ULTRA PETROLEUM CORP
Form 10-Q
August 04, 2009

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

Form 10-Q

þ	**QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934** **For the quarterly period ended June 30, 2009**
	or
o	**TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934** **For the transition period from to**

Commission file number 001-33614

ULTRA PETROLEUM CORP.
(Exact name of registrant as specified in its charter)

Yukon Territory, Canada	**N/A**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. employer identification number)*
363 North Sam Houston Parkway, Suite 1200, Houston, Texas	**77060**
(Address of principal executive offices)	*(Zip code)*

(281) 876-0120
(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 þ NO o

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 during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). YES þ NO o

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 þ	Accelerated filer o	Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act).
YES o NO þ

The number of common shares, without par value, of Ultra Petroleum Corp., outstanding as of July 31, 2009 was 151,440,114.

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PART I FINANCIAL INFORMATION

ITEM 1 *FINANCIAL STATEMENTS*

ULTRA PETROLEUM CORP.

CONSOLIDATED STATEMENTS OF OPERATIONS

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2009	2008	2009	2008
	(Unaudited) (Amounts in thousands of U.S. dollars, except per share data)			
Revenues:				
Natural gas sales	$ 115,079	$ 277,446	$ 273,908	$ 526,568
Oil sales	15,262	30,794	24,386	52,809
Total operating revenues	130,341	308,240	298,294	579,377
Expenses:				
Lease operating expenses	10,144	8,562	20,387	19,299
Production taxes	12,738	35,776	30,089	66,711
Gathering fees	11,573	8,766	22,364	18,764
Transportation charges	13,185	12,013	26,540	21,671
Depletion and depreciation	44,974	42,780	105,635	85,030
Write-down of proved oil and gas properties			1,037,000	
General and administrative	5,650	4,449	10,224	8,794
Total operating expenses	98,264	112,346	1,252,239	220,269
Operating income (loss)	32,077	195,894	(953,945)	359,108
Other income (expense), net:				
Interest expense	(9,897)	(4,543)	(17,195)	(9,814)
(Loss) gain on commodity derivatives	(60,698)	(11,596)	145,730	(39,269)
Other (expense) income, net	(505)	609	(3,117)	692
Total other (expense) income, net	(71,100)	(15,530)	125,418	(48,391)
(Loss) income before income tax (benefit) provision	(39,023)	180,364	(828,527)	310,717
Income tax (benefit) provision	(13,497)	63,489	(290,413)	110,510
Net (loss) income	$ (25,526)	$ 116,875	$ (538,114)	$ 200,207
Net (loss) income per common share basic	$ (0.17)	$ 0.76	$ (3.56)	$ 1.31
Net (loss) income per common share fully diluted	$ (0.17)	$ 0.74	$ (3.56)	$ 1.27

Weighted average common shares outstanding basic	151,331	153,061	151,285	152,781
Weighted average common shares outstanding fully diluted	151,331	157,818	151,285	157,905

See accompanying notes to consolidated financial statements.

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ULTRA PETROLEUM CORP.

CONSOLIDATED BALANCE SHEETS

	June 30, 2009 (Unaudited)	December 31, 2008
	(Amounts in thousands of U.S. dollars)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 9,299	$ 14,157
Restricted cash	1,682	2,727
Accounts receivable	117,235	126,710
Derivative assets	125,652	39,939
Inventory	6,575	8,522
Prepaid drilling costs and other current assets	2,778	6,163
Total current assets	263,221	198,218
Oil and gas properties, net, using the full cost method of accounting:		
Proved	1,594,200	2,294,982
Unproved properties not being amortized		55,544
Property, plant and equipment	5,972	5,770
Long-term derivative assets	2,441	
Deferred financing costs and other	7,656	3,648
Total assets	$ 1,873,490	$ 2,558,162
LIABILITIES AND SHAREHOLDERS EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$ 106,374	$ 163,902
Production taxes payable	73,069	61,416
Derivative liabilities	3,665	1,712
Capital cost accrual	60,759	120,543
Total current liabilities	243,867	347,573
Long-term debt	764,000	570,000
Deferred income tax liability	206,358	503,597
Long-term derivative liabilities	72,592	
Other long-term obligations	29,415	46,206
Shareholders equity:		
Common stock no par value; authorized unlimited; issued and outstanding 151,440,114 and 151,232,545, respectively	356,535	346,832
Treasury stock	(31,075)	(45,740)
Retained earnings	224,373	774,117
Accumulated other comprehensive income	7,425	15,577

Total shareholders equity	557,258	1,090,786
Total liabilities and shareholders equity	$ 1,873,490	$ 2,558,162

See accompanying notes to consolidated financial statements.

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ULTRA PETROLEUM CORP.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Six Months Ended June 30, 2009	2008
	(Unaudited) (Amounts in thousands of U.S. dollars)	
Cash provided by (used in):		
Operating activities:		
Net (loss) income for the period	$ (538,114)	$ 200,207
Adjustments to reconcile net income to net cash provided by operating activities:		
Income from discontinued operations, net of tax provision of $225		(415)
Depletion and depreciation	105,635	85,030
Write-down of proved oil and gas properties	1,037,000	
Deferred income taxes	(290,436)	110,704
Unrealized (gain) loss on commodity derivatives	(26,169)	25,150
Excess tax benefit from stock based compensation	(2,394)	(62,627)
Stock compensation	4,819	2,755
Other	720	189
Net changes in non-cash working capital:		
Restricted cash	1,045	(34)
Accounts receivable	9,475	(41,560)
Prepaid expenses and other	3,876	(1,702)
Other non-current assets	(2,868)	
Accounts payable and accrued liabilities	(45,519)	76,058
Other long-term obligations	(16,670)	20,424
Current taxes payable		(10,839)
Net cash provided by operating activities	240,400	403,340
Investing activities:		
Oil and gas property expenditures	(382,366)	(409,089)
Post-closing adjustments on sale of subsidiary		640
Change in capital cost accrual	(59,784)	29,639
Inventory	1,947	6,600
Other	(704)	
Purchase of capital assets	(667)	(461)
Net cash used in investing activities	(441,574)	(372,671)
Financing activities:		
Borrowings on long-term debt	676,000	332,000
Payments on long-term debt	(482,000)	(322,000)
Deferred financing costs	(1,283)	(1,580)
Repurchased shares		(68,635)

Excess tax benefit from stock based compensation		2,394		62,627
Proceeds from exercise of options		1,205		16,631
Net cash provided by financing activities		196,316		19,043
(Decrease)/increase in cash during the period		(4,858)		49,712
Cash and cash equivalents, beginning of period		14,157		10,632
Cash and cash equivalents, end of period	$	9,299	$	60,344

See accompanying notes to consolidated financial statements.

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ULTRA PETROLEUM CORP.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

(All dollar amounts in this Quarterly Report on Form 10-Q are expressed in thousands of U.S. dollars (except per share data) unless otherwise noted)

DESCRIPTION OF THE BUSINESS:

Ultra Petroleum Corp. (the Company) is an independent oil and gas company engaged in the acquisition, exploration, development, and production of oil and gas properties. The Company is incorporated under the laws of the Yukon Territory, Canada. The Company s principal business activities are conducted in the Green River Basin of Southwest Wyoming.

1. SIGNIFICANT ACCOUNTING POLICIES:

The accompanying financial statements, other than the balance sheet data as of December 31, 2008, are unaudited and were prepared from the Company s records. Balance sheet data as of December 31, 2008 was derived from the Company s audited financial statements, but does not include all disclosures required by U.S. Generally Accepted Accounting Principles (GAAP). The Company s management believes that these financial statements include all adjustments necessary for a fair presentation of the Company s financial position and results of operations. All adjustments are of a normal and recurring nature unless specifically noted. The Company prepared these statements on a basis consistent with the Company s annual audited statements and Regulation S-X. Regulation S-X allows the Company to omit some of the footnote and policy disclosures required by generally accepted accounting principles and normally included in annual reports on Form 10-K. You should read these interim financial statements together with the financial statements, summary of significant accounting policies and notes to the Company s most recent annual report on Form 10-K.

(a) *Basis of presentation and principles of consolidation:* The consolidated financial statements include the accounts of the Company and its wholly owned subsidiaries UP Energy Corporation and Ultra Resources, Inc. The Company presents its financial statements in accordance with GAAP. All inter-company transactions and balances have been eliminated upon consolidation.

(b) *Cash and cash equivalents:* We consider all highly liquid investments with an original maturity of three months or less to be cash equivalents.

(c) *Restricted cash:* Restricted cash represents cash received by the Company from production sold where the final division of ownership of the production is unknown or in dispute. Wyoming law requires that these funds be held in a federally insured bank in Wyoming.

(d) *Capital assets other than oil and gas properties:* Capital assets are recorded at cost and depreciated using the declining-balance method based on a seven-year useful life.

(e) *Oil and natural gas properties:* The Company uses the full cost method of accounting for exploration and development activities as defined by the Securities and Exchange Commission (SEC). Under this method of accounting, the costs of unsuccessful, as well as successful, exploration and development activities are capitalized as oil and gas properties. This includes any internal costs that are directly related to exploration and development activities but does not include any costs related to production, general corporate overhead or similar activities. The carrying amount of oil and natural gas properties also includes estimated asset retirement costs recorded based on the fair value of the asset retirement obligation when incurred. Gain or loss on the sale or other disposition of oil and natural gas properties is not recognized, unless the gain or loss would significantly alter the relationship between capitalized costs and proved reserves of oil and natural gas attributable to a country.

The sum of net capitalized costs and estimated future development costs of oil and natural gas properties are amortized using the units-of-production method based on the proved reserves as determined by independent

ULTRA PETROLEUM CORP.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

petroleum engineers. Oil and natural gas reserves and production are converted into equivalent units based on relative energy content. Asset retirement obligations are included in the base costs for calculating depletion.

Under the full cost method, costs of unevaluated properties and major development projects expected to require significant future costs may be excluded from capitalized costs being amortized. The Company excludes significant costs until proved reserves are found or until it is determined that the costs are impaired. Excluded costs, if any, are reviewed quarterly to determine if impairment has occurred. The amount of any impairment is transferred to the capitalized costs being amortized.

Companies that use the full cost method of accounting for oil and natural gas exploration and development activities are required to perform a ceiling test calculation each quarter. The full cost ceiling test is an impairment test prescribed by SEC Regulation S-X Rule 4-10. The ceiling test is performed quarterly, on a country-by-country basis, utilizing prices in effect on the last day of the quarter. SEC regulation S-X Rule 4-10 states that if prices in effect at the end of a quarter are the result of a temporary decline and prices improve prior to the issuance of the financial statements, the increased price may be applied in the computation of the ceiling test. The ceiling limits such pooled costs to the aggregate of the present value of future net revenues attributable to proved crude oil and natural gas reserves discounted at 10% plus the lower of cost or market value of unproved properties less any associated tax effects. If such capitalized costs exceed the ceiling, the Company will record a write-down to the extent of such excess as a non-cash charge to earnings. Any such write-down will reduce earnings in the period of occurrence and result in lower DD&A expense in future periods. A write-down may not be reversed in future periods even though higher oil and natural gas prices may subsequently increase the ceiling. The effect of implementing SFAS No. 143 had no effect on the ceiling test calculation as the future cash outflows associated with settling asset retirement obligations are excluded from this calculation.

During the first quarter of 2009, the Company recorded a $1.0 billion ($673.0 million net of tax) non-cash write-down of the carrying value of the Company s proved oil and gas properties as of March 31, 2009, as a result of the ceiling test limitations, which is reflected as write-down of oil and gas properties in the accompanying consolidated statements of operations. The ceiling test was calculated based on March 31, 2009 wellhead prices of $2.47 per Mcf for natural gas and $33.91 per barrel for condensate.

(f) *Inventories:* Materials and supplies inventories are carried at cost. Inventory costs include expenditures and other charges directly and indirectly incurred in bringing the inventory to its existing condition and location. The Company uses the weighted average method of recording its inventory. Selling expenses and general and administrative expenses are reported as period costs and excluded from inventory cost. At June 30, 2009, drilling and completion supplies inventory of $6.6 million primarily includes the cost of pipe and production equipment that will be utilized during the 2009 drilling program.

(g) *Derivative Instruments and Hedging Activities:* The Company relies on derivative instruments to manage its exposure to commodity price risk. The Company enters into fixed price to index price swap agreements in order to mitigate its commodity price exposure on a portion of its natural gas production. The natural gas reference prices of these commodity derivative contracts are typically referenced to natural gas index prices as published by independent third parties. The Company also utilizes fixed price forward gas sales to manage its commodity price exposure. These fixed price forward gas sales are considered normal sales in the ordinary course of business and outside the scope of SFAS No. 133. The Company does not offset the value of its derivative arrangements with the same counterparty.

(See Note 6).

In March 2008, the FASB issued SFAS No. 161, Disclosures about Derivative Instruments and Hedging Activities (SFAS No. 161). This statement is intended to improve financial reporting about derivative instruments and hedging activities by requiring enhanced disclosures to increase transparency about the location and amounts of derivative instruments in an entity s financial statements; how derivative instruments and related hedged items are accounted for under SFAS No. 133; and how derivative instruments and related

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

hedged items affect financial position, financial performance, and cash flows. The Company adopted SFAS No. 161 effective January 1, 2009. The adoption of SFAS 161 did not have a material impact on the Company s results of operations and financial condition.

(h) *Income taxes:* Income taxes are accounted for under the asset and liability method. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax basis and operating loss and tax credit carryforwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date. Valuation allowances are recorded related to deferred tax assets based on the more likely than not criteria of SFAS No. 109.

The Company follows FASB Interpretation No. 48 (FIN 48) which requires that we recognize the financial statement benefit of a tax position only after determining that the relevant tax authority would more likely than not sustain the position following an audit.

(i) *Earnings per share:* Basic earnings per share is computed by dividing net earnings attributable to common stockholders by the weighted average number of common shares outstanding during each period. Diluted earnings per share is computed by adjusting the average number of common shares outstanding for the dilutive effect, if any, of common stock equivalents. The Company uses the treasury stock method to determine the dilutive effect.

The following table provides a reconciliation of the components of basic and diluted net income per common share:

	Three Months Ended		**Six Months Ended**	
	June 30, 2009(1)	**June 30, 2008**	**June 30, 2009(2)**	**June 30, 2008**
Net (loss) income	$ (25,526)	$ 116,875	$ (538,114)	$ 200,207
Weighted average common shares outstanding during the period	151,331	153,061	151,285	152,781
Effect of dilutive instruments		4,757		5,124
Weighted average common shares outstanding during the period including the effects of dilutive instruments	151,331	157,818	151,285	157,905
Basic (Loss) Earnings per Share:				
Net (loss) income per common share basic	$ (0.17)	$ 0.76	$ (3.56)	$ 1.31
Fully Diluted (Loss) Earnings per Share:				
Net (loss) income per common share fully diluted	$ (0.17)	$ 0.74	$ (3.56)	$ 1.27

(1) Due to the net loss for the three months ended June 30, 2009, options for 2.2 million shares and 0.7 million shares of restricted stock were anti-dilutive and excluded from the computation of loss per share.

(2) Due to the net loss for the six months ended June 30, 2009, options for 2.2 million shares and 0.5 million shares of restricted stock were anti-dilutive and excluded from the computation of loss per share.

(j) *Use of estimates:* Preparation of consolidated financial statements in accordance with U.S. GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(k) *Accounting for share-based compensation:* The Company applies Statement of Financial Accounting Standards No. 123 (revised 2004), Share-Based Payment (SFAS No. 123R) which requires the measurement and recognition of compensation expense for all share-based payment awards made to employees and directors, including employee stock options, based on estimated fair values.

(l) *Fair Value Accounting.* In September 2006, the Financial Accounting Standards Board (FASB) issued SFAS No. 157, Fair Value Measurements (SFAS No. 157). This Statement defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles, and expands disclosures about fair value measurements. This statement applies under other accounting pronouncements that require or permit fair value measurements. Accordingly, this statement did not require any new fair value measurements. The changes to current practice resulting from the application of this statement relate to the definition of fair value, the methods used to measure fair value, and the expanded disclosures about fair value measurements. The Company adopted SFAS No. 157 as of January 1, 2008. The implementation of SFAS No. 157 was applied prospectively for our assets and liabilities that are measured at fair value on a recurring basis, primarily our commodity derivatives, with no material impact on consolidated results of operations, financial position or liquidity. For those non-financial assets and liabilities measured or disclosed at fair value on a non-recurring basis, primarily our asset retirement obligation, SFAS No. 157-2 was effective January 1, 2009. Implementation of this portion of the standard did not have a material impact on consolidated results of operations, financial position or liquidity. See Note 7 for additional information.

(m) *Asset Retirement Obligation.* The initial estimated retirement obligation of properties is recognized as a liability with an associated increase in oil and gas properties for the asset retirement cost. Accretion expense is recognized over the estimated productive life of the related assets. If the fair value of the estimated asset retirement obligation changes, an adjustment is recorded to both the asset retirement obligation and the asset retirement cost. Revisions in estimated liabilities can result from revisions of estimated inflation rates, changes in service and equipment costs and changes in the estimated timing of settling asset retirement obligations.

(n) *Revenue Recognition.* Natural gas revenues are recorded based on the entitlement method. Under the entitlement method, revenue is recorded when title passes based on the Company s net interest. The Company initially records its entitled share of revenues based on estimated production volumes. Subsequently, these estimated volumes are adjusted to reflect actual volumes that are supported by third party pipeline statements or cash receipts. Since there is a ready market for natural gas, the Company sells the majority of its products immediately after production at various locations at which time title and risk of loss pass to the buyer. Gas imbalances occur when the Company sells more or less than its entitled ownership percentage of total gas production. Any amount received in excess of the Company s share is treated as a liability. If the Company receives less than its entitled share, the underproduction is recorded as a receivable.

(o) *Other Comprehensive Income:* Other comprehensive income is a term used to define revenues, expenses, gains and losses that under generally accepted accounting principles impact Shareholders Equity, excluding transactions with shareholders.

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2009	2008	2009	2008

Net (loss) income	$ (25,526)	$ 116,875	$ (538,114)	$ 200,207
Loss on derivative instruments*	(7,145)	(7,638)	(12,561)	(37,556)
Tax benefit on loss on derivative instruments*	2,508	2,681	4,409	13,182
Other comprehensive (loss) income	$ (30,163)	$ 111,918	$ (546,266)	$ 175,833

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ULTRA PETROLEUM CORP.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

* Effective November 3, 2008, the Company changed its method of accounting for natural gas commodity derivatives to reflect unrealized gains and losses on commodity derivative contracts in the income statement rather than on the balance sheet (See Note 6). The net gain or loss in accumulated other comprehensive income at November 3, 2008 will remain on the balance sheet and the respective month s gains or losses will continue to be reclassified from accumulated other comprehensive income to earnings as the counterparty settlements affect earnings (January through December 2009). It is still considered probable that the original forecasted transactions will occur; therefore, the net gain or loss in accumulated other comprehensive income shall not be immediately reclassified into earnings. As a result of the de-designation on November 3, 2008, the company no longer has any derivative instruments which qualify for cash flow hedge accounting.

(p) *Reclassifications:* Certain amounts in the financial statements of prior periods have been reclassified to conform to the current period financial statement presentation.

(q) *Impact of recently issued accounting pronouncements:* On July 1, 2009, the FASB approved the final version of the Codification, which is effective for reporting periods after September 15, 2009. The codification will become the single source of authoritative U.S. GAAP. Going forward, U.S. GAAP will no longer be issued in the form of an accounting standard , but rather as an update to the applicable topic or subtopic within the Codification. As such, accounting guidance will be classified as either authoritative or non-authoritative based on its inclusion or exclusion from the Codification.

In April 2009, the FASB issued FSP No. FAS 115-2 and FAS 124-2, Recognition and Presentation of Other-Than-Temporary Impairments (FSP FAS 115-2 and FAS 124-2), which amends the existing other-than-temporary impairment guidance for debt securities to make the guidance more operational and to improve the presentation and disclosure of other-than-temporary impairments on debt and equity securities in the financial statements. Other-than-temporary impairment relates to investments in debt and equity securities for which changes in fair value are not regularly recognized in earnings (such as securities classified as held-to-maturity or available-for-sale). This pronouncement is effective for interim and annual reporting periods ending after June 15, 2009. Accordingly, the Company has adopted this pronouncement for the quarter ended June 30, 2009; however, since the Company has no such investments in debt or equity securities, there was no impact on the Company s financial position or results of operations as a result of the adoption.

On December 31, 2008, the SEC issued Release No. 33-8995, Modernization of Oil and Gas Reporting, amending oil and gas reporting requirements under Rule 4-10 of Regulation S-X and Industry Guide 2 in Regulation S-K revising oil and gas reserves estimation and disclosure requirements. The new rules include changes to pricing used to estimate reserves, the ability to include non- traditional resources in reserves, the use of new technology for determining reserves and permitting disclosure of probable and possible reserves. The primary objectives of the revisions are to increase the transparency and information value of reserve disclosures and improve comparability among oil and gas companies. The rule is effective for annual reports on Form 10-K for fiscal years ending on or after December 31, 2009. The Company anticipates that the implementation of the new rule will provide a more meaningful and comprehensive understanding of the nature and associated risks of the Company s underlying oil and gas reserves. The Company is continuing to evaluate the impact of this release.

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ULTRA PETROLEUM CORP.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

2. OIL AND GAS PROPERTIES:

	June 30, 2009	December 31, 2008
Developed Properties:		
Acquisition, equipment, exploration, drilling and environmental costs	$ 3,249,934	$ 2,809,082
Less accumulated depletion, depreciation and amortization	(1,655,734)	(514,100)
	1,594,200	2,294,982
Unproven Properties*:		
Acquisition and exploration costs not being amortized		55,544
	$ 1,594,200	$ 2,350,526

* The Company holds interests in unproven properties in which leasehold costs and seismic costs related to these interests of $55.5 million were excluded from the amortization base at December 31, 2008. Exclusion from amortization is permitted in order to avoid distortion in the amortization per unit that could result if the cost of unevaluated properties with no proved reserves attributed to them was included in the amortization base. Effective January 1, 2009, the Company has determined that these costs are not significant enough to warrant exclusion from the amortization base and has begun amortizing the costs on a unit of production basis.

During the first quarter of 2009, the Company recorded a $1.0 billion ($673.0 million net of tax) non-cash write-down of the carrying value of the Company s proved oil and gas properties as of March 31, 2009, as a result of the ceiling test limitations, which is reflected as write-down of oil and gas properties in the accompanying consolidated statements of operations. The ceiling test was calculated based on March 31, 2009 wellhead prices of $2.47 per Mcf for natural gas and $33.91 per barrel for condensate.

3. LONG-TERM LIABILITIES:

	June 30, 2009	December 31, 2008
Bank indebtedness	$ 229,000	$ 270,000
Senior notes	535,000	300,000
Other long-term obligations	29,415	46,206
	$ 793,415	$ 616,206

Bank indebtedness: The Company (through its subsidiary) is a party to a revolving credit facility with a syndicate of banks led by JP Morgan Chase Bank, N.A. which matures in April 2012. This agreement provides an initial loan commitment of $500.0 million and may be increased to a maximum aggregate amount of $750.0 million at the request of the Company. Each bank has the right, but not the obligation, to increase the amount of its commitment as requested by the Company. In the event the existing banks increase their commitment to an amount less than the requested commitment amount, then it would be necessary to add new financial institutions to the credit facility.

Loans under the credit facility are unsecured and bear interest, at our option, based on (A) a rate per annum equal to the higher of the prime rate or the weighted average fed funds rate on overnight transactions during the preceding business day plus 50 basis points, or (B) a base Eurodollar rate, substantially equal to the LIBOR rate, plus a margin based on a grid of our consolidated leverage ratio (100.0 basis points per annum as of June 30, 2009).

ULTRA PETROLEUM CORP.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

At June 30, 2009, we had $229.0 million in outstanding borrowings and $271.0 million of available borrowing capacity under our credit facility.

The facility has restrictive covenants that include the maintenance of a ratio of consolidated funded debt to EBITDAX (earnings before interest, taxes, DD&A and exploration expense) not to exceed 31/2 times; and as long as our debt rating is below investment grade, the maintenance of an annual ratio of the net present value of our oil and gas properties to total funded debt of at least 1.75 to 1.00. At June 30, 2009, we were in compliance with all of our debt covenants under our credit facility.

Senior Notes, due 2016 and 2019: On March 5, 2009, our wholly-owned subsidiary, Ultra Resources, Inc., issued $235.0 million Senior Notes (the 2009 Senior Notes) pursuant to a Master Note Purchase Agreement dated March 6, 2008 as supplemented by a First Supplement thereto dated March 5, 2009 between the Company and the purchasers of the 2009 Senior Notes. The 2009 Senior Notes rank pari passu with the Company s bank credit facility. Payment of the 2009 Senior Notes is guaranteed by Ultra Petroleum Corp. and UP Energy Corporation. Of the 2009 Senior Notes, $173.0 million are 7.77% senior notes due March 1, 2019 and $62.0 million are 7.31% senior notes due March 1, 2016.

Proceeds from the sale of the 2009 Senior Notes were used to repay bank debt, but did not reduce the borrowings available to us under the revolving credit facility.

The 2009 Senior Notes are pre-payable in whole or in part at any time. The 2009 Senior Notes are subject to representations, warranties, covenants and events of default customary for a senior note financing. If payment default occurs, any note holder may accelerate its notes; if a non-payment default occurs, holders of 51% of the outstanding principal amount of the 2009 Senior Notes may accelerate all the 2009 Senior Notes. At June 30, 2009, we were in compliance with all of our debt covenants under the 2009 Senior Notes.

Senior Notes, due 2015 and 2018: On March 6, 2008, our wholly-owned subsidiary, Ultra Resources, Inc. issued $300.0 million Senior Notes (the 2008 Senior Notes) pursuant to a Master Note Purchase Agreement between the Company and the purchasers of the Notes. The 2008 Senior Notes rank pari passu with the Company s bank credit facility. Payment of the 2008 Senior Notes is guaranteed by Ultra Petroleum Corp. and UP Energy Corporation. Of the 2008 Senior Notes, $200.0 million are 5.92% senior notes due March 1, 2018 and $100.0 million are 5.45% senior notes due March 1, 2015.

Proceeds from the sale of the 2008 Senior Notes were used to repay bank debt, but did not reduce the borrowings available to us under the revolving credit facility. The 2008 Senior Notes are pre-payable in whole or in part at any time. The 2008 Senior Notes are subject to representations, warranties, covenants and events of default customary for a senior note financing. If payment default occurs, any note holder may accelerate its notes; if a non-payment default occurs, holders of 51% of the outstanding principal amount of the 2008 Senior Notes may accelerate all the 2008 Senior Notes. At June 30, 2009, we were in compliance with all of our debt covenants under the 2008 Senior Notes.

Other long-term obligations: These costs primarily relate to the long-term portion of production taxes payable and our asset retirement obligations.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

4. SHARE BASED COMPENSATION:

Valuation and Expense Information under SFAS 123R

The following table summarizes share-based compensation expense for the three and six months ended June 30, 2009 and 2008:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
Total cost of share-based payment plans	$ 4,690	$ 3,121	$ 8,432	$ 4,866
Amounts capitalized in fixed assets	$ 1,996	$ 1,220	$ 3,613	$ 2,111
Amounts charged against income, before income tax benefit	$ 2,694	$ 1,901	$ 4,819	$ 2,755
Amount of related income tax benefit recognized in income	$ 945	$ 667	$ 1,690	$ 967

The fair value of each share option award is estimated on the date of grant using a Black-Scholes pricing. The Company s employee stock options have various restrictions including vesting provisions and restrictions on transfers and hedging, among others, and are often exercised prior to their contractual maturity. Expected volatilities used in the fair value estimates are based on historical volatility of the Company s stock. The Company uses historical data to estimate share option exercises, expected term and employee departure behavior used in the Black-Scholes pricing model. Groups of employees (executives and non-executives) that have similar historical behavior are considered separately for purposes of determining the expected term used to estimate fair value. The assumptions utilized result from differing pre- and post-vesting behaviors among executive and non-executive groups. The risk-free rate for periods within the contractual term of the share option is based on the U.S. Treasury yield curve in effect at the time of grant. There were no stock options granted during the six months ended June 30, 2009.

Changes in Stock Options and Stock Options Outstanding

The following table summarizes the changes in stock options for the six months ended June 30, 2009 and the year ended December 31, 2008:

	Number of Options	Weighted Average Exercise Price (US$)
Balance, December 31, 2007	7,589	$ 0.25 to $67.73

Granted	299	$	51.14 to $98.87
Forfeited	(80)	$	51.60 to $85.05
Exercised	(3,595)	$	0.25 to $67.73
Balance, December 31, 2008	4,213	$	0.25 to $98.87
Granted			
Forfeited	(43)	$	51.60 to $78.55
Exercised	(163)	$	2.04 to $33.57
Balance, June 30, 2009	4,007	$	0.25 to $98.87

ULTRA PETROLEUM CORP.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

PERFORMANCE SHARE PLANS:

Long Term Incentive Plans. Each year since 2005, the Company has adopted a Long Term Incentive Plan (LTIP) in order to further align the interests of key employees with shareholders and to give key employees the opportunity to share in the long-term performance of the Company when specific corporate financial and operational goals are achieved. Each LTIP covers a performance period of three years. For 2007 and 2008, each LTIP had two components: an LTIP Stock Option Award and an LTIP Common Stock Award. In 2009, the Compensation Committee (the Committee) approved an award consisting only of performance-based restricted stock units to be awarded to each participant.

Under each LTIP, the Committee establishes a percentage of base salary for each participant which is multiplied by the participant s base salary to derive a Long Term Incentive Value (LTI Value). The LTIP Common Stock Award in 2007 and 2008 and the 2009 LTIP award of restricted stock units are performance-based and are measured over a three year performance period. For each LTIP award, the Committee establishes performance measures at the beginning of each performance period, and each participant is assigned threshold and maximum award levels in the event that actual performance is below or above target levels. For the 2007, 2008 and 2009 LTIP awards, the Committee established the following performance measures: return on equity, reserve replacement ratio, and production growth.

For the six months ended June 30, 2009, the Company recognized $2.4 million in pre-tax compensation expense related to the 2007 LTIP Common Stock Award, 2008 LTIP Common Stock Award and 2009 LTIP award of restricted stock units. For the six months ended June 30, 2008, the Company recognized $1.0 million in pre-tax compensation expense related to the 2006, 2007, and 2008 LTIP Common Stock Awards. The amounts recognized during the six months ended June 30, 2009 assumes that maximum performance objectives are attained. If the Company ultimately attains these performance objectives, the associated total compensation, estimated at June 30, 2009, for each of the three year performance periods is expected to be approximately $3.9 million, $3.7 million, and $9.6 million related to the 2007 LTIP Common Stock Award, 2008 LTIP Common Stock Award and 2009 LTIP award of restricted stock units, respectively. Additional awards of restricted stock units were granted to eligible employees during 2009 with estimated total compensation of $9.5 million over the three year performance period assuming that maximum performance objectives are attained. The 2006 LTIP Common Stock Award was paid in shares of the Company s stock to employees during the first quarter of 2009 and totaled $2.7 million.

Best in Class Program. In May 2008, the Company established the 2008 Best in Class Program for all permanent, full-time employees. Under the 2008 Best in Class Program, participants are eligible to receive a number of shares of the Company s common stock based on the performance of the Company. As with the LTIP, the 2008 Best in Class Program is measured over a three year performance period. The 2008 Best in Class Program recognizes and financially rewards the collective efforts of all of the Company s employees in achieving sustained industry leading performance and the enhancement of shareholder value. Under the 2008 Best in Class Program, on January 1, 2008 or the employment date if subsequent to January 1, 2008, eligible employees received a contingent award of stock units equal to $60,000 worth of the Company s common stock based on the average high and low share price on the first day of the performance period. Employees joining the Company after January 1, 2008 participate on a pro-rata basis based on their length of employment during the performance period.

The number of contingent units that will vest and become payable is based on the Company s performance relative to the industry during a three year performance period beginning January 1, 2008, and ending December 31, 2010, and are set at threshold (50%), target (100%), and maximum (150%) levels. For each vested unit, the participant will receive one share of common stock. The participant must be employed on the date the awards are distributed in order to receive the award.

ULTRA PETROLEUM CORP.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

For the six months ended June 30, 2009, the Company recognized $0.4 million in pre-tax compensation expense related to the 2008 Best in Class Program. For the six months ended June 30, 2008 the Company recognized $0.3 million in pre-tax compensation expense related to the 2008 Best in Class Program. The amount recognized for the six months ended June 30, 2009 and 2008 assumes that target performance levels are achieved. If the Company ultimately attains the target performance level, the associated total compensation related to the 2008 Best in Class Program is estimated at $3.9 million at June 30, 2009.

5. INCOME TAXES:

The following table summarizes the components of income tax (benefit) provision for the three and six months ended June 30, 2009 and 2008:

	For the Three Months Ended June 30,				For the Six Months Ended June 30,			
	2009		2008		2009		2008	
	$	Rate	$	Rate	$	Rate	$	Rate
Current State tax payments	$	0.0%	$ 6	0.0%	$ 23	0.0%	$ 16	0.0%
Current Federal tax credit		0.0%		0.0%		0.0%	(209)	(0.1)%
Deferred tax (benefit) expense	(13,497)	(34.6)%	63,483	35.3%	(290,436)	(35.1)%	110,703	35.7%
Income tax (benefit) provision	$ (13,497)	(34.6)%	$ 63,489	35.3%	$ (290,413)	(35.1)%	$ 110,510	35.6%

6. DERIVATIVE FINANCIAL INSTRUMENTS:

The Company s major market risk exposure is in the pricing applicable to its natural gas and oil production. Realized pricing is currently driven primarily by the prevailing price for the Company s Wyoming natural gas production. Historically, prices received for natural gas production have been volatile and unpredictable. Pricing volatility is expected to continue. Realized natural gas prices are derived from the financial statements which include the effects of realized gains and losses on commodity derivatives.

The Company relies on derivative instruments to manage its exposure to commodity price risk and to provide a level of certainty in the Company s forward cash flows supporting the Company s capital investment program. The Company enters into fixed price to index price swap agreements in order to mitigate its commodity price exposure on a portion of its natural gas production. The natural gas reference prices of these commodity derivative contracts are typically referenced to natural gas index prices as published by independent third parties such as Inside FERC Gas Market Report. The Company also utilizes fixed price forward gas sales to manage its commodity price exposure. These fixed price forward gas sales are considered normal sales in the ordinary course of business and outside the scope of SFAS No. 133.

Under SFAS No. 133, all derivative instruments are recorded on the balance sheet at fair value. Changes in the derivative s fair value are recognized currently in earnings unless specific hedge accounting criteria are met. For qualifying cash flow hedges, the unrealized gain or loss on the derivative is deferred in accumulated other comprehensive income (loss) to the extent the hedge is effective. Gains and losses on hedging instruments included in accumulated other comprehensive income (loss) are reclassified to oil and natural gas sales revenue in the period that the related production is delivered. Derivative contracts that do not qualify for hedge accounting treatment are recorded as derivative assets and liabilities at market value in the Consolidated Balance Sheets, and the associated unrealized gains and losses are recorded as current expense or income in the Consolidated Statements of Operations. Unrealized gains or losses on commodity derivatives represents the non-cash change in the fair value of these derivative instruments and does not impact operating cash flows on the Consolidated Statements of Cash Flows.

Effective November 3, 2008, the Company changed its method of accounting for natural gas commodity derivatives to reflect unrealized gains and losses on commodity derivative contracts in the income statement

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

rather than on the balance sheet. The net gain or loss in accumulated other comprehensive income at November 3, 2008 will remain on the balance sheet and the respective month s gains or losses will continue to be reclassified from accumulated other comprehensive income to earnings as the counterparty settlements affect earnings (January through December 2009). It is still considered probable that the original forecasted transactions will occur; therefore, the net gain or loss in accumulated other comprehensive income shall not be immediately reclassified into earnings. As a result of the de-designation on November 3, 2008, the company no longer has any derivative instruments which qualify for cash flow hedge accounting.

During the first quarter of 2009, the Company converted its physical, fixed price, forward natural gas sales to physical, indexed natural gas sales combined with financial swaps whereby the Company receives the fixed price and pays the variable price. This change provides operational flexibility to curtail gas production in the event of continued declines in natural gas prices. The contracts were converted at no cost to the Company and the conversion of these contracts to derivative instruments was effective upon entering into these transactions in March 2009, with upcoming settlements for production months through December 2010.

At June 30, 2009, the Company had the following open commodity derivative contracts to manage price risk on a portion of its natural gas production whereby the Company receives the fixed price and pays the variable price. See Note 7 for the detail of the asset and liability values of the following derivatives.

Type	Point of Sale	Remaining Contract Period	Volume-MMBTU/Day	Average Price/MMBTU	Fair Value June 30, 2009
Swap	Mid Continent	July 2009 October 2009	130,000	$ 4.99	$ 26,519
Swap	NW Rockies	July 2009 October 2009	130,000	$ 5.85	$ 48,166
Swap	NW Rockies	November 2009	50,000	$ 3.53	$ (220)
Swap	NW Rockies	July 2009 December 2009	100,000	$ 5.65	$ 43,272
Swap	NW Rockies	April 2010 October 2010	50,000	$ 5.05	$ 1,499
Swap	NW Rockies	January 2010 December 2010	50,000	$ 4.99	$ (2,432)
Swap	NW Rockies	January 2010 December 2011	160,000	$ 5.00	$ (60,436)
Swap	Northeast	January 2010 December 2011	30,000	$ 6.38	$ (4,532)

The following table summarizes the pre-tax realized and unrealized gains and losses the Company recognized related to its natural gas derivative instruments in the Consolidated Statements of Operations for the three and six months ended June 30, 2009 and 2008 (refer to Note 1(o) for details of unrealized gains or losses included in accumulated other comprehensive income in the Consolidated Balance Sheets):

Natural Gas Commodity Derivatives:	For the Three Months Ended June 30, 2009	2008	For the Six Months Ended June 30, 2009	2008
Realized gain (loss) on derivatives(1)	$ 99,205	$ (14,119)	$ 119,561	$ (14,119)

Unrealized gain (loss) on commodity derivatives(1)	$ (159,903)	$ 2,523	$ 26,169	$ (25,150)
Total gain (loss) on commodity derivatives	$ (60,698)	$ (11,596)	$ 145,730	$ (39,269)

(1) Included in gain (loss) on commodity derivatives in the Consolidated Statements of Operations.

7. FAIR VALUE MEASUREMENTS:

On September 15, 2006, the FASB issued SFAS No. 157, Fair Value Measurement . We adopted SFAS No. 157 effective January 1, 2008. SFAS No. 157 defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the

ULTRA PETROLEUM CORP.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

measurement date and establishes a three level hierarchy for measuring fair value. The statement requires fair value measurements be classified and disclosed in one of the following categories:

Level 1: Quoted prices (unadjusted) in active markets for identical assets and liabilities that we have the ability to access at the measurement date.

Level 2: Inputs other than quoted prices included within Level 1 that are either directly or indirectly observable for the asset or liability, including quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, inputs other than quoted prices that are observable for the asset or liability, and inputs that are derived from observable market data by correlation or other means. Instruments categorized in Level 2 include non-exchange traded derivatives such as over-the-counter forwards and swaps.

Level 3: Unobservable inputs for the asset or liability, including situations where there is little, if any, market activity for the asset or liability.

The valuation assumptions utilized to measure the fair value of the Company s commodity derivatives were observable inputs based on market data obtained from independent sources and are considered Level 2 inputs (quoted prices for similar assets, liabilities (adjusted) and market-corroborated inputs).

The following table presents for each hierarchy level our assets and liabilities, including both current and non-current portions, measured at fair value on a recurring basis, as of June 30, 2009. The company has no derivative instruments which qualify for cash flow hedge accounting.

	Level 1	Level 2	Level 3	Total
Assets:				
Current derivative asset	$	$ 125,652	$	$ 125,652
Non-current derivative asset	$	$ 2,441	$	$ 2,441
Liabilities:				
Current derivative liability	$	$ 3,665	$	$ 3,665
Non-current derivative liability	$	$ 72,592	$	$ 72,592

In consideration of counterparty credit risk, the Company assessed the possibility of whether each counterparty to the derivative would default by failing to make any contractually required payments as scheduled in the derivative instrument in determining the fair value. Additionally, the Company considers that it is of substantial credit quality and has the financial resources and willingness to meet its potential repayment obligations associated with the derivative transactions.

For those non-financial assets and liabilities measured or disclosed at fair value on a non-recurring basis, primarily asset retirement obligations, SFAS No. 157-2 was effective January 1, 2009. Implementation of this portion of the standard did not have a material impact on consolidated results of operations, financial position or liquidity.

Fair Market Value of Financial Instruments

The estimated fair value of financial instruments is the amount at which the instrument could be exchanged currently between willing parties. The carrying amounts reported in the consolidated balance sheet for cash and cash equivalents, accounts receivable, and accounts payable approximate fair value due to the immediate or short-term maturity of these financial instruments. We use available market data and valuation methodologies to estimate the fair value of debt. This disclosure is presented in accordance with SFAS 107, Disclosures about Fair Value of Financial Instruments and does not impact our financial position, results of operations or cash flows.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

In April 2009, the FASB issued FSP FAS 107-1 and Accounting Principles Board (APB) Opinion No. 28-1 (collectively, FSP FAS 107-1), Interim Disclosures about Fair Value of Financial Instruments. FSP FAS 107-1 amends SFAS No. 107, Disclosures about Fair Value of Financial Instruments, to require an entity to provide disclosures about fair value of financial instruments in interim financial information. The FSP FAS 107-1 also amends APB Opinion No. 28, Interim Financial Reporting, to require those disclosures about the fair value of financial instruments in summarized financial information at interim reporting periods. Under FSP FAS 107-1, the Company is required to include disclosures about the fair value of its financial instruments whenever it issues financial information for interim reporting periods. In addition, the Company is required to disclose in the body or in the accompanying notes of its summarized financial information for interim reporting periods and in its financial statements for annual reporting periods, the fair value of all financial instruments for which it is practicable to estimate that value, whether recognized or not recognized in the statement of financial position. FSP FAS 107-1 is effective for periods ending after June 15, 2009 and its adoption had no impact on the Company s results of operations and financial condition but requires additional disclosures about the fair value of financial instruments in the financial statements.

	June 30, 2009		December 31, 2008	
	Carrying Amount	**Estimated Fair Value**	**Carrying Amount**	**Estimated Fair Value**
Long-Term Debt				
5.45% Notes due 2015	$ 100,000	$ 99,899	$ 100,000	$ 93,836
5.92% Notes due 2018	200,000	197,765	200,000	180,729
7.31% Notes due 2016	62,000	67,690		
7.77% Notes due 2019	173,000	190,540		
Credit Facility	229,000	229,000	270,000	270,000
Long-Term Debt	$ 764,000	$ 784,894	$ 570,000	$ 544,565

8. LEGAL PROCEEDINGS:

The Company is currently involved in various routine disputes and allegations incidental to its business operations. While it is not possible to determine the ultimate disposition of these matters, the Company believes that the resolution of all such pending or threatened litigation is not likely to have a material adverse effect on the Company s financial position or results of operations.

9. SUBSEQUENT EVENTS:

In May 2009, the FASB issued SFAS No. 165, Subsequent Events (SFAS No. 165), setting forth principles and requirements to be applied to the accounting for and disclosure of subsequent events. The statement sets forth the period after the balance sheet date during which management shall evaluate events or transactions that may occur for potential recognition or disclosure in the financial statements, the circumstances under which events or transactions occurring after the balance sheet date shall be recognized in the financial statements and the required disclosures about events or transactions that occurred after the balance sheet date. SFAS No. 165 is effective for interim or annual reporting periods ending after June 15, 2009, and shall be applied prospectively. Accordingly, the Company has adopted this pronouncement for the quarter ended June 30, 2009. The Company has evaluated the period subsequent to June 30, 2009 and through August 4, 2009 (the date the financial statements were available to be issued) for events that did not exist at the balance sheet date but arose after that date and determined that no subsequent events arose that should be disclosed in order to keep the financial statements from being misleading.

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

The following discussion of the financial condition and operating results of the Company should be read in conjunction with the consolidated financial statements and related notes of the Company. Except as otherwise indicated, all amounts are expressed in U.S. dollars. We operate in one industry segment, natural gas and oil exploration and development with one geographical segment, the United States.

The Company currently generates substantially all of its revenue, earnings and cash flow from the production and sales of natural gas and oil from its property in southwest Wyoming. The price of natural gas in the southwest Wyoming region is a critical factor to the Company s business. The price of gas in southwest Wyoming historically has been volatile. The average realizations for the period 2003-2009 have ranged from $2.33 to $8.81 per Mcf. This volatility could be detrimental to the Company s financial performance. The Company seeks to limit the impact of this volatility on its results by entering into fixed price forward physical delivery contracts and swap agreements for gas in southwest Wyoming. During the quarter ended June 30, 2009, the average price realization for the Company s natural gas was $5.04 per Mcf, including realized gain or loss on commodity derivatives. The Company s average price realization for natural gas was $2.71 per Mcf, excluding the realized gain or loss on commodity derivatives. (See Note 6).

The Company has grown its natural gas and oil production significantly over the past three years and management believes it has the ability to continue growing production by drilling already identified locations on its leases in Wyoming. The Company delivered 30% production growth on an Mcfe basis during the quarter ended June 30, 2009 as compared to the same quarter in 2008.

The Company currently conducts operations exclusively in the United States. Substantially all of the oil and natural gas activities are conducted jointly with others and, accordingly, amounts presented reflect only the Company s proportionate interest in such activities. Inflation has not had a material impact on the Company s results of operations and is not expected to have a material impact on the Company s results of operations in the future.

In 2008 and the first half of 2009, we saw significant changes in the business environment in which we operate, including severe economic uncertainty, increasing market volatility and continued tightening of credit markets. These market conditions contributed to record high commodity prices during most of 2008 and nearly unprecedented drops in these commodity prices in the second half of 2008 and the first half of 2009. We believe we are well positioned to weather the current economic downturn because of our status as a low cost operator in the industry and our financial flexibility. Although we expect that our net cash provided by operating activities may be negatively affected by general economic conditions, we believe that we will continue to generate strong cash flow from operations, which, along with our available cash, will provide sufficient liquidity to allow us to return value to our shareholders. While it is possible that we may not have access to the credit markets on acceptable terms, we expect to rely on our available cash, our existing credit facility and the cash we generate from our operations to meet our obligations and fund our capital expenditures and operations over the next twelve months. A continued, long-term disruption in the credit markets could make financing more expensive or unavailable, which could have a material adverse effect on our operations.

Rockies Express Pipeline. In December 2005, the Company agreed to become an anchor shipper on the Rockies Express Pipeline (REX) securing pipeline infrastructure providing sufficient capacity to transport a portion of our natural gas production away from southwest Wyoming and to provide for reasonable basis differentials for our natural gas in the future. The Company s commitment involves capacity of 200,000 MMBtu per day of natural gas for a term of 10 years (beginning in the first quarter of 2008 when REX West became operational), and the Company is obligated to pay REX certain demand charges related to its rights to hold this firm transportation capacity as an anchor shipper.

The pipeline is being built in two phases: REX West (Wyoming to Missouri in service) and REX East (Missouri to Ohio under construction). The REX partners have recently updated guidance on the timing for completion of various portions of REX East. As of June 29, 2009, REX announced that service began on the portion of the REX East pipeline from Audrain County, Missouri to the Lebanon Hub in

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Warren County, Ohio with capacity up to 1.8 billion cubic feet of natural gas per day. This section of REX East includes interconnects to NGPL, Ameren, Trunkline, Midwestern Gas Transmission, Panhandle Eastern, Texas Eastern, Dominion transmission and Columbia Gas with future interconnects to Texas Gas, ANR, Citizens and Vectren. REX further advised that the balance of the REX East pipeline eastward to Clarington, Ohio is expected to be placed into service by November 1, 2009.

Derivative Instruments and Hedging Activities. The Company relies on derivative instruments to manage its exposure to commodity price risk. The Company enters into fixed price to index price swap agreements in order to mitigate its commodity price exposure on a portion of its natural gas production. The natural gas reference prices of these commodity derivative contracts are typically referenced to natural gas index prices as published by independent third parties. The Company also utilizes fixed price forward gas sales to manage its commodity price exposure. These fixed price forward gas sales are considered normal sales in the ordinary course of business and outside the scope of SFAS No. 133.

Effective November 3, 2008, the Company has changed its method of accounting for natural gas commodity derivatives to reflect unrealized gains and losses on commodity derivative contracts in the income statement rather than on the balance sheet. The Company has historically followed hedge accounting for its natural gas hedges. Under this accounting method, the unrealized gain or loss on qualifying cash flow hedges (calculated on a mark to market basis, net of tax) was recorded on the balance sheet in stockholders equity as accumulated other comprehensive income (loss). When an unrealized hedging gain or loss was realized upon contract expiration, it was reclassified into earnings through inclusion in natural gas sales revenues. The Company will continue to record the fair value of its commodity derivatives as an asset or liability on the Consolidated Balance Sheets, but will record the changes in the fair value of its commodity derivatives in the Consolidated Statements of Operations as an unrealized gain or loss on commodity derivatives. There will be no resulting effect on overall cash flow, total assets, total liabilities or total stockholders equity, and there is no impact on any of the financial covenants under the Company s Senior Credit Facility, 2008 Senior Notes or 2009 Senior Notes (See Note 3).

During the first quarter of 2009, the Company converted its physical, fixed price, forward natural gas sales to physical, indexed natural gas sales combined with financial swaps whereby the Company receives the fixed price and pays the variable price. This change provides operational flexibility to curtail gas production in the event of continued declines in natural gas prices. The contracts were converted at no cost to the Company and the conversion of these contracts to derivative instruments was effective upon entering into these transactions in March 2009, with upcoming settlements for production months through December 2010.

Fair Value Measurements. The Company adopted SFAS No. 157 as of January 1, 2008. The implementation of SFAS No. 157 was applied prospectively for our assets and liabilities that are measured at fair value on a recurring basis, primarily our commodity derivatives, with no material impact on consolidated results of operations, financial position or liquidity. See Note 7 for additional information. For those non-financial assets and liabilities measured or disclosed at fair value on a non-recurring basis, primarily asset retirement obligations, SFAS No. 157-2 was effective January 1, 2009. Implementation of this portion of the standard did not have a material impact on consolidated results of operations, financial position or liquidity.

SFAS No. 157 defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at measurement date and establishes a three level hierarchy for measuring fair value. The valuation assumptions utilized to measure the fair value of the Company s commodity derivatives were observable inputs based on market data obtained from independent sources and are considered Level 2 inputs (quoted prices for similar assets, liabilities (adjusted) and market-corroborated inputs).

In consideration of counterparty credit risk, the Company assessed the possibility of whether each counterparty to the derivative would default by failing to make any contractually required payments as scheduled in the derivative instrument in determining the fair value. Additionally, the Company considers that it is of substantial credit quality and has the financial resources and willingness to meet its potential repayment obligations associated with the derivative transactions.

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The fair values summarized below were determined in accordance with the requirements of SFAS No. 157. In addition, we aligned the categories below with the Level 1, 2, and 3 fair value measurements as defined by SFAS No. 157. The balance of net unrealized gains and losses recognized for our energy-related derivative instruments at June 30, 2009 is summarized in the following table based on the inputs used to determine fair value:

	Level 1(a)	Level 2(b)	Level 3(c)	Total
Assets:				
Current derivative asset	$	$ 125,652	$	$ 125,652
Non-current derivative asset	$	$ 2,441	$	$ 2,441
Liabilities:				
Current derivative liability	$	$ 3,665	$	$ 3,665
Non-current derivative liability	$	$ 72,592	$	$ 72,592

(a) Values represent observable unadjusted quoted prices for traded instruments in active markets.

(b) Values with inputs that are observable directly or indirectly for the instrument, but do not qualify for Level 1.

(c) Values with a significant amount of inputs that are not observable for the instrument.

Asset Retirement Obligation. The initial estimated retirement obligation of properties is recognized as a liability, with an associated increase in oil and gas properties for the asset retirement cost. Accretion expense is recognized over the estimated productive life of the related assets. If the fair value of the estimated asset retirement obligation changes, an adjustment is recorded to both the asset retirement obligation and the asset retirement cost. Revisions in estimated liabilities can result from revisions of estimated inflation rates, changes in service and equipment costs and changes in the estimated timing of settling asset retirement obligations.

Share-Based Payment Arrangements. The Company applies Statement of Financial Accounting Standards No. 123 (revised 2004), Share-Based Payment (SFAS No. 123R) which requires the measurement and recognition of compensation expense for all share-based payment awards made to employees and directors, including employee stock options, based on estimated fair values. Share-based compensation expense recognized under SFAS No. 123R for the six months ended June 30, 2009 and 2008 was $4.8 million and $2.8 million, respectively. At June 30, 2009, there was $6.5 million of total unrecognized compensation cost related to non-vested share-based compensation arrangements granted under stock option plans. That cost is expected to be recognized over a weighted average period of 1.2 years. See Note 4 for additional information.

SFAS No. 123R requires companies to estimate the fair value of share-based payment awards on the date of grant using an option-pricing model. The Company utilized a Black-Scholes option pricing model to measure the fair value of stock options granted to employees. The value of the portion of the award that is ultimately expected to vest is recognized as expense over the requisite service period in the Company s Consolidated Statement of Operations. The Company s determination of fair value of share-based payment awards on the date of grant using an option-pricing model is affected by the Company s stock price as well as assumptions regarding a number of highly complex and subjective variables. These variables include, but are not limited to, the Company s expected stock price volatility over the term of the awards and actual and projected employee stock option exercise behaviors.

Write-down of oil and gas properties. The Company uses the full cost method of accounting for oil and gas operations whereby all costs associated with the exploration for and development of oil and gas reserves are capitalized on a country-by-country basis. Such costs include land acquisition costs, geological and geophysical expenses, carrying charges on non-producing properties, costs of drilling both productive and non-productive wells and overhead charges directly related to acquisition, exploration and development activities. Substantially all of the oil and gas activities are conducted jointly with others and, accordingly, the amounts reflect only the Company s proportionate interest in such activities.

Companies that use the full cost method of accounting for oil and natural gas exploration and development activities are required to perform a ceiling test calculation each quarter. The full cost ceiling test

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is an impairment test prescribed by SEC Regulation S-X Rule 4-10. The ceiling test is performed quarterly on a country-by-country basis utilizing prices in effect on the last day of the quarter. SEC regulation S-X Rule 4-10 states that if prices in effect at the end of a quarter are the result of a temporary decline and prices improve prior to the issuance of the financial statements, the increased price may be applied in the computation of the ceiling test. The ceiling limits such pooled costs to the aggregate of the present value of future net revenues attributable to proved crude oil and natural gas reserves discounted at 10% plus the lower of cost or market value of unproved properties less any associated tax effects. If such capitalized costs exceed the ceiling, the Company will record a write-down to the extent of such excess as a non-cash charge to earnings. Any such write-down will reduce earnings in the period of occurrence and result in lower DD&A expense in future periods. A write-down may not be reversed in future periods, even though higher oil and natural gas prices may subsequently increase the ceiling.

During the first quarter of 2009, the Company recorded a $1.0 billion ($673.0 million net of tax) non-cash write-down of the carrying value of the Company s proved oil and gas properties as of March 31, 2009, as a result of the ceiling test limitations, which is reflected as write-down of oil and gas properties in the accompanying consolidated statements of operations. The ceiling test was calculated based on March 31, 2009 wellhead prices of $2.47 per Mcf for natural gas and $33.91 per barrel for condensate.

The calculation of the ceiling test is based upon estimates of proved reserves. There are numerous uncertainties inherent in estimating quantities of proved reserves, in projecting the future rates of production and in the timing of development activities. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of drilling, testing and production subsequent to the date of the estimate may justify revision of such estimate. Accordingly, reserve estimates are often different from the quantities of oil and natural gas that are ultimately recovered.

RESULTS OF OPERATIONS

QUARTER ENDED JUNE 30, 2009 VS. QUARTER ENDED JUNE 30, 2008

During the quarter ended June 30, 2009, production increased 30% on a gas equivalent basis to 44.5 Bcfe from 34.3 Bcfe for the same quarter in 2008 attributable to the Company s successful drilling activities during 2008 and in the first six months of 2009. Realized natural gas prices, including realized gain and loss on commodity derivatives, decreased 37% to $5.04 per Mcf in the second quarter of 2009 as compared to $8.06 for the same quarter of 2008. During the three months ended June 30, 2009, the Company s average price for natural gas was $2.71 per Mcf, excluding realized gains and losses on commodity derivatives. The decrease in average natural gas prices partially offset by the increase in production contributed to a 58% decrease in revenues to $130.3 million as compared to $308.2 million in 2008.

Lease operating expense (LOE) increased to $10.1 million during the second quarter of 2009 compared to $8.6 million during the same period in 2008 due primarily to increased production volumes during the quarter ended June 30, 2009. On a unit of production basis, LOE costs decreased to $0.23 per Mcfe at June 30, 2009 compared to $0.25 per Mcfe at June 30, 2008 largely as a result of increased production volumes and a higher mix of Ultra operated production during the quarter ended June 30, 2009.

During the three months ended June 30, 2009, production taxes were $12.7 million compared to $35.8 million during the same period in 2008, or $0.29 per Mcfe, compared to $1.04 per Mcfe. The decrease in per unit taxes is attributable to decreased sales revenues as a result of lower realized gas prices during the quarter ended June 30, 2009 as compared to the same period in 2008. Production taxes are calculated based on a percentage of revenue from production.

Gathering fees increased to $11.6 million for the three months ended June 30, 2009 compared to $8.8 million during the same period in 2008 largely due to increased production volumes. On a per unit basis, gathering fees remained flat at $0.26 per Mcfe for the three months ended June 30, 2009 as compared to the same period in 2008.

To secure pipeline infrastructure providing sufficient capacity to transport a portion of the Company s natural gas production away from southwest Wyoming and to provide for reasonable basis differentials for its

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natural gas, the Company incurred firm transportation charges totaling $13.2 million for the quarter ended June 30, 2009 as compared to $12.0 million for the same period in 2008 in association with REX Pipeline transportation charges. On a per unit basis, transportation charges decreased to $0.30 per Mcfe (on total company volumes) for the three months ended June 30, 2009 as compared to $0.35 per Mcfe (on total company volumes) for the same period in 2008 as a result of increased production volumes.

Depletion, depreciation and amortization (DD&A) expenses increased to $45.0 million during the three months ended June 30, 2009 from $42.8 million for the same period in 2008, attributable to increased production volumes partially offset by a lower depletion rate due mainly to a lower depletable base as a result of the ceiling test write-down during the first quarter of 2009. On a unit basis, DD&A decreased to $1.01 per Mcfe for the quarter ended June 30, 2009 from $1.25 for the quarter ended June 30, 2008. The Company recorded a $1.0 billion non-cash write-down of the carrying value of the Company s proved oil and gas properties at March 31, 2009 as a result of ceiling test limitations. Under the full cost method of accounting, the ceiling test limits pooled costs to the aggregate of the present value of future net revenues attributable to proved crude oil and natural gas reserves discounted at 10% plus the lower of cost or market value of unproved properties less any associated tax effects. The capitalized costs exceeded the ceiling limitation at March 31, 2009 and the Company recorded a write-down to the extent of the excess as a non-cash charge to earnings. The write-down reduced earnings in first quarter of 2009 and results in lower DD&A expense in future periods.

General and administrative expenses increased to $5.7 million ($0.13 per Mcfe) for the quarter ended June 30, 2009 compared to $4.4 million ($0.13 per Mcfe) for the same period in 2008. The increase in general and administrative expenses is primarily attributable to increased headcount and related compensation.

Interest expense increased to $9.9 million during the quarter ended June 30, 2009 compared to $4.5 million during the same period in 2008 as a result of increased borrowings. At June 30, 2009, the Company had $764.0 million in borrowings outstanding.

During the quarter ended June 30, 2009, the Company recognized $99.2 million related to realized gain on commodity derivatives and $159.9 million in unrealized loss on commodity derivatives as compared to $14.1 million related to realized loss on commodity derivatives and $2.5 million in unrealized gain on commodity derivatives during the quarter ended June 30, 2008. The realized gain or loss on commodity derivatives relates to actual amounts received or paid under these derivative contracts while the unrealized gain or loss on commodity derivatives represents the change in the fair market value of these derivative instruments.

The Company recognized a loss before income taxes of $39.0 million for the quarter ended June 30, 2009 compared with income of $179.9 million for the same period in 2008. The decrease in earnings is primarily a result of decreased natural gas prices and non-cash, unrealized losses on commodity derivatives partially offset by increased production during the three months ended June 30, 2009 as compared to the same period in 2008.

The income tax benefit recognized for the quarter ended June 30, 2009 was $13.5 million compared with an income tax provision of $63.5 million for the three months ended June 30, 2008 due to a net loss during the quarter ended June 30, 2009 primarily as a result of non-cash, unrealized losses on commodity derivatives.

For the three months ended June 30, 2009, the Company recognized a net loss of $25.5 million or $0.17 per diluted share as compared with net income of $116.9 million or $0.74 per diluted share for the same period in 2008 primarily attributable to decreased natural gas prices and non-cash, unrealized losses on commodity derivatives partially offset by increased production during the three months ended June 30, 2009 as compared to the same period in 2008.

SIX MONTHS ENDED JUNE 30, 2009 VS. SIX MONTHS ENDED JUNE 30, 2008

During the six months ended June 30, 2009, production increased 27% on a gas equivalent basis to 86.6 Bcfe from 68.4 Bcfe for the same period in 2008 attributable to the Company s successful drilling activities during 2008 and in the first six months of 2009. Realized natural gas prices, including realized gain

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and loss on commodity derivatives, decreased 39% to $4.76 per Mcf during the six months ended June 30, 2009 as compared to $7.86 for the same period in 2008. During the six months ended June 30, 2009, the Company s average price for natural gas was $3.31 per Mcf, excluding realized gains and losses on commodity derivatives. The decrease in average natural gas prices partially offset by the increase in production contributed to a 49% decrease in revenues for the six months ended June 30, 2009 to $298.3 million as compared to $579.4 million in 2008.

Lease operating expense (LOE) increased to $20.4 million during the six months ended June 30, 2009 compared to $19.3 million during the same period in 2008 due primarily to increased production volumes and partially offset by decreased costs related to water disposal on non-operated properties during the six months ended June 30, 2009. On a unit of production basis, LOE costs decreased to $0.24 per Mcfe at June 30, 2009 compared to $0.28 per Mcfe at June 30, 2008 as a result of increased production volumes and a higher mix of Ultra operated production during the six months ended June 30, 2009.

During the six months ended June 30, 2009, production taxes were $30.1 million compared to $66.7 million during the same period in 2008, or $0.35 per Mcfe, compared to $0.98 per Mcfe. The decrease in per unit taxes is attributable to decreased sales revenues as a result of lower realized gas prices during the six months ended June 30, 2009 as compared to the same period in 2008. Production taxes are calculated based on a percentage of revenue from production.

Gathering fees increased to $22.4 million for the six months ended June 30, 2009 compared to $18.8 million during the same period in 2008 largely due to increased production volumes. On a per unit basis, gathering fees decreased to $0.26 per Mcfe for the six months ended June 30, 2009 as compared to $0.27 per Mcfe for the same period in 2008.

To secure pipeline infrastructure providing sufficient capacity to transport a portion of the Company s natural gas production away from southwest Wyoming and to provide for reasonable basis differentials for its natural gas, the Company incurred firm transportation charges totaling $26.5 million for the period ended June 30, 2009 as compared to $21.7 million for the same period in 2008 in association with REX Pipeline transportation charges. On a per unit basis, transportation charges decreased to $0.31 per Mcfe (on total company volumes) for the six months ended June 30, 2009 as compared to $0.32 per Mcfe (on total company volumes) for the same period in 2008.

DD&A increased to $105.6 million during the period ended June 30, 2009 from $85.0 million for the same period in 2008, attributable to increased production volumes, partially offset by a lower depletion rate due mainly to a lower depletable base as a result of the ceiling test write-down during the first quarter of 2009. On a unit basis, DD&A decreased to $1.22 per Mcfe at June 30, 2009 from $1.24 at June 30, 2008. The Company recorded a $1.0 billion non-cash write-down of the carrying value of the Company s proved oil and gas properties at March 31, 2009 as a result of ceiling test limitations. Under the full cost method of accounting, the ceiling test limits pooled costs to the aggregate of the present value of future net revenues attributable to proved crude oil and natural gas reserves discounted at 10% plus the lower of cost or market value of unproved properties less any associated tax effects. The capitalized costs exceeded the ceiling limitation at March 31, 2009 and the Company recorded a write-down to the extent of the excess as a non-cash charge to earnings. The write-down reduced earnings in first quarter of 2009 and results in lower DD&A expense in future periods.

General and administrative expenses increased to $10.2 million ($0.12 per Mcfe) for the period ended June 30, 2009 compared to $8.8 million ($0.13 per Mcfe) for the same period in 2008. The increase in general and administrative expenses is primarily attributable to increased headcount and related compensation.

Interest expense increased to $17.2 million during the period ended June 30, 2009 compared to $9.8 million during the same period in 2008 as a result of increased borrowings during the period ended June 30, 2009. At June 30, 2009, the Company had $764.0 million in borrowings outstanding.

Other expense increased to $3.1 million as of June 30, 2009 primarily as a result of rig termination payments during the period ended June 30, 2009.

During the six months ended June 30, 2009, the Company recognized $119.6 million and $26.2 million related to realized gain on commodity derivatives and unrealized gain on commodity derivatives, respectively as compared to $14.1 million related to realized loss on commodity derivatives and $25.2 million in unrealized loss on commodity derivatives during the six months ended June 30, 2008. The realized gain or loss on commodity derivatives relates to actual amounts received or paid under these derivative contracts while the unrealized gain or loss on commodity derivatives represents the change in the fair market value of these derivative instruments.

The Company recognized a loss before income taxes of $828.5 million for the six months ended June 30, 2009 compared with income of $310.3 million for the same period in 2008. The decrease in earnings is primarily a result of the non-cash write-down of oil and gas properties associated with the ceiling test limitation, decreased natural gas prices partially offset by increased production and gains on commodity derivatives during the six months ended June 30, 2009 as compared to the same period in 2008.

The income tax benefit recognized for the six months ended June 30, 2009 was $290.4 million compared with an income tax provision of $110.5 million for the six months ended June 30, 2008 due to a net loss during the six months ended June 30, 2009 primarily as a result of the non-cash write-down of oil and gas properties associated with the ceiling test limitation.

For the six months ended June 30, 2009, the Company recognized a net loss of $538.1 million or $3.56 per diluted share as compared with net income of $200.2 million or $1.27 per diluted share for the same period in 2008 primarily attributable to the non-cash write-down of oil and gas properties associated with the ceiling test limitation, decreased natural gas prices partially offset by increased production and gains on commodity derivatives during the six months ended June 30, 2009 as compared to the same period in 2008.

The discussion and analysis of the Company s financial condition and results of operations is based upon consolidated financial statements, which have been prepared in accordance with U.S. GAAP. In addition, application of generally accepted accounting principles requires the use of estimates, judgments and assumptions that affect the reported amounts of assets and liabilities as of the date of the financial statements as well as the revenues and expenses reported during the period. Changes in these estimates, judgments and assumptions will occur as a result of future events, and, accordingly, actual results could differ from amounts estimated.

LIQUIDITY AND CAPITAL RESOURCES

During the six month period ended June 30, 2009, the Company relied on cash provided by operations along with borrowings under the senior credit facility and the issuance of the 2009 Senior Notes to finance its capital expenditures. The Company participated in the drilling of 165 wells in Wyoming and Pennsylvania. For the six month period ended June 30, 2009, net capital expenditures were $382.4 million. At June 30, 2009, the Company reported a cash position of $9.3 million compared to $60.3 million at June 30, 2008. Working capital at June 30, 2009 was $19.4 million compared to a deficit of $136.7 million at June 30, 2008. At June 30, 2009, we had $229.0 million in outstanding borrowings and $271.0 million of available borrowing capacity under our credit facility. In addition, the Company had $300.0 million and $235.0 million outstanding under its 2008 Senior Notes and 2009 Senior Notes, respectively (See Note 3). Other long-term obligations of $29.4 million at June 30, 2009 is comprised of items payable in more than one year, primarily related to production taxes and our asset retirement obligation.

The Company s positive cash provided by operating activities, along with availability under the senior credit facility, are projected to be sufficient to fund the Company s budgeted capital expenditures for 2009, which are currently projected to be $735.0 million. Of the $735.0 million budget, the Company plans to allocate approximately 85% to Wyoming and 15% to Pennsylvania.

Bank indebtedness. The Company (through its subsidiary) is a party to a revolving credit facility with a syndicate of banks led by JP Morgan Chase Bank, N.A. which matures in April 2012. This agreement provides an initial loan commitment of $500.0 million and may be increased to a maximum aggregate amount of $750.0 million at the request of the Company. Each bank has the right, but not the obligation, to increase the amount of its commitment as requested by the Company. In the event the existing banks increase their commitment to an amount less than the requested commitment amount, then it would be necessary to add new financial institutions to the credit facility.

Loans under the credit facility are unsecured and bear interest, at our option, based on (A) a rate per annum equal to the higher of the prime rate or the weighted average fed funds rate on overnight transactions during the preceding business day plus 50 basis points, or (B) a base Eurodollar rate, substantially equal to the LIBOR rate, plus a margin based on a grid of our consolidated leverage ratio (100.0 basis points per annum as of June 30, 2009).

The facility has restrictive covenants that include the maintenance of a ratio of consolidated funded debt to EBITDAX (earnings before interest, taxes, DD&A and exploration expense) not to exceed 31/2 times; and as long as our debt rating is below investment grade, the maintenance of an annual ratio of the net present value of our oil and gas properties to total funded debt of at least 1.75 to 1.00. At June 30, 2009, we were in compliance with all of our debt covenants under our credit facility.

Senior Notes, due 2016 and 2019: On March 5, 2009, our wholly-owned subsidiary, Ultra Resources, Inc., issued $235.0 million Senior Notes pursuant to a Master Note Purchase Agreement dated March 6, 2008 as supplemented by a First Supplement thereto dated March 5, 2009 between the Company and the purchasers of the 2009 Senior Notes. The 2009 Senior Notes rank pari passu with the Company s bank credit facility. Payment of the 2009 Senior Notes is guaranteed by Ultra Petroleum Corp. and UP Energy Corporation. Of the 2009 Senior Notes, $173.0 million are 7.77% senior notes due March 1, 2019 and $62.0 million are 7.31% senior notes due March 1, 2016.

Proceeds from the sale of the 2009 Senior Notes were used to repay bank debt, but did not reduce the borrowings available to us under the revolving credit facility.

The 2009 Senior Notes are pre-payable in whole or in part at any time. The 2009 Senior Notes are subject to representations, warranties, covenants and events of default customary for a senior note financing. If payment default occurs, any note holder may accelerate its notes; if a non-payment default occurs, holders of 51% of the outstanding principal amount of the 2009 Senior Notes may accelerate all the 2009 Senior Notes. At June 30, 2009, we were in compliance with all of our debt covenants under the 2009 Senior Notes.

Senior Notes, due 2015 and 2018: On March 6, 2008, our wholly-owned subsidiary, Ultra Resources, Inc. issued $300.0 million Senior Notes pursuant to a Master Note Purchase Agreement between the Company and the purchasers of the Notes. The 2008 Senior Notes rank pari passu with the Company s bank credit facility. Payment of the 2008 Senior Notes is guaranteed by Ultra Petroleum Corp. and UP Energy Corporation. Of the 2008 Senior Notes, $200.0 million are 5.92% senior notes due March 1, 2018 and $100.0 million are 5.45% senior notes due March 1, 2015.

Proceeds from the sale of the 2008 Senior Notes were used to repay bank debt, but did not reduce the borrowings available to us under the revolving credit facility.

The 2008 Senior Notes are pre-payable in whole or in part at any time. The 2008 Senior Notes are subject to representations, warranties, covenants and events of default customary for a senior note financing. If payment default occurs, any note holder may accelerate its notes; if a non-payment default occurs, holders of 51% of the outstanding principal amount of the 2008 Senior Notes may accelerate all the 2008 Senior Notes. At June 30, 2009, we were in compliance with all of our debt covenants under the 2008 Senior Notes.

Operating Activities. During the six months ended June 30, 2009, net cash provided by operating activities was $240.4 million, a 40% decrease from $403.3 million for the same period in 2008. The decrease in net cash provided by operating activities was largely attributable to the decrease in realized natural gas prices partially offset by increased production during the six months ended June 30, 2009 as compared to the same period in 2008.

Investing Activities. During the six months ended June 30, 2009, net cash used in investing activities was $441.6 million as compared to $372.7 million for the same period in 2008. The increase in net cash used in investing activities is largely due to the timing of payments associated with capital costs incurred during

2008 and paid during the first six months of 2009 partially offset by decreased capital expenditures associated with the Company s drilling activities in 2009 as compared to 2008.

Financing Activities. During the six months ended June 30, 2009, net cash provided by financing activities was $196.3 million as compared to $19.0 million for the same period in 2008. The increase in cash provided by net financing activities is primarily attributable to increased net borrowings of $194.0 million during the six months ended June 30, 2009 as compared to net borrowings of $10.0 million during the same period in 2008.

Recent Disruption in the Credit Markets. We are experiencing unprecedented disruption in the U.S. and international credit markets. These disruptions have resulted in greater volatility, less liquidity, widening of credit spreads and more limited availability of financing. While we believe our cash on hand and availability under our credit facility will be sufficient to finance our capital expenditures and operations over the next twelve months, continued, long-term disruption in the credit markets could make financing more expensive or unavailable, which could have a material adverse effect on our operations.

OFF BALANCE SHEET ARRANGEMENTS

The Company did not have any off-balance sheet arrangements as of June 30, 2009.

CAUTIONARY STATEMENT PURSUANT TO SAFE HARBOR PROVISION OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995

This report contains or incorporates by reference forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, Section 21E of the Securities Exchange Act of 1934 and the Private Securities Litigation Reform Act of 1995. All statements other than statements of historical facts included in this document, including without limitation, statements in Management s Discussion and Analysis of Financial Condition and Results of Operations regarding our financial position, estimated quantities and net present values of reserves, business strategy, plans and objectives of the Company s management for future operations, covenant compliance and those statements preceded by, followed by or that otherwise include the words believe , expects , anticipates , intends , estimates , projects , target , goal , plans , objective , should , or similar expressions or variations on such expre forward-looking statements. The Company can give no assurances that the assumptions upon which such forward-looking statements are based will prove to be correct nor can the Company assure adequate funding will be available to execute the Company s planned future capital program.

Other risks and uncertainties include, but are not limited to, fluctuations in the price the Company receives for oil and gas production, reductions in the quantity of oil and gas sold due to increased industry-wide demand and/or curtailments in production from specific properties due to mechanical, marketing or other problems, operating and capital expenditures that are either significantly higher or lower than anticipated because the actual cost of identified projects varied from original estimates and/or from the number of exploration and development opportunities being greater or fewer than currently anticipated and increased financing costs due to a significant increase in interest rates. We are also subject to risks associated with the current unprecedented volatility in the financial markets, including the duration of the crisis and effectiveness of government solutions. See the Company s annual report on Form 10-K for the year ended December 31, 2008 for additional risks related to the Company s business.

ITEM 3 *QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK*

The Company s major market risk exposure is in the pricing applicable to its natural gas and oil production. Realized pricing is currently driven primarily by the prevailing price for the Company s Wyoming natural gas production. Historically, prices received for natural gas production have been volatile and unpredictable. Pricing volatility is expected to continue. Realized natural gas prices are derived from the financial statements which include the effects of realized gains and losses on commodity derivatives.

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The Company relies on derivative instruments to manage its exposure to commodity price risk and to provide a level of certainty in the Company s forward cash flows supporting the Company s capital investment program. The Company enters into fixed price to index price swap agreements in order to mitigate its commodity price exposure on a portion of its natural gas production. The natural gas reference prices of these commodity derivative contracts are typically referenced to natural gas index prices as published by independent third parties such as Inside FERC Gas Market Report. The Company also utilizes fixed price forward gas sales to manage its commodity price exposure. These fixed price forward gas sales are considered normal sales in the ordinary course of business and outside the scope of SFAS No. 133.

Under SFAS No. 133, all derivative instruments are recorded on the balance sheet at fair value. Changes in the derivative s fair value are recognized currently in earnings unless specific hedge accounting criteria are met. For qualifying cash flow hedges, the unrealized gain or loss on the derivative is deferred in accumulated other comprehensive income (loss) to the extent the hedge is effective. Gains and losses on hedging instruments included in accumulated other comprehensive income (loss) are reclassified to oil and natural gas sales revenue in the period that the related production is delivered. Derivative contracts that do not qualify for hedge accounting treatment are recorded as derivative assets and liabilities at market value in the Consolidated Balance Sheets, and the associated unrealized gains and losses are recorded as current expense or income in the Consolidated Statements of Operations. Unrealized gains or losses on commodity derivatives represents the non-cash change in the fair value of these derivative instruments and does not impact operating cash flows on the Consolidated Statements of Cash Flows.

Effective November 3, 2008, the Company changed its method of accounting for natural gas commodity derivatives to reflect unrealized gains and losses on commodity derivative contracts in the income statement rather than on the balance sheet. The net gain or loss in accumulated other comprehensive income at November 3, 2008 will remain on the balance sheet and the respective month s gains or losses will continue to be reclassified from accumulated other comprehensive income to earnings as the counterparty settlements affect earnings (January through December 2009). It is still considered probable that the original forecasted transactions will occur; therefore, the net gain or loss in accumulated other comprehensive income shall not be immediately reclassified into earnings. As a result of the de-designation on November 3, 2008, the company no longer has any derivative instruments which qualify for cash flow hedge accounting.

During the first quarter of 2009, the Company converted its physical, fixed price, forward natural gas sales to physical, indexed natural gas sales combined with financial swaps whereby the Company receives the fixed price and pays the variable price. This change provides operational flexibility to curtail gas production in the event of continued declines in natural gas prices. The contracts were converted at no cost to the Company and the conversion of these contracts to derivative instruments was effective upon entering into these transactions in March 2009, with upcoming settlements for production months from April 2009 through December 2010.

At June 30, 2009, the Company had the following open commodity derivative contracts to manage price risk on a portion of its natural gas production whereby the Company receives the fixed price and pays the variable price. See Note 7 for the detail of the asset and liability values of the following derivatives.

Type	**Point of Sale**	**Remaining Contract Period**	**Volume-MMBTU/Day**	**Average Price/MMBTU**	**Fair Value June 30, 2009**
Swap	Mid Continent	July 2009 October 2009	130,000	$ 4.99	$ 26,519
Swap	NW Rockies	July 2009 October 2009	130,000	$ 5.85	$ 48,166
Swap	NW Rockies	November 2009	50,000	$ 3.53	$ (220)

Swap	NW Rockies	July 2009	December 2009	100,000	$	5.65	$	43,272
Swap	NW Rockies	April 2010	October 2010	50,000	$	5.05	$	1,499
Swap	NW Rockies	January 2010	December 2010	50,000	$	4.99	$	(2,432)
Swap	NW Rockies	January 2010	December 2011	160,000	$	5.00	$	(60,436)
Swap	Northeast	January 2010	December 2011	30,000	$	6.38	$	(4,532)

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The following table summarizes the pre-tax realized and unrealized gains and losses the Company recognized related to its natural gas derivative instruments in the Consolidated Statements of Operations for the three and six months ended June 30, 2009 and 2008 (refer to Note 1(o) for details of unrealized gains or losses included in accumulated other comprehensive income in the Consolidated Balance Sheets):

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
Natural Gas Commodity Derivatives:	**2009**	**2008**	**2009**	**2008**
Realized gain (loss) on derivatives(1)	$ 99,205	$ (14,119)	$ 119,561	$ (14,119)
Unrealized gain (loss) on commodity derivatives(1)	$ (159,903)	$ 2,523	$ 26,169	$ (25,150)
Total gain (loss) on commodity derivatives	$ (60,698)	$ (11,596)	$ 145,730	$ (39,269)

(1) Included in gain (loss) on commodity derivatives in the Consolidated Statements of Operations.

ITEM 4 *CONTROLS AND PROCEDURES*

(a) Evaluation of Disclosure Controls and Procedures

We have performed an evaluation under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of our disclosure controls and procedures, as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934 (the Exchange Act). Our disclosure controls and procedures are the controls and other procedures that we have designed to ensure that we record, process, accumulate and communicate information to our management, including our Chief Executive Officer and Chief Financial Officer, to allow timely decisions regarding required disclosures and submissions within the time periods specified in the SEC s rules and forms. All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those determined to be effective can provide only a reasonable assurance with respect to financial statement preparation and presentation. Based on the evaluation, our management, including our Chief Executive Officer and Chief Financial Officer, concluded that our disclosure controls and procedures were effective as of June 30, 2009. There were no changes in our internal control over financial reporting during the six months ended June 30, 2009 that have materially affected or are reasonably likely to affect, our internal control over financial reporting.

PART II OTHER INFORMATION

ITEM 1. *LEGAL PROCEEDINGS*

The Company is currently involved in various routine disputes and allegations incidental to its business operations. While it is not possible to determine the ultimate disposition of these matters, the Company believes that the resolution of all such pending or threatened litigation is not likely to have a material adverse effect on the Company s financial position, or results of operations.

ITEM 1A. *RISK FACTORS*

There have been no material changes with respect to the risk factors disclosed in our Annual Report on Form 10-K for the fiscal year ended December 31, 2008.

ITEM 2. ***CHANGES IN SECURITIES AND USE OF PROCEEDS***

None.

ITEM 3. ***DEFAULTS IN SENIOR SECURITIES***

None.

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

The Company held its annual meeting on May 21, 2009. At the annual meeting, the entire board of directors of the Company was elected. The votes cast for each of the directors proposed by the Company s definitive proxy statement on Schedule 14A was as follows:

Michael D. Watford	124,094,305 voted in favor, zero voted against, and 3,033,838 withheld.
W. Charles Helton	124,789,073 voted in favor, zero voted against, and 2,339,070 withheld.
Stephen J. McDaniel	124,427,061 voted in favor, zero voted against, and 2,701,082 withheld.
Roger A. Brown	124,313,512 voted in favor, zero voted against, and 2,814,631 withheld.
Robert E. Rigney	124,378,991 voted in favor, zero voted against, and 2,749,152 withheld.

The shareholders of the Company approved the appointment of Ernst & Young, LLP as the Company s independent auditors for 2009. There were 126,780,925 votes in favor of approval of the appointment of Ernst & Young, LLP as the Company s auditors, zero votes against and 354,168 votes withheld.

In accordance with the rules of the SEC and Yukon law, a representative of the shareholder proponent must be in attendance to present the proposal. Such representative was not in attendance when the proposal was presented.

A total of 127,135,094 shares were voted by 210 shareholders, representing 84% of the Company s outstanding shares.

ITEM 5. *OTHER INFORMATION*

None.

ITEM 6. *EXHIBITS AND REPORTS ON FORM 8-K -*

(a) Exhibits

3.1	Articles of Incorporation of Ultra Petroleum Corp. (incorporated by reference to Exhibit 3.1 of the Company s Quarterly Report on Form 10Q for the period ended June 30, 2001.)
3.2	By-Laws of Ultra Petroleum Corp-(incorporated by reference to Exhibit 3.2 of the Company s Quarterly Report on Form 10Q for the period ended June 30, 2001.)
3.3	Articles of Amendment to Articles of Incorporation of Ultra Petroleum Corp. (incorporated by reference to Exhibit 3.3 of the Company s Report on Form 10-K/A for the period ended December 31, 2005.)
4.1	Specimen Common Share Certificate (incorporated by reference to Exhibit 4.1 of the Company s Quarterly Report on Form 10Q for the period ended June 30, 2001.)
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 of Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
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101.SCH**	XBRL Taxonomy Extension Schema Document.
101.CAL**	XBRL Taxonomy Calculation Linkbase Document.
101.LAB**	XBRL Label Linkbase Document.

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101.PRE**	XBRL Presentation Linkbase Document.
101.DEF**	XBRL Taxonomy Extension Definition.

* Filed or furnished herewith.

** The documents formatted in XBRL (Extensible Business Reporting Language) and attached as Exhibit 101 to this report are deemed not filed or part of a registration statement or prospectus for purposes of sections 11 or 12 of the Securities Act, are deemed not filed for purposes of section 18 of the Exchange Act, and otherwise, not subject to liability under these sections.

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SIGNATURES

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

ULTRA PETROLEUM CORP.

By: /s/ Michael D. Watford

Name: Michael D. Watford

Title: Chairman, President and

Chief Executive Officer

Date: August 4, 2009

By: /s/ Marshall D. Smith

Name: Marshall D. Smith

Title: Chief Financial Officer

Date: August 4, 2009

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EXHIBIT INDEX

3.1	Articles of Incorporation of Ultra Petroleum Corp. (incorporated by reference to Exhibit 3.1 of the Company s Quarterly Report on Form 10Q for the period ended June 30, 2001.)
3.2	By-Laws of Ultra Petroleum Corp-(incorporated by reference to Exhibit 3.2 of the Company s Quarterly Report on Form 10Q for the period ended June 30, 2001.)
3.3	Articles of Amendment to Articles of Incorporation of Ultra Petroleum Corp. (incorporated by reference to Exhibit 3.3 of the Company s Report on Form 10-K/A for the period ended December 31, 2005.)
4.1	Specimen Common Share Certificate (incorporated by reference to Exhibit 4.1 of the Company s Quarterly Report on Form 10Q for the period ended June 30, 2001.)
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