniform Interest Provisions. Schedule 7.2(l) sets forth all agreements burdening the Assets that contain maintenance of uniform interest or similar provisions.

(m) Lease Extensions. Schedule 7.2(m) sets forth a list of all Leases which contain options to extend the primary term.

(n) Proper Pooling. All of the Leases that are, as of the Effective Date, included in pooled units, have been properly pooled under the terms of the applicable Leases, and there are no claims by the Lessors thereof that: (i) a Lease has terminated as to some or all of the Lease due to improper

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pooling; or (ii) that the lessor thereof is entitled to a share of the unit production that is greater than the lessor's proportionate share of the surface acreage of the unit.

7.3 EnCana Representations. For a period of time ending twelve months following the Effective Date, EnCana makes the following representations and warranties to STML:

(a) Independent Evaluation. EnCana acknowledges that it is an experienced and knowledgeable investor in the oil and gas business, and the business of purchasing, owning, developing, and operating oil and gas properties such as the Assets. If Closing occurs, EnCana represents, warrants, and acknowledges to STML that it has had full access to the Assets, the officers and employees of STML, and to the books, records, and files of STML relating to the Assets. In making the decision to enter into this Agreement and to consummate the transactions contemplated hereby, EnCana has relied solely upon the representations, warranties, covenants, and agreements of EnCana and STML set forth in this Agreement and EnCana's own independent due diligence and investigation of the Assets, and has been advised by and has relied solely on its own expertise and its own legal, tax, operations, environmental, reservoir engineering, and other professional counsel and advisors concerning this transaction, the Assets and the value thereof. In addition, EnCana acknowledges and agrees that EnCana will be or has been advised by and relies solely on its own expertise, and its legal counsel and any advisors or experts concerning matters relating to Title Defects, Title Benefits, and Environmental Defects.

(b) Qualification. As of the Closing, EnCana or one of its affiliates shall be, and thereafter shall continue to be, qualified with all applicable governmental authorities to own and operate the Assets, including meeting all bonding requirements.

(c) Securities Laws. EnCana is acquiring the Assets for its own account or that of its affiliates and not with a view to, or for offer of resale in connection with, a distribution thereof, within the meaning of the Securities Act of 1933, 15 U.S.C. § 77a *et seq.*, and any other rules, regulations, and laws pertaining to the distribution of securities. EnCana has not sought or solicited, nor is EnCana participating with, investors, partners, or other third parties other than its lenders in order to fund the Carry Amount and to close this transaction, and all funds to be used by EnCana in connection with this transaction are EnCana's own funds or those borrowed from its lenders.

(d) No Investment Company. EnCana is not (a) an investment company or a company controlled by an investment company within the meaning of the Investment Company Act of 1940, as amended, or (b) subject in any respect to the provisions of that Act.

(e) Funds. EnCana has arranged to have available by the Closing Date immediately available funds to enable EnCana to pay in full the Purchase Price as herein provided and otherwise to perform its obligations under this Agreement.

7.4 No Other Representations. Other than the representations and warranties expressly set forth in this Agreement and the assignments delivered pursuant hereto, no Party hereto makes any representations or warranties to the other Parties concerning the subject matter of this Agreement.

ARTICLE VIII
MISCELLANEOUS

8.1 Force Majeure. If any Party is rendered unable, wholly or in part by force majeure, to carry out its obligations under this Agreement, other than any obligation to make any money payments (which obligation will never be extended or suspended due to force majeure), such Party must give to the other Parties prompt written notice of the force majeure, with reasonably full particulars, and thereupon the obligations of the Party giving the notice, so far as they are affected by the act of force majeure, will be suspended, and the running of all time periods within which certain actions must be completed will be tolled, during, but not longer, than the continuance of the force majeure, plus such reasonable further period of time, if any, required to resume the suspended operation. The affected Party must use all reasonable diligence to remove the force majeure situation as quickly as practicable; provided, that it will not be required to settle strikes, lockouts or other labor difficulty contrary to its wishes. All such difficulties are to be handled entirely within the discretion of the Party concerned. "Force majeure" means an act of nature, strike, lock-out or other industrial disturbance, act of the public enemy, war, blockade, public riot, lightning, fire, storm, flood or other adverse weather condition, explosion, inability to obtain surface access, governmental action, governmental inaction, restraint or delay, or any other cause, whether of the kind specifically enumerated above or otherwise, which is not reasonably within the control of the Party claiming force majeure, but not the unavailability of drilling rigs.

8.2 Monetary Amounts. All monetary amounts stated in this Agreement are cited in, and must be paid in, United States dollars.

8.3 Further Assurances. As necessary, the Parties shall execute any all documents including, but not limited to, any documents, forms, etc. and take all actions, (in each case) that are necessary to effectuate the terms and provisions of this Agreement and/or the JOA, whichever is applicable, including, but not limited to, the execution of designation of operator forms and other governmental forms and other similar matters.

8.4 Partnership Disclaimer/Creation of Tax Partnership. The rights, duties, obligations and liabilities of the Parties shall be several, not joint or collective. It is not the purpose or intention to create any mining partnership, joint venture, general partnership or other partnership relation and none shall be inferred. Notwithstanding the foregoing, the Parties agree that the agreements and undertakings herein will be treated as the formation of a partnership for purposes of federal income taxation. Therefore, the Parties agree to be governed, for federal income tax purposes only, by the tax partnership agreement attached to the JOA. For every purpose other than the above described income tax purposes, however, and notwithstanding any other provision of this Agreement to the contrary, the Parties understand and agree that their relationship hereunder is not one of partnership, association, trust, joint venture, mining partnership or entity of any kind.

8.5 Press Releases. A Party to this Agreement shall not issue any media release or make a public announcement relating to this Agreement without the prior written approval of the other unaffiliated Party, which approval shall not be unreasonably withheld; provided, however, that any Party may make any public disclosure it believes in good faith is required by applicable law or any listing or trading agreement concerning its publicly traded securities (in which case the disclosing Party agrees to use its reasonable efforts to consult with and obtain the consent of the other unaffiliated Party prior to making the disclosure).

8.6 Taxes and Recording Fees. Any sales taxes, transfer taxes, documentary taxes and recording fees relating to an assignment hereunder shall be paid by the assignee. Subject

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to the terms of the JOA, each Party shall be responsible for its own local, state and federal income tax reporting, recognition of gain or loss, if any, and the taxes, if any, payable with respect to the transactions effected and to be effected pursuant to this Agreement. All taxes, including ad valorem taxes, imposed with respect to periods or portions of periods prior to the Effective Date shall be the burden of STML and all such taxes imposed with respect to periods or portions of periods after the Effective Date shall be the burden of STML and EnCana with each paying its Proportionate Share of such taxes. Any such Party which pays any such taxes which are the responsibility of such other Party shall be entitled to prompt reimbursement upon evidence of such payment. STML shall be entitled to all refunds or rebates of taxes paid pertaining to those taxable periods ending on or prior to the Effective Date.

8.7 Governing Law. This Agreement shall be governed, construed, and enforced in all respects, including validity, interpretation, and effect, according to the laws of the State of Texas, excluding any conflicts of law rule or principle that might apply the law of another jurisdiction .

8.8 Waiver of Consequential Damages. NOTWITHSTANDING ANYTHING TO THE CONTRARY IN THIS AGREEMENT, THE PARTIES EXPRESSLY AGREE THAT NO PARTY SHALL BE LIABLE FOR ANY EXEMPLARY, PUNITIVE, SPECIAL, INDIRECT, CONSEQUENTIAL, REMOTE, OR SPECULATIVE DAMAGES, INCLUDING LOST PROFITS, SUFFERED BY THE OTHER PARTY IN CONNECTION WITH THIS AGREEMENT OR THE TRANSACTIONS CONTEMPLATED HEREBY.

8.9 Inherent Risk. Each Party hereby acknowledges its understanding and acceptance of the inherent risks associated with the exploration for oil and gas.

8.10 Confidentiality. Except as expressly set forth herein and except as required by applicable laws, the Parties hereto acknowledge and agree that this Agreement, their negotiations in connection herewith and all information obtained by or provided to any of them in connection with the matters contemplated herein or as it relates to the Assets will be maintained as confidential, except for disclosures to:

(a) Representatives of the Parties;

(b) Disclosures by EnCana to ExxonMobil Corporation in conjunction with its area of mutual interest obligations to ExxonMobil corporation; or

(c) Disclosures by EnCana to a third party that may be interested in participating in the drilling of any Commitment Well or other well (to the extent permitted hereunder) on the Leases. The term "Representatives" as used herein shall mean (a) partners, employees, officers, directors, members, equity owners and counsel of a Party or any of its affiliates or any prospective purchaser of a Party or an interest in a Party; (b) any consultant or agent retained by a Party or the parties listed in subsection (a) above; and (c) any bank, other financial institution or entity funding, or proposing to fund, such Party's operations in connection with the Leases, including any consultant retained by such bank, other financial institution or entity.

8.11 Notices.

(a) All notices required or permitted under this Agreement shall be in writing and delivered in person, by overnight courier, by certified or registered mail return receipt requested, by

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facsimile, or by electronic transmission, delivered or addressed to the persons and at the addresses as provided below. When a response to another Party is required, each Party's response shall be in writing to such other Party.

(b) A notice is deemed to have been delivered upon actual receipt.

(c) Notwithstanding the foregoing, unless otherwise specifically provided herein, if a Notice is received after 5:00 P.M. on a business day where the addressee is located, or on a day that is not a business day where the addressee is located, such notice is deemed received at 9:00 A.M. on the next business day where the addressee is located.

ADDRESSES:

STML	ST. MARY LAND & EXPLORATION COMPANY 330 Marshall Street, Suite 1200 Shreveport, LA 71101 Attention: David Dubiel Fax No.: 318-226-5554 Tel. No.: 318-226-5536 Email: ddubiel@stmaryland.com
ENCANA:	EnCana Oil & Gas (USA) Inc. 14001 N. Dallas Parkway Suite 1100 Dallas, TX 75240 Attn: Mark A. Virant Tel. No.: 214-987-7156 Fax: 214-242-7204 Email: mark.virant@encana.com

8.12 Electronic Transmissions. Each of the Parties hereto agrees that: (i) any notice transmitted by electronic transmission shall be treated in all manner and respects as an original written document; (ii) any such notice shall be considered to have the same binding and legal effect as a notice sent by other approved means. Each of the parties further agrees that they will not raise the transmission of a consent or document by electronic transmission as a defense in any proceeding or action in which the validity of such consent or document is at issue and hereby forever waives such defense. For purposes of this Agreement, the term "electronic transmission" means any form of communication not directly involving the physical transmission of paper, that creates a record that may be retained, retrieved and reviewed by a recipient thereof, and that may be directly reproduced in paper form by such a recipient through an automated process. With respect to any notice delivered by electronic transmission and involving a time-sensitive matter, the addressee covenants and agrees to use its reasonable efforts to promptly respond to any such notice such that the notice shall be deemed to have been received as set forth in Section 8.11 above.

8.13 Headings for Convenience. All captions, numbering sequences, and headings used in this Agreement are inserted for convenience only and shall in no way define, limit or describe

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the scope or intent of this Agreement or any part thereof, nor have any legal effect other than to aid a reasonable interpretation of this Agreement. A reference to "Article" or "Section" is to an Article or Section of this Agreement.

8.14 Amendment. No provision of this Agreement shall be modified or amended except by the written agreement of the Parties.

8.15 Severance of Invalid Provisions. In case of a conflict between the provisions of this Agreement and the provisions of any applicable laws or regulations, the provisions of the laws or regulations shall govern over the provisions of this Agreement. If, for any reason and for so long as, any clause or provision of this Agreement is held by a court of competent jurisdiction to be illegal, invalid, unenforceable or unconscionable under any present or future law (or interpretation thereof), the remainder of this Agreement shall not be affected by such illegality or invalidity. Any such invalid provision shall be deemed severed from this Agreement as if this Agreement had been executed with the invalid provisions eliminated. The surviving provisions of this Agreement shall remain in full force and effect unless the removal of the invalid provisions destroys the legitimate purposes of this Agreement; in which event this Agreement shall no longer be of any force or effect. The Parties shall negotiate in good faith for any required modifications to this Agreement required as a result of this provision.

8.16 Binding Effect. This Agreement shall be binding upon and inure to the benefit of the Parties and their respective heirs, successors and assigns and shall constitute a covenant running with the lands covered by the Leases.

8.17 Entire Agreement. This Agreement and the documents referred to herein and to be delivered pursuant hereto constitute the entire agreement between the parties pertaining to the subject matter hereof, and supersede all prior and contemporaneous agreements, understandings, negotiations and discussions of the parties, whether oral or written, and there are no warranties, representations or other agreements between the parties in connection with the subject matter hereof, except as specifically set forth herein or therein.

8.18 Counterparts: Facsimile Signature. The Parties may execute this Agreement in any number of duplicate originals, each of which constitutes an original, and all of which, collectively, constitute only one Agreement. The Parties may execute this Agreement in counterparts, each of which constitutes an original, and all of which, collectively, constitute only one Agreement. Delivery of an executed counterpart signature page by facsimile or electronic transmission is as effective as executing and delivering this Agreement in the presence of the Parties hereto. This Agreement is effective upon delivery of one executed counterpart from each Party to the other Parties. In proving this Agreement, a Party must produce or account only for the executed counterpart of the Party to be charged.

8.19 Binding on Successors and Assigns. This Agreement will extend to, inure to the benefit of, and be binding upon the Parties and each of their successors and permitted assigns. Without obtaining the prior written consent of the other Party hereto, no Party shall have the right to assign its rights and obligations under this Agreement; provided that (a) any Party shall be permitted to assign its rights and obligations hereunder in connection with a sale by such Party of all or substantially all of its assets, (b) any Party shall be permitted to mortgage or pledge all or any part of interests under this Agreement, and (c) EnCana shall be permitted to assign one-half of its interest in the South Block to ExxonMobil corporation in connection with its pre-existing area of mutual interest obligations. Any request for a

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consent to assign shall not be unreasonably withheld and unless the Party from whom the consent is requested shall show good cause for withholding its consent, such consent shall be granted in writing to the requesting Party within 30 days of any request therefor. Once the Carry Amount has been spent by STML in accordance with the terms of this Agreement, either Party may assign all or a portion of its interest in the Leases without the consent of the other Party except as may be limited by the JOA.

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IN WITNESS WHEREOF, this Agreement is executed as of the date first above written, effective as of the Effective Date.

ENCANA OIL & GAS (USA) INC.

By: /s/ PAUL SANDER
Name: Paul Sander
Title: Vice President – Mid-Continent

ST. MARY LAND & EXPLORATION COMPANY

By: /s/ MILAM RANDOLPH PHARO
Name: Milam Randolph Pharo
Title: Senior Vice President and General Counsel

SCHEDULE 1

SCHEDULE OF DEFINITIONS
LIST OF EXHIBITS AND SCHEDULES

Defined Term	Section/Schedule Where Defined
Acceptance Period	6.1(c)
AFE	3.4(a)
Agreement	Introductory Paragraph
AMI	6.1(a)
Article	8.13
Assets	1.2
Assigned Interest	Background 3.
Assigned Interval	1.1(a)
Assignment	2.1(b)

Block/Blocks	Background 2.
Carried Well Costs	3.2(b)
Carry Amount	3.2(a)
Carry Period	3.2(c)
Commitment Well/Wells	3.3(a)
Complete, Completing, Completion	3.3(d)
Cure Period	3.9
Drill, drilling	3.3(e)
Effective Date	Introductory Paragraph
Electronic transmission	8.12
EnCana	Introductory Paragraph
Examination Period	4.1
Excluded Assets	1.2
Excluded Wells	1.3(b)
Force Majeure	8.1
Initial Payment	2.1(e)
Interest/Interests	6.1(b)
JOA	2.1(a)
Lease, Leases	Background 1.
Material Contracts	7.2(h)
Net Mineral Acres	4.9(a)
Net Revenue Interest	4.9(b)
North Block	Background 2.
Party, Parties	Introductory Paragraph
Per Acre Value	4.4(b)(ii)
Permitted Encumbrances	4.9(c)
Proportionate Share	3.1
Representatives	8.10
Section	8.13
South Block	Background 2.
STML	Introductory Paragraph
STML Drilling Wells	1.2(d)
Tax	7.2(e)
Tenaska Agreement	3.8(a)
Time-sensitive matter	8.11(a)(v)
Title Arbitrator	4.8(a)
Title Defect	4.4(a)
Title Defect Amount	4.4(b)
Title Defect Notice	4.3(a)
Working Interest	4.9(d)
XTO Agreements	1.2(c)
XTO Drilling Wells	1.2(b)

LIST OF EXHIBITS AND SCHEDULES

Exhibit A-1	North Block Leases
Exhibit A-2	South Block Leases
Exhibit A-3	XTO Drilling Wells and STML Drilling Wells
Exhibit A-4	XTO Agreements
Exhibit A-5	Excluded Wells
Exhibit A-6	Assigned Rights of Way
Exhibit B	Plat of Blocks
Exhibit C	JOA
Exhibit D-1 and D-2	Assignments (Form of)
Exhibit E	Tenaska Agreement
Schedule 1	Schedule of Defined Terms
Schedule 2.2(a)	STML Drilling Wells Costs
Schedule 3.9	Consents
Schedule 7.2(a)	Contractual Restrictions
Schedule 7.2(b)	Imbalances
Schedule 7.2(c)	Preferential Rights
Schedule 7.2(g)	Hydrocarbon Sales Contracts
Schedule 7.2(h)	Material Contracts
Schedule 7.2(l)	Maintenance of Uniform Interest Provisions
Schedule 7.2(m)	Lease Extensions

EXHIBIT 10.3

SM ENERGY COMPANY

PERFORMANCE SHARE AND RESTRICTED STOCK UNIT AWARD AGREEMENT

This Performance Share and Restricted Stock Unit Award Agreement (the "Agreement") is made effective as of [Award Date] (1) (the "Award Date"), by and between SM Energy Company, a Delaware corporation formerly named St. Mary Land & Exploration Company (the "Company"), and [Name of Participant] (the "Participant") to whom performance shares and restricted stock units have been awarded pursuant to the Company's long term incentive program ("LTIP") under the Company's Equity Incentive Compensation Plan, as amended (the "Plan").

Pursuant to the terms of the Plan and this Agreement, as of the Award Date the Company has made an award (the "Award") to the Participant of [Amount] performance shares (the "Performance Shares") and [Amount] restricted stock units (the "Units"). Capitalized terms used but not defined in this Agreement shall have the meanings given to them in the Plan.

ARTICLE I

PERFORMANCE SHARES

1.1 Performance Shares and Performance Period. The Performance Shares represent the right to receive, upon the payment of the Performance Shares pursuant to Section 1.4 hereof after the completion of the Performance Period (as defined below), a number of shares of the Company's common stock, $.01 par value per share (sometimes referred to herein as the "Common Stock"), that will be calculated as set forth in Section 1.2 below based on the extent to which the Company's Performance Criteria (as defined in Section 1.2) have been achieved and the extent to which the Performance Shares have vested. Any Common Stock that is issued pursuant to any provision of this Agreement may be referred to in this Agreement as a "Share" or "Shares." Such actual number of Shares that may be issued upon payment of the Performance Shares may be from zero (0) to two (2.0) times the number of Performance Shares granted on the Award Date. The number of Performance Shares granted herein may be referred to as the "target" number of Shares. The performance period (the "Performance Period") for the Performance Shares shall be the three-year period set forth in the attached Performance Share and Restricted Stock Unit Award Notice (the "Award Notice").

1.2 Determination of Number of Shares Earned.

(a) Performance Criteria. The actual number of Shares that may be earned from the Performance Shares and issued upon payment of the Performance Shares after completion of the Performance Period shall be based upon the Company's achievement of performance criteria (the "Performance Criteria") established by the

(1) Items in brackets are features that may vary among individual awards.

Compensation Committee of the Board of Directors of the Company (the "Committee") for the Performance Period in accordance with the terms of the Plan and as set forth below and reflected in the payout matrix (the "Payout Matrix") attached as Appendix A hereto and discussed further in subsection (d) hereof. The Performance Criteria for the calculation of the actual number of Shares to be issued upon payment of the Performance Shares as reflected in the Payout Matrix are based on a combination of (i) the absolute measure of the cumulative total shareholder return ("TSR") and associated Compound Annual Growth Rate ("CAGR") of the Company for the Performance Period, and (ii) the relative measure of the Company's TSR and CAGR for the Performance Period compared with the cumulative TSR and CAGR of the Peer Companies (as defined below) for the Performance Period as reflected in the Company's Performance Share Plan Peer Group Custom Index (the "Custom Index") to be specifically prepared by Standard & Poor's, a division of The McGraw-Hill Companies, Inc. ("S&P"), for the purpose of administering the LTIP.

(b) Calculation of TSR and CAGR. The TSR and CAGR of the Company and the Peer Companies for the Performance Period shall be calculated in accordance with the methodology utilized by S&P with respect to the Custom Index.

(c) Peer Companies and Custom Index. The "Peer Companies" to be reflected in the Custom Index shall consist of the constituents of the Oil & Gas Exploration & Production GIC Sub-Industry Group in the S&P SmallCap 600 Index and the S&P MidCap 400 Index, excluding the Company. The Custom Index will be equally weighted, and will be adjusted to include the dividend payments of the constituents of the Custom Index. The Custom Index will be rebalanced on a quarterly basis, and will also be rebalanced whenever there are additions and deletions to the S&P SmallCap 600 and the S&P MidCap 400 indices. The Custom Index is the exclusive property of S&P. The Company has contracted with S&P to maintain and calculate the Custom Index. S&P shall have no liability for any errors or omissions in calculating the Custom Index.

(d) Payout Matrix. The Payout Matrix attached as Appendix A hereto sets forth the possible multipliers, which range from zero percent (0%) to two hundred percent (200%), which may be applied to the number of vested Performance Shares to determine the actual number of Shares to be issued upon payment of the vested Performance Shares after the completion of the Performance Period. The final multiplier (the "Final Multiplier") shall be determined by the Committee after the completion of the Performance Period based on the two variables that comprise the Performance Criteria, related to (i) the Company's TSR and CAGR for the Performance Period, and (ii) the Peer Companies' TSR and CAGR for the Performance Period as reflected in the Custom Index. The number of Shares, if any, that shall be issued to the Participant upon payment of the Performance Shares shall be calculated as the number of Performance Shares that have vested in accordance with Section 1.3 or Section 1.6 hereof, multiplied by the Final Multiplier, as determined by the Committee in accordance with the Payout Matrix. There shall be no rounding of variables or extrapolation of variables between data points within the Payout Matrix, and the data point for which the associated variables equal or exceed the target variables for such data point, but do not result in qualification for another

higher data point, shall be utilized with respect to the Final Multiplier. Any fractional Shares which would otherwise result from application of the Final Multiplier shall be rounded up to the nearest whole share of Common Stock.

1.3 Vesting of Performance Shares.

(a) Vesting. Subject to the provisions contained herein, the Performance Shares shall vest over the Performance Period as set forth in the vesting schedule for Performance Shares contained in the Award Notice (the "PSA Vesting Schedule"). As of the Award Date, the Participant must be an employee of the Company or a subsidiary thereof. If the Participant ceases to be an employee of the Company or a subsidiary thereof prior to the vesting of all of the Performance Shares pursuant to the PSA Vesting Schedule, the Participant shall forfeit the remaining unvested Performance Shares under the Award, except as otherwise provided in this Section 1.3 and Section 1.6.

(b) Continued Vesting Upon Early Retirement. The Performance Shares shall, notwithstanding any other provisions of this Section 1.3, continue to vest according to the PSA Vesting Schedule after the termination of the Participant's employment with the Company or a subsidiary thereof if (i) such termination is the result of the Participant's retirement from the Company or a subsidiary thereof upon the Participant's having both reached the age of sixty (60) and completed twelve (12) years of service with the Company or a subsidiary thereof, and (ii) the Participant does not after such early retirement become employed on a full-time basis by a competitor of the Company prior to the earlier of the payment of the Performance Shares or the Participant's reaching the age of sixty-five (65). Any such continued vesting of the Performance Shares pursuant to this Section 1.3(b) will not result in an acceleration of the PSA Payment Date (as defined in Section 1.4), since the number of Shares earned from the Performance Shares shall be calculated after the completion of the Performance Period.

(c) Acceleration Upon Death, Total Disability or Normal Retirement. The Performance Shares shall become fully vested, notwithstanding any other provisions of this Section 1.3, upon termination of the Participant's employment with the Company or a subsidiary thereof because of death, Total Disability (as defined below), or retirement upon reaching the Company's normal retirement age of sixty-five (65). Any such acceleration of the vesting of the Performance Shares pursuant to this Section 1.3(c) will not result in an acceleration of the PSA Payment Date, since the number of Shares earned from the Performance Shares shall be calculated after the completion of the Performance Period. For purposes of this Agreement, "Total Disability" means a medically determinable physical or mental impairment that can be expected to result in death or can be expected to last for a continuous period of not less than 12 months, by reason of which the Participant is unable to engage in any substantial gainful activity or is receiving income replacement benefits for a period of not less than three months under an accident and health plan covering employees of the Company.

(d) Termination for Cause. Notwithstanding any other provisions of this Section 1.3, the Participant shall forfeit all Performance Shares under this Award, including those that have previously vested, upon the termination of the employment of the Participant by the Company or a subsidiary thereof for Cause (as defined below) prior to the completion of the Performance Period. As used in this Agreement with respect to the Performance Shares, the term Cause shall have the meaning defined in Section 1.6(a), and shall also include the termination of the employment of the Participant by the Company or a subsidiary thereof due to the Participant's having committed (i) a wrongful taking of money, property, goods, services, or other items of value from the Company, whether or not such wrongful taking is prosecuted in a civil or criminal proceeding, (ii) any act of fraud or willful misconduct in connection with the performance of the Participant's duties for the Company, or (iii) a significant violation of the Company's written policies and procedures, in each case which is demonstrably harmful to the Company.

1.4 Payment of Performance Shares. Following the last day of the Performance Period and prior to the payment of the earned and vested Performance Shares on or about the PSA Payment Date, the Committee shall determine, and certify in writing to the extent deemed necessary or advisable or as required to comply with Section 162(m) of the Internal Revenue Code of 1986, as amended (the "Code"), (i) the extent to which the Performance Criteria have been achieved over the Performance Period, and (ii) the Final Multiplier. The Final Multiplier shall then be applied to the number of vested Performance Shares to determine the number of Shares (the "Earned Shares"), if any, to be issued to the Participant in payment of the Performance Shares. The determination of the Earned Shares by the Committee shall be binding on the Participant and conclusive for all purposes. The Earned Shares, if any, shall be issued to the Participant in payment of the Performance Shares on or about the payment date set forth in the Award Notice (the "PSA Payment Date"). Upon the payment of the Performance Shares, the Company shall deliver to the Participant evidence of book-entry Shares or a certificate for the number of Shares issued to the Participant in payment of the Performance Shares. The Earned Shares shall not be subject to any holding or transfer restrictions after payment of the Performance Shares.

1.5 Transfer Restrictions for Unpaid Performance Shares. Performance Shares that have not been paid shall not be transferable by the Participant, and the Participant shall not be permitted to sell, transfer, pledge, assign, or otherwise alienate or encumber such Performance Shares or the Shares issuable in payment thereof, other than (i) to the person or persons to whom the Participant's rights under such Performance Shares pass by will or the laws of descent and distribution, (ii) to the spouse or the descendants of the Participant or to trusts for such persons to whom or which the Participant may transfer such Performance Shares by gift, (iii) to the legal representative of any of the foregoing, or (iv) pursuant to a qualified domestic relations order as defined under Section 414(p) of the Code or a similar order or agreement pursuant to state domestic relations law (including a community property law) relating to the provision of child support, alimony payments, or marital property rights to a spouse, former spouse, child, or other dependent of the Participant. Any such transfer shall be made only in compliance with the Securities Act of 1933 and the requirements therefor as set forth by the

Company. Any attempted transfer in contravention of the foregoing provisions shall be null and void and of no effect.

1.6 Change of Control Termination.

(a) Vesting upon Change of Control Termination. Notwithstanding any other provision of this Agreement, the Performance Shares shall become fully vested upon a Change of Control Termination. For purposes of this Agreement, a "Change of Control Termination" occurs upon the termination of the Participant's employment with the Company or a subsidiary thereof in the event that (i) a Change of Control (as defined in the Plan) of the Company occurs, and (ii) the Participant's employment with the Company or a subsidiary thereof is subsequently terminated without Cause (as defined below) or the Participant terminates his or her employment with the Company or a subsidiary thereof for Good Reason (as defined below), and such termination of employment occurs (x) within 30 months of the Change of Control and (y) with respect to Performance Shares, prior to the normal completion of vesting of the Performance Shares at the end of the Performance Period, or, with respect to Units, prior to the normal completion of vesting of the Units. The normal vesting and payment provisions in Article I of this Agreement shall not be affected by the first sentence of this subsection if a Change of Control of the Company occurs but there is not also a Change of Control Termination with respect to the Participant's employment with the Company or a subsidiary thereof. If the Participant has entered into a separate written Change of Control Executive Severance Agreement or Change of Control Severance Agreement (with either to be subsequently referred to herein as a "Change of Control Severance Agreement") with the Company, the terms "Cause" and "Good Reason" used herein shall have the meanings set forth in such Change of Control Severance Agreement, with the definition of the term "Cause" to be as modified in Section 1.3(d) of this Agreement. If the Participant has not entered into a separate written Change of Control Severance Agreement, the terms "Cause" and "Good Reason" used herein shall have the meanings set forth in the Company's Change of Control Severance Plan (the "Change of Control Severance Plan"), with the definition of the term "Cause" to be as modified in Section 1.3(d) of this Agreement.

(b) Payment upon Change of Control Termination. Notwithstanding any other provisions of this Agreement to the contrary, in the event of a Change of Control Termination with respect to the Participant's employment with the Company or a subsidiary thereof as set forth in Section 1.6(a) above, the vested Performance Shares shall be paid in accordance with this Section 1.6(b). In the event of a Change of Control Termination, the Committee shall determine the extent to which the Performance Criteria have been achieved and the Final Multiplier to apply to the vested Performance Shares by utilizing the same method as set forth in Section 1.2 hereof; provided, however, that the Performance Period for the calculation of the TSR and CAGR of the Company and the Peer Companies to obtain the Final Multiplier shall be shortened to end as of the effective date of the Change of Control. The Final Multiplier shall then be applied to the number of vested Performance Shares to calculate the number of Earned Shares, if any, that the Participant is entitled to in payment of the Performance Shares. In the event of a Change of Control Termination, any Earned Shares shall be paid to the Participant in payment of the Performance Shares either in Shares or in cash of equivalent value, as determined by the Committee or other duly authorized administrator of the Plan, in its discretion, within thirty (30) days following the effective date of the Change of Control Termination; provided, however, that the time and manner of such payment shall comply with Section 409A of the Code as referred to in Section 3.11 of this Agreement.

(c) Controlling Documents for Change of Control Termination. To the extent that the Participant is subject to either a written Change of Control Severance Agreement or the Change of Control Severance Plan, the terms and conditions of such Change of Control Severance Agreement or Change of Control Severance Plan, as applicable, shall also apply to this Award in the event of a Change of Control Termination; provided, however, that with respect to the Performance Shares under this Award, the terms of the Plan and this Agreement shall control in the event of any inconsistency between their terms and the terms of the Change of Control Severance Agreement or the Change of Control Severance Plan.

ARTICLE II

RESTRICTED STOCK UNITS

2.1 Units. Each Unit represents the right to receive one Share of Common Stock to be delivered upon settlement of the Units as set forth in Section 2.3 below, subject to the terms and conditions set forth in the Plan and this Agreement.

2.2 Vesting of Units.

(a) Vesting. Subject to the provisions contained herein, the Units shall vest as set forth in the vesting schedule for Units contained in the Award Notice (the “RSU Vesting Schedule”). As of the Award Date, the Participant must be an employee of the Company or a subsidiary thereof. If the Participant ceases to be an employee of the Company or a subsidiary thereof prior to the vesting of all of the Units pursuant to the RSU Vesting Schedule, the Participant shall forfeit the remaining unvested Units under the Award, except as otherwise provided in this Section 2.2 and Section 2.5.

(b) Continued Vesting Upon Early Retirement. The Units shall, notwithstanding any other provisions of this Section 2.2, continue to vest according to the RSU Vesting Schedule after the termination of the Participant’s employment with the Company or a subsidiary thereof if (i) such termination is the result of the Participant’s retirement from the Company or a subsidiary thereof upon the Participant’s having both reached the age of sixty (60) and completed twelve (12) years of service with the Company or a subsidiary thereof, and (ii) the Participant does not after such early retirement become employed on a full-time basis by a competitor of the Company prior to the earlier of the settlement of the Units or the Participant’s reaching the age of sixty-five (65).

(c) Acceleration Upon Death, Total Disability or Normal Retirement. The Units shall become fully vested, notwithstanding any other provisions of this Section 2.2, upon termination of the Participant’s employment with the Company or a subsidiary thereof because of death, Total Disability, or retirement upon reaching the Company’s normal retirement age of sixty-five (65). In the event of such acceleration of the vesting of the Units, the RSU Settlement Date (as defined in Section 2.3) shall also be accelerated to permit prompt settlement of the Units.

(d) Termination for Cause. Notwithstanding any other provisions of this Section 2.2, the Participant shall forfeit any unvested and unsettled Units under this Award upon the termination of the employment of the Participant by the Company or a subsidiary thereof for cause, which term is specifically not capitalized as such term was in Sections 1.3(d) and 1.6(a) of this Agreement, it being the specific intent of the Company and the Participant that “cause” in this instance shall be broadly defined as any event, action, or inaction by the Participant that would reasonably be the basis for an employer to terminate the employment of the affected individual.

2.3 Settlement of Units. The portion of the Units that vest on a particular vesting installment date as set forth in the RSU Vesting Schedule in the Award Notice shall be settled on such vesting installment date (the “RSU Settlement Date”), provided that such portion of the Units has not been previously terminated. Settlement of the vested Units may be made (a) solely through the issuance of Shares or (b) at the mutual election of the Participant and the Company, in a combination of Shares and cash. The cash value of Units settled in cash shall be based on the closing price of a Share as reported on the New York Stock Exchange or other applicable public market on the trading day corresponding to the RSU Settlement Date. In no event shall the total value of Unit settlements with the Participant under the Plan during any calendar year exceed the value at the time of settlement of the maximum number of Shares issuable to any one participant under the Plan during any calendar year pursuant to Section 4.1 of the Plan. Upon the settlement of the Units through the issuance of Shares, the Company shall deliver to the Participant evidence of book-entry Shares or a certificate for the number of Shares issued to the Participant in settlement of the Units. The Shares shall not be subject to any holding or transfer restrictions after settlement of the Units. The Participant shall not be permitted to elect to further defer settlement beyond the RSU Settlement Date pursuant to Section 6.1(b)(ii) of the Plan.

2.4 Transfer Restrictions. Outstanding Units that have not been settled shall not be transferable by the Participant, and the Participant shall not be permitted to sell, transfer, pledge, assign, or otherwise alienate or encumber such Units or the Shares issuable in settlement thereof, other than (i) to the person or persons to whom the Participant’s rights under such Units pass by will or the laws of descent and distribution, (ii) to the spouse or the descendants of the Participant or to trusts for such persons to whom or which the Participant may transfer such Units by gift, (iii) to the legal representative of any of the foregoing, or (iv) pursuant to a qualified domestic relations order as defined under Section 414(p) of the Code or a similar order or agreement pursuant to state domestic relations law (including a community property law) relating to the provision of child support, alimony payments, or marital property rights to a spouse, former spouse, child, or other dependent of the Participant. Any such transfer shall be

made only in compliance with the Securities Act of 1933 and the requirements therefor as set forth by the Company. Any attempted transfer in contravention of the foregoing provisions shall be null and void and of no effect.

2.5 Change of Control Termination.

(a) Vesting upon Change of Control Termination. Notwithstanding any other provisions of this Agreement, the Units shall become fully vested upon a Change of Control Termination (as defined in Section 1.6(a)). The normal vesting and settlement provisions in Article II of this Agreement shall not be affected by the immediately foregoing sentence if a Change of Control of the Company occurs but there is not also a Change of Control Termination with respect to the Participant’s employment with the Company or a subsidiary thereof. For purposes of determining whether a Change of Control Termination has occurred with respect to this section, the term “Cause” shall be as defined in Section 1.6(a); provided, however, in the context of a Change of Control Termination, the term “Cause” shall be as modified in Section 1.3(d), and not as set forth in Section 2.2(d).

(b) Settlement upon Change of Control Termination. Notwithstanding any other provisions of this Agreement to the contrary, in the event of a Change of Control Termination with respect to the Participant’s employment with the Company or a subsidiary thereof as set forth in Section 2.5(a) above, the vested Units shall be settled either in Shares or in cash of equivalent value, as determined by the Committee or other duly authorized administrator of the Plan, in its discretion, within thirty (30) days following the effective date of the Change of Control Termination; provided, however, that the time and manner of such settlement shall comply with Section 409A of the Code as referred to in Section 3.11 of this Agreement.

(c) Controlling Documents for Change of Control Termination. To the extent that the Participant is subject to either a written Change of Control Severance Agreement or the Change of Control Severance Plan, the terms and conditions of such Change of Control Severance Agreement or Change of Control Severance Plan, as applicable, shall also apply to this Award in the event of a Change of Control Termination; provided, however, that with respect to the Units under this Award, the terms of the Plan and this Agreement shall control in the event of any inconsistency between their terms and the terms of the Change of Control Severance Agreement or the Change of Control Severance Plan.

ARTICLE III

GENERAL PROVISIONS

3.1 Adjustments Upon Changes in Capitalization. In the event that a stock split, stock dividend, or other similar change in capitalization of the Company occurs, the number and kind of Shares that may be issued under this Agreement and that have not yet been issued shall be proportionately and appropriately adjusted.

3.2 No Dividend Equivalents or Stockholder Rights Until Shares Issued. The Performance Shares and Units shall not be credited with Dividend Equivalents. In addition, the Participant shall have no voting, transfer, liquidation, or other rights of a holder of Shares with respect to the Performance Shares or Units until such time as Shares, if any, have been issued by the Company to the Participant in payment of the Performance Shares or settlement of the Units. Until the Performances Shares or Units are paid or settled or terminated, they will represent only bookkeeping entries by the Company to evidence unfunded and unsecured obligations of the Company.

3.3 Notices. Any notice relating to this Agreement shall be in writing and delivered in person or by mail, fax, or email transmission to the address or addresses on file with the Company. Any notice to the Company shall be addressed to it at its principal office, and be specifically directed to the attention of the Secretary. Anyone to whom a notice may be given under this Agreement may designate a new address by notice to that effect.

3.4 Benefits of Agreement. This Agreement shall inure to the benefit of and be binding upon each successor of the Company and the Participant's heirs, legal representatives, and permitted transferees. This Agreement and the Plan shall be the sole and exclusive source of any and all rights that the Participant and the Participant's heirs, legal representatives, and permitted transferees may have with respect to this Award, the Performance Shares and Units, and the Plan.

3.5 Resolution of Disputes. Any dispute or disagreement which arises under, or is a result of, or in any way relates to, the interpretation, construction, or applicability of this Agreement shall be resolved as determined by the Committee, or the Board of Directors of the Company (the "Board"), or by any other committee appointed by the Board for such purpose. Any determination made hereunder shall be final, binding, and conclusive for all purposes.

3.6 Controlling Documents. The provisions of the Plan are hereby incorporated into this Agreement by reference. In the event of any inconsistency between this Agreement and the Plan, the Plan shall control. The provisions of the Award Notice are also hereby incorporated into this Agreement by reference. In the event of any inconsistency between this Agreement and the Award Notice, this Agreement shall control.

3.7 Amendments. This Agreement may be amended only by a written instrument executed by both the Company and the Participant.

3.8 No Right of Participant to Continued Employment. Nothing contained in this Agreement or the Plan shall confer on the Participant any right to continue to be employed by the Company or any subsidiary thereof, or shall limit the Company's right to terminate the employment of the Participant at any time; provided, however, that nothing contained in this Agreement shall affect any separate contractual provisions that exist between the Participant and the Company or its subsidiaries with respect to the employment of the Participant.

3.9 Vesting Dates, Payment Dates and Settlement Dates. In the event that any vesting date, payment date, settlement date, or any other measurement date with respect to this

Award, does not fall on a normal business day, such date shall be deemed to occur on the next following normal business day.

3.10 Tax Withholding. The Company may make such provisions and take such steps as it deems necessary or appropriate for the withholding of any taxes that the Company is required by law or regulation of any governmental authority, whether Federal, state, or local, to withhold in connection with the Performance Shares, Units, or Shares subject to this Agreement. The Participant shall elect, prior to any tax withholding event related to this Award and at a time when the Participant is not aware of any material nonpublic information about the Company and the Participant would be permitted to engage in a transaction in the Company's securities under the Company's Securities Trading Policy, whether the Participant will satisfy all or part of such tax withholding requirement by paying the taxes in cash or by having the Company withhold Shares having a fair market value equal to the minimum statutory withholding that may be imposed on the transaction (based on minimum statutory withholding rates for Federal, state, and local tax purposes, as applicable, that are applicable to such transaction). The Participant's election shall be irrevocable, made in writing, signed by the Participant, and shall be subject to any restrictions or limitations that the Committee, in its sole discretion, deems appropriate.

3.11 Compliance with Section 409A of the Code. Notwithstanding any provision in this Agreement to the contrary, to the extent that this Agreement constitutes a nonqualified deferred compensation plan or arrangement to which Section 409A of the Code applies, the administration of this Award (including the time and manner of payments under the Award and this Agreement) shall comply with Section 409A of the Code. In connection therewith, any settlement or payment to the Participant with respect to the Award under this Agreement which Section 409A(a)(2)(B)(i) of the Code indicates may not be made before the date which is six months after the date of the Participant's separation from employment service (the "Section 409A Six-Month Waiting Period"), as a result of the fact that the Participant is a specified key employee referred to in Section 409A(a)(2)(B)(i) of the Code, shall not occur or be made during the Section 409A Six-Month Waiting Period but rather shall be delayed, if such settlement or payment would otherwise occur during the Section 409A Six-Month Waiting Period, until the expiration of the Section 409A Six-Month Waiting Period.

3.12 Personal Data. The Participant hereby consents to the collection, use, and transfer, in electronic or other form, of the Participant's personal data as described in this Agreement by and among, as applicable, the Company and its affiliates for the exclusive purpose of implementing, administering, and managing the Participant's participation in the Plan. The Company holds, or may receive from any agent designated by the Company, certain personal information about the Participant, including, but not limited to, the Participant's name, home address and telephone number, date of birth, social security insurance number or other identification number, salary, nationality, job title, any shares of Common Stock held, details of this Award and any other rights to shares of Common Stock awarded, canceled, exercised, vested, unvested, or outstanding in the Participant's favor, for the purpose of implementing, administering, and managing the Plan, including complying with applicable tax and securities laws (the "Personal Data"). The Personal Data may be transferred to any third parties assisting in the implementation, administration, and management of the Plan. The Participant authorizes such recipients of the Personal Data to receive, possess, use, retain, and transfer the Personal

Data, in electronic or other form, for the purposes described above. The Participant may, at any time, view the Personal Data, request additional information about the storage and processing of the Personal Data, require any necessary amendments to the Personal Data, or refuse or withdraw the consents herein, in any case without cost, by contacting the Secretary of the Company in writing. Any such refusal or withdrawal of the consents herein may affect the Participant's ability to participate in the Plan.

3.13 Electronic Delivery of Documents. The Company may, in its sole discretion, deliver any documents related to this Award, or any future awards that may be granted under the Plan, by electronic means, or request the Participant's consent to participate in the Plan or other authorizations from the Participant in connection therewith by electronic means. The Participant hereby consents to receive such documents by electronic delivery and, if requested, to participate in the Plan through an on-line or electronic system established and maintained by the Company or another third party designated by the Company.

3.14 Execution and Counterparts. This Agreement may be executed in counterparts and signature pages may be delivered by email or fax transmission. Execution of a written instrument for this Agreement may be evidenced by any appropriate form of electronic signature or affirmative email or other electronic response attached to or logically associated with such written instrument, which is executed or adopted by a party with an indication of the intention by such party to execute or adopt such instrument for purposes of execution thereof.

* * * * *

[Signature page follows]

IN WITNESS WHEREOF, the Company and the Participant have caused this Performance Share and Restricted Stock Unit Award Agreement to be entered into effective as of the Award Date.

COMPANY:

SM ENERGY COMPANY,
a Delaware corporation

By: ______________________________

Printed Name: ______________________________

Title: ______________________________

Date Signed: ______________________________

PARTICIPANT:

Signature: ______________________________

Printed Name: ______________________________

Date Signed: ______________________________

APPENDIX A

PAYOUT MATRIX FOR PERFORMANCE SHARES

2010 PAYOUT MATRIX
Simple Matrix - Add result in Column A and Column B
TOTAL CANNOT BE GREATER THAN 2.0 OR LESS THAN ZERO

Column A

Absolute St. Mary TSR

Annual TSR	EARNED MULTIPLIER
0%	—
1%	0.050
2%	0.100
3%	0.150
4%	0.200
5%	0.275
6%	0.350
7%	0.425
8%	0.500
9%	0.575
10%	0.650
11%	0.725
12%	0.800

13%	0.875
14%	0.950
15%	1.025
16%	1.100
17%	1.200
18%	1.300
19%	1.400
20%	1.500
21%	1.600
22%	1.700
23%	1.800
24%	1.900
25%	2.000

Column B

St. Mary Annual TSR vs Peer Index

Annual % Point Deviation From Peers	MULTIPLIER MODIFIER
-10%	(0.80)
-8%	(0.60)
-6%	(0.40)
-4%	(0.20)
-2%	—
0% (Index TSR)	0.20
+2%	0.40
+4%	0.60
+6%	0.80
+8%	1.00

TABULAR EXPRESSION OF PAYOUT MATRIX

St. Mary	Percentage Point Deviation From Peer Index									
TSR (%)	-10%	-8%	-6%	-4%	-2%	0%	2%	4%	6%	8%
0%					**0**	**0.20**	**0.40**	**0.60**	**0.80**	**1.00**
1%					0.05	**0.25**	0.45	0.65	0.85	**1.05**
2%					0.10	**0.30**	0.50	0.70	0.90	**1.10**
3%					0.15	**0.35**	0.55	0.75	0.95	**1.15**
4%				**0**	0.20	**0.40**	0.60	0.80	1.00	**1.20**
5%				0.08	0.28	**0.48**	0.68	0.88	1.08	**1.28**
6%			**0**	0.15	0.35	**0.55**	0.75	0.95	1.15	**1.35**
7%			0.03	0.23	0.43	**0.63**	0.83	1.03	1.23	**1.43**
8%			0.10	0.30	0.50	**0.70**	0.90	1.10	1.30	**1.50**
9%		**0**	0.18	0.38	0.58	**0.78**	0.98	1.18	1.38	**1.58**
10%		0.05	0.25	0.45	0.65	**0.85**	1.05	1.25	1.45	**1.65**
11%		0.13	0.33	0.53	0.73	**0.93**	1.13	1.33	1.53	**1.73**
12%	**0**	0.20	0.40	0.60	0.80	**1.00**	1.20	1.40	1.60	**1.80**
13%	**0.07**	0.28	0.48	0.68	0.88	**1.08**	1.28	1.48	1.68	**1.88**
14%	**0.15**	0.35	0.55	0.75	0.95	**1.15**	1.35	1.55	1.75	**1.95**
15%	**0.23**	0.43	0.63	0.83	1.03	**1.23**	1.43	1.63	1.83	**2.00**
16%	**0.30**	0.50	0.70	0.90	1.10	**1.30**	1.50	1.70	1.90	
17%	**0.40**	0.60	0.80	**1.00**	1.20	**1.40**	1.60	1.80	**2.00**	
18%	**0.50**	0.70	0.90	1.10	1.30	**1.50**	1.70	1.90		
19%	**0.60**	0.80	**1.00**	1.20	1.40	**1.60**	1.80	**2.00**		
20%	**0.70**	0.90	1.10	1.30	1.50	**1.70**	1.90			
21%	**0.80**	**1.00**	1.20	1.40	1.60	**1.80**	**2.00**			
22%	**0.90**	1.10	1.30	1.50	1.70	**1.90**				
23%	**1.00**	1.20	1.40	1.60	1.80	**2.00**				
24%	**1.10**	1.30	1.50	1.70	1.90					
25%	**1.20**	**1.40**	**1.60**	**1.80**	**2.00**					

RED= MINIMUMS
BLUE = MAXIMUMS

EXHIBIT 10.4

SM ENERGY COMPANY

PERFORMANCE SHARE AND RESTRICTED STOCK UNIT AWARD NOTICE

[Date](1)

[Name and Address]

Dear [Name]:

Pursuant to the SM Energy Company long term incentive program ("LTIP") under the Company's Equity Incentive Compensation Plan, as amended (the "Plan"), you have been awarded [Number] performance shares (the "Performance Shares") and [Number] restricted stock units (the "Units"). The Performance Shares represent the right to receive, upon payment of the Performance Shares after the completion of the Performance Period set forth below, a number of shares of the Company's common stock that will be calculated as set forth in the Performance Share and Restricted Stock Unit Award Agreement (the "Agreement"), which Agreement will set forth terms and conditions for the Performance Shares and the Units and will be separately delivered to you, based on the Company's performance for the Performance Period and the extent to which the Performance Shares are vested. That number of shares relating to the Performance Shares may be from zero (0) to two (2.0) times the number of Performance Shares awarded. Each Unit represents the right to receive one share of the Company's common stock to be delivered upon settlement of the vested Units as set forth in the Agreement. The Performance Shares and the Units are subject to all of the terms and conditions of the Plan and the Agreement, which are both incorporated herein in their entirety.

Awarded To:	[Name]
Award Date:	[Award Date]

PERFORMANCE SHARES:

Number of Performance Shares:	[Number]
Performance Period:	The three-year period beginning on [Date], and ending on [Date]
PSA Vesting Schedule:	The Performance Shares will vest as follows (provided that on such vesting date you are then employed by the Company or a subsidiary): 1/7th (approximately 14.3%) on [Vesting Date]

(1) Items in brackets are features that may vary among individual awards.

	2/7ths (approximately 28.6%) on [Vesting Date] 4/7ths (approximately 57.1%) on [Vesting Date] In addition, the Performance Shares may become fully vested or be forfeited under certain circumstances specified in the Agreement.
PSA Payment Date:	[Settlement Date]

UNITS:

Number of Units:	[Number]
RSU Vesting Schedule:	The Units will vest as follows (provided that on such vesting date you are then employed by the Company or a subsidiary): 1/7th (approximately 14.3%) on [Vesting Date] 2/7ths (approximately 28.6%) on [Vesting Date] 4/7ths (approximately 57.1%) on [Vesting Date] In addition, the Units may become fully vested or be forfeited under certain circumstances specified in the Agreement.
RSU Settlement Dates:	For each vested portion of the Units, the RSU Settlement Date will be the same date as the vesting date.

* * * * *

[Signature page follows]

By your signature below, you hereby acknowledge receipt of the Performance Shares and Units awarded on the date shown above, which have been awarded to you under the terms and conditions of the Plan and the Agreement. You further acknowledge receipt either directly or electronically of a copy of the Plan, a prospectus for the Plan, and the Agreement, and agree to conform to all of the terms and conditions of the Performance Shares, the Units, the Plan, and the Agreement.

Execution of a written instrument for purposes of this award may be evidenced by any appropriate form of electronic signature or affirmative email or other electronic response attached to or logically associated with such written instrument, which is executed or adopted by a party with an indication of the intention by such party to execute or adopt such instrument for purposes of execution thereof.

COMPANY:

SM ENERGY COMPANY,
a Delaware corporation

By: ______________________________

Printed Name: ______________________________

Title: ______________________________

Date Signed: ______________________________

PARTICIPANT:

Signature: ______________________________

Printed Name: ______________________________

Date Signed: ______________________________

SM ENERGY COMPANY

NON-EMPLOYEE DIRECTOR RESTRICTED STOCK AWARD AGREEMENT

THIS NON-EMPLOYEE DIRECTOR RESTRICTED STOCK AWARD AGREEMENT, hereinafter referred to as the "Agreement," is made effective as of the Award Date set forth in the attached Non-Employee Director Restricted Stock Award Notice (the "Award Notice"), by and between SM ENERGY COMPANY, a Delaware corporation (the "Company"), and the undersigned person, who is a non-employee member of the Company's Board of Directors (the "Board") as of the Award Date, to whom restricted stock has been awarded as set forth in the Award Notice (the "Director").

Pursuant to the terms of the Company's Equity Incentive Compensation Plan, as amended (the "Plan"), the attached Award Notice and this Agreement, as of the Award Date the Company has made an Award (the "Award") to the Director of [Number](1) shares of common stock of the Company (the "Stock") delivered on the Award Date as set forth in the Award Notice, subject to the terms and conditions set forth in the Plan, this Agreement and the Award Notice. Capitalized terms used but not defined in this Agreement shall have the meanings given to them in the Plan or in the Award Notice.

1. Earning and Vesting of Shares.

(a) Subject to the provisions contained herein, the Stock shall be earned over the Earning Period set forth in the Award Notice, which shall correspond to the fiscal year of Board service by the Director following the Award Date, provided that earning shall cease when the Director is no longer a member of the Board. The Stock shall become completely vested upon completion of the Earning Period through Board service by the Director. Notwithstanding any other provisions of this Section 1(a), if the Director resigns from the Board prior to the completion of the Earning Period, but after the Director has completed at least five years of service to the Company as a Non-Employee Director, the Stock shall be deemed to be fully earned and vested upon such resignation.

(b) Irrespective of the other provisions of this Section 1, as set forth in Article III of the Plan, the Board's Compensation Committee (the "Compensation Committee") is authorized to administer the Plan, and in its discretion may accelerate the earning and vesting period of the Stock within the current Earning Period; provided, however, that any such acceleration shall occur only if in compliance with any applicable provisions of Section 409A of the Internal Revenue Code of 1986, as amended (the "Code"), and the regulations thereunder.

(1) Items in brackets are features that may vary among individual awards.

2. Transfer Restrictions.

(a) The shares of Stock issued under the Plan and which are subject to the terms and conditions set forth in this Agreement have been registered under the Securities Act of 1933, as amended (the "Securities Act"). However, since the Director is considered to be an "affiliate" of the Company for securities law purposes, the shares of Stock will be subject to restrictions on transferability and sale and may not be offered for sale, sold or otherwise transferred except pursuant to an effective registration statement under the Securities Act for the resale of the Stock or pursuant to an exemption from registration under the Securities Act, the availability of which is to be established to the satisfaction of the Company.

(b) In addition, the shares of Stock shall be subject to a Holding Period of one year following the expiration of the Earning Period set forth in the Award Notice. During such Holding Period the shares of Stock may not be offered for sale, sold or otherwise transferred by the Director, other than (i) to the person or persons to whom the Director's rights under such shares pass by will or the laws of descent and distribution, (ii) to the spouse or the descendants of the Director or to trusts for such persons to whom or which the Director may transfer such shares by gift, (iii) to the legal representative of any of the foregoing, or (iv) pursuant to a qualified domestic relations order as defined under Section 414(p) of the Code or a similar order or agreement pursuant to state domestic relations law (including a community property law) relating to the provision of child support, alimony payments, or marital property rights to a spouse, former spouse, child, or other dependent of the Director. Any such transfer shall be made only in compliance with the Securities Act and the requirements therefor as set forth by the Company. Any attempted transfer in contravention of the foregoing provisions shall be null and void and of no effect. Any permitted transferee under the foregoing provisions shall be subject to the remainder of the Holding Period for the Stock.

(c) Any certificates for shares of Stock issued under this Agreement shall bear a restrictive legend consistent with the foregoing, and any book-entry accounts credited with shares of Stock issued under this Agreement shall be subject to stop-transfer orders with respect to such shares consistent with the foregoing.

3. Notices. Any notice relating to this Agreement shall be in writing and delivered in person or by mail, fax, or email transmission to the address or addresses on file with the Company. Any notice to the Company shall be addressed to it at its principal office, and be specifically directed to the attention of the Secretary. Anyone to whom a notice may be given under this Agreement may designate a new address by notice to that effect.

4. Benefits of Agreement. This Agreement shall inure to the benefit of and be binding upon each successor of the Company and the Director's heirs, legal representatives and permitted transferees. This Agreement shall be the sole and exclusive source of any and all rights which the Director and the Director's heirs, legal representatives and permitted transferees may have with respect to the Plan and the Stock.

5. Resolution of Disputes. Any dispute or disagreement which arises under, or as a result of, or in any way relates to, the interpretation, construction or applicability of this

Agreement shall be resolved as determined by the Compensation Committee. Any determination made hereunder shall be final, binding and conclusive for all purposes.

6. Controlling Documents. The provisions of the Plan are hereby incorporated into this Agreement by reference. In the event of any inconsistency between this Agreement and the Plan, the Plan shall control.

7. Amendments. This Agreement may be amended only by a written instrument executed by both the Company and the Director.

8. Compliance with Section 409A of the Code. Notwithstanding any provision in this Agreement to the contrary, to the extent that this Agreement constitutes a nonqualified deferred compensation plan or arrangement to which Section 409A of the Code applies, the administration of this Award (including the time and manner of payments under the Award and this Agreement) shall comply with Section 409A of the Code.

9. Electronic Delivery of Documents. The Company may, in its sole discretion, deliver any documents related to this Award, or any future awards that may be

granted under the Plan, by electronic means, or request the Director's consent to participate in the Plan or other authorizations from the Director in connection therewith by electronic means. The Director hereby consents to receive such documents by electronic delivery and, if requested, to participate in the Plan through an on-line or electronic system established and maintained by the Company or another third party designated by the Company.

10. Execution and Counterparts. This Agreement may be executed in counterparts and signature pages may be delivered by email or fax transmission. Execution of a written instrument for this Agreement may be evidenced by any appropriate form of electronic signature or affirmative email or other electronic response attached to or logically associated with such written instrument, which is executed or adopted by a party with an indication of the intention by such party to execute or adopt such instrument for purposes of execution thereof.

* * * * *

[Signature page follows]

IN WITNESS WHEREOF, the Company and the Director have caused this NON-EMPLOYEE DIRECTOR RESTRICTED STOCK AWARD AGREEMENT to be entered into effective as of the Award Date.

COMPANY:

SM ENERGY COMPANY,
a Delaware corporation

By: ____________________
Printed Name: ____________________
Title: ____________________
Date Signed: ____________________

DIRECTOR:

____
Printed Name: ____________________
Date Signed: ____________________

Attachment: Non-Employee Director Restricted Stock Award Notice

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SM ENERGY COMPANY

NON-EMPLOYEE DIRECTOR RESTRICTED STOCK AWARD NOTICE

Effective as of [Date]

Dear [Name]:

Pursuant to the terms and conditions of the Company's Equity Incentive Compensation Plan, as amended (the "Plan"), you have been awarded [Number] shares of common stock of the Company delivered upon the Award Date set forth below. The Stock is subject to all of the terms and conditions of the Plan and the attached Non-Employee Director Restricted Stock Award Agreement (the "Award Agreement"), which are both incorporated herein in their entirety.

Awarded To:	[Name]
Award Date:	[Award Date]
Shares Awarded:	[Number]
Earning Period:	The annual Board of Directors service period beginning with your election as a Board member on [Date] and ending with the election of Directors at the Company's [Year] annual stockholders meeting, which is currently scheduled to occur on or about [date].
Holding Period:	One year following the expiration of the Earning Period.

* * * * *

[Signature page follows]

By your signature below, you hereby acknowledge receipt of the Stock awarded on the date shown above, which has been awarded to you under the terms and conditions of the Plan and the attached Award Agreement. You further acknowledge receipt either directly or electronically of a copy of the Plan, a prospectus for the Plan, and the Award Agreement, and agree to conform to all of the terms and conditions of the Plan and the Award Agreement.

Execution of a written instrument for purposes of this award may be evidenced by any appropriate form of electronic signature or affirmative email or other electronic response attached to or logically associated with such written instrument, which is executed or adopted by a party with an indication of the intention by such party to execute or adopt such instrument for purposes of execution thereof.

COMPANY:

SM ENERGY COMPANY,
a Delaware corporation

By:		Date Signed:	
Printed Name:			
Title:			

DIRECTOR:

Signature:		Date Signed:	
Printed Name:			

Attachment: Non-Employee Director Restricted Stock Award Agreement

CERTIFICATION

I, Anthony J. Best certify that:

1. I have reviewed this quarterly report on Form 10-Q of SM Energy Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 3, 2010

/s/ ANTHONY J. BEST
Anthony J. Best
President and Chief Executive Officer

CERTIFICATION

I, A. Wade Pursell certify that:

1. I have reviewed this quarterly report on Form 10-Q of SM Energy Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 3, 2010

/s/ A. WADE PURSELL

A. Wade Pursell
Executive Vice President and Chief Financial Officer

EXHIBIT 32.1

CERTIFICATION
PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Quarterly Report on Form 10-Q of SM Energy Company (the “Company”) for the quarterly period ended June 30, 2010 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), Anthony J. Best, as President and Chief Executive Officer of the Company, and A. Wade Pursell, as Executive Vice President and Chief Financial Officer of the Company, each hereby certifies, pursuant to and solely for the purpose of 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, to the best of his knowledge and belief, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ ANTHONY J. BEST
Anthony J. Best
President and Chief Executive Officer
August 3, 2010

/s/ A. WADE PURSELL
A. Wade Pursell
Executive Vice President and Chief Financial Officer
August 3, 2010

Exhibit 99.1

Audit Committee Pre-Approval of Non-Audit Services

On April 30, 2010, the Audit Committee of the Board of Directors of SM Energy Company approved in advance certain non-audit services to be performed by Deloitte & Touche LLP, SM Energy's independent auditor. These non-audit services were for SM Energy's income tax refund for the Company's 2009 federal income tax return.